Department of Energy
Washington, DC 20585

Order No. 202-26-22

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, Michigan. In 2021, Consumers announced that it planned to implement a "speed closure" of the Campbell Plant fifteen years before the end of its scheduled design life.[3] Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant's retirement and discontinue its operations on May 31, 2025.

Order Nos. 202-25-3, 202-25-7, and 202-25-9 issued pursuant to FPA section 202(c), each required that the Campbell Plant remain in operation for 90 days, until August 21, 2025, November 19, 2025, and February 17, 2026, respectively. Subsequently, Order No. 202-26-16, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, through May 18, 2026. Those orders were based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO).

Specifically, I determined that MISO likely faced tight reserve margins due to well-documented year-round resource adequacy concerns, particularly during periods of high demand or low generation resource output.[4] I determined that the continued operation of the Campbell Plant would provide additional generation capacity during

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] *See* Consumers Energy, *Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation* (June 23, 2021), https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation.

[4] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc., and Consumers Energy Co.*, Order No. 202-25-9, at 1 (Nov. 18, 2025), https://www.energy.gov/sites/default/files/2025-11/Order%20No%20202-25-9.pdf.

these periods, which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety.[5] I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability.[6] My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC stated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[7] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply shortfalls. NERC anticipated that the near -term period of greatest capacity shortfall for MISO would likely occur in August.[8]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[9] Additionally, EIA stated, "Michigan's nuclear power plants typically supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[10] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. The Palisades plant remains unavailable, although the plant will reportedly resume service in 2026.[11]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024.

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[5] *Id.* at 5; *see also id.* at 1, 8.

[6] *Id.* at 1.

[7] NERC, *2025 Summer Reliability Assessment*, at 16 (May 2025), https://www.nerc.com/globalassets/programs/rapa/ra/nerc_sra_2025.pdf.

[8] *Id*.

[9] EIA, *Mich. State Profile & Energy Estimates* (Nov. 19, 2025), https://www.eia.gov/states/MI/analysis.

[10] *Id*.

[11] *See* Dustin Dwyer, *Palisades nuclear plant restart plans pushed back to "early 2026,"* MICH. PUB. (Dec. 17, 2025), https://www.michiganpublic.org/environment-climate-change/2025-12-17/palisades-nuclear-plant-restart-plans-pushed-back-to-early-2026; Will Wade, *Despite $80-billion commitment, nuclear plants face decadelong timeline to meet AI energy needs*, L.A. TIMES (Nov. 13, 2025), https://www.latimes.com/business/story/2025-11-13/despite-80-billion-commitment-nuclear-plants-face-decade-long-timeline-to-meet-ai-energy-needs.

Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts, and Consumers acquired a 1,200 MW natural gas power plant in Covert, Michigan, NERC has noted "[e]scalating demand forecasts and uncertainty around new resource commercialization timing contribute to heightened resource adequacy concerns in the MISO area."[12]

Fourth, MISO's Planning Resource Auction Results for the 2025–2026 Planning Year, released in April 2025, noted that for the northern and central zones, which include Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[13] While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance."[14] According to MISO, these results "reinforce the need to increase capacity."[15]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-3, 202-25-7, 202-25-9, and 202-26-16 continue, both in the near and long term.[16] The production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO. According to the EIA-923 Power Plant Operations Report's monthly generation data for February 2026, the total net generation for the

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[12] NERC, *2025 Long-Term Reliability Assessment*, at 15 (Jan. 2026) (2025 NERC Long-Term Reliability Assessment), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[13] MISO, *Planning Resource Auction—Results for Planning Year 2025–2026*, at 13 (May 29, 2025) (MISO 2025–2026 Planning Resource Auction), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

[14] *Id.* at 12.

[15] *Id*. at 2. *See Midcontinent Indep. Sys. Operator, Inc. & Consumers Energy Co.*, Order No. 202-25-7 (Aug. 20, 2025) (determining that emergency conditions existed), https://www.energy.gov/sites/default/files/2025-08/MISO%20Order%20No.%20202-25-7.pdf.

[16] Further, as noted in Order No. 202-25-7, as a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. If Consumers were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Order No. 202-25-7 at 1 n.1.

Campbell Plant was 394,703 MWh and from June 2025 through December 2025 the plant generated an average of approximately 520,670 MWh per month.[17] The historic data of consistent generation indicates the Campbell plant is providing vital generation capacity to the region. From June 11, 2025, through November 5, 2025, MISO issued dozens of alerts to manage grid reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits.[18]

MISO's resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when it operated under a cold weather alert and declared conservative operations from January 23 through February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 "MaxGen" event for MISO's North and Central Regions due to generational outages, high demand, and transfer capability limits.[19]

MISO's year-round resource adequacy concerns are well documented. In 2021, MISO requested that the Federal Energy Regulatory Commission (FERC) approve its revised resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[20] MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round concern."[21] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[22]

In December 2023, MISO released its *Attributes Roadmap*, in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a

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[17] *See* EIA, Form EIA-923 detailed data with previous form data (EIA-906/920), February 2026 Data (Mar. 2026), https://www.eia.gov/electricity/data/eia923/. On the "Page 1 Generation and Fuel Data" tab, Plant Name filtered for J H Campbell, Rows 533–535.

[18] MISO *Operations Report* (Sept. 16, 2025) cdn.misoenergy.org/20250916%20Markets%20Committee%20of%20the%20BOD%20Item%2005%20MISO%20Operations%20Report717458.pdf

[19] Midcontinent ISO, @MISO_energy, X (Jan. 24, 2026, 9:39 AM), https://x.com/MISO_energy/status/2015072060876140805.

[20] *Midcontinent Indep. Sys. Operator, Inc.*, Transmittal Letter, Docket No. ER22-495-000 (filed Nov. 30, 2021). FERC accepted MISO's proposed tariff revisions on August 31, 2022. *Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141 (2022), *order on reh'g & compliance*, 182 FERC ¶ 61,096 (2023).

[21] MISO Transmittal Letter at 3.

[22] *Id.* at 3–4.

rapidly transforming energy landscape."[23] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023–2024 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons.[24] MISO also projected that the risk of loss of load in the winter and spring seasons will nevertheless increase over time, although not as high as in the summer or fall.[25]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, *MISO's Response to the Reliability Imperative*.[26] In a section of that report labeled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[27]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

In its 2025 Long-Term Reliability Assessment, NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,[28] stating that it faces significant reliability challenges as "projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements."[29] This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.[30] Moreover, the 2025 NERC Long-Term Reliability Assessment notes that "MISO's accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and

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[23] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

[24] *Id.* at 11.

[25] *Id.*

[26] MISO, *MISO's Response to the Reliability Imperative* (updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.

[27] *Id.* at 12.

[28] 2025 NERC Long-Term Reliability Assessment at 6.

[29] *Id.* at 8.

[30] *Id.* at 43.

retirements."[31] The report observes that winter peak periods are a particular concern, with projections showing "shortfalls in planned resources for winter peak periods."[32] However, NERC also concluded that "risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high."[33]

While the 2025–2026 NERC Winter Reliability Assessment found the MISO region to be at normal risk in 2026 and elevated risk in 2027, two earlier winter studies were more critical. The 2023–2024 NERC Winter Reliability Assessment characterized MISO as a region at elevated risk with the "[p]otential for insufficient operating reserves in above-normal conditions."[34] These findings were echoed in NERC's 2024–2025 Winter Reliability Assessment, which noted that "[g]enerating capacity is 10 GW lower (-6.8%) compared to the prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity."[35]

The evidence indicates that there is also a potential longer-term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025–2026 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Michigan.[36]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[37] The 2025 OMS-MISO Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[38] The 2025 OMS-MISO Survey also projected that there would be insufficient capacity to meet the peak demand for

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[31] *Id.* at 15.

[32] *Id*.

[33] *Id*.

[34] NERC, *2023–2024 Winter Reliability Assessment*, at 5 (Nov. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.

[35] NERC, *2024–2025 Winter Reliability Assessment*, at 15 (Nov. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.

[36] MISO 2025–2026 Planning Resource Auction at 13.

[37] OMS & MISO, *OMS-MISO Survey Results* (updated June 6, 2025) (2025 OMS-MISO Survey), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[38] *Id.* at 2.

electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[39] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[40]

The primary reasons for these projected deficits also are shown on the 2025 OMS-MISO Survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[41] Although the 2025 OMS-MISO Survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[42]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[43] MISO's ERAS should help expedite the construction of needed new capacity; however, resources studied under the ERAS will have commercial operation dates that are at least three years away and are provided an additional three-year grace period to commence commercial operations.[44] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[45] Consequently, the

[39] *Id.* at 7.

[40] *Id.* at 9.

[41] *Id.* at 7, 9.

[42] *Id*.

[43] *Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064 (2025), https://cdn.misoenergy.org/2025-07-21_192%20FERC%20%C2%B6%2061,064_Docket%20No.%20ER25-2454-000709770.pdf.

[44] *Id.* P 84.

[45] *See generally* S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025), https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply. ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts.").

new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order Nos. 202-25-3, 202-25-7, 202-25-9, and 202-26-16 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[46] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[47] In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[48]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[49] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[50] In addition, as just one example, Consumers

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[46] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[47] *Id*.

[48] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

[49] U.S. Dep't of Energy, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[50] Ekku Jokinen, *Top 21 A.I. Cos. in Mich.* (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[51]

Grid operators—including MISO itself—have also acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[52] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[53] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[54]

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy . . . or other causes," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in his judgment will best meet the emergency and serve the public

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[51] *See* Data Center Dynamics, *Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center* (Aug. 5, 2025) (quoting Consumers CEO Garrick Rochow), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-to-provide-1gw-of-power-to-new-hyperscale-data-center/.

[52] *Keeping the Lights On: Examining the State of Regional Grid Reliability; Hearing Before the House Committee on Energy and Commerce, Subcommittee on Energy*, 119th Cong. 5 (2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-CurranJ-20250325.pdf.

[53] *Id.* at 6

[54] *Id.* at 7.

interest."[55] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

As described above, the emergency conditions resulting from the combination of increasing demand for electricity and the capacity shortfall stemming from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-3, 202-25-7, 202-25-9, and 202-26-16, will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the increased demand for electricity and mitigate the observed shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes, thus serving the public interest pursuant to FPA section 202(c).

To ensure that the Campbell Plant will be available if needed to address emergency conditions, it shall remain in operation through August 16, 2026.[56]

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

A. From May 19, 2026, MISO and Consumers shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize costs to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

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

[56] 16 U.S.C. § 824a(c)(4).

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

D. By June 2, 2026, MISO is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time.

E. Consumers is directed to file with FERC tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

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

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

H. This Order shall be effective on May 19, 2026, through August 16, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 19th day of May 2026.

Chris Wright

Chris Wright
Secretary of Energy
cc:

FERC Commissioners

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

Michigan Public Service Commissioners

Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

UNITED STATES DEPARTMENT OF ENERGY

Midcontinent Independent System Operator	Order No. 202-25-3

MOTION TO INTERVENE AND PETITION FOR REHEARING OF THE STATES OF MINNESOTA AND ILLINOIS

Pursuant to section 202 (c) of the Federal Power Act, 16 U.S.C. §§ 824a(c), 825l, the States of Minnesota and Illinois ("the States") move to intervene and petition for rehearing of the Department of Energy's ("DOE") May 23, 2025, Order No. 202-25-3 ("Order," Exhibit 1) directing the Midcontinent Independent System Operator ("MISO") to ensure that the coal-burning J.H. Campbell Plant ("Campbell Plant") in West Olive, Michigan, operated by Consumers Energy, remains available to operate through August 20, 2025, expiring at 00:00h on August 21, 2025.

Pursuant to the Federal Power Act ("the Act") and Department procedures applying it to petitions for rehearing, the States hereby file this timely request for rehearing of DOE's Order. The Order proceeds from a faulty conclusion that an emergency exists for the MISO Regional Transmission Organization ("RTO")—specifically for the summer months of 2025. This Order exceeds DOE's legal authority in several respects. And even if an emergency did exist and DOE had the legal authority to issue an Order, this Order is not rationally related to meet the purported need. It should be rescinded.

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E. The Order exceeds DOE's authority because Section 201(b)(1) reserves decisions about plant retirements to the states. 27

F. The Order impermissibly calls for state governments to assist in its execution. 31

G. The Order is unreasoned, arbitrary, and capricious because the actions it mandates will not meet the purported emergency. 32

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MOTION TO INTERVENE

The States[1] move to intervene in this proceeding and thereby to become a party for purposes of Section 313l of the Act, 16 U.S.C. § 825l. The States have an interest in and are aggrieved by the Order in several ways and seek to intervene and petition for rehearing. *FDR v. R.J. Reynolds Vapor Co.*, 606 U. S. ___ (2025) (slip op., at 3–8) (defining an "adversely affected or aggrieved" party within the APA and without as "anyone even 'arguably within the zone of interests to be protected or regulated by the statute . . . in question.'" (quoting *Association of Data Processing Service Organizations, Inc. v. Camp*, 397 U. S. 150, 153 (1970))).

Factual Background

The utilities in the States are members of MISO, the electric grid operator for the central United States. MISO covers the largest geographical range of any independent system operator ("ISO") in the U.S. The 15 states covered by MISO are: Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin. As the ISO of the electric grid in this region, MISO manages the flow of electricity across the high-voltage, long-distance power lines. To do so, MISO develops rules so that the wholesale electricity transmission system operates reliably and safely. MISO has described this as being like the "air traffic controller" for the grid in its territory[2], meaning that MISO seeks to resolve power congestion (traffic) issues in real-time through its control room and has processes in place to anticipate and avoid emergencies that could lead to the loss of power.

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[1] *See* Minn. Stat. § 8.01 ("The attorney general shall appear for the state in all causes in the supreme and federal courts wherein the state is directly interested; also in all civil causes of like nature in all other courts of the state whenever, in the attorney general's opinion, the interests of the state require it.).

[2] "Meet MISO," https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/what-we-do/ (last visited June 23, 2025).

On May 23, 2025, the DOE issued an emergency order pursuant to section 202(c) of the Federal Power Act to MISO. *See* Ex. 1; *see also* 16 U.S.C. § 824(c)(1). The Order directs MISO, in coordination with Consumers Energy, the owner of the plant, to ensure that the Campbell Plant in West Olive, Michigan remains available for operation. *Id.* Consumers Energy announced its plan to retire the coal facility in 2021, and MISO approved that plan three years ago, in March 2022.[3]

Adverse Effects

The States will be adversely affected by the emergency order preventing the planned retirement of the Campbell Plant in two primary ways.

First, households and businesses in the States, and the States as consumers in their own right, all will pay higher electricity bills as a result of the Order's imposition of costs and cost-recovery to the States. By ordering the Campbell Plant to take all steps necessary to be available and ordering MISO to take all steps necessary for the Campbell Plant to provide economic dispatch, costs are already being incurred and more costs will continue to be generated. Notably, the age of the units is concerning for costs, and Consumers Energy projected in 2021 that retiring Campbell in 2025 would avoid $365,008,000 in capital expenditures and major maintenance costs.[4] The Order would likely require at least a portion of capital expenditures and major maintenance costs that were not completed in the last four years, which will potentially drive up

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[3] *See* Consumers Energy, "2021 Clean Energy Plan," https://www.consumersenergy.com/-/media/CE/Documents/company/IRP-2021.pdf (last accessed June 23, 2025).

[4] *In the matter of the application of Consumers Energy Company for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief*, MPSC Case No. U-21090, Revised Direct Testimony of Norman J. Kapala on Behalf of Consumers Energy Company at 3 (Oct. 2021).

costs and impact ratepayer bills. This would be in addition to the cost of rehiring operators and obtaining more coal, among other expenses.

Although the precise amount is not yet known, the Order provides that cost recovery is available to Consumers Energy through Federal Energy Regulatory Commission ("FERC") proceedings, which Consumers Energy has already initiated. Consumers Energy filed a petition FERC[5] asking for a process to allocate costs (net of market revenues) across all of MISO Zones 1 through 7 (which includes Minnesota and Illinois). They ask that costs be apportioned according to load, which would assign costs to the States. MISO has already filed its answer indicating its general support for adjusting its tariff to account for Consumers Energy's cost recovery petition, meaning the costs would be charged to the States according to their respective share of load.

Second, the States will suffer environmental harms as a result of the Order. The Campbell Plant is a significant source of particulate matter, nitrogen oxides, sulfur oxides, and carbon dioxide,[6] among other pollutants. By prolonging the operations of the Campbell Plant beyond its planned retirement date, the Order will increase the amount of pollution emitted in the state of Michigan and other MISO States, causing harm to the public health and welfare.[7] Coal-fired power plants also contribute to regional, national, and global greenhouse gas emissions, which cause global climate change. Climate change directly harms the States, imposes significant additional costs on them for responsive actions and resiliency programs, and threatens state climate goals and comply with federal and state air pollution requirements.

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[5] FERC Docket: EL25-90.

[6] *See In the Matter of the Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to Mcl 460.6t & for Other Relief.*, No. U-21090, 2022 WL 2915368, at *73 (June 23, 2022).

[7] *See* Cross-State Air Pollution Rule (CSAPR) and Clean Air Act § 110.

Minnesota, for example, is experiencing rapid changes including higher winter temperatures and larger, more frequent extreme precipitation events, extreme heat, and drought.[8] Each of Minnesota's top-ten combined warmest and wettest years on record have occurred since 1998, with 2024 standing as the warmest year on record and 2019 the wettest.[9] Minnesota is already suffering from a significant uptick in devastating, large-area extreme rain events, threatening the state with ever greater frequency and intensity.[10] These events damage streets, wastewater facilities, businesses, homes, farms, and natural resources, costing local governments, business owners, and residents millions of dollars in cleanup, repairs, and adaptation expenses.[11] Wildfires are also becoming larger and more frequent, including a rash of devastating fires in the spring of 2025 that consumed more than 32,000 acres and destroyed an estimated 150 structures. The spring of 2024 included heavy precipitation and extreme rainfall events, leading to extensive flooding and federal declarations for large parts of the state.[12] From 1980 to 2024, the annual average for billion-dollar weather and climate disasters in Minnesota is 1.4 events per year, but the annual average from 2020 to 2024 is 4.6 events.[13] The "Lost Winter" of 2023-2024 was the

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[8] Minnesota Climate Trends, *Minnesota Department of Natural Resources* (2023), https://www.dnr.state.mn.us/climate/climate_change_info/climate-trends.html.
[9] *Id*.
[10] *Id*.
[11] *Id*.
[12] "Extreme Rainfall Drenches Northeastern Minnesota," Minnesota Department of Natural Resources, https://www.dnr.state.mn.us/climate/journal/extreme-rainfall-northeast-mn-june-18-2024; "Extreme Rain and Flooding in Southern Minnesota, June 20-22," Minnesota Department of Natural Resources, (August 9, 2024), https://www.dnr.state.mn.us/climate/journal/extreme-rain-flooding-southern-minnesota-june-20-22.html; "Disaster information," Minnesota Department of Public Safety, https://dps.mn.gov/divisions/hsem/em-resources/disaster-information (last visited June 23, 2025).
[13] "Billion Dollar Weather and Climate Disasters, Minnesota Summary, *NOAA National Centers for Environmental Information*, Billion-Dollar Weather and Climate Disasters | Minnesota Summary | National Centers for Environmental Information (NCEI)," https://www.ncei.noaa.gov/access/billions/state-summary/MN.

warmest on record, with temperatures averaging 10.9°F above 1991-2020 averages, greatly harming Minnesota's recreational economy.[14] These impacts will continue, and emissions from the Campbell Plant will contribute to them.

Climate change is affecting Illinois in a number of ways. Illinois' farming industry is vulnerable to cycles of extreme drought and extreme precipitation caused by climate change. In 2023, a severe drought dried up soil throughout the state, with extreme dryness extending down to 20 inches below the surface in some areas.[15] In other years, extreme precipitation has threatened Illinois' agriculture. For instance, January to June of 2013 was the wettest period ever recorded in Illinois, causing widespread flooding in farmland that forced farmers to delay planting and lose revenue.[16] Climate change is also intensifying catastrophic extreme weather events. In 2024, the Illinois State Climatologist recorded strong wind, hail, and tornadoes across all of Illinois' 102 counties and the state logged 142 tornadoes—a new annual record.[17] These storms included a July 15, 2024 "derecho" that produced 100 mile-per-hour winds and 48 separate tornados.[18] In the

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[14] *Id*.
[15] Illinois State Climatologist, Drought Worsens in a Very Dry June (June 30, 2023), https://stateclimatologist.web.illinois.edu/2023/06/30/drought-worsens-in-a-very-dry-june/ (last visited May 23, 2025).
[16] University of Illinois–Institute of Government & Public Affairs, Preparing for Climate Change in Illinois: An Overview of Anticipated Impacts (2015), https://indigo.uic.edu/articles/report/Preparing_for_Climate_Change_in_Illinois_An_Overview_of_Anticipated_Impacts/15078939/1 (last visited May 23, 2025). See also U.S. Dept. of Agriculture Climate Hubs and Great Lakes Research Integrated Science Assessment, Climate Change Impacts on Illinois Agriculture (2022), https://www.climatehubs.usda.gov/sites/default/files/2022_ClimateChangeImpactsOnIllinoisAgriculture.pdf (last visited May 23, 2025).
[17] Tony Briscoe, Lake Michigan Water Levels Rising at Near Record Rate, CHICAGO TRIBUNE (July 12, 2015), https://www.chicagotribune.com/2015/07/12/lake-michigan-water-levels-rising-at-near-record-rate/ (last visited May 23, 2025).
[18] National Weather Service, July 15, 2024 Derecho Produces Widespread Wind Damage and Numerous Tornadoes, available at https://www.weather.gov/lot/2024_07_15_Derecho#:~:text=With%2032%20tornadoes%2C%20t

Chicago area alone, the derecho produced 32 tornados, breaking the previous records set by the July 2014 "double derecho" and March 2023 storm.

PETITION FOR REHEARING

I. Overview and Concise Statement of Error

The challenged Order declares an emergency based on a shortage of electric energy generation when there is no emergency. Even if there were an emergency, the Order imposes several requirements that are inconsistent with and exceed DOE's legal authority. And even if DOE had the authority to impose the requirements, they are not directed to actions that will actually meet the purported emergency.

The Order

The challenged Order is premised on an incomplete recitation of MISO's planned capacity and reserves for the summer of 2025. It notes that MISO "faces potential tight reserve margins during the summer 2025 period." Ex. 1 at 1 (emphasis added). It relies on the North American Electric Reliability Corporation's ("NERC") 2025 Summer Reliability Assessment. Ex. 2. That report does not identify any war, fuel shortage, or natural disaster. *Id*. Rather, it evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. Ex. 2 at 5. Here are NERC's main conclusions regarding MISO:

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he%20July,March%2031%2C%202023%20tornado%20outbreaks. (last visited May 25, 2025). See also David Struett, Tornado Record Broken with 27 Chicago Area Twisters July 15—Spawned by 'Ring of Fire', WBEZ CHICAGO, available at https://www.wbez.org/weather/2024/07/24/chicago-weather-tornado-record-derecho-july-15 (last accessed May 23, 2025)

Midcontinent Independent System Operator (MISO): MISO is expecting to have an existing certain capacity of 142,793 MW in the *2025 SRA*, which is a slight reduction from the 143,866 MW submitted for the *2024 SRA*. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity outside the MISO market opting out of the MISO planning resource auction, is contributing to less dispatchable generation in MISO. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand.

Id. at 5. NERC concluded that all areas were projected to have "adequate anticipated resources for normal summer peak load conditions." *Id.* Indeed, the "elevated risk" designation means the probabilistic indices are low but not negligible. *Id.* at 10, Table 1. And further, the MISO-specific "dashboard" concludes that MISO's expected resources meet operating reserve requirements under normal peak-demand scenarios. At worst, operating mitigations "could" be necessary for above-normal summer peak load and extreme generator outage conditions:

Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (demand response) when operating reserve shortfalls are projected.

Id. at 16.

The Order then describes how the Campbell Plant was scheduled to cease operations on May 31, 2025, and claims that the Campbell Plant's retirement would further decrease available dispatchable generation within MISO's service territory. Ex. 1 at 1. But NERC's analysis already

factored in an assumption that the Campbell Plant would be retired and unavailable for the summer of 2025.

The Campbell Plant's retirement was well known to MISO operators and accounted for in their robust resource planning processes described in further detail below. Indeed, the Order acknowledges that the retirement was already factored into MISO's own supply forecasts. *Id*. at 2. MISO's Planning Resource Auction Results for Planning Year 2025-26 ("PRA," Exhibit 3), cited in the Order, confirm adequate margin for a reliable summer season. *Id*.

Nonetheless, the Order determined than an emergency exists, and that "additional dispatch of the Campbell Plant is necessary," Ex. 1 at 2, even though the Campbell Plant was not included in any of the MISO forecasts finding sufficient capacity. It further based its determination "on the insufficiency of dispatchable capacity and anticipated demand" even though MISO had already determined that there was sufficient capacity to meet anticipated demand (Exs. 3-4) and NERC's Summer Reliability Assessment also does not conclude otherwise. Ex. 2 at *passim*. Nonetheless, the Order concludes with several imperatives:

- That Consumers Energy must take steps to ensure that the Campbell Plant is "available to operate." And that MISO "is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers" Ex. 1 ¶ A.
- That MISO is directed to provide DOE a report "concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest." Ex. 1 ¶ D.
- That "relevant government authorities" are directed to take such action and make accommodations as may be necessary to effectuate the dispatch and operation of the Campbell Plant if the MISO current tariff provisions "are inapposite." Ex. 1 ¶ E.

- That rate recovery is available pursuant to 16 U.S.C. § 824a(c) (also referred to as section 202(c) of the Federal Power Act). Ex. 1 ¶ G.
- That the Order runs through August 20, 2025. Ex. 1 ¶ H.

DOE's Order issued in error. The Department did not have substantial evidence or engage in reasoned decision-making in declaring the existence of an emergency. It starts from the proposition that there is only a "potential" for insufficient capacity that "could" result in a need for mitigation, which does not present an actual existing or imminent emergency. Plus, section 202(c)'s plain terms limit DOE to actual emergencies—not the potential that emergencies might arise. Section 202(c) is also limited in the type of conduct it allows DOE to order, such as directing the generation, delivery, or transmission of electric energy. This Order, however, requires the Campbell Plant to be available to operate. Ex. 1 ¶ A. Nothing in section 202(c) grants DOE authority to order a plant to remain on standby in case an emergency occurs—especially absent any demonstrated need identified by the utility or grid operator. And even if an emergency did exist and DOE had the legal authority to issue an Order, directing a the Campbell Plant to participate in the bidding market using economic dispatch would not rationally the purported need (because there is no evidence the Campbell Plant can reasonably address any given future emergency need, because emergency responses do not require economic evaluation, and because the Campbell Plant takes so long to ramp up). It should be rescinded.

II. Legal Background

Under section 202(c) of the Federal Power Act, the Commission[19] has authority to issue an order:

> [d]uring the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes. . . .

16 U.S.C. § 824(c)(1). The same subsection states that the Commission may order "temporary connections of facilities" and "generation, delivery, interchange, or transmission of electric energy" that, in the Commission's "judgment will best meet the emergency and serve the public interest." *Id*. The next subsection, 16 U.S.C. § 824(c)(2), establishes that an emergency order must be limited to only those hours necessary to meet the emergency. It states:

> With respect to an order issued under this subsection that may result in a conflict with a requirement of any Federal, State, or local environmental law or regulation, the Commission shall ensure that such order requires generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet

[19] The "Commission" refers to the Federal Power Commission (FPC), whose powers were transferred in 1977 to either the Secretary of DOE or the Federal Energy Regulatory Commission (FERC). 16 U.S.C. § 796(14); Department of Energy Organization Act, Pub. L. No. 95-91, 91 Stat. 565, 565-613 (1977). This transfer gave FERC the authority over "the interconnection, under section 202(b), of such Act [16 U.S.C. 824a(b)], of facilities for the generation, transmission, and sale of electric energy (*other than emergency interconnection*)." 42 U.S.C. § 7172(a)(1)(B) (emphasis added). However, this transfer also gave DOE "the function of the Federal Power Commission, or of the members, officers, or components thereof" except as provided in subchapter IV of the act. 42 U.S.C. § 7151(b). Because 42 U.S.C. § 7172(a)(1)(B) explicitly excludes emergency interconnection from FERC's authority, the authority over emergency interconnection has historically been delegated to DOE. However, the delegation of this emergency authority to DOE has not been consistently applied. In *Richmond Power & Light v. FERC*, 574 F.2d 610 (1978), a petitioner objected to FERC's (not DOE's) failure to invoke emergency powers under 16 U.S.C. § 824a(c) and order utilities with excess capacity to supply the petitioner with energy. The court did not address whether FERC had the authority to declare an emergency to begin with. *Id*. Thus, whether FERC or DOE has the power to declare an emergency is inconclusive.

> the emergency and serve the public interest, and, to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation and minimizes any adverse environmental impacts.

Id. at § 824(c)(2).

The applicable regulations define "emergency," 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*.

10 C.F.R. § 205.371[20] (emphasis added).

III. Statement of Issues

Issue A: Did DOE have substantial evidence for its declaration of an emergency, and did it exercise reasoned decision-making in declaring that an actual emergency exists?

No. DOE relied on a NERC assessment that identified an elevated risk for potential capacity exceedance if an extreme weather event were to occur**.** Further, DOE failed to consider substantial countervailing evidence, including the MISO States' Integrated Resource Plans and MISO's PRA for the summer of 2025. The Order fails to identify any reasoned basis for concluding an actual emergency exists or is imminent.

Issue B: Section 202(c)(1) allows DOE to issue temporary emergency orders in times of actual extant or impending emergencies such as war, sudden demand for electric energy, shortage of fuel or water, or other similar conditions creating a specific inadequate power supply

[20] DOE issued 10 C.F.R. §§ 205.370-379 pursuant to the Department of Energy Organization Act's transfer of emergency responsibilities to the Secretary of Energy.

situation. Did DOE exceed this authority where its Order is based on the nonspecific possibility that such a situation might occur over a period of several months?

Yes. An actual "emergency" is a sudden occurrence requiring immediate response action or a concrete need for energy to be produced; conversely, it is not the mere potential that an emergency might occur. 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371. Emergency orders must respond to "a specific inadequate power supply situation." 10 C.F.R. § 205.371. The Order does not address any sudden occurrence needing imminent response, nor does it identify any actual and specific insufficient supply situation. Thus the Order is contrary to law.

Issue C. Section 202(c)(1) allows DOE to issue emergency orders requiring the "generation, delivery, interchange, or transmission of electric energy." Did DOE exceed this authority where its Order requires the Campbell Plant to take steps to be "available" to generate electricity and requires MISO to employ economic dispatch?

Yes. DOE's emergency powers allow it to order the generation, delivery, interchange, or transmission of electric energy. Section 202(c)(1) does not give the DOE the authority to order that a plant be merely available (absent a showing of why that is needed), nor does it give the DOE authority to order MISO to engage in potential economic dispatch. 42 U.S.C. §16432(b). Because it is not confined to the types of actions allowed under section 202(c)(1), the Order is without authority and contrary to law.

Issue D. If DOE issues an order pursuant to 202(c)(1), then 202(c)(2) requires it to set limits on hours of operation and ensure that environmental impact is minimized. Did DOE exceed its authority by invoking section 202(c) to issue an Order that sets no specific hours of operation, places no limits on hours of operation, and adopts no specific requirements to minimize environmental impact?

Yes. The express statutory language requires an emergency order be limited to only those hours necessary to meet the emergency and minimize adverse environmental impacts. 16 U.S.C. § 824a(c)(2). The Order does not establish any limited hours for operation, and at the same time it allows the Campbell Plant to potentially run at any and all hours for the entire 90 days covered bye the Order. It also does not meaningfully take steps to minimize adverse environmental impacts.

Because the Order does not set any specific hours the Campbell Plant must run, allows for unlimited hours for much of the summer, and doesn't meaningfully minimize adverse environmental impacts, the Order violates the requirements of section 202(c)(2). It is without authority and contrary to law.

Issue E: The Federal Power Act reserves resource adequacy planning to the individual states. Did DOE exceed its authority where its Order directly compels a plant slated for retirement to take steps to be available to operate?

Yes. Section 201(a) of the Federal Power Act explicitly provides that federal regulation over generation and transmission is related to matters of interstate commerce and extends "only to those matters which are not subject to regulation by the States." 16 U. S. C. § 824(a). States retain jurisdiction "over facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1). Because DOE's Order exceeds its authority by contradicting Michigan's resource plans, it is contrary to law.

Issue F: The states retain primary authority for developing and establishing Integrated Resource Plans or Strategic Energy Plans that get factored into MISO's tariffs. The Order directs "relevant governmental authorities" to accommodate the Order. Does this portion of the Order violate the Tenth Amendment, exceed DOE's authority, and impose arbitrary-and-capricious requirements not based on substantial evidence?

Yes, on all fronts. This section of the Order is incomprehensible and unexplained. It violates the Tenth Amendment to the extent it directs state or local officials to carry out the Order. And Section 202(c) does not include authority to order any unit of government to take any particular action. For all of these reasons, the Order is contrary to law.

Issue G: Even if DOE were correct that an emergency exists and that it had the authority to issue the Order, will the Order's requirements rationally meet the emergency?

No. Section 202(c) contemplates emergency orders that are precisely tailored to meet the specific emergency.16 U.S.C. § 824a(c). Emergency generation is not economic dispatch. Plus, the Campbell Plant is high cost and uneconomical, it requires a long time to ramp up, and there is

no reason to think it would be used to meet any shortfall if one were to happen given other considerations such as transmission infrastructure. The Order's specific requirement for MISO to take steps to effectuate "economic dispatch" of the Campbell Plant is not rationally related to the emergency it purports to address, so the Order is without substantial evidence and lacks reasoned decision-making.

IV. Description of MISO

MISO is a regional transmission organization (RTO), an independent, non-profit, membership-based organization responsible for optimizing generation and transmission of electricity and ensuring the reliability of the electric power system within its region, consisting of nearly 3,000 generating units.[21] 18 C.F.R. § 35.34(a), (j)(1). MISO administers bulk or wholesale power markets that centrally commit and dispatch power to facilitate least-cost and reliable power production and delivery throughout the region. The wholesale markets within MISO signal and value power needs and identify the most economically efficient way—the least-cost approach where demand for energy equals the cost supplied—to meet them across the system.[22] MISO also works to coordinate generation and transmission of electricity with other RTOs, exporting power at times and at others allowing electricity to be imported to MISO.[23] MISO uses advanced

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[21] MISO, *Fact Sheet* (July 2024), available at https://www.misoenergy.org/meetmiso/media-center/2024/corporate-fact-sheet.
[22] MISO, *Electric Grid 101*, available at https://www.misoenergy.org/meet-miso/grid-operations-basics.
[23] MISO, *Interregional Coordination*, available at https://www.misoenergy.org/planning/interregional-coodination/; see also MISO, Historical Net Scheduled Interchange (NSI), at https://www.misoenergy.org/markets-and-operations/real-time--marketdata/ market-reports/ (data found under "Summary" Market Reports).

modeling and thorough research to coordinate short and long-term planning for the benefit of generating units and consumers.[24]

MISO planned for adequate capacity during the summer of 2025: "As recognized by the Order, MISO's Planning Resource Auction for the 2025-2026 Planning Year demonstrated sufficient capacity for all zones within the MISO Region." Ex. 3 at 2. It reports: "it is important to recognize existing processes have *cleared sufficient electric generating capacity across MISO for the periods of time covered by the Order*." *Id*. (emphasis added). And it goes on to describe its confidence that it has already ensured "sufficient capacity to meet anticipated demand across the MISO Region for the 2025-2026 Planning Year." *Id*.

The long-planned retirement of the Campbell Plant is not an impediment to summer reliability in the MISO region. Since 2010, MISO has experienced the retirement of 30.8 gigawatts (GW) of generation capacity, a large proportion of which (21.9 GW) was coal-fired generating units.[25] That trend is shown below in the bar graph (from MISO's 2023 Transmission Expansion Plan Report[26]), which displays the retired capacity by generation type over time:

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[24] MISO, *Transmission and Generation Planning 101*, available at https://www.misoenergy.org/meet-miso/grid_planning_basics.

[25] *See also* MISO, *Approved Generator Retirements (Public) as of June 28, 2024* ("*Approved Retirements 2024*"), https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/OASIS_Posting_of_Approved_Generator_Retirements_(Public)_2024-06-28.pdf).

[26] MISO, *2023 Transmission Expansion Plan*, available at https://cdn.misoenergy.org/MTEP23%20Executive%20Summary630586.pdf.

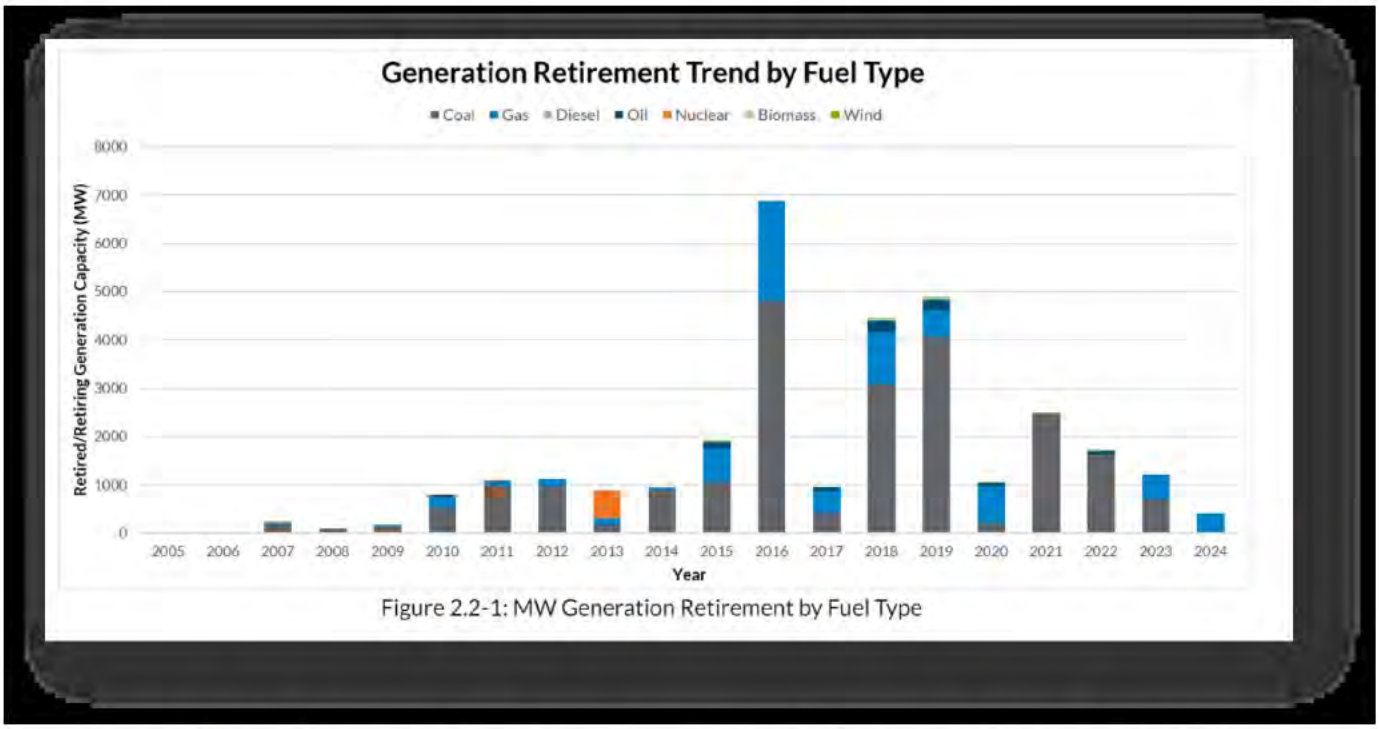


Figure 2.2-1: MW Generation Retirement by Fuel Type

Through use of generation capacity and transmission infrastructure planning, the addition of new capacity—in particular renewables, and the implementation of the other measures discussed above, MISO has been able to absorb these retirements and maintain overall system reliability. *Id*. at 34-35.

V. Argument

A. The Order lacks substantial evidence demonstrating the existence of an actual emergency and DOE failed to engage in reasoned decision-making.

The DOE failed to provide substantial evidence that an unexpected emergency presently exists, as required by 16 U.S.C. § 824a(c)(5). The relevant standard is whether the DOE's determination is supported by substantial evidence. 16 U.S.C. § 824a(c)(5) refers to the possibility of judicial review under 16 U.S.C. § 825l. After an objection has been brought before DOE, the Court may consider it with the understanding that "[t]he finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive." 16 U.S.C. § 825l. Substantial evidence means "such relevant evidence as a reasonable mind might accept as adequate to support a conclusion." *Duke*

Energy Corp. v. FERC, 892 F.3d 416, 420 (2018). This standard implies deference to an agency's factual determinations. *See, e.g., id*.

While DOE failed to provide substantial evidence of a current and unexpected emergency, the evidence DOE provided, does prove however, that there is currently no energy emergency and will not be an "unexpected emergency" that warrants this Order. MISO is well situated to deliver reliable power throughout its area in the summer of 2025.

In declaring the contrary, DOE relied on a NERC assessment that identified an elevated risk for potential capacity exceedance if an extreme weather event were to occur**.** But the Order makes too much out of too little—the "elevated" category is hardly a call for immediate and unnecessary emergency action. As the NERC assessment points out, MISO expects to have an existing certain capacity of 142,783 MW during the summer—a figure that factored in an assumption that the Campbell Plant would be retired and unavailable for the summer of 2025 and that exceeds both expected demand and the reserve margin[27] anyway. While retirements and fewer suppliers meant that MISO would have fewer firm resources and dispatchable generation, that was no cause for alarm. To the contrary, NERC concluded that all areas were projected to have "adequate anticipated resources for normal summer peak load conditions." *Id*. And nothing in the NERC assessment determined that MISO's interconnection with other RTOs would be insufficient to cover any needs that could arise.

The "elevated risk" category is not tantamount to an emergency. Even though NERC used the term "elevated risk" for the possibility that there could be an operating reserve shortfall, NERC did not apply the "high risk" category to MISO, and did not call for any retired plants to be brought

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[27] MISO PRA, Results for Planning Year 2025-26 at 18 (Corrected May 29, 2025).

back online. Ex. 2. at 5. Moreover, the "elevated risk" designation means the probabilistic indices are low but not negligible. *Id*. at 10, Table 1. And further, the MISO-specific "dashboard" concludes that MISO's expected resources meet operating reserve requirements under normal peak-demand scenarios. At worst, operating mitigations "could" be necessary for above-normal summer peak load and extreme generator outage conditions: *Id*. at 16. The "elevated risk" designation is also far from unusual; it has never required an emergency order before, and the grid has remained stable. MISO has been designated as at "elevated" risk in every NERC Summer Reliability Assessment since NERC initiated the practice of designating regions as "high," elevated," or "normal" risk in 2021.[28] NERC has also designated MISO as "elevated" risk in every Winter Reliability Assessment since 2021. *Id*. Yet no energy shortage has occurred and DOE has never imposed an emergency declaration until now.

Such a declaration is simply unnecessary when considering the bigger picture. DOE clearly erred in its consideration of the evidence, *see Wisconsin Power & Light Co. v. FERC*, 363 F.3d 453, 461 (D.C. Cir. 2004) (an appeals court "must consider . . . 'whether there has been a clear error of judgment.'"), including the contradiction in the Order's citation of MISO's PRA for the summer of 2025 which contrary to the Order actually found sufficient capacity throughout the region. The PRA provides a strong conclusion that supply will be adequate. Ex. 3. The press release announcing the PRA, (Exhibit 4), confirms "adequate resources are available to maintain reliability during the upcoming planning year (June 2025 – May 2026)." Ex. 4. And while "the 2025 auction prices reflect a tightening supply-demand balance during the summer months, there is sufficient capacity throughout the MISO footprint." *Id*. The PRA was based on NERC's standard

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[28] *See* NERC, *Reliability Assessments,* https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx (last visited June 23, 2025).

BAL-502-RF-03 (Exhibit 5), requiring assessment of "one day in ten year" loss of load expectation principles. In short, the NERC standard that MISO applied to conduct the PRA demonstrated that MISO will have sufficient capacity through the summer of 2025. Exs. 3-4. MISO's PRA results show that there will be enough capacity in the summer planning year, and MISO notes that the summer auction price provides a signal to the market to add more capacity for future auction years. DOE appears to have cherry-picked certain phrases from the PRA but does not give it full consideration.

Indeed, in MISO's Answer to the cost-recovery docket dated June 19, 2025, MISO highlights the PRA when it describes its certainty it has planned for adequate capacity: "As recognized by the Order, MISO's Planning Resource Auction for the 2025-2026 Planning Year demonstrated sufficient capacity for all zones within the MISO Region." Ex.10 at 2. It further writes, "it is important to recognize existing processes have cleared sufficient electric generating capacity across MISO for the periods of time covered by the Order." *Id*. (emphasis added). And it goes on to describe its confidence that it has already ensured "sufficient capacity to meet anticipated demand across the MISO Region for the 2025-2026 Planning Year." *Id*. This recent submission undermines DOE's conclusions in the order that MISO faces insufficient capacity.

DOE failed to consider recent comments by MISO's Independent Market Monitor to the Markets Committee of the MISO Board of Directors dispelling NERC's purported concerns. See Exhibit 11. The Independent Market Monitor is charged with ensuring adequate supply markets for the MISO region. He criticized a separate NERC long-term reliability assessment (which has

since been revised[29]) that included capacity shortfalls in 2025, noting that NERC's assessment compared the wrong numbers. In doing so, the Independent Market Monitor declared MISO capacity to be "more than adequate," and that he had "no material concerns" over MISO's resource adequacy for the upcoming summer.

DOE also failed to consider MISO's history of strong performance through several extreme weather events including Winter Storms Elliot and Uri, and did not credit MISO's proven track record of engaging in a variety of mechanisms to ensure grid reliability.

DOE further failed to acknowledge that no part of MISO is currently afflicted by any unexpected outage or extreme weather event, and the entire system is running as planned with no outages, unexpected demand, lack of fuel or water, or other such emergencies in place at the time of the order.

Given all of these countervailing considerations, DOE did not have substantial evidence supporting its emergency determination. It did not exercise reasoned decision-making in declaring that an emergency exists. Its Order is arbitrary and capricious.

B. The Order exceeds DOE's authority because it is not limited to a specific inadequate power supply situation as required by Section 202(c) and 10 C.F.R. § 205.371.

An actual "emergency" is a sudden occurrence requiring immediate responsive action; conversely, it is not the mere potential that an emergency might occur. The statute describes the temporary response needed to address a sudden event by its black-letter terms. 16 U.S.C. § 824a(c). And Department regulations define "emergency" to mean an unexpected inadequate supply of

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[29] NERC, *Statement of NERC's Long-term Reliability Assessment*, (June 17, 2025) https://www.nerc.com/news/Pages/Statement-on-NERC%E2%80%99s-2024-Long-Term-Reliability-Assessment.aspx?utm_source=substack&utm_medium=email.

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." 10 C.F.R. § 205.371. Further, emergency orders must meet "a specific inadequate power supply situation," and although emergencies with extended periods of insufficient supply could qualify, the impacted entity is supposed to firm up commitments for supply "so that a continuing emergency order is not needed." *Id*

These requirements have been demonstrated by DOE's historic use of 202(c) authority to address natural disasters and specific capacity crises. The most common reason to invoke Section 202(c) authority has been to address natural disasters like hurricanes, cold weather events, and extreme heat. *See* DOE Order Nos. 202-05-1 & -2 (Sept. 28, 2005) (Hurricane Rita); DOE Order No. 20208-1 (Sept. 14, 2008) (Hurricane Ike); DOE Order No. 202-20-1 (Aug. 27, 2020) (Hurricane Laura); DOE Order No. 202-24-1 (Oct. 9, 2024) (Hurricane Milton); DOE Order No. 202-21-1 (Feb. 14, 2021) (Winter Storm Uri); DOE Order No. 202-22-3 (Dec. 23, 2022) (Winter Storm Elliot – Texas ERCOT); DOE Order No. 202-22-4 (Dec. 24, 2022) (Winter Storm Elliot – PJM); DOE Order No. 202-20-2 (Sept. 6, 2020) (extreme heat in California); DOE Order No. 202-21-2 (responding to extreme heat, wildfires and drought in California); DOE Order Nos. 20222-1 & 2 and amendments (same). Indeed, during Winter Storm Elliot, MISO exported power to neighboring regions.[30]

[30] MISO, *Overview of Winter Storm Elliott December 23, Maximum Generation Event* (Jan. 17, 2023) ("*Winter Storm Elliott Overview*") at 7, https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf.

While DOE's emergency powers have occasionally been used to address retirements like the Campbell Plant, it has done so only when requested by the operator or local government and there was a specific need demonstrated for the units to operate due to an unexpected emergency. DOE Order No. 202-05-3 (Dec. 20, 2005) (Mirant to supply Washington D.C. when transmission lines were out of service); DOE Order No. 202-17-1 at 2 (Grand River Energy to operate Unit 1 due to lighting strike to Unit 2 and delay in construction for Unit 3); DOE Order No. 202-17-2 (need to operate Yorktown to avoid imminent risk of load-shedding).

A memorandum by the Congressional Research Service, Exhibit 12, confirms that DOE's use of Section 202(c) to order a plant to be generally available is novel. Ex.12 at 3 (Department engaging in "seemingly new interpretations of the emergency authority").

Courts have also likewise recognized Section 202(c)'s limitation to actual or imminent crises. For example, in *Richmond Power and Light v. FERC*, the D.C. Circuit noted that the statute "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply." 574 F.2d 610, 615 (D.C. Cir. 1978). And in *Otter Tail Power Co. v. Fed. Power Comm'n*., the Eighth Circuit noted that 202(c) provides authority to "react to a war or national disaster and order immediate interconnection. . . to maintain electrical service during such emergency." 429 F.2d 232, 234 (8th Cir. 1970). In *Otter Tail*, the Eighth Circuit distinguished between an emergency that is likely to occur and one that is actually occurring, concluding that a separate provision, section 202(b) [31] applies to the former, while section 202(c) applies to the latter:

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[31] Section 202(b) refers to 16 U.S.C. § 824a(b), which states "[w]henever the Commission, upon application of any State commission or of any person engaged in the transmission or sale of electric energy, and after notice to each State commission and public utility affected and after opportunity for hearing, finds such action necessary or appropriate in the public interest it may

> On its face, § 202(c) enables the Commission to react to a war or national disaster and order immediate interconnection of the facilities to maintain electrical service during such emergency. . . On the other hand, § 202(b) applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission.

Otter Tail Power Co., 429 F.2d at 234. In that case, a power company challenged the FPC's order issued under § 202(b) of a temporary connection between the power company and a small municipally owned power producer that was "dangerously close to eroding its firm power supply" due to the proximity between the generator load capacities and the peak load demand. *Id.* It claimed that because the ordered connection was temporary, the order could only be issued under section 202(c), and only in emergency conditions. *Id.* The court disagreed that section 202(c) only applies to temporary orders but agreed that a potential crisis in the foreseeable future was not an emergency, making it "just the type of situation to fit into a § 202(b) hearing rather than § 202(c)." *Id.* The caselaw is therefore clear: for DOE to have any authority under section 202(c) the emergency must be actual and not merely a broadly asserted projected risk.

DOE exceeds its authority because the Order does not address any actual emergency or sudden occurrence needing imminent response, and because it has not identified any actual and specific insufficient supply situation. Thus the Order is without authority and contrary to law.

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by order direct a public utility" if the utility would not face an undue burden. The DOE's authority is much more limited in these situations. Further, 42 U.S.C. § 7172(a)(1)(B) vests this power in FERC, not the Secretary.

C. The Order exceeds DOE's authority because it requires actions not listed in Section 202(c)(1).

DOE's power is limited to orders that require connections or the generation, delivery, interchange, or transmission of electric energy. 16 U.S.C. § 824a(c). This authority does not cover mandating general plant availability untethered to meeting any specific need, nor does it allow for potential economic dispatch (which is not an apt solution for an actual emergency anyway—more on this in Section G below). Section 202(c)(1) does not allow for preemptive measures just in case an emergency might occur, and specifically does not allow for the Department to order availability without a specific need to be available.[32] Plus, "Economic dispatch" is not equivalent to the generation of electric energy. Economic dispatch is constrained by statute to mean only the lowest-cost option under the Energy Policy Act of 2005 Section 1234(c). 42 U.S.C. §16432(b). MISO's determination of lowest-cost sources may not result in the Campbell Plant producing *any* generation whatsoever. Thus the Order is without authority and contrary to law.

D. The Order exceeds DOE's authority because it does not set any hours of operation, limit hours of operation, or minimize environmental impact as required by Section 202(c)(3).

The order must be limited to only those hours necessary to meet the emergency. 16 U.S.C. § 824a(c)(2).

The Order addresses only the potential for an emergency, but does not identify a need for the Campbell Plant to generate electricity to meet it. By the same token, the Order does not establish any limited hours or other parameters for the Campbell Plant to follow to ensure it meets

[32] Of the 19 times the DOE has issued a 202(c)(1) Order, only once, for Mirant in 2005, did it require a plant to supply as-needed additional capacity—but even then it was based on a specific application demonstrating a concrete and specific need. DOE Order No. 202-05-3 (Dec. 20, 2005). That is not the case here.

the purported emergency, only that it be available at all times. Thus the Order is without authority and contrary to law, and allows the Campbell Plant to generate electricity during times there are not even "elevated risks." Allowing a coal plant to generate electricity and pollute beyond the purported emergency needs would increase the environmental impacts that, by law, the Order must strive to minimize. 16 U.S.C. § 824a(c)(2). Thus the Order is without authority and contrary to law.

E. The Order exceeds DOE's authority because Section 201(b)(1) reserves decisions about plant retirements to the states.

Section 201(a) of the Federal Power Act explicitly provides that federal regulation over generation and transmission is related to matters of interstate commerce and extends "only to those matters which are not subject to regulation by the States." 16 U. S. C. § 824(a). Decisions over what plants should be constructed or retired is traditionally subject to state regulation. States retain jurisdiction "over facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1). "The states are thus authorized to regulate energy production . . . and facilities used for the generation of electric energy" *Coal. for Competitive Elec., Dynergy Inc. v. Zibelman*, 906 F.3d 41, 50 (2d Cir. 2018). What facilities to build, whether they remain feasible, and utility rates are areas governed by the states. *Pac. Gas & Elec. Co. v. State Energy Res. Conservation and Dev. Comm'n*, 461 U.S. 190, 205 (1983).

The energy market is governed by longstanding principles of cooperative federalism encouraged in Section 209(b) of the Federal Power Act—which explicitly declares that the Federal Energy Regulatory Commission may consult with states "regarding the relationship between rate structures, costs, accounts, charges, practices, classifications, and regulations of public utilities subject to the jurisdiction of such State commission and of the Commission.") 16 U.S. Code § 824h(b). Indeed, FERC has embraced these cooperative federalism principles and developed long-

standing consultation practices with the states, including through creation of a Joint Federal-State Task Force. Exhibit 8. And more recently, a Federal-State Current Issues Collaborative. Exhibit 9.

Section 103 of the Department of Energy Organization Act is also applicable; it mandates due consideration to state retirement plans and requires, where practicable, consultation with relevant state officials. 42 U.S.C. § 7113.

States are responsible for developing and approving power generation plans, typically through public commissions like the Public Utilities Commission[33] in Minnesota, the Public Service Commission.[34]. These bodies oversee the development of Integrated Resource Plans ("IRPs"), or Strategic Energy Assessments, which are the blueprints for how a utility plans to generate sufficient electric power to meet its expected demand. *E.g.*, Minn. Stat. § 216B.2422 (Minnesota's IRP statute). An IRP can consider and adopt plans with myriad inputs and considerations and impact overall electricity rates, the specific communities or areas where power plants are located, determinations of which power plants might be built or retired and the fuels that they will use, overall electric system reliability (like the likelihood of power outages and how quickly the lights come back on), and the environment.[35] Such processes can be rigorous and commissions will open a docket to publicly vet a proposed plan, receive comments, and make an informed decision that is in the best interest of the states and its ratepayers.[36]

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[33] Minnesota Public Utilities Commission, *Utility Planning*, https://mn.gov/puc/activities/economic-analysis/planning/ (last visited June 23, 2025).
[34] Wis. Stat. Ann. § 196.491 (West).
[35] *Id*.
[36] Minnesota Public Utilities Commission, *Electric Integrated Resource Planning (EILRP)*, https://mn.gov/puc/activities/economic-analysis/planning/irp/ (last visited June 23, 2025).

MISO, in turn, is one of the country's largest regional transmission organizations (RTOs), which were formed to develop transmission systems, trading markets, and attendant procedures.[37] MISO works collaboratively with its member states to ensure resource adequacy throughout its service area.[38] This means that it ensures there is sufficient generation capacity to meet future electricity demands, including forecasting demand growth, assessing existing generation assets, and planning for new generation resources.[39] MISO works with utilities during their development of submissions to state regulators for the IRPs that that the regulators ultimately approve. And MISO then accounts for the final IRPS in its planning and analyses forecasting the balance between load and capacity. MISO also operates a capacity auction where utilities and other load-serving entities can procure the necessary generation capacity to meet projected demand. This incentivizes the development and maintenance of adequate generation resources.[40] MISO works with utilities, local regulators, and other stakeholders to maintain resource adequacy, including through its annual Planning Resource Auction ("PRA"), which procures sufficient resources and allows market participants to buy and sell capacity via an auction. MISO determines the capacity requirements in its region for each season covering the June 1 to May 31 time period.[41]

The Campbell Plant's planned retirement is subject to precisely such state regulation and MISO integration. The plan to retire the plant received intense scrutiny over years before being approved and worked into MISO's projections—all under the auspices of state law including

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[37] FERC, *Energy Primer*, https://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf
[38] MISO, *System Planning*, https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/grid_planning_basics/ (last visited June 23, 2025).
[39] *Id*.
[40] *Id*.
[41] MISO, *Resource Adequacy*, https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc (last visited June 23, 2025).

Michigan's IRP processes, state regulatory proceedings, state judicial proceedings, and state participation in MISO. *See In re Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to Mcl 460.6t & for Other Relief.*, No. U-21090, 2022 WL 2915368, at *73 (June 23, 2022). The MPSC approved of Consumers Energy's plan to replace the capacity that the Campbell Plant would have produced with the purchase of a natural gas plant and extension of two units of natural gas peaking plants. *Id*. at *33. The Michigan Court of Appeals affirmed. *Wolverine Power Supply Coop., Inc. v Michigan Public Service Commission (In re Consumers Energy)*; No. 362294, 2023 WL 2620437 (Mich. Ct. App. March 23, 2023).

MISO also reviews planned plant retirements to ensure resource adequacy and grid reliability. Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff requires an operator to provide 26 weeks of advance notice of a planned retirement. MISO then performs a Reliability Study to determine whether the retirement will pose any concern for grid reliability. [42]

Consumers Energy submitted the Attachment Y form to MISO on December 14, 2021, providing notice that it planned to suspend generation at the Campbell Plant by June 1, 2025. MISO approved the Campbell Plant's retirement on March 11, 2022. In making its approval, MISO determined that "the suspension of Campbell Units 1, 2 & 3 would not result in violations of applicable reliability criteria."

DOE did not adequately consult with the state, much less account for or incorporate the findings of MISO in approving Consumer's Energy's Attachment Y submission. Michigan state regulators have primary jurisdiction over IRPs, siting, and cost recovery for utilities operating in

[42] If MISO does identify a threat to grid reliability if the resource retires, the MISO tariff provides a mechanism to retain that resource until the constraint can be alleviated.

their states including the Campbell Plant. *Zibelman*, 906 F.3d at 50. DOE's failure to consult violates the principles behind FERC and DOT policies to involve the states in light of the statutory reservation of state authority in federal-state regulatory balance, 16 U.S.C. § 824(b)(1). It avoids 209(b) of Federal Power Act regarding federal-state collaboration and upends FERC's historic practice of seeking to develop a robust dialogue between regulators. 16 U.S. Code § 824h(b). And it flouts Section 103 of the Department of Energy Organization Act which requires consultation with relevant state officials—consultation was absolutely "practicable" here given the lack of an imminent emergency and the Order did not give any consideration (much less due consideration) to Michigan's IRP. 42 U.S.C. § 7113.

The Order usurps the State of Michigan's primary rule in resource planning and development; it is contrary to law.

F. The Order impermissibly calls for state governments to assist in its execution.

As discussed in the previous subsection, states retain jurisdiction over facilities used for the generation of electric energy and play a key role in development of MISO's tariff provisions. The Order mandates that to "[t]he extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, *the relevant governmental authorities* are directed to take such action and make accommodations as may be necessary to do so." Order ¶ E. As applied to state and local authorities, this mandate is unlawful for several reasons.

First, the Order violates the Tenth Amendment by commandeering state and local officials to implement a federal program. *See, e.g.*, *Printz v. United States*, 521 U.S. 898, 933 (1997). While the Order is not specific as to the object or the nature of its direction to "government authorities," vagueness does not erase the constitutional infirmity; it exacerbates it. *Cf. Murphy v. NCAA*, 584

U.S. 453, 469 (2018). All the more so where the Order lacks specific limited hours for operation and environmental conditions as discussed in Section D above.

Second, the Order violates the plain terms of Section 202(c), which does not grant authority to issue any order directing any governmental authority to do anything. 16 U.S.C. § 824a(c)(1). Third, the Order does not explain why directing state officials to act (or refrain from acting) pursuant to the powers reserved to them by the Constitution would help achieve the Order's purposes, and DOE lacked substantial evidence to support such a conclusion.

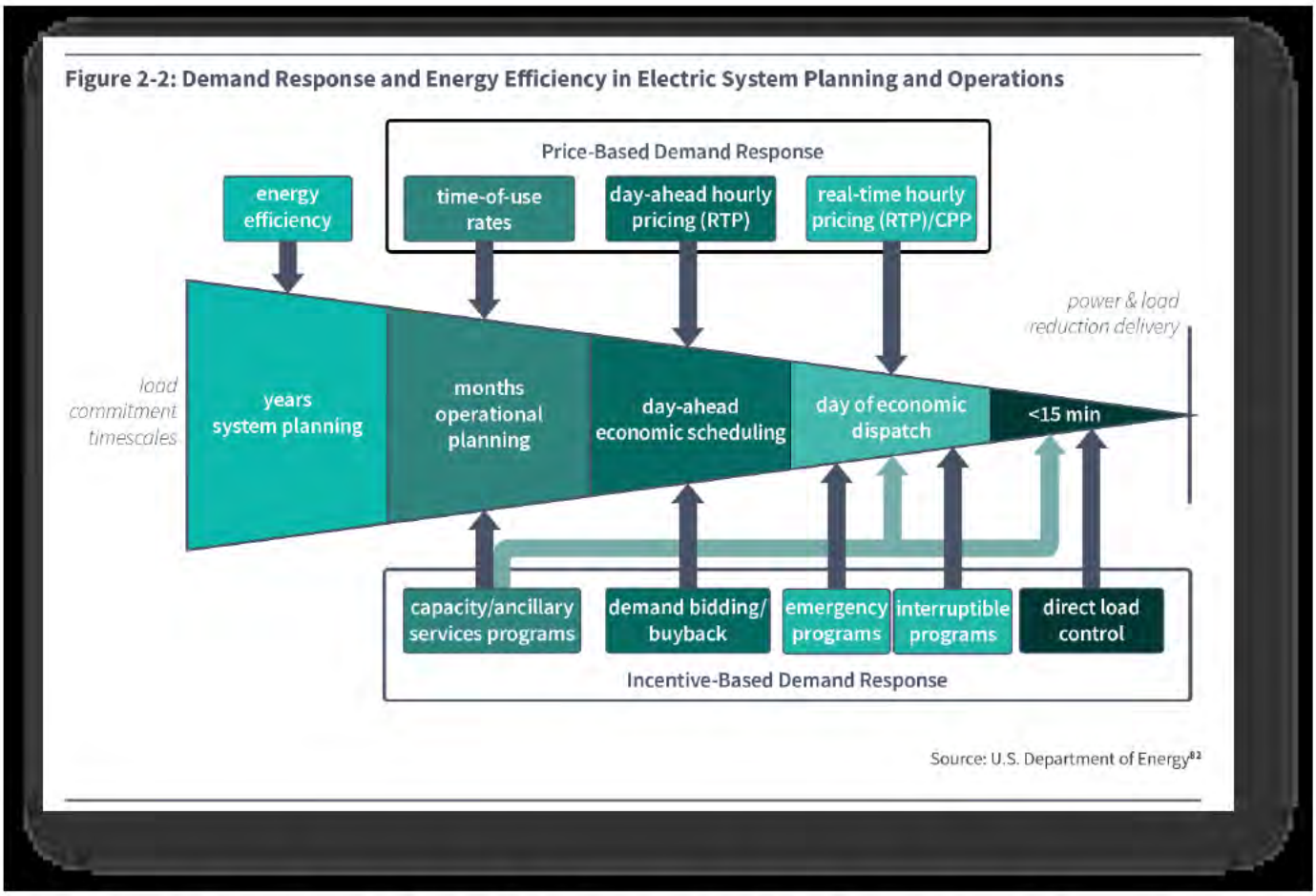
G. The Order is unreasoned, arbitrary, and capricious because the actions it mandates will not meet the purported emergency.

Section 202(c) contemplates emergency orders that are tailored to the specific emergency—they must "best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c). Even if an emergency did exist and DOE had the legal authority to issue an Order, this Order is not rationally related to address the emergency that the order identifies.

The Order's specific requirement for MISO to take steps to effectuate "economic dispatch" of the Campbell Plant is noteworthy. Economic dispatch is a term of art for the procedure by which MISO selects generators to add electric energy to the grid. It is designed to ensure that the electricity generated matches the demand in its service area in the most cost-effective way. Beyond must-run units, MISO dispatches additional capacity from generators in increasing order of their respective costs, starting with the cheapest sources and moving up to more expensive ones as demand increases. MISO will also consider longer-term forecasts of generation given constraints such as forced outages and to ensure adequate margin. And then MISO monitors the grid in real time and calls upon available capacity as needed the day-ahead or day-of markets.

"Economic dispatch," by definition, is awarded to the lowest-cost option (all else being equal). Exhibit 6. That is because much of the base load planning takes place years or months

ahead of time and is comprised of the must-run units. Additional capacity is then called upon in the day-ahead or day-of markets for which additional generation is required:



FERC *Energy Primer*, *supra* n.37 at 43. As explained by DOE's 2007 Report to Congress on economic dispatch, most of the generation available to meet load in real time for economic dispatch is identified and scheduled the day before, based upon the day-ahead load forecast used in the security-constrained unit commitment process. Exhibit 6 at 6. A 2024 report from the Government Accountability Office, Exhibit 13, found that based on 2021 data the vast majority of peaking plants operated on natural gas and oil which can be dispatched in much shorter order; only 3.3 percent of all peakers nationwide burned coal.

Taken together, economic dispatch considers a variety of factors including (1) the cost of generation, (2) the standby condition of the generator, (3) ramp-up time to provide the needed capacity, and (4) whether electric energy can be transmitted to the area of need.

In the context of an emergency, however, plants are generally allowed to run without regard to lowest-cost considerations or bid-submission-and-selection processes. The Order's proposed solution for "economic dispatch" of the Campbell Plant is wholly incompatible with addressing emergency operation (likely because there is no emergency in the first place). In a true emergency, an even uneconomic plants receive cost-of-service payments when they are required to run to alleviate the emergency condition. The RTO does not require the emergency generator to bid into the market and *then* make a determination about whether it will be selected to run as with economic dispatch. Rather, the emergency generator becomes a "price taker" using MISO's "must run" classification. Thus, the order does not use "economic dispatch" in a rational way because an emergency is not addressed with economic dispatch.

Moreover, coal is an expensive fuel type in our current energy mix—indeed the inefficiency of running a coal plant makes it economic in general, and is one of the reasons why this specific Campbell plant was slated for retirement. *See In re Application of Consumers Energy*, No. U-21090, 2022 WL 2915368, at *73.

The Order also does not cite to any evidence that economically dispatching the Campbell Plant will be the appropriate solution for amorphous purported emergency—which is only that a need *might* arise in the future. If, for example, there were a need for additional electricity in North Dakota, it is not likely that there would be sufficient transmission infrastructure across the Great Lakes to deliver electricity from the Campbell Plant to meet that need. And if the need occurs in the day-of or real-time markets, the Campbell Plant will not be able to spool up in time to meet

that need, either. That is because it takes over 12 hours to reach peak load. Exhibit 14.[43] And even if there were adequate transmission and lead time, the Campbell Plant still uses an expensive fuel source. If the Campbell Plant's bid is higher than other lower-cost dispatchable alternatives (natural gas, storage, or renewables), then it would not be selected as the most economic resource to meet the need.

Section 202(c)(2) requires the emergency measures to be tailored the actual need; yet here, the Order improperly imposes measures that are not tailored to anything. All the while, the Order imposes costs on the States to maintain an idle plant, adds potentially expensive generation to the mix if it ever were to run, and would generate harmful pollution at the same time. Thus, the Order requiring the Campbell Plant to remain available and for MISO to take steps to use the Campbell Plant for economic dispatch is irrational and arbitrary where the Campbell Plant is unlikely to be a good candidate to serve either economic dispatch or emergency-need functions—especially where it is unclear what need it is supposed to meet in the first place.

Therefore, the Order is not rationally related to meeting the need of the purported emergency that it identifies.

CONCLUSION

For all of the foregoing reasons, the Department should rescind the Order.

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[43] Adapted from U.S. Energy Information Administration submissions according to Forms EIA-860 and EIA923, in which "OVER" indicates ramp-up time exceeding 12 hours. *See* https://www.eia.gov/electricity/data/eia860/; https://www.eia.gov/electricity/data/eia923/.

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Dated: June 23, 2025

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Dated: June 23, 2025

Order No. 202-25-3

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

The Midcontinent Independent System Operator (MISO) faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. The North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[1] In particular, the retirement of thermal generation capacity creates the potential for electricity supply shortfalls. NERC anticipates that the near-term period of highest capacity shortfall for MISO will occur in August.[2]

Multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[3] Additionally EIA stated, "[t]ypically Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[4] The state's Big Rock Point nuclear power plant shut down in 1997 and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it will not be available during the peak demand period this summer.

The 1,560 MW J.H. Campbell coal-fired power plant in West Olive, MI, is scheduled to cease operations on May 31, 2025. Its retirement would further decrease available dispatchable generation within MISO's service territory, removing additional such generation along with the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. In 2021, Consumers announced that it planned to "speed closure" of Campbell in 2025, several years before the end of its scheduled design life.[5] Although MISO and Consumers have

[1] 2025 summer reliability assessment. (May 14, 2025). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf
[2] *Id*.
[3] U.S. Energy Information Administration, Michigan State Energy Profile, Oct. 17, 2024, *available at*: https://www.eia.gov/state/print.php?sid=mi.
[4] *Id*.
[5] https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation

incorporated the planned retirement into their supply forecasts and acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."

MISO's Planning Resource Auction Results for Planning Year 2025-26, released in April 2025, note that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources." While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and the results "reinforce the need to increase capacity."[6]

ORDER

Given the determination that an emergency exists as discussed above, the responsibility of MISO to ensure reliability of its system, and the ability of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety.

This Order is limited in duration to align with the emergency circumstances. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts.

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

A. From the time this Order is issued on May 23, 2025, MISO and Consumers Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

[6] https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250428694160.pdf

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

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

D. By June 15, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. The extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.

F. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

G. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on August 21, 2025, with the exception of the reporting requirements in paragraph D and applicable compliance obligations in paragraph E.

I. Issued in Washington, D.C. at 3:15:pm Eastern Daylight Time on this 23rd day of May 2025.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Mark Christie
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang

Michigan Public Service Commissioners
Chairman Dan Cripps
Commissioner Katherine Peretick
Commissioner Alessandra Carreon

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2025 Summer Reliability Assessment

May 2025



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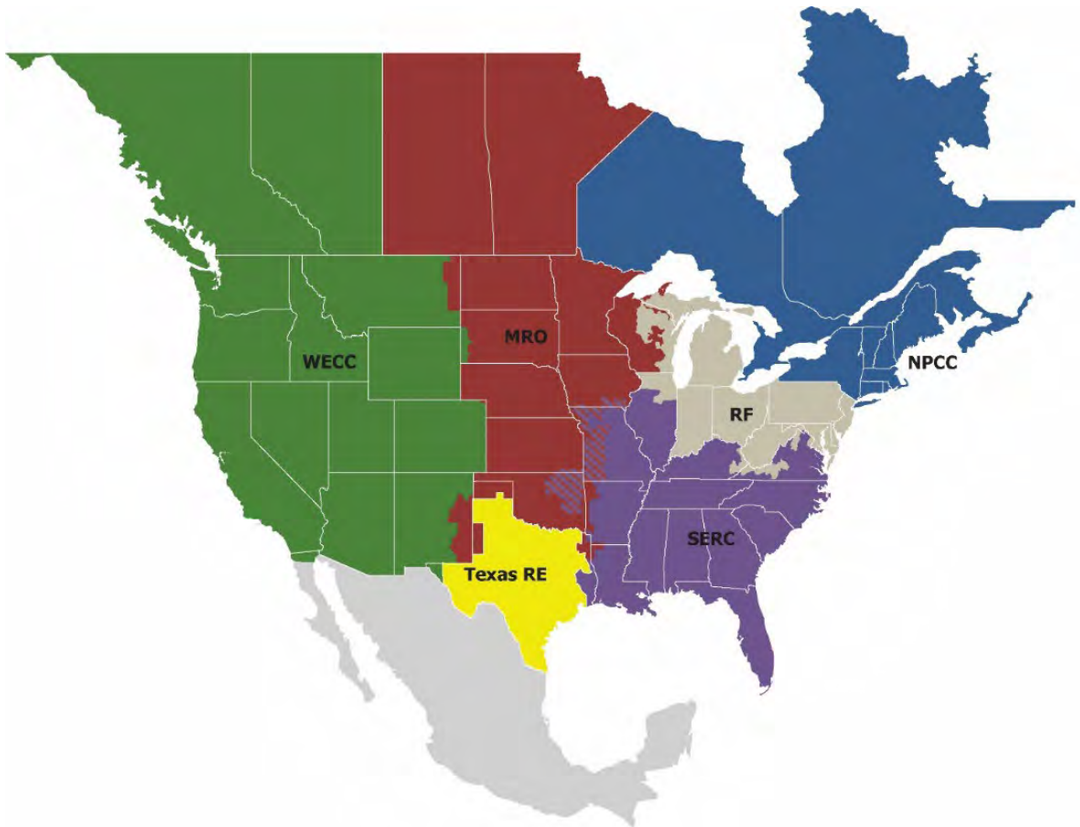
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is spans six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC's *2025 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual *SRA* covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2024 Long-Term Reliability Assessment (LTRA*), which covers a 10-year horizon, and other earlier reliability assessments and reports.[1]

Rising electricity demand forecasts, generation growth, and the increasing pace of change in the resource mix feature prominently in the summer risk profile. Since last summer, the aggregate of peak electricity demand for NERC's 23 assessment areas has risen by over 10 GW—more than double the year-to-year increase that occurred between the summers of 2023 and 2024. Over 7.4 GW of generator capacity (nameplate) has retired or become inactive for the upcoming summer, including 2.5 GW of natural-gas-fired and 2.1 GW of coal-fired generators.[2] Meanwhile, growth in solar photovoltaic (PV) and battery storage resources has accelerated with the addition of 30 GW of nameplate solar PV resources and 13 GW of new battery storage. The new solar and battery resource additions are expected to provide over 35 GW in summer on-peak capacity. New wind resources are expected to provide 5 GW on peak. Operators in many parts of the BPS face challenges in meeting higher demand this summer with a resource mix that, in general, has less flexibility and more variability.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for Summer 2025.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar PV energy conditions:

- **Midcontinent Independent System Operator (MISO):** MISO is expecting to have an existing certain capacity of 142,793 MW in the *2025 SRA*, which is a slight reduction from the 143,866 MW submitted for the *2024 SRA*. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity outside the MISO market opting out of the MISO planning resource auction, is contributing to less dispatchable generation in MISO. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand.
- **NPCC-New England:** The New England area expects to have sufficient resources to meet the 2025 summer peak demand forecast. As of April 1, the 50/50 peak summer demand is forecast to be 24,803 MW for the weeks beginning June 1, 2025, through September 14, 2025, with a lowest projected net margin of -1,473 MW (6.0%). The lowest projected net margin assumes a net interchange of 1,245 MW, which is capacity-backed; however, ISO New England (ISO-NE) has typically imported around 3,000 MW during summer peak load conditions. ISO-NE anticipates an increase of approximately 500 MW in forced outages from its generating fleet compared to Summer 2024. Based on NPCC's most recent energy assessment, some use of New England's operating procedures for mitigating resource shortages is anticipated during Summer 2025. Cumulative loss of load expectation (LOLE) of <0.031 days/period, loss of load hours (LOLH) of <0.120 hours/period, and expected unserved energy (EUE) of <94 MWh/period were estimated for the expected load with expected summer resources while the reduced resources and highest peak load scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH of 19.554 hours/period and EUE of 19,847 MWh/period.
- **MRO-SaskPower:** For the upcoming summer months, no capacity constraints or reliability issues are expected under normal conditions. However, in the event of generator forced outages of more than 350 MW, combined with above-normal peak demand, SaskPower may need to rely on short-term imports from neighboring utilities. Other remedial actions could include quickly activating demand-response programs, adjusting maintenance schedules, and, if necessary, implementing temporary load interruptions. SaskPower's modeling projects

[1] NERC's long-term, seasonal, and special reliability assessments are published on the Reliability Assessments webpage.

[2] Other retirements include 1.2 GW nuclear capacity following the retirement of some units at the Pickering Nuclear Generator Station in Ontario, and 1.6 GW of petroleum, hydro, and other generation. Source: NERC and EIA data.

the probability of experiencing a generation forced outage exceeding 350 MW to be 21.5%. Assuming maximum available imports, the same modeling projects the number of hours with an operating reserve shortfall this summer to be about 0.65 hours with the highest likelihood occurring in June, estimated at 0.43 hours.

- **MRO-SPP:** SPP's Anticipated Reserve Margin (28.5%) is similar to last summer, and resource shortfalls are not expected for the upcoming Summer 2025 season under normal conditions. However, SPP remains at risk for energy shortfalls if above-normal peak demand periods coincide with low wind output and high generator forced outages. Other known operational challenges for the upcoming season include managing wind energy fluctuations; SPP often experiences sharp ramps of its wind generation that can cause transmission system congestion as well as scarcity conditions.
- **Texas RE-ERCOT:** An additional 7 GW of installed solar PV resource capacity and nearly 7.5 GW in new battery storage is helping ERCOT meet rising summer peak demand. ERCOT is projected to have sufficient operating reserves for the August peak load hour given normal summer system conditions. Nevertheless, continued growth in both loads and intermittent renewable resources drives a risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated. ERCOT's probabilistic risk assessment of energy emergency alert (EEA) likelihood for the highest risk periods associated with evening hours in the peak month of August is projected to fall to 3%, down from over 15% in 2024. Lower risk is attributed to a nearly doubling of battery energy storage capacity and improved energy availability from new battery storage and operational rules. The South Texas Interconnection reliability operating limit (IROL) continues to present a system constraint, which, under specific unlikely conditions, could ultimately require ERCOT system operators to direct firm load shedding to remain within IROL limits and prevent cascading load loss. For Summer 2025, this risk is being mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits.
- **WECC-Mexico:** The WECC-Mexico assessment area in Baja California has a peak summer demand of 3,770 MW and is served by a resource mix that is mainly natural-gas-fired generation, with some geothermal, solar, wind, and oil-fired resources (5,636 MW total installed capacity, of which 4,125 MW are gas-fired generators). WECC-Mexico's 14% Anticipated Reserve Margin exceeds the Reference Margin Level for reliability (10%) calculated by WECC. For the upcoming summer, NERC assesses that historically average generator outage rates for peak demand periods can cause a supply shortfall within the WECC-Mexico assessment area and trigger the need for non-firm resources from neighboring areas. Note, in prior SRA reports, the Baja California portion of the BPS was included as part of the WECC-CA/MX assessment area. The *2025 SRA* includes a new assessment area map for the Western Interconnection. The new assessment area boundaries provide reliability risk information in more geographic detail for the United States and Mexico.

Resource additions since last summer have helped lower the risk of energy shortfalls in several areas. Across the U.S. portion of the Western Interconnection, over 6.5 GW of installed solar capacity has been added, along with nearly 7 GW in battery storage. The resources are expected to provide close to 14 GW in on-peak capacity. In British Columbia, new hydroelectric generators were commissioned, contributing to an additional 500 MW in capacity for the summer. The resource additions have alleviated capacity and energy shortfall risks identified in these assessment areas prior to Summer 2024 and provide supplies across the Western Interconnection.

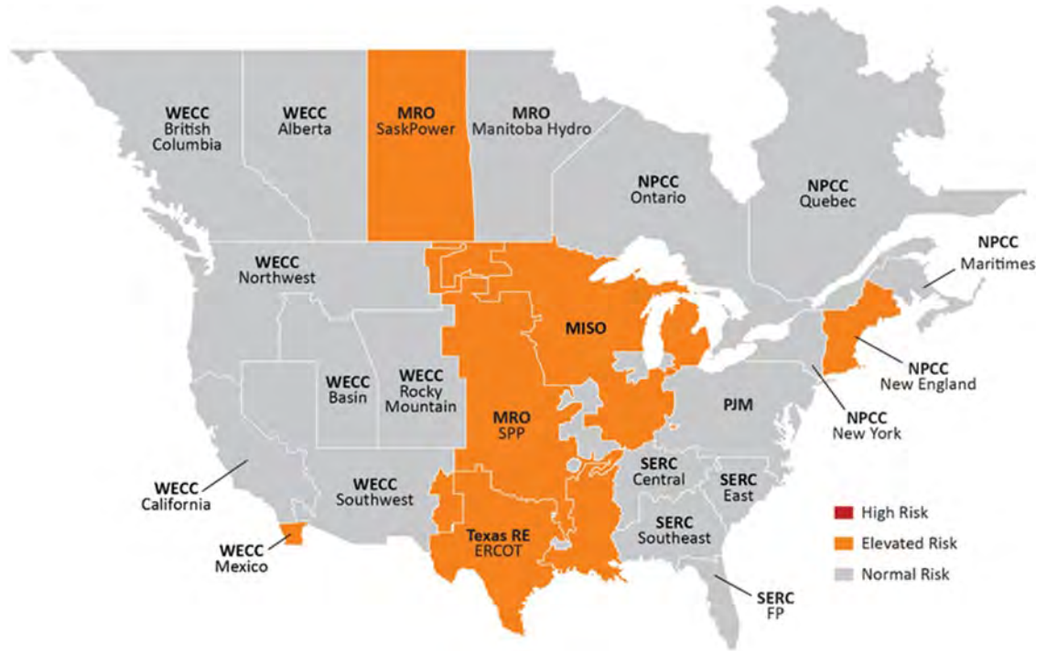


Figure 1: Summer Reliability Risk Area Summary

Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

Other Reliability Issues

- **Weather services are expecting above-average summer temperatures across much of North America and continued below-average precipitation in the Northwest and Midwest.** In summer-peaking areas, temperature is one of the main drivers of demand and can also contribute to forced outages for generation and other BPS equipment. Average temperatures last summer across the United States and Canada were not as hot as Summer 2023, but Summer 2024 still managed to rank in the top four hottest recorded summers with certain areas breaking records yet again. Few high-level EEAs were issued between June and September 2024, and there were no supply disruptions that resulted from inadequate resources as Balancing Authorities (BA), Transmission Operators (TOP), and Reliability Coordinators (RC) employed a variety of operational mitigations and demand-side management measures. Natural-gas-fired electricity generation broke records last year—highlighting the criticality of natural gas in meeting electric demand. This continuing trend will be key in operator preparations that help to ensure fuel availability for the coming summer. The **Review of 2024 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

- **Load growth is driving higher peak demand forecasts and contributing to resource and transmission adequacy challenges in many areas.** Fifteen of the 23 assessment areas are expecting an increase in peak summer demand from Summer 2024. Aggregated peak demand across all assessment areas has increased by over 10 GW since 2024. This is more than double the increase in peak demand from 2023 to 2024. One of the largest increases is seen in the U.S. West (+5%), where a new peak demand record was set last summer. Extreme heat is reported as a main reliability concern this year among BAs in WECC. With precipitation expected to be lower than average in the Northwest, natural-gas-fired generation and demand-side management could be important in offsetting any lower-than-normal levels of hydroelectric generation availability. SERC Southeast is also projecting a sizable increase in peak demand of more than 2% from NERC's *2024 SRA.* Entities in the assessment area cite economic growth and increased industrial and data mining loads as the main drivers.

- **Aging generation facilities present increased challenges to maintaining generator readiness and resource adequacy.** Forced outage rates for conventional generators and wind resources have trended toward historically high levels in recent years.[3] System operators face increasing risk of resource shortfalls and operating challenges caused by forced generator outages, especially during periods of high demand or when relatively few conventional resources are dispatched to serve load. The threat to BPS reliability can be compounded in areas where aging resources are further depended upon to provide essential reliability services. In the Southwest, for example, a portion of capacity has been in operation for roughly 60 years. Electric utilities in SERC-Central have also described aging generation as a reliability challenge. Historical performance has demonstrated the need for planning assumptions that account for elevated forced outage rates for these generators. Older generators can also require extensive overhauls, such as generator rewinds, that take resources out of service for extended periods of time as discovery work can lead to additional unplanned maintenance.

- **Battery resource additions are helping reduce energy shortfall risks that can arise from resource variability and peaks in demand.** In Texas, California, and across the U.S. West, the influx of battery energy storage systems (BESS) in recent years has markedly improved the ability to manage energy risks during challenging summer periods. These areas can be exposed to energy shortfalls during hours of peak demand and into evening as solar PV output diminishes, but BESS resources that maintain their charge during the day can help meet peak demand and also overcome energy shortfalls on the system that might otherwise occur with solar down-ramps or variability. Natural-gas-fired generation also continues to play an important role in meeting peak demand and flexibly responding to fluctuations output from variable energy resources (VER).

- **Grid operators need to remain vigilant for the potential of inverter-based resources (IBR) to unexpectedly trip during grid disturbances.** While this near-term challenge persists, NERC continues to work diligently with industry to develop long-term solutions to this issue. In April, NERC published the *Aggregated Report on NERC Level 2 Recommendation to Industry: Findings from Inverter-Based Resource Model Quality Deficiencies Alert*.[4] In the report, NERC summarized the deficiencies identified in the Level 2 alert issued in June 2024. The report's findings were as follows:
  - Many grid operators indicated that they did not have the requested data readily available, supporting the previous finding that data acquisition and management was insufficient.
  - Interconnection process requirements are insufficient.
  - Two-thirds of the protection settings used by grid operators are not set to provide the maximum capability. This creates a significant artificial limitation of overall ride-through capability of BPS-connected solar photovoltaic (PV) facilities.
  - 20% of the surveyed facilities use a facility capability with a 0.95 power factor limit, which means that a significant amount of underused reactive capability exists on the BPS.
  - Dynamic model data is inconsistent.

[3] See Key Findings in NERC's 2024 *State of Reliability* report

[4] *Findings from Inverter-Based Resource Model Quality Deficiencies Alert*

As solar, wind, and battery resources remain the predominant types of resources being added to the BPS, it is imperative for industry, vendors, and manufacturers to take the recommended steps for system modeling and study practices and IBR performance.

- **Operators of natural-gas-fired generators should maintain lines of communication with natural gas system operators to support electric grid reliability.** The 2024 summer season was the fourth hottest on record,[5] and natural-gas-fired generation broke records with a peak monthly average in July of 208 TWh, up 4% from July 2023, per the latest data from the Energy Information Administration (EIA). The EIA projects that rising demand for natural gas exports this year in the wake of ramped up liquefied natural gas (LNG) production combined with lower field production levels could tighten natural gas supplies relative to last summer. Amid year-over-year increases in load projections in most assessment areas, this summer could see another record year for natural-gas-fired generation, thereby stretching supplies even further. Given that late spring and early summer are seasons when natural gas system owners and operators typically perform maintenance requiring system outages, vigilance is needed to ensure the reliability of fuel delivery to natural-gas-fired-generators.[6]
- **Supply chain issues continue to affect lead times for Bulk Electric System (BES) equipment maintenance, replacement, and construction.** While no specific reliability issues for the upcoming summer have been identified, Transmission Owners (TO) and Generator Owners (GO) face delays in parts, materials, and skilled technicians. When summer maintenance preparations or installations are delayed, effects on equipment availability can challenge system operators. Over the long term, supply chain issues and uncertainty continue to affect development. Lead times for transformers remain virtually unchanged, averaging 120 weeks in 2024. Large transformer lead times averaged 80–210 weeks.[7]
- **Wildfire risks in the areas that comprise the Western Interconnection remain ever present.** Wildfire conditions can affect transmission operations by prompting preemptive circuit outages to reduce the risk of fire ignition as well as through fire impacts to transmission infrastructure. Transmission system congestion and reduced import capacity can accompany wildfire conditions. Moreover, fires near wind generation result in curtailment for safety reasons, and solar facilities can be susceptible to range fires. Fire damage to transmission lines interconnected to remote hydro sites in the Pacific Northwest can be particularly problematic with restoration typically taking weeks to months to accomplish.

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels.
  - Consider the potential for higher-than-anticipated forced generator outage rates in operating plans due to plant age, operating patterns, or limited pre-seasonal maintenance availability.
  - Employ conservative generation and transmission outage coordination procedures and operate conservatively commensurate with long-range weather forecasts to ensure adequate resource availability. The review of system performance during the January 2025 cold weather event noted that early declaration of conservative operations in advance of extreme conditions helped reduce grid congestion and enhance transfer capability.[8]
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans.
- GOs with solar PV resources should implement recommendations in the IBR performance issues alert that NERC issued in March 2023.[9]
- State regulators and industry should have protocols in place at the start of summer for managing emergent requests from generators for air-quality restriction waivers. If warranted, U.S. Department Energy (DOE) action to exercise emergency authority under the Federal Power Act (FPA) section 202(c) may be needed to ensure that sufficient generation is available during extreme weather conditions.

[5] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[6] Short-Term Energy Outlook - U.S. Energy Information Administration (EIA)
[7] Supply shortages and an inflexible market give rise to high power transformer lead times | Wood Mackenzie
[8] See notable operations practices in Appendix 2 of the *January 2025 Arctic Events System Performance Review | FERC, NERC, and its Regional Entities: A Joint Staff Report*, April 2025.
[9] See NERC Level 2 Alert: Inverter-Based Resource Performance Issues, March, 2023. Owners and operators of BPS-connected IBRs that are currently not registered with NERC should consult NERC's IBR Registration Initiative for information on the registration process.

Summer Temperature and Drought Forecasts

During the summer season, heat drives peak electricity demand as consumers use more electricity to cool their homes and businesses. Summer 2024 was the fourth hottest summer on record for the United States and Canada, and Summer 2025 is expected to bring similar intensity. Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. According to their probabilistic assessments of the coming summer season, late July and early August are the periods most frequently identified among the assessment areas as the expected period of peak demand. Peak demand hours may not coincide with the highest risk hours in the summer as the resource mix shifts during a 24-hour cycle, particularly when there are prolonged periods of above-normal temperatures. Coordinating pre-season preparations and maintenance remains critical to avoiding forced outages where possible and mitigating risks to BPS reliability.

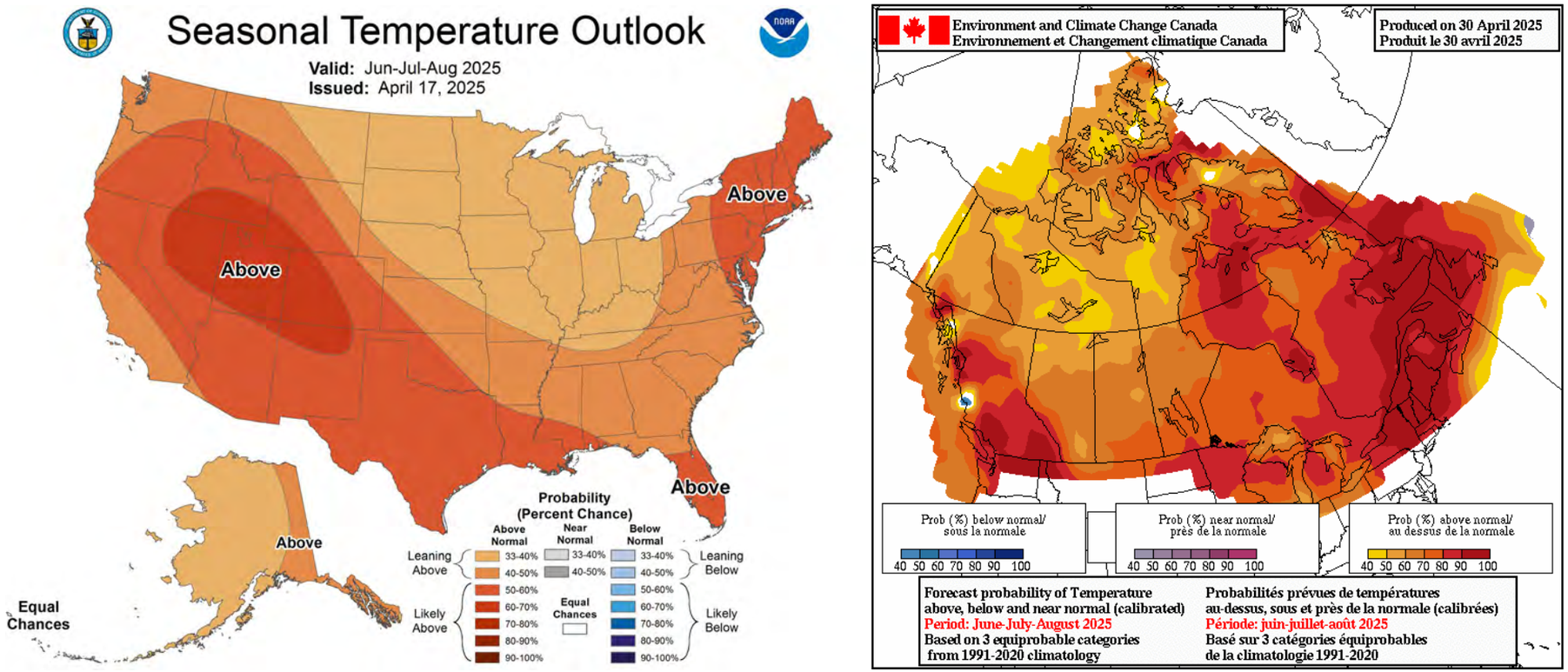


Figure 2: United States and Canada Summer Temperature Outlook[10]

[10] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in Table 1.

Table 1: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels • Probabilistic indices exceed benchmarks (e.g., LOLH of 2.4 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions)[2] • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[3]**Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4]Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins, which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins for seasonal risk scenarios of more extreme conditions are provided in Table 2.

Table 2: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	24.7%	9.3%	-1.9%
MRO-Manitoba	14.6%	11.2%	3.8%
MRO-SaskPower	33.5%	28.3%	22.4%
MRO-SPP	28.5%	18.2%	3.4%
NPCC-Maritimes	42.2%	31.7%	18.6%
NPCC-New England	14.1%	3.9%	4.0%
NPCC-New York	31.6%	12.5%	5.2%
NPCC-Ontario	23.4%	23.4%	3.7%
NPCC-Québec	32.7%	28.2%	19.1%
PJM	24.7%	15.0%	5.3%
SERC-C	19.6%	12.7%	3.2%
SERC-E	29.1%	21.8%	13.0%
SERC-FP	20.2%	14.0%	11.8%
SERC-SE	41.3%	37.7%	12.5%
TRE-ERCOT	43.2%	33.0%	-5.1%
WECC-AB	42.6%	40.3%	20.5%
WECC-Basin	24.3%	15.9%	-27.2%
WECC-BC	24.3%	24.2%	-6.6%
WECC-CA	56.9%	51.0%	4.7%
WECC-Mex	14.1%	1.6%	-16.8%
WECC-NW	32.1%	29.4%	-13.0%
WECC-RM	25.7%	18.2%	-18.9%
WECC-SW	22.3%	14.0%	-13.0%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 2**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in **orange** are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are summarized in **Table 3**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of an EEA occurrence.

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2025. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum contingency reserve requirements.
EEA3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum contingency reserve requirements.

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	The Planning Year 2025–2026 LOLE Study Report, an annual LOLE probabilistic study[11]	The values for LOLH and EUE are taken from the assessment report noted, where the annual LOLE is set at 1 day in 10 years, or 0.1 LOLE for the summer season. For Summer 2025, LOLH is 0.252 hrs/year and EUE is 626.2 MWH/year for the Reference Margin Level. Expectations for load-loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level.
MRO-Manitoba	The 2024 LOLE Study	Manitoba Hydro's probability-based resource adequacy risk assessment for the summer (June–September) season is that there is a low risk of resource adequacy issues. The study indicated Annual Probabilistic Indices for the Manitoba Hydro system for 2026 of 5 MWh per year of EUE, considering a range of flow conditions, and that all of this risk would be in the higher load winter season. The increases in Manitoba load since the 2022 LOLE Study were more than offset by a reduction in long-term exports contract with the expiration of a major export sale in April 2025.
MRO-SaskPower	Probability-based capacity adequacy assessment Summer 2025	According to the study, SaskPower's expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. June has the highest likelihood of an EEA, estimated at 0.43 hours. For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood, during any given hour of the summer period, of encountering a generation forced outage surpassing the 350 MW threshold.
MRO-SPP	2024 NERC *LTRA* with Probabilistic Assessment (ProbA)	With the current SPP fleet, the ProbA base case Year 2 produced no LOLE.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. NPCC anticipates releasing the assessment in May.
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes expects minimal LOLE, LOLH, and EUE over the May–September period, with the highest risk occurring in July and August. The assessment projected LOLE at less than 0.089 days per period, LOLH at less than 0.4 hours per period, and EUE at less than 16.5 MWh per period under the reduced resources and highest peak demand scenario.
NPCC-New England		Based on NPCC's assessment, cumulative LOLE (<0.031 days/period), LOLH (<0.120 hours/period), and EUE (<94 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources scenario. The highest peak load level conditions with reduced resources scenario resulted in an estimated cumulative LOLE risk (4.369 days/period), with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period) with the highest risk occurring in June, with some in July and August.
NPCC-New York		Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May–September period for the expected load with expected resources for the summer. For highest peak load level with low likelihood, reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4,860 MWh/period) with the highest risk occurring in July and August.

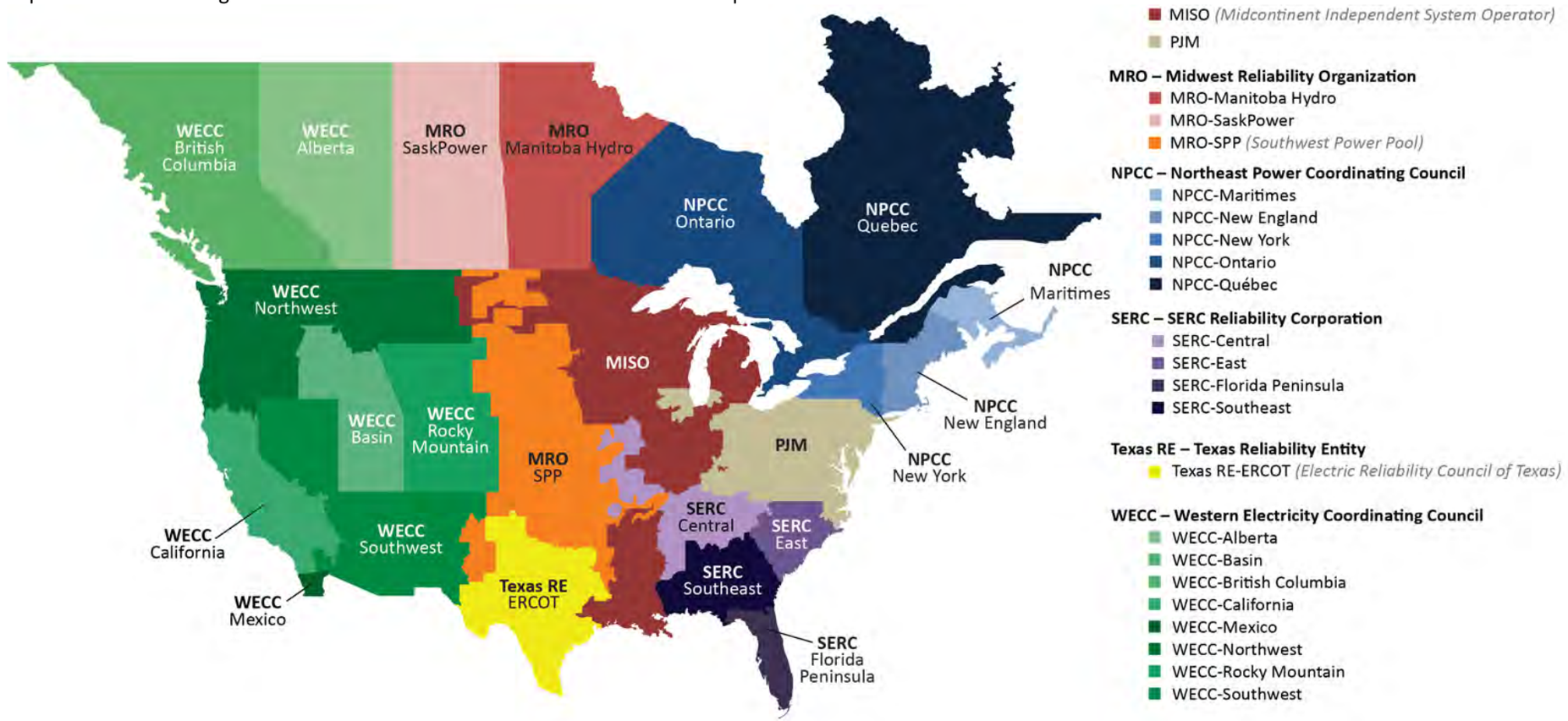
[11] PY 2025–2026 LOLE Study Report

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Ontario		NPCC's preliminary result of this assessment indicates that the low-likelihood resource case, highest peak load level conditions resulted in a negligible cumulative LOLE (0.081 days/period), with associated cumulative LOLH (0.212 hours/period) and EUE (145.4 MWh/period) with the highest risks occurring predominantly in July, with some in August. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the May–September summer period for the other scenarios modeled.
NPCC-Québec		The Québec assessment area is not expected to require use of their operating procedures designed to mitigate resource shortages during Summer 2025. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking.
PJM	2023 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves during Summer 2025. PJM is forecasting around 27% installed reserves (including expected committed demand resources), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion. The Reserve Requirement Study analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with the most loss-of-load risk remains the hour with the highest forecasted demand.
SERC-Central SERC-East SERC-Florida Peninsula SERC-Southeast	2024 NERC *LTRA* with ProbA. For the ProbA, SERC evaluates 8,760 hourly load and 1,900 sequential Monte Carlo simulations. The results are a probability weighted average of cases, including 38 historic weather-years that are applied to load forecasts for years 2026 and 2028. The model applies a range of economic load forecast errors from -4% to 4% and other noted assumptions.	The 2024 ProbA indicates some resource adequacy risk to SERC with the results for the year 2028 showing slightly higher risk than the year 2026. For the entire SERC footprint, Summer 2026 shows a low risk in summer afternoons into evenings, and for Summer 2028, that risk is still low but extends from summer evenings later into summer nights.
Texas RE-ERCOT	ERCOT probabilistic assessment using the Probabilistic Reserve Risk Model	The simulation indicates some risk of having to declare an EEA for hours ending 20 and 21 for the peak load day in August. These two hours have the highest EEA risk (reflecting corresponding high net load conditions) with probabilities of declaring an EEA 3.05% and 1.54%, respectively. This is categorized by ERCOT as "Low risk" per its criteria of hourly EEA probability that is equal to or less than 10%. For the *2024 SRA*, ERCOT reported EEA declaration probabilities for hours ending 20 and 21 of 18.4% and 9.2%, respectively. The large decrease in EEA probabilities is due to the addition of 7,414 MW of BESS capacity.
WECC	2024 Western Assessment on Resource Adequacy employs a probabilistic energy, area-wide assessment, using Multi Area Variable Resource Integration Convolution (MAVRIC) model	

Table 3: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-AB		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. All resource margins have increased since last summer with the addition of new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%) on-line. The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
WECC-Basin		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer—existing-certain is forecast at 19% with anticipated and prospective at 24%. The area is expected to peak in early July around 3:00 p.m.
WECC-BC		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. All reserve margins have increased since 2024 due to increased capacity and energy availability. The peak hour for summer is forecast for early August around 4 p.m.
WECC-CA		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The reserve margins are not anticipated to fall below the reference margin for the upcoming summer. Reserve margins have increased since last summer with the increased existing-certain and Tier 1 planned capacity more than offsetting the decrease in available demand response.
WECC-Mex		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early August around 4:00 p.m. The reserve margins (14%) are not anticipated to fall below the reference margin (10%) for the upcoming summer. An extreme summer peak load is anticipated to be 4,067 MW. Under extreme conditions, typical forced outages are expected to be 472 MW and derates for thermal generation resources are expected to be 330 MW, requiring imports from neighboring areas. The expected operating reserve requirement on peak is 226 MW.
WECC-RM		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in late July around 4:00 p.m. Summer 2025 reserve margins (existing-certain 25%, and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%). An extreme summer peak load may be around 15 GW, and the area has 17.3 GW of existing-certain capacity plus 104 MW of planned new resources. Typical forced outages could be 1,044 MW and derates under extreme conditions of 1,561 MW for thermal and 990 MW for wind. The expected operating reserve requirement on peak is 846 MW.
WECC-NW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. Summer 2025 peak hour is expected to occur in early July around 5:00 p.m. Reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%). An extreme summer peak load may be around 32,740 MW. Typical forced outages are forecast to be 777 MW with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
WECC-SW		Probabilistic analysis performed by WECC found no LOLH or EUE for this summer. The peak hour is expected to occur in early July around 5:00 p.m. The existing-certain 17% reserve margin does not fall below the reference margin (13%) for the upcoming summer. The anticipated and prospective reserve margin rises to 22%. An extreme summer peak load could approach 40 GW during the riskiest hour, while the region is anticipated to have 40.3 GW of existing-certain energy available and an additional 2 GW of Tier 1 planned resources. Typical forced outages are estimated near 3 GW, and derates for thermal under extreme conditions can shave another 3 GW from available energy. The expected operating reserve requirement is 2,119 MW.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-peak reserve margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left **blue** column shows anticipated resources (from the **Demand and Resource Tables**), and the **orange** column at the right shows the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the *SRA* reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.





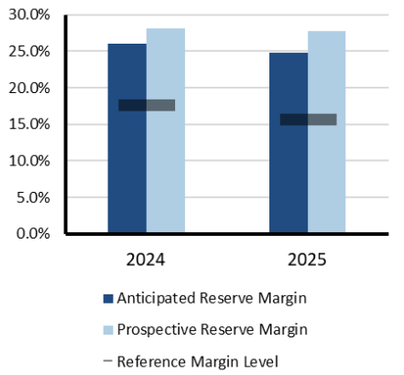
MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Highlights

- Demand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.
- The performance of wind and solar generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum generation declarations and energy emergencies; MISO has over 31,000 MW of installed wind capacity and 18,245 MW of installed solar capacity; however, the historically based on-peak capacity contribution is 5,616 MW and 9,123 MW, respectively.
- Since last summer, over 1,400 MW of thermal generating capacity has been retired in MISO, and the new generation that has been added is predominantly solar (8,080 MW nameplate/4,140 MW on-peak).
- MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August.

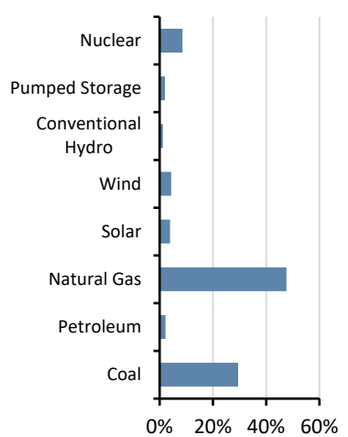
On-Peak Reserve Margin



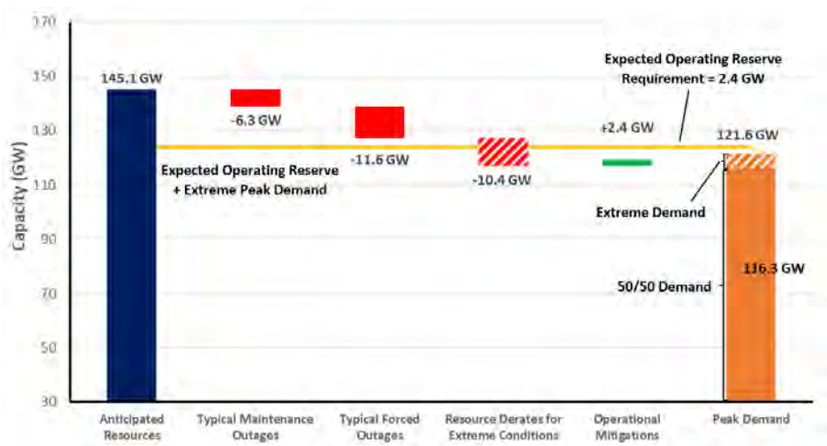
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (demand response) when operating reserve shortfalls are projected.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year summer average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme operating conditions



MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

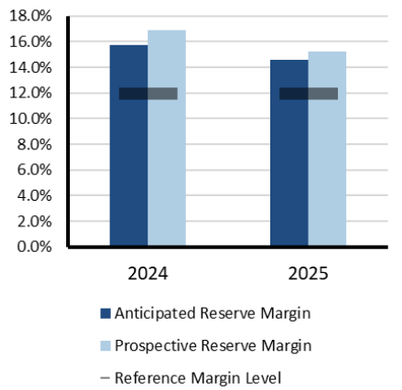
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Summer 2025; the Anticipated Reserve Margin for Summer 2025 exceeds the 12% Reference Margin Level.
- While Manitoba Hydro experienced demand growth in the past year, the growth is less than the recent reduction in firm export contracts.
- Manitoba Hydro water supply conditions are below average but improved from this time last year, and above-average winter snowfall will favorably impact spring runoff.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even if extreme drought develops throughout the year.

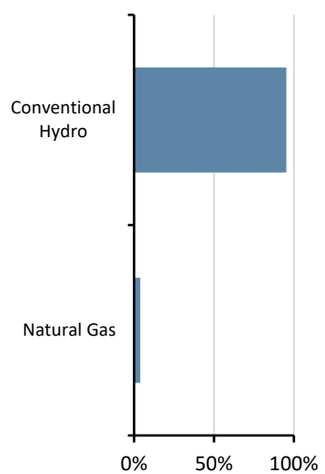
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

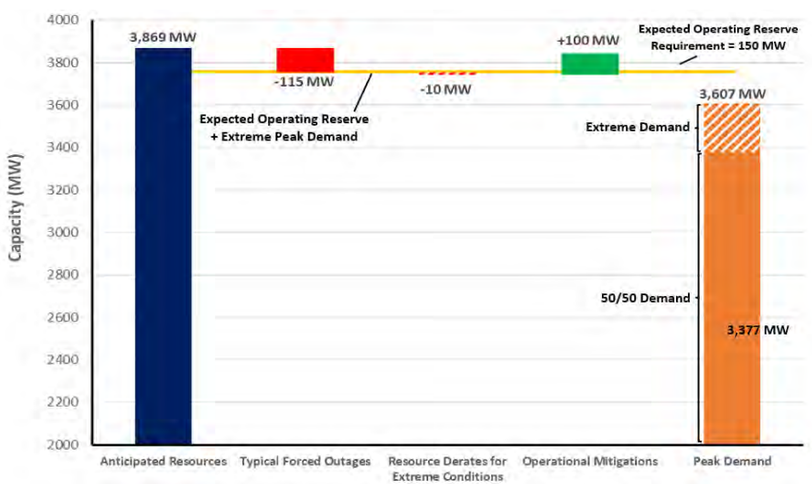
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: (50/50) Demand with allowance for extreme demand based on extreme summer weather scenario of 35.4 C (96 F)

Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required



MRO-SaskPower

MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.1 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its Interconnections.

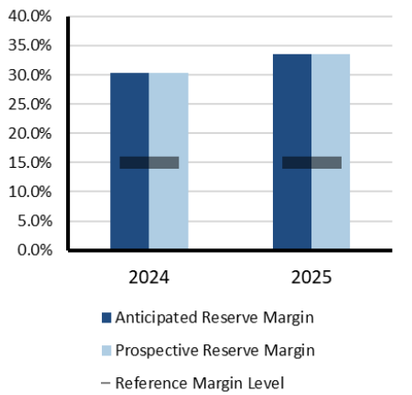
Highlights

- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- Each year, SaskPower works with Manitoba Hydro on a joint summer operating study with input from the Western Area Power Administration and Basin Electric to develop operational guidelines to address any potential challenges.
- The expected number of hours with an operating reserve shortfall between June and September is about 0.65 hours, assuming maximum available imports. The risk of shortfall increases if major unplanned generator outages coincide with scheduled maintenance during peak demand months (June to September). For Summer 2025, the projected probability of experiencing a generation forced outage exceeding 350 MW stands at 21.5%. This number represents an approximation of the likelihood of encountering a generation forced outage surpassing the 350 MW threshold during any given hour of the summer period.
- If extreme heat coincides with significant generation outages, SaskPower will act by activating demand-response programs, arranging short-term power imports from neighboring utilities, and, if necessary, implementing temporary load interruptions to maintain grid stability.

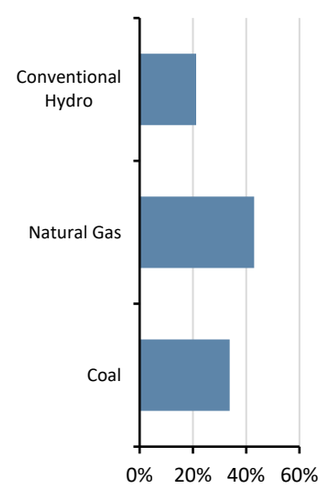
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand and outage conditions. Above-normal summer peak load and outage conditions are likely to result in the need to employ operating mitigations (e.g., demand response and transfers) and EEAs.

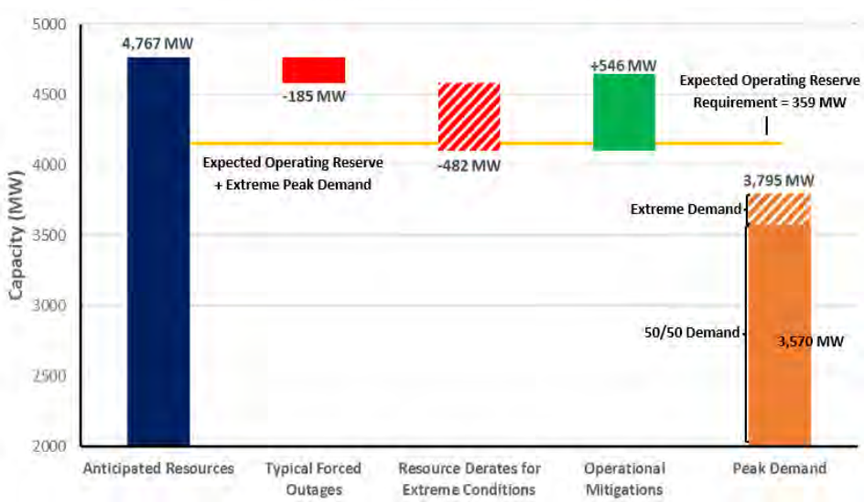
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7-day notice



MRO-SPP

SPP PC's footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

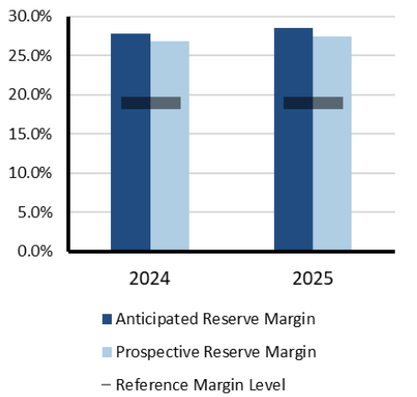
Highlights

- SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2025 Summer season.
- Generation availability is not expected to be impacted by fuel shortages or river conditions this summer.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- Using the current operational processes and procedures, SPP will continue to assess the resource needs for the 2025 Summer season and will adjust generation and energy supply portfolios as needed to ensure that real-time energy sufficiency is maintained throughout the summer.

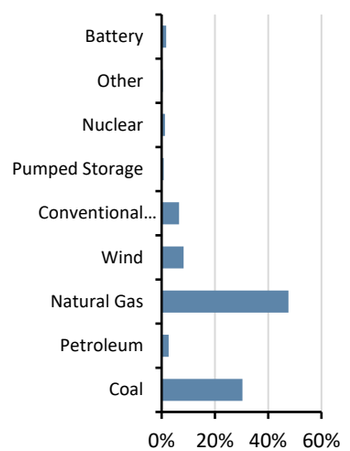
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load, low wind conditions, and higher-than-normal forced outages could result in the need for operating mitigations (e.g., demand response and transfers from neighboring systems) and EEAs.

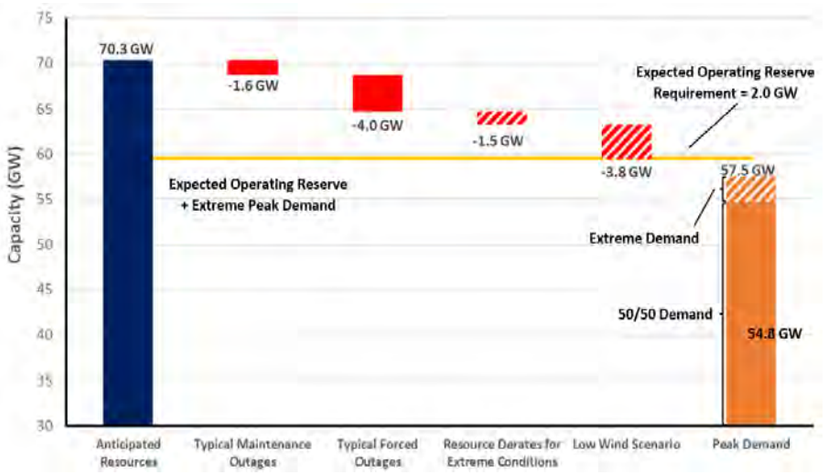
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance and Forced Outages: Represent five-year historical averages; calculated from SPP's generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high-demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer



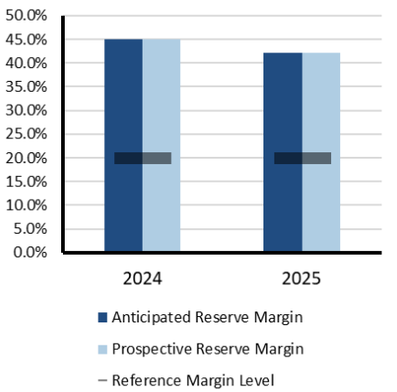
NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

Highlights

- As Maritimes is a winter-peaking system, no issues are expected for the upcoming summer assessment period with sufficient firm capacity to meet forecast peak demand. If an event were to occur, emergency operations and planning procedures are in place.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found negligible LOLH and EUE for the expected load and resource levels this summer. A scenario with an extreme high load shape produced minimal amounts of cumulative LOLE (<0.089 days/period), LOLH (<0.4 hours/period), or EUE (< 16.5 MWh/period) over the May–September summer period with the highest risk occurring in July and August.
- Dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to sustain operations in the event of natural gas supply interruptions.

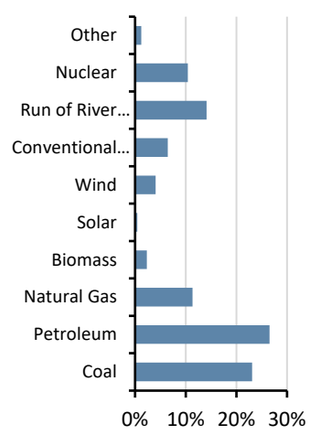
On-Peak Reserve Margin



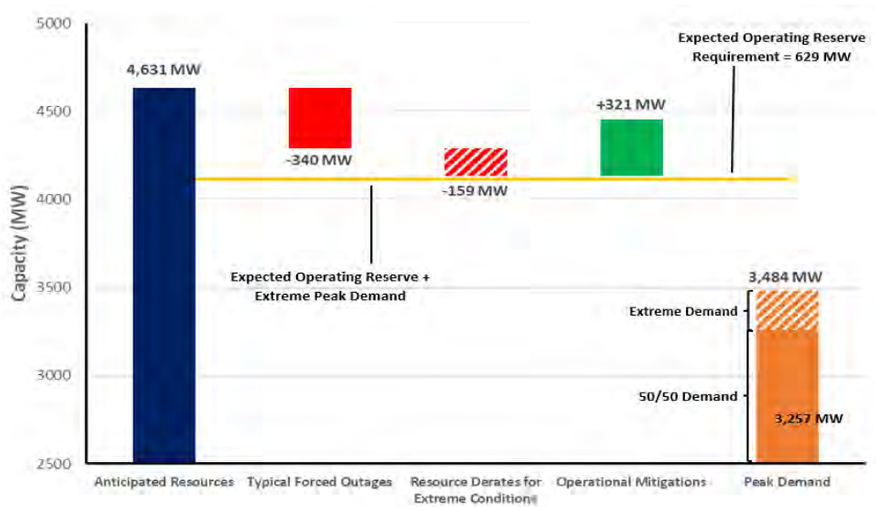
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could necessitate operating mitigations (e.g., demand response and non-firm transfers) and EEAs.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (above 90/10) extreme demand forecast

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies, (e.g. New Brunswick Power System Operator can increase import capability from 200 MW to 550 MW under emergency operations for up to 30 minutes)



NPCC-New England

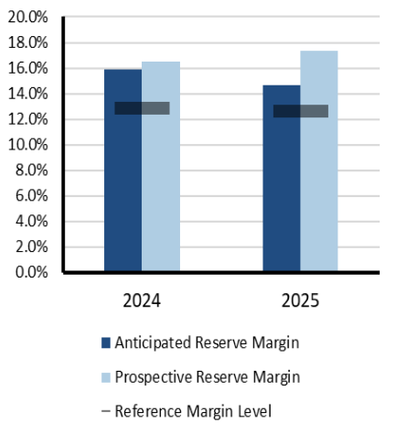
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- ISO-NE forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* identified small amounts of cumulative LOLE, LOLH, and EUE for the expected load with anticipated resources for the summer. A reduced resources and highest peak load level scenario resulted in an estimated cumulative LOLE risk of 4.369 days/period, with associated LOLH (19.554 hours/period) and EUE (19,847 MWh/period). The highest risk occurs in June, with some risk in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

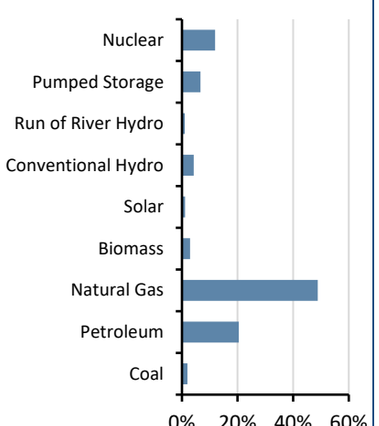
On-Peak Reserve Margin



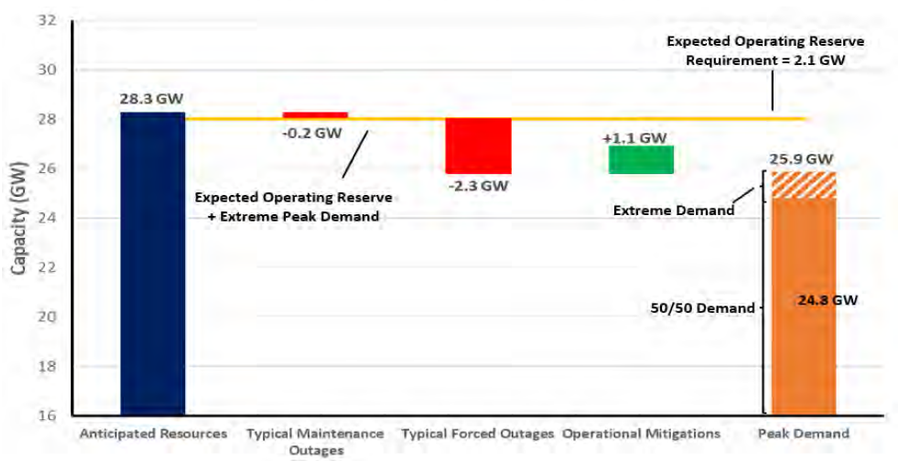
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios. Additional non-firm transfers are likely to be needed and available from neighbors. More severe conditions (e.g., above-normal summer peak load and outage conditions) could result in an EEA.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures



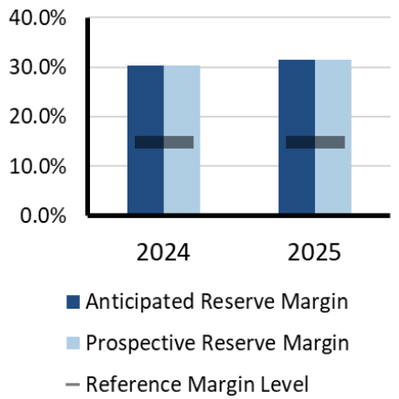
NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this *SRA*, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2025–2026 IRM at 24.4%.

Highlights

- NYISO is not anticipating any operational issues for the upcoming summer operating period. Adequate reserve margins are anticipated.
- Probabilistic analysis performed by NPCC for the NPCC *Summer Reliability Assessment* found that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2025. Negligible cumulative LOLE (<0.018 days/period), LOLH (<0.054 hours/period), and EUE (33 MWh/period) risks were estimated over the summer May to September period for the expected load with expected resources for the summer. The highest peak load level with low likelihood reduced resource conditions resulted in an estimated cumulative LOLE risk (1.7 days/period), with associated LOLH (6.5 hours/period) and EUE (4860 MWh/period) with the highest risk occurring in July and August.
- The NPCC 2025 *Summer Reliability Assessment* will be approved on or about May 12, 2025, and posted on NPCC's website.

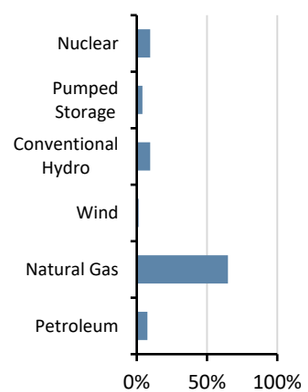
On-Peak Reserve Margin



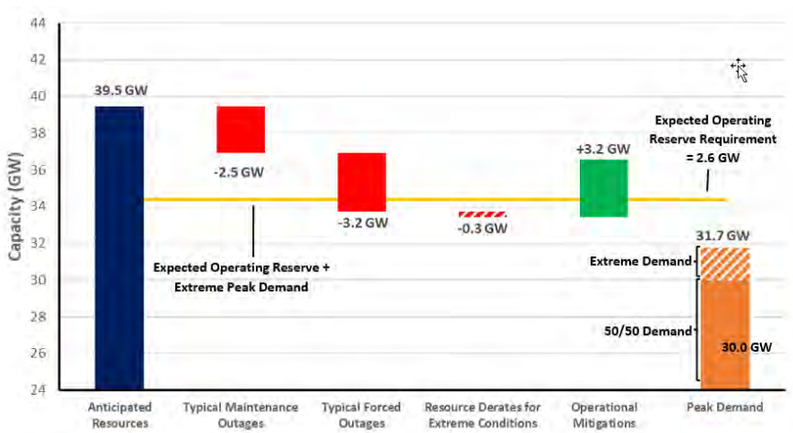
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios. Operating mitigations (e.g., demand response and transfers) may be needed to meet above-normal summer peak load and outage conditions.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages: Based on historical performance and the new NYISO capacity accreditation process

Forced Outages: Based on historical five-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.2 GW based on operational/emergency procedures in area emergency operations manual



NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of m16 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

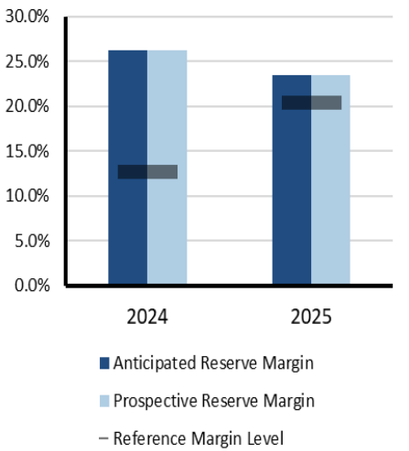
Highlights

- Overall, Ontario is operating within a period where generation and transmission outages are more challenging to accommodate. The IESO is prepared and expects to have adequate supply for Summer 2025.
- The IESO has been actively coordinating and planning with market participants to maintain reliability.
- This season, the grid will benefit from increased capacity secured through the capacity auction and more planned projects, including new storage, coming into service.
- The IESO is working throughout 2025 to better integrate storage solutions into the electricity markets.
- Starting with this seasonal assessment, demand is forecasted by using probabilistic weather modeling, comparable to the methodology used in the IESO 18-month *Reliability Outlook* as opposed to the previous approach of using weather scenarios."

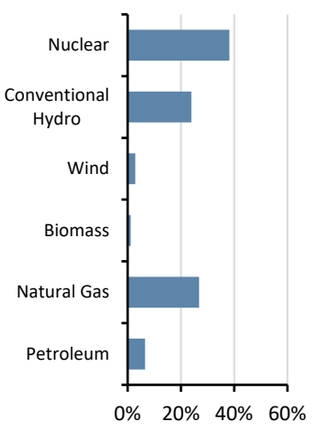
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

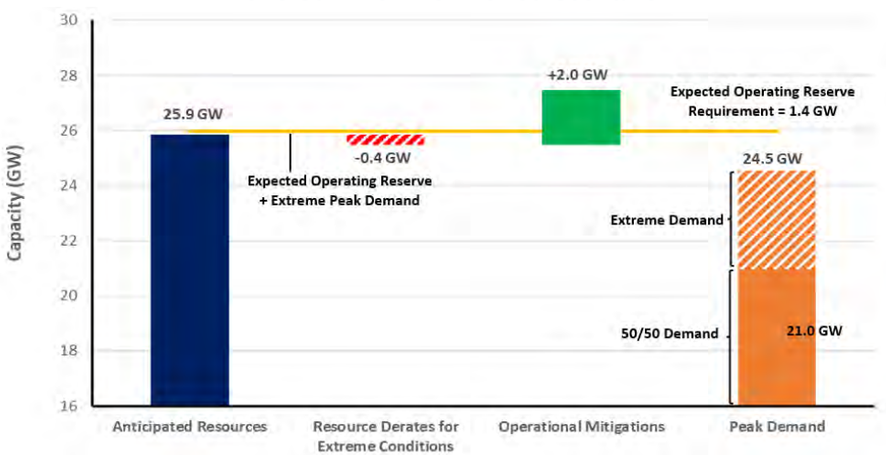
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand based on 31 years of demand history, and extreme weather represents a 97/3 distribution of probabilistically modelled data

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: The operational procedures used to mitigate extreme conditions total approximately 2,010 MW for the On-Peak Risk Scenario, consisting of imports, public appeals, and voltage reductions. Public appeals and voltage reductions were not included in the 2024 On-Peak Risk Scenario.



NPCC-Québec

The Québec assessment area (province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes consisting of either high-voltage direct current ties, radial generation, or load to and from neighboring systems.

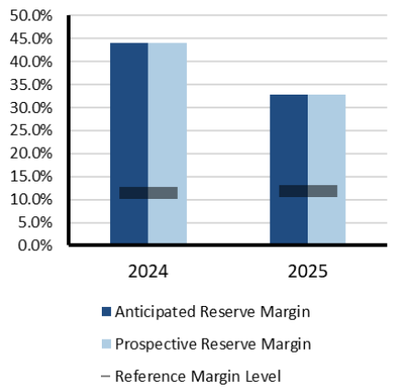
Highlights

- The Québec area forecasted summer peak demand is 23,283 MW during the week beginning August 3, 2025, with a forecasted net margin of 5,698 MW (24.5%).
- Resource adequacy issues are not expected this summer.
- The Québec area expects to be able to assist other areas.
- Modeling was made more precise this year with the inclusion of summer demand-response programs, dispatchable demand-side management (DSM), and weekly modeling of the reserve requirements and bottled generation.

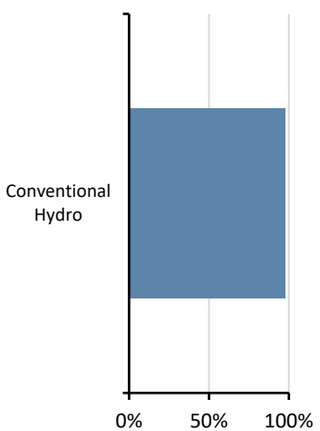
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

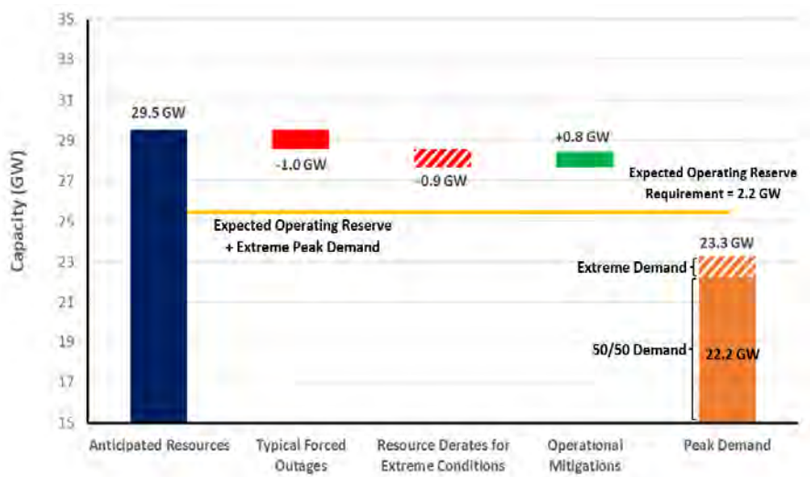
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast

Operational mitigations: An operational procedure used to mitigate extreme conditions and not already included in margins is the depletion of some operating reserves by 750 MW.



PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.

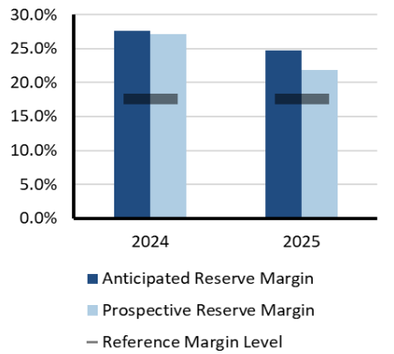
Highlights

- PJM is forecasting 27% installed reserves (including expected committed demand response), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- During extreme high temperatures that can cause record demand, PJM anticipates the need for demand-response resources to help reduce load at times this summer.

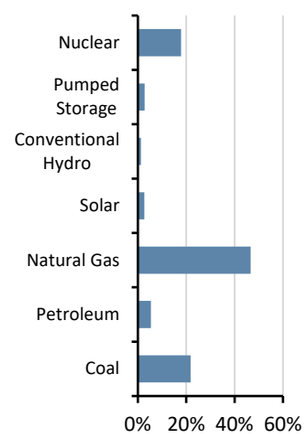
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

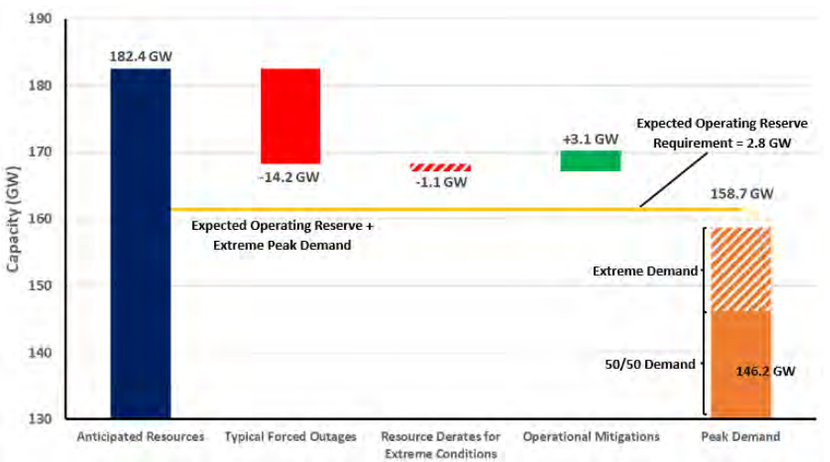
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures



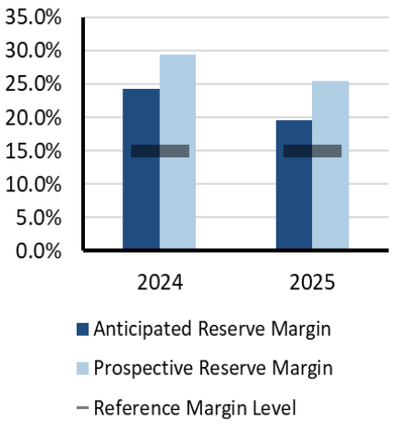
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC)-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-Central saw a sizable increase in its reserves last summer, but coal retirements this summer will result in SERC-Central having lower reserves.
- SERC-Central's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the area.
- Entities perform resource studies to ensure resource adequacy to meet the summer peak demand and maintain the reliability of the system.
- Members of SERC-Central actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

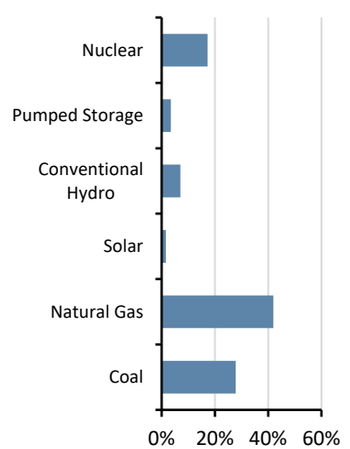
On-Peak Reserve Margin



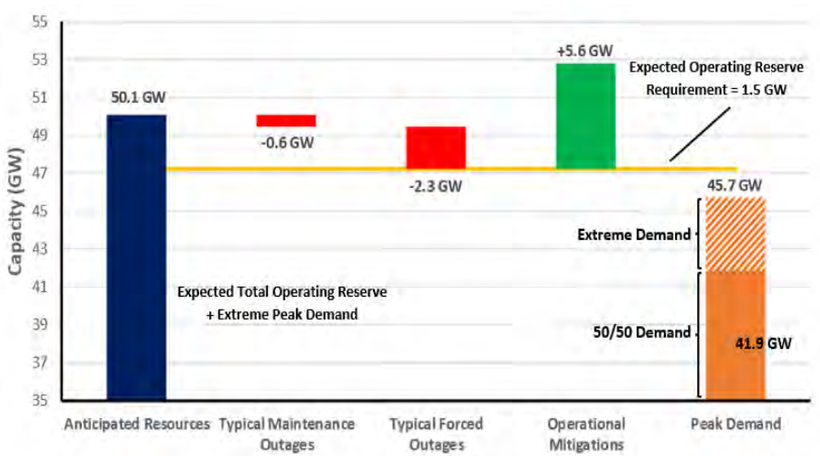
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios. More severe conditions (e.g., above-normal summer peak load and outage conditions) result in the need for additional non-firm transfers available from neighbors.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: 5.6 GW based on operational/emergency procedures



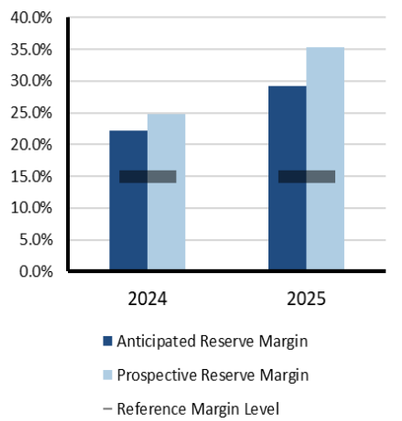
SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-East's reserves are largely unchanged compared to the reference margin as compared to last summer's assessment.
- SERC-East's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- While the last probabilistic analysis indicated that SERC-East could face potential unserved energy in summer, the 2026 and 2028 probabilistic analysis found the SERC-East unserved energy risk has shifted to winter mornings.
- Members of SERC-East actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

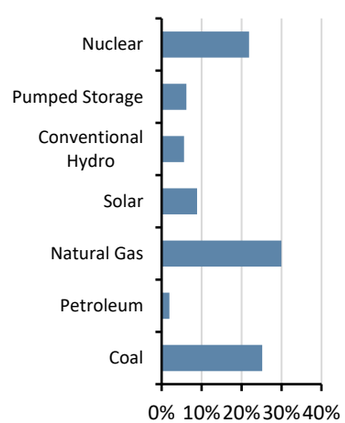
On-Peak Reserve Margin



Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 45 MW based on operational/emergency procedures



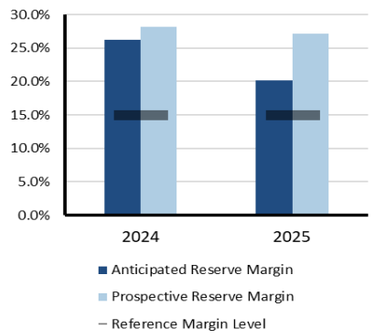
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC Florida-Peninsula's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion during the summer.
- Members of SERC-Florida Peninsula actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.

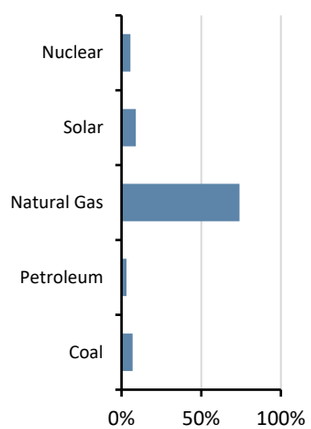
On-Peak Reserve Margin



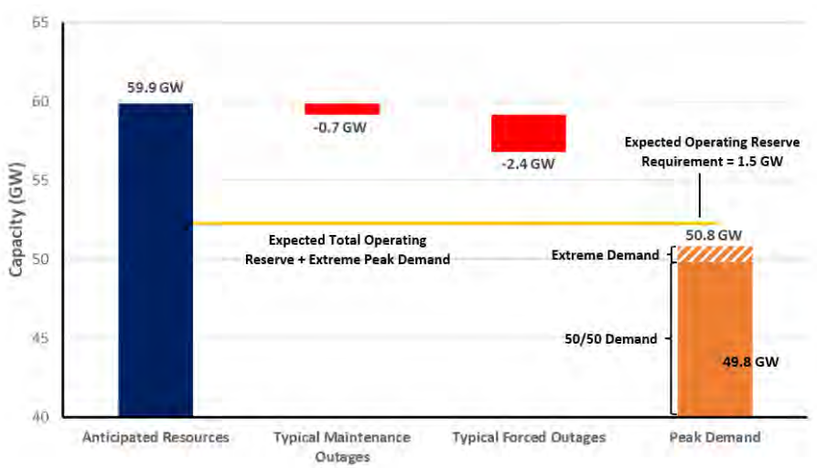
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions



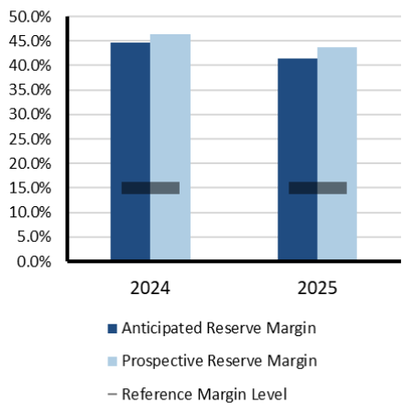
SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- An area within SERC-Southeast notes that natural gas pipeline constraints could impact reliability in summer, but this is not expected to pose a significant summer operational challenge.
- SERC-Southeast's anticipated resources meet operating reserve requirements under the expected conditions and under the summer risk period scenario.
- The probabilistic analysis metrics indicate adequate energy resources for the subregion.
- Members of SERC-Southeast actively participate in the SERC working groups to perform coordinated studies and develop mitigating actions for any potential or emerging reliability impacts on transmission and resource adequacy.

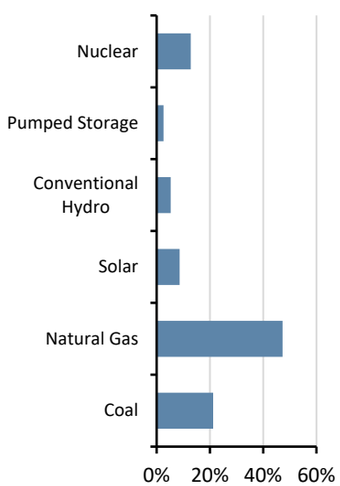
On-Peak Reserve Margin



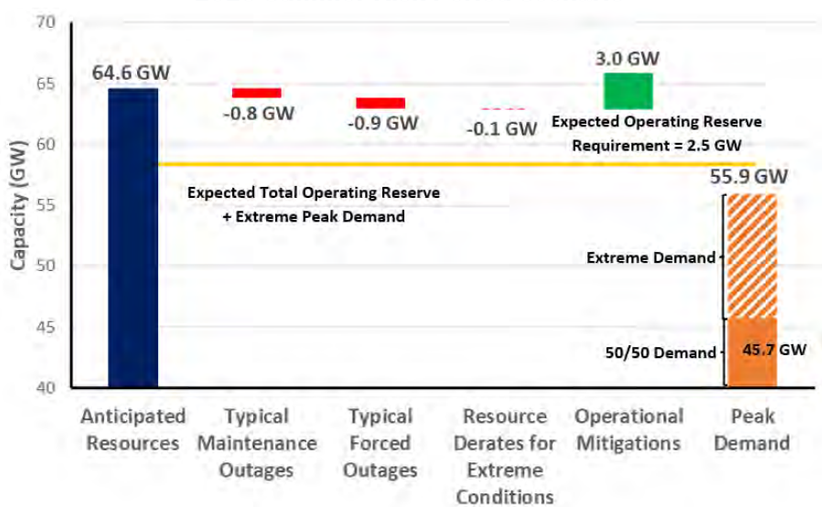
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3 GW based on operational/emergency procedures



Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

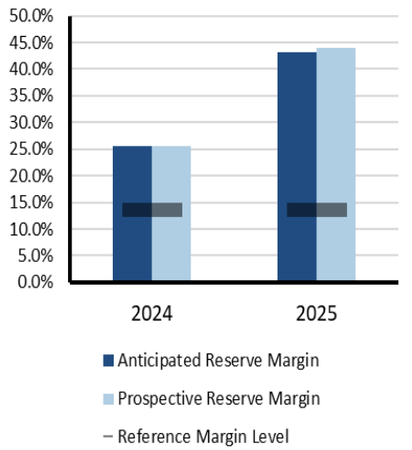
Highlights

- ERCOT expects to have sufficient operating reserves for the August peak load hour given normal summer system conditions.
- ERCOT's probabilistic risk assessment indicates a low risk of having to declare EEAs during the expected August (and summer) peak load day; the EEA probability for the highest-risk hour—hour ending 9:00 p.m.—is 3.6%. The likelihood of an EEA is down significantly from the 2024 SRA due to almost a doubling of battery energy storage capacity and improved energy availability reflecting new battery storage and operational rules.
- Continued robust growth in both loads and intermittent renewable resources drives a higher risk of emergency conditions in the evening hours when solar generation ramps down and loads remain elevated.
- The South Texas IROL continues to present a risk of ERCOT directing system-wide firm load shedding to remain within IROL limits. This risk has been mitigated by updating transmission line dynamic ratings and switching actions to divert power away from the most limiting transmission circuits. The South Texas transmission limits are expected to be needed at least until the San Antonio South Reliability Project is placed in service, which is anticipated to be in Summer 2027.
- ERCOT will release its own August 2025 Monthly Outlook for Resource Adequacy on June 6.

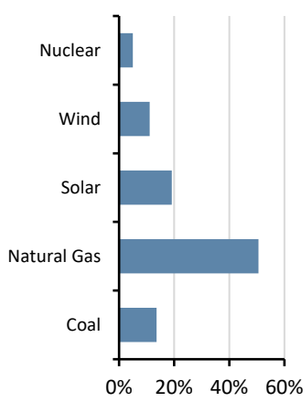
Risk Scenario Summary

Expected resources meet operating reserve requirements for the peak demand hour scenario. However, there is a risk of supply shortages during evening hours (when solar generation ramps down and demand remains high) if there are conventional generation forced outages or extreme low-wind conditions.

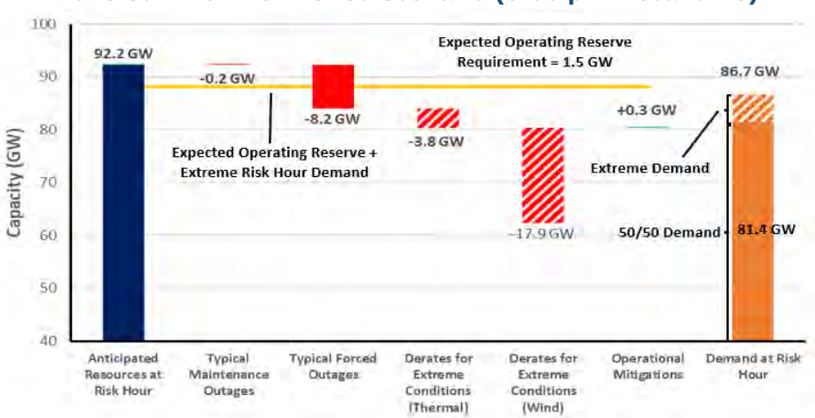
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario (9:00 p.m. local time)



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 9 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) and extreme demand (95/5) based on August peak load

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three summer seasons

Extreme Derates: Based on the 90th percentile of thermal forced outages for peak August load day

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Operational Mitigations: Additional capacity from switchable generation and additional imports



WECC-Alberta

WECC-Alberta is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta. It has 16,369 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

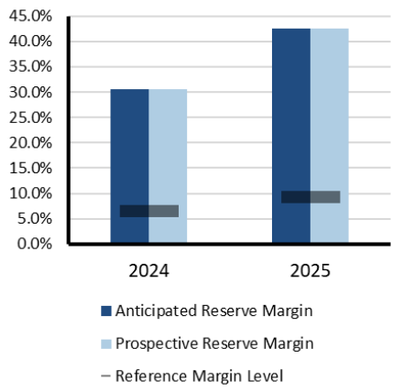
Highlights

- Anticipated and prospective reserve margins are projected to remain above the Reference Margin Level.
- All resource margins have increased by about 50% since last summer with the addition of 23.2% new capacity, including almost 2,700 MW of new natural gas capacity, 1,200 MW of new wind (+27%), 200 MW of new solar (+13%), and 54 MW of new energy storage systems (+27.5%).
- The peak hour has moved earlier, to 3:00 p.m. from 4:00 p.m., still in late July.
- High temperatures, import limitations, and low or declining renewable output during summer evenings can result in grid alerts.
- Wildfires can threaten generating assets and transmission infrastructure requiring invocation of Alberta Electric System Operator (AESO) protocols that include instructing available assets and long lead-time assets to deliver energy up to their maximum capability, calling upon demand response, and maximizing import capability.

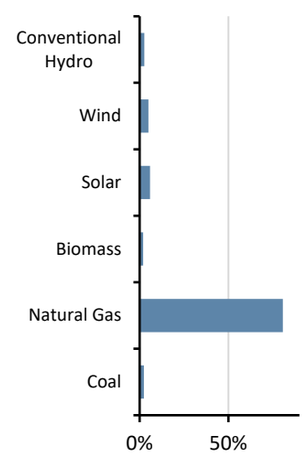
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

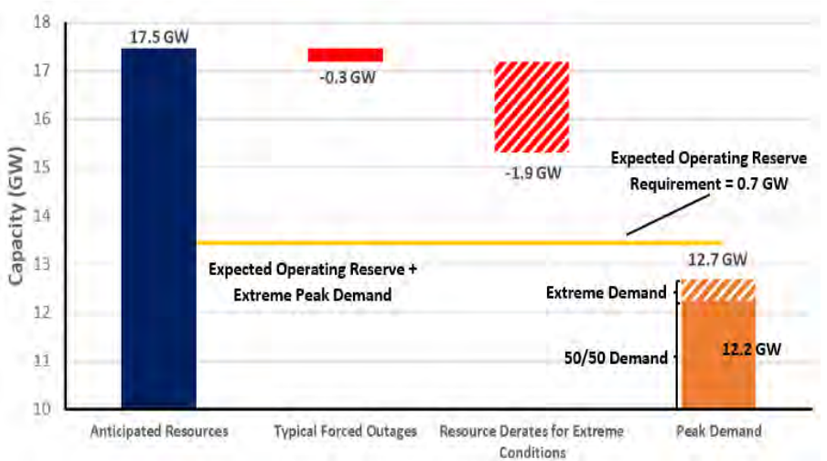
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution



WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern Balancing Authority Area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA.*

Highlights

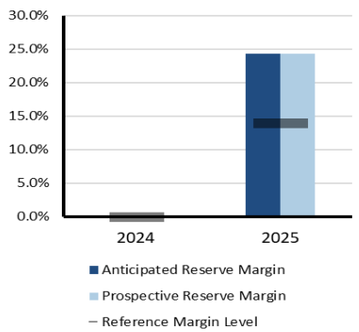
- Total internal expected demand has increased 8% and demand response has increased almost 28% for a net internal demand increase of 7.2%.
- Reserve margins are not anticipated to fall below the reference margin (14%) for the upcoming summer; an early July peak is expected at around 3:00 p.m.
- During periods of contingency reserve shortage, EEAs may be declared in the region to obtain reserves from the Northwest Power Pool.
- Seasonal fluctuations in hydro supply require monitoring and forecasting to have high certainty that these resources will meet anticipated capacity; the Summer 2025 drought outlook for the United States indicates minimal drought conditions in Idaho and some drought areas in Utah this summer.
- Wildfires near wind generation can result in safety curtailments, and fire damage to transmission lines interconnected to hydro sites can present restoration challenges.

Risk Scenario Summary

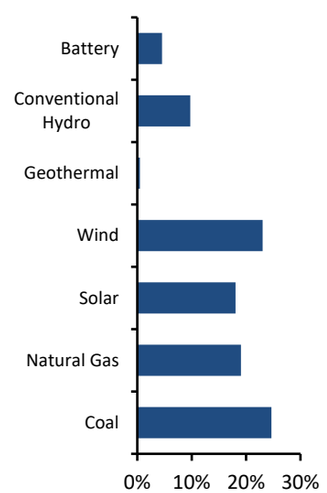
Expected resources meet operating reserve requirements under the assessed scenarios with imports.

On-Peak Reserve Margin

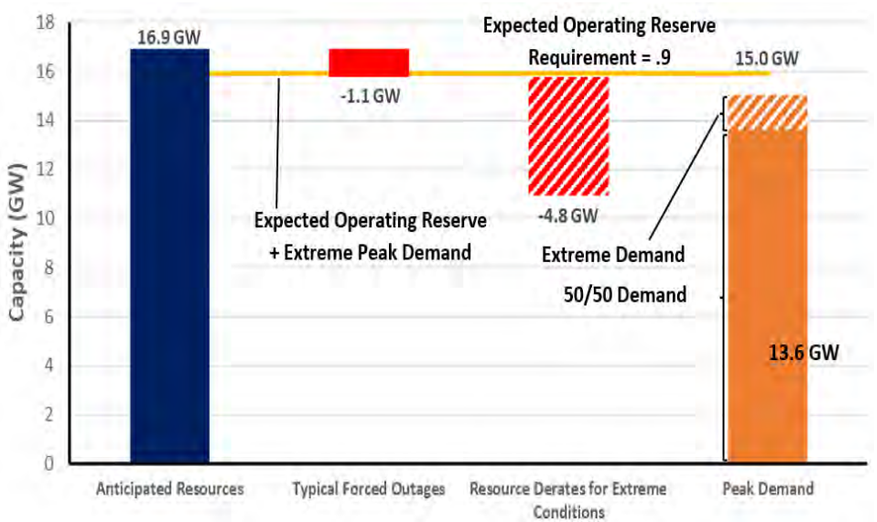
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour



WECC-British Columbia

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia. It has 11,184 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

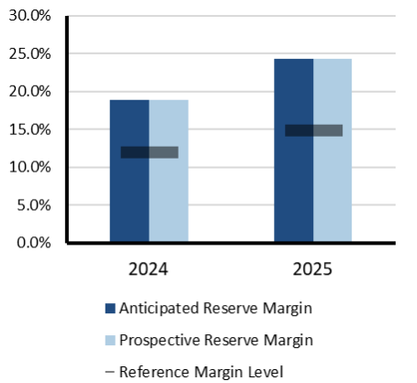
Highlights

- Existing capacity reserve margin has increased from 19% to 22%, and anticipated and prospective reserve margin from 19% to 24%.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer.
- The peak hour is forecast for early August at 4:00 p.m., two hours earlier than last summer's outlook of 6:00 p.m.
- About 60% of hydro owned or contracted energy comes from the Columbia and Peace basins. Heavy precipitation in Fall 2024 mitigated the impact of below-average snowpack the previous winter, resulting in hydro storage tracking close to historical averages as of Spring 2025.
- Wildfires can affect the transmission network and generator availability and have caused energy emergencies on the electric system in the past.

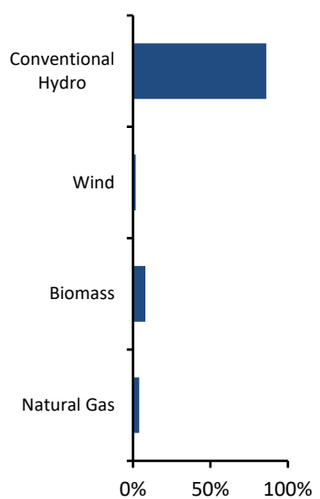
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

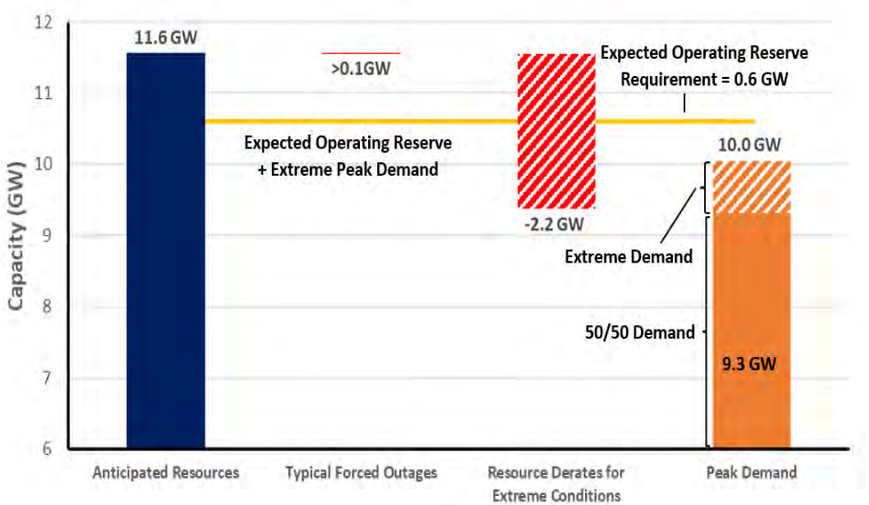
On-Peak Reserve Margin



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour



WECC-California

WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-California is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA*.

Highlights

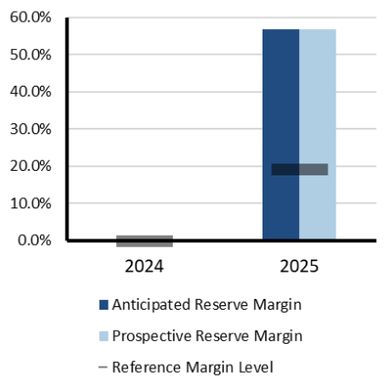
- Demand response is down 8.6% since last summer, existing-certain capacity is up 5.8%, and Tier 1 planned capacity is up 41.2% for a net increase in anticipated resources of 9%; anticipated and prospective reserve margins are up by 11.4%. The peak hour is still forecasted for early September around 4:00 p.m.
- Reserve margins are not anticipated to fall below the reference margin for the upcoming summer, and probabilistic assessment of normal and extreme resource/demand scenarios reveal no EUE or LOLH.
- Wildfires can and have threatened both the California Oregon Intertie line, resulting in import capability limitations.
- Prolonged elevated demand during heat waves in combination with thermal resource derates and forced outage rates present significant risk.
- An influx of IBRs and corresponding reduction in system inertia can potentially trigger system reliability issues and require additional regulation, flexible ramp, and future imbalance reserve requirements.
- Increased solar penetrations in this region along with changing load patterns from elevated temperatures and residential demand are shifting the hours with the most challenging resource adequacy needs later into the evening rather than traditional afternoon gross peak load periods.

Risk Scenario Summary

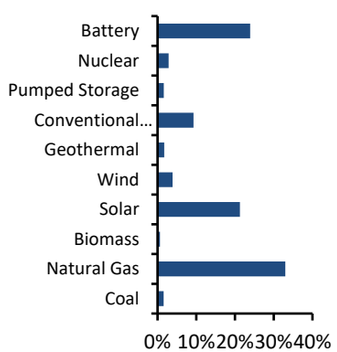
Expected resources meet operating reserve requirements under assessed scenarios, and a probabilistic assessment of normal and extreme resource/demand scenarios reveals neither EUE nor LOLH.

On-Peak Reserve Margin

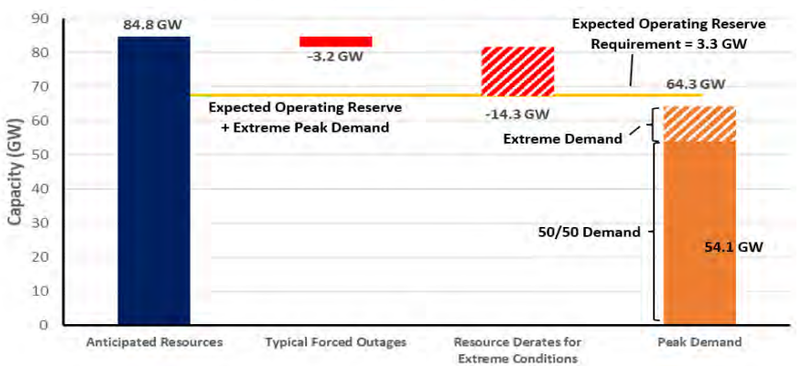
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historical data and manufacturer data for temperature performance and outages



WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Mexico is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 SRA.*

Highlights

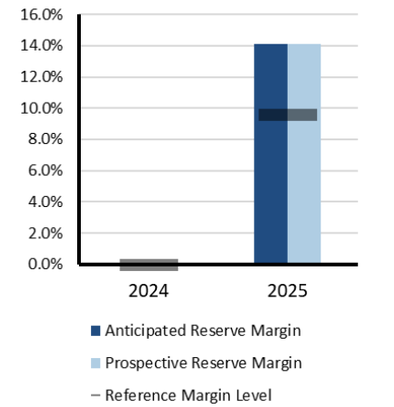
- Total and net internal expected (50/50) demand are up 6.8%, existing-certain capacity is up 29.8% or 989 MW, and Tier 1 planned capacity has fallen 100% to zero, leading to a decrease in the anticipated reserve margin from 22.9% down to 14.1%
- The peak hour is expected to occur in early August around 4:00 p.m.
- Operating reserves are a concern in this region during periods of extreme heat and elevated demand. High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this region can result in the declaration of an EAA and a request for assistance from RC West.

Risk Scenario Summary

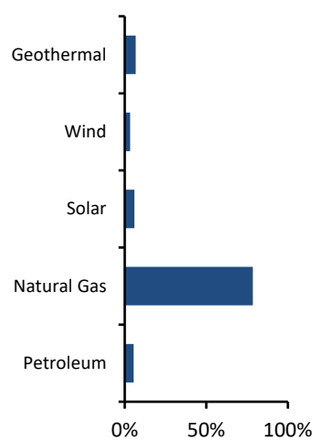
Expected resources at normal peak demand and outage conditions require some imports to maintain operating reserves. Thus, above-normal demand, high forced outage conditions, or transmission derates in the neighboring area could place WECC-Mexico in an energy emergency.

On-Peak Reserve Margin

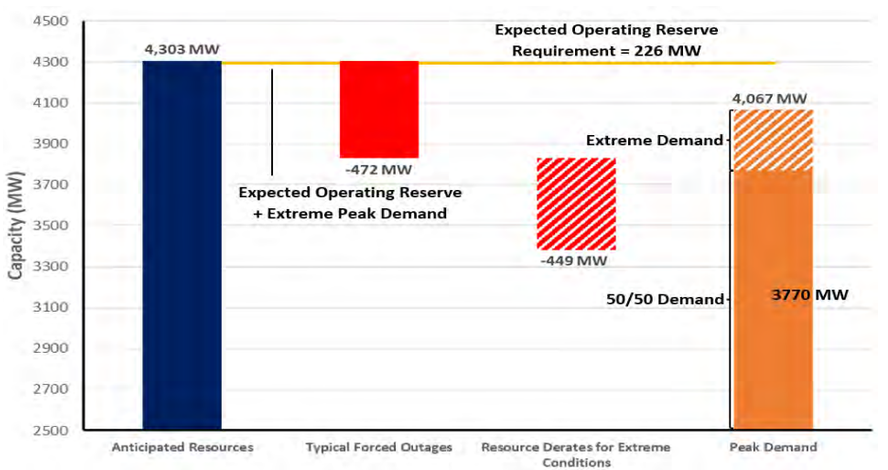
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour



WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Rocky Mountain is a new assessment area in 2025 that was part of WECC-NW in the 2024 SRA*.

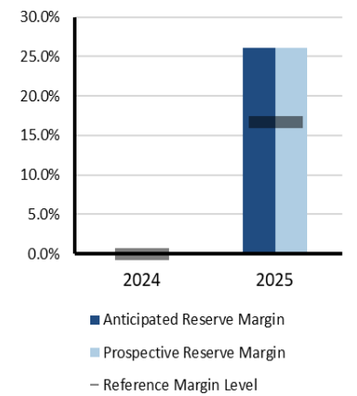
Highlights

- The reserve margins (existing-certain 25% and anticipated and prospective 26%) are not anticipated to fall below the reference margin (17%) for Summer 2025.
- Total and net internal demand (50/50) is up 25% or almost 2,800 MW, leading to a decline in the Anticipated Reserve Margin by almost a third.
- During the summer, there is increased load and decreased market purchase availability. Low wind availability and ramping scarcity events are a concern.
- Environmental and ecological factors have contributed to a rise in wildfire frequency and shortening of the fire return interval in the Rocky Mountain region, which, in addition to having caused generation outages, threatens rural co-ops disproportionately due to the extensive line buildout over remote regions.

Risk Scenario Summary

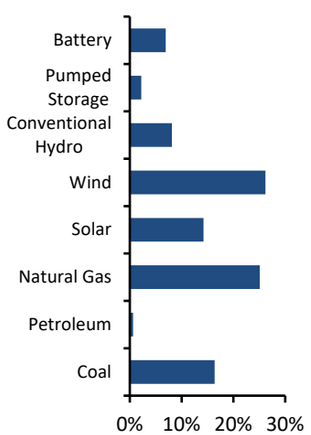
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

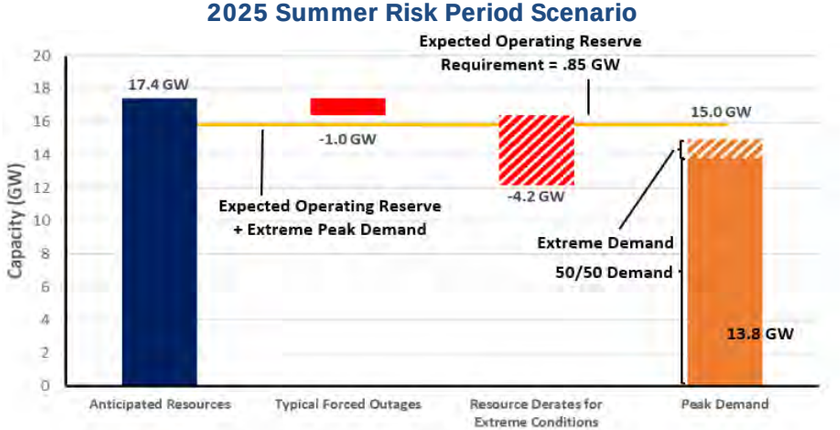


(Note: year comparison not available)

On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario



WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Northwest is a new assessment area in 2025 that was part of a larger WECC-NW footprint in the 2024 SRA.*

Highlights

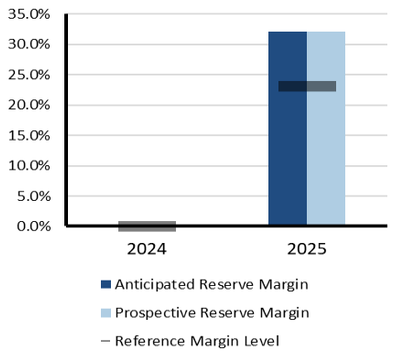
- The reserve margins (existing-certain 29% and anticipated and prospective 32%) are not anticipated to fall below the reference margin (23%) for the upcoming summer. An extreme summer peak load may be around 32,740 MW.
- Typical forced outages are forecast to be 771 MW, with derates for thermal under extreme conditions to be 1,584 MW and 2,649 MW for wind. The expected operating reserve requirement on peak is 1,750 MW.
- Extreme heat corresponds with elevated loads, reduced transmission ratings, and temperature derates of thermal resources, which can strain resource adequacy and grid reliability.
- Seasonal hydro variability is a risk.

Risk Scenario Summary

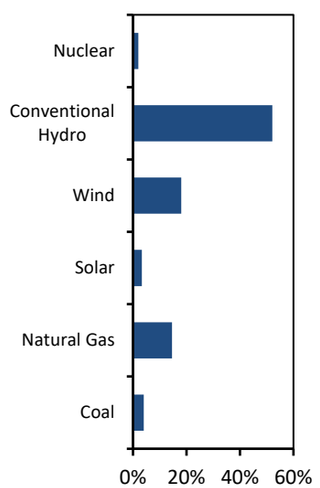
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

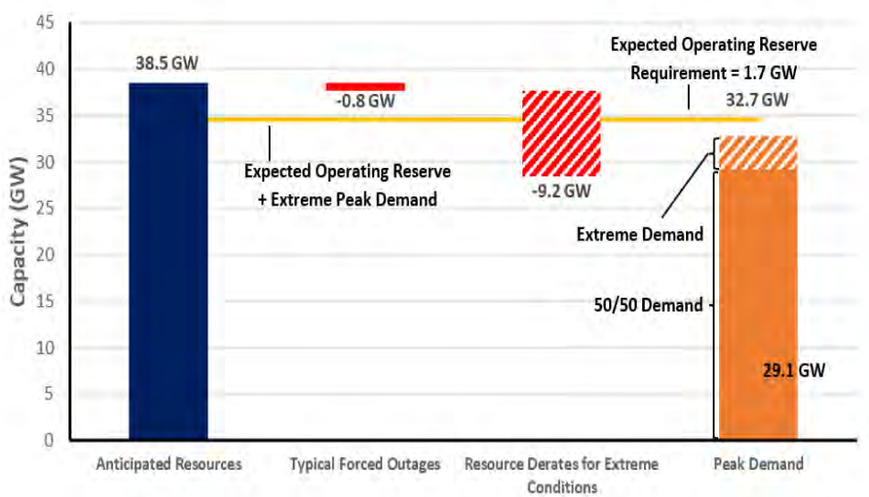
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario



WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 SRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Southwest is a new, larger assessment area in 2025 that now includes a portion of WECC-NW in the 2024 SRA.*

Highlights

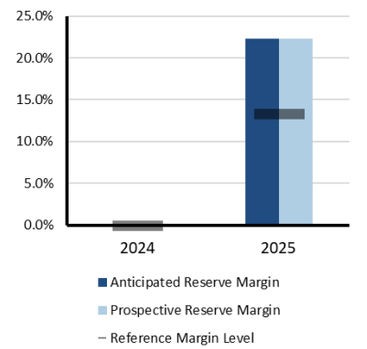
- Anticipated Reserve Margins for the summer are 22%, exceeding the Reference Margin Level for reliability calculated by WECC.
- WECC's probabilistic analysis indicates that the area is not expected to encounter LOLH or EUE under a range of demand and resource conditions.
- The peak hour is expected to occur in early July around 5:00 p.m., when solar generation output begins to diminish.
- Wide-area heat events or wildfires that affect resource and transmission availability across the western interconnection area a reliability concern for the Southwest. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability to export to the Southwest.

Risk Scenario Summary

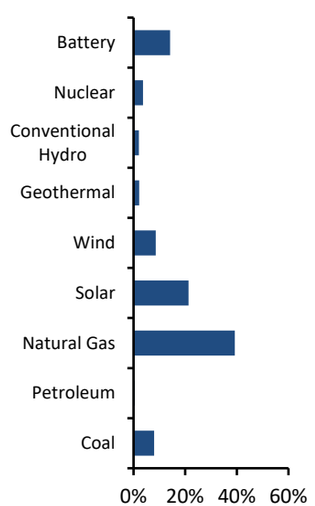
Expected resources meet operating reserve requirements under assessed scenarios with imports.

On-Peak Reserve Margin

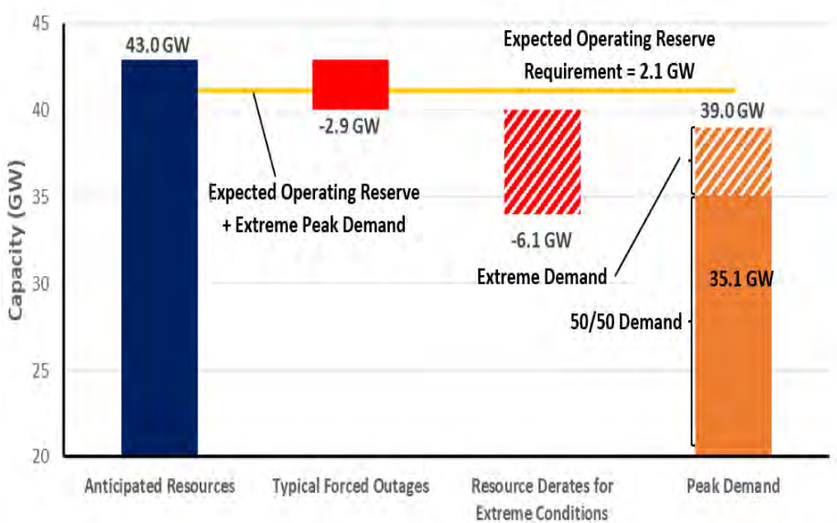
(Note: year comparison not available)



On-Peak Fuel Mix



2025 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local)

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[12] or total internal demand for the summer and winter of each year.[13]
• Total internal demand projections are based on normal weather (50/50 distribution)[14] and are provided on a coincident[15] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.
Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following: **Existing-Other Capacity**: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

[12] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[13] The summer season represents June–September and the winter season represents December–February.

[14] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[15] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the RML is a requirement. RMLs may be different for the summer and winter seasons. If an RML is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left **blue** column shows anticipated resources, and the two **orange** columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin (ARM), which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[16] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient ARMs to meet or exceed their RML for the summer 2025 as shown in **Figure 4**.

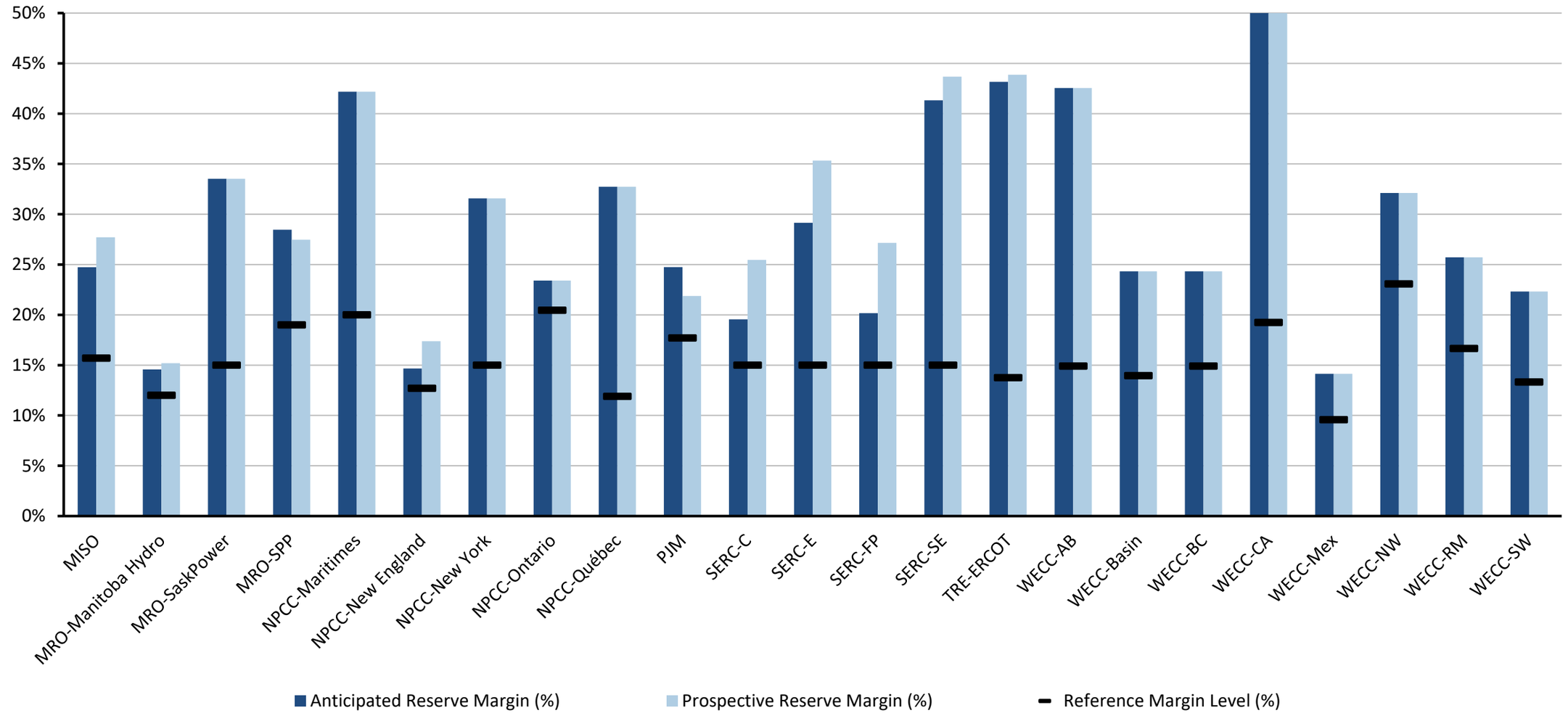


Figure 4: Summer 2025 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[16] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and RMLs.

Changes from Year to Year

Figure 5 provides the relative change in the forecast ARMs from the 2024 Summer to the 2025 Summer. A significant decline can signal potential operational issues for the upcoming season. Additional details for each assessment area are provided in the Data Concepts and Assumptions and Regional Assessments Dashboards sections.

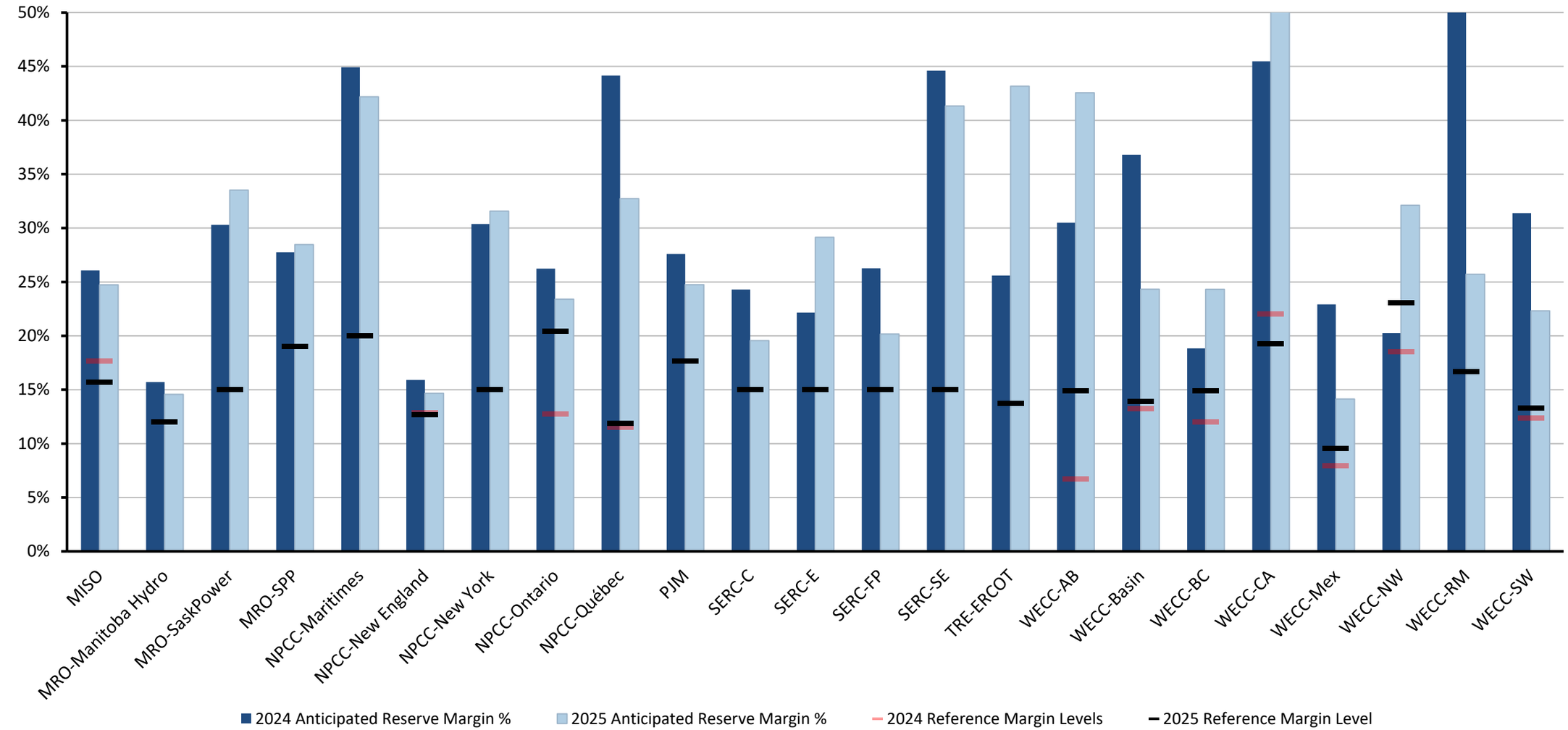


Figure 5: Summer 2024 and Summer 2025 Anticipated Reserve Margins Year-to-Year Change

Note: Yearly trends are not available for new WECC assessment areas in the United States and Baja California, Mexico.

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in Figure 6.[17] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

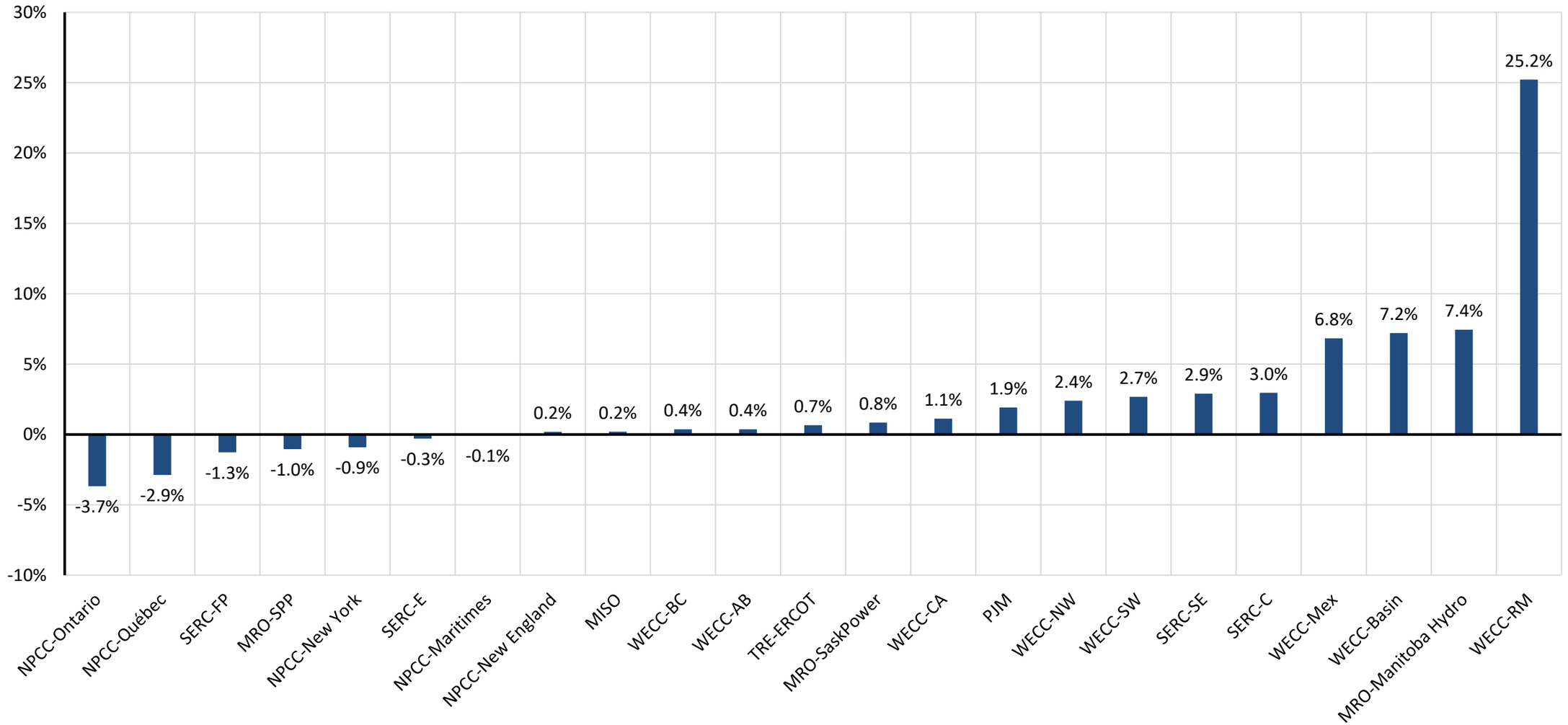


Figure 6: Changes in Net Internal Demand—Summer 2024 Forecast Compared to Summer 2025 Forecast

[17] Changes in modeling and methods are contributing to year-to-year changes in forecasted net internal demand projections in NPCC Maritimes and NPCC Ontario. See assessment area dashboards.

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	124,830	125,313	0.4%
Demand Response: Available	8,750	9,004	2.9%
Net Internal Demand	116,079	116,309	0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	143,866	142,793	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,471	2,280	-7.7%
Anticipated Resources	146,337	145,073	-0.9%
Existing-Other Capacity	1,833	1,190	-35.1%
Prospective Resources	148,740	148,543	-0.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.1%	24.7%	-1.3
Prospective Reserve Margin	28.1%	27.7%	-0.4
Reference Margin Level	17.7%	15.7%	-2.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,143	3,377	7.4%
Demand Response: Available	0	0	-
Net Internal Demand	3,143	3,377	7.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,615	5,583	-0.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,978	-1,714	-13.3%
Anticipated Resources	3,637	3,869	6.4%
Existing-Other Capacity	37	21	-42.9%
Prospective Resources	3,674	3,890	5.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.7%	14.6%	-1.1
Prospective Reserve Margin	16.9%	15.2%	-1.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,590	3,620	0.8%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,540	3,570	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,323	4,477	3.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,613	4,767	3.3%
Existing-Other Capacity	0	0	-
Prospective Resources	4,613	4,767	3.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.3%	33.5%	3.2
Prospective Reserve Margin	30.3%	33.5%	3.2
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,316	56,168	-0.3%
Demand Response: Available	979	1,408	43.8%
Net Internal Demand	55,337	54,760	-1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,855	70,549	-0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-157	-201	27.5%
Anticipated Resources	70,698	70,348	-0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	70,151	69,801	-0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.8%	28.5%	0.7
Prospective Reserve Margin	26.8%	27.5%	0.7
Reference Margin Level	19.0%	19.0%	0.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,586	3,584	-0.1%
Demand Response: Available	327	327	0.0%
Net Internal Demand	3,259	3,257	-0.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,660	4,348	-6.7%
Tier 1 Planned Capacity	0	220	-
Net Firm Capacity Transfers	63	63	0.0%
Anticipated Resources	4,723	4,631	-1.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,723	4,631	-1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.9%	42.2%	-2.7
Prospective Reserve Margin	44.9%	42.2%	-2.7
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,541	31,471	-0.2%
Demand Response: Available	1,281	1,487	16.1%
Net Internal Demand	30,260	29,984	-0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,867	37,682	-0.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,585	1,769	11.6%
Anticipated Resources	39,452	39,451	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	39,452	39,451	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.4%	31.6%	1.2
Prospective Reserve Margin	30.4%	31.6%	1.2
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,294	25,202	-0.4%
Demand Response: Available	661	399	-39.6%
Net Internal Demand	24,633	24,803	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,255	27,054	-0.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,297	1,245	-4.0%
Anticipated Resources	28,552	28,299	-0.9%
Existing-Other Capacity	138	668	384.1%
Prospective Resources	28,690	28,967	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.9%	14.1%	-1.8
Prospective Reserve Margin	16.5%	16.8%	0.3
Reference Margin Level	12.9%	12.7%	-0.2

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,753	21,955	-3.5%
Demand Response: Available	996	998	0.2%
Net Internal Demand	21,757	20,957	-3.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,856	24,760	-7.8%
Tier 1 Planned Capacity	9	413	4568.6%
Net Firm Capacity Transfers	600	689	14.8%
Anticipated Resources	27,465	25,862	-5.8%
Existing-Other Capacity	0	0	-
Prospective Resources	27,465	25,862	-5.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.2%	23.4%	-2.8
Prospective Reserve Margin	26.2%	23.4%	-2.8
Reference Margin Level	12.8%	20.5%	7.7

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,922	23,283	1.6%
Demand Response: Available	0	1,020	-
Net Internal Demand	22,922	22,263	-2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	35,731	32,132	-10.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,689	-2,582	-4.0%
Anticipated Resources	33,042	29,550	-10.6%
Existing-Other Capacity	0	0	-
Prospective Resources	33,042	29,550	-10.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.1%	32.7%	-11.4
Prospective Reserve Margin	44.1%	32.7%	-11.4
Reference Margin Level	11.5%	11.9%	0.4

SERC-Central			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,636	42,765	0.3%
Demand Response: Available	1,941	864	-55.5%
Net Internal Demand	40,695	41,900	3.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	47,674	46,949	-1.5%
Tier 1 Planned Capacity	332	592	78.1%
Net Firm Capacity Transfers	2,578	2,554	-0.9%
Anticipated Resources	50,584	50,095	-1.0%
Existing-Other Capacity	2,075	2,475	19.2%
Prospective Resources	52,659	52,570	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	19.6%	-4.7
Prospective Reserve Margin	29.4%	25.5%	-3.9
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	151,247	154,144	1.9%
Demand Response: Available	7,756	7,898	1.8%
Net Internal Demand	143,491	146,246	1.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	183,690	186,638	1.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-607	-4,200	591.9%
Anticipated Resources	183,083	182,438	-0.4%
Existing-Other Capacity	0	0	-
Prospective Resources	182,476	178,238	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	24.7%	-2.8
Prospective Reserve Margin	27.2%	21.9%	-5.3
Reference Margin Level	17.7%	17.7%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	43,567	44,015	1.0%
Demand Response: Available	985	1,558	58.2%
Net Internal Demand	42,582	42,457	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,304	54,665	6.5%
Tier 1 Planned Capacity	122	17	-86.0%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	52,019	54,832	5.4%
Existing-Other Capacity	1,131	2,628	132.3%
Prospective Resources	53,150	57,459	8.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.2%	29.1%	7.0
Prospective Reserve Margin	24.8%	35.3%	10.5
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	53,293	52,987	-0.6%
Demand Response: Available	2,824	3,158	11.8%
Net Internal Demand	50,469	49,829	-1.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,199	59,395	-6.0%
Tier 1 Planned Capacity	34	102	197.8%
Net Firm Capacity Transfers	491	381	-22.4%
Anticipated Resources	63,724	59,878	-6.0%
Existing-Other Capacity	972	3,482	258.2%
Prospective Resources	64,696	63,360	-2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	26.3%	20.2%	-6.1
Prospective Reserve Margin	28.2%	27.2%	-1.0
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	84,818	85,151	0.4%
Demand Response: Available	3,496	3,292	-5.8%
Net Internal Demand	81,323	81,859	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	99,541	112,321	12.8%
Tier 1 Planned Capacity	2,578	4,854	88.3%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	102,139	117,195	14.7%
Existing-Other Capacity	0	0	-
Prospective Resources	102,167	117,770	15.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.6%	43.2%	17.6
Prospective Reserve Margin	25.6%	43.9%	18.2
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	46,021	47,049	2.2%
Demand Response: Available	1,599	1,338	-16.3%
Net Internal Demand	44,422	45,711	2.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	63,693	64,111	0.7%
Tier 1 Planned Capacity	1,738	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	64,238	64,600	0.6%
Existing-Other Capacity	785	1,077	37.1%
Prospective Resources	65,024	65,676	1.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.6%	41.3%	-3.3
Prospective Reserve Margin	46.4%	43.7%	-2.7
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,201	12,246	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	12,201	12,246	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,941	17,176	23.2%
Tier 1 Planned Capacity	1,981	281	-85.8%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	15,922	17,457	9.6%
Existing-Other Capacity	0	0	-
Prospective Resources	15,922	17,457	9.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.5%	42.6%	12.1
Prospective Reserve Margin	30.5%	42.6%	12.1
Reference Margin Level	6.7%	9.0%	2.7

WECC-BC			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	9,275	9,309	0.4%
Demand Response: Available	0	0	-
Net Internal Demand	9,275	9,309	0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,022	11,313	2.6%
Tier 1 Planned Capacity	0	260	-
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,022	11,573	5.0%
Existing-Other Capacity	0	0	-
Prospective Resources	11,022	11,573	5.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.8%	24.3%	5.5
Prospective Reserve Margin	18.8%	24.3%	5.5
Reference Margin Level	12.0%	14.9%	2.9

WECC-California			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	54,267	54,797	1.0%
Demand Response: Available	816	746	-8.6%
Net Internal Demand	53,451	54,051	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	71,564	75,726	5.8%
Tier 1 Planned Capacity	5,998	8,470	41.2%
Net Firm Capacity Transfers	197	598	203.6%
Anticipated Resources	77,759	84,794	9.0%
Existing-Other Capacity	0	0	-
Prospective Resources	77,759	84,794	9.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	45.5%	56.9%	11.4
Prospective Reserve Margin	45.5%	56.9%	11.4
Reference Margin Level	22.0%	19.2%	-2.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	34,629	35,321	2.0%
Demand Response: Available	422	199	-52.9%
Net Internal Demand	34,207	35,122	2.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,716	40,300	6.9%
Tier 1 Planned Capacity	4,272	1,966	-54.0%
Net Firm Capacity Transfers	2,957	695	-76.5%
Anticipated Resources	44,945	42,961	-4.4%
Existing-Other Capacity	0	0	-
Prospective Resources	44,945	42,961	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.4%	22.3%	-9.1
Prospective Reserve Margin	31.4%	22.3%	-9.1
Reference Margin Level	12.4%	13.3%	1.0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	28,475	29,157	2.4%
Demand Response: Available	30	30	0.0%
Net Internal Demand	28,445	29,127	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,164	36,388	9.7%
Tier 1 Planned Capacity	201	844	319.9%
Net Firm Capacity Transfers	838	1,249	49.0%
Anticipated Resources	34,203	38,481	12.5%
Existing-Other Capacity	0	0	-
Prospective Resources	34,203	38,481	12.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.2%	32.1%	11.9
Prospective Reserve Margin	20.2%	32.1%	11.9
Reference Margin Level	18.5%	23.1%	4.6

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	13,165	14,214	8.0%
Demand Response: Available	485	620	27.8%
Net Internal Demand	12,680	13,594	7.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,534	14,923	10.3%
Tier 1 Planned Capacity	2,436	704	-71.1%
Net Firm Capacity Transfers	1,376	1,274	-7.4%
Anticipated Resources	17,346	16,901	-2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	17,346	16,901	-2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.8%	24.3%	-12.5
Prospective Reserve Margin	36.8%	24.3%	-12.5
Reference Margin Level	13.3%	14.0%	0.7

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,313	14,098	24.6%
Demand Response: Available	281	284	1.1%
Net Internal Demand	11,032	13,814	25.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,345	17,262	-0.5%
Tier 1 Planned Capacity	55	104	89.1%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	17,400	17,366	-0.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,400	17,366	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	57.7%	25.7%	-32.0
Prospective Reserve Margin	57.7%	25.7%	-32.0
Reference Margin Level	18.0%	16.7%	-1.3

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024 SRA**	**2025 SRA**	**2024 vs. 2025 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,529	3,770	6.8%
Demand Response: Available	0	0	-
Net Internal Demand	3,529	3,770	6.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,314	4,303	29.8%
Tier 1 Planned Capacity	874	0	-100.0%
Net Firm Capacity Transfers	150	0	-100.0%
Anticipated Resources	4,338	4,303	-0.8%
Existing-Other Capacity	0	0	-
Prospective Resources	4,338	4,303	-0.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.9%	14.1%	-8.8
Prospective Reserve Margin	22.9%	14.1%	-8.8
Reference Margin Level	7.9%	9.6%	1.6

Variable Energy Resource Contributions

Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (e.g., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area

	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	30,992	6,039	19%	18,246	9,123	50%	1,572	1,467	93%	3,159	3,107	98%
MRO-Manitoba Hydro	259	48	19%	-	-	0%	202	60	30%	-	-	0%
MRO-SaskPower	816	310	38%	30	9	29%	848	686	81%	-	-	0%
NPCC-Maritimes	1,230	314	26%	147	-	0%	1,313	1,313	100%	12	6	50%
NPCC-New England	1,546	142	9%	3,266	1,412	43%	575	175	31%	192	110	57%
NPCC-New York	2,586	446	17%	609	243	40%	976	478	49%	32	17	53%
NPCC-Ontario	4,943	742	15%	478	66	14%	8,862	5,320	60%	-	-	0%
NPCC-Québec	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
PJM	12,465	1,855	15%	13,731	6,244	45%	2,505	2,505	100%	310	288	93%
SERC-Central	1,324	370	28%	1,810	1,053	58%	4,991	3,418	68%	100	100	100%
SERC-East	-	-	0%	7,097	5,022	71%	3,078	3,008	98%	19	8	41%
SERC-Florida Peninsula	-	-	0%	8,295	5,749	54%	-	-	0%	631	631	100%
SERC-Southeast	-	-	0%	8,507	7,728	91%	3,258	3,308	102%	115	105	92%
SPP	35,613	5,556	16%	1,159	492	42%	114	56	49%	182	41	23%
Texas RE-ERCOT	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC-AB	5,712	796	14%	2,174	1,480	68%	894	456	51%	250	235	94%
WECC-BC	747	149	20%	2	-	0%	16,918	10,181	60%	-	-	0%
WECC-Basin	4,859	911	19%	2,648	2,231	84%	2,637	2,022	77%	120	118	98%
WECC-CA	7,836	1,207	15%	25,059	14,756	59%	14,565	6,518	45%	11,459	11,115	97%
WECC-Mexico	300	50	17%	350	227	65%	-	-	0%	-	-	0%
WECC-NW	9,199	3,107	34%	1,349	666	49%	33,068	20,145	61%	11	10	91%
WECC-RM	5,681	1,359	24%	2,523	1,669	66%	3,251	2,446	75%	242	235	97%
WECC-SW	4,848	1,091	23%	9,288	4,293	46%	1,316	845	64%	4,187	3,982	95%
EASTERN INTERCONNECTION	91,773	15,822	17%	67,138	37,886	56%	28,294	21,794	77%	4,752	4,413	93%
QUÉBEC INTERCONNECTION	4,024	885	22%	10	-	0%	444	444	100%	-	-	0%
TEXAS INTERCONNECTION	40,102	9,396	23%	31,473	22,962	73%	572	439	77%	15,291	12,190	80%
WECC INTERCONNECTION	39,182	8,670	22%	43,393	25,322	58%	72,649	42,613	59%	16,269	15,695	96%
All INTERCONNECTIONS	**175,081**	**34,774**	**20%**	**142,014**	**86,170**	**61%**	**101,959**	**65,290**	**64%**	**36,311**	**32,298**	**89%**

Review of 2024 Capacity and Energy Performance

The summer of 2024 was the fourth hottest on record for both the contiguous United States[18] and Canada,[19] with some areas experiencing their hottest summer ever. The result was record electricity demand in the United States as well as in Canada, which was particularly pronounced in the Western Interconnection. While peak demand exceeded normal summer forecasts in most areas, only one area experienced demand that met or exceeded a 90/10 demand scenario as defined in the prior year's *SRA*. In addition, Hurricane Helene, the deadliest Atlantic hurricane to strike the US mainland since 2005, made landfall in Florida in September and led to widespread flooding and power outages from Florida to North Carolina. Helene was one of five hurricanes to impact the US last summer, joining other extreme weather incidents such as drought across the West and wildfires in the Southwest. To manage the challenging grid conditions brought about by heat domes and these other extreme weather events, grid operators across North America used various operating mitigations up to, and including, the issuance of EEAs. No disruptions to the BPS occurred due to inadequate resources. The following section describes actual demand and resource levels in comparison with NERC's *2024 SRA* and summarizes 2024 resource adequacy events.

Eastern Interconnection–Canada and Québec Interconnection

During the June heat wave that extended across the eastern half of the United States and Canada, system operators in Ontario and the Maritimes provinces followed conservative operating protocols and issued energy emergencies. A late-summer heat wave resulted in an energy emergency in Maritimes.

Eastern Interconnection–United States

MISO experienced peak electricity demand during late August. Demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were near expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. On the day prior to MISO's peak demand, operators issued advisories to maximize generation. Similar advisories were issued earlier in the summer, coinciding with above-normal temperatures and periods of high generator forced outages.

In SPP, summer electricity demand peaked in mid-July at a level below normal 50/50 forecasts. Above-normal wind performance and sufficient generator availability contributed to sufficient electricity supplies during peak conditions. In late August, however, SPP operators issued an EEA1 due to high load forecasts, generator outages, and forecasts for low wind output. The period coincided with MISO's peak demand period, making excess supplies for import uncertain. Also in August during a period of high demand and low resource availability, operators issued public appeals for conservation when a 345 kV line outage caused a transmission emergency. During other summer periods, SPP operators responded to forecasts for high demand and low resource conditions with resource advisories intended to maximize available generators.

Like SPP, PJM also experienced peak electricity demand in mid-July and issued an EEA in August. Peak demand in July was near 90/10 forecast levels. Generator outages were below normal at the time of peak demand. In late August, PJM operators issued an EEA1 in expectation of extreme demand.

A period of unseasonably high demand in early summer brought on by high temperatures in the Northeast contributed to an EEA1 in NPCC-New England when a large thermal generator encountered a forced outage. Peak demand in New England occurred in mid-July at a near-normal summer peak demand level. At the time of peak demand, generator outages were below historical averages.

Peak demand in the NPCC-New York area occurred in early July at a level below the normal summer peak demand forecast. Generator outages were below historical levels for peak summer conditions.

[18] US sweltered through its 4th-hottest summer on record – National Oceanic and Atmospheric Administration
[19] Climate Trends and Variations Bulletin – Summer 2024 – Government of Canada

Systems in the U.S. Southeast saw successive heat waves beginning prior to the official start to summer and extending to early fall. Operators in the SERC region used conservative operations and resource advisories to maximize generation and transmission network availability and issued EEAs when warranted by conditions. In some instances, EEAs were issued when generator outages threatened supplies needed for high demand. Peak demand in all assessment areas within the SERC region exceeded normal summer peak demand levels and approached 90/10 demand forecasts.

Texas Interconnection–ERCOT

Peak demand in ERCOT was at or near record levels last summer, as load growth and extreme temperatures contributed to escalating summer electricity needs. Demand peaked in August well above the 90/10 demand forecast. At the time of peak demand, wind generation was below expected levels for peak demand periods, while output from solar generation was near forecasted levels. Forced generator outages were well below historical average levels for peak demand, helping to meet the extreme electricity demand. Unlike the prior summer, ERCOT did not issue any conservation appeals to customers to reduce demand during high-demand periods. New solar generation, battery resources, and some thermal generation additions since Summer 2023 boosted electricity supplies, enabling operators to meet demand records without demand-side management.

Western Interconnection

In July, the Western Interconnection set a new peak demand record of 167,988 MW. Operators in United States and Canada employed procedures throughout summer to manage challenging grid conditions from extended extreme heat and wildfires.

Western Interconnection–Canada

In the province of Alberta, the electric system operator issued an EEA3 in early July as high temperatures contributed to elevated demand that coincided with a forced generator outage. A new summer peak demand record was set in Alberta later in July at 12.2 MW (up from 11.5 GW in summer 2023). Alberta's demand peak was slightly higher than the normal demand peak scenario projected in the spring of last year.

In British Columbia, peak demand reached 9.4 GW (up from 9.2 GW the previous year), also slightly above the normal peak demand that was projected last year.

In both Alberta and British Columbia, peak demand was still below the extreme peak demand scenarios previously projected, which lowered the risk profile of those provinces over Summer 2024.

Western Interconnection–United States

Demand peaked in July in the U.S. Northwest at a level below the normal summer peak demand. During a period of high demand in July, operators at a BA in the U.S. Northwest issued an EEA1 to address forecasted conditions.

The California-Mexico assessment area, which consists of the CAISO, Northern California, and CENACE BAs, experienced system peak electricity demand in early September at a level nearing the 90/10 peak demand forecast. The extreme demand contributed to localized supply concerns and led CAISO to declare a transmission emergency and use conservative operations protocols to posture the system. Despite the extreme demand, operators were able to maintain sufficient supply without resorting to public appeals, as was required in prior summers. New battery resources were instrumental in providing energy to meet high demand during late afternoon and early evenings. Natural-gas-fired generators also performed well and were important to meeting high demand during these same periods. Dry conditions from early summer prompted operators in CA/MX to frequently employ public safety power shutoff (PSPS) procedures beginning in June. Active wildfires led transmission operators to de-energize transmission lines in Northern California and declare transmission emergencies that affected operations across CAISO.

The U.S. Southwest experienced extended heat conditions and demand levels that exceeded 90/10 peak summer forecasts, with peak occurring in early August. Higher-than-expected wind and solar output and low generator outages helped maintain sufficient supplies.

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	SRA Peak Demand Scenarios[2] (GW)	Wind – Actual[1] (MW)	Wind – Expected[3] (MW)	Solar – Actual[1] (MW)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
MISO	118.6	116.1 125.8	4,565	5,599	5,858	4,981	4,412
MRO-Manitoba Hydro	3.6	3.1 3.3	50	48	0	0	290
MRO-SaskPower	3.7	3.5 3.7	170	208	22	6	0
MRO-SPP	54.3	55.3 57.5	10,869	5,876	442	486	6,046
NPCC-Maritimes	3.5	3.3 3.6	428	262	21	-	777
NPCC-New England	24.3	24.6 26.5	174	122	167	1,111	1,496
NPCC-New York	29	30.3 32	130	340	0	53	1,451
NPCC-Ontario	23.9	21.8 23.7	915	720	260	66	1,174
NPCC-Québec	23	22.9 24	2,270	-	0	-	10,500*
PJM	153.1	143.5 156.9	3,366	1,703	2,709	5,694	6,402
SERC-C	42.3	40.7 43.9	312	172	813	996	959
SERC-E	44	42.6 44.7	0	-	3,009	2,405	1,878
SERC-FP	52.4	50.5 53.6	0	-	5,376	5,643	
SERC-SE	44.9	44.4 45.3	0	-	3,507	7,217	1,007
TRE-ERCOT	85.5	81.3 82.3	6,286	9,070	17,566	17,797	3,622
WECC-AB	12.2	12.2 12.7	1,091	666	1,114	786	-**
WECC-BC	9.4	9.3 9.8	257	140	0.94	0	-**

2024 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	**Actual Peak Demand[1] (GW)**	**SRA Peak Demand Scenarios[2] (GW)**	**Wind – Actual[1] (MW)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MW)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
WECC-CA/MX	58.9	53.2 61.6	1,633	1,124	10,112	13,147	921
WECC-NW	59.7	63 69.7	4,694	2,964	6,339	2,595	3,655
WECC-SW	30.8	26.4 28.8	1,179	542	3,357	1,294	2,042
Highlighting Notes	Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.		Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

Table Notes:
[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities.
[2] See NERC *2024 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.
[3] Expected values of wind and solar resources from the *2024 SRA*.
[4] Values from NERC Generator Availability Data System for the 2024 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024 summer risk period scenarios in the *2024 SRA*.
*Values include both maintenance and forced outages.
**Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

Planning Resource Auction
Results for Planning Year 2025-26

April 2025

CORRECTIONS

Reposted 05/29/25

Slides Updated: 7, 11, 18-20, 23, 32-34

MISO met the planning year 2025/26 resource adequacy requirements, but pressure persists with reduced capacity surplus across the region and is reflected through improved price signals in this year's auction

Summer
$666.50
—
Fall
$91.60 (North/Central)
$74.09 (South)
—
Winter
$33.20
—
Spring
$69.88
—
Annualized
$217 (North/Central)
$212 (South)

- MISO's Reliability-Based Demand Curve (RBDC) improves price signals, reflecting the increased value of accredited capacity beyond the seasonal Planning Reserve Margin (PRM) target
  - For example, the auction cleared 1.9% above the 7.9% summer PRM target
- Summer price reflects the lowest available surplus capacity
  - Fall price varied slightly due to transfer limitations between the North and South
- Consistent with past years, most Load Service Entities (LSEs) self-supplied or secured capacity in advance and are hedged with respect to auction prices
- Surplus above the target PRM dropped 43% compared to last summer, despite the slightly lower PRM target (7.9% vs. 9.0% last year)
  - New capacity additions did not keep pace with reduced accreditation, suspensions/retirements and slightly reduced imports
- The results reinforce the need to increase capacity, as demand is expected to grow with new large load additions

Auction outcomes are consistent with the design intent of the Reliability-Based Demand Curve (RBDC), and MISO and its members can expect more stable and predictable capacity pricing, especially in surplus situations

In the 2025 PRA, the RBDC…

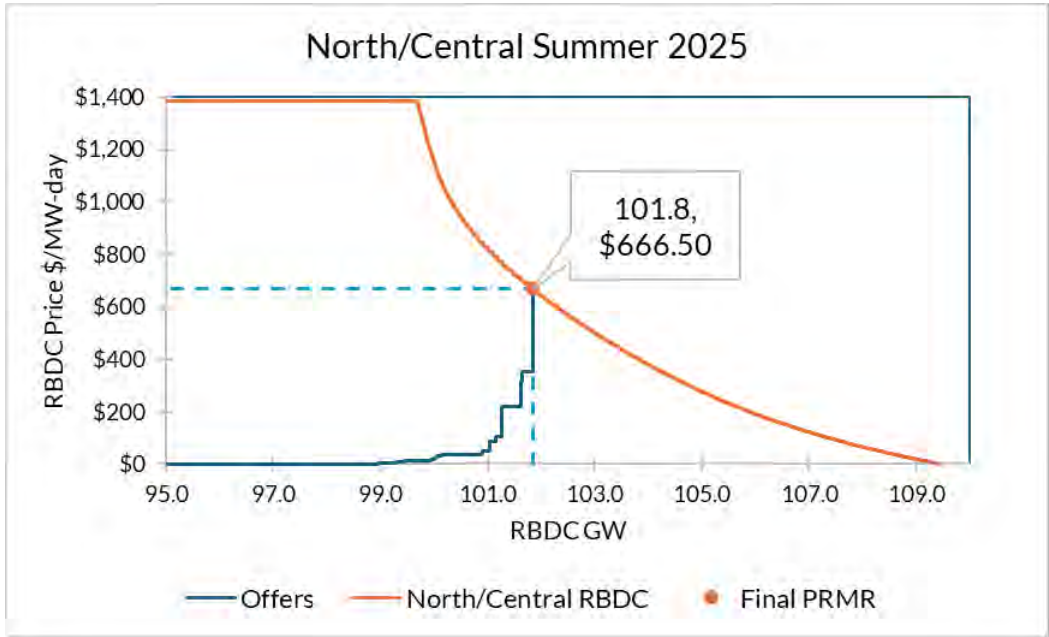
- Delivers competitive prices aligned with seasonal risks and tightening surplus
    - Prioritizes summer availability, the system's highest-risk season (based on 1-in-10 LOLE)
- Values incremental capacity above and below the LOLE target based on its reliability
    - Clears capacity above target Planning Reserve Margin based on its reliability value in each season
- Stabilizes prices in non-summer seasons, avoiding extreme volatility

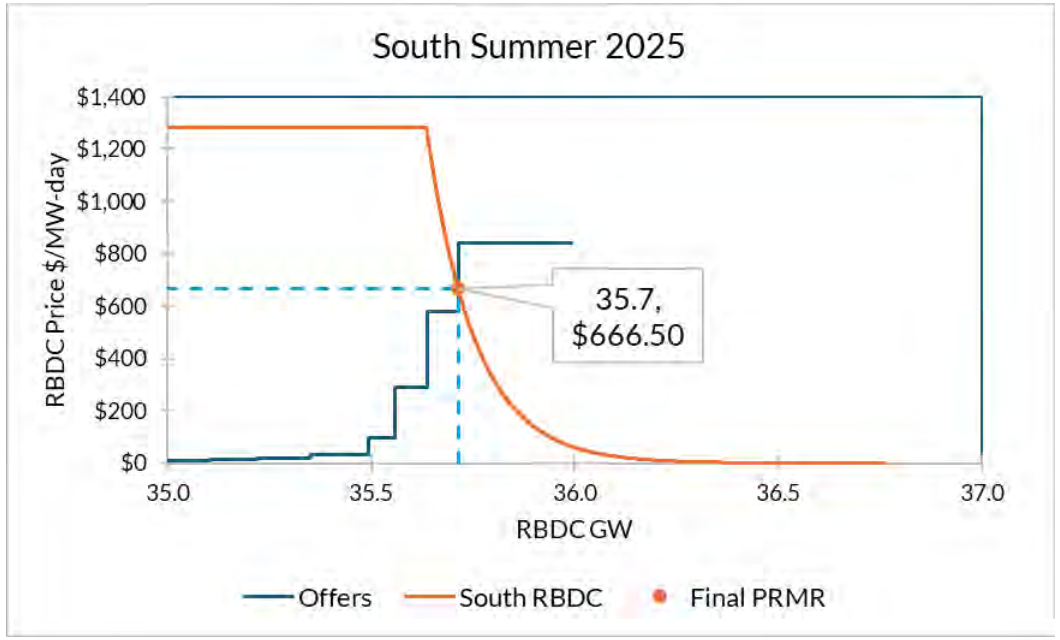
Why it Matters

- Sends clear and stable investment signals across the system, including to external resources
- Provides transparent value for capacity that exceeds the Planning Reserve Margin target
- Reflects subregional capacity needs and clears accordingly across all seasons

LOLE: Loss of Load Expectation

Auction pricing outcomes with the Reliability-Based Demand Curve (RBDC) better reflect value of capacity and resource adequacy risk across seasons





- Summer clearing of $666.50 reflects highest reliability risk and reducing surplus capacity year-over-year
  - Surplus capacity in the summer has reduced from approximately 6.5 GW in 2023, to 4.6 GW in 2024, to 2.6 GW in 2025
- Incremental capacity cleared beyond the target Planning Reserve Margin based on the value it adds to reliability (e.g., North/Central "effective" summer margin at 10.1% and South at 8.7% vs. target 7.9%)
  - A small quantity of capacity, that was offered at a price higher than the reliability value indicated through the demand curve, did not clear

LOLE: Loss of Load Expectation

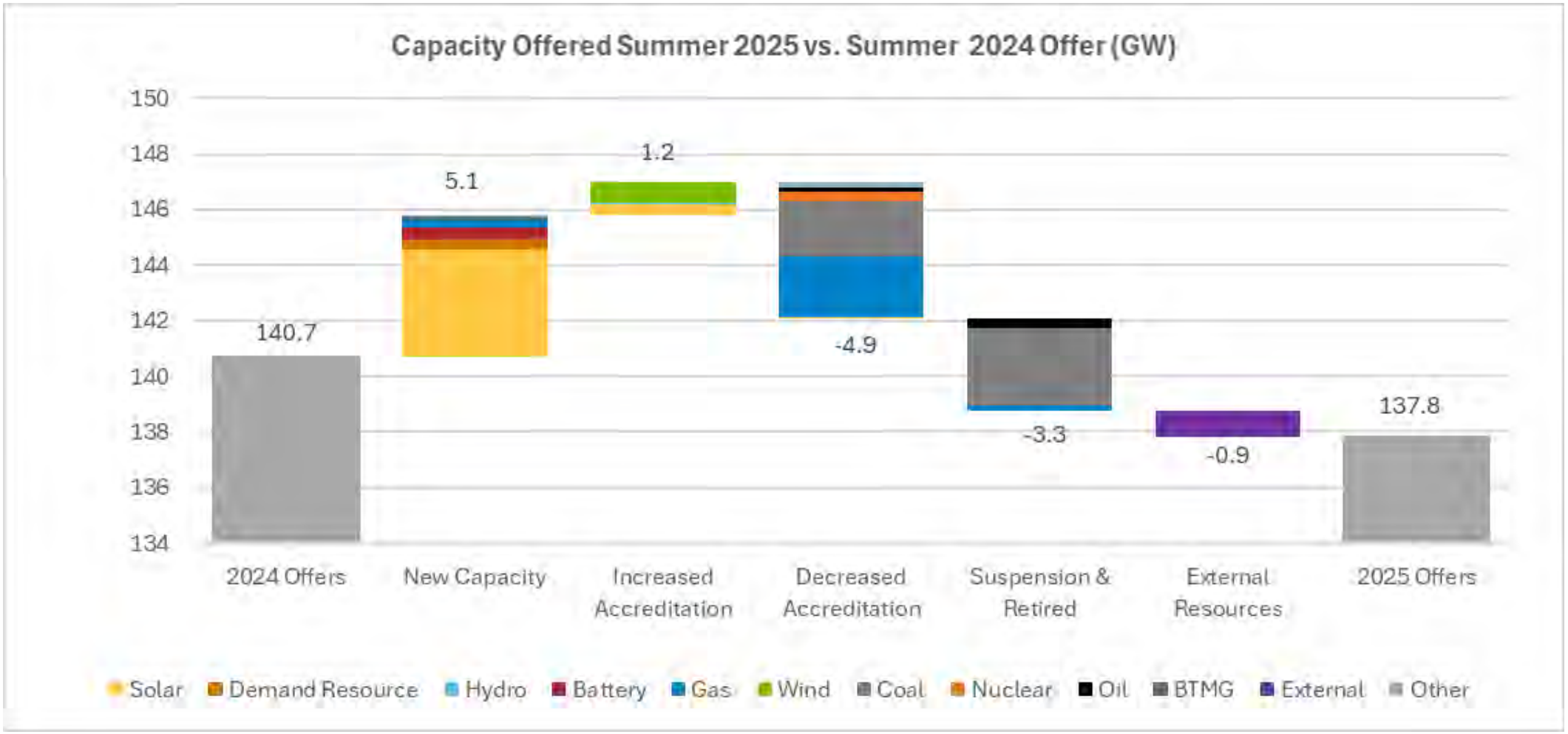
MISO's Reliability-Based Demand Curve (RBDC) improves price signals, reflecting the increased value of accredited capacity beyond seasonal reliability targets

- Under RBDC, each season has an initial reliability target (PRM%)
- Auction cleared above seasonal final reliability target, representing additional reliability value at cost-competitive prices

	2025 Planning Resource Auction Initial Target vs. Final Cleared	Additional Reliability	Auction Clearing Price
Summer	Initial, 7.90% Cleared, 9.80%	+1.9%	$666.50
Fall	Initial, 14.90% Cleared, 17.50%	+2.6%	$91.60 N/C $74.09 S
Winter	Initial, 18.40% Cleared, 24.50%	+6.1%	$33.20
Spring	Initial, 25.30% Cleared, 26.80%	+1.5%	$69.88 ***Annualized*** **$217** (North/Central) **$212** (South)

PRM: Planning Reserve Margin

New capacity additions did not keep pace with decreased accreditation, suspensions/ retirements and external resources



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

MISO has taken action on many Reliability Imperative initiatives to address resource adequacy challenges, but there's more to be done

Ongoing Challenges

- Accelerating demand for electricity
- Rapid pace of generation retirements continue
- Loss of accredited capacity and reliability attributes
- Majority of new resources with variable, intermittent output and high weather correlation
- Delays of new resource additions
- More frequent extreme weather

Completed Initiatives

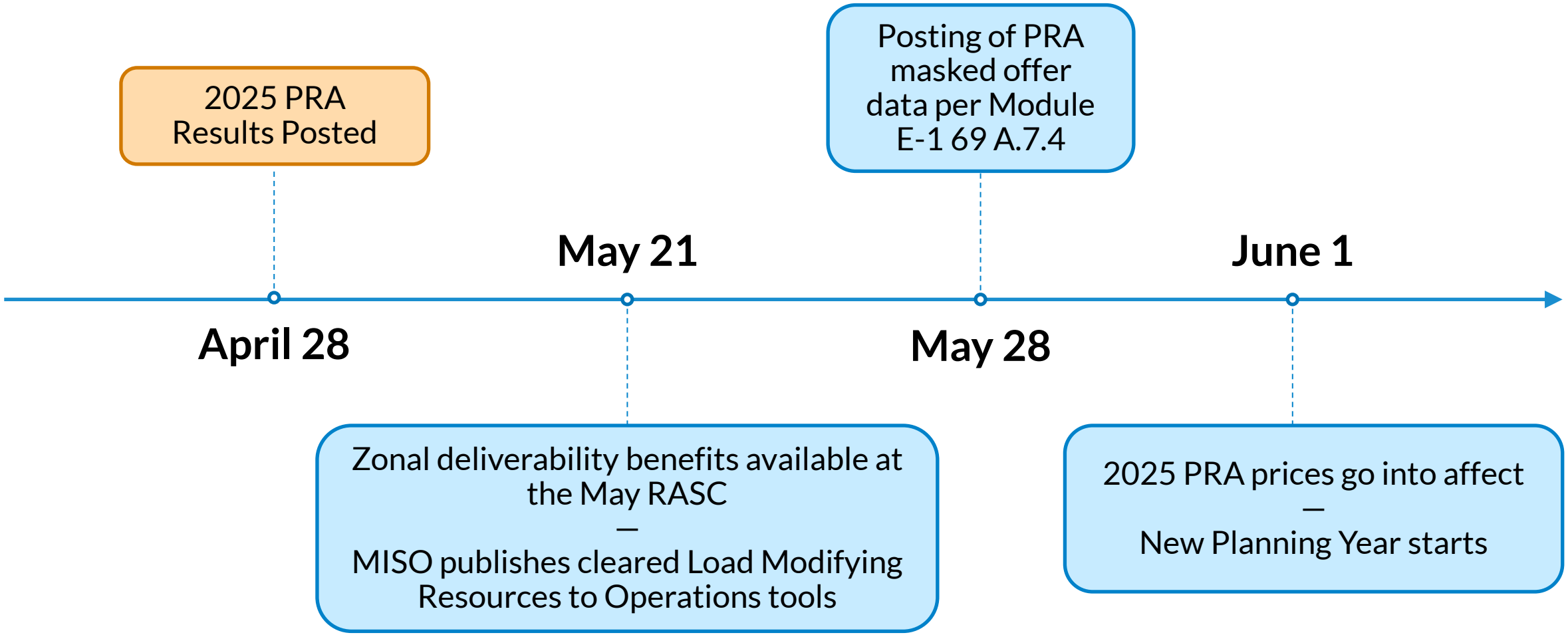
- ✓ Implemented Reliability-Based Demand Curve in 2025 PRA
- ✓ Non-emergency resource accreditation *(effective PY 2028/29)*
- ✓ Generation interconnection queue cap
- ✓ Improved generator interconnection queue process (*New application portal coming June 2025)*
- ✓ Approved over $30 billion in new transmission lines

Initiatives In Progress

- ❑ Implement Direct Loss of Load (DLOL)-based accreditation
- ❑ Enhance resource adequacy risk modeling
- ❑ Reduce queue cycle times through automation
- ❑ Implement interim Expedited Resource Addition Study (ERAS) process *(June 2025)*
- ❑ Demand Response and Emergency Resource reforms
- ❑ Enhance allocation of resource adequacy requirements

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Next Steps


2025 PRA Results Posted
April 28
May 21
Zonal deliverability benefits available at the May RASC
—
MISO publishes cleared Load Modifying Resources to Operations tools
Posting of PRA masked offer data per Module E-1 69 A.7.4
May 28
June 1
2025 PRA prices go into affect
—
New Planning Year starts

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Acronyms

ACP: Auction Clearing Price

ARC: Aggregator of Retail Customers

BTMG: Behind the Meter Generator

CIL: Capacity Import Limit

CEL: Capacity Export Limit

CONE: Cost of New Entry

CPF: Coincident Peak Forecast

DLOL: Direct Loss-of-Load

DR: Demand Resource

ELCC: Effective Load Carrying Capability

EE: Energy Efficiency

ER: External Resource

ERAS: Expedited Resource Addition Study

ERZ: External Resource Zones

FRAP: Fixed Resource Adequacy Plan

ICAP: Installed Capacity

IMM: Independent Market Monitor

LBA: Load Balancing Authority

LCR: Local Clearing Requirement

LOLE: Loss of Load Expectation

LMR: Load Modifying Resource

LRR: Local Reliability Requirement

LRZ: Local Resource Zone

LSE: Load Serving Entity

OMS: Organization of MISO States

PO: Planned Outage

PRA: Planning Resource Auction

PRM: Planning Reserve Margin

PRMR: Planning Reserve Margin Requirement

RASC: Resource Adequacy Sub-Committee

RBDC: Reliability-Based Demand Curve

SAC: Seasonal Accredited Capacity

SREC: Sub-Regional Export Constraint

SRIC: Sub-Regional Import Constraint

SRPBC: Sub-Regional Power Balance Constraint

SS: Self Schedule

UCAP: Unforced Capacity

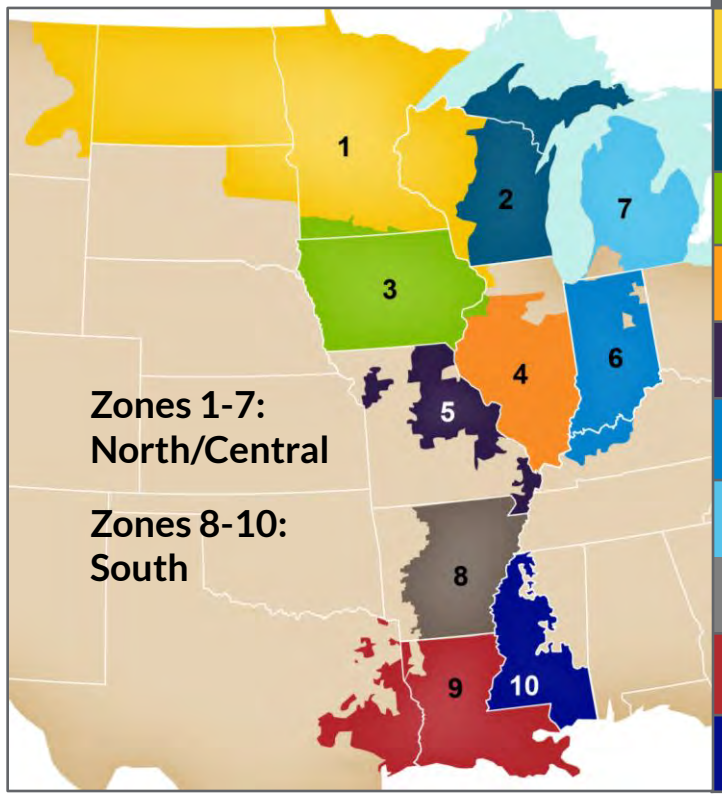
ZIA: Zonal Import Ability

ZRC: Zonal Resource Credit

The 2025 PRA demonstrated sufficient capacity at the regional, subregional and zonal levels, with the summer price reflecting the highest risk and a tighter supply-demand balance

2025 PRA Results

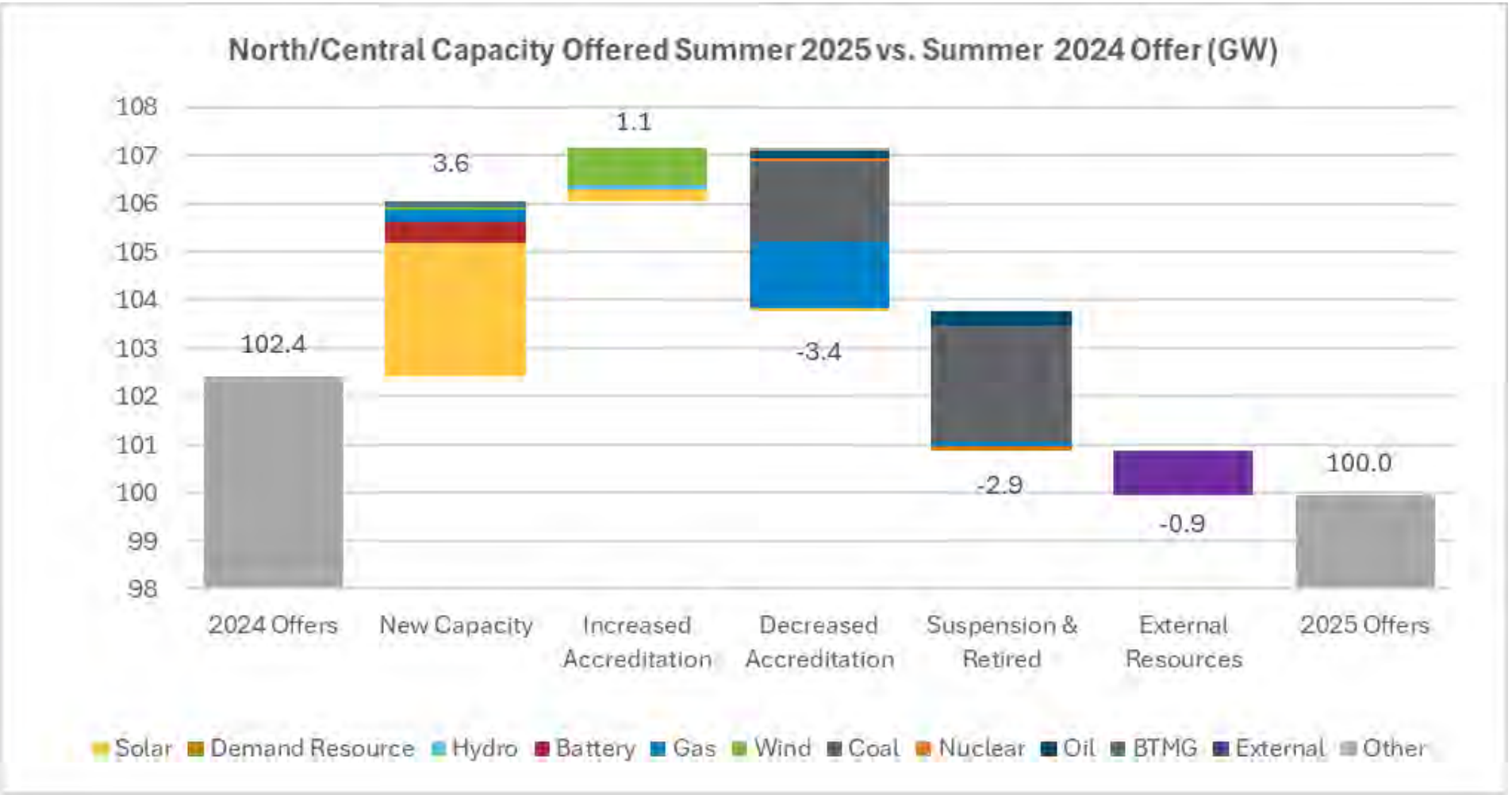
MISO Resource Adequacy Zones



	Price/MW-Day			
	Summer	Fall	Winter	Spring
1	$666.50	$91.60	$33.20	$69.88
2				
3				
4				
5				
6				
7				
8		$74.09		
9				
10				

Annualized
$217 (North/Central)
$212 (South)

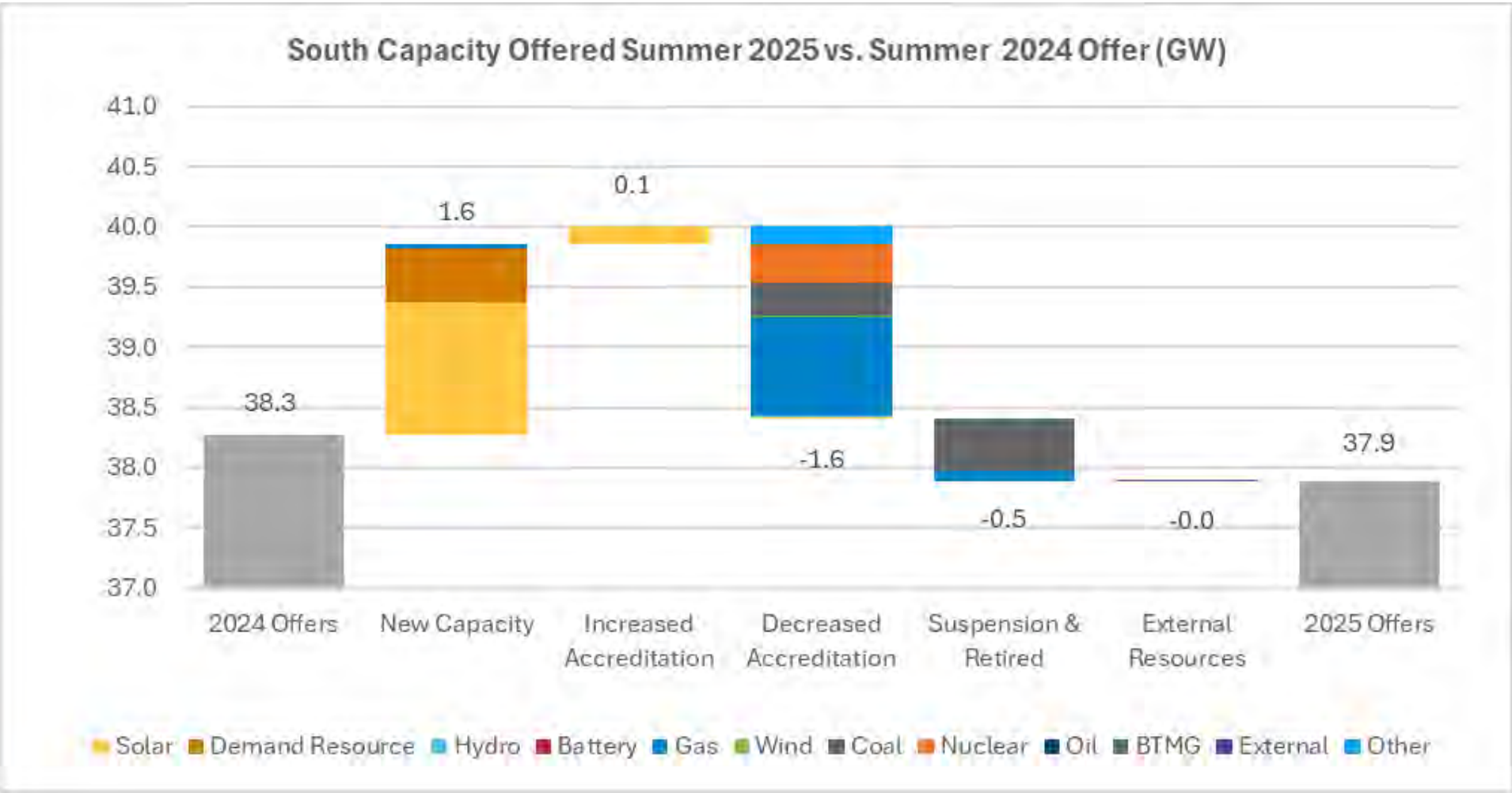
For North/Central, new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

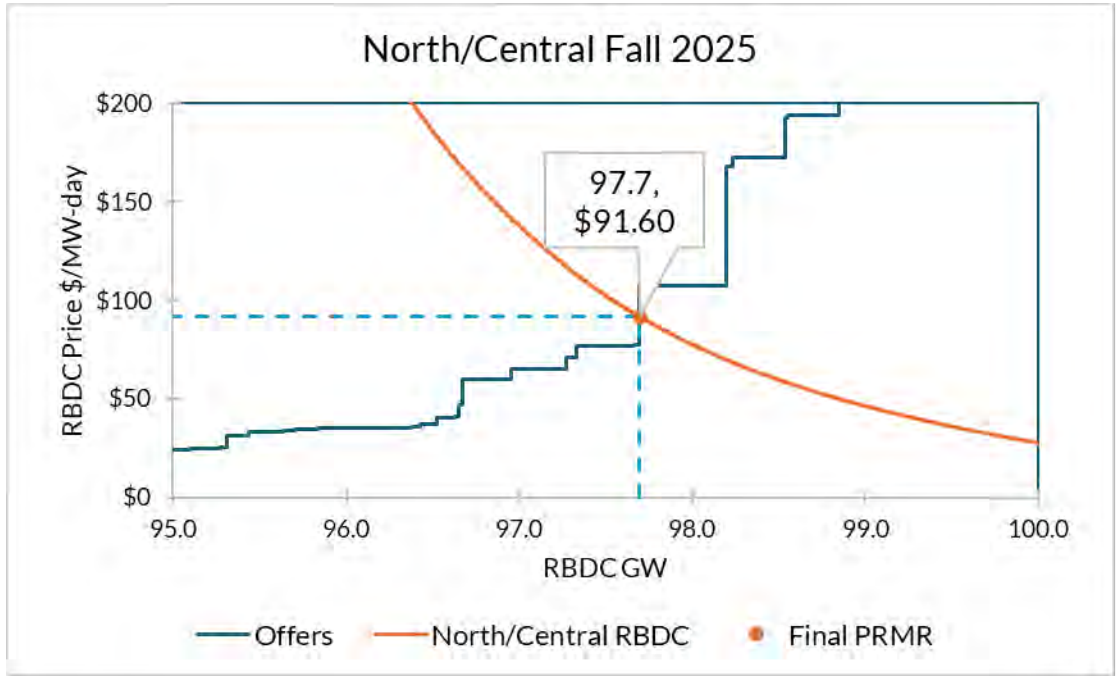
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

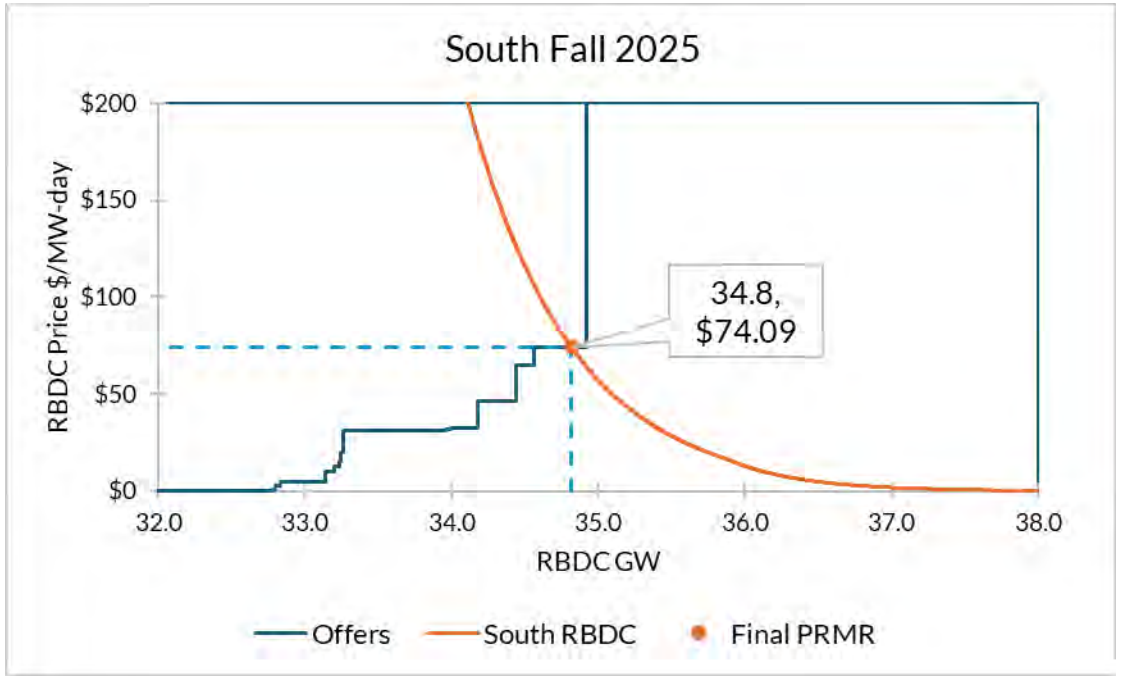
For the South, new capacity additions nearly offset the negative impacts of decreased accreditation, suspensions/retirements



BTMG: Behind the Meter Generation | Capacity indicated is offered accredited value

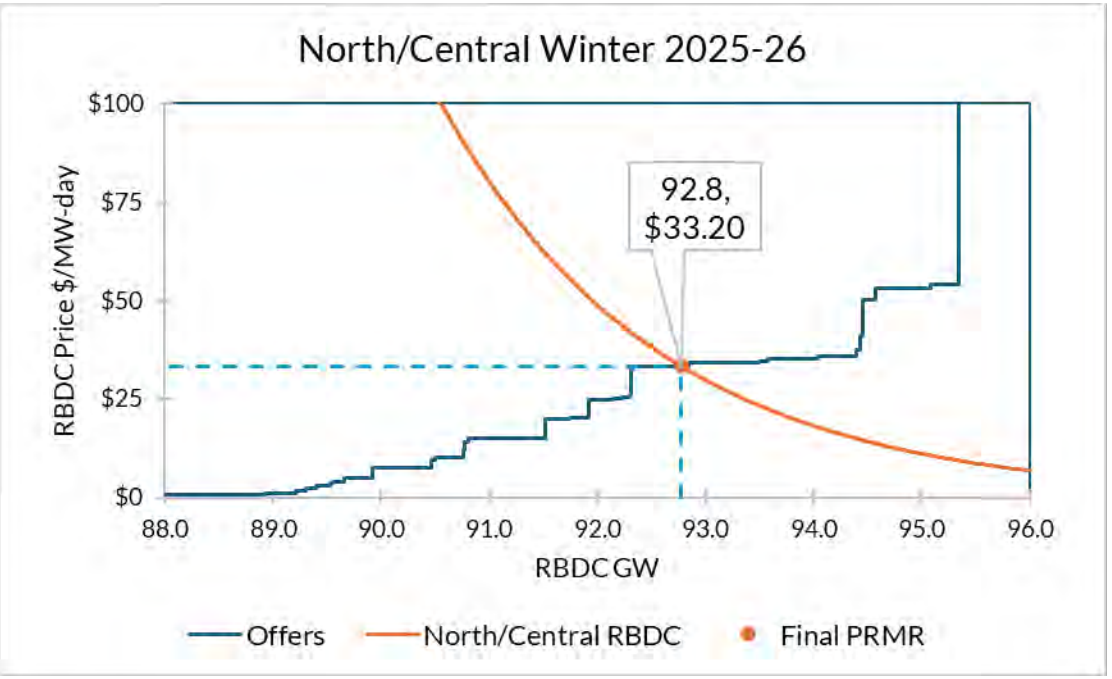
Fall 2025 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

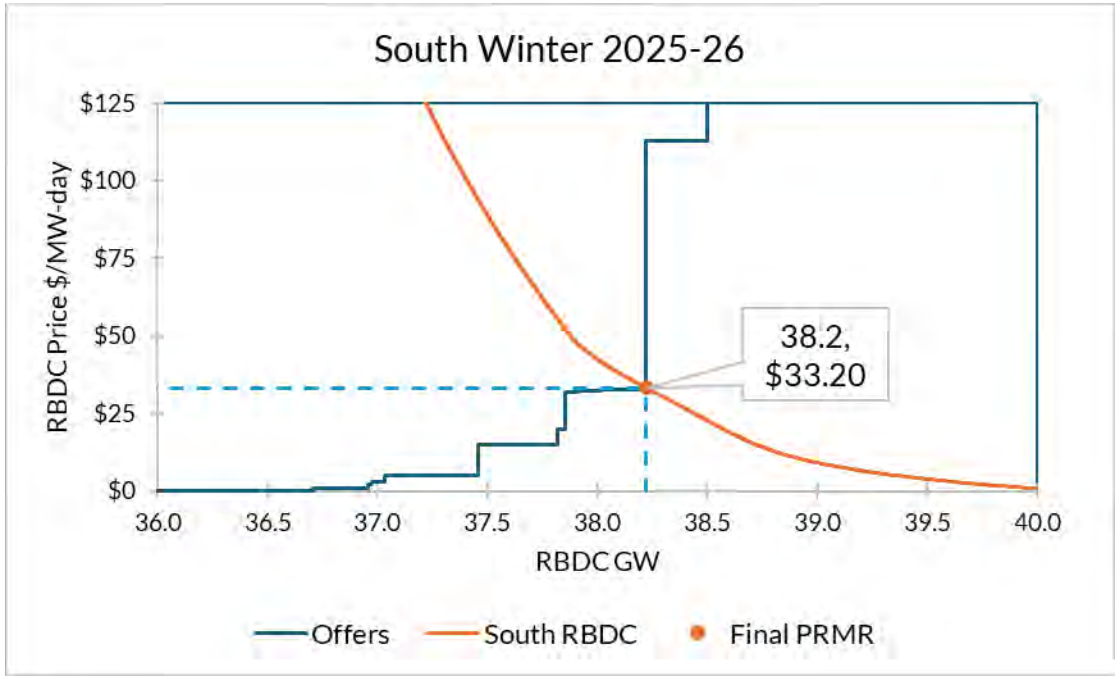




- Subregional RBDCs are determining clearing for both subregions
- Subregional Power Balance Constraint (SRPBC), South to North, is binding resulting in price separation between North/Central and South subregions in Fall season
  - ACP for North subregion is $91.60, and $74.09 South subregion
  - A marginal resource in the South sets the price in that subregion
- In fall season, "effective" margin for North/Central subregion is at 18.4% and 15.2 % for South subregion vs. target of 14.9%

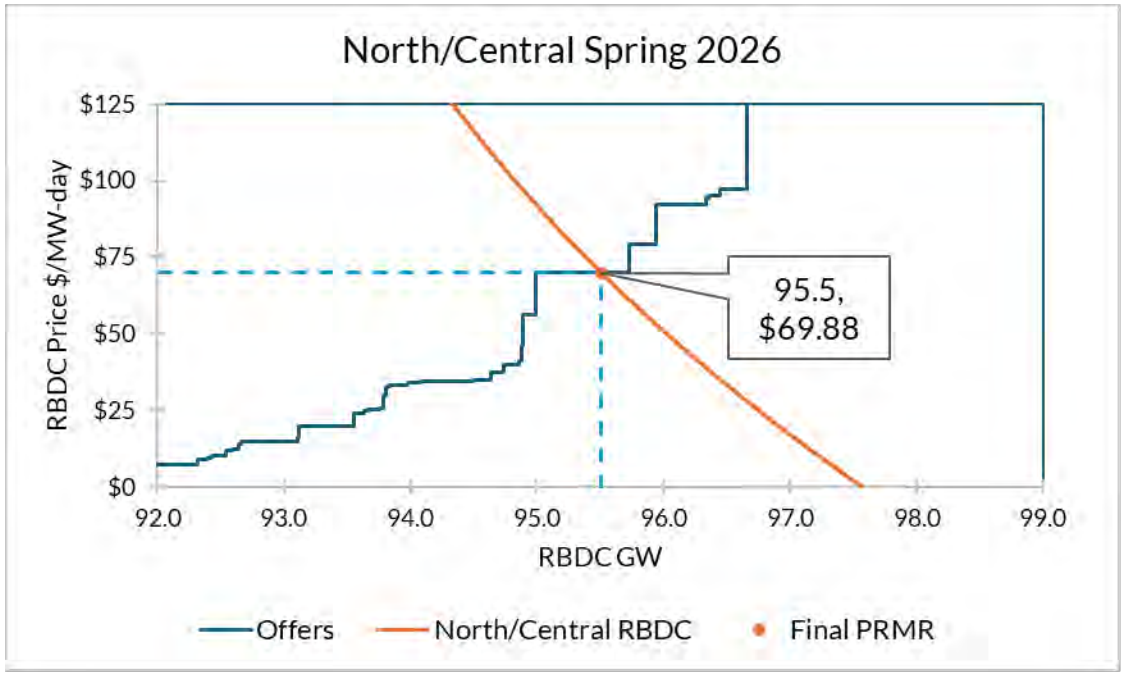
Winter 2025/26 Reliability-Based Demand Curve, Offer Curves and Auction Clearing Prices

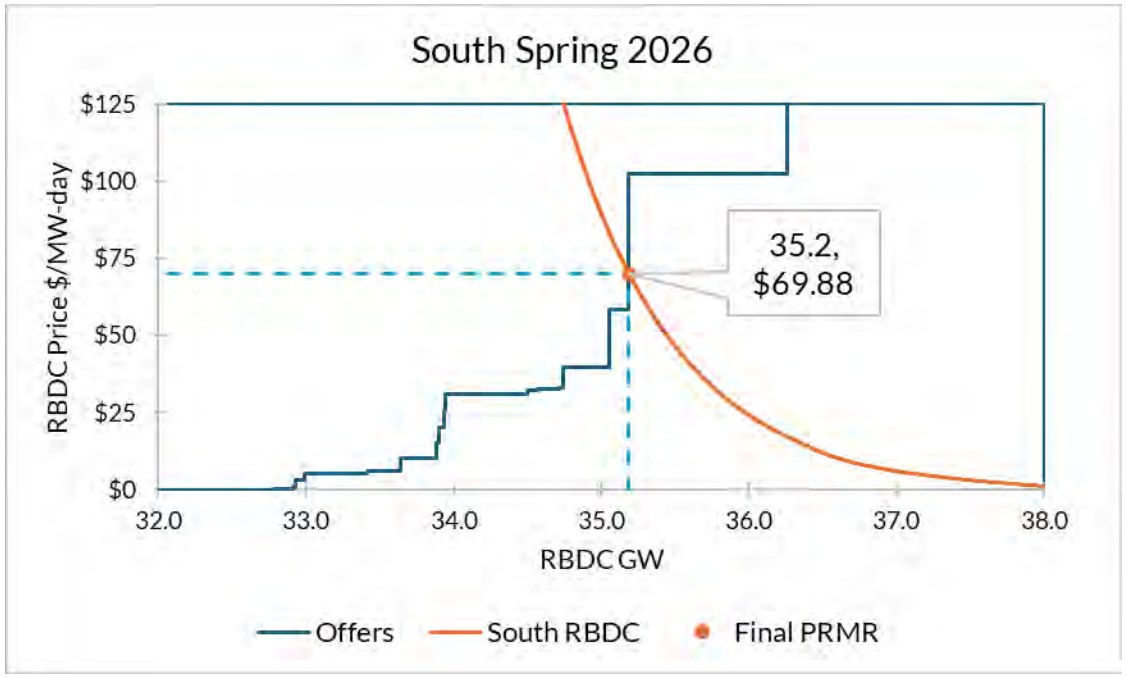




- Subregional RBDCs are determining clearing for both subregions
- No price separation between North/Central and South subregions in winter
  - ACP for both subregions is $33.20
  - Multiple marginal resources, cleared *pro rata*, sets the price
- In winter, "effective" margin for North/Central subregion is at 23.3% and $27.3% for South subregion vs. target of 18.4%

Spring 2026 Reliability-Based Demand Curve, Offer Curves and Auction Clearing





- Subregional RBDCs are determining clearing for both subregions
- No price separation between North/Central and South subregions in spring
  - ACP for both subregions is $69.88
  - A marginal resource sets the price
- In spring, "effective" margin for North/Central subregion is at 27.5% and 25% for South subregion vs. target of 25.3%

Summer 2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	18,459.4	13,190.2	10,889.2	9,237.6	8,281.3	18,484.8	21,228.0	8,487.8	21,812.2	5,142.9	N/A	99,770.5	35,442.9	135,213.4
Final PRMR	18,843.5	13,464.4	11,116.0	9,430.10	8,453.5	18,868.9	21,669.2	8,552.6	21,978.8	5,182.3	N/A	101,845.6	35,713.7	137,559.3
Offer Submitted (Including FRAP)	19,732.4	14,569.7	11,321.4	9,328.1	6,737.9	16,123.6	20,883.9	11,517.3	20,498.6	5,543.3	1580.1	99,952.6	37,883.7	137,836.3
FRAP	4,619.2	10,252.6	456.9	789.4	0.0	1,080.7	541.3	494.9	157.5	1,507.7	46.8	17,779.2	2,167.8	19,947.0
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,985.3	3,344.1	10,450.2	7,677.2	6,647.8	11,080.3	20,305.5	10,260.6	17,870.6	3,831.3	1,358.8	65,567.6	32,244,1	97,811.7
Non-SS Offer Cleared	10,127.9	973.0	414.3	861.5	90.1	3,962.6	37.1	761.8	2,193.5	204.3	174.5	16,605.8	3,194.8	19,800.6
Committed (Offer Cleared + FRAP)	19,732.4	14,569.7	11,321.4	9,328.1	6,737.9	16,123.6	20,883.9	11,517.3	20,221.6	5,543.3	1,580.1	99,952.6	37,606.7	137,559.3
LCR	15,696.9	9,719.3	8,049.3	2,577.8	6,071.1	13,051.7	19,681.4	8,487.0	19,615.0	2,523.8	-	N/A	N/A	N/A
CIL	6,025	4,370	5,555	8,525	4,117	8,651	3,569	2,568	4,361	4,474	-	N/A	N/A	N/A
ZIA	6,023	4,370	5,460	7,757	4,117	8,366	3,569	2,358	4,361	4,474	-	N/A	N/A	N/A
Import	0.0	0.0	0.0	101.7	1,715.5	2,745.5	785.5	0.0	1,757.1	0.0	-	1,893.0	0.0	1,580.1
CEL	3,991	4,614	4,618	4,584	3,939	6,881	5,726	6,299	4,286	2,097	-	N/A	N/A	N/A
Export	888.8	1105.2	205.5	0.0	0.0	0.0	0.0	2964.7	0.0	360.9	1,580.1	0.0	1,893.0	-
ACP ($/MW-Day)	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50	666.50			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Fall 2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,290.4	12,086.4	10,179.1	8,950.4	7,898.3	17,939.5	20,493.9	8,019.3	21,578.1	5,142.6	N/A	94,838.0	34,740.0	129,578.0
Final PRMR	17,811.9	12,450.7	10,486.0	9,220.4	8,136.0	18,480.2	21,111.9	8,037.4	21,627.1	5,154.2	N/A	97,697.1	34,818.7	132,515.8
Offer Submitted (Including FRAP)	18,893.1	14,291.7	13,615.9	8,887.5	6,839.6	15,518.1	19,517.6	11,000.8	21,112.5	5,516.6	1,582.1	98,835.3	37,940.2	136,775.5
FRAP	4,233.2	9,259.1	582.7	773.3	0.0	983.1	533.1	459.4	153.4	1,518.3	44.6	16,402.6	2,137.6	18,540.2
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,646.8	3,423.5	10,580.4	7,036.0	6,706.5	10,590.4	16,911.4	9,029.4	17,788.1	3,286.3	1,208.0	60,831.1	30,375.7	91,206.8
Non-SS Offer Cleared	9,019.0	834.8	2,452.8	1,078.2	133.1	3,728.7	1,089.1	1,512.0	2,406.6	254.9	259.6	18,563.3	4,205.5	22,768.8
Committed (Offer Cleared + FRAP)	17,899.0	13,517.4	13,615.9	8,887.5	6,839.6	15,302.2	18,533.6	11,000.8	20,348.1	5,059.5	1,512.2	95,797.1	36,718.7	132,515.8
LCR	14,691.0	6,591.1	6,331.4	2,588.7	4,857.2	11,725.4	18,196.1	5,006.3	18,963.6	2,577.6	-	N/A	N/A	N/A
CIL	5,740	6,537	7,797	7,773	4,679	8,952	5,115	5,839	4,741	4,508	-	N/A	N/A	N/A
ZIA	5,688	6,537	7,704	7,013	4,679	8,672	5,115	5,675	4,741	4,508	-	N/A	N/A	N/A
Import	0.0	0.0	0.0	332.8	1,296.8	3,178.0	2,578.2	0.0	1,278.9	94.7	-	1,900.0	0.0	1,512.2
CEL	6,115	4,259	5,831	4,309	5,816	5,191	5,168	4,055	4,173	3,164	-	N/A	N/A	N/A
Export	87.2	1,066.8	3,129.9	0.0	0.0	0.0	0.0	2,963.3	0.0	0.0	1,512.2	0.0	1,900.0	-
ACP ($/MW-Day)	91.60	91.60	91.60	91.60	91.60	91.60	91.60	74.09	74.09	74.10	83.24-91.60			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Winter 2025/26 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,823.8	10,789.8	9,889.1	8,549.5	7,954.8	17,939.1	16,123.6	8,545.6	21,864.3	5,136.1	N/A	89,069.7	35,546.0	124,615.7
Final PRMR	18,565.8	11,238.7	10,300.9	8,905.1	8,285.9	18,685.7	16,794.7	9,189.0	23,511.0	5,522.7	N/A	92,776.8	38,222.7	130,999.5
Offer Submitted (Including FRAP)	19,750.7	13,217.2	12,059.1	7,547.1	6,339.9	14,679.5	19,957.3	10,751.9	22,273.0	5,939.7	1,746.5	94,964.8	39,297.1	134,261.9
FRAP	4,683.9	8,342.7	479.4	513.4	0.0	1,176.6	566.3	441.6	130.9	1,822.6	16.1	15,771.2	2,402.3	18,173.5
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	5,835.8	3,156.0	10,468.3	6,685.7	6,188.7	9,146.2	18,640.6	10,018.6	18,579.3	4,046.0	1,550.8	61,380.9	32,935.1	94,316.0
Non-SS Offer Cleared	7,977.9	1,062.6	1,044.5	271.5	99.9	4,008.7	397.0	291.7	3,105.5	71.1	179.6	15,007.6	3,502.4	18,510.0
Committed (Offer Cleared + FRAP)	18,497.6	12,561.3	11,992.2	7,470.6	6,288.6	14,331.5	19,603.9	10,751.9	21,815.7	5,939.7	1,746.5	92,159.7	38,839.8	130,999.5
LCR	13,462.0	5,951.6	8,008.4	1,371.4	3,644.7	11,074.8	15,500.2	8,014.7	20,593.7	3,534.1	-	N/A	N/A	N/A
CIL	6,177	6,522	5,877	7,232	4,922	7,927	4,762	3,613	4,418	3,458	-	N/A	N/A	N/A
ZIA	5,575	6,435	5,785	6,457	4,922	7,690	4,762	3,432	4,418	3,458	-	N/A	N/A	N/A
Import	68.0	0.0	0.0	1,434.8	1,997.3	4,354.1	0.0	0.0	1,695.2	0.0	-	617.1	0.0	1,746.5
CEL	2,991	4,706	7,388	4,756	4,814	1,674	5,712	3,602	3,618	2,028	-	N/A	N/A	N/A
Export	0.0	1,322.6	1,691.5	0.0	0.0	0.0	2,809.2	1,562.8	0.0	416.9	1,746.5	0.0	617.1	0.0
ACP ($/MW-Day)	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20	33.20			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Spring 2026 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	North	South	System
Initial PRMR	17,866.7	12,149.2	10,152.2	8,304.0	7,707.9	17,858.6	19,853.2	7,977.8	22,139.8	5,167.9	N/A	93,891.8	35,285.5	129,177.3
Final PRMR	18,174.5	12,358.6	10,327.0	8,447.2	7,841.0	18,166.7	20,195.5	7,955.2	22,076.1	5,157.7	N/A	95,510.5	35,189.0	130,699.5
Offer Submitted (Including FRAP)	18,662.6	14,525.3	12,333.3	9,178.5	6,118.7	15,824.7	19,451.0	11,495.2	21,064.7	5,864.0	1,542.6	97,313.7	38,746.9	136,060.6
FRAP	4,560.6	9,393.4	529.5	629.6	0.0	1,212.4	512.5	475.3	142.1	1,464.3	45.9	16,877.1	2,088.5	18,965.6
RBDC Opt-Out	-	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0
Self Scheduled (SS)	4,600.8	3,602.8	10,816.2	7,415.0	5,968.5	9,967.6	17,621.9	8,476.0	16,778.9	4,073.9	1,260.8	60,972.6	29,609.8	90,582.4
Non-SS Offer Cleared	8,578.5	1,069.5	589.6	1,133.9	150.2	4,001.0	719.2	1,470.2	2,947.5	325.8	166.1	16,372.9	4,778.6	21,151.5
Committed (Offer Cleared + FRAP)	17,739.9	14,065.7	11,935.3	9,178.5	6,118.7	15,181.0	18,853.6	10,421.5	19,868.5	5,864.0	1,472.8	94,222.5	36,477.0	130,699.5
LCR	12,239.1	6,737.5	5,014.7	1,823.8	4,700.3	10,377.1	16,453.6	4,243.1	19,790.5	3,178.8	-	N/A	N/A	N/A
CIL	6,598	6,439	7,829	8,142	4,453	9,457	5,166	6,289	4,855	4,365	-	N/A	N/A	N/A
ZIA	6,396	6,439	7,726	7,373	4,453	9,176	5,166	6,085	4,855	4,365	-	N/A	N/A	N/A
Import	434.5	0.0	0.0	0.0	1,722.2	2,985.6	1,341.9	0.0	2,210.8	0.0	-	1,288.0	0.0	1,472.8
CEL	5,083	6,119	5,936	5,111	5,797	6,425	5,499	3,520	4,146	3,072	-	N/A	N/A	N/A
Export	0.0	1,707.2	1,608.0	731.2	0.0	0.0	0.0	2,465.6	0.0	710.3	1,472.8	0.0	1,288.0	-
ACP ($/MW-Day)	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88	69.88			N/A

Values displayed in MW SAC; ERZ: External Resource Zones | Final PRMR values provided at Zonal level given lack of RBDC Opt-Out.

Summer Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Summer 2023**	**Summer 2024**	**Summer 2025**	**Summer 2023**	**Summer 2024**	**Summer 2025**
Generation	122,375.6	123,395.6	121,015.6	116,989.7	119,479.2	120,738.6
External Resources	4,514.6	4,430.4	3,505.9	4,072.5	4,309.8	3,505.9
Behind the Meter Generation	4,175.2	4,180.2	4,282.8	4,129.4	4,143.5	4,282.8
Demand Resources	8,303.5	8,660.2	9,004.4	7,694.6	8,109.4	9,004.4
Energy Efficiency	5.0	22.5	27.6	5.0	22.5	27.6
Total	**139,373.9**	**140,688.9**	**137,836.3**	**132,891.2**	**136,064.4**	**137,559.3**

ZRC: Zonal Resource Credit

Fall Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Fall 2023**	**Fall 2024**	**Fall 2025**	**Fall 2023**	**Fall 2024**	**Fall 2025**
Generation	121,403.5	119,745.3	122,283.4	111,713.8	111,791.5	118,309.5
External Resources	4,095.4	4,366.8	2,833.5	3,979.6	3,990.2	2,763.6
Behind the Meter Generation	3,874.2	3,877.9	3,646.8	3,842.8	3,789.7	3,646.8
Demand Resources	6,999.2	6,866.1	7,983.7	6,254.4	5,957.5	7,767.8
Energy Efficiency	4.9	22.5	28.1	4.8	22.5	28.1
Total	**136,377.2**	**134,878.6**	**136,775.5**	**125,795.4**	**125,551.4**	**132,515.8**

ZRC: Zonal Resource Credit

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Winter Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	Winter 2023-2024	Winter 2024-2025	Winter 2025-2026	Winter 2023-2024	Winter 2024-2025	Winter 2025-2026
Generation	124,632.7	133,457.4	120,225.1	114,886.6	118,253.8	117,392.0
External Resources	3,937.1	3,973.0	2,808.7	3,334.6	3,313.3	2,793.7
Behind the Meter Generation	3,257.8	3,111.5	3,082.9	3,173.9	2,957.3	3,082.6
Demand Resources	7,644.4	7,866.4	8,112.3	6,702.4	6,822.7	7,698.3
Energy Efficiency	6.7	29.7	32.9	6.7	29.7	32.9
Total	**139,478.7**	**148,438.0**	**134,261.9**	**128,104.2**	**131,376.8**	**130,999.5**

ZRC: Zonal Resource Credit

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Spring Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	**Spring 2024**	**Spring 2025**	**Spring 2026**	**Spring 2024**	**Spring 2025**	**Spring 2026**
Generation	119,254.7	121,303.8	120,780.6	110,195.8	113,091.4	115,724.7
External Resources	3,794.1	3,481.8	2,640.1	3,409.1	3,406.5	2,570.3
Behind the Meter Generation	4,096.4	4,201.6	4,133.5	4,058.9	4,180.5	4,133.5
Demand Resources	7,282.9	7602.9	8,475.9	6,720.0	7,087.2	8,240.5
Energy Efficiency	5.3	25.0	30.5	5.3	25.0	30.5
Total	**134,433.4**	**136,615.1**	**136,060.6**	**124,389.1**	**127,790.6**	**130,699.5**

ZRC: Zonal Resource Credit

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

2025 PRA pricing compared with Independent Market Monitor (IMM) Conduct Threshold and Cost of New Entry (CONE)

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs	System CONE (Seasonal)	North/Central CONE (Seasonal)	South CONE (Seasonal)
Summer 2025	$666.50											$1,353.84	$1,384.36	$1,282.61
Fall 2025	$91.60							$74.09			$83.24-$91.60	$1,368.71	$1,399.58	$1,296.70
Winter 2025-26	$33.20											$1,383.92	$1,415.13	$1,311.11
Spring 2026	$69.88											$1,353.84	$1,384.36	$1,282.61
Cost of New Entry (Annual)	$127,720	$125,090	$121,220	$126,040	$136,170	$124,360	$130,930	$118,960	$117,710	$117,330	$136,170			
IMM Conduct Threshold*	$34.99	$34.27	$33.21	$34.53	$37.31	$34.07	$35.87	$32.59	$32.25	$32.15	-			

- *Zonal Auction Clearing Prices (ACP) shown in $/MW-day*

**Zonal Resource Credit (ZRC) offers that impact pricing should generally stay below the IMM Conduct Threshold and applies to all seasons.*

ERZ: External Resource Zones

Historical Summer Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
2015-2016	$3.48			$150.00	$3.48			$3.29		N/A	N/A
2016-2017	$19.72	$72.00						$2.99			N/A
2017-2018	$1.50										N/A
2018-2019	$1.00	$10.00									N/A
2019-2020	$2.99						$24.30	$2.99			
2020-2021	$5.00						$257.53	$4.75	$6.88	$4.75	$4.89-$5.00
2021-2022	$5.00							$0.01			$2.78-$5.00
2022-2023	$236.66							$2.88			$2.88-236.66
Summer 2023	$10.00										
Summer 2024	$30.00										
Summer 2025	$666.50										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Fall Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Fall 2023	$15.00								$59.21	$15.00	
Fall 2024	$15.00				$719.81	$15.00					
Fall 2025	$91.60							$74.09			$83.24-$91.60

- Auction Clearing Prices shown in $/MW-Day
- Price separation present in Fall 2025 between the North and South subregions since the Sub-Regional Import Constraint (SRIC) / Sub-Regional Export Constraint (SREC) bound

ERZ: External Resource Zones

Winter Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Winter 2023-24	$2.00								$18.88	$2.00	
Winter 2024-25	$0.75										
Winter 2025-26	$33.20										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

Spring Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Spring 2024	$10.00										
Spring 2025	$34.10				$719.81	$34.10					
Spring 2026	$69.88										

- Auction Clearing Prices shown in $/MW-Day

ERZ: External Resource Zones

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Summer 2025 Capacity

Offered Capacity & Final PRMR (MW)



Cleared Capacity, Imports & Exports (MW)



PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Fall 2025 Capacity

Offered Capacity & Final PRMR (MW)



Cleared Capacity, Imports & Exports (MW)



PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Winter 2025/26 Capacity

Offered Capacity & Final PRMR (MW)



Cleared Capacity, Imports & Exports (MW)



PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Spring 2026 Capacity

Offered Capacity & Final PRMR (MW)



Cleared Capacity, Imports & Exports (MW)



PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

The 2025 auction resulted in a surplus compared to the PRMR target, in contrast to the 2024 OMS-MISO Survey projection of a shortfall

Summer 2025 auction outcomes vs. 2024 OMS-MISO Survey projection for 2025

- Resource offers in the auction were comparable to "High Certainty" values projected in the OMS-MISO Survey
- Incremental accreditation reductions in the auction were offset by incremental increases in new resource additions
- Notably, initial PRMR was lower (5.5 GW) than projected in the OMS-MISO Survey

2024 OMS-MISO Survey Projection vs.
2025 PRA Actual PRMR Surplus (MW)

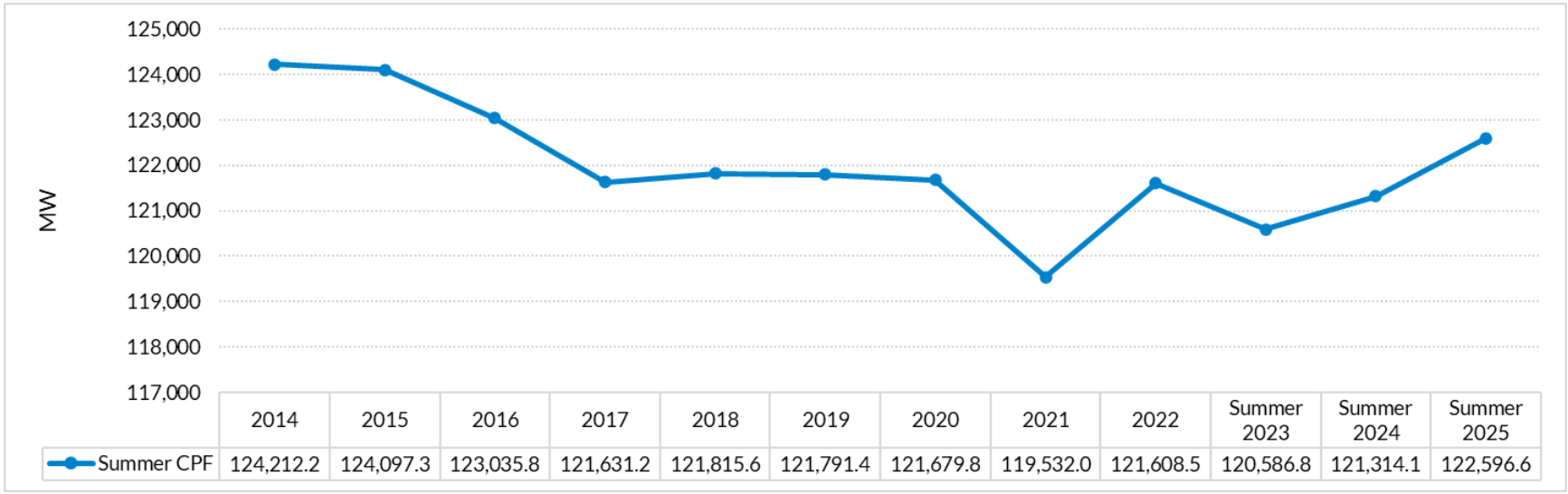


*PRA Shortfall/Surplus relative to Initial PRMR | PRMR: Planning Reserve Margin Requirement

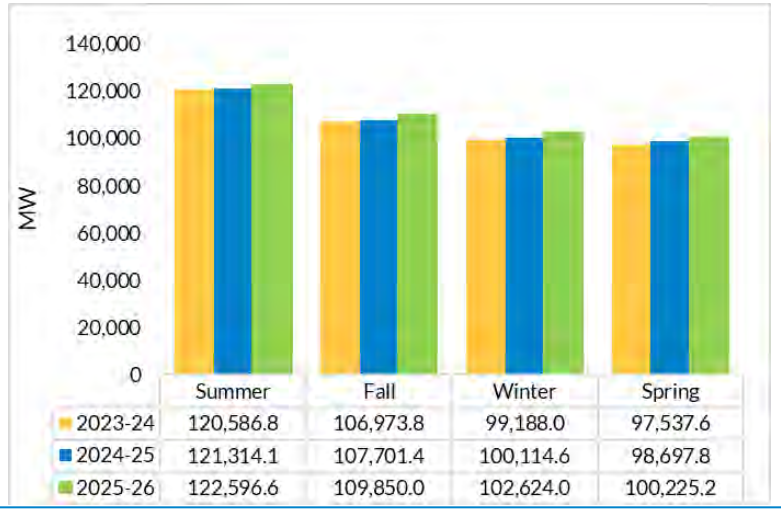
05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Coincident Peak Forecast

Year over year the Summer CPF (+1.3 GW), PRM (-1.1%) and Final PRMR (+1.5 GW) are higher.



	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
Summer CPF	124,212.2	124,097.3	123,035.8	121,631.2	121,815.6	121,791.4	121,679.8	119,532.0	121,608.5	120,586.8	121,314.1	122,596.6

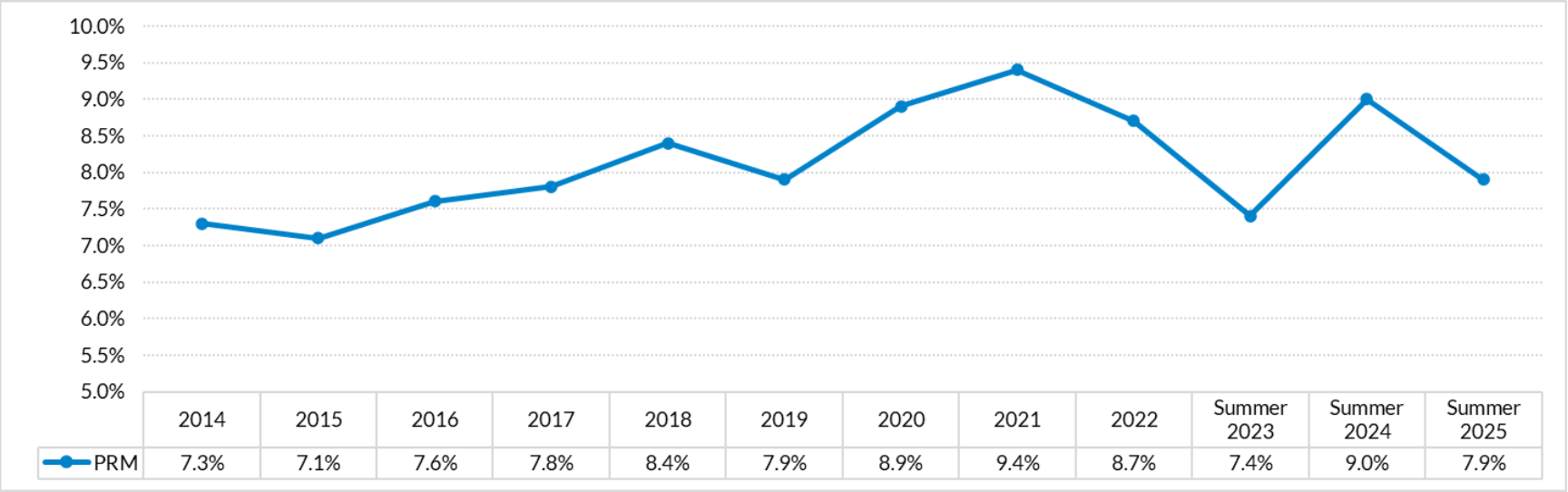


	Summer	Fall	Winter	Spring
2023-24	120,586.8	106,973.8	99,188.0	97,537.6
2024-25	121,314.1	107,701.4	100,114.6	98,697.8
2025-26	122,596.6	109,850.0	102,624.0	100,225.2

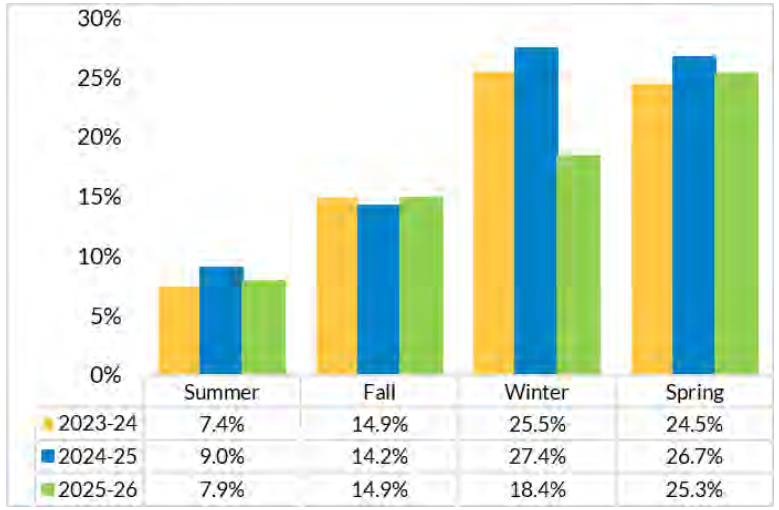
PRMR: Planning Reserve Margin Requirement

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Planning Reserve Margin (%)

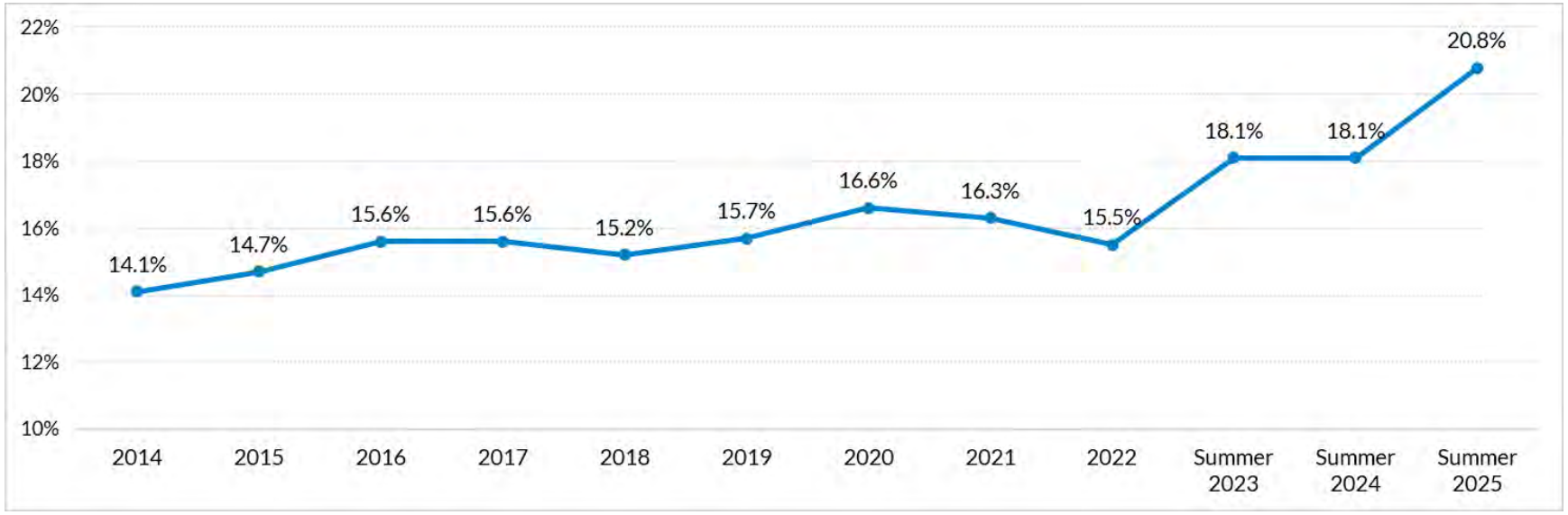


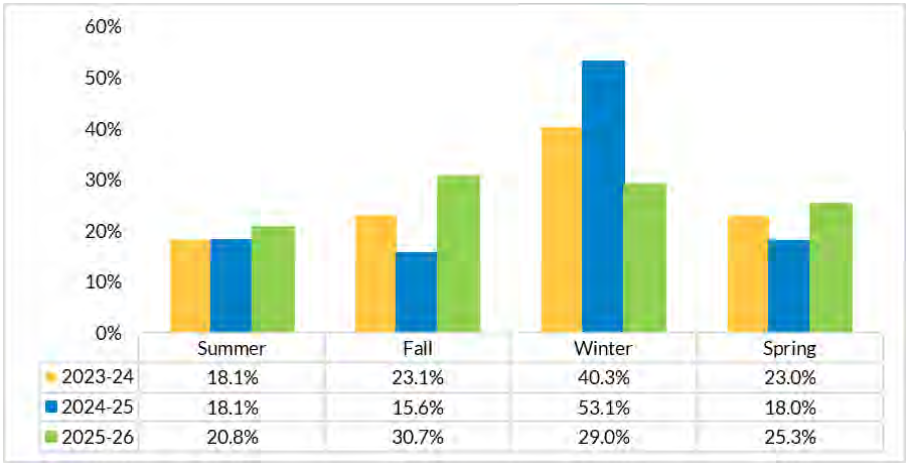
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024	Summer 2025
PRM	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%	7.9%



	Summer	Fall	Winter	Spring
2023-24	7.4%	14.9%	25.5%	24.5%
2024-25	9.0%	14.2%	27.4%	26.7%
2025-26	7.9%	14.9%	18.4%	25.3%

Wind Effective Load Carrying Capacity (%)



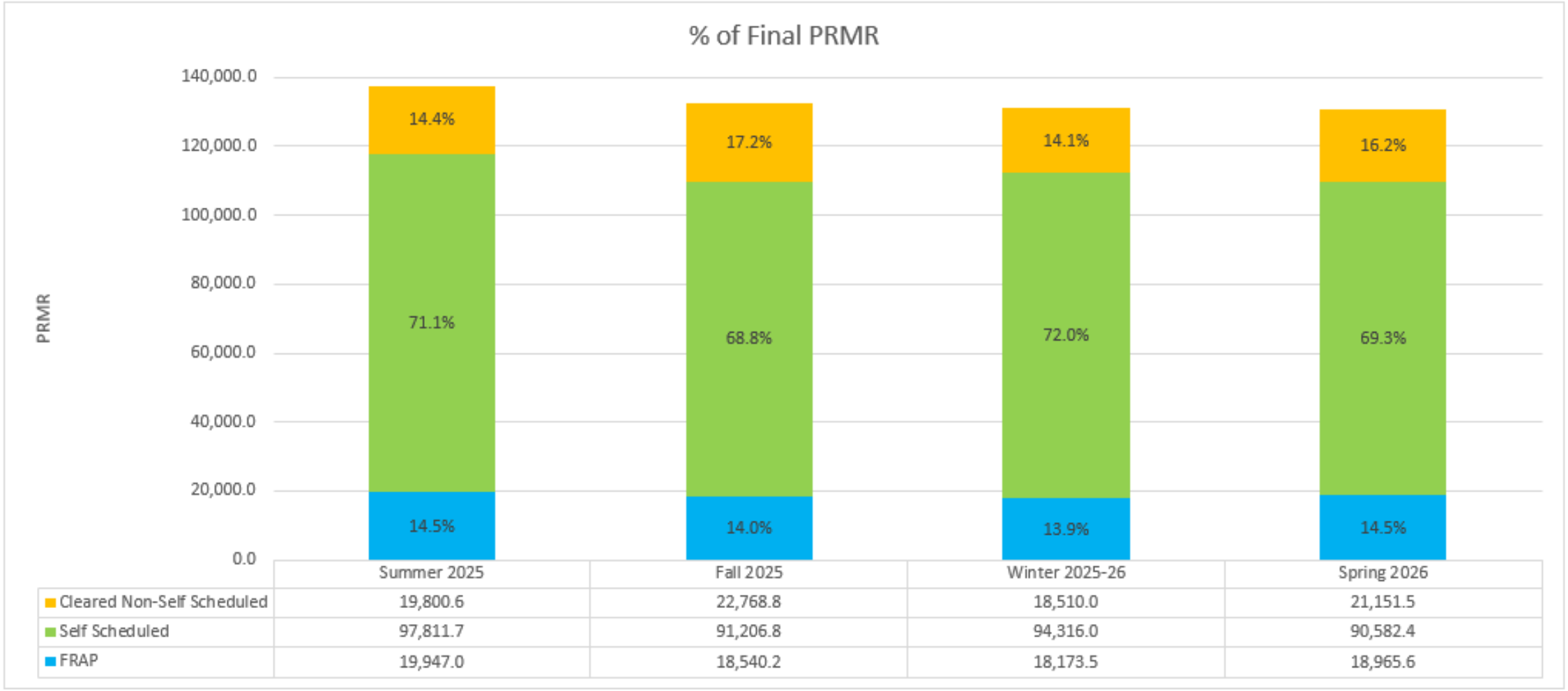


	Summer	Fall	Winter	Spring
2023-24	18.1%	23.1%	40.3%	23.0%
2024-25	18.1%	15.6%	53.1%	18.0%
2025-26	20.8%	30.7%	29.0%	25.3%

- No change to wind or solar accreditation methodology from previous years.
- Methodology applied on a seasonal basis.
- Wind ELCC and new solar capacity is established in the LOLE Study
- New solar class average
  - Summer, fall, spring 50%
  - Winter 5%

ELCC: Effective Load Carrying Capability LOLE: Loss of Load Expectation

2025/26 Seasonal Resource Adequacy Requirements are fulfilled similarly across all four seasons

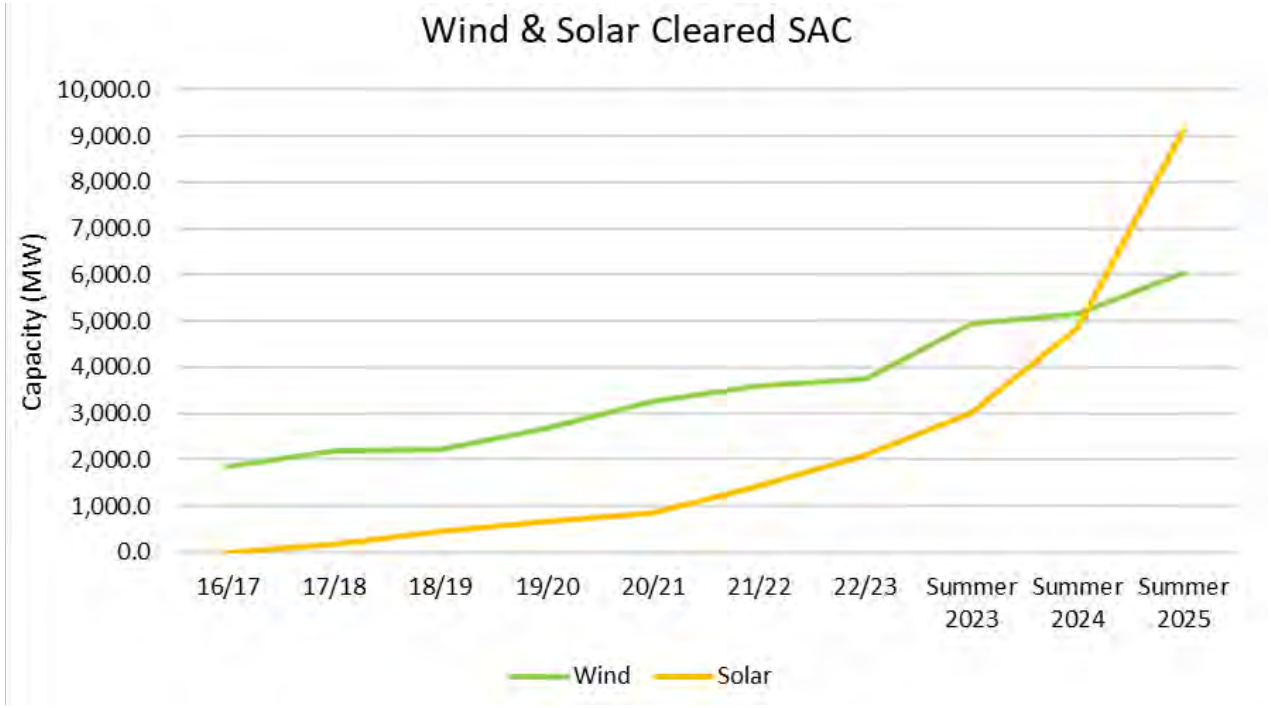


	Summer 2025	Fall 2025	Winter 2025-26	Spring 2026
Cleared Non-Self Scheduled	19,800.6	22,768.8	18,510.0	21,151.5
Self Scheduled	97,811.7	91,206.8	94,316.0	90,582.4
FRAP	19,947.0	18,540.2	18,173.5	18,965.6

PRMR: Planning Reserve Margin Requirement

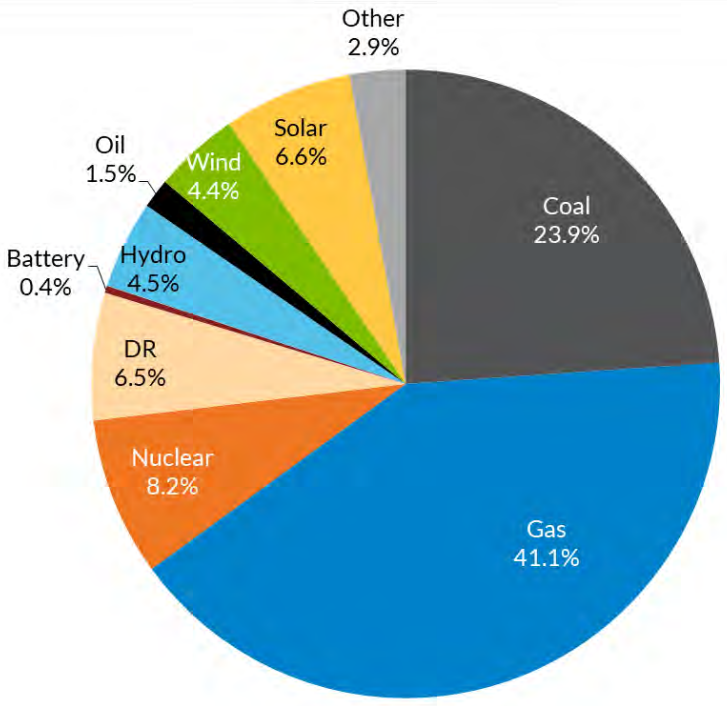
Although conventional generation still comprises most of the capacity, wind and solar continue to grow

- 9.1 GW of solar cleared this year's auction, an increase of 88% from Planning Year 2024/25 (4.9 GW)
- 6 GW of wind cleared this year, an increase of 17% compared to last year (5.2 GW)



Winter final PRMR is 6.6 GW (4.8%) lower than the summer with fewer solar resources to meet final PRMR in the winter versus the summer

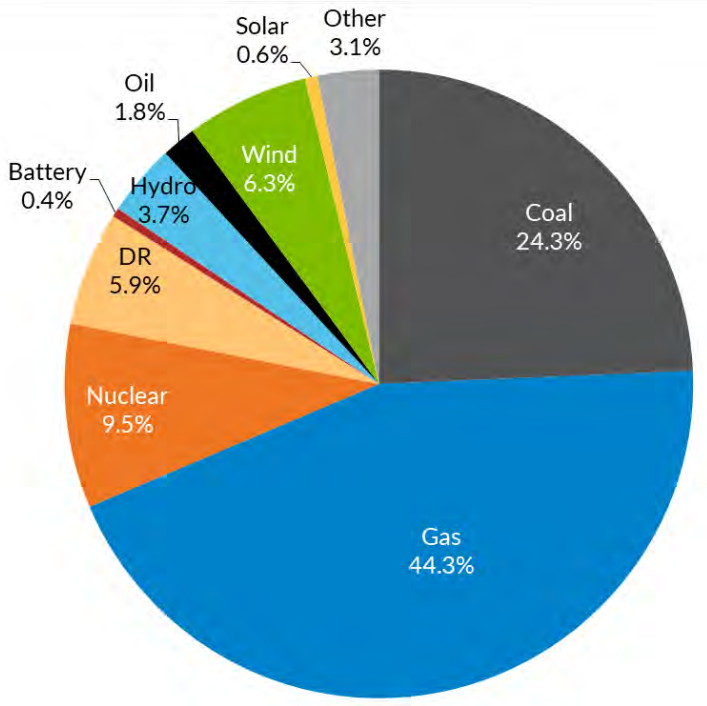
Summer 2025



MISO-wide

Cleared ZRC	Summer 2025	Winter 2025/26	Difference
Coal	32,909.6	31,887.2	1,022.4
Gas	56,470.0	57,990.5	-1,520.5
Nuclear	11,232.1	12,416.7	-1,184.6
DR	9,004.4	7,698.3	1,306.1
Battery	499.2	588.5	-89.3
EE	27.6	32.9	-5.3
Hydro	6,231.3	4,823.7	1,407.6
Oil	2,088.8	2,315.7	-226.9
Wind	6,039.1	8,282.9	-2,243.8
Solar	9,122.8	847.3	8,275.5
Misc	3,934.4	4,115.8	-181.4
PRMR	137,559.3	130,999.5	6,559.8

Winter 2025/26

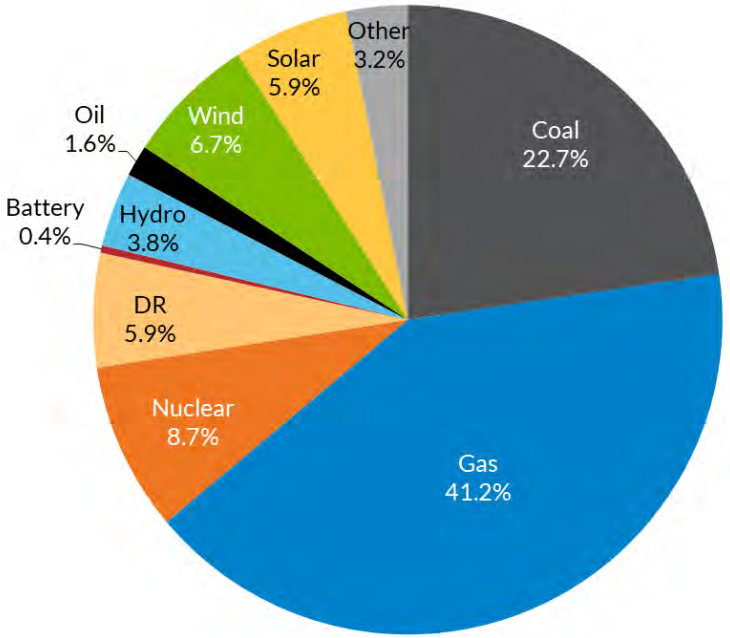


PRMR: Planning Reserve Margin Requirement

05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

Fall 2025 and Spring 2026 - Cleared ZRCs and Final PRMR

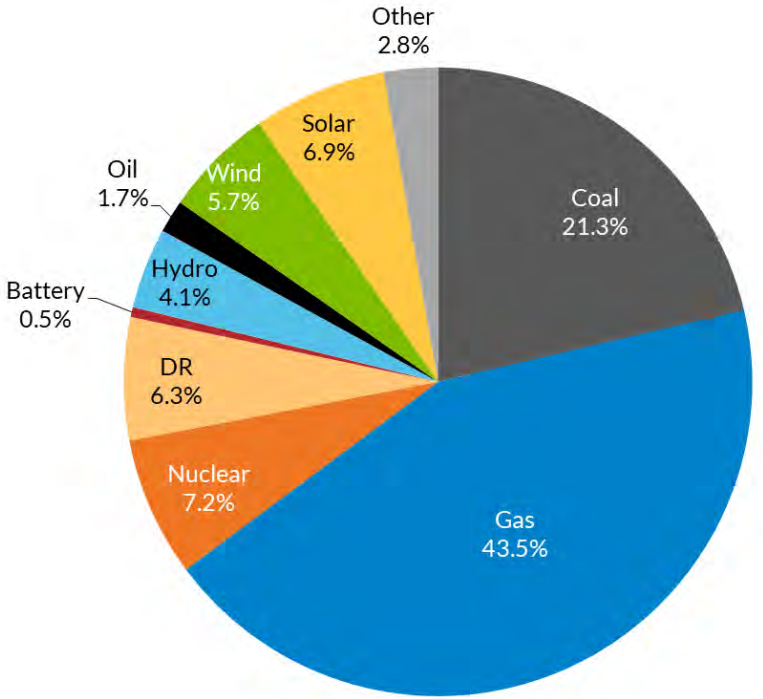
Fall 2025



MISO-Wide

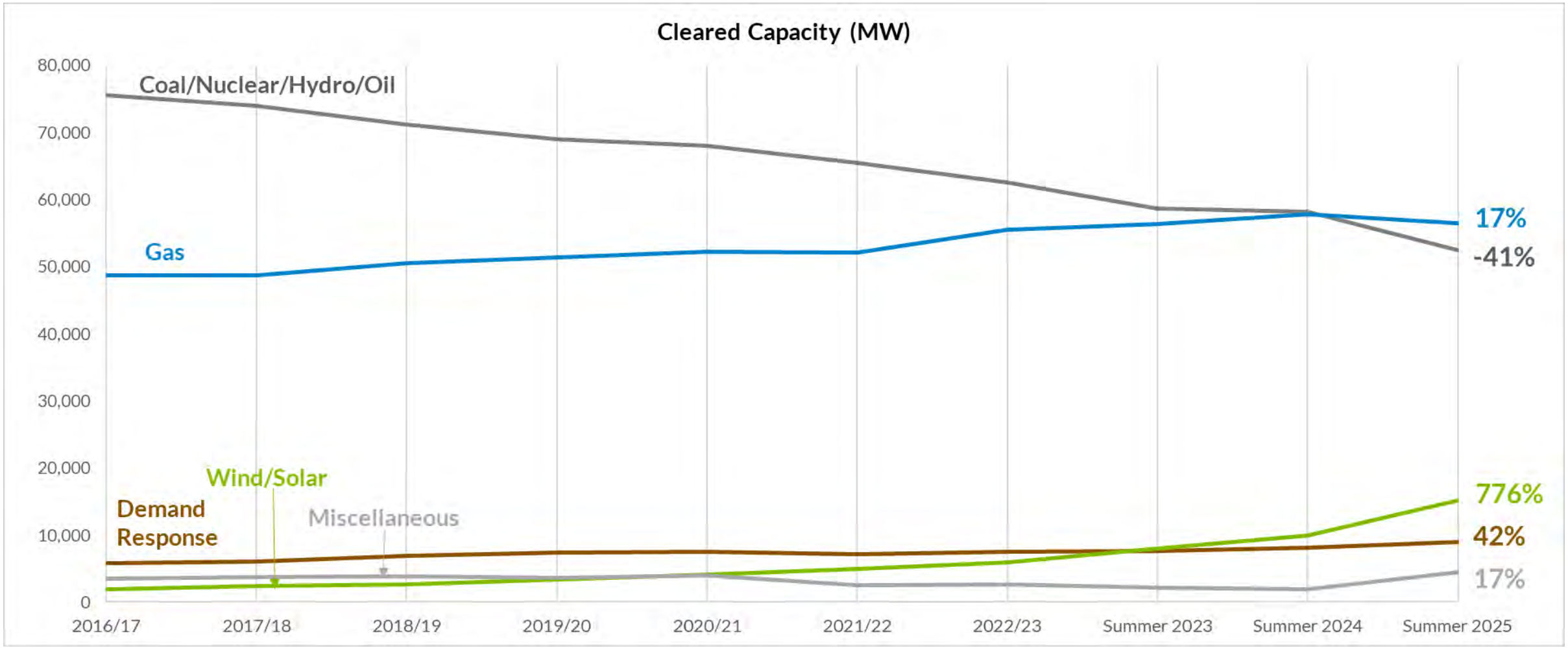
Cleared ZRC	Fall 2025	Spring 2026
Coal	30,038.9	27,886.8
Gas	54,636.4	56,820.7
Nuclear	11,482.1	9,405.4
DR	7,767.8	8,240.5
Battery	497.9	663.3
EE	28.1	30.5
Hydro	5,047.4	5,415.8
Oil	2,123.8	2,190.4
Wind	8,864.8	7,438.0
Solar	7,843.8	8,975.1
Misc	4,184.8	3,633.0
PRMR	132,515.8	130,699.5

Spring 2026



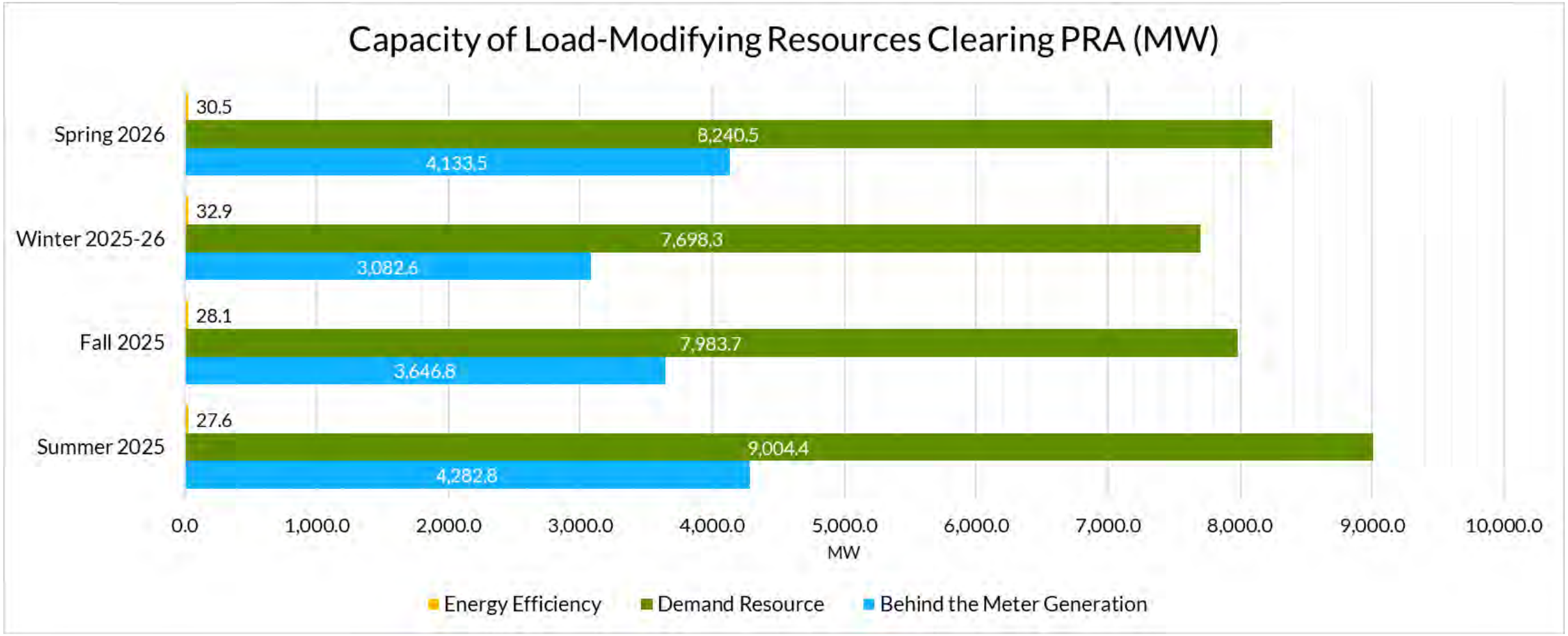
PRMR: Planning Reserve Margin Requirement

The planning resource mix shows the continuation of a multi-year trend towards less coal/nuclear/hydro/oil and increased gas and non-conventional resources



05/29/2025: MISO Planning Resource Auction for Planning Year 2025/26 Results Posting

2025/26 Seasonally Cleared Load Modifying Resources Comparison



Visit MISO's Help Center
for more information
https://help.misoenergy.org/

MISO's Planning Resource Auction indicates sufficient resources

Improved pricing signal more accurately highlights reliability risk

For Immediate Release

April 28, 2025

Media Contact

Brandon Morris

CARMEL, Ind. — Today, MISO released the 2025 Planning Resource Auction (PRA) results indicating adequate resources are available to maintain reliability during the upcoming planning year (June 2025 – May 2026). While the 2025 auction prices reflect a tightening supply-demand balance during the summer months, there is sufficient capacity throughout the MISO footprint.

This is the first year MISO utilized a Reliability-Based Demand Curve (RBDC), which introduces a reliability-focused pricing structure that more accurately reflects the increasing value of accredited capacity as the system approaches minimum resource adequacy targets.

"MISO's market reforms continue to assist in providing pricing signals that improve market efficiency and enhance reliability across the footprint," said Aubrey Johnson, MISO's vice president of system planning and competitive transmission. ""We developed the RBDC through extensive collaboration with the Organization of MISO states, our stakeholders and our Independent Market Monitor to ensure this proactive approach helps meet the future needs of our evolving fleet."

The seasonal Auction Clearing Prices are:

- Summer (June, July and August) $666.50/MW-day
- Fall (September, October and November)
  - $91.60/MW-day for the North/Central subregion
  - $74.09/MW-day for the South subregion
- Winter (December, January and February) $33.20/MW-day
- Spring (March, April and May) $69.88/MW-day
- Annualized, the prices are $217/MW-day for the North/Central region and $212 for the South region.

The majority of MISO's Load Serving Entities (LSEs) either self-supply or secure the capacity they need before the auction. Those that enter the auction to procure capacity must pay the Auction Clearing Price and those holding excess capacity sell it at the same clearing price. The impact on consumer costs will vary and depends on factors such as the size of any capacity shortfall and the terms of wholesale power purchase agreements or state-regulated retail rates.

"This year's results underscore MISO's proactive Market Redefinition efforts to enhance resource availability as outlined in the Reliability Imperative." Johnson continues. "MISO, our states and our stakeholders continue to make progress responding to the resource adequacy challenges we face, and these results offer valuable insights to allow members to maximize their existing resources and plan for the ongoing energy transition."

MISO's Independent Market Monitor has reviewed and agreed with the offers and results of the 2025 PRA. MISO will host the 2025 Planning Resource Auction Results meeting April, 29 at 10 a.m. ET.

##

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About MISO

Midcontinent Independent System Operator (MISO) is an independent, not-for-profit organization that delivers safe, cost-effective electric power across 15 U.S. states and the Canadian province of Manitoba. 45 million people depend on MISO to generate and transmit the right amount of electricity every minute of every day. MISO is committed to reliable, nondiscriminatory operation of the bulk power transmission system and collaborating with all stakeholders to create cost-effective and innovative solutions for our changing industry. MISO operates one of the world's largest energy markets with more than $40 billion in annual gross market energy transactions.

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A. Introduction

1. Title: **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. Number: **BAL-502-RF-03**

3. Purpose: To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the ReliabilityFirst Corporation (RF) region

4. Applicability

4.1 Functional Entities

4.1.1 Planning Coordinator

5. Effective Date:

5.1 BAL-502-RF-03 shall become effective on the first day of the first calendar quarter that is after the date that this standard is approved by applicable regulatory authorities or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect.

B. Requirements and Measures

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*:

1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

1.2 Be performed or verified separately for each of the following planning years:

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

1.2.1 Perform an analysis for Year One.

1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

1.3 Include the following subject matter and documentation of its use:

1.3.1 Load forecast characteristics:

1.3.1.1 Median (50:50) forecast peak Load.

1.3.1.2 Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).

1.3.1.3 Load diversity.

1.3.1.4 Seasonal Load variations.

1.3.1.5 Daily demand modeling assumptions (firm, interruptible).

1.3.1.6 Contractual arrangements concerning curtailable/Interruptible Demand.

1.3.2 Resource characteristics:

1.3.2.1 Historic resource performance and any projected changes

1.3.2.2 Seasonal resource ratings

1.3.2.3 Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.

1.3.2.4 Resource planned outage schedules, deratings, and retirements.

1.3.2.5 Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.

1.3.2.6 Criteria for including planned resource additions in the analysis

1.3.3 Transmission limitations that prevent the delivery of generation reserves

1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

1.4.1 Availability and deliverability of fuel.

1.4.2 Common mode outages that affect resource availability

1.4.3 Environmental or regulatory restrictions of resource availability.

1.4.4 Any other demand (Load) response programs not included in R1.3.1.

1.4.5 Sensitivity to resource outage rates.

1.4.6 Impacts of extreme weather/drought conditions that affect unit availability.

1.4.7 Modeling assumptions for emergency operation procedures used to make reserves available.

1.4.8 Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

2.1 This documentation shall cover each of the years in Year One through ten.

2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2 *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*.

M3 Each Planning Coordinator shall possess the documentation identifying any gaps between the needed amounts of planning reserves and projected planning reserves in accordance with R3.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Applicable Entity shall keep data or evidence to show compliance with Requirements R1 through R3, and Measures M1 through M3 from the most current and prior two years.

If an Applicable Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes

Compliance Audit
Self-Certification
Spot Checking

Compliance Investigation
Self-Reporting
Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	VIOLATION SEVERITY LEVEL			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per Requirement R1, Part 1.5	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from Requirement R1, Part 1.1 as a percentage of the net Median forecast peak Load per Requirement R1, Part 1.1.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of its use **OR**	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per Requirement R1, Part 1.2 **OR** The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per Requirement R1, Part 1.2.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or	The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1. **OR** The Planning Coordinator Resource Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per Requirement R1, Part 1.1 **OR**

				The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of its use **Or** The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.7	more of the Load forecast Characteristics subcomponents under Requirement R1, Part 1.3.1 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under Requirement R1, Part 1.3.2 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	The Planning Coordinator failed to perform an analysis for Year One per Requirement R1, Part 1.2.1

					per Requirement R1, Part 1.3.3 **OR** The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per Requirement R1, Part 1.3.4 **OR** The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under Requirement R1, Part 1.4 and documentation of how and why they were included in the analysis or why they were not included	

					OR The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per Requirement R1, Part 1.6	
R2	Long-term Planning	Lower	The Planning Coordinator failed to publicly post the documents as specified per requirement Requirement R2, Part 2.1 and Requirement R2, Part 2.2 later than 30 calendar days prior to the beginning of Year One per Requirement R2, Part 2.3	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the Planning	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per Requirement R2, Part 2.1. **OR** The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis per Requirement R2, Part 2.

				Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per Requirement R2, Part 2.2.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per Requirement R2, Part 2.1.	
R3	Long-term Planning	Lower	None	None	None	The Planning Coordinator failed to identify any gaps between the needed amount of planning reserves and the projected planning reserves, per R3

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02	12/04/08	ReliabilityFirst Board Approved	
BAL-502-RFC-02	08/05/09	NERC BoT Approved	
BAL-502-RFC-02	03/17/11	FERC Approved	
BAL-502-RFC-03	06/01/17	ReliabilityFirst Board Approved	
BAL-502-RF-03	08/10/17	NERC BOT Approved	
BAL-502-RF-03	10/16/17	FERC Approved	

ECONOMIC DISPATCH

OF

ELECTRIC GENERATION CAPACITY

A REPORT TO CONGRESS AND THE STATES PURSUANT TO SECTIONS 1234 AND 1832 OF THE ENERGY POLICY ACT OF 2005

United States Department of Energy

February 2007

ECONOMIC DISPATCH

OF

ELECTRIC GENERATION CAPACITY

A REPORT TO CONGRESS AND THE STATES PURSUANT TO SECTIONS 1234 AND 1832 OF THE ENERGY POLICY ACT OF 2005

Sections 1234 and 1832 of the Energy Policy Act of 2005 (EPAct)[1] direct the U.S. Department of Energy (the Department, or DOE) to:

1) Study the procedures currently used by electric utilities to perform economic dispatch;
2) Identify possible revisions to those procedures to improve the ability of non-utility generation resources to offer their output for sale for the purpose of inclusion in economic dispatch; and
3) Study the potential benefits to residential, commercial and industrial electricity consumers nationally and in each State if economic dispatch procedures were revised to improve the ability of non-utility generation resources to offer their output for inclusion in economic dispatch.

EPAct defines "economic dispatch" to mean "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities." [EPAct 2005, Sec. 1234 (b)] On November 7, 2005, the Department submitted a report to Congress in fulfillment of this requirement, *The Value of Economic Dispatch*.[2] The Act also requires the Secretary of Energy to submit a yearly report to Congress and the States "on the results of the study conducted under subsection (a), including recommendations to Congress and the States for any suggested legislative or regulatory changes." [EPAct 2005, Sec. 1234 (c)]

This report responds to the latter requirement, as the first annual study following up on the initial economic dispatch report to Congress and the States. It concludes that while the value of economic dispatch to promote reliability and efficiency of generation resources remains unchanged, national or state policy with respect to economic dispatch has changed very little since November 7, 2005. Accordingly, it does not appear that the practice of economic dispatch has undergone significant change.

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[1] The two sections have identical language. Hereafter in this report, citations will be to section 1234.

[2] This report, issued by the Department of Energy on November 7, 2005, can be found at http://www.oe.energy.gov/epa_sec1234.htm .

Review of the Department of Energy's 2005 Economic Dispatch Report

Security-constrained economic dispatch is an area-wide optimization process designed to meet electricity demand at the lowest cost, given the operational and reliability limitations of the area's generation fleet and transmission system. DOE's 2005 report found that security-constrained economic dispatch benefits electricity consumers by systematically increasing the use of the most efficient generation units (and demand-side resources, where available). This can lead to:

> … better fuel utilization, lower fuel usage, and reduced air emissions than would result from using less efficient generation. As the geographic and electrical scope integrated under unified economic dispatch increases, additional cost savings result from pooled operating reserves, which allow an area to meet loads reliably using less total generation capacity than would be needed otherwise. Economic dispatch requires operators to pay close attention to system conditions and to maintain secure grid operation, thus increasing operational reliability without increasing costs. Economic dispatch methods are also flexible enough to incorporate policy goals such as promoting fuel diversity or respecting demand as well as supply resources. Over the long term, economic dispatch can encourage new investment in generation as well as in transmission expansion and upgrades that enhance both reliability and cost savings.[3]

The initial report found that there have been many studies of the savings from various aspects of economic dispatch, but the studies do not provide consistent estimates of the benefits and effectiveness of economic dispatch. Compiling the results of an extensive survey of the electric industry's use of economic dispatch, the report found that all of the regional grid operators (Regional Transmission Operators and Independent System Operators), and the utilities in the third of the nation outside grid operator footprints use economic dispatch to manage and dispatch their generation units. At the same time, although regional grid operators and utilities observe the basic principles of security-constrained economic dispatch, the details of dispatch execution and the constraints placed around dispatch operations vary widely. The report concluded that there is room to improve economic dispatch practices to reduce the total cost of electricity and increase grid reliability. It did not attempt, however, to estimate the magnitude of such potential improvements.

Review of the FERC-State Economic Dispatch Joint Board Recommendations and Outcomes

Section 1298 of EPAct directed the Federal Energy Regulatory Commission (FERC) to convene regional joint boards with state regulators to:

> … consider issues relevant to what constitutes "security constrained economic dispatch" and how such a mode of operating an electric energy system affects or

[3] *Ibid.* at 3-4.

> enhances the reliability and affordability of service to customers in the region concerned and to make recommendations to the Commission regarding such issues.[4]

On September 30, 2005, FERC issued an order convening joint boards in each of four designated regions (Northeast, PJM-MISO, South and West). The boards met over a period of several months and submitted regional reports to FERC, which compiled those reports with additional commentary in a submittal to Congress on July 31, 2006.[5]

The analysis and conclusions about economic dispatch varied significantly across the four regions. However, no joint board recommended any material changes to the way that economic dispatch is conducted within its region. FERC's report summarizes:

> … Regions where centralized dispatch predominates (PJM-MISO, Northeast) did not propose changing the basic dispatch or pricing mechanisms, and regions where individual utility dispatch predominates (South, West) did not propose new initiatives for greater centralization of the dispatch. In regions with existing RTOs, there were a number of recommendations for specific improvements within the existing centralized dispatch framework, but no new proposals for fundamental changes in the way the RTOs operate the dispatch. In regions where individual utility dispatch predominates, the boards were open to voluntary changes to aspects of the existing dispatch, or continued industry pursuit of regional dispatch on a voluntary basis, as long as these initiatives could be demonstrated to provide benefits to customers and gain appropriate state and federal approvals. However, these boards did not call for any specific initiatives and opposed any form of mandated modification.[6]

Since the FERC joint board report contains an excellent summary of the joint boards' concerns and conclusions, the present report addresses only the specific, affirmative recommendations offered by the various joint boards:

- The Northeast Joint Board recommended broadening the application of economic dispatch through greater coordination between the NYISO and ISO-NE, consideration of possible coordination with other areas, meetings with stakeholders on such coordination, examination of the possibility of coordination with other areas, and preparation of a report by NYISO and ISO-NE to FERC describing their seams elimination plans. That report had not been filed when this report was written.

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[4] EPAct, Section 1298.

[5] Federal Energy Regulatory Commission, "Security Constrained Economic Dispatch: Definition, Practices, Issues and Recommendations – A Report to Congress Regarding the Recommendations of Regional Joint Boards For the Study of Economic Dispatch Pursuant to Section 223 of the Federal Power Act as Added by Section 1298 of the Energy Policy Act of 2005," July 31, 2006, at http://www.ferc.gov/industries/electric/indus-act/joint-boards/final-cong-rpt.pdf .

[6] *Ibid.* at 10.

- The PJM-MISO Joint Board recommended examining the cost and feasibility of consolidating MISO and PJM economic dispatch and expanding further to include areas not currently under RTO-managed dispatch, subject to cost-effectiveness and applicable state laws. They also recommended continued improvements to the seams coordination between the two RTOs. This work is ongoing.
- The Western Joint Board recommended the conduct of studies to determine the potential of better dispatch coordination across larger sections of the region, particularly to improve the dispatch of renewables and to coordinate import and export scheduling.
- The Northeast Joint Board recommended that the RTOs improve data transparency by making bid data available more quickly to market participants.
- The PJM-MISO Joint Board asserted the need for continued RTO independence and objectivity in the conduct of economic dispatch.
- The PJM-MISO Joint Board recommended continued attention by the RTOs and state regulators to enable greater demand response participation in economic dispatch. PJM now allows demand response resources to bid into its real-time energy markets.
- Similarly, the Western Joint Board recommended broadening the definition of security-constrained economic dispatch to include policies such as demand response that affect dispatch beyond purely economic and security considerations.
- The PJM-MISO Joint Board recommended that the RTOs establish a clear benchmark to assess the effectiveness of economic dispatch at achieving reliability and cost-effectiveness objectives.
- The Western Joint Board recommended against conducting a more detailed study of utility economic dispatch methods (as suggested in the Department's 2005 report), on the grounds that such a review was not likely to add value.
- The Southern and Western Joint Boards considered the DOE recommendation concerning the standardization of non-utility generator-to-buyer contract terms, and concluded that this was worth pursuing on the condition that the results maintain flexibility and be applied regionally rather than nationally. However, no organization or agency has pursued this recommendation.
- The Northeast Joint Board recommended that FERC request the ISO-RTO Council to identify best practices for future improvements in economic dispatch tools. However, to date FERC has not issued a request of this nature.

Other Activities and Issues Related to Economic Dispatch

FERC Reform of Open Access Transmission Tariff

The Commission recently issued Order 890, in which it revised its *pro forma* Open Access Transmission Tariff, under which transmission operators offer transmission service for all bulk power sellers and buyers.[7] A common theme within FERC's reform effort, supported by many

[7] FERC Order No. 890, "Preventing Undue Discrimination and Preference in Transmission Service," February 16, 2007, RM05-17-000 and RM05-25-000.

comments in response to FERC's Notice of Inquiry on OATT reform,[8] was that greater transparency in grid conditions, operations, and planning would enable many transmission customers – producers and purchasers – to participate more effectively in the wholesale electric market.

While many of the subjects covered by Order 890 do not address economic dispatch directly, the order will affect the ways that generation resources (including independent power producers) are treated under economic dispatch, whether conducted by a vertically integrated utility or an independent grid operator. The principal changes required by the order include:

- A requirement that public utilities work through the North American Electric Reliability Corporation (NERC) to develop consistent methodologies for calculating Available Transfer Capability (ATC) and to publish those methodologies. Calculating and publishing ATC is one of the "most critical functions under the *pro forma* OATT because it determines whether transmission customers can access alternative power supplies," the Commission said.[9]
- Each transmission provider's planning process must meet nine specified planning principles: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation.
- The rule reforms the pricing of energy and generator imbalances to require charges to be related to the cost of correcting the imbalance, to encourage efficient scheduling behavior and to exempt intermittent generators, such as wind power producers, from higher imbalance charges in recognition of the special circumstances presented by such resources.
- The Commission adopted a conditional firm component to long-term point-to-point transmission service addressing situations in which firm service can be provided for most, but not all, hours of the requested time period. The rule also reforms the existing requirements for redispatch service to ensure that the requirements are of greater use to transmission customers and more consistent with reliable planning and operation of an area's system.

Load forecasting

As noted in the Department's November 2005 Economic Dispatch Report, improving the quality and accuracy of load forecasting would improve the reliability and cost-minimization outcomes of economic dispatch. This is because most of the units available to meet load in real time were identified and scheduled the day before, based upon the day-ahead load forecast used in the security-constrained unit commitment process. While the cost of over-estimating load (in which case the load prediction is notably lower than actual) is relatively low and primarily financial (because money and fuel was expended to make a generator available although it was not fully

[8] Federal Energy Regulatory Commission, "Preventing Undue Discrimination and Preference in Transmission Services," Notice of Inquiry, September 16, 2005, and comments, found at http://www.ferc.gov/industries/electric/indus-act/oatt-reform.asp .
[9] Federal Energy Regulatory Commission, news release regarding Order 890, February 15, 2007.

utilized), significantly under-estimating load can compromise reliability and cause sharp short-term increases in real-time wholesale market prices.

The importance of accurate load forecasting was demonstrated recently by the heat wave that occurred across most of the nation in July, 2006, the second hottest July on record in the United States. Due to the combination of the heat wave and a strong economy, total energy production in July 2006 was 4.3 percent higher than that in July 2005.[10] The California ISO, for example, reported that energy demand experienced within its control area on July 21 and 22 broke all previous records, demonstrating "tremendous growth in the demand for electricity – the amount of growth [not] forecasted to appear [until] five years from now."[11] Further, demand in California continued to rise on following days and was prevented from exceeding the area's production capacity only through the combination of aggressive customer conservation efforts and the loss of hundreds of distribution transformers which failed in the heat, removing significant additional load from the grid. A similar but less protracted disruption in electric service occurred in Texas on April 17-18, 2006.[12] Although long-term load forecasting is subject to many uncertainties, improvements in near-term load forecasting could lead to greater cost savings as well as improved reliability.

Private Sector Initiatives

The largest geographic and electric systems integrated under security-constrained economic dispatch are operated by RTOs and ISOs. Those grid operators have made specific changes to their economic dispatch efforts, including coordination of market operations, congestion management and redispatch between PJM and MISO, and co-optimization of resource prices across multiple markets by ISO-New England.

Commercial software vendors continue to work to improve the quality and scope of the tools used for security-constrained unit commitment and security-constrained economic dispatch. Because RTOs manage significantly greater resource fleets than traditional utilities – for instance, PJM handles over 150 gigawatts of resources spanning 30,000 "buses,"[13] while traditional utilities might dispatch across 5,000 buses – the scope of dispatch calculations has raised new computational challenges. At the same time, software developers are developing new algorithms to solve large-scale security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) problems, using new techniques such as temporal coupling and mixed integer programming to improve modeling of specific resource types and

[10] Energy Information Administration," Monthly Flash Estimates of Electric Power Data", September 19, 2006, Data for July 2006.
[11] California ISO, "Conservation Works! More Conservation Needed as Peak Demand Skyrockets to Critical Peak Monday," July 23, 2006.
[12] See http://www.nbc5i.com/news/8794207/detail.html?rss=dfw&psp=news and other local news sources.
[13] The term "bus" is used in the electricity industry to refer to a node in an electrical transmission network where one or more elements are connected together.

optimize multiple complex power flows simultaneously.[14] Demands from the software vendors' most challenging customers -- large grid operators such as the NYISO, ISO-NE and PJM -- are driving and supporting such vendor initiatives.

Conclusions

Other than some responses to the FERC-State Joint Board studies, few significant changes were made in 2006 in the policies and practices for economic dispatch in the United States electric grid. More significant changes are likely to result, however, from the industry's implementation of FERC's Order 890. Although the order was issued in mid-February 2007, the rulemaking process was initiated in September 2005, and full implementation of the order will take many months.

[14] E-mail from Avnaesh Jayantilal, Director Market Management Systems, Areva T&D, Redmond WA, October 13, 2006.

175 FERC ¶ 61,224
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Richard Glick, Chairman;
James P. Danly, Allison Clements,
and Mark C. Christie.

Joint Federal-State Task Force on Electric Transmission Docket No. AD21-15-000

ORDER ESTABLISHING TASK FORCE AND SOLICITING NOMINATIONS

(Issued June 17, 2021)

1. Section 209(b) of the Federal Power Act (FPA) authorizes the Federal Energy Regulatory Commission (the Commission or FERC) to confer with state commissions "regarding the relationship between rate structures, costs, accounts, charges, practices, classifications, and regulations of public utilities subject to the jurisdiction" of such state commissions and FERC, including through joint hearings.[1] Pursuant to that authority, in this order, we establish a Joint Federal-State Task Force on Electric Transmission (Task Force); solicit nominations for state commission representation on the Task Force; set forth preliminary details of the Task Force; and identify topics for the Task Force to consider.

I. Task Force

2. Pursuant to section 209(b) of the FPA, we hereby establish the Task Force to conduct joint hearings on the transmission-related topics outlined below. Developing new transmission infrastructure implicates a host of different issues, including how to plan and pay for these facilities. Federal and state regulators each have authority over transmission-related issues, meaning that transmission developers must successfully navigate different federal and state regulatory processes. In addition, the development of new transmission infrastructure often affects numerous different priorities of federal and state regulators (e.g., reliability, customer protection, environmental considerations). As a result, the area is ripe for greater federal-state coordination and cooperation. We

[1] 16 U.S.C. § 824h(b).

believe that a formal structure to jointly explore transmission-related issues is important in order to secure the benefits that transmission can provide and is in the public interest.[2]

3. The Task Force will be comprised of all FERC Commissioners as well as representatives from 10 state commissions. State commission representatives will serve one-year terms from the date of appointment by FERC and in no event will serve on the Task Force for more than three consecutive terms. State commission representatives will sit in an advisory capacity. We request that the National Association of Regulatory Utility Commissioners (NARUC) submit nominations to the Commission, in this docket, for the 10 state commission representatives no later than 30 days from the date of this order. We further request that two state commission representatives originate from each NARUC region,[3] recognizing that transmission-related issues may be viewed differently not only within, but also among different parts of the country. Although we solicit 10 nominations for state commission representatives on the Task Force, all state commissions will be invited to suggest agenda topics for public meetings of the Task Force and to submit comments before and after on the topics being discussed at such meetings. In addition, in the future, the Task Force may convene regional meetings with opportunity for participation by all state commissions in the region. Staff from FERC, NARUC, and the state commissions of state commission representatives will be appointed to support the work of the Task Force.

4. The Task Force will convene for multiple formal meetings annually, with FERC issuing orders fixing the time and place and agenda for each meeting, after consulting with all Task Force members and considering suggestions from state commissions. Meetings will be open to the public for listening and observing and on the record. We expect the initial public meeting of the Task Force to be held during the Fall 2021. The Task Force will expire three years after the first public meeting but may be extended for an additional period of time prior to its expiration by agreement of both FERC and NARUC.

5. The Task Force has the authority to examine the issues identified below, including soliciting oral and written input from interested parties. The Task Force may make

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[2] *See* 18 C.F.R. § 385.1301(b) (2020) (suggesting FERC or any state commission "will freely suggest cooperation with respect to any proceeding or matter affecting any public utility . . . subject to the jurisdiction of the Commission and of a State commission, and concerning which it is believed that cooperation will be in the public interest"); *see also id.* § 385.1305(c) (stating that FERC or any state commission "should feel free to suggest or request a joint . . . hearing at any time").

[3] *See* Nat'l Ass'n of Regul. Util. Comm'rs, https://www.naruc.org/meetings-and-events/regionals/ (last visited June 2, 2021) (identifying five regional associations).

recommendations to FERC on potential modifications to FERC's regulations, present recommendations at a monthly FERC open meeting, and develop a record to be incorporated into FERC and/or state commission proceedings.

II. Issue Statement

6. The Task Force will focus on topics related to efficiently and fairly planning and paying for transmission, including transmission to facilitate generator interconnection, that provides benefits from a federal and state perspective. Topics that the Task Force may consider include the following:

- Identifying barriers that inhibit planning and development of optimal transmission necessary to achieve federal and state policy goals, as well as potential solutions to those barriers;

- Exploring potential bases for one or more states to use FERC-jurisdictional transmission planning processes to advance their policy goals, including multi-state goals;

- Exploring opportunities for states to voluntarily coordinate in order to identify, plan, and develop regional transmission solutions;

- Reviewing FERC rules and regulations regarding planning and cost allocation of transmission projects and potentially identifying recommendations for reforms;

- Examining barriers to the efficient and expeditious interconnection of new resources through the FERC-jurisdictional interconnection processes, as well as potential solutions to those barriers; and

- Discussing mechanisms to ensure that transmission investment is cost effective, including approaches to enhance transparency and improve oversight of transmission investment including, potentially, through enhanced federal-state coordination.

III. Next Steps

7. After receiving nominations from NARUC, due within 30 days of the date of this order, for the 10 state commission representatives, we will issue a subsequent order, listing members of the Task Force and their roles and fixing the time and place for the first public meeting. At least two weeks prior to the first public meeting, we will issue an order with an agenda, developed in collaboration with Task Force members and in consideration of suggestions from state commissions.

By the Commission. Commissioner Chatterjee is not participating.

(S E A L)

Kimberly D. Bose,
Secretary.

NEWS RELEASES

FERC, NARUC Establish Federal-State Current Issues Collaborative

March 21, 2024
Items E-5
Docket Nos. AD21-15, AD24-7

FERC voted today to establish a new Federal-State Current Issues Collaborative to build on nearly three years of successful transmission-related task force discussions with state utility regulators and expand their efforts to energy sector issues where there are relevant jurisdictional connections or potential regulatory gaps.

The new Collaborative, formed in conjunction with the National Association of Regulatory Utility Commissioners (NARUC), expands on the last three years of work of the Joint Federal-State Task Force on Transmission. The Collaborative will provide a venue for federal and state regulators to share perspectives, improve understanding and, where appropriate, identify potential solutions regarding challenges and coordination on matters that affect specific state and federal regulatory jurisdictions. Potential topics include exploring where best to coordinate between state and federal regulators on issues ranging from electric reliability and resource adequacy to natural gas-electric coordination, wholesale and retail markets, new technologies and innovations, and infrastructure.

> "The past three years of our Task Force work have proven just how important it is for FERC and state regulators to meet and expand our shared perspectives on important electricity sector matters that we all grapple with on a daily basis," FERC Chairman Willie Phillips said. "I look forward to this expanded collaboration with our state colleagues."

"The role of state utility commissioners is increasingly more challenging and consequential to the quality of life, safety and economic health of this nation. Ensuring the reliability of the grid as the energy sector evolves at a rapid pace is crucial," said NARUC President Julie Fedorchak. "We appreciate the opportunity to continue these dialogues with FERC on matters at the cross-section of state and federal jurisdictions, which ultimately affect the well-being of our society."

"Transmission planning, siting and cost allocation are growing issues in some portions of our nation that are presenting challenges for state and federal regulators alike," said North Carolina Commissioner Kim Duffley, who represented the states as the co-chair of the task

force. “I greatly appreciate the opportunity to have served with my fellow regulators on the task force, as the process allowed for meaningful dialogue and assisted in providing a clearer understanding of regional differences. The states look forward to seeing the beneficial results of our conversations and working with our federal partners on other significant federal-state issues.”

The Joint Federal-State Task Force on Electric Transmission, established in 2021, had its final meeting in February 2024. Since its first meeting in November 2021, the Task Force addressed numerous transmission-related topics, including regional transmission planning and cost allocation, generator interconnection, interregional transmission, oversight of transmission costs, physical security, grid enhancing technologies and siting.

The Federal-State Issues Collaborative will convene its first meeting this fall; it will expire in the fall of 2027. The Collaborative structure will be similar to that of the Task Force: It will be comprised of all sitting FERC Commissioners and representatives from 10 state commissions to be nominated by NARUC, with two state nominees from each NARUC region. State members will serve one-year terms.

R24-12

Contact Information

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This page was last updated on March 21, 2024

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Consumers Energy Company	)	
	)	**Docket No. EL25-90-000**
v.	)	
	)	
Midcontinent Independent System Operator, Inc.	)	

ANSWER OF THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

The Midcontinent Independent System Operator, Inc. ("MISO" or "Respondent") submits[1] this Answer to the Complaint of Consumers Energy Company ("Consumers Energy" or "Complainant"). Consumers Energy filed the Complaint in response to an order issued by the U.S. Secretary of Energy pursuant to Federal Power Act ("FPA") section 202(c) and section 201(b) of the Department of Energy Authorization Act.[2] The DOE Order determined "that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes[.]"[3] To address that emergency, the DOE Order directs MISO and Consumers Energy to take all measures necessary to ensure that the J.H. Campbell coal-fired power plant in West Olive, MI ("Campbell Plant") is available to operate.[4] Consumers Energy's Complaint requests that MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff") be revised to permit

1 *See* Rules 206 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 385.206(f) (2025); 18 C.F.R. § 385.213 (2025).
2 U.S. Department of Energy, Order No. 202-25-3, at 2 (May 23, 2025) ("DOE Order").
3 DOE Order at 1.
4 DOE Order at 2.

recovery of costs incurred incident to the DOE Order, and provides draft Tariff language for the Commission's review.

As recognized by the Order, MISO's Planning Resource Auction for the 2025-2026 Planning Year demonstrated sufficient capacity for all zones within the MISO Region.[5] While MISO does not intend to contest, within the context of this docket, the characterization within the Order that an emergency exists "due to a shortage of electric energy . . . [or] a shortage of facilities," it is important to recognize existing processes have cleared sufficient electric generating capacity across MISO for the periods of time covered by the Order. The clearing of sufficient capacity to meet anticipated demand across the MISO Region for the 2025-2026 Planning Year reflects the diligent efforts of MISO's members, Market Participants, Relevant Electric Retail Regulatory Authorities (RERRA) and the Federal Energy Regulatory Commission (FERC) to establish policies and processes that address both immediate, and future capacity requirements. MISO continues to work with these parties in the context of anticipated growing demand for electricity, planned electric generating facility retirements, and an evolving mix of new electric generating resources to refine processes that address the challenges ahead. MISO is confident that these collaborative efforts do not require further intervention and will help ensure the region continues to procure sufficient capacity to meet demand.

MISO acknowledges that the DOE Order directs Consumers Energy "to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order."[6] MISO also acknowledges that the DOE Order provides that "[r]ate recovery is available pursuant to 16 U.S.C. § 824a(c)."[7] MISO supports the addition of a cost recovery schedule to the

5 Department of Energy Order No. 202-25-3 (May 23, 2025) at p. 2.
6 DOE Order at 3.
7 DOE Order at 3.

Tariff, subject to the reservations noted below, and believes that a Commission finding that such a mechanism be incorporated in the Tariff would further compliance with the DOE Order by both Consumers and MISO.

I. BACKGROUND

The Secretary of Energy issued the DOE Order on May 23, 2025.[8] The DOE Order identifies an "emergency situation" in the MISO region and states that MISO "faces potential tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output."[9] The DOE Order notes that the Campbell Plant is scheduled to cease operations on May 31, 2025," and concludes that the Campbell Plant's retirement "would further decrease available dispatchable generation within MISO's service territory[.]"[10] The DOE Order states that, although MISO and Consumers Energy incorporated the Campbell Plant's planned retirement into their supply forecasts and acquired a 1,200 MW natural gas plant in Covert, MI, the North American Electric Reliability Corporation's ("NERC") analysis still anticipates an "elevated risk of operating reserve shortfalls."[11] The DOE Order concludes that "additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c)."[12]

The DOE Order directs MISO and Consumers Energy to "take all measures necessary to ensure that the Campbell Plant is available to operate."[13] MISO is "directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers" and "to provide the [DOE] with information concerning the measures it has taken and is planning to take to ensure

8 DOE Order at 3.
9 DOE Order at 1.
10 DOE Order at 1.
11 DOE Order at 2.
12 DOE Order at 3.
13 DOE Order at 2.

the operational availability and economic dispatch of the Campbell Plant consistent with the public interest."[14] MISO notes that it is working closely with Consumers and the other owners of the Campbell Plant to ensure the plant is available to operate in compliance with the DOE Order.

The DOE Order states that, to "[t]he extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so."[15] The Order further provides that "Consumers [Energy] is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order."[16] The DOE Order states that "[r]ate recovery is available pursuant to 16 U.S.C. § 824a(c)."[17]

II. ANSWER

A. The Tariff Does Not Currently Include a Mechanism to Allow Cost Recovery Pursuant to the DOE Order.

Consumers Energy observes that there is no MISO Tariff provision that would permit Consumers Energy's costs of complying with the DOE Order to be allocated to Load Serving Entities ("LSEs") in MISO's northern and central zones, and that MISO does not have the unilateral authority to offer Consumers Energy a section 202(c) rate agreement.[18] MISO agrees. MISO acknowledges that its Tariff does not currently include a mechanism to allow the cost recovery contemplated by the DOE Order. As discussed below, MISO does not oppose the addition of a cost recovery schedule to its Tariff that would allow Consumers Energy to recover its costs as contemplated by the DOE Order.

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14 DOE Order at 2-3.
15 DOE Order at 3.
16 DOE Order at 3.
17 DOE Order at 3.
18 Complaint at 18.

B. MISO Does Not Oppose the Addition of a Cost Recovery Schedule for the Recovery of These Costs, and Will File a Cost Recovery Schedule to the Extent Directed by the Commission.

MISO does not oppose the addition of a cost recovery schedule that would permit Consumers Energy to recover the costs incurred as a result of its efforts to comply the DOE Order. MISO will file such a schedule if directed by the Commission.

C. MISO Reserves Its Right to Modify or Otherwise Change the Cost Recovery Allocation Formula, As Necessary, to Account for Existing Tariff Requirements or Changes.

MISO reserves the right to modify, adjust, or otherwise change the cost recovery allocation formula proposed by Consumers, should it be necessary, to account for existing Tariff requirements and to include other clarifications as may be appropriate.

III. ADMISSIONS AND DENIALS; AFFIRMATIVE DEFENSES

MISO denies all allegations in the Complaint not specifically and expressly admitted herein.[19]

IV. COMMUNICATIONS

All notices and communications with respect to this proceeding should be directed to:

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[19] 18 C.F.R. § 385.213(c)(2)(i)-(ii).

V. CONCLUSION

WHEREFORE, MISO respectfully requests that the Commission accept this answer.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have on this day e-served a copy of this document upon all parties listed on the official service list compiled by the Secretary in the above-captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated this 19th day of June, 2025 in Carmel, Indiana.

/s/ Adriana Rodriguez
Adriana Rodriguez
Midcontinent Independent
System Operator, Inc.

Dated: June 19, 2025

MISO IMM Blasts NERC Long-term Assessment, Says RTO in Good RA Spot

By Amanda Durish Cook

MINNEAPOLIS — MISO Independent Market Monitor David Patton called NERC's Long-Term Reliability Assessment inaccurate for labeling MISO a high-risk area and said he believes MISO is in a good reliability position.

"We find that it is completely inaccurate. MISO should not be colored in red," Patton said at a June 10 Markets Committee meeting of the MISO Board of Directors.

Patton faulted NERC for apparently conflating installed capacity with unforced capacity in the assessment's totals. He said NERC tallied unforced capacity values for MISO when calculating a margin that it ultimately compared to an installed capacity requirement. He said the blunder lowered the footprint's capacity sums on paper by more than 10 GW.

"I don't frankly understand how they did this," Patton said. "They basically presented an apples and oranges assessment."

NERC's Long-Term Reliability Assessment predicted MISO could be confronted with capacity shortfalls in 2025. It assumed the RTO would have 132.2 GW in generating capacity, or 124.4 GW after factoring in all retirement announcements. (See *NERC Warns Challenges 'Mounting' in Coming Decade*.)

Ahead of summer, MISO reported it has 143.1 GW in offered capacity available to it to meet a likely 123-GW annual peak. (See *MISO Prepping for Likely 123-GW Summer 2025 Peak*.) Altogether, the RTO has 203 GW of installed capacity.

Patton said NERC's lapse is influencing national policy, evidenced by the Department of Energy's directive to keep Consumers Energy's 1.4-GW J.H. Campbell coal plant in Michigan operating over the summer. (See *Consumers Energy Seeking Compensation for Keeping Campbell Open*.) He said NERC's projection could bleed into other rule changes.

"That sort of initiative can lead to FERC ordering market changes that are unnecessary," Patton said.

Patton also said MISO overstated load predictions used in NERC's assessment by submitting non-coincident peak forecasts instead of coincident peaks, raising its load requirements and lowering the calculated capacity margin.

Patton said of the four RTO markets he monitors, "I would say MISO is most reliable of the four."

"It seems like a combination of errors that seems correctable here, but there isn't a path for correction," MISO Director Barbara Krumsiek said.

Patton said he hopes NERC will rectify its methods that inform the long-term assessment by the next December report. He said he has reached out to NERC and committed to working with the regulatory authority on its approach.

Michelle Bloodworth, CEO of coal lobby organization America's Power, questioned whether it was appropriate for the MISO Market Monitor to question a "credible institution" such as NERC. She said she believed MISO's "elevated risk" status under the assessment was apt.

Bloodworth praised the DOE's actions to keep J.H. Campbell available for a little while longer. She noted that Cleco's 568-MW Big Cajun II Unit 1 shuttered March 31 due to a settlement decree; she said having the coal plant online at the time might have helped matters during MISO's load shedding orders in the New Orleans area on May 25. (See *NOLA City Council Puts Entergy, MISO in Hot Seat over Outages*.)

At the same meeting, MISO said it likely will manage higher-than-normal temperatures paired with drought over the summer.

"If you're dry and have a pervasive heatwave going on, it can compound challenges in the operating room," MISO Executive Director of Market Operations JT Smith said.

Smith said a doubled-in-size solar fleet also likely will test MISO's ramp and regulation capabilities in its ancillary market. He said MISO operators could be managing unavailable resources and higher-than-expected load throughout summer.

Why This Matters

MISO IMM David Patton panned the RTO's precarious standing in NERC's Long-Term Reliability Assessment. He waved away resource adequacy concerns and said NERC botched a margin-to-capacity requirement comparison, apparently mixing up unforced capacity and installed capacity.

As part of a five-year update, Vice President of Operations Renuka Chatterjee said MISO finds itself in the most "dynamic and demanding" operating environment it ever has. She cited steeper evening ramps and mounting long-duration outages, forecasting challenges and stability risks.

MISO entered summer June 1 with a $666.50/MW-day capacity price, signifying the premium the RTO has put on new capacity. (See *MISO Summer Capacity Prices Shoot to $666.50 in 2025/26 Auction*.)

Carrie Milton, of the IMM staff, said if generation operators had held off on powering down about 1.6 GW until September, it would have lowered capacity prices to $472/MW-day in the summer.

But Milton said the Campbell plant is not factored into MISO's clearing prices and isn't necessary for reliability during the season. She said MISO's auction already returned a better than one-day-in-10-years standard without the large coal plant.

"We are more than adequate," Patton said. He repeated that he has "no material concerns" over MISO's resource adequacy for the upcoming summer.

Patton said factoring in imports and typical planned and forced outages, MISO has a comfortable, 12.2% reserve margin. ■

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Federal Power Act: The Department of Energy's Emergency Authority

June 12, 2025

Congressional Research Service
https://crsreports.congress.gov
R48568

CRS REPORT
Prepared for Members and
Committees of Congress

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Section 202(c) of the Federal Power Act (16 U.S.C. §824a(c)) grants the Secretary of Energy certain authorities over the temporary operation of the electricity system during emergencies. Actions by the Trump Administration have highlighted this authority and raised questions about its future implementation. This report provides a brief history of the emergency authorities and discusses current issues.

History of Section 202(c)

The Federal Power Act was enacted in 1935 and included emergency authority language. At the time, federal oversight of the electricity system was conducted by the Federal Power Commission (FPC). Now, the Federal Energy Regulatory Commission (FERC) has most responsibilities for electricity system oversight—but not for emergencies. The emergency authority was transferred to the Secretary of Energy when the Department of Energy (DOE) was established by the Department of Energy Organization Act (P.L. 95-91) in 1977. Hereinafter, the emergency authority is described as residing with DOE.

Section 202(c) provides DOE broad discretion to require almost any change to the operation of the U.S. electricity system on a temporary basis. Specifically, DOE may "require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."

DOE may execute this authority during war or at any other time it "determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes." This report focuses on the authority as used during emergencies, not war, and it focuses on DOE's authority—it does not discuss other energy emergency authorities.[1]

In 2015, Congress amended Section 202(c) to specify how the emergency authority should interact with environmental requirements for power plants. In practice, the amendments prioritize electric reliability over environmental outcomes, essentially by providing a waiver of federal, state, or local environmental laws and regulations during times of emergencies.

This waiver has limitations. First, DOE emergency orders that may result in conflicts with environmental requirements may be issued only for 90-day periods. They may be renewed for additional 90-day periods as long as DOE deems these renewals necessary to meet the emergency.

Second, if an emergency order would result in a violation of a federal, state, or local environmental law or regulation, DOE must ensure the order is in effect "only during hours necessary to meet the emergency and serve the public interest." Lastly, DOE must "to the maximum extent practicable" ensure the order is consistent with environmental laws or regulations and "minimizes any adverse environmental impacts."

DOE Implementation

DOE's regulations for implementing its emergency authority were finalized in 1981.[2] The regulations define terms, including "emergency," and specify requirements for requesting an emergency order.

[1] For example, in the 1970s, Congress passed several laws granting the President certain authorities to respond to energy shortages at the time. A discussion of those laws is beyond the scope of this report.

[2] 10 C.F.R. §§205.370-205.379.

The Section 202(c) emergency authority is focused primarily on short-term situations—though, as shown below, DOE has exercised this authority in situations of varying duration. DOE's regulations emphasize the short-term nature of "emergencies" in this context. In the 1981 rulemaking, DOE explained,

> The DOE does not intend these regulations to replace prudent utility planning and system expansion. This intent has been reinforced in the final rule by expanding the 'Definition of Emergency' to indicate that, while a utility may rely upon these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself.[3]

DOE and FPC have used the emergency authority several dozen times since 1935 in response to different kinds of emergencies.

DOE's website contains information on use of the emergency authority from 2000.[4] From 2000 through May 2025, DOE used its emergency authority in response to 19 events. Eleven events were weather-related and included hurricanes, heat waves, and winter storms. Some events prompted multiple emergency orders, either because more than one utility experienced emergency conditions (e.g., Winter Storm Elliot in 2022) or because the initial emergency order was extended (e.g., the California energy crisis of 2000-2001).

Details on the use of the Section 202(c) emergency authority prior to 2000 are not available in a single DOE repository; they are therefore more difficult to comprehensively compile. According to one compilation, the emergency authority was used 29 times prior to 2000; 22 of these occasions were in association with World War II.[5]

The duration of emergency orders under Section 202(c) has varied; some have lasted just a few hours, while others have been extended to cover events lasting more than a year. Among the orders listed on DOE's website, the shortest order CRS identified occurred in response to a heat wave in Texas in September 2023. DOE granted an emergency order in this case for four hours on each of two days to respond to the highest levels of expected electricity demand.[6] The order allowed one coal-fired unit and 16 natural gas-fired units to operate in violation of limits on sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and wastewater during those hours, if required to maintain reliability.

In the longest event CRS identified, DOE granted multiple renewals to a request to allow two coal-fired units in Virginia to continue operating, as needed for reliability, in violation of mercury emissions limitations while a transmission facility was constructed. Emergency orders in response to that event were in effect from June 16, 2017, to March 8, 2019.[7]

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[3] Department of Energy (DOE), Economic Regulatory Administration, "Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power" (final rule), 46 *Federal Register* 39985, August 6, 1981, https://archives.federalregister.gov/issue_slice/1981/8/6/39984-39991.pdf#page=2.

[4] See DOE, "DOE's Use of Federal Power Act Emergency Authority," https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority; and DOE, "DOE's Use of Federal Power Act Emergency Authority – Archived," https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority-archived.

[5] Benjamin Rolsma, "The New Reliability Override," *Connecticut Law Review*, vol. 57, no. 3 (May 2025).

[6] Additional information is available at DOE, "Federal Power Act Section 202(c): ERCOT September 2023," https://www.energy.gov/ceser/federal-power-act-section-202c-ercot-september-2023.

[7] Additional information is available at DOE, "Federal Power Act Section 202(c) – PJM Interconnection & Dominion Energy Virginia, 2017," June 19, 2017, https://www.energy.gov/oe/articles/federal-power-act-section-202c-pjm-interconnection-dominion-energy-virginia-2017.

Trump Administration Actions

On April 8, 2025, President Trump issued Executive Order (E.O.) 14262, "Strengthening the Reliability and Security of the United States Electric Grid."[8] E.O. 14262 directs DOE to "streamline, systemize, and expedite" its processes for issuing emergency orders when "the relevant grid operator forecasts a temporary interruption of electricity supply is necessary to prevent a complete grid failure." A blackout is an example of a temporary interruption of electricity supply.

The E.O. additionally directs DOE to develop a protocol to identify generation resources that are critical to system reliability. The protocol must "include all mechanisms available under applicable law, including Section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained." Further, the protocol must prevent, "as the Secretary of Energy deems appropriate and consistent with applicable law," identified resources from "leaving the bulk-power system" or converting fuels in such a way that reduces their accredited capacity. An example of fuel conversion that could reduce accredited capacity is replacing a coal-fired power plant with a solar farm.

The language of the E.O. is nonspecific regarding the duration of any DOE action to retain resources or prevent them from leaving the bulk-power system. The E.O. language could be interpreted to mean DOE should take long-term action (i.e., lasting multiple years) or indefinite action. Emergency orders issued in response to multiyear events would be unusual, though not unprecedented, applications of DOE's Section 202(c) authority. It is unclear the extent to which limits to the authority might exist through judicial review or other avenues if DOE chose to issue long-term or indefinite emergency orders.

DOE issued emergency orders for three separate events in May 2025, all involving seemingly new interpretations of the emergency authority. One event is anticipated electricity supply shortages in Puerto Rico in summer 2025.[9] One of the DOE emergency orders pertaining to Puerto Rico directs the local utility to conduct vegetation management (e.g., shrub clearing) around specified transmission lines on the island.[10] No other emergency order issued from 2000 to the present has addressed vegetation management.

The other events involve elevated risk of supply shortages in parts of the Midwest and Eastern United States this summer. DOE ordered a delay in retirement plans for a coal-fired power plant in Michigan and a natural gas/oil dual-fired power plant in Pennsylvania.[11] Unlike in the cases of other emergency orders issued since 2000, the grid operators in these cases had not requested the delayed retirements. Moreover, neither had identified reliability risks specifically associated with

[8] Executive Order 14262 of April 8, 2025, "Strengthening the Reliability and Security of the United States Electric Grid," 90 *Federal Register* 15521-15522, April 14, 2025, https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[9] For background on Puerto Rico's electricity system, see CRS In Focus IF12913, *Electric Reliability and Resiliency in Puerto Rico*, by Corrie E. Clark.

[10] Secretary of Energy Chris Wright, *Order No. 202-25-2*, May 16, 2025, https://www.energy.gov/sites/default/files/2025-05/PREPA%20202%28c%29%20Emergency%20Measures%20Transmission.pdf.

[11] Secretary of Energy Chris Wright, *Order No. 202-25-3*, May 23, 2025, https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf; and Secretary of Energy Chris Wright, *Order No. 202-25-4*, May 30, 2025, https://www.energy.gov/sites/default/files/2025-05/Federal%20Power%20Act%20Section%20202%28c%29%20PJM%20Interconnection.pdf.

the retirement of the power plants in question at the time they approved those retirements. One of the affected grid operators, PJM, issued a supportive statement following the emergency order.[12]

Issues for Congress

E.O. 14262 does not specify how DOE should streamline its processes for issuing emergency orders. Congress could evaluate whether DOE's existing regulations require streamlining and, if Congress determines they do, could provide policy direction and set a timeline for updating the regulations. Congress could also leave it to DOE's discretion as to when and how to update its regulations.

Congress could weigh DOE action in this space against other priorities for the department, given that updating processes for issuing emergency orders could divert DOE resources from other activities. On the one hand, brownouts or blackouts due to insufficient electricity supplies are relatively rare in the United States. Grid operators have their own processes in place for managing the grid during times of supply shortages and, historically, DOE emergency orders have rarely been requested. On the other hand, many observers anticipate electricity demand to increase in the coming years faster than new supply can be brought online. If these trends continue, brownouts or blackouts could become more common, potentially increasing DOE's use of its emergency authority or Congress's interest in addressing emergency situations for electricity supply.

Regarding the statutory authority itself, Congress could consider whether amendments to Section 202(c) of the Federal Power Act are appropriate. The language has remained unchanged since 1935, potentially reflecting Congress's continued view over this time period that the original authorization is appropriate. Nonetheless, the U.S. electricity system has changed in many ways since 1935, and Congress might choose to consider reevaluating the authority.

One potential aspect for congressional consideration is the duration of DOE emergency orders, especially in relation to critical resources identified pursuant to E.O. 14262. Under current law, and assuming such orders might result in a conflict with environmental requirements, DOE could potentially reissue its emergency orders every 90 days for an indeterminate amount of time. Repeated emergency orders may raise feasibility questions, such as whether successive emergency orders would be upheld by the courts or whether power plant owners would make long-term investments to maintain power plants that are operating primarily under emergency orders.

Congress could consider evaluating and clarifying via legislation whether the Section 202(c) authority is better reserved for short-term situations or whether application to long-term situations is appropriate. Some backers of power plants at risk of retirement (e.g., coal-fired power plants) might support extended emergency orders based on long-term economic considerations. At the same time, some backers of power plants with low greenhouse gas emissions (e.g., solar generators) might support extended emergency orders based on long-term environmental considerations. Others might prefer to limit DOE's emergency authorities to short-term situations. A more limited role for DOE in electricity system operations allows for greater use of market forces and reliance on local- and state-level processes to prepare for and respond to emergencies.

[12] PJM, "PJM Statement on the U.S. Department of Energy 202(c) Order of May 30," press release, May 31, 2025, https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/2025-releases/20250531-doe-202c-statement-to-defer-retirements-of-certain-generators.pdf.

Another potential aspect for congressional consideration is the definition of "emergency" in the context of Section 202(c). Current law gives DOE broad discretion in determining what constitutes an emergency. Congress could consider whether this level of discretion is appropriate, or whether additional (or alternative) statutory direction would better serve current system needs.

As noted above, some supporters of specific kinds of power plants might view sustained economic conditions or environmental impacts as emergencies that warrant DOE action. Those situations would appear to be novel exercises of DOE authority under Section 202(c), if DOE were to interpret them in such a way. Amendments to the Federal Power Act could clarify congressional intent regarding use of DOE's emergency authority in response to those situations or any other long-term situation.

Other stakeholders might wish to limit DOE's discretion in when to issue emergency orders—for example, by modifying the currently broad statutory language or by requiring additional review by FERC or another entity.

A third potential aspect for congressional consideration is the scope of interventions allowed under the emergency authority. Current law allows DOE to order almost any change in operation of the electricity system.

Emergency orders between 2000 and 2024 directed either the operation of certain generators as needed for reliability or the temporary interconnection of the main Texas grid with neighboring regions' grids. One of DOE's May 2025 emergency orders requires Puerto Rico's local utility to conduct vegetation management activities.

One operational consideration that has not been tested under DOE's emergency authority (at least not in the orders available on DOE's website) is the curtailment of certain generators. Curtailment occurs when a grid operator directs a generator to reduce its output or cease operating altogether for a certain amount of time. Curtailment is sometimes necessary when generation levels in a given location exceed the transmission system's capacity to transmit energy out of that location.

Congress could evaluate the appropriateness of DOE's currently broad discretion to order interventions in the operation of the electricity system. Amendments to the Federal Power Act could clarify what kinds of interventions DOE may require.

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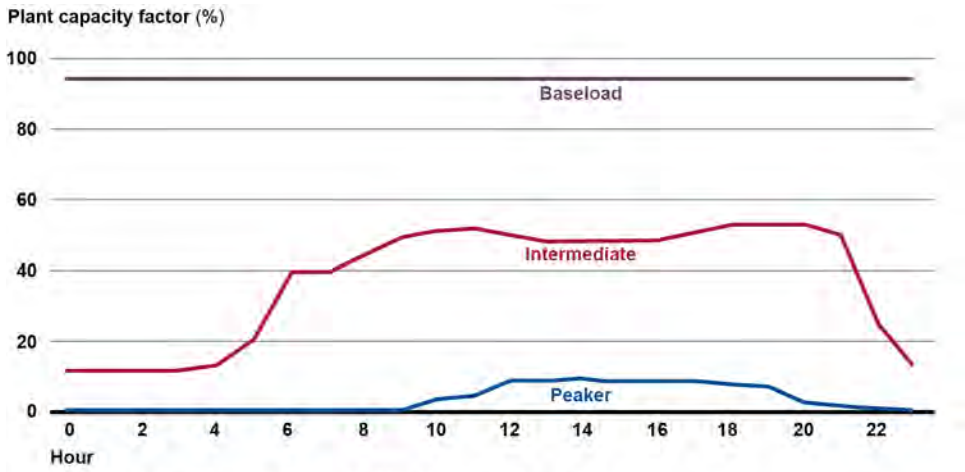
Electricity: Information on Peak Demand Power Plants

GAO-24-106145
Q&A Report to Congressional Requesters
May 21, 2024

Why This Matters

Peaker power plants are part of the U.S. energy infrastructure and help meet peak electricity demand. Peak demand generally occurs at times during the day when cooling and heating needs are generally the highest among households. Peakers are used to supplement other types of power plants, such as baseload plants, which run consistently throughout the day and night, and intermediate plants, which run mostly during the day and less at night (see fig. 1).

Figure 1: Illustrative Example of Annual Average Hourly Capacity Factors, by Plant Type



Source: GAO Analysis of Environmental Protection Agency data. | GAO-24-106145

Note: A plant's capacity factor is the percent of energy it produced of the total energy it could have produced during a certain time frame if it operated continuously at full power.

Peakers may be less efficient than other types of plants—such as intermediate and baseload plants—because they undergo frequent startups using comparatively large amounts of fuel. Further, environmental advocates and some congressional leaders have expressed concerns that peakers may also negatively affect the air quality in communities—which may be historically disadvantaged or disproportionately low income—around the plants.

We were asked to examine pollution from peakers across the nation. We are providing information on the number and locations of peakers in the U.S.; the proximity of peakers to disproportionately low-income, and historically disadvantaged racial or ethnic populations; the extent to which they emit pollutants and how these pollutants affect the health of people exposed; alternatives for replacing them; and potential challenges of replacing them.

Key Takeaways

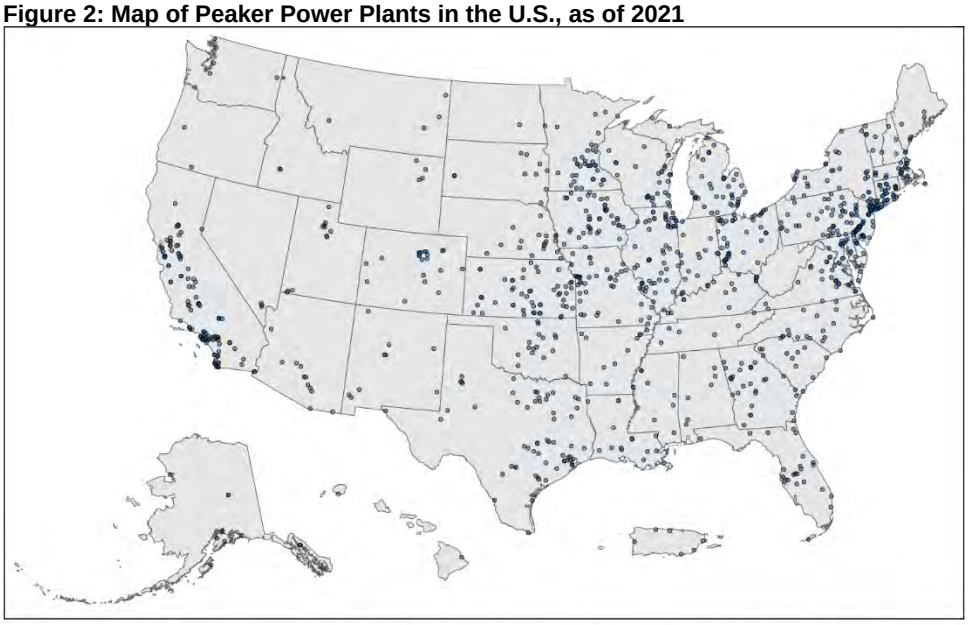
- Historically disadvantaged racial or ethnic communities tend to be closer to peakers.

- Fossil-fueled peakers are primarily fueled by natural gas and emit air pollutants associated with various negative health effects, including on respiratory, cardiovascular, and nervous systems.
- Alternatives are available that could potentially replace or provide similar services as peakers, but we identified challenges for their use related to costs, reliability, space, and location.

How many peakers are there in the U.S., and where are they located?

We identified 999 peakers in the U.S. in 2021, based on our analysis of Environmental Protection Agency (EPA) data (see fig. 2).[1] For the purpose of our report, we generally define peakers as plants that use fossil fuels, including natural gas, coal, and oil; have a capacity factor (the percent of energy produced over a certain time frame, out of what could have been produced at continuous full power operation) of 15 percent or less; and have a nameplate capacity (the designed full-load sustained output of a facility) of greater than 10 megawatts (MW) of electricity.[2] Most of these peakers are fueled by natural gas (see table 1). In 2021, these peakers accounted for 3.1 percent of annual net generation and 19 percent of total nameplate capacity for all power plants.

Figure 2: Map of Peaker Power Plants in the U.S., as of 2021



Source: GAO analysis of Environmental Protection Agency Emissions & Generation Resource Integrated Database (eGRID). | GAO-24-106145

Note: Alaska, Hawaii, and Puerto Rico are shifted for display purposes. We define peakers as fossil-fueled power plants that have a capacity factor of 15 percent or less and a nameplate capacity of greater than 10 megawatts of electricity. Areas with multiple peakers appear darker than those with only one. This map does not identify whether there is any statistically significant spatial association or differentiate whether peakers are more concentrated in certain geographies relative to underlying population size.

Table 1: Total Net Electricity Generation and Total Nameplate Capacity of Peaker Power Plants, by Primary Fuel Type, 2021

Plant primary fossil fuel type	Number (%)	Total net generation (MWh)[a] (%)	Total nameplate capacity[b] (MW)
Natural gas	698 (69.87)	106,791,342 (82.75)	190,373
Oil	267 (26.73)	2,646,700 (2.05)	23,991
Coal	33 (3.30)	19,617,924 (15.20)	22,904
Other[c]	1 (0.10)	-9,824 (0.00)[d]	99
Total	**999 (100)**	**129,046,142 (100)**	**237,367**

Source: GAO analysis of Environmental Protection Agency data. | GAO-24-106145

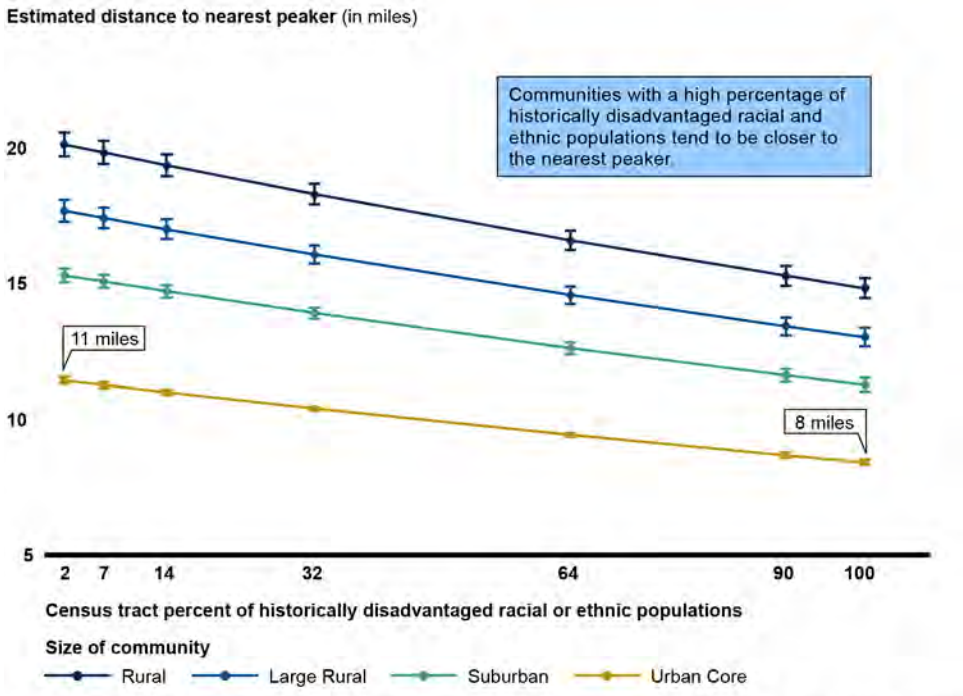
Note: We define peakers as fossil-fueled power plants that have a capacity factor of 15 percent or less and a nameplate capacity of greater than 10 megawatts of electricity.

[a]MWh = megawatt hour
[b]Nameplate capacity is the maximum output of electricity a power plant can produce without exceeding design thermal limits.
[c]This category includes other fossil fuels including blast furnace gas, other gasses, or tire-derived fuel.
[d]This plant has a negative net generation because electricity consumed by the plant exceeds the gross generation of the plant.

How closely are peakers located to historically disadvantaged and low-income communities?

We found that historically disadvantaged racial or ethnic communities (i.e., census tracts with higher percentages of historically disadvantaged racial or ethnic populations) are associated with being closer to peakers (see fig. 3).[3] To perform this analysis, we developed a statistical model to assess how community demographics are associated with proximity to peakers.[4] We tested this model with four alternative definitions of peakers and found that historically disadvantaged racial or ethnic communities are associated with being closer to peakers for all four definitions.[5] For example, based on our model and main definition of a peaker, a community that is 71 percent historically disadvantaged is expected to be 9 percent closer to the nearest peaker than the average community, which is 40 percent historically disadvantaged.[6] In addition, we found that the estimated distance to the nearest peaker varies according to population density, where urban communities have smaller estimated distances to the nearest peaker when compared to otherwise similar rural or suburban communities.

Figure 3: Estimated Distance to Nearest Peaker Power Plant Based on Percent of Community That Is Historically Disadvantaged, by Population Density



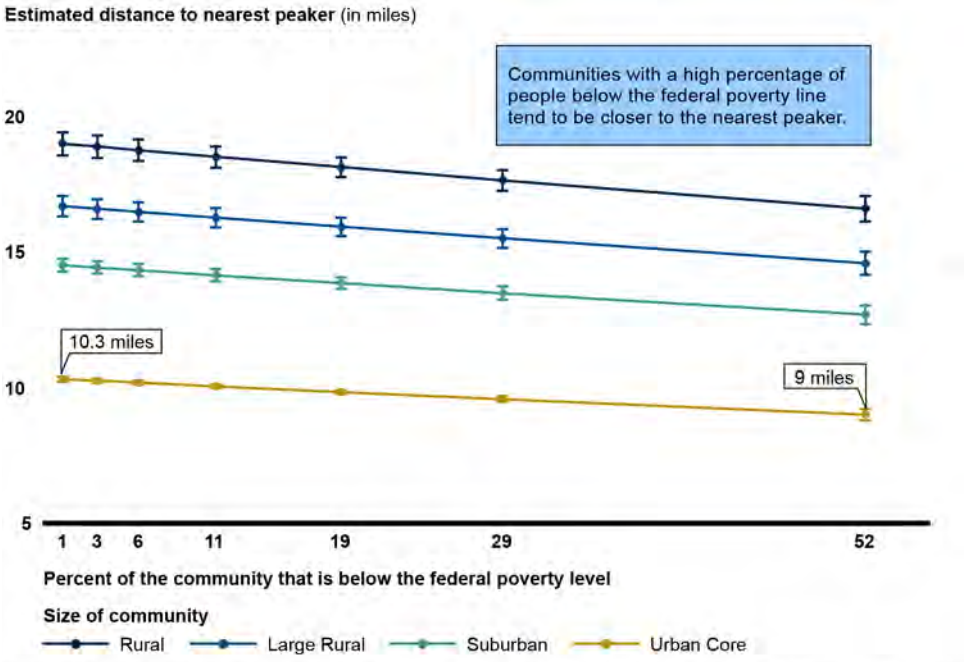
Source: GAO analysis of Census Bureau American Community Survey, Department of Agriculture Economic Research Services, National Oceanic and Atmospheric Administration National Weather Service, and Energy Information Administration data. | GAO-24-106145

Note: We define peakers as fossil-fueled power plants that have a capacity factor of 15 percent or less and that generate greater than 10 megawatts of electricity. We tested our model with alternative definitions of peakers and found similar results. This figure summarizes the results of our model assessing the relationship between the distance from a census tract to the nearest peaker and the demographic characteristics of that census tract. Our model includes controls for population density (e.g., rural or urban), climate, and other factors. Values on the x-axis represent various sample percentiles. Whiskers represent 95 percent confidence intervals, and non-overlapping whiskers are significantly different.

We found mixed results for income. Specifically, for three of our four definitions of a peaker, we found that communities with higher percentages of people below

the federal poverty level were statistically significantly closer to the nearest peaker (see fig. 4).[7] Income was not statistically significant for our fourth definition.[8]

Figure 4: Estimated Distance to Nearest Peaker Power Plant Based on Percent of Community That Is Below the Federal Poverty Level, by Population Density



Source: GAO analysis of Census Bureau American Community Survey, Department of Agriculture Economic Research Services, National Oceanic and Atmospheric Administration National Weather Service, and Energy Information Administration data. | GAO-24-106145

Note: We define peakers as fossil-fueled power plants that have a capacity factor of 15 percent or less and that generate greater than 10 megawatts of electricity. We tested our model with alternative definitions of peakers and found similar results for three definitions, but insignificant results for one definition. This figure summarizes the results of our model assessing the relationship between the distance from a census tract to the nearest peaker and the demographic characteristics of that census tract. Our model includes controls for population density (e.g., rural or urban), climate, and other factors. Values on the x-axis represent various sample percentiles. Whiskers represent 95 percent confidence intervals, and non-overlapping whiskers are significantly different.

To what extent do peakers emit pollutants, and how can these pollutants affect the health of people exposed?

When operating, peakers emit similar types of pollutants to other power plants that also use fossil fuels, and these pollutants are associated with various negative health effects, according to existing literature.

Pollutants

Compared to non-peakers, peakers emitted more pollutants—such as nitrogen oxides and sulfur dioxide—per unit of electricity generated, but fewer total annual pollutants in 2021, according to our analysis of EPA data (see table 2).[9] In other words, peakers emit less in total because there are fewer peakers and they operate less frequently overall than non-peakers. However, when they do operate, they emit more pollution per unit of electricity produced. For example, the median sulfur dioxide emission rate for natural gas fueled peakers was 1.6 times more per unit of electricity generated than the median emission rate for non-peakers. Conversely, total annual sulfur dioxide emissions from peakers were 96.8 percent lower than total non-peaker annual sulfur dioxide emissions. Overall, peakers contributed 3 percent of the total annual sulfur dioxide emissions and 9 percent of total annual nitrogen oxide emissions.

Table 2: Sulfur Dioxide and Nitrogen Oxide Emissions from Fossil-fueled Peaker and Non-peaker Power Plants with Nameplate Capacity Greater than 25 MW, 2021

	Fuel Type	Peaker	Non-peaker
Median sulfur dioxide emission rate (pounds per megawatt hour)	Natural Gas	0.008[b]	0.005
	Coal	2.487	1.308
	Oil	4.218	2.174
	Other[a]	—	0.027
	All fuel types	**0.009**	**0.008**
Median nitrogen oxides emission rate (pounds per megawatt hour)	Natural Gas	0.949[b]	0.156
	Coal	1.554	1.330
	Oil	15.014[b]	3.152
	Other	—	0.670
	All fuel types	**1.272[b]**	**0.468**
Total annual sulfur dioxide emissions (tons)	—	32,111	1,014,787
Total annual nitrogen oxides emissions (tons)	—	83,874	885,345

Source: GAO analysis of Environmental Protection Agency data. | GAO-24-106145

Note: This analysis is limited to fossil-fueled plants with a nameplate capacity greater than 25 megawatts of electricity (1,605 plants) because plants of this size are required to report certain emissions, including sulfur dioxide and nitrogen oxides. Peakers in this analysis include plants with a capacity factor of 15 percent or less, and non-peakers include baseload and intermediate plants that supply more consistent power throughout the day. This analysis excludes plants that had incomplete emissions or generation data (57 plants).

[a]This category includes other fossil fuels including blast furnace gas, other gasses, or tire-derived fuel.
[b]Statistically, the median for peakers is significantly different from the median for non-peakers at the 0.05 level.

In addition to sulfur dioxide and nitrogen oxides, ground-level ozone and particulate matter are pollutants related to the operation of peaker plants. Ground-level ozone is formed through chemical reactions between nitrogen oxides—emitted by peakers—and volatile organic compounds. Particulate matter is a mixture of solid particles and liquid droplets found in the ambient air and can be directly emitted from power plants or formed by chemical reactions involving pollutants such as sulfur dioxide that are emitted by peakers.

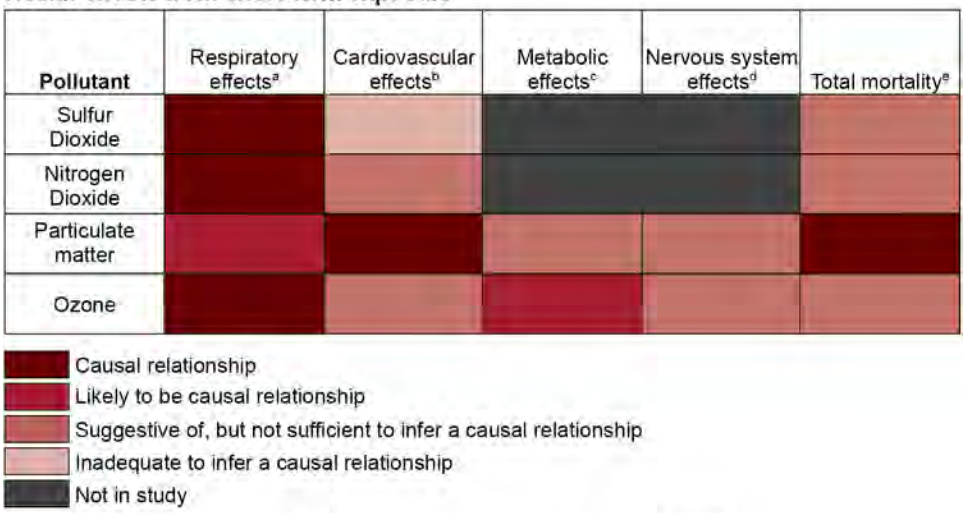
Peakers may have higher median emission rates per unit of electricity generated because of the nature of their operations. According to EPA, emissions generally increase under partial load conditions, which is how peakers operate.[10] Further, peakers typically do not have emissions control technologies, according to EPA officials.

Health effects

Multiple pollutants that are emitted from peakers and other plants are associated with various negative health effects for the people exposed, according to federal agency reports we reviewed.[11] In particular, EPA's Integrated Science Assessments identified causal relationships between short-term exposures to four key pollutants (nitrogen dioxide, sulfur dioxide, particulate matter, and ozone) and health effects that vary in degree of severity and duration (see fig. 5).[12] For instance, short-term exposure to sulfur dioxide—the indicator for sulfur oxides used in EPA's assessments—can lead to negative respiratory effects, such as decreased lung function, cough, chest tightness, and throat irritation.

Figure 5: EPA's Assessment of Causal Determinations for Relationships between Short-Term Exposure to Certain Air Pollutants and Health Effects

Health effects from short-term exposure



Source: Environmental Protection Agency (EPA) Integrated Science Assessments. | GAO-24-106145

Notes: Short-term exposure refers to time periods from minutes to 1 month.

We used sulfur dioxide and nitrogen dioxide in the figure because they are the indicators for sulfur oxides and nitrogen oxides, respectively, and sources of health effects studies for causal determinations in EPA's integrated science assessments.

The causal determinations related to particulate matter in the figure are associated with exposure to particles that are 2.5 microns or less in diameter. Causal determinations are also made for exposure to particles of other sizes (e.g., 10 microns or less).

We selected four of the six criteria air pollutants because we deemed them the most relevant pollutants to our analysis. This figure focuses on health effects of short-term exposures to these four pollutants. EPA's Integrated Science Assessments also include causal determinations for long-term exposures and for health effects that are not specific to short-term or long-term exposures (e.g., cancer and pregnancy and birth outcomes for particulate matter exposure).

[a]Respiratory effects include decreased lung function, cough, chest tightness, and throat irritation.
[b]Cardiovascular effects include heart attack, stroke, and changes in blood pressure.
[c]Metabolic effects include changes in blood glucose level and inflammation.
[d]Nervous system effects include brain inflammation and oxidative stress.
[e]Total mortality includes all nonaccidental causes of mortality and is informed by findings for the spectrum of morbidity effects (e.g., respiratory, cardiovascular) that can lead to mortality.

Additionally, mercury emitted from peakers, and other sources, is associated with neurological health effects, including tremors and disturbances of vision and cognitive performance, according to federal agency reports we reviewed.[13]

According to EPA, elevated temperatures can directly increase the rate of ground-level ozone formation, worsening air quality effects on human health. Elevated temperatures can also drive increased electricity demand, which is associated with the operation of peakers. As previously noted, the operation of peakers further increases ozone—and other pollutant—levels, exacerbating air quality issues and poor public health days.

What are some available alternatives that can potentially replace fossil-fueled peakers?

Available alternatives such as battery storage systems could potentially replace fossil-fueled peakers, according to studies we reviewed and stakeholders we interviewed (see table 3).[14] These alternatives could decrease emissions associated with peakers.

Table 3: Examples of Alternatives That Could Potentially Replace Fossil-fueled Peakers

Alternative type	Potential examples
Electricity generation and storage: Alternatives able to store or generate electricity to directly replace the output of peakers.	• Battery storage, which consists of rechargeable batteries charged during off-peak times, and discharged during times of peak demand. • Pumped hydroelectric storage is an energy storage system that pumps water to higher

	levels during off-peak times and releases said water to turn turbines and generate electricity during peak times. • Thermal energy storage is an energy storage system that stores thermal energy, which is released to power turbines during times of peak demand. • Renewable energy systems (e.g., wind and solar) may be paired with energy storage. For example, adding roof-top solar and battery storage to houses could reduce the demand for peakers in adjacent areas.
Transmission and distribution infrastructure improvements: Upgrades or expansions to increase the capacity of current infrastructure that transmits and distributes electricity. These upgrades or expansions may help enable existing underutilized plants to meet peak demand.	• Upgrading transmission lines by expanding the capacity of current lines or adding additional lines to solve bottlenecks in the grid and allow electricity to be moved to other locations. • Upgrading distribution systems by expanding or adding infrastructure to deliver electricity more efficiently.
Efforts to decrease consumers' use of power during peak times: Efforts to incentivize consumers to reduce or shift electricity use during times of peak use to off-peak times.	• Consumer based demand initiatives that provide lower prices for energy consumption during off peak hours, such as overnight electric vehicle charging. • Various energy efficiency programs.

Source: GAO analysis of literature and stakeholder interviews. | GAO-24-106145

Note: These alternatives are not comprehensive. For example, there are other alternatives that are not ready for grid-scale deployment and are in early development stages, such as other types of energy storage technologies.

What are the potential challenges of replacing peakers?

Potential challenges to replacing peakers with non-emitting or non-combustion alternatives include challenges related to cost, reliability, and location, according to studies we reviewed and stakeholders we interviewed (see table 4).

Table 4: Potential Challenges Associated with Alternatives for Replacing Fossil-fueled Peakers

	Alternatives		
	Electricity generation and storage	**Transmission and distribution improvements**	**Efforts to decrease consumers' use of power during peak times**
Cost: some alternatives may have higher capital and operating costs compared to current fossil-fueled peakers	✓	✓	✓
Reliability: current alternatives may not be able to provide the same reliability of current fossil-fueled peakers	✓	—	✓
Location: alternatives may not be able to be installed because of space and location concerns	✓	✓	—

Source: GAO analysis of literature and stakeholder interviews. | GAO-24-106145

Replacing peakers, some of which have already paid off their capital costs, will likely lead to additional up-front or operating costs compared to keeping the

existing peakers. Further, the U.S. Energy Information Administration (EIA) reported that solar and wind plants had higher average construction costs compared to natural gas-fired plants in 2023.[15]

Similarly, some alternatives may create reliability challenges. For the grid to be reliable, the energy resources in an area need to be able to supply power to meet peak demand for as long as it lasts, according to U.S. Department of Energy (DOE) officials. Some battery storage systems provide up to 4 hours of output, but peak demand may be longer in some areas. In contrast, a fossil-fueled peaker is only limited by fuel availability—a natural gas-fueled peaker could keep operating so long as natural gas is available.

Some alternatives may also run into space constraints or location concerns. For example, a densely populated urban community likely would not have sufficient space for a large renewable energy system paired with battery storage to help meet peak electricity demand.

In general, recognizing these challenges, some officials with whom we spoke identified trends that may lead to the continued use of fossil-fueled peakers. According to DOE officials, some U.S. peakers may not be able to be replaced with existing alternatives within cost, reliability, and location constraints. Combinations of electricity generation and storage technologies, transmission and distribution improvements, and efforts to decrease consumer's use of power during peak times may be too costly for consumers in some areas to provide an adequate level of grid reliability. Further, officials at two utilities noted that due to increased use of intermittent renewable resources on the grid (e.g., wind and solar power), the continued use of peakers to meet electricity demand may be necessary to maintain grid reliability. For example, the availability of sunlight for a solar installation may not match with peak demand in the evening when the sun goes down. Therefore, additional supplemental energy resources would be needed to fill the gaps and meet demand.

Agency Comments

We provided a draft of this report to DOE, EPA, and the Federal Energy Regulatory Commission (FERC) for review and comment. DOE and EPA provided technical comments, which we incorporated, as appropriate. FERC did not have any comments on the report.

How GAO Did This Study

To identify the number and location of peakers, we analyzed data from EPA's Emissions and Generation Resource Integrated Database and EIA power plant data. We generally define peakers as plants that use fossil fuels, have a capacity factor of 15 percent or less, and have a nameplate capacity of greater than 10 megawatts of electricity. In addition to the primary definition of peakers used in this report, we also considered several other definitions including plants with a capacity factor of 10 percent or less and a nameplate capacity over 0 megawatts (total of 1495 peakers).

To describe the relationship between community demographic characteristics (e.g., race, ethnicity, and income)[16] and distance to a peaker, we developed a statistical model that includes controls for population density (e.g., rural or urban), climate, and other factors. (See app. I for more detail.)

To identify air quality effects associated with peakers, we analyzed data from EPA's Emissions and Generation Resource Integrated Database to describe emissions and emission rates from peakers versus non-peakers. Our emission rate analysis focused on plants with a nameplate capacity greater than 25 MW because EPA regulations define that as the threshold for continuous emission monitoring and reporting requirements, including for emissions of sulfur dioxide and nitrogen oxides, under the state and federal Acid Rain Program.[17] We

reported median emission rates because the median is robust to outliers. For example, the top three emitting plants for sulfur dioxide had emission rates in the hundreds of pounds per megawatt, and two of the three had nitrogen oxide emission rates in the thousands of pounds per megawatt. Officials from EPA and EIA told us these plants were likely used infrequently as peakers, or they generated electricity for on-site consumption.

To identify health effects, we reviewed reports from EPA, the Agency for Toxic Substances and Disease Registry, and the Centers for Disease Control and Prevention that assess the health effects of exposure to selected pollutants that are emitted from, or related to, emissions from power plants. We also conducted a systematic literature search of peer reviewed journals and grey literature published from 2013–2023 in databases such as ProQuest Research Library and Natural Science Collection, and Dialog Energy & Environment collection. We conducted an additional search to identify studies on the health effects of peakers in the same databases, and additionally PubMed, published from 2018–2023. Based on these searches, conducted from November 2022 to March 2023, we did not identify studies that looked specifically at health effects of peaker plants.

To identify available alternatives for and challenges to replacing peakers, and to inform our other reporting questions, we conducted a systematic literature search. We conducted searches of databases such as ProQuest Research Library, Harvard Kennedy School Think Tank Search, SCOPUS, and Dialog Energy and Environment collection to identify studies and grey literature published between 2013 and 2023 that were relevant to our research objectives. We performed these searches from November 2022 to March 2023. Additionally, we reviewed studies recommended to us by stakeholders.

To inform all our questions, we also interviewed federal officials from DOE, EPA, and FERC, and state officials from California, Georgia, Indiana, New York, and Texas. We selected these states based on their geographic diversity and electricity market structure (e.g., traditionally regulated or deregulated). We also interviewed stakeholders representing 13 industry and nongovernmental organizations with a diversity of perspectives about peakers. The sample of officials and stakeholders we interviewed is non-generalizable.

We used data from EPA, EIA, and the U.S. Census Bureau. We reviewed information about the data and the systems that produced them, and interviewed agency officials knowledgeable about the data. We requested and received written responses about data reliability from EPA and EIA. We determined that the data were sufficiently reliable for the purposes of our reporting objectives.

We conducted this performance audit from July 2022 through May 2024 in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

List of Addressees

The Honorable Jamie Raskin
Ranking Member
Committee on Oversight and Accountability
House of Representatives

The Honorable Alexandria Ocasio-Cortez
House of Representatives

The Honorable Yvette D. Clarke
House of Representatives

We are sending copies of this report to the appropriate congressional committees, the Secretary of Energy, the Administrator of EPA, and the Chairman of FERC. In addition, the report is available at no charge on the GAO website at https://www.gao.gov.

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Staff Acknowledgments: Quindi Franco (Assistant Director), Andrew Moore (Analyst-in-Charge), Adrian Apodaca, Mark Braza, Katherine Chambers, Noelle Du Bois, William Gerard, Michael Kendix, Mollie Lemon, Andony Payne, Caitlin Scoville, Amber Sinclair, and Sonya Vartivarian.

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Appendix I: Technical Appendix

To assess the relationship between the distance to the nearest peaker and the demographic characteristics of a community (i.e., census tract), we developed an ordinary least squares regression model where the outcome is distance and the covariates are the demographic characteristics of a community. These characteristics are the percent of a community that are from historically disadvantaged racial or ethnic populations and percent of a community at or below the federal poverty level. We also controlled for the community's climate, population density, and distance to the nearest power plant.

The resulting coefficients from our model allowed us to

- describe whether there was a statistically significant relationship, and if so, the direction of the relationship. For an otherwise similar community and for significant coefficients, a negative coefficient means communities with higher values of the covariate are associated with being closer to a peaker, whereas a positive coefficient means they are further.
- quantify the estimated distance in miles to the nearest peaker for communities with higher rates of disadvantaged populations and for those with lower rates of this demographic, but that are otherwise similar.
- estimate the percentage decrease in distance to the nearest peaker for a community that is "above average" on a demographic, compared to an otherwise similar, but average community. Note we define "above average" as one standard deviation above the sample value of that demographic.

Model Variables/Data Sources

- Distance. We assigned to each community the distance between its central point and the central point of the nearest peaker's property, and this formed the outcome of our model. Similarly, we assigned to each community the distance between its central point and the nearest power plant, which was included as a control in our model. We used great circle distances.
- Demographics. We used American Community Survey (ACS) 2021 5-year estimates for the percent of people in a community who are below the federal poverty level and the percent of people in the community who are from historically disadvantaged racial or ethnic populations. Specifically, individuals who identify as African American or Black; American Indian or Alaska Native; Asian; Hispanic or Latino; Native Hawaiian or Other Pacific Islander; and two or more races.
- Climate. We included the county level heating and cooling degree days from 2017–2019 as indicators of electricity demand for heating and cooling. These indicators are intended to control for climate variations within states in our model. These data are not available for Alaska or Hawaii; therefore, any models with climate data excluded these states. We assessed models that were otherwise similar, but that excluded climate data (hence included Alaska and Hawaii), and the results were consistent. We calculated county level averages using data accessed from Columbia University on daily minimum and maximum temperatures on a 2.5x2.5-mile grid for the contiguous United States.
- Population density. We used U.S. Department of Agriculture (USDA) Economic Research Service (ERS) 2010 rural/urban commuting area codes (RUCAs), the most recently available data, with a four-category classification scheme based on Secondary RUCA Codes to classify each tract's population density.

    - We associated the 2019 USDA ERS tract codes with 2020 U.S. Census tracts using the U.S Census tract relationship files between the 2020 census tract entities and the 2010 tract entities.
    - In cases where there is more than one record for a 2020 tract, we select the tract that has the largest area of intersection.
- Definition of peakers. We identified plants as peakers using each of the four definitions described and ran separate models for each definition. To capture potential variation within a plant in recent years, the peaker status in our regression is based on 2018–2021 Environmental Protection Agency (EPA) data.

Model Specifications. We took several steps to assess the validity and sensitivity of our models.

- Statistical significance was determined at the 0.05 level of significance.
- Our distance and climate measures were on the logarithm scale to satisfy model assumptions, such as normality of errors, and to scale the effect of these factors and account for non-linearity.
- We used robust standard error estimation.
- We included fixed-effects for states to account for state-to-state variation.
- We assessed models that were otherwise similar to our primary model, but that excluded climate, and results were consistent. This allowed us to assess the sensitivity of our results when including Alaska and Hawaii, states that did not have weather data.
- We examined the four different definitions of peaker described in this report, and conclusions regarding race or ethnicity and population density were consistent across peaker definitions, but conclusions regarding poverty were inconsistent. In particular, models that did not factor in the plant startup time when defining a plant as a peaker resulted in a significant association with poverty, whereas only one definition of peaker that incorporated plant startup time was significant for the primary definition of poverty.
- We examined an alternative specification of race and ethnicity that separately accounted for race and ethnicity within the model. The results were consistent with our primary model and models that used alternative definitions of peaker.
- We examined an alternative specification of poverty that examined the percent of a community that was at twice the federal poverty level, and results were again inconsistent for different definitions of peakers.
- While we chose to examine race, ethnicity, and poverty, other measures of vulnerability exist, and are often correlated. Therefore, similar results might be discovered when examining other measures of vulnerability. Some of these measures—such as the ACS 5-year estimates for percent of a tract that speaks English less than “very well,” or the Council on Environmental Quality (CEQ) Climate and Economic Justice (CEJ) Screening Tool—have large margins of error, do not assess margins of error, or have higher rates of missingness when compared to our selected demographics. Additionally, the CEQ Screening Tool uses the census tract boundaries from 2010 because many of the data sources in that tool use the 2010 census boundaries, but those boundaries are not consistent with most recently available 2020 U.S. Census and ACS demographics. Further, the CEQ Screening Tool uses a binary classification of

communities as “disadvantaged” or “not” based on indicators of burdens, but other classifications exist. We chose to use continuous measures of the proportion of population in different race, ethnicity, and poverty groups to assess the association between communities with a range of percentages, from low or high, of their populations with these demographics, rather than using a definitive, yet subjective, classification of a community as “disadvantaged” or “not.”

Limitations. We took several steps to assess the validity and sensitivity of our models, but certain limitations remain. Importantly, our measure of distance does not include other aspects—such as stack height, wind speed, or wind direction—that play important roles in the dispersion of pollutants and potential populations exposure. In addition, although we include some variables to control for factors that could influence the findings, it is possible that other controls might be important and were not accounted for in our model. Inclusion of a state fixed-effect partially addresses this by controlling for factors that vary by state. Still, our findings of associations between distance to peakers and historically disadvantaged racial and ethnic communities does not imply any causal relationships.

Endnotes

[1]2021 data was the most recent year of data available from EPA.

[2]There is no standard definition of a peaker plant. We considered several other definitions for peakers in our analysis. These included plants with: (a) a capacity factor of 10 percent or less and a nameplate capacity over 0 megawatts (total of 1495 peakers), (b) a capacity factor of 15 or less, a nameplate capacity of 10 megawatts or more, and a startup time below 60 minutes (665 peakers), and (c) a capacity factor of 15 percent or less, a nameplate capacity of at least 0 megawatts, and a startup time below 60 minutes (1175 peakers).

[3]We use the terms “historically disadvantaged racial or ethnic populations” and “historically disadvantaged communities” to include individuals who identify as African American or Black; American Indian or Alaska Native; Asian; Hispanic or Latino; Native Hawaiian or Other Pacific Islander; and two or more races. Census tracts are small, relatively permanent statistical subdivisions of a county.

[4]Executive Order 13985 of Jan. 20, 2021, “Advancing Racial Equity and Support for Underserved Communities Through the Federal Government,” 86 Fed. Reg. 7009 (Jan. 25, 2021), charged the federal government with advancing equity for all, including communities that have long been underserved, and identifying and overcoming systemic barriers to opportunity for such communities in federal policies and programs. We chose race and ethnicity, and poverty as two dimensions of disadvantage. Both measures are components of the EPA’s Environmental Justice Screening and Mapping Tool. See appendix I for additional details.

[5]In our model, we primarily focus on peakers with a capacity factor of 15 percent or less and a nameplate capacity of greater than 10 megawatts, as previously noted. We also ran results with other definitions including plants with: (a) a capacity factor of 10 percent or less and a nameplate capacity over 0 megawatts (total of 1495 peakers), (b) a capacity factor of 15 percent or less, a nameplate capacity of 10 megawatts or more, and a startup time below 60 minutes (665 peakers), and (c) a capacity factor of 15 percent or less, a nameplate capacity of at least 0 megawatts, and a startup time below 60 minutes (1175 peakers). We found consistent results in the relationship between race/ethnicity and distance to the nearest peaker regardless of definition.

[6]The value of 40 percent corresponds to our sample average for this demographic, whereas 71 percent corresponds to one standard deviation above the sample average.

[7]References to the “federal poverty level” in this document are based on the Census Bureau’s poverty threshold, which follows the Office of Management and Budget’s Directive 14. According to the Census Bureau, it uses a set of money income thresholds that vary by family size and composition to detect who is in poverty. If a family’s total income is less than that family’s threshold, then that family, and every individual in it, is considered to be in poverty. In our model, we look at the percent of families in a Census tract whose income in the past 12 months is below the federal poverty level.

[8]In the case of poverty, for peakers defined as plants with a capacity factor of 15 percent or less, a nameplate capacity of 10 megawatts or more, and a startup time below 60 minutes, the association (regression coefficient) between a tract’s poverty rate and distance to peakers is insignificant at the 0.05 level.

[9]Our emission rate analysis focuses on fossil-fueled peakers and non-peakers with a nameplate capacity greater than 25 megawatts because that is a threshold defined in EPA regulations for continuous emission monitoring and reporting requirements, including for emissions of sulfur dioxide and nitrogen oxides, under the state and federal Acid Rain Program. *See* 40 C.F.R. Part 75.

[10]Environmental Protection Agency, Combined Heat and Power Partnership, *Catalog of CHP Technologies*, September 2017.

[11]We conducted a literature search to identify health effects related to peakers specifically, but our literature search did not identify any such studies (e.g., studies that compare health effects based on proximity to peakers or attribution of ambient air pollution attributed to peakers). Our search strategy included conducting a systematic literature search of peer-reviewed journals as described in the section "How GAO Did This Study." We also inquired about published studies on the health effects of peakers during our interviews with agency officials and stakeholders. Our search identified some studies of the health effects related to retirements of coal fired power plants (for example, see Joan A. Casey, Deborah Karasek, Elizabeth L. Ogburn, Dana E. Goin, Kristina Dang, Paula A. Braveman, and Rachel Morello-Frosch, "Retirements of Coal and Oil Power Plants in California: Association with Reduced Preterm Birth Among Populations Nearby," *American Journal of Epidemiology*, vol. 187, no. 8 (2018), 1586-1594, DOI 10.1093/aje/kwy110). We did not conduct a systematic review of such articles because they are not peaker-specific, and because a low percentage of peakers are coal-fired.

[12]EPA's Integrated Science Assessments integrate information on criteria pollutant exposures and health effects from controlled human exposure, epidemiologic, and toxicological studies to form conclusions about the causal nature of relationships between exposure and health effects. For more information, see the EPA Preamble for Integrated Science Assessments at Preamble To The Integrated Science Assessments (ISA) | ISA: Integrated Science Assessments | Environmental Assessment | US EPA (accessed 8/30/2023).

[13]Department of Health and Human Services, Agency for Toxic Substances and Disease Registry, *Toxicological Profile for Mercury: Draft for Public Comment,* CS274127-A (April 2022). Environmental Protection Agency, National Center for Environmental Assessment, *Mercury, Elemental*, Integrated Risk Information System (IRIS) CASRN 7439-97-6.

[14]The discussion in this section applies to fossil-fueled peakers as defined above–those with a capacity factor less than 15 percent and a nameplate capacity greater than 10 megawatts—as well as to fossil-fueled peakers more broadly.

[15]U.S. Energy Information Administration, US Construction Costs Dropped for Solar, Wind, and Natural Gas-fired Generators in 2021 (October 3, 2023), https://www.eia.gov/todayinenergy/detail.php?id=60562.

[16]See appendix I for additional details.

[17]*See* 40 C.F.R. Part 75.

EIA-923							EIA-860					
Plant Id	Plant Name	Operator Name	Operator Id	Plant State	Net Generation (Megawatthours)	YEAR	Nameplate Capacity (MW)	Nameplate Power Factor	Summer Capacity (MW)	Winter Capacity (MW)	Minimum Load (MW)	Time from Cold Shutdown to Full Load
1710	J H Campbell	Consumers Energy Co - (MI)	4254	MI	136,387	2024	265.2	0.850	260.0	260.0	100.0	OVER
1710	J H Campbell	Consumers Energy Co - (MI)	4254	MI	14,384	2024	378.8	0.770	279.8	280.0	100.0	OVER
1710	J H Campbell	Consumers Energy Co - (MI)	4254	MI	8,077,299	2024	916.8	0.860	790.7	789.3	350.0	OVER

UNITED STATES DEPARTMENT OF ENERGY

Midcontinent Independent System Operator	Order No. 202-25-7

MOTION TO INTERVENE AND PETITION FOR REHEARING OF THE STATES OF MINNESOTA AND ILLINOIS

Pursuant to section 202(c) of the Federal Power Act, 16 U.S.C. §§ 824a(c), 825l, the States of Minnesota and Illinois ("the States") move to intervene and petition for rehearing of the Department of Energy's ("DOE") May 23, 2025, Order No. 202-25-7 ("Renewed Order," Ex. A)[1] directing the Midcontinent Independent System Operator ("MISO") and Consumers Energy Company ("Consumers Energy") to take all measures necessary to ensure that the coal-burning J.H. Campbell Plant ("Campbell Plant") in West Olive, Michigan "is available to operate" and "to take every step to employ economic dispatch of the Campbell Plant." The Renewed Order is in effect from 00:00 Eastern Daylight Time (EDT) on August 21,2025, and expires at 00:00 EDT on November 19, 2025.

This Renewed Order is dated August 20, 2025, and continues the prior DOE Order No. 202-25-3, which directed MISO and Consumers Energy to keep the Campbell Plant available to provide economic dispatch from its planned retirement date through August 20, 2025, expiring at 00:00h on August 21, 2025 (the "Original Campbell Order)."

Pursuant to the Federal Power Act ("the Act") and Department procedures applying it to

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[1] All Exhibits are lettered and attached; to be submitted in separate serial emails to the DOE's AskCR <askcr@hq.doe.gov> account.

petitions for rehearing, the States hereby file this timely request for rehearing of DOE's Renewed Order. The Renewed Order extends the Original Order, perpetuating the Original Order's flawed analyses, faulty conclusion that an emergency exists for the MISO Regional Transmission Organization ("RTO") for the summer months of 2025, and unlawful directives. This Order exceeds DOE's legal authority in several respects. And even if an emergency did exist and DOE had the legal authority to issue an Order, this Order is not rationally related to meet the purported need. It should be rescinded.

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B. The Renewed Order exceeds DOE's authority because it is not limited to a specific inadequate power supply situation as required by Section 202(c) and 10 C.F.R. § 205.371. 36

C. The Renewed Order exceeds DOE's authority because it requires actions not listed in Section 202(c)(1). 40

D. The Renewed Order exceeds DOE's authority because it does not set hours of operation, limit hours of operation, or minimize environmental impact as required by Section 202(c)(3). 41

E. The Renewed Order exceeds DOE's authority because Section 201(b)(1) reserves decisions about plant retirements to the states. 42

F. The Renewed Order is unreasoned, arbitrary, and capricious because its directive for "economic dispatch" is inherently contradictory with the needs to meet an actual emergency. 46

G. The purported emergency is pretext for a prejudged outcome. 52

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MOTION TO INTERVENE

The States[2] move to intervene in this proceeding and thereby to become parties for purposes of Section 313l of the Act, 16 U.S.C. § 825l. The States have an interest in and are aggrieved by the Renewed Order (Ex. A) in several ways and seek to intervene and petition for rehearing. *FDR v. R.J. Reynolds Vapor Co.*, 606 U.S. ___ (2025) (slip op., at 3–8) (defining an "adversely affected or aggrieved" party within the APA as "anyone even 'arguably within the zone of interests to be protected or regulated by the statute . . . in question.'" (quoting *Ass'n of Data Processing Svc. Orgs. v. Camp*, 397 U. S. 150, 153 (1970))).

Factual Background

The utilities regulated by the States are members of MISO, the electric grid operator for the central United States. MISO covers the largest geographical range of any independent system operator ("ISO") in the U.S. The 15 states covered by MISO are: Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin. As the ISO of the electric grid in this region, MISO manages the flow of electricity across the high-voltage, long-distance power lines. To do so, MISO develops rules so that the wholesale electricity transmission system operates reliably and safely. MISO has described this as being like the "air traffic controller" for the grid in its territory,[3] meaning that MISO seeks to resolve power congestion (traffic) issues in real-time through its control room and has processes in place to anticipate and avoid emergencies that could lead to the loss of power.

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[2] *See* Minn. Stat. § 8.01 ("The attorney general shall appear for the state in all causes in the supreme and federal courts wherein the state is directly interested; also in all civil causes of like nature in all other courts of the state whenever, in the attorney general's opinion, the interests of the state require it.).

[3] "Meet MISO," https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/what-we-do/ (last visited June 23, 2025).

On May 23, 2025, the DOE issued the Original Campbell Order pursuant to section 202(c) of the Federal Power Act to MISO. *See* Ex. B; *see also* 16 U.S.C. § 824(c)(1). The Order directed MISO, in coordination with Consumers Energy, the owner of the plant, to ensure that the Campbell Plant remained available for operation during the summer season; expiring on August 20, 2025. *Id.*

This eleventh-hour Original Campbell Order disrupted a longstanding planning sequence handled by state authorities and submitted to MISO. Consumers Energy had already announced its plan to retire the Campbell Plant in 2021, and MISO approved that retirement plan three years ago, in March 2022.[4]

Minnesota and Illinois timely submitted a Petition for Rehearing of the Original Order on June 23, 2025. Ex. D. DOE did not act on that petition within 30 days; and later issued that it had been denied by operation of law given the passage of time. Ex. C. Minnesota and Illinois filed a Petition for Review in the D.C. Circuit Court of Appeals (No. 25-1162, consolidated with 25-1159 and 25-1160) on July 28, 2025.

On August 20, 2025, the DOE issued the Renewed Order requiring MISO and Consumers Energy to ensure that the Campbell Plant "is available to operate" and "to take every step to employ economic dispatch of the Campbell Plant." The Renewed Order is in effect from 00:00 Eastern Daylight Time (EDT) on August 21,2025, and expires at 00:00 EDT on November 19, 2025.

On September 8, 2025, DOE issued a document fashioned as "ORDER ADDRESSING ARGUMENTS RAISED ON REHEARING." Ex. E.

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[4] *See* Consumers Energy, "2021 Clean Energy Plan," https://www.consumersenergy.com/-/media/CE/Documents/company/IRP-2021.pdf (last accessed June 23, 2025).

Adverse Effects

The States will be adversely affected by the Renewed Order in many of the same ways that they were harmed by the Original Campbell Order. The Renewed Order prevents the planned retirement of the Campbell Plant, with consequent negative impacts on the States.

First, households and businesses in the States, and the States as consumers in their own right, will pay higher electricity bills as a result of the Renewed Order's imposition of costs and cost-recovery to the States. By ordering the Campbell Plant to take all steps necessary to be available and ordering MISO to take all steps necessary for the Campbell Plant to provide economic dispatch, costs are already being incurred and more costs will continue to be generated. Notably, the age of the units is concerning for costs, and Consumers Energy projected in 2021 that retiring Campbell in 2025 would avoid $365,008,000 in capital expenditures and major maintenance costs.[5] The Renewed Order would likely require at least a portion of capital expenditures and major maintenance costs, which will drive up costs and impact ratepayer bills. This would be in addition to the cost of rehiring operators and obtaining more coal, among other expenses.

Although the precise amount is not yet known, the Renewed Order provides that cost recovery is available to Consumers Energy through Federal Energy Regulatory Commission ("FERC") proceedings, (¶E). Consumers Energy already initiated a cost recovery complaint before FERC on the Original Campbell Order,[6] asking to allocate costs (net of market revenues) across

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[5] In the matter of the application of Consumers Energy Company for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief, MPSC Case No. U-21090, Revised Direct Testimony of Norman J. Kapala on Behalf of Consumers Energy Company at 3 (Oct. 2021).

[6] FERC Docket: EL25-90.

all of MISO Zones 1 through 7 (which includes Minnesota and Illinois). Consumers Energy asked that these costs be apportioned according to load, which would assign costs to the States. MISO filed its answer indicating its general support for adjusting its tariff to account for Consumers Energy's cost recovery petition, meaning the costs will be charged to the States according to their respective share of load. FERC granted cost recovery on August 15, 2025.

The Renewed Order will have substantially the same impact, and more if additional maintenance—deferred or otherwise—needs to be performed to keep the aging (and greatly deteriorated) Campbell Plant units online.

Second, the States will suffer environmental harms as a result of the Order. The Campbell Plant is a significant source of particulate matter, nitrogen oxides, sulfur oxides, and carbon dioxide,[7] among other pollutants. By extending the operations of the Campbell Plant beyond its planned retirement date, the Order increases the amount of pollution emitted in the state of Michigan and other MISO States, causing harm to the public health and welfare.[8] The States of Minnesota and Illinois share the upper Midwest region and Great Lakes environment with Michigan. Depending on weather, air emissions in Michigan impact conditions in Minnesota and Illinois. Further, Minnesota and Illinois have an interest in the Great Lakes ecosystem into which pollutants from coal-burning power plants such as mercury are deposited. Such pollution is harmful to state economies including fisheries and recreation, human health, and the environment in general. The Campbell Plant is situated on the shores of Lake Michigan across from Illinois, including the highly populated Chicago metropolitan area. Thus Minnesota and Illinois have an

[7] See In the Matter of the Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to Mcl 460.6t & for Other Relief., No. U-21090, 2022 WL 2915368, at *73 (June 23, 2022).
[8] *See* Cross-State Air Pollution Rule (CSAPR) and Clean Air Act § 110.

economic, public health, and ecological interest in protecting their environment and natural resources from unnecessary pollution emanating from the Campbell plant. Minnesota and Illinois are harmed because the Order results in the unnecessary consumption of fuel that generates such pollution.

Coal-fired power plants also contribute to regional, national, and global greenhouse gas emissions, which cause global climate change. Climate change directly harms the States by imposing significant additional costs for responsive actions, disaster recovery, and resiliency programs. Increased emissions threaten state climate goals and the States' ability to comply with federal and state air pollution requirements.

Minnesota, for example, is experiencing rapid changes including higher winter temperatures and larger, more frequent extreme precipitation events, extreme heat, and drought.[9] Each of Minnesota's top-ten combined warmest and wettest years on record have occurred since 1998, with 2024 standing as the warmest year on record and 2019 the wettest.[10] Minnesota is already suffering from a significant uptick in devastating, large-area extreme rain events, threatening the state with ever greater frequency and intensity.[11] These events damage streets, wastewater facilities, businesses, homes, farms, and natural resources, costing local governments, business owners, and residents millions of dollars in cleanup, repairs, and adaptation expenses.[12] Wildfires are also becoming larger and more frequent, including a rash of devastating fires in the spring of 2025 that consumed more than 32,000 acres and destroyed an estimated 150 structures.

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[9] Minnesota Climate Trends, *Minnesota Department of Natural Resources* (2023), https://www.dnr.state.mn.us/climate/climate_change_info/climate-trends.html.
[10] *Id*.
[11] *Id*.
[12] *Id*.

The spring of 2024 included heavy precipitation and extreme rainfall events, leading to extensive flooding and federal disaster declarations for large parts of the state.[13] From 1980 to 2024, the annual average for billion-dollar weather and climate disasters in Minnesota is 1.4 events per year, but the annual average from 2020 to 2024 is 4.6 events.[14] The "Lost Winter" of 2023-2024 was the warmest on record, with temperatures averaging 10.9°F above 1991-2020 averages, greatly harming Minnesota's recreational economy.[15] These impacts will continue, and emissions from the Campbell Plant contribute to them.

Climate change is affecting Illinois in a number of ways. Illinois' farming industry is vulnerable to cycles of extreme drought and extreme precipitation caused by climate change. In 2023, a severe drought dried up soil throughout the state, with extreme dryness extending down to 20 inches below the surface in some areas.[16] In other years, extreme precipitation has threatened Illinois' agriculture. For instance, January to June of 2013 was the wettest period ever recorded in Illinois, causing widespread flooding in farmland that forced farmers to delay planting and lose

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[13] "Extreme Rainfall Drenches Northeastern Minnesota," Minnesota Department of Natural Resources, https://www.dnr.state.mn.us/climate/journal/extreme-rainfall-northeast-mn-june-18-2024; "Extreme Rain and Flooding in Southern Minnesota, June 20-22," Minnesota Department of Natural Resources, (August 9, 2024), https://www.dnr.state.mn.us/climate/journal/extreme-rain-flooding-southern-minnesota-june-20-22.html; "Disaster information," Minnesota Department of Public Safety, https://dps.mn.gov/divisions/hsem/em-resources/disaster-information (last visited June 23, 2025).

[14] "Billion Dollar Weather and Climate Disasters, Minnesota Summary, *NOAA National Centers for Environmental Information*, Billion-Dollar Weather and Climate Disasters | Minnesota Summary | National Centers for Environmental Information (NCEI)," https://www.ncei.noaa.gov/access/billions/state-summary/MN.

[15] *Id*.

[16] Illinois State Climatologist, Drought Worsens in a Very Dry June (June 30, 2023), https://stateclimatologist.web.illinois.edu/2023/06/30/drought-worsens-in-a-very-dry-june/ (last visited May 23, 2025).

revenue.[17] Climate change is also intensifying catastrophic extreme weather events. In 2024, the Illinois State Climatologist recorded strong wind, hail, and tornadoes across all of Illinois' 102 counties and the state logged 142 tornadoes—a new annual record.[18] These storms included a July 15, 2024 "derecho" that produced 100 mile-per-hour winds and 48 separate tornados.[19] In the Chicago area alone, the derecho produced 32 tornados, breaking the previous records set by the July 2014 "double derecho" and a March 2023 storm.

Moreover, the States have an interest given their primary responsibility for resource planning and ensuring that there will be adequate and reliable electricity generation. The processes that States employ to ensure reliability—which takes into account planned retirements, new generation projects, transmission infrastructure, and meeting consumer demand—are both sophisticated and robust. The Renewed Order harms Minnesota and Illinois by usurping the traditional role that states play in generation planning and resource adequacy.

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[17] University of Illinois–Institute of Government & Public Affairs, Preparing for Climate Change in Illinois: An Overview of Anticipated Impacts (2015), https://indigo.uic.edu/articles/report/Preparing_for_Climate_Change_in_Illinois_An_Overview_of_Anticipated_Impacts/15078939/1 (last visited May 23, 2025). *See also* U.S. Dept. of Agriculture Climate Hubs and Great Lakes Research Integrated Science Assessment, Climate Change Impacts on Illinois Agriculture (2022), https://www.climatehubs.usda.gov/sites/default/files/2022_ClimateChangeImpactsOnIllinoisAgriculture.pdf (last visited May 23, 2025).

[18] Tony Briscoe, Lake Michigan Water Levels Rising at Near Record Rate, CHICAGO TRIBUNE (July 12, 2015), https://www.chicagotribune.com/2015/07/12/lake-michigan-water-levels-rising-at-near-record-rate/ (last visited May 23, 2025).

[19] National Weather Service, July 15, 2024, Derecho Produces Widespread Wind Damage and Numerous Tornadoes, available at https://www.weather.gov/lot/2024_07_15_Derecho#:~:text=With%2032%20tornadoes%2C%20the%20July,March%2031%2C%202023%20tornado%20outbreaks. (last visited May 25, 2025). *See also* David Struett, Tornado Record Broken with 27 Chicago Area Twisters July 15—Spawned by 'Ring of Fire', WBEZ CHICAGO, available at https://www.wbez.org/weather/2024/07/24/chicago-weather-tornado-record-derecho-july-15 (last accessed May 23, 2025)

PETITION FOR REHEARING

I. Overview and Concise Statement of Error

The challenged Renewed Order compounds the error of the Original Order in that it declares an emergency based on a shortage of electric energy generation when there is no emergency. Even if there is an emergency, the Renewed Order imposes several requirements that are inconsistent with and exceed DOE's legal authority. And even if DOE has the authority to impose the requirements, they are not directed to actions that will actually meet the purported emergency.

The challenged Renewed Order is premised on an incomplete recitation of MISO's planned capacity and reserves for the summer of 2025.

It first relies on the Original Order, which was fundamentally flawed and misstated the purported "evidence" on which it relied for all of the reasons set forth in the States' Petition for Rehearing, filed June 23, 2025. Ex. D.

The Renewed Order continues to misconstrue the source material on which it relies and still concludes only that there is a possibility of shortfalls. But it does not cite or rely on any evidence that there is any likelihood or probability that they will occur during the relevant timeframe of the Renewed Order.

The Renewed Order concludes that the evidence collected (and discussed below) supports the issuance of Order No. 202-25-3. It contends that the purported emergency will continue in the near term and is likely to continue in subsequent years. It declares—without any evidence identifying an emergency in the August 20 to November 19 timeframe—that the alleged emergency "could lead to the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety." Ex.

A at 7 (emphasis added). It then orders that MISO and Consumers Energy shall take "all measures necessary to ensure that the Campbell Plant is available to operate." And MISO must "take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers." Further, it orders that the Campbell Plant operate according to times as determined by MISO. Importantly, the Renewed Order prohibits the Campbell Plant from being considered a capacity resource.

The Renewed Order was issued in error. The DOE did not have substantial evidence or engage in reasoned decision-making in declaring the existence of an emergency in general, be it far into the future or even in the August 20 to November 19, 2025, timeframe.

It starts from the proposition that there is only a "potential" for insufficient capacity that "could" result in a need for mitigation, which does not present an actual existing or imminent emergency. Section 202(c)'s plain terms limit DOE to actual emergencies—not the potential that emergencies might arise. Section 202(c) is also limited in the type of conduct it allows DOE to order, such as directing the generation, delivery, or transmission of electric energy. This Renewed Order, however, requires the Campbell Plant to be "available to operate." Nothing in section 202(c) grants DOE authority to order a plant be available to operate without any demonstrated need identified by the states with primary resource planning authority, the utility operating the resource, or grid operator responsible for forecasting and coordinating adequate and reliable supply.

Even if an emergency did exist and DOE had the legal authority to issue the Renewed Order, directing the Campbell Plant to participate in the bidding market using economic dispatch would not rationally "best" meet the purported need (because there is no evidence the Campbell Plant can reasonably address any given future emergency need. This is because emergency responses do not require economic evaluation, and because the Campbell Plant takes so long to ramp up). The Renewed Order should be rescinded.

II. Legal Background

Under section 202(c) of the Federal Power Act, the Commission[20] has authority to issue an order:

> [d]uring the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes. . . .

16 U.S.C. § 824(c)(1). The same subsection states that the Commission may order "temporary connections of facilities" and "generation, delivery, interchange, or transmission of electric energy" that, in the Commission's "judgment will best meet the emergency and serve the public interest." *Id*. The next subsection, 16 U.S.C. § 824(c)(2), establishes that an emergency order must be limited to only those hours necessary to meet the emergency. It states:

> With respect to an order issued under this subsection that may result in a conflict with a requirement of any Federal, State, or local environmental law or regulation, the Commission shall ensure that such order requires generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet

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[20] The "Commission" refers to the Federal Power Commission (FPC), whose powers were transferred in 1977 to either the Secretary of DOE or the Federal Energy Regulatory Commission ("FERC"). 16 U.S.C. § 796(14); Department of Energy Organization Act, Pub. L. No. 95-91, 91 Stat. 565, 565-613 (1977). This transfer gave FERC the authority over "the interconnection, under section 202(b), of such Act [16 U.S.C. 824a(b)], of facilities for the generation, transmission, and sale of electric energy (*other than emergency interconnection*)." 42 U.S.C. § 7172(a)(1)(B) (emphasis added). However, this transfer also gave DOE "the function of the [FPC], or of the members, officers, or components thereof" except as provided in subchapter IV of the act. 42 U.S.C. § 7151(b). Because 42 U.S.C. § 7172(a)(1)(B) explicitly excludes emergency interconnection from FERC's authority, the authority over emergency interconnection has historically been delegated to DOE. However, the delegation of this emergency authority to DOE has not been consistently applied. In *Richmond Power & Light v. FERC*, 574 F.2d 610 (1978), a petitioner objected to FERC's (not DOE's) failure to invoke emergency powers under 16 U.S.C. § 824a(c) and order utilities with excess capacity to supply the petitioner with energy. The court did not address whether FERC had the authority to declare an emergency to begin with. *Id*. Thus, whether FERC or DOE has the power to declare an emergency is inconclusive.

> the emergency and serve the public interest, and, to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation and minimizes any adverse environmental impacts.

Id. at § 824(c)(2).

The applicable regulations define "emergency," 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*.

10 C.F.R. § 205.371[21] (emphasis added).

III. Statement of Issues

Issue A: Did DOE have substantial evidence for the Renewed Order's declaration of an emergency, and did it exercise reasoned decision-making in declaring that an actual emergency exists?

No. DOE relied on evidence that did not identify any likelihood or probability that there would be a shortfall during the relevant timeframe of the Renewed Order's requirements—August 20 to November 19, 2025. Further, DOE failed to consider substantial countervailing evidence, including the MISO States' Integrated Resource Plans and MISO's PRA for the summer of 2025. The Renewed Order fails to identify any reasoned basis for concluding an

[21] DOE issued 10 C.F.R. §§ 205.370-379 pursuant to the Department of Energy Organization Act's transfer of emergency responsibilities to the Secretary of Energy.

actual emergency exists or is imminent, much less one that will occur between August 20 and November 19.

Issue B: Section 202(c)(1) allows DOE to issue temporary emergency orders in times of actual or impending emergencies such as war, sudden demand for electric energy, shortage of fuel or water, or other similar conditions creating a specific inadequate power supply situation. Did DOE exceed this authority where its Renewed Order is based on the nonspecific possibility that such a situation might occur over a period of several months—or in the 2027-2030 timeframe, well outside of the Renewed Order's applicability?

Yes. An actual "emergency" is a sudden occurrence requiring immediate response action or a concrete need for energy to be produced; conversely, it is not the mere potential that an emergency might occur. 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371. Emergency orders must respond to "a specific inadequate power supply situation." 10 C.F.R. § 205.371. The Renewed Order does not address any sudden occurrence needing imminent response, nor does it identify any actual and specific insufficient supply situation. Instead, the Renewed Order focuses on vague non-summer needs and the potential for shortfalls several years away. Because the Renewed Order is not directed to any emergency at all, much less one occurring in the August 20 to November 19 timeframe, DOE lacks authority, and the Renewed Order is contrary to law.

Issue C. Section 202(c)(1) allows DOE to issue emergency orders requiring the "generation, delivery, interchange, or transmission of electric energy." Did DOE exceed this authority where its Order requires the Campbell Plant to take steps to be "available" to generate electricity and requires MISO to employ economic dispatch?

Yes. DOE's emergency powers allow it to order the generation, delivery, interchange, or transmission of electric energy. Section 202(c)(1) does not give the DOE the authority to order that a plant be available (absent a showing of why that is needed), nor does it give the DOE authority to order MISO to engage in potential economic dispatch. 42 U.S.C. §16432(b). Because the Order does not adhere to the types of actions allowed under section 202(c)(1), DOE lacks authority, and the Renewed Order is contrary to law.

Issue D. If DOE issues an order pursuant to 202(c)(1), then 202(c)(2) requires it to set limits on hours of operation and ensure that environmental impact is minimized. Did DOE exceed its authority by invoking section 202(c) to issue a Renewed Order that sets no specific hours of operation, places no limits on hours of operation, and adopts no specific requirements to minimize environmental impact?

Yes. The statutory language requires an emergency order be limited to only those hours necessary to meet the emergency and minimize adverse environmental impacts. 16 U.S.C. § 824a(c)(2). The Renewed Order does not establish any limited hours for operation, instead deferring to MISO. The Renewed Order also does not meaningfully take steps to minimize adverse environmental impacts. Because the Renewed Order does not set any specific hours the Campbell Plant must run, and does not meaningfully minimize adverse environmental impacts, the Renewed Order violates the requirements of section 202(c)(2). The DOE is without authority, and the Renewed Order is contrary to law.

Issue E: The Federal Power Act reserves resource adequacy planning to the individual states. Did DOE exceed its authority where its Order directly compels a plant slated for retirement to take steps to be available to operate?

Yes. Section 201(a) of the Federal Power Act explicitly provides that federal regulation over generation and transmission is related to matters of interstate commerce and extends "only to those matters which are not subject to regulation by the States." 16 U. S. C. § 824(a). States retain jurisdiction "over facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1). DOE's Order exceeds its authority by contradicting Michigan's resource plans. It also exceeds DOE's authority by purporting to engage in long-term resource planning for the years 2027-2030, which is a role reserved to the states. For both reasons, the Renewed Order is contrary to law.

Issue F: Even if DOE were correct that an emergency exists and that it had the authority to issue the Order, will the Order's requirements rationally meet the emergency?

No. Section 202(c) contemplates emergency orders that are precisely tailored to "best" meet the specific emergency. 16 U.S.C. § 824a(c). The Order's specific requirement for MISO to

take steps to effectuate "economic dispatch" of the Campbell Plant is not rationally related to the emergency it purports to address. Even during the peak days in June of 2025, MISO had adequate resources to generate power without the Campbell Plant's output—with capacity to spare. The Renewed Order does not explain how keeping the Campbell Plant available to run will meet any particular need when MISO has adequate resources at its disposal without the Campbell Plant. The Renewed Order, therefore, is without substantial evidence and lacks reasoned decision-making.

Issue G: Federal law prohibits agencies from prejudging the outcome of an action. Did the Secretary of Energy and the federal administration improperly prejudge the need for the Renewed Order?

Yes. As evidenced by public statements, the purported emergency is pretext for an improperly-prejudged outcome to preserve coal as a fuel for electrical generation.

IV. MISO's Robust Capacity and Planning Projections are Adequate to Ensure Reliability.

MISO is a regional transmission organization (RTO), an independent, non-profit, membership-based organization responsible for optimizing generation and transmission of electricity and ensuring the reliability of the electric power system within its region, consisting of nearly 3,000 generating units.[22] 18 C.F.R. § 35.34(a), (j)(1). MISO administers bulk or wholesale power markets that centrally commit and dispatch power to facilitate least-cost and reliable power production and delivery throughout the region. The wholesale markets within MISO signal and value power needs and identify the most economically efficient way—the least-cost approach where demand for energy equals the cost supplied—to meet them across the system.[23] MISO also

[22] MISO, *Fact Sheet* (July 2024), available at https://www.misoenergy.org/meetmiso/media-center/2024/corporate-fact-sheet.
[23] MISO, *Electric Grid 101*, available at https://www.misoenergy.org/meet-miso/grid-operations-basics.

works to coordinate generation and transmission of electricity with other RTOs, exporting power at times and at others allowing electricity to be imported to MISO.[24] MISO uses advanced modeling and thorough research to coordinate short and long-term planning for the benefit of generating units and consumers.[25]

MISO planned for adequate capacity during the summer of 2025: "As recognized by the Renewed Order, MISO's Planning Resource Auction ["PRA"] for the 2025-2026 Planning Year demonstrated sufficient capacity for all zones within the MISO Region." Ex. F at 2. It reports: "it is important to recognize existing processes have *cleared sufficient electric generating capacity across MISO for the periods of time covered by the Order*." *Id*. (emphasis added). And it goes on to describe its confidence that it has already ensured "sufficient capacity to meet anticipated demand across the MISO Region for the 2025-2026 Planning Year." *Id*.

The long-planned retirement of the Campbell Plant is not an impediment to summer reliability in the MISO region. Since 2010, MISO has experienced the retirement of 30.8 gigawatts (GW) of generation capacity, a large proportion of which (21.9 GW) was coal-fired generating

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[24] MISO, *Interregional Coordination*, available at https://www.misoenergy.org/planning/interregional-coodination/; see also MISO, Historical Net Scheduled Interchange (NSI), at https://www.misoenergy.org/markets-and-operations/real-time--marketdata/ market-reports/ (data found under "Summary" Market Reports).

[25] MISO, *Transmission and Generation Planning 101*, available at https://www.misoenergy.org/meet-miso/grid_planning_basics.

units.[26] That trend is shown below in the bar graph (from MISO's 2023 Transmission Expansion Plan Report,[27] Ex. G at 35), which displays the retired capacity by generation type over time:

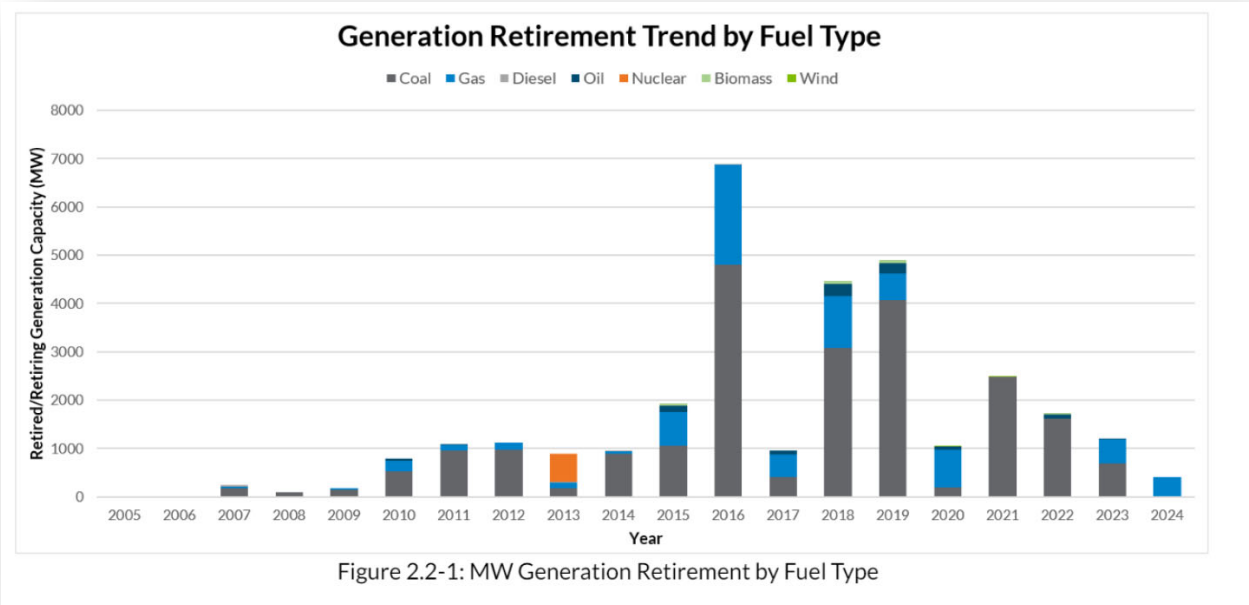


Figure 2.2-1: MW Generation Retirement by Fuel Type

Through use of generation capacity and transmission infrastructure planning, the addition of new capacity—in particular renewables, and the implementation of the other measures discussed above, MISO has been able to absorb these retirements and maintain overall system reliability. *Id*. at 34–35.

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[26] *See also* MISO, *Approved Generator Retirements (Public) as of June 28, 2024* ("*Approved Retirements 2024*"), https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/OASIS_Posting_of_Approved_Generator_Retirements_(Public)_2024-06-28.pdf).

[27] MISO, *2023 Transmission Expansion Plan*, available at https://cdn.misoenergy.org/MTEP23%20Executive%20Summary630586.pdf.

V. Argument

A. The Renewed Order is not supported by substantial evidence demonstrating the existence of an actual emergency and does not demonstrate reasoned decision-making.

The DOE failed to provide substantial evidence that an unexpected emergency presently exists, as required by 16 U.S.C. § 824a(c)(5). The relevant standard is whether the DOE's determination is supported by substantial evidence. 16 U.S.C. § 824a(c)(5) refers to the possibility of judicial review under 16 U.S.C. § 825l. After an objection has been brought before DOE, the Court may consider it with the understanding that "[t]he finding of the Commission as to the facts, if supported by substantial evidence, shall be conclusive." 16 U.S.C. § 825l. Substantial evidence means "such relevant evidence as a reasonable mind might accept as adequate to support a conclusion." *Duke Energy Corp. v. FERC*, 892 F.3d 416, 420 (2018). This standard implies deference to an agency's factual determinations. *See, e.g., id.*

DOE failed to point to substantial evidence of a current and unexpected emergency in the August 20 to November 19, 2025, timeframe during which the Renewed Order is in effect. The evidence DOE provided does, however, prove that there is currently no energy emergency and that there will not be an "unexpected emergency" that warrants this Renewed Order. MISO is well situated to deliver reliable power throughout its area in the fall of 2025.

In declaring the contrary, DOE relied on a NERC assessment that identified an elevated risk for potential capacity exceedance if an extreme weather event were to occur**.** But the Renewed Order makes too much out of too little—the "elevated" category is hardly a call for immediate and unnecessary emergency action. As the NERC assessment points out, MISO expects to have an existing certain capacity of 142,783 MW during the summer—which already factored in the assumption that the Campbell Plant would be retired and unavailable for the summer of 2025. That

projection also exceeds both expected demand and the reserve margin.[28] While retirements and fewer suppliers meant that MISO would have fewer firm resources and dispatchable generation, that was no cause for alarm. To the contrary, NERC concluded that all areas were projected to have "adequate anticipated resources for normal summer peak load conditions." *Id*. And nothing in the NERC assessment determined that MISO's interconnection with other RTOs would be insufficient to cover any needs that could arise.

The "elevated risk" category is not tantamount to an emergency. Even though NERC used the term "elevated risk" for the possibility that there could be an operating reserve shortfall, NERC did not apply the "high risk" category to MISO and did not call for any retired plants to be brought back online. Ex. H. at 5. Moreover, the "elevated risk" designation means the probabilistic indices are low but not negligible. *Id*. at 10, Table 1. And further, the MISO-specific "dashboard" concludes that MISO's expected resources meet operating reserve requirements under normal peak-demand scenarios. At worst, operating mitigations "could" be necessary for above-normal summer peak load and extreme generator outage conditions. *Id*. at 16.

Perhaps most simply, the "elevated risk" designation is far from unusual; it has never required an emergency order before, and the grid has remained stable. MISO has been designated an "elevated" risk in every NERC Summer Reliability Assessment since NERC initiated the practice of designating regions as "high," elevated," or "normal" risk in 2021.[29] NERC has also designated MISO as "elevated" risk in every Winter Reliability Assessment since 2021. *Id*. Yet no

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[28] MISO PRA, Results for Planning Year 2025-26 at 18 (Corrected May 29, 2025).
[29] *See* NERC*, Reliability Assessments,* https://www.nerc.com/pa/RAPA/ra/Pages/default.aspx (last visited June 23, 2025).

energy shortage has occurred, and DOE has never imposed an emergency declaration until now (see *infra* regarding prejudgment and pretext).

In fact, the evidence before DOE cuts against the Renewed Order. This includes MISO's PRA for the summer of 2025, which found sufficient capacity throughout the region for the summer 2025 season. The PRA provides a strong conclusion that supply will be adequate. Ex. F. The press release announcing the PRA, (Ex. I), confirms "adequate resources are available to maintain reliability during the upcoming planning year (June 2025 – May 2026)." Ex. I. And while "the 2025 auction prices reflect a tightening supply-demand balance during the summer months, there is sufficient capacity throughout the MISO footprint." *Id*. The PRA was based on NERC's standard BAL-502-RF-03 (Ex. J), requiring assessment of "one day in ten year" loss of load expectation principles. In short, the NERC standard that MISO applied to conduct the PRA demonstrated that MISO will have sufficient capacity through the summer of 2025. Exs. F, I. J. MISO's PRA results show that there will be enough capacity in the summer planning year, and MISO notes that the summer auction price provides a signal to the market to add more capacity for future auction years. DOE appears to have cherry-picked certain phrases from the PRA but does not give it full consideration.

Indeed, in MISO's Answer to the cost-recovery docket dated June 19, 2025, MISO highlights the PRA when it describes, with certainty, that it has planned for adequate capacity: In the FERC rate recovery proceeding, MISO wrote in its answer that it had sufficient capacity: "As recognized by the Order, MISO's PRA demonstrated sufficient capacity for all zones within the MISO Region." Ex. K at 2. MISO's Answer further writes, "it is important to recognize existing processes have cleared sufficient electric generating capacity across MISO for the periods of time covered by the Order." *Id*. (emphasis added). And it goes on to describe its confidence that it has

already ensured "sufficient capacity to meet anticipated demand across the MISO Region for the 2025-2026 Planning Year." *Id*. This recent submission undermines DOE's conclusions in the order that MISO faces insufficient capacity.

And beyond the lack of supporting evidence, DOE also acted arbitrarily and capriciously by ignoring well-known and readily-accessible contrary information. For example, DOE failed to consider recent comments by MISO's Independent Market Monitor to the Markets Committee of the MISO Board of Directors dispelling NERC's purported concerns—these comments were cited in the States Petition for Rehearing of the Original Campbell Order. Ex. L. The Independent Market Monitor is charged with ensuring adequate supply markets for the MISO region. He criticized a separate NERC long-term reliability assessment (which has since been revised[30]) that included capacity shortfalls in 2025, noting that NERC's assessment compared the wrong numbers. In doing so, the Independent Market Monitor declared MISO capacity to be "more than adequate," and that he had "no material concerns" over MISO's resource adequacy for the upcoming summer.

DOE also failed to consider MISO's history of strong performance through several extreme weather events including Winter Storms Elliot and Uri and did not credit MISO's proven track record of engaging in a variety of mechanisms to ensure grid reliability.

DOE further failed to acknowledge that no part of MISO is currently afflicted by any unexpected outage or extreme weather event, and the entire system is running as planned with no outages, unexpected demand, lack of fuel or water, or other such emergencies in place at the time of the Renewed Order.

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[30] NERC, *Statement of NERC's Long-term Reliability Assessment*, (June 17, 2025), available at https://www.nerc.com/news/Pages/Statement-on-NERC%E2%80%99s-2024-Long-Term-Reliability-Assessment.aspx?utm_source=substack&utm_medium=email.

1. The materials cited in the Original Order do not support the existence of an emergency.

The evidence supporting the Original Campbell Order does not support the Renewed Order. The Renewed Order continues to rely on some of the same evidence that DOE cited in the Original Campbell Order, including the North American Electric Reliability Corporation's ("NERC") 2025 Summer Reliability Assessment. Ex. H. That report does not identify any war, fuel shortage, or natural disaster. *Id*. Rather, it evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. Ex. H at 5. Here are NERC's main conclusions regarding MISO:

> **Midcontinent Independent System Operator (MISO):** MISO is expecting to have an existing certain capacity of 142,793 MW in the *2025 SRA*, which is a slight reduction from the 143,866 MW submitted for the *2024 SRA*. The retirement of 1,575 MW of natural gas and coal-fired generation since last summer, combined with a reduction in net firm capacity transfers due to some capacity outside the MISO market opting out of the MISO planning resource auction, is contributing to less dispatchable generation in MISO. With higher demand and less firm resources, MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's most recent energy assessment reveals that the period of highest energy shortfall risk has shifted from July to August. This shift is driven by the decline in dispatchable generation and the increasing share that solar and wind resources have in meeting demand. The risk of supply shortfalls increases in late summer as solar output diminishes earlier in the day, leaving variable wind and a more limited amount of dispatchable resources to meet demand.

Id. at 5. NERC concluded that all areas were projected to have "adequate anticipated resources for normal summer peak load conditions." *Id*. Indeed, the "elevated risk" designation means the probabilistic indices are low but not negligible. *Id*. at 10, Table 1. And further, the MISO-specific "dashboard" concludes that MISO's expected resources meet operating reserve requirements under normal peak-demand scenarios. At worst, operating mitigations "could" be necessary for above-normal summer peak load and extreme generator outage conditions:

Risk Scenario Summary
Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and extreme generator outage conditions could result in the need to employ operating mitigations (e.g., load-modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (demand response) when operating reserve shortfalls are projected.

Id. at 16.

Second, the Renewed Order describes a sequence of resource retirements without acknowledging the replacement capacity that came online (or that is/was planned to come online) to offset those retirements. Ex. A at 2. In any event, NERC's 2025 Summer Reliability Assessment analysis already factored in an assumption that included those retirements including the Campbell Plant' slated retirement for the summer of 2025. Ex. H at 5, 16.

Third, the Renewed Order cites NERC's "elevated risk" determination. But the Campbell Plant's retirement was well known to MISO operators who accounted for the retirement in their robust resource planning processes (described in further detail herein). Indeed, the Renewed Order acknowledges that the retirement was already factored into MISO's own supply forecasts. *Id*. at 2. MISO's PRA (Ex. F), cited in the Original Campbell Order, confirms adequate margin. *Id*. In fact, for the fall 2025 timeframe, the auction results exceeded MISO's Reserve Margin Requirement by 2.6%. That means MISO entered the fall with more resources than necessary to ensure grid reliability. Ex. F at 19.

And as the States' Petition for Rehearing on the Original Campbell Order explains, the "elevated risk" designation that DOE cites is relatively common and has never presented an emergency before. Ex. D at 19-20. In fact, NERC concluded that all areas were projected to have "adequate anticipated resources for normal summer peak load conditions." Ex. H at 5. And nothing in the NERC assessment determined that MISO's interconnection with other RTOs would be insufficient for additional capacity if needed. Nonetheless, the Renewed Order relies on the NERC

Summer Assessment, and that "additional dispatch of the Campbell Plant is necessary," Ex. A at 2, even though the Campbell Plant was not included in any of the MISO forecasts finding sufficient capacity.

Fourth, the Renewed Order cites the PRA by cherry-picking reference to capacity offset while simultaneously acknowledging its conclusion that the results "demonstrated sufficient capacity." Ex. A at 2. Sufficient capacity, by definition, is not an emergency.

All this evidence was improperly credited when DOE issued the Original Campbell Order, and the Renewed Order compounds that error by reasserting the same flaws and mischaracterizations. This is even more troubling since the petitions challenging the Original Order placed DOE squarely on notice of the fundamental flaws in these sources. Rather than identifying and responding to an emergency, both orders together demonstrate that DOE instead started with a desired result (keeping a coal-fired plant online) and worked backwards to justify that outcome.

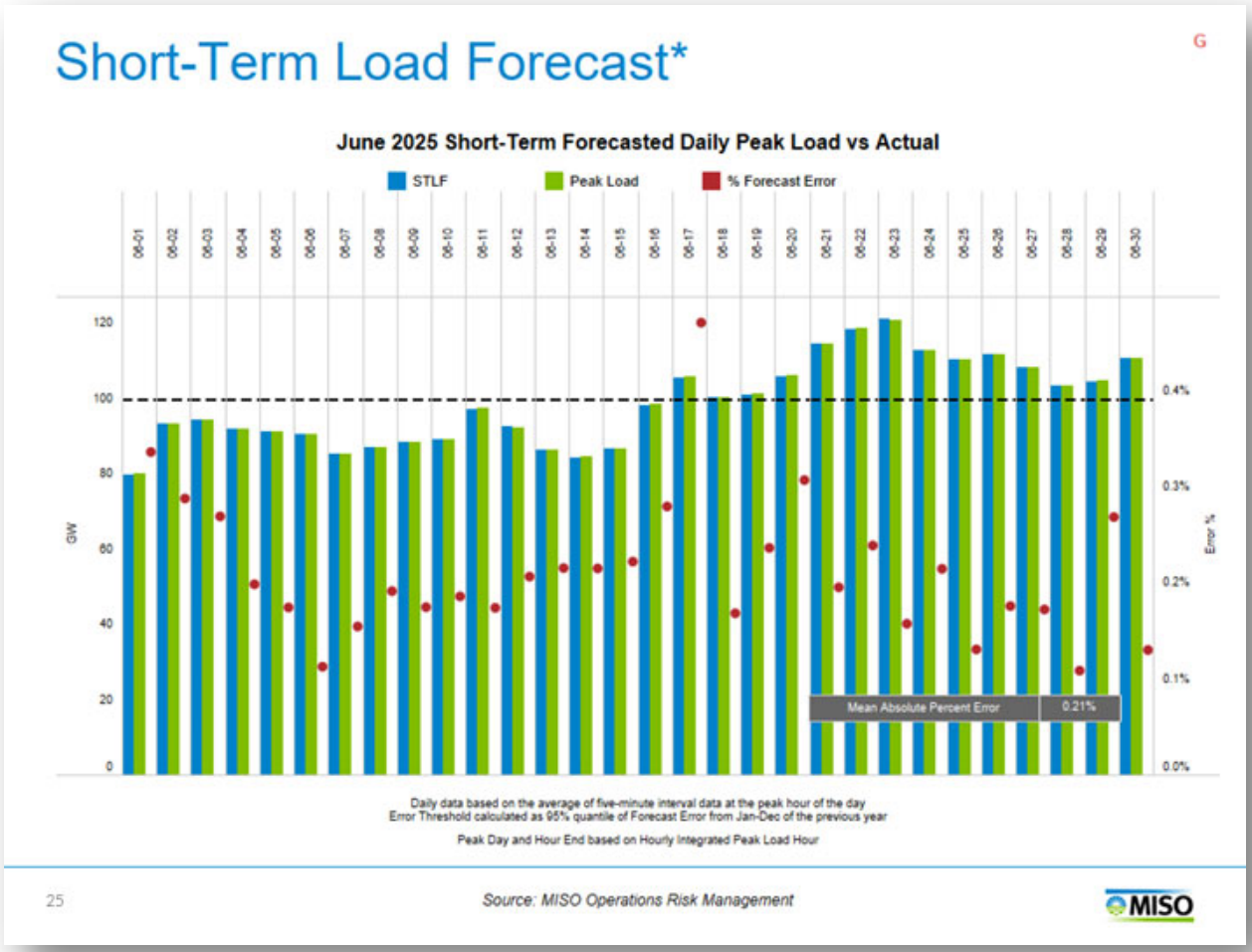
2. The additional evidence cited in the Renewed Order does not demonstrate a continuing emergency.

A continuing emergency condition does not exist, especially during the Renewed Order's applicable timeframe. After recounting the same purported evidence supplied in the Original Campbell Order, the Renewed Order then enters into a section entitled "Continuing Emergency Conditions" which presents several additional flaws, cherry-picked and out-of-context citations, and unsupported or illogical conclusions:

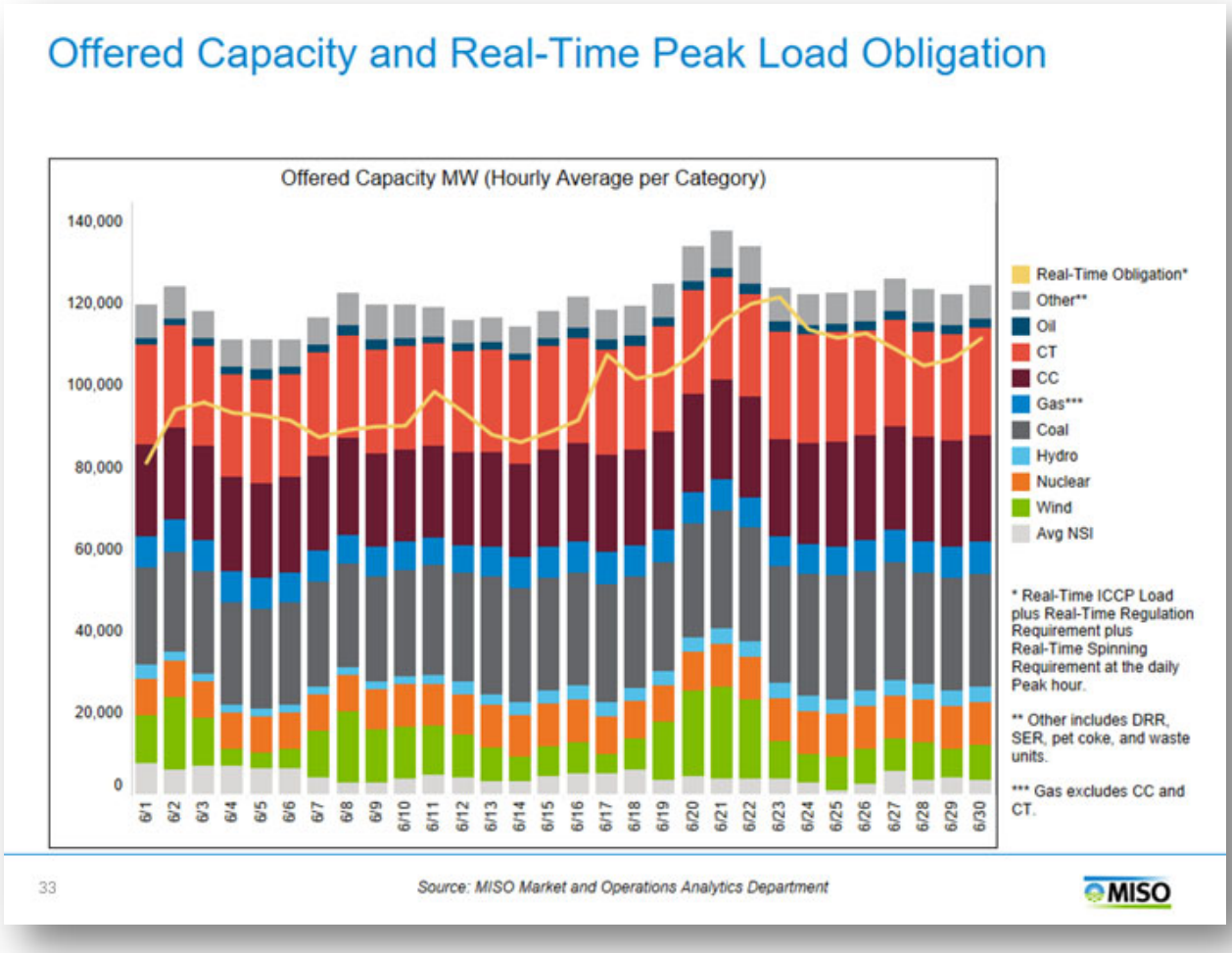
It declares that the "summer season has not yet ended" (Ex. A. at 2), but this fails to acknowledge multiple critical points. These include that peak demand is historically in June and July, not late August, that the Renewed Order was issued just days before the start of the meteorological fall, and that the Renewed Order remains in place through late November.

The Renewed Order describes how MISO called on the Campbell Plant to run in June 2025 (Ex. A at 3) without acknowledging: (1) that the Campbell Plant was only available because of the Original Order in the first place, or (2) that other resources could have supplied the capacity that the Campbell plant provided, or (3) that there was sufficient capacity within MISO even without the Campbell Plant operating, or (4) that there is no reason for DOE to conclude that the Campbell Plant's operation in June indicated any need to respond to a heat wave in September, October, or November of 2025 while the Renewed Order remains in effect.

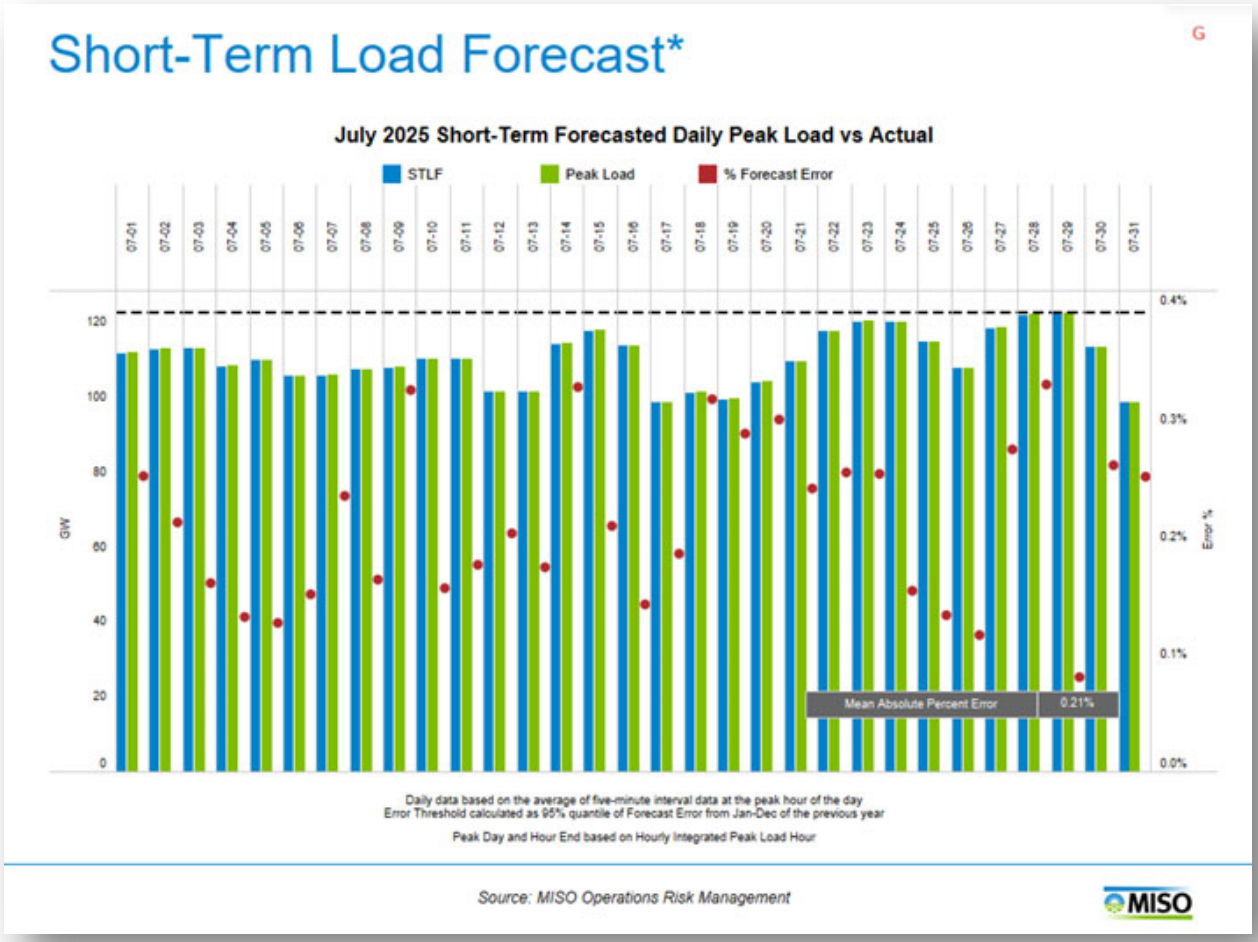
The Renewed Order attempts to justify its emergency finding by observing that MISO issued various alerts over the course of the summer (Ex. A at 3) without acknowledging: (1) that such alerts are common mechanisms for managing peak load demand every summer, and have been used for decades without any need for Section 202(c) emergency orders by DOE to keep a resource that had been slated for retirement online, or (2) that the alerts responded to summer conditions that will not be present in September, October, or November of 2025 while the Renewed Order remains in effect. Moreover, even in the peak-demand timeframe of June (Ex. M) and July (Ex. N.), when actual demand reached 120 GW on June 23, MISO had more than enough offered capacity:


Short-Term Load Forecast*
G
June 2025 Short-Term Forecasted Daily Peak Load vs Actual
STLF
Peak Load
% Forecast Error
06-01
06-02
06-03
06-04
06-05
06-06
06-07
06-08
06-09
06-10
06-11
06-12
06-13
06-14
06-15
06-16
06-17
06-18
06-19
06-20
06-21
06-22
06-23
06-24
06-25
06-26
06-27
06-28
06-29
06-30
GW
120
100
80
60
40
20
0
Error %
0.4%
0.3%
0.2%
0.1%
0.0%
Mean Absolute Percent Error
0.21%
Daily data based on the average of five-minute interval data at the peak hour of the day
Error Threshold calculated as 95% quantile of Forecast Error from Jan-Dec of the previous year
Peak Day and Hour End based on Hourly Integrated Peak Load Hour
25
Source: MISO Operations Risk Management
MISO

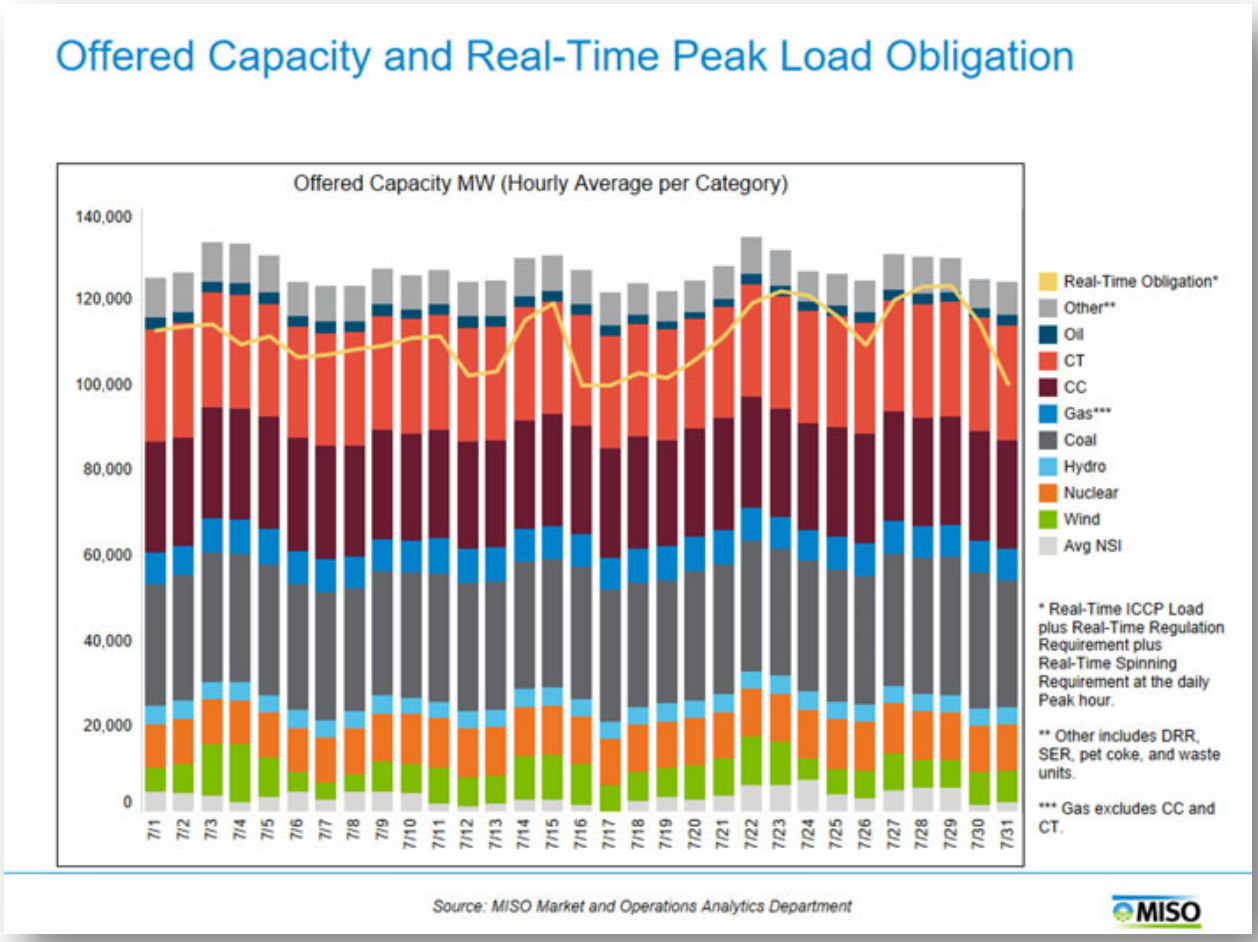
Ex. M at 25.


Offered Capacity and Real-Time Peak Load Obligation
Offered Capacity MW (Hourly Average per Category)
140,000
120,000
100,000
80,000
60,000
40,000
20,000
0
6/1 6/2 6/3 6/4 6/5 6/6 6/7 6/8 6/9 6/10 6/11 6/12 6/13 6/14 6/15 6/16 6/17 6/18 6/19 6/20 6/21 6/22 6/23 6/24 6/25 6/26 6/27 6/28 6/29 6/30
Real-Time Obligation*
Other**
Oil
CT
CC
Gas***
Coal
Hydro
Nuclear
Wind
Avg NSI
* Real-Time ICCP Load plus Real-Time Regulation Requirement plus Real-Time Spinning Requirement at the daily Peak hour.
** Other includes DRR, SER, pet coke, and waste units.
*** Gas excludes CC and CT.
33
Source: MISO Market and Operations Analytics Department
MISO

Ex. M at 33.


Short-Term Load Forecast*
July 2025 Short-Term Forecasted Daily Peak Load vs Actual
STLF
Peak Load
% Forecast Error
GW
Error %
Mean Absolute Percent Error
0.21%
Daily data based on the average of five-minute interval data at the peak hour of the day
Error Threshold calculated as 95% quantile of Forecast Error from Jan-Dec of the previous year
Peak Day and Hour End based on Hourly Integrated Peak Load Hour
Source: MISO Operations Risk Management
MISO

Ex. N at 24.



Ex. N at 32. These charts do not include more than 7000MW in headroom available to MISO beyond the offered capacity shown.[31]

The Renewed Order then cites MISO's three-year-old 2022 application to revise its resource adequacy construct to argue that the alleged "emergency" that the Renewed Order purports to address in the fall of 2025 is a year-round phenomenon. Ex. A at 3. But DOE's reliance on the application fails to acknowledge that MISO has been operating through 2025 without any

[31] *See* Public Interest Organization's Petition for Rehearing submitted to DOE on September 8, 2025, Exhibit 70 at ¶¶ 16-19.

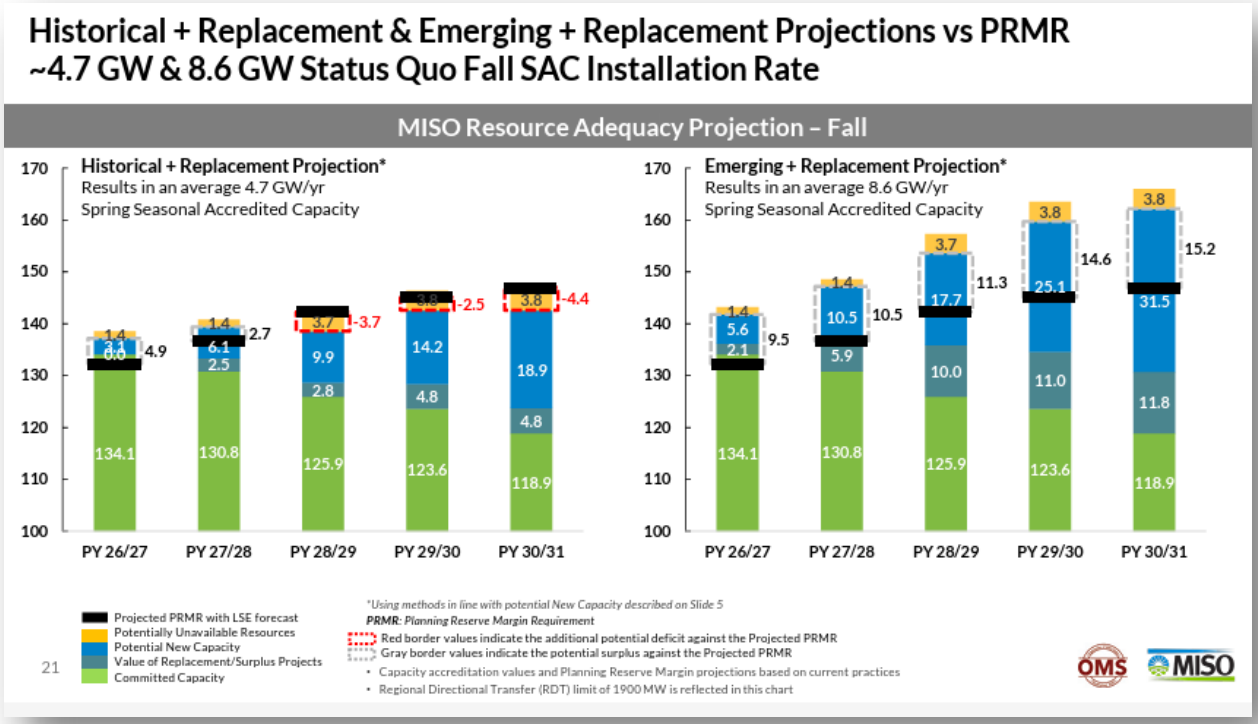
need for a Section 202(c) emergency order (other than 202-25-3) by engaging in its robust planning process that ensures adequacy and reliability.

The Renewed Order also cites MISO's 2023 Attributes Roadmap for the proposition that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. The Renewed Order does not explain how a Section 202(c) order directed to the August to November 2025 timeframe will address that eventuality several years away.

The Renewed Order also cites MISO's Response to the Reliability Imperative, concluding that MISO purportedly has "resource reliability concerns" and quotes a passage acknowledging "risks in non-summer months" that were not historically of concern. Ex. A at 4. But the Renewed Order fails to identify how generalized discussion of non-summer "concerns" and potential "risks" demonstrate any particular emergency, much less a specific one that is posed for the August to November 2025 timeframe. To the contrary, the MISO Response to the Reliability Imperative describes the risks posed by non-summer operations in the context of explaining the steps it is taking to address these risks to ensure adequate capacity and overall system reliability. Ex. O at 11. It specifically describes four pillars of approaches that MISO intends to deploy, (Ex. O at 12–24), and concludes with a "Roadmap" for how it will deploy its strategy. Ex. O at Appendix A-1. Nothing in the Renewed Order contends that these measures are inadequate or that there is an emergency despite MISO's robust efforts. *Contra* Ex. A.

The Renewed Order also cites (again) the 2025-2026 PRA results, which included a statement that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources." Ex. A at 4; Ex. F at 13. Again, the actual document, in its full context, confirms adequate margin for reliability.

The Renewed Order further cites the Organization of MISO states and MISO's joint publication of a survey dated June 6, 2025. Ex. A at 4–5. But as the Renewed Order confirms, the survey confirms a surplus through the summer of 2026, well beyond the scope of the Renewed Order's timeframe. In fact, the survey shows a fall 2026 surplus using seasonally-accredited capacity against the planning reserve margin requirement:



Ex. P at 21. The Renewed Order then relies on the survey results to identify potential forecast deficits (which are not emergencies) in the 2027-2030 timeframe—but that is well outside the fall 2025 timeframe in which the Renewed Order will be in effect, and fails to account for the "Emerging + Replacement Projection" metrics throughout the document showing surpluses against the projected Planning Reserve Margin Requirement. *Id*. at 7, 9, 19–26.

The Renewed Order further cites the development of the AI industry in general, including citing the existence of 21 AI companies in Michigan. Ex. A at 6.[32] But a company's business address is not necessarily the same as where its data centers might be located, and the Renewed Order does not identify whether any of the listed companies have or intend to build data centers that would be served by the Campbell Plant's output. To the contrary, the cited article confirms that many of them have a predominance of foreign employment.[33]

The Renewed Order further cites the DOE's 2025 July 2025 Resource Adequacy Report. Ex. A at 6; Ex. Q. But that Report uses the wrong data for MISO, as the Renewal Order explicitly acknowledges. Ex. Q at 20, fn25 ("Following the initial data collection for this report, MISO issued its 2025 Summer Reliability Assessment. Based on that report, NERC revised evaluations from its 2024 LTRA and reclassified the MISO footprint from being an 'elevated risk' to 'high risk' in the 2028–2031 timeframe, depending on new resource additions/retirements. While DOE's analysis is based on the previously reported figures, DOE is committed to assessing the implications of updated data on overall resource adequacy and providing technical updates on findings, as appropriate." (emphasis added).). The Renewed Order fails to explain how data that the Report has yet to even consider can support a finding that an emergency exists in the fall of 2025.

The DOE Report also defines a shortfall, even where there is a 3%-6% operating surplus. Ex. Q at 12. And the report completely fails to apply a "perfect capacity" estimate for MISO. Ex.

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[32] Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan*, (last accessed Sep. 15, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.
[33] These include: Soothsayer Analytics: 65% of employees in India; Netlink Software Group America Inc: 65% of employees in India; Suneratech: 82% of employees in India; Ventuit: 51% of employees in India; Verdai: 100% of employees in Italy; Communication Valley Reply: 100% of employees in Italy; Altair RapidMiner: 44% in Hungary, 29% in Germany; and LENS Corporation: 100% of employees in India

Q at 20. Instead, the Report confirms that its work was done by hand with a limited number of iterations, acknowledging an incomplete analysis that explicitly should not be relied upon. *Id.* at 19 ("As the work was done by hand with a limited number of iterations (15), this should not be considered the minimum possible capacity to accomplish these targets." (emphasis added)). Yet the Renewed Order relies upon it.

The Renewed Order further cites testimony by MISO's Senior Vice President of Planning and Operations, Jennifer Curran. Ex. A at 6. But the Renewed Order (apparently intentionally) omits a critical sentence from the passage it cites, which provides important context: "A growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them. This can be addressed by letting local reliability requirements determine the pace of retirement of existing power plants." Ex. R at 7 (emphasis added). Further testimony undermines the very proposition for which the Renewed Order purports to rely on Ms. Curran's testimony. She also repeatedly confirmed that resource planning is the purview of individual states and utilities in the MISO region, which can be used to mitigate the risk:

- "More work remains to be done… Let reliability needs help inform the pace of retirement of existing electric generating resources, ensuring they aren't retired before adequate new electric generation is available." Ex. R. at 2.
- "The MISO region predominantly consists of vertically integrated utilities with responsibility for providing adequate electric generation to meet needed load for their area and states having jurisdiction over electric resource adequacy decisions." Ex. R at 4.

- "Two of our most important tools are the Futures Planning Scenarios, which are MISO projections capturing a range of potential system conditions over a 20-year horizon, and the annual Organization of MISO States and MISO survey, a voluntary survey of generation owners to assess available resource capacity to serve the projected load over the next five years. These regularly updated studies provide the basis for long-term transmission planning efforts and help inform the electric resource planning decisions, which are the purview of the states and utilities in the MISO region." Ex. R at 6.

In total, none of this evidence demonstrates that there is any emergency, much less one that might occur in the August 20 to November 19 timeframe. To be sure, there are normal capacity considerations including some that pose some degree of potential risk, but not one of the sources cited in the Renewed Order evidences any lack of adequate planning to address those risks, much less any likelihood of a shortfall between August 20 and November 19, 2025.

Instead, the robust and comprehensive planning processes undertaken by the prime authorities—the individual states, the utilities, and MISO—have comprehensively planned for resource adequacy and system reliability during the fall 2025 and beyond.

Given all these countervailing considerations, and the full context of the sources that DOE purports to cite, DOE did not have substantial evidence supporting its emergency determination. It did not exercise reasoned decision-making in declaring that an emergency exists. Its Renewed Order is arbitrary and capricious.

B. The Renewed Order exceeds DOE's authority because it is not limited to a specific inadequate power supply situation as required by Section 202(c) and 10 C.F.R. § 205.371.

DOE exceeds its authority because the Renewed Order does not address any actual emergency or sudden occurrence needing imminent response, and because it has not identified any

actual and specific insufficient supply situation, for the August 20 to November 19 timeframe. Thus the Renewed Order is without authority and contrary to law.

As the statutes make clear, an actual "emergency" is a sudden occurrence requiring immediate responsive action; conversely, it is not the mere potential that an emergency might occur. 16 U.S.C. § 824a(c). And Department regulations define "emergency" to mean 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." 10 C.F.R. § 205.371. Further, emergency orders must meet "a specific inadequate power supply situation," and although emergencies with extended periods of insufficient supply could qualify, the impacted entity is supposed to firm up commitments for supply "so that a continuing emergency order is not needed." *Id*

These requirements have been demonstrated by DOE's historic use of 202(c) authority to address natural disasters and specific capacity crises. The most common reason to invoke Section 202(c) authority has been to address natural disasters like hurricanes, cold weather events, and extreme heat. *See* DOE Order Nos. 202-05-1 & -2 (Sept. 28, 2005) (Hurricane Rita); DOE Order No. 20208-1 (Sept. 14, 2008) (Hurricane Ike); DOE Order No. 202-20-1 (Aug. 27, 2020) (Hurricane Laura); DOE Order No. 202-24-1 (Oct. 9, 2024) (Hurricane Milton); DOE Order No. 202-21-1 (Feb. 14, 2021) (Winter Storm Uri); DOE Order No. 202-22-3 (Dec. 23, 2022) (Winter Storm Elliot – Texas ERCOT); DOE Order No. 202-22-4 (Dec. 24, 2022) (Winter Storm Elliot – PJM); DOE Order No. 202-20-2 (Sept. 6, 2020) (extreme heat in California); DOE Order No. 202-21-2 (responding to extreme heat, wildfires and drought in California); DOE Order Nos. 20222-1

& 2 and amendments (same). Indeed, during Winter Storm Elliot, MISO exported power to neighboring regions.[34]

Past practice further confirms the impropriety of the Renewed Order. While DOE's emergency powers have occasionally been used to address retirements like the Campbell Plant, it has done so only when requested by the operator or local government and there was a specific need demonstrated for the units to operate due to an unexpected emergency. DOE Order No. 202-05-3 (Dec. 20, 2005) (Mirant to supply Washington D.C. when transmission lines were out of service); DOE Order No. 202-17-1 at 2 (Grand River Energy to operate Unit 1 due to lighting strike to Unit 2 and delay in construction for Unit 3); DOE Order No. 202-17-2 (need to operate Yorktown to avoid imminent risk of load-shedding).

A memorandum by the Congressional Research Service, Ex. S, confirms that DOE's use of Section 202(c) to order a plant to be generally available is novel. Ex. S at 3 (Department engaging in "seemingly new interpretations of the emergency authority").

Indeed, the statutory structure of the Federal Power Act confirms the short-term nature of emergency approaches. That is because long-term planning authority appears in an entirely different Section of the Federal Power Act – Section 215—which indicates that the emergency authority of Section 202(c) is a different authority altogether. 16 U.S.C. § 824o. Given all the procedures attendant to resource planning, this statutory structure confirms that emergency orders are not the proper mechanism to engage in resource planning five years into the future. *See FDA v. Brown & Williamson Tobacco Corp*., 529 U.S. 120, 142, 149 (2000); s*ee also Cal.*

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[34] MISO, *Overview of Winter Storm Elliott December 23, Maximum Generation Event* (Jan. 17, 2023) ("*Winter Storm Elliott Overview*") at 7, available at https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf.

Indep. Sys. Operator Corp. v. FERC, 372 F.3d 395, 401–02 (D.C. Cir. 2004) (DOE's authority in one Section of the Federal Power Act "is strong evidence" that a separate Section does not confer the same authority on the agency).

Courts have also recognized Section 202(c)'s limitation to actual or imminent crises. For example, in *Richmond Power and Light v. FERC*, the D.C. Circuit noted that the statute "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply." 574 F.2d 610, 615 (D.C. Cir. 1978). And in *Otter Tail Power Co. v. Fed. Power Comm'n*., the Eighth Circuit noted that 202(c) provides authority to "react to a war or national disaster and order immediate interconnection. . . to maintain electrical service during such emergency." 429 F.2d 232, 234 (8th Cir. 1970). In *Otter Tail*, the Eighth Circuit distinguished between an emergency that is likely to occur and one that is actually occurring, concluding that a separate provision, section 202(b) [35] applies to the former, while section 202(c) applies to the latter:

> On its face, § 202(c) enables the Commission to react to a war or national disaster and order immediate interconnection of the facilities to maintain electrical service during such emergency. . . On the other hand, § 202(b) applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission.

[35] Section 202(b) refers to 16 U.S.C. § 824a(b), which states "[w]henever the Commission, upon application of any State commission or of any person engaged in the transmission or sale of electric energy, and after notice to each State commission and public utility affected and after opportunity for hearing, finds such action necessary or appropriate in the public interest it may by order direct a public utility" if the utility would not face an undue burden. The DOE's authority is much more limited in these situations. Further, 42 U.S.C. § 7172(a)(1)(B) vests this power in FERC, not the Secretary.

Id. at 234. In that case, a power company challenged the FPC's order issued under § 202(b) of a temporary connection between the power company and a small municipally owned power producer that was "dangerously close to eroding its firm power supply" due to the proximity between the generator load capacities and the peak load demand. *Id.* It claimed that because the ordered connection was temporary, the order could only be issued under section 202(c), and only in emergency conditions. *Id.* The court disagreed that section 202(c) only applies to temporary orders but agreed that a potential crisis in the foreseeable future was not an emergency, making it "just the type of situation to fit into a § 202(b) hearing rather than § 202(c)." *Id.* The caselaw is therefore clear: for DOE to have any authority under section 202(c) the emergency must be actual and not merely a broadly asserted projected risk.

Statutory text and structure, past practice, and caselaw are therefore all clear: for DOE to have any authority under section 202(c), the emergency must be actual and not merely a broadly asserted projected risk. With no such actual or even imminent emergency, the Renewed Order is unlawful.

C. The Renewed Order exceeds DOE's authority because it requires actions not listed in Section 202(c)(1).

The Renewed Order also is unlawful because it purports to require actions not within DOE's statutory authority.

DOE's authority is limited to issuing orders that require connections or the generation, delivery, interchange, or transmission of electric energy. 16 U.S.C. § 824a(c). This authority does not cover mandating general plant <u>availability</u> untethered to meeting any specific need, nor does it allow for <u>potential</u> economic dispatch (which is not an apt solution for an actual emergency anyway—more on this in Section G below). Section 202(c)(1) does not allow for preemptive measures just in case an emergency might occur and specifically does not allow for the Department

to order availability without a specific need to be available.[36] Plus, "economic dispatch" is not equivalent to the generation of electric energy. Economic dispatch is constrained by statute to mean only the lowest-cost option under the Energy Policy Act of 2005 Section 1234(c). 42 U.S.C. §16432(b). MISO's determination of lowest-cost sources may not result in the Campbell Plant producing *any* generation whatsoever during the fall of 2025. (Or if it does, it could be as a result of the Original Campbell Order or the Renewed Order being in place rather than an external need.) Thus, the DOE is without authority, and the Renewed Order is contrary to law.

D. The Renewed Order exceeds DOE's authority because it does not set hours of operation, limit hours of operation, or minimize environmental impact as required by Section 202(c)(3).

The order must be limited to only those hours necessary to meet the emergency. 16 U.S.C. § 824a(c)(2).

The Renewed Order addresses only the potential for an emergency, but it does not identify a need for the Campbell Plant to generate electricity to meet it. By the same token, the Renewed Order does not establish any limited hours or other parameters for the Campbell Plant to follow to ensure it meets the purported emergency, only that it always be available. Thus, the DOE is without authority, and the Renewed Order is contrary to law, because it allows the Campbell Plant to generate electricity during times there are not even "elevated risks." Allowing a coal plant to generate electricity and pollute beyond the purported emergency needs would increase the

[36] Before the Original Campbell Order, of the 19 times the DOE has issued a 202(c)(1) Order, only once, for Mirant in 2005, did it require a plant to supply as-needed additional capacity—but even then, it was based on a specific application demonstrating a concrete and specific need. DOE Order No. 202-05-3 (Dec. 20, 2005). That is not the case here.

environmental impacts that, by law, the Renewed Order must strive to minimize. 16 U.S.C. § 824a(c)(2). Thus, the DOE is without authority, and THE Renewed Order is contrary to law.

E. The Renewed Order exceeds DOE's authority because Section 201(b)(1) reserves decisions about plant retirements to the states.

Section 201(a) of the Federal Power Act explicitly provides that federal regulation over generation and transmission is related to matters of interstate commerce and extends "only to those matters which are not subject to regulation by the States." 16 U. S. C. § 824(a). Decisions over what plants should be constructed or retired are traditionally subject to state regulation. States retain jurisdiction "over facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1). "The states are thus authorized to regulate energy production . . . and facilities used for the generation of electric energy" *Coal. for Competitive Elec., Dynergy Inc. v. Zibelman*, 906 F.3d 41, 50 (2d Cir. 2018). What facilities to build, whether they remain feasible, and utility rates are areas governed by the states. *Pac. Gas & Elec. Co. v. State Energy Res. Conservation and Dev. Comm'n*, 461 U.S. 190, 205 (1983).

The energy market is governed by longstanding principles of cooperative federalism encouraged in Section 209(b) of the Federal Power Act—which explicitly declares that FERC may consult with states "regarding the relationship between rate structures, costs, accounts, charges, practices, classifications, and regulations of public utilities subject to the jurisdiction of such State commission and of the Commission." 16 U.S.C. § 824h(b). Indeed, FERC has embraced these cooperative federalism principles and developed long-standing consultation practices with the states, including through creation of a Joint Federal-State Task Force. Ex. T. And more recently, a Federal-State Current Issues Collaborative. Ex. U.

Section 103 of the Department of Energy Organization Act, also applicable, mandates due consideration to state retirement plans and requires, where practicable, consultation with relevant state officials. 42 U.S.C. § 7113.

States are responsible for developing and approving power generation plans, typically through public commissions like the Minnesota Public Utilities Commission[37] and the Wisconsin Public Service Commission.[38] These bodies oversee the development of Integrated Resource Plans ("IRPs"), or Strategic Energy Assessments, which are the blueprints for how a utility plans to generate sufficient electric power to meet its expected demand. *E.g.*, Minn. Stat. § 216B.2422 (Minnesota's IRP statute). An IRP can consider and adopt plans with myriad inputs and considerations and impact overall electricity rates, the specific communities or areas where power plants are located, determinations of which power plants might be built or retired and the fuels that they will use, overall electric system reliability (like the likelihood of power outages and how quickly the lights come back on), and the environment.[39] Such processes can be rigorous and commissions will open a docket to publicly vet a proposed plan, receive comments, and make an informed decision that is in the best interest of the states and its ratepayers.[40]

MISO, in turn, is one of the country's largest RTO, which was formed to develop transmission systems, trading markets, and attendant procedures.[41] MISO works collaboratively

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[37] Minnesota Public Utilities Commission, *Utility Planning*, https://mn.gov/puc/activities/economic-analysis/planning/ (last visited June 23, 2025).
[38] Wis. Stat. Ann. § 196.491 (West).
[39] *Id*.
[40] Minnesota Public Utilities Commission, *Electric Integrated Resource Planning (EILRP)*, https://mn.gov/puc/activities/economic-analysis/planning/irp/ (last visited June 23, 2025).
[41] FERC, *Energy Primer*, https://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf

with its member states to ensure resource adequacy throughout its service area.[42] This means that it ensures there is sufficient generation capacity to meet future electricity demands, including forecasting demand growth, assessing existing generation assets, and planning for new generation resources.[43] MISO works with utilities during their development of submissions to state regulators for the IRPs that that the regulators ultimately approve. And MISO then accounts for the final IRPs in its planning and analyses forecasting the balance between load and capacity. MISO also operates a capacity auction where utilities and other load-serving entities can procure the necessary generation capacity to meet projected demand. This incentivizes the development and maintenance of adequate generation resources.[44] MISO works with utilities, local regulators, and other stakeholders to maintain resource adequacy, including through its annual PRA, which procures sufficient resources and allows market participants to buy and sell capacity via an auction. MISO determines the capacity requirements in its region for each season covering the June 1 to May 31 time period.[45]

The Campbell Plant's planned retirement is subject to precisely such state regulation and MISO integration. The plan to retire the plant received intense scrutiny over years before being approved and worked into MISO's projections—all under the auspices of state law including Michigan's IRP processes, state regulatory proceedings, state judicial proceedings, and state participation in MISO. *See In re Application of Consumers Energy Co. for Approval of Its Integrated Res. Plan Pursuant to MCL 460.6t & for Other Relief.*, No. U-21090, 2022 WL

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[42] MISO, *System Planning*, https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/grid_planning_basics/ (last visited June 23, 2025).
[43] *Id*.
[44] *Id*.
[45] MISO, *Resource Adequacy*, https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc (last visited June 23, 2025).

2915368, at *73 (June 23, 2022). The Michigan Public Services Commission approved Consumers Energy's plan to replace the capacity that the Campbell Plant would have produced with the purchase of a natural gas plant and extension of two units of natural gas peaking plants. *Id*. at *33. The Michigan Court of Appeals affirmed. *Wolverine Power Supply Coop., Inc. v. Mich. Pub. Surv. Comm'n (In re Consumers Energy)*; No. 362294, 2023 WL 2620437 (Mich. Ct. App. March 23, 2023).

MISO also reviews planned plant retirements to ensure resource adequacy and grid reliability. Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff requires an operator to provide 26 weeks of advance notice of a planned retirement. MISO then performs a Reliability Study to determine whether retirement will pose any concern for grid reliability. [46]

Consumers Energy submitted Attachment Y form to MISO on December 14, 2021, providing notice that it planned to suspend generation at the Campbell Plant by June 1, 2025. MISO approved the Campbell Plant's retirement on March 11, 2022. In making its approval, MISO determined that "the suspension of Campbell Units 1, 2 & 3 would not result in violations of applicable reliability criteria."

DOE did not adequately consult with the state, much less account for or incorporate the findings of MISO when it approved Consumer's Energy's Attachment Y submission. Michigan state regulators have primary jurisdiction over IRPs, siting, and cost recovery for utilities operating in their states including the Campbell Plant. *Zibelman*, 906 F.3d at 50. DOE's failure to consult violates the principles behind FERC and DOT policies to involve the states in light of the statutory

[46] If MISO does identify a threat to grid reliability if the resource retires, the MISO tariff provides a mechanism to retain that resource until the constraint can be alleviated.

reservation of state authority in federal-state regulatory balance, 16 U.S.C. § 824(b)(1). It avoids 209(b) of the Federal Power Act regarding federal-state collaboration and upends FERC's historic practice of seeking to develop a robust dialogue between regulators. 16 U.S. Code § 824h(b). And it flouts Section 103 of the Department of Energy Organization Act which requires consultation with relevant state officials—consultation was absolutely "practicable" here given the lack of an imminent emergency. The Renewed Order did not give any consideration (much less due consideration) to Michigan's IRP, in violation of law. 42 U.S.C. § 7113.

In the Renewed Order's focus on longer-term risks, including the growth of data centers and the projections out into the 2027-2030 timeframe, DOE is improperly inserting itself into long-term resource planning, usurping a role belonging to the respective states. The DOE cannot use short-term emergency orders to serve a purpose for which DOE's emergency authority was not designed: to supplant the states' primary authority in the long-term resource planning arena.

The Order usurps the State of Michigan's primary rule in resource planning and development; it is contrary to law.

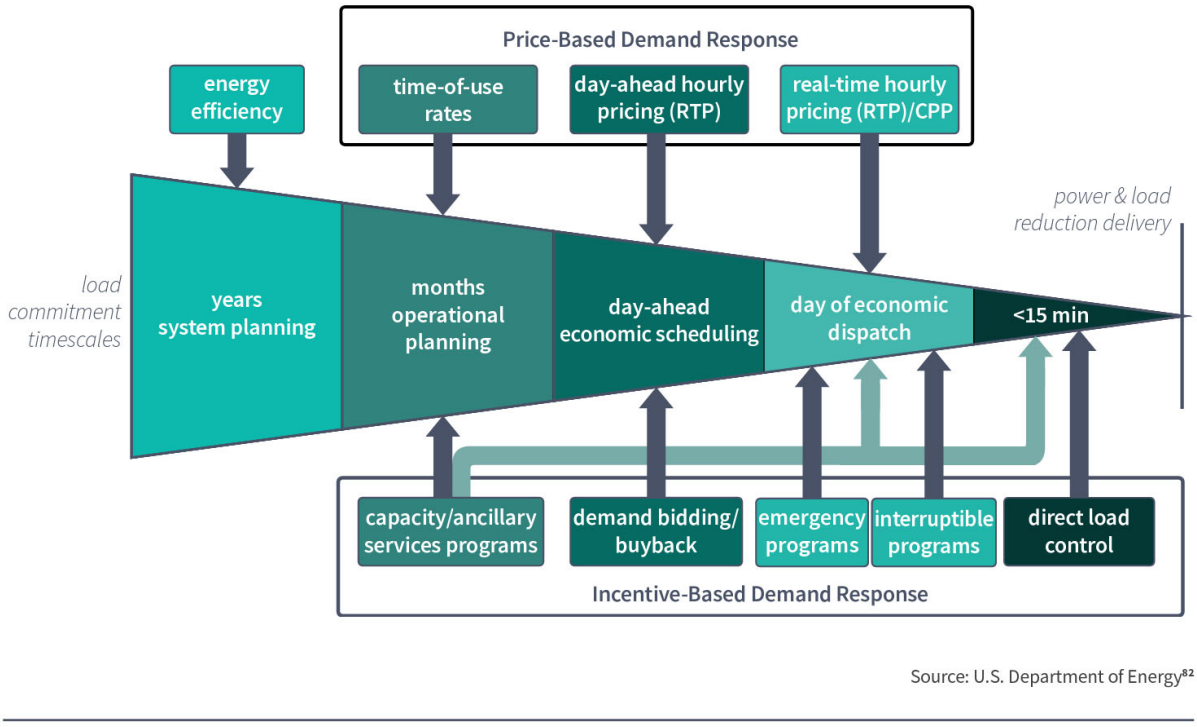
F. The Renewed Order is unreasoned, arbitrary, and capricious because its directive for "economic dispatch" is inherently contradictory with the needs to meet an actual emergency.

Section 202(c) contemplates emergency orders that are tailored to the specific emergency—they must "best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c). Even if an emergency did exist and DOE had the legal authority to issue an order, this Renewed Order is not rationally related to addressing the emergency that the order identifies.

The Order's specific requirement for MISO to take steps to effectuate "economic dispatch" of the Campbell Plant undermines its determination that an emergency exists and cannot "best meet" the purported emergency. Economic dispatch is a term of art for the procedure by which

MISO selects generators to add electric energy to the grid. It is designed to ensure that the electricity generated matches the demand in its service area in the most cost-effective way. "Economic dispatch," by definition, is awarded to the lowest-cost option (all else being equal). Ex. V. That is because much of the base load planning takes place years or months ahead of time and is comprised of the must-run units. Additional capacity is then called upon in the day-ahead or day-of markets for which additional generation is required:

Figure 2-2: Demand Response and Energy Efficiency in Electric System Planning and Operations



Source: U.S. Department of Energy[82]

Ex. V at 43. Most of the generation available to meet load in real time for economic dispatch is identified and scheduled the day before, based upon the day-ahead load forecast used in the security-constrained unit commitment process. Ex. W at 6–7, 13, 51. As recently as 2021, the vast

majority of peaking plants operated on natural gas and oil which can be dispatched in much shorter order; only 3.3 percent of all peakers nationwide burned coal. See Ex. X at 2.

Taken together, economic dispatch considers a variety of factors including (1) the cost of generation, (2) the standby condition of the generator, (3) ramp-up time to provide the needed capacity, and (4) whether electric energy can be transmitted to the area of need.

The Renewed Order's proposed solution for "economic dispatch" of the Campbell Plant is thus inherently incompatible with addressing emergency operation (likely because there is no emergency in the first place). In a true emergency, even uneconomic plants receive cost-of-service payments when they are required to run to alleviate the emergency condition. The RTO does not require the emergency generator to bid into the market and *then* make a determination about whether it will be selected to run as with economic dispatch. Rather, the emergency generator becomes a "price taker" using MISO's "must run" classification. Thus, the Order's directive to use "economic dispatch" is irrational: actual emergencies are not addressed with economic dispatch, and economic dispatch is a necessarily ineffective method to address an actual emergency.[47]

Moreover, the Renewed Order's requirement that the Campbell Plant be "available to operate" does not accord with 202(c)(1)'s requirement that DOE select the temporary measure that will "best meet the emergency and serve the public interest." Section 202(c)(1)'s use of the term "best" shows that the Commission cannot require temporary power generation from the Campbell Plant when better means are available to meet the alleged emergency and serve the public interest.

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[47] Campbell's situation illustrates this inefficiency. Coal is an expensive fuel type in our current energy mix. The inefficiency of running a coal plant makes it uneconomic in general, which is one of the reasons why this specific Campbell plant was slated for retirement. *See In re Application of Consumers Energy*, No. U-21090, 2022 WL 2915368, at *73.

Entergy Corp. v. Riverkeeper, Inc., 556 U.S. 208, 218 (2009) ("Best" means what is "most advantageous." (Quoting Webster's New International Dictionary 258 (2d ed.1953))). DOE's decision to require the Campbell Plant to be available disregarded its obligation to consider alternatives and select the best one.

Although DOE need not consider every conceivable alternative, it must consider those that are obvious and viable. *See Dep't of Homeland Sec. v. Regents of the Univ. of Calif.*, 591 U.S. 1, 30 (2020); *Motor Vehicle Manufs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 51 (1983); *Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200, 215 (D.C. Cir. 2013). Intervenors and the public may also introduce information that requires the Department to evaluate alternatives and reconsider its decision to impose or maintain a requirement. *See, e.g.*, *Chamber of Com. of the U.S. v. Secs. & Exch. Comm'n*, 412 F.3d 133, 144 (D.C. Cir. 2005) (evaluating agency failure to consider alternative raised by dissenting Commissioners and introduced by commenters); *cf.* 10 C.F.R. § 205.370 (stating ability to cancel, modify, or otherwise change an order). Indeed, DOE's regulations specify information it shall consider when deciding to issue an order under section 202(c). 10 C.F.R. § 205.373. The specified information includes "conservation or load reduction actions," "efforts . . . to obtain additional power through voluntary means," and "available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions." *Id*. § 205.373(g)–(h); Ex. Y at 4 (DOE Order No. 202-22-4). DOE has not explained why ordering the Campbell Plant to remain "available" meets any of these criteria, especially considering alternatives such as power pooling and utility coordination.

DOE has not explained why its Renewed Order "best" meets the emergency, because it does not. Again, the Renewed Order alleges only that the Campbell Plant should remain available

because a need *might* arise in the future (and even then, most likely years from now, not in the August to November timeframe). Given the speculative nature of the alleged emergency, it is incorrect as a matter of fact that ordering the Campbell Plant to remain available is the best means of addressing it. DOE's failure to consider alternatives other than the inefficient and incapable Campbell Plant does not meet section 202(c) requirement for DOE to use its judgment to choose the best temporary source of emergency energy.

First, if an emergency need occurs in the day-of or real-time markets, the Campbell Plant will not be able to spool up in time to meet that need. That is because it takes over 12 hours to reach peak load. Ex. Z.[48]

Second, even if there was adequate notice for the Campbell Plant to deliver energy in an emergency, its age and unreliability make it a poor choice to rely on for emergency services.[49] The Campbell Plant's unreliability was one of the reasons it was slated for retirement. In 2023 and 2024, Campbell experienced long, recurring outages that demonstrated it should not be relied on as an emergency power source. For example, in 2023, Unit 2 experienced four outages totaling 3,445 hours—nearly 40 percent of the year—due to a pump failure, and in 2024, Unit 3 experienced an outage totaling 1,104 hours due to a failure in one of the turbine's gears.[50] Even during the June 23, 2025, peak load event during the heat wave, Campbell did not run two of its three units. *Id*.

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[48] Adapted from U.S. Energy Information Administration submissions according to Forms EIA-860 and EIA923, in which "OVER" indicates ramp-up time exceeding 12 hours. *See* https://www.eia.gov/electricity/data/eia860/; https://www.eia.gov/electricity/data/eia923/.
[49] *See* Public Interest Organization's Petition for Rehearing submitted to DOE on September 8, 2025, Exhibits 103-104.
[50] *Id*. Exhibit 3.

Even if there was adequate transmission and lead time, the Campbell Plant's expensive fuel source means that its bid to provide electricity would be higher than other lower-cost dispatchable alternatives (natural gas, storage, or renewables), which would prevent it from being selected as the most economic resource to meet the need. Again, even during the peak load in June of 2025, only one of the Campbell Plant's units was online, and it produced only 761MW of power. Ex. AA.[51] That represents a small fraction of the remaining margin that MISO had available and demonstrates that the Campbell Plant is not an efficient means of meeting an emergency energy demand.

Finally, if, for example, there was a need for additional electricity in North Dakota in October of 2025, it is unlikely that there would be sufficient transmission infrastructure across the Great Lakes to deliver electricity from the Campbell Plant to meet that need.

Rather than ordering the Campbell Plant to remain available, DOE was required to consider obvious alternatives that MISO has available and uses as part of its role as a regional transmission grid operator. The Department has long recognized that power pools and utility coordination "are a basic element in resolving electric energy shortages." *Emergency Interconnection of Elec. Facilities and the Transfer of Elec. to Alleviate an Emergency Shortage of Elec. Power,* 46 Fed. Reg. 39,984, 39,985–86 (Aug. 6, 1981). And recent history bears out the important role of transmission connectivity along with imports and exports.[52] The fact that DOE has intruded on

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[51] *Sourced from* https://campd.epa.gov/data/custom-data-download.

[52] *See, e.g.*, Public Interest Organization's Petition for Rehearing submitted to DOE on September 8, 2025, Exhibit 43 at § III.A.3.b (Winter Storm Elliott System Operations Inquiry) ("Despite tightening conditions on the MISO system . . . MISO maintained steadily increasing exports to TVA throughout the day."); Exhibit 44 at 43 (PJM Elliott Report) (describing PJM exports of between 8 and 11 GW to TVA and other neighboring regions), 83–84 (describing PJM power exports to MISO and graphically depicting those exports over time); Exhibit 36 at 6 (MISO Elliott Max. Gen. Event Overview) ("MISO consistently exported power to southern

MISO's role of planning for and meeting fluctuations in demand without considering these viable and obvious alternatives shows that it did not comply with section 202(c).

Section 202(c)(2) requires the emergency measures to be tailored the actual need; yet here, the Renewed Order improperly imposes measures that are not tailored to anything. All the while, the Order imposes costs on the States to bring the Campbell Plant to operational status beyond its planned retirement, adds potentially expensive generation to the mix if it were to run in the August 20-November 19 timeframe, and generates harmful pollution at the same time. Thus, the Renewed Order requiring the Campbell Plant to remain available and for MISO to take steps to use the Campbell Plant for economic dispatch is irrational and arbitrary where the Campbell Plant is unlikely to be a good candidate to serve either economic dispatch or emergency-need functions—especially where it is unclear what need it is supposed to meet in the first place.

Therefore, the Renewed Order is not rationally related to meeting the need of the purported emergency that it identifies.

G. The purported emergency is pretext for a prejudged outcome.

The Renewed Order is not a good faith effort to carry out DOE's duties under the Federal Power Act. Rather, the materials supporting the Renewed Order demonstrate a pretextual effort to further the administration's policy support for fossil fuels, and in particular coal electricity generation.

Where the conduct of the agency shows an "unalterably closed mind on matters critical to the disposition of th[is] proceeding," it requires either disqualification of the administrator or

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neighbors with a maximum value of nearly 5 GW."); *and* Exhibit 7 at 1 (DOE Order No. 202-02-1) (providing for usage of interregional transmission).

withdrawal of the proposal. *Ass'n of Nat'l Advertisers v. FTC*, 627 F.2d 1151, 1170 (D.C. Cir. 1979); *Nehemiah Corp. of Am. v. Jackson*, 546 F.Supp. 2d 830, 847 (E.D. Cal. 2008) (describing the appropriate remedies when an agency official has prejudged the outcome of a particular matter). A preexisting internal directive to reach a particular result is strong evidence that the official is not "free, both in theory and in reality, to change his mind" in the agency proceedings. *Nat'l Advertisers*, 627 F.2d at 1172; *see Int'l Snowmobile Mfrs. Ass'n v. Norton*, 340 F. Supp. 2d 1249, 1260 (D. Wyo. 2004).

The Renewed Order cites a bevy of Executive Orders declaring an energy emergency. Even if these Executive Orders are taken at face value, they are incoherent with the President's other actions to reduce capacity of new energy generation, such as from ongoing and nearly-completed wind projects. *Temporary Withdrawal of All Areas on the Outer Continental Shelf From Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects* 90 Fed. Reg. 8,363 (Jan. 20, 2025); *Ending Market Distorting Subsidies for Unreliable, Foreign-Controlled Energy Sources*, 90 Fed. Reg. 30,821 (Jul. 10, 2025).

Further, the administration has declared a preference for coal energy. *Executive Order 14261: Reinvigorating America's Beautiful Clean Coal Industry and Amending Executive Order 14241*, 90 Fed. Reg. 15,517 (Apr. 8, 2025). The express mandate of Executive Order 14261 declared it to be the national policy "to support the domestic coal industry by removing Federal regulatory barriers that undermine coal production, encouraging the utilization of coal to meet growing domestic energy demands, increasing American coal exports, and ensuring that Federal policy does not discriminate against coal production or coal-fired electricity generation."

But this was not a simple policy preference—the administration had already predetermined that it would resort to emergency authority to reopen or forestall closure of coal plants before it

ever issued the Original Campbell Order or the Renewed Order. On April 8, 2025, President Trump gave remarks during the signing ceremony for Executive Order 14261. In those remarks, he noted that the administration would take action to reopen coal plants.[53] Also on April 8, 2025, the Department of Energy announced several initiatives directed to increasing coal production.[54]

During a Bloomberg TV interview in February 2025, Secretary Wright declared that the United States should stop the closure of coal power plants, and asserted that DOE had the authority to do so.[55]

On July 7, 2025, Secretary Wright was quoted as saying, "I think our biggest impact by far is going to be — there are like 40 coal plants that are supposed to close this year — and our biggest impact is going to be to stop the closure of most of those."[56]

On July 11, 2025, the DOE posted a video Secretary Wright to the department's social media accounts with the chyron, "BIG BEAUTIFUL CLEAN COAL. This is the largest source of global electricity and third largest source of electricity in the U.S."[57]

The DOE's social media feeds are full of clips from Secretary Wright media appearances extoling coal plants, promising to increase the use of coal for energy production, and asserting that DOE had the authority to forestall closures.

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[53] https://www.presidency.ucsb.edu/documents/remarks-domestic-coal-production ("And all those plants that have been closed are going to be opened if they're modern enough." And "From now on, we'll ensure that our Nation's critically needed coal plants, as an example, remain online and fully operational. They're always going to be operational.")
[54] https://www.energy.gov/articles/energy-department-acts-unleash-american-coal-strengthening-coal-technology-and-securing
[55] https://www.bloomberg.com/news/articles/2025-02-11/us-should-stop-closure-of-coal-fired-power-plants-wright-says.
[56] https://www.wvnews.com/statejournal/news/top_story/energy-secretary-chris-wright-future-of-u-s-coal-is-long-and-bright/article_4ffcdad0-9030-4e6f-8ca7-0816e1786cbc.html
[57] *E.g.*, https://www.facebook.com/energy/videos/big-beautiful-clean-coal-this-is-the-largest-source-of-global-electricity-and-th/1468968367585884/.

The administration, and DOE in particular, engaged in prejudgment of the Renewed Order. Knowing that it needed to effectuate the administration's policy preference to keep coal plants open, DOE worked backwards from that preferred result and justified it using post-hoc rationalizations. Secretary Wright demonstrated an "unalterably closed mind on matters critical to the disposition" of the use of emergency authority, requiring the Renewed Order to be set aside. *Nat'l Advertisers*, 627 F.2d at 1170; *Nehemiah Corp.*, 546 F. Supp. 2d at 847.

CONCLUSION

For all of the foregoing reasons, the Department should rescind the Renewed Order.

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UNITED STATES DEPARTMENT OF ENERGY

Midcontinent Independent System Operator	Order No. 202-25-9

MOTION TO INTERVENE AND PETITION FOR REHEARING OF THE STATES OF MINNESOTA AND ILLINOIS

Pursuant to section 202(c) of the Federal Power Act, 16 U.S.C. §§ 824a(c), 825l, the States of Minnesota and Illinois ("the States") move to intervene and apply for rehearing of the Department of Energy's ("DOE") November 18, 2025, Order No. 202-25-9 ("Campbell Order III," Ex. A)[1] directing the Midcontinent Independent System Operator ("MISO") and Consumers Energy Company ("Consumers Energy") to take all measures necessary to ensure that the coal-burning J.H. Campbell Plant ("Campbell Plant") in West Olive, Michigan "is available to operate" and "to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers." The Campbell III Order is in effect from 00:00 Eastern Standard Time ("EST") on November 19, 2025, and expires at 00:00 EST on February 17, 2026.[2] This is the third in a series of orders directing MISO to take the same actions for the same facility and based on the same alleged statutory authority and factual circumstances.

The States have an interest in and are aggrieved by Campbell Order III. *FDA v. R.J. Reynolds Vapor Co.*, 606 U.S. 226, 232–36 (2025) (defining an "adversely affected or aggrieved"

[1] All Exhibits are lettered and attached.
[2] This petition is being submitted to DOE's AskCR <askcr@hq.doe.gov> account as DOE instructs.

party within the APA as "anyone even 'arguably within the zone of interests to be protected or regulated by the statute . . . in question.'" (quoting *Ass'n of Data Processing Svc. Orgs. v. Camp*, 397 U. S. 150, 153 (1970))).

The Campbell III Order continues the pattern established by two prior DOE Orders numbered 202-25-3 ("Campbell I") and 202-25-7 ("Campbell II") that also directed MISO and Consumers Energy to keep the Campbell Plant available to provide economic dispatch from its planned retirement date of June 1, 2025, through November 18, 2025.

The States requested rehearing of the Campbell I and II Orders and described the applicable facts, with record support, in those challenges. Exs. B-C (nested exhibits omitted). Campbell III is almost identical to Campbell II, which in turn extended Campbell I. Because the legal and factual issues here directly overlap and repeat the same matters previously raised, the States hereby incorporate by reference the petitions for rehearing of the Campbell I and II Orders, including all arguments, exhibits, and other referenced materials, and reassert them as grounds for rehearing of the Campbell III Order.

The States will be adversely affected by the Campbell III Order in the same ways they were harmed by the Campbell I and II Orders, but Campbell III also compounds and increases those harms through ongoing, cumulative emissions and related impacts. The negative effects on the States were described in the prior challenges and are hereby incorporated by reference.[3]

[3] The harms include economic harm to ratepayers in the States who are saddled with the increased costs associated with operating the inefficient, coal-burning Campbell Plant, the environmental harms of operating the coal plant, and the harm caused by usurping the States' role in planning resource adequacy and generation.

The Campbell III Order compounds the errors of the prior orders for all of the reasons set forth in the States' Petitions for Rehearing filed June 23, 2025 (Campbell I) and September 19, 2025 (Campbell II).

As with the Campbell I and II Orders, the Campbell III Order should be rescinded because it lacked reasoned decisionmaking, exceeded DOE's authority, was not rationally tailored to meet the purported emergency, and demonstrated impermissible prejudgment of the relevant issues.

In addition to the grounds laid out in the requests for rehearing on the Campbell I and II Orders, Consumers Energy Company filed its most recent 10-Q and 8-K reports with the Securities and Exchange Commission on October 30, 2025. Consumers Energy reported that for the period from May 23, 2025 through September 30, 2025, the costs of keeping Campbell online were $164 million, but the plant made only $84 million in revenue from the sale of its output, netting an $80 million loss. Exs. D (summary of contents), E (copy of 10-Q). Specifically,

> During the initial emergency order period, the net financial impact of compliance was $53 million after applying MISO revenues of $67 million. For the second emergency order period through September 30, 2025, the net financial impact of compliance was $27 million after applying MISO revenues of $17 million.

Ex. E. at 62. Consumers Energy concluded that it would seek to recover the $80 million in net losses from ratepayers through FERC tariff proceedings. *Id*. These real-world figures confirm that the plant cannot be effectively used for "economic dispatch" because it is uneconomical and runs at a loss when operated as the Campbell III Order requires. They also confirm that operating Campell plant as ordered has not and will not "minimize cost to ratepayers" where net losses will be charged to them. Thus, the Consumers Energy SEC filings demonstrate that the Campbell III Order cannot be fulfilled according to its own terms. Ex. A at 8.

In addition to the Exhibits (A through E) attached to this request for rehearing, DOE is already in possession of the exhibits the States submitted in support of their petitions for rehearing of the Campbell I and II Orders. The States are not resubmitting those same documents since they are incorporated by reference into the record for this petition. If DOE needs additional copies of any documents, please contact any of the signatories to this request.

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UNITED STATES DEPARTMENT OF ENERGY

Midcontinent Independent System Operator	Order No. 202-26-16

MOTION TO INTERVENE AND PETITION FOR REHEARING OF THE STATES OF MINNESOTA AND ILLINOIS

Pursuant to section 202(c) of the Federal Power Act, 16 U.S.C. §§ 824a(c), 825l, the States of Minnesota and Illinois ("the States") move to intervene and apply for rehearing of the Department of Energy's ("DOE") February 17, 2026, Order No. 202-26-16 ("Campbell Order IV," Ex. A)[1] directing the Midcontinent Independent System Operator ("MISO") and Consumers Energy Company ("Consumers Energy") to take all measures necessary to ensure that the coal-burning J.H. Campbell Plant ("Campbell Plant") in West Olive, Michigan "is available to operate" and "to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers." The Campbell IV Order is in effect from February 17, 2026, until May 18, 2026.[2] This is the fourth in a series of orders directing MISO to take the same actions for the same facility and based on the same alleged statutory authority and factual circumstances.

The States have an interest in and are aggrieved by Campbell Order IV. *FDA v. R.J. Reynolds Vapor Co.*, 606 U.S. 226, 232–36 (2025) (defining an "adversely affected or aggrieved" party within the APA as "anyone even 'arguably within the zone of interests to be protected or

[1] All Exhibits are lettered and attached.
[2] This petition is being submitted to DOE's AskCR <askcr@hq.doe.gov> account as DOE instructs.

regulated by the statute . . . in question.'" (quoting *Ass'n of Data Processing Svc. Orgs. v. Camp*, 397 U. S. 150, 153 (1970))).

The Campbell IV Order continues the pattern established by three prior DOE Orders numbered 202-25-3 ("Campbell I"), 202-25-7 ("Campbell II"), 202-25-9 ("Campbell III") that also directed MISO and Consumers Energy to keep the Campbell Plant available to provide economic dispatch from its planned retirement date of June 1, 2025, through February 17, 2026.

The States requested rehearing of the Campbell I, II, and III Orders and described the applicable facts, with record support, in those challenges. Exs. B–D (nested exhibits omitted). Campbell IV is almost identical to Campbell III, which extended Campbell II, which in turn extended Campbell I. Because the legal and factual issues here directly overlap and repeat the same matters previously raised, the States hereby incorporate by reference the petitions for rehearing of the Campbell I, II, and III Orders, including all arguments, exhibits, and other referenced materials, and reassert them as grounds for rehearing of the Campbell IV Order.

The States will be adversely affected by the Campbell IV Order in the same ways they were harmed by the Campbell I, II, and III Orders, but Campbell IV also compounds and increases those harms through ongoing, cumulative emissions and related impacts. The negative effects on the States were described in the prior challenges and are hereby incorporated by reference.[3]

[3] The harms include economic harm to ratepayers in the States who are saddled with the increased costs associated with operating the inefficient, coal-burning Campbell Plant, the environmental harms of operating the coal plant, and the harm caused by usurping the States' role in planning resource adequacy and generation.

The Campbell IV Order compounds the errors of the prior orders for all of the reasons set forth in the States' Petitions for Rehearing filed June 23, 2025 (Campbell I), September 19, 2025 (Campbell II), and December (Campbell III).

As with the Campbell I, II, and III Orders, the Campbell IV Order should be rescinded because it lacked reasoned decisionmaking, exceeded DOE's authority, was not rationally tailored to meet the purported emergency, and demonstrated impermissible prejudgment of the relevant issues.

In addition to the grounds laid out in the requests for rehearing on the Campbell I, II, and III Orders, Consumers Energy Company filed its most recent 10-K report with the Securities and Exchange Commission on February 10, 2026. Ex. E. Consumers Energy reported:

> In January 2026, Consumers filed a request at FERC seeking recovery of the net financial impact of complying with the May 2025 emergency order, which was $42 million after applying MISO revenues of $78 million. This filing encompasses recovery sought by the joint owners of J.H. Campbell.
>
> For the second emergency order period through December 31, 2025, the net financial impact of compliance was $93 million after applying MISO revenues of $77 million. Consumers will seek recovery of these compliance costs at a later date, consistent with rate recovery sought for the May 2025 emergency order. The ultimate financial impact remains subject to the outcome of the FERC proceeding and any future guidance or interpretation.

Ex. E at 117–18. In total, DOE's orders in Campbell I and Campbell II cost ratepayers in MISO a total of $135 million. These real-world figures confirm that the plant cannot be effectively used for "economic dispatch" because it is uneconomical and runs at a loss when operated as the Campbell Orders I–IV require. They also confirm that operating Campell plant as ordered has not and will not "minimize cost to ratepayers" where net losses will be charged to them. Thus, the Consumers Energy SEC filings demonstrate that the Campbell III Order cannot be fulfilled according to its own terms. Ex. A at 10.

Finally, although the Campbell IV order purports to rely on emergency weather alerts related to Winter Storm Fern, the States' prior submissions have already put DOE on notice that such alerts are of limited value for supporting an emergency declaration. *See* Ex. C at 27. That is because alerts are commonplace, have been used for decades, and have never before required declaring a Section 202(c) emergency. The purpose of the alerts is to put system-wide resources on notice that they may be needed. They do not indicate an emergency that would require invoking Section 202(c), especially considering the availability of other system operators to meet any additional need. Rather, DOE's shifting reliance on seasonal alerts shows that the alerts are merely post-hoc justifications for prior orders used to accomplish DOE's goal of commandeering regional resource-planning. Even if such alerts were relevant, it is telling that there were no actual shortfalls, brownouts, or blackouts during Winter Storm Fern that would have required the specific additional capacity from J.H. Campbell versus other more cost-effective and less-polluting alternatives. Thus, the Campbell IV Order's discussion of Winter Storm Fern does not identify any particular need for which operating the Campbell Plant would have been an appropriate or even reasonable response, much less one that "best-meets" the purported emergency.

DOE is already in possession of the exhibits the States submitted in support of their petitions for rehearing of the Campbell I, II, and III Orders. The States are not resubmitting those same documents since they are incorporated by reference into the record for this petition. If DOE needs additional copies of any documents, please contact any of the signatories to this request.

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THE PRESIDENT AND THE POWER GRID

Mich. L. Rev. Online (forthcoming 2026)

Alexandra B. Klass[*] & Dave Owen[**]

There is a sharp discontinuity between the second Trump administration's electricity policies and those of previous presidential administrations. President Trump has directed the Department of Energy to use statutory authority designed for wartime conditions and sudden emergencies to prevent electric utilities from retiring aging coal plants. In doing so, he has elevated the President's role in electric grid governance and reduced the primacy of the independent expert regulatory agency—the Federal Energy Regulatory Commission—that Congress authorized to govern electricity markets and grid reliability.

This Essay places these actions in historical context. It recounts the executive branch's role in electricity policy during the first part of the twentieth century, when the federal government responded to wartime crises by building new electricity supplies and actively managing existing electricity infrastructure. While these early and mid-twentieth century executive actions may superficially resemble present-day events, they were profoundly different. Even amid the urgency of wartime, the executive branch was laying the foundation for an integrated grid managed by expert government agencies, not through direct presidential decrees, and it was working for technological progress, not regression. Building on this history, this Essay then explains why the present-day shift from expert agencies to presidential power in electric grid governance matters. The most obvious reason is that it will carry heavy financial and environmental costs to consumers and the nation. But the increased assertion of presidential power in electric grid governance also has doctrinal significance in light of recent developments in Supreme Court jurisprudence governing statutory interpretation and presidential use of emergency authorities.

INTRODUCTION

In May 2025, the U.S. Department of Energy ("DOE") ordered Consumers Energy, an electric utility serving Michigan, to halt the planned retirement of its J.H. Campbell power plant.[1] The 1,500-megawatt ("MW") plant is the state's

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[1] *Federal Power Act Section 202(c): Midcontinent Independent System Operator (MISO)*, U.S. DEP'T OF ENERGY, https://www.energy.gov/ceser/federal-power-act-section-202c-midcontinent-independent-system-operator-miso (DOE website linking to order and subsequent filings); *J.H. Campbell Complex Retirement*, CONSUMERS ENERGY, https://www.consumersenergy.com/about-us/electric-generation/campbell-complex-retirement (discussing power plant).

second-largest coal plant and one of its largest stationary sources of air pollution.[2] For Consumers Energy, this was a disruptive order. The 63-year-old plant was scheduled to permanently retire the following week, after years of planning and signoffs from all relevant state and federal regulators and grid operators.[3] Consumers Energy had already spent hundreds of millions of dollars replacing the coal plant's output with renewable energy and a new natural-gas-fired power plant.[4] When the utility received the DOE order at the start of Memorial Day weekend, it had to turn on a dime to re-hire workers, obtain coal supplies at inflated prices, and begin incurring what in just a few months would become over $100 million in losses, all to keep online an aging plant that the utility and grid operators had determined was no longer needed.[5] Who should pay for those losses—only Consumers Energy ratepayers or all ratepayers in the region—and whether such costs should have been incurred at all are questions now being litigated in multiple forums.[6]

DOE's order was unprecedented in multiple ways. In issuing the order, DOE relied on Section 202(c) of the Federal Power Act ("FPA"), which authorizes DOE to order the "temporary" connection of power plants or electric transmission facilities during "the continuance of any war" or "emergency" conditions.[7] State and federal regulators had already determined that the Campbell plant was *not* needed to serve the utility's customers or to ensure regional or local grid reliability.[8]

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[2] Sarah Leach, *Activists, Officials Call for Closure of Ottawa County Coal Plant As Utility Looks To Recover Costs*, MICH. ADVANCE (Aug. 13, 2025), https://michiganadvance.com/2025/08/13/activists-officials-call-for-closure-of-ottawa-county-coal-plant-as-utility-looks-to-recover-costs/; Marianne Lavelle, *Trump's Order To Keep Michigan Coal Plant Running Has Cost $80 Million So Far*, INSIDE CLIMATE NEWS (Oct. 31, 2025), https://insideclimatenews.org/news/31102025/michigan-campbell-coal-plant-operation-has-cost-80-million/.

[3] Leach, *supra* note 2.

[4] *See* Brian Martucci, *Consumers Energy to Invest More Than $13B in Renewables, Distribution by 2029*, UTIL. DIVE (Nov. 18, 2025), https://www.utilitydive.com/news/consumers-energy-campbell-large-load-earnings/805778/.

[5] Lucas Smolcic Larson, *Tab for Keeping Michigan Coal Plant Open Under Trump Orders Grows to $135M*, MLive (Feb. 12, 2026), https://www.mlive.com/news/2026/02/tab-for-keeping-michigan-coal-plant-open-under-trump-orders-grows-to-135m.html; Consumers Energy Co., Annual Report (Form 10-K) 117-118 (Dec. 30, 2025), https://d18rn0p25nwr6d.cloudfront.net/CIK-0000201533/016cee55-60d5-4eb2-b0be-b7e9b0f07c57.pdf (discussing net costs of DOE orders); Brett Dahlberg, *Michigan Coal Plant Set to Shut Down in 8 Days Must Stay Open, Trump Administration Says*, MICH. PUB. (May 24, 2025, at 13:55 ET) https://www.michiganpublic.org/transportation-infrastructure/2025-05-23/michigan-coal-plant-set-to-shut-down-in-8-days-must-stay-open-trump-administration-says (discussing criticism of DOE order by leaders of the Michigan Public Service Commission); Leach, *supra* note 2 (describing costs).

[6] *See infra* Part III (discussing litigation).

[7] 16 U.S.C. § 824a(c)(1) (describing conditions for use of emergency authority).

[8] Dahlberg, *supra* note 5.

But DOE nevertheless alleged that Michigan was facing emergency conditions due to insufficient regional electricity supply.[9]

The DOE order also departed significantly from the distinct roles Congress had created for federal agencies and states to regulate electricity production. Those roles have emphasized the development of market-structuring regulations by the Federal Energy Regulatory Commission ("FERC")—an independent and relatively technocratic agency—through processes governed by the procedural and substantive constraints of administrative law.[10] Congress also preserved substantial state authority over power plants within their territories.[11] But with electricity, as in many other realms,[12] the second Trump administration has changed the rules. The Consumers Energy order was just a starting point. More FPA Section 202(c) orders followed, with all similarly requiring aging, expensive, and in some cases inoperable coal-fired power plants (along with one dual-fuel oil and gas plant) to stay online regardless of their costs or ability to even generate electricity.[13] Still more appear to be in the works.[14]

These orders are part of a broader shift. They followed a series of executive orders in which President Trump declared an "energy emergency,"[15] told federal agencies to stop permitting wind and solar projects, and directed DOE to adopt new planning rules that favor coal and nuclear power and to use those new rules to force plants to stay open.[16] Collectively, these executive orders represent a new vision for centralized authority over the management of the electric grid. Technocratic,

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[9] *Federal Power Act Section 202(c): Midcontinent Independent System Operator (MISO)*, *supra* note 1; Martucci, *supra* note 4.

[10] Sharon B. Jacobs, *The Statutory Separation of Powers*, 129 YALE L.J. 378, 407-27 (2019) (discussing history, structure, and role of FERC).

[11] 16 U.S.C. §§ 842(a), (b)(1) (discussing state authority).

[12] For two among many possible examples, see *Justice Department Struggles as Thousands Exit—and Few Are Replaced*, ABA J. (Nov. 19, 2025), https://www.americanbar.org/advocacy/governmental_legislative_work/publications/washingtonletter/november-25-wl/outside-the-gao-1125wl/ (describing the loss of much of the DOJ's workforce and the politicization of hiring); Mattathias Schwartz, Zach Montague & Ernesto Londoño, *Judges Grow Angry Over Trump Administration Violating their Orders*, N.Y. TIMES (Feb. 24, 2026), https://www.nytimes.com/2026/02/23/us/politics/judges-contempt-immigration-trump.html?login=email&auth=login-email (describing persistent disregard for judicial orders).

[13] *See* Sonal Patel, *DOE Uses Emergency Powers to Freeze More Than 2 GW of Coal Retirements as Opposition Intensifies*, POWER (Dec. 31, 2025), https://www.powermag.com/doe-uses-emergency-powers-to-freeze-more-than-2-gw-of-coal-retirements-as-opposition-intensifies/; infra Part III (discussing DOE orders to keep coal plants open in Indiana, Colorado, and Washington); Jeffrey Tomich, *DOE Ordered Indiana Coal Plant to Run Despite Owner's Objection*, CLIMATEWIRE (Apr. 17, 2026), https://subscriber.politicopro.com/article/eenews/2026/04/17/doe-ordered-indiana-coal-plant-to-run-despite-owners-objection-cw-00877750; Appendix (describing plants subject to Section 202(c) orders in 2025).

[14] *See 2025 DOE 202(c) Orders*, U.S. DEP'T OF ENERGY, https://www.energy.gov/ceser/2025-doe-202c-orders; Claire Brown & Brad Plumer, *Trump Wants to Halt Almost All Coal Plant Shutdowns. It Could Get Messy*, N.Y. TIMES (Jan. 16, 2026), https://www.nytimes.com/2026/01/16/climate/trump-coal-plants.html.

[15] Exec. Order No. 14,156, 90 Fed. Reg. 8433 (Jan. 20, 2025).

[16] *See infra* Part III.

expert-driven decision-making is increasingly on the outs, as is the notion that economic value will be a central driver of policy choices. For instance, the orders prohibiting the J.H. Campbell plant in Michigan from retiring marked the first time the DOE had ever issued an order under Section 202(c) on its own initiative, rather than in response to a formal request by a utility, a state, or a regional grid operator.[17]

Though the DOE Section 202(c) orders mark a major change from recent electricity-governance practices, they might at first seem to have historical antecedents. During and after both world wars, the federal executive branch played an active role in managing existing electricity resources to support the war effort.[18] Thus, one might infer that, as much as the Trump Administration's use of emergency statutory authority to override expert decision-making processes is unusual, it might still have historical support. That possible inference creates a need to place the current use of Section 202(c) orders in historical context, and this Essay supplies that context.

Part I recounts the executive branch's role in electricity governance during the first part of the twentieth century. In what until recently would have seemed like a maximalist use of federal authority, the federal government responded to the imperatives of war by building new electricity supplies and actively managing existing electricity infrastructure. But even amid the urgency of wartime, the executive branch was laying the foundation for an integrated grid managed by expert government agencies, not through direct presidential decrees. Part II describes the executive branch's involvement in electricity governance over the latter part of the twentieth century and the beginning of the twenty-first. The general theme of this era also was not assertive presidential control, but instead deference to Congressionally created regulatory and ratemaking agencies. Part III details the second Trump administration's increased reliance on never-before-used statutory emergency authorities to depart from longstanding electric grid governance. Finally, Part IV explains why this matters, focusing on both on its doctrinal significance, as well as the heavy financial and environmental costs of the current exercise of presidential authority.

I. ELECTRICITY AND EXECUTIVE POWER DURING WARTIME

There is an element of nostalgic militarism in the Trump administration's energy rhetoric.[19] The administration's emphasis on conflict and its proclivity for declaring emergencies seem calibrated to recall periods of national ambition in the face of crisis, as though the perceived imperatives of acquiring Greenland and powering

[17] Dahlberg, *supra* note 5; *see also* Appendix (describing events leading up to 202(c) orders issued by DOE).

[18] *See infra* Part I.

[19] This is in addition to the administration's militaristic rhetoric more generally. *See*, *e.g.*, Exec. Order No. 14,347, 90 Fed. Reg. 43893 (Sept. 10, 2025) (Trump executive order changing the name of the Department of Defense to the Department of War).

data centers are on par with opposing Nazi aggression.[20] The allusions might seem strained, but the President's rhetoric does evoke a real past. During World War I and World War II, the United States really did face major challenges with electricity generation, and the federal government played an active role in responding to these challenges.[21] But any initial appearance of similarity is largely illusory. As described below, the wartime executive branch addressed electricity-related challenges primarily through the work of legislatively authorized administrative-agency programs, not through direct presidential control. When the wars ended, the emergency measures stopped, but wartime innovations, like heightened grid integration, laid the foundations for future economic growth.

A. World War I

On the eve of the United States' entry into World War I in 1917, electricity systems in the United States were poorly prepared to support a war. Electricity was still a relatively new technology, and though deployment was growing rapidly,[22] and manufacturers increasingly relied on electricity,[23] 75% of U.S. dwellings still lacked electric power.[24] Because the technology for long-distance, high-voltage transmission lines had yet to emerge, electricity generation and consumption were intensely local processes.[25] The nation generally lacked regional, let alone national, grids, and a direct federal role in governing electricity sales was still decades away. As a result, the sudden and sharp increase in manufacturing war supplies and munitions[27] caused power shortages and rolling blackouts throughout the "Steel Belt," including urban industrial centers such as Niagara Falls, Buffalo, and Pittsburgh.[28]

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[20] Robert Jimison, *Some Republicans Begin to Echo Trump's Case to Acquire Greenland*, N.Y. TIMES (Jan. 20, 2026), https://www.nytimes.com/2026/01/20/us/politics/republicans-trump-greenland.html; Alexandra B. Klass & Dave Owen, *Allocating Electricity*, 94 GEO. WASH. L. REV. (forthcoming 2026) (discussing data centers).

[21] *See infra* Part II.

[22] U.S. DEP'T OF COMMERCE, BUREAU OF THE CENSUS, HISTORICAL STATISTICS OF THE UNITED STATES, COLONIAL TIMES TO 1970, 827 (Bicentennial Ed., 1975), 1975/compendia/hist_stats_colonial-1970/hist_stats_colonial-1970p2-chS.pdf (see Growth of Residential Table Service) [hereinafter *Electrical Census Data*].

[23] Arthur G. Woolf, *The Residential Adoption of Electricity in Early Twentieth-Century America*, 8 ENERGY J. 19, 20 (1987).

[24] *Electrical Census Data*, *supra* note 22.

[25] Woolf, *supra* note 19, at 23.

[27] *See, e.g.*, COL. CHARLES KELLER, OFF. OF THE CHIEF OF ENG'RS, WAR DEP'T, DOC. NO. 1039, THE POWER SITUATION DURING THE WAR, WITH APPENDIXES CONTAINING REPORTS ON CONDITIONS IN THE SEVERAL POWER DISTRICTS (1921) [hereinafter KELLER REPORT]; Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. 789, 798–800 (2025).

[28] KELLER REPORT, *supra* note 27, at 3 (explaining how "[t]he tremendous industrial activity resulting from the war orders placed by the English, French, and Russian Governments, in the Buffalo-Niagara Falls territory had, in 1915, resulted in so complete an exhaustion of surplus power . . . .").

One of the federal government's responses was the creation of an entity called the "Fuel Administration."[29] The agency was born out of the Food and Fuel Control Act of 1917, which granted President Wilson sweeping authority "to facilitate the movement, of foods, feeds, fuel . . . to prevent, locally or generally, scarcity, monopolization, hoarding, injurious speculation, manipulations, and private controls . . . and to establish and maintain governmental control of such necessaries during the war."[30] Much of the agency's work focused on coal consumption, but in contrast to present-day efforts, the goal was to limit consumption, not increase it. For example, it fixed coal prices to control retail consumption[32] and it appointed local committees to enforce price schedules.[33] More creative efforts included "Heatless Mondays," which were weekly prohibitions against heating certain buildings,[34] and "Gasless Sundays," which discouraged pleasure driving of automobiles.[35]

The Fuel Administration was one of several wartime agencies. Congress also created a Council of National Defense,[36] which in turn proposed the formation of a War Industries Board ("WIB").[37] President Wilson ultimately approved the board, and it was tasked with coordinating the purchase of supplies between the Army and the Navy (since the Department of Defense did not yet exist to facilitate such coordination).[38] Its initial efforts were lackluster, but the Board eventually found some success in negotiating contracts between the military and private industry, creating a model of coordination later used in the Great Depression and World War II.[40]

Most of these efforts did not appear to be heavily influenced by President Wilson, and most focused on contracting for supplies and on consumption of energy resources rather than on managing the nation's still-nascent electricity-transmission infrastructure. Nevertheless, the WIB worked, initially unsuccessfully, toward the

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[29] *Records of the U.S. Fuel Administration [USFA],* THE U.S. NAT'L ARCHIVES AND RECORDS ADMIN., https://www.archives.gov/research/guide-fed-records/groups/067.html#67.1.

[30] Food and Fuel Control Act, Pub. L. No. 65-41, 40 Stat. 276 (1917).

[32] *See e.g.*, *Price Fixed for Lake Coal*, N.Y. TIMES, Oct. 29, 1917, at 14.

[33] *Garfield Asks Aid of Coal Consumers; Wants Them to Co-operate in Enforcing Prices Fixed by Him. To Name State Agents Seeks Voluntary Arrangements with Operators for Adjustment of Contracts*, N.Y. TIMES (Sept. 8, 1917), at 3.

[34] Ed Lewis, *Look Back: Heatless Mondays Began in 1918 to Conserve Fuel*, TIMES LEADER (Jan. 16, 2022), https://www.timesleader.com/news/1534897/look-back-heatless-mondays-began-in-1918-to-conserve-fuel.

[35] David Proper, *World War I Gasless Sundays Shut Down Much Travel*, THE KEENE SENTINEL (Nov. 22, 2005), https://www.keenesentinel.com/opinion/columnists/guest/world-war-i-gasless-sundays-shut-down-much-travel-by-david-proper/article_5dae9f48-fea1-5aab-b65e-c0a19f709bee.html.

[36] Created and funded through the 1916 Army Appropriations Act. 50 U.S.C. § 1, Editorial Notes.

[37] *War Purchase Board of Three Proposed*, N.Y. TIMES, July 11, 1917, at 3.

[38] Benjamin R. Beede, *War Industries Board*, INT'L ENCYCLOPEDIA OF THE FIRST WORLD WAR, https://encyclopedia.1914-1918-online.net/article/war-industries-board/ (last modified Oct. 8, 2014).

[40] *Id.*

development of an interregional electrical grid. Recognizing that the United States' industrial strength was limited by the localization of electrical power, the WIB requested that Congress introduce a bill granting the President authority to (1) centralize control over existing electric infrastructure and (2) develop new sources of generation.[41] During the war itself, those efforts came to naught; Congress did not pass the proposed bill.[42] But the WIB succeeded in bringing attention to the importance of a nationwide power network, finding supporters in both industry and government.[43]

When the federal government wound down its wartime operations, it continued to assess its wartime efforts, and the resulting study helped lay the foundations for the modern grid. In 1919, the Secretary of War tasked Colonel Charles Keller with investigating and reporting on the shortcomings of American electrical production during the war.[44] Keller focused on power shortages in areas of critical wartime production.[45] For instance, Keller described the complete exhaustion of electrical supply in the Niagara Falls district, which stymied the wartime production of steel and chemicals for nearby plants,[46] and serious output reductions in Pittsburgh, where a "congestion of war orders and manufacturing completely exhausted the power resources of the district."[47] Keller's report emphasized the importance of diversification of electricity supplies,[48] but his primary proposed solution was grid integration. He reasoned that while some regions struggled to meet the power demands of production, power elsewhere was held "idle" and "unused."[49] By building "broad lines" connecting regions and allowing electricity to flow to locations where demand outstripped supply, interconnection would increase the efficiency of consumption.[50]

B. The Interwar Period

After World War I, interconnection and electricity consumption continued to grow rapidly. Expansions of electrical infrastructure allowed transmission beyond the central hubs of cities.[51] Electricity use shifted towards an economy-wide customer base rather than primarily powering American industry.[52] By 1930, over 68% of dwellings were electrified.[53] Meanwhile, electricity provision shifted

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[41] EMANUEL ET AL., POWERING THE FIGHT 6 (2025).
[42] H.R. 12776, 65th Congress, 2nd Sess. (Aug. 19, 1918).
[43] EMANUEL ET AL., *supra* note 41.
[44] *See* KELLER REPORT, *supra* note 27.
[45] *Id.* at 1.
[46] *Id.* at 2–8.
[47] *Id*. at 11.
[48] *Id.* at 20.
[49] *Id.*
[50] *Id*. at 19.
[51] Sam Kalen, *Muddling Through Modern Energy Policy: The Dormant Commerce Clause and Unmasking the Illusion of an* Attleboro *Line*, 24 N.Y.U. ENV'T L.J. 283, 292 (2016).
[52] *Id.* at 291.
[53] Woolf, *supra* note 23, at 21.

increasingly toward large, consolidated companies, leading to an enduring business and governance model involving private monopolies and governmental price regulation.[54]

Much of that regulation was handled by state public utility commissions, which still regulate the retail prices charged by electric utilities.[55] But federal roles also evolved, and the interwar period saw the emergence of regulatory structures that would endure and grow through the rest of the twentieth century—and that are central to the controversies of the present day. In 1920, Congress created the Federal Power Commission ("FPC") and granted it "the authority to regulate the construction, operation, and maintenance of nonfederal hydroelectric power generation."[56] Congress also gave the FPC partial insulation from political control.[57] .

Congress would soon enhance the FPC's authority. The continued expansion and interconnection of electrical grids, the increase in market power of privately-owned utilities, and a Supreme Court case limiting state regulation of interstate electricity sales[59] led, in 1935, to the enactment of reform legislation, including major amendments to the Federal Power Act ("FPA").[60] The law expanded the FPC's jurisdiction, mandated that all rates and charges for interstate wholesale electricity sales and the transmission of electricity be "just and reasonable," and provided a mechanism to remedy rates that failed to meet this standard.[61] Retail sales remained subject to state regulation, as did decisions about the siting and permitting of power plants and transmission facilities.[62]

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[54] Kalen, *supra* note 51, at 301–03.

[55] LINCOLN L. DAVIES, ALEXANDRA B. KLASS, UMA OUTKA, HARI M. OSOFSKY, JOSEPH P. TOMAIN & ELIZABETH WILSON, ENERGY LAW AND POLICY 378, 384-85 (4th ed. 2026) (discussing history of federal and state regulation of the electricity sector); New York v. FERC, 535 U.S. 1, 5-7 (2002) (same).

[56] Adam Vann, *The Legal Framework of the Federal Power Act*, LIBR. OF CONG. (Jan. 22, 2020), https://www.congress.gov/crs-product/IF11411.

[57] Congress specified that the FPC would have five members, who would be appointed by the President with the advice and consent of the Senate; that the members would serve fixed terms; and that no more than three members would be from the same political party. Federal Water Power Act, ch. 284, 41 Stat. 1063 (1920) (codified as amended at 15 U.S.C. ch. 12 (2012)); Marla Barnes, *Tracing the Timeline: 101 Years of the Federal Power Act*, Nat'l Hydropower Ass'n (June 7, 2021), https://hydro.org/powerhouse/article/tracing-the-timeline-101-years-of-the-federal-power-act/ (recounting Congress's creation of the FPC in 1920 and its decision to convert it to a five-member commission in 1930).

[59] Pub. Utils. Comm'n v. Attleboro Steam & Elec. Co., 273 U.S. 83 (1927).

[60] 16 U.S.C. § 791a. On the same day it enacted the FPA, Congress also enacted the Public Utility Holding Company Act of 1935 (PUHCA), designed to reduce the size and economic power of utility holding companies. *See*, Aneil Kovvali & Joshua C. Macey, *The Corporate Governance of Public Utilities*, 40 Yale J. Reg. 569, 616 (2023) (discussing PUHCA).

[61] Vann, *supra* note 56.

[62] *See* 16 U.S.C. § 824; Matthew R. Christenson & Joshua Macey, *Long Live the Federal Power Act's Bright Line*, 134 HARV. L. REV. 1360, 1371-72 (2021).

The FPA gave the FPC only modest authority over interconnections,[63] but also included broader interconnection authority under limited circumstances. Section 202(c) provided:

> During the continuance of any war in which the United States is engaged, or whenever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes, the Commission shall have authority, either upon its own motion or upon complaint, with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.[64]

That provision was narrow by design.[65] It was motivated by Congress's experience with severe electricity shortages during World War I.[66] Post-war investigations, including the Keller Report, had revealed that many power shortages during the war resulted from the lack of interconnection among isolated utility systems, not because the nation had insufficient generating capacity.[67] But Congress also remained reluctant to grant the FPC broad authority over electric utilities' grid interconnections.[68] Consequently, and "with the Keller report in mind," it drafted Section 202(c) as an extraordinary power.[69] A Senate committee report stated that the provision was "a temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose."[70] The report also observed that natural emergencies such as droughts could lead to similar crises,[71] an apparent reference to drought-fueled power shortages in California from 1918 to 1920.[72] But the context for the provision, like its text, shows that Congress intended it as an extraordinary power for emergency use.

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[63] Public Utility Act of 1935, ch. 687, § 202(b), 49 Stat. 803, 848 (current version at 16 U.S.C. § 824a(b)) (giving the FPC power to order "a public utility . . . to establish physical connection of its transmission facilities").

[64] Public Utility Act of 1935, ch. 687, § 202(c), 49 Stat. 803, 849 (current version at 16 U.S.C. § 824a(c)).

[65] *See generally* Rolsma, *supra* note 27 (recounting legislative history).

[66] S. REP. NO. 74-621, at 19 (1935).

[67] *See* KELLER REPORT, *supra* note 27, at 18–19.

[68] *See* Horace M. Gray, *The Integration of the Electric Power Industry*, 41 AM. ECON. REV. 538, 538 (1951).

[69] Rolsma, *supra* note 23, at 801.

[70] S. REP. NO. 74-621, at 49 (1935).

[71] *Id.*

[72] *Public Utility Holding Companies: Hearings on H.R. 5423 Before the H. Comm. on Interstate and Foreign Com.*, 74th Cong. 272–74 (1935) (statement of Comm'r Frank R. McNinch, Chairman, Fed. Power Comm'n).

C. World War II

Throughout the 1930s, memories of the last war and the possibility of the next one loomed over federal electricity governance. As early as 1935, the FPC published a survey—completed at President Roosevelt's request—that assessed the nation's existing and potential hydropower systems and addressed problems of national defense.[73] The report described the potential for power shortages in the eastern and midwestern industrial centers if the United States "should become involved in war,"[74] emphasized the need for increased interconnection, and imagined a larger role for the federal government in planning future electrification.[75]

By the late 1930s, as events in Europe turned increasingly ominous, that focus intensified.[76] In March 1938, President Roosevelt directed the FPC and the War Department to jointly survey the nation's wartime power capacity.[77] Roosevelt was aware of President Wilson's struggles during World War I, and "resolved beforehand to map out a national defense power program in order to avert a shortage of electricity."[78] The agencies concluded that wartime load would lead to a widespread energy shortage and deemed the state of the nation's electricity landscape "so serious as to require immediate attention."[79] The warnings proved prescient. Within weeks of Pearl Harbor, industry groups reported shortages.[80]

Even before the war, there were intense disagreements about how those needs should be met. One conflict concerned whether the federal government should emphasize interconnection of electricity systems, the construction of new power plants, or both. The FPC, building on preferences dating back to the Keller Report, favored a combination. In the summer of 1938, the FPC engineering staff proposed a comprehensive plan that would serve both wartime needs and long-term national power policy through the construction of an interconnected network of high-capacity transmission lines and the expansion of hydroelectric and steam-electric power.[81] The War Department opposed this approach, arguing that it was unnecessarily expensive and would divert resources from military rearmament.[82] Instead, the War Department favored constructing additional coal-fired power

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[73] *See* Fed. Power Comm'n, Power Ser. No. 1, National Power Survey Interim Report (1935).

[74] *Id*. at xi.

[75] *Id.* at 55.

[76] JULIE A. COHN, THE GRID: BIOGRAPHY OF AN AMERICAN TECHNOLOGY 106 (2017).

[77] Philip J. Funigiello, *Kilowatts for Defense: The New Deal and the Coming of the Second World War*, 56 J. OF AM. HIST. 604, 605 (1969).

[78] *Id.* at 604.

[79] Confidential Memorandum on Shortages of Electric Generating Capacity for War-Time Needs (July 1, 1938) (on file with Manuscript Division, Library of Congress, George W. Norris Papers, Box 2, Tray 72).

[80] *Power Needs Met, Kellogg Reports*, N.Y. TIMES, Dec. 22, 1941, at 31.

[81] PHILIP J. FUNIGIELLO, TOWARD A NATIONAL POWER POLICY: THE NEW DEAL AND THE ELECTRIC UTILITY INDUSTRY, 1933–1941 234 (1973).

[82] Memorandum to the National Defense Power Committee (Aug. 12, 1938) (on file with Franklin D. Roosevelt Library, Hyde Park, N.Y, Leland Olds Papers, Box 61).

plants in each industrial center.[83] The FPC stuck to its position. It saw no reason why its "more comprehensive program should be sacrificed because in the past the military had done a poor job of looking after its armaments."[84] Ultimately, the FPC's approach prevailed, with key administration figures concluding the it was better suited to meeting defense needs and more consistent with broader New Deal policy commitments.[85]

A second conflict concerned who within the government should exercise wartime authority. In September 1938, President Roosevelt established the National Defense Power Committee ("NDPC") to recommend solutions for alleviating the predicted wartime energy shortages identified by the FPC and War Department's survey.[86] However, after significant bureaucratic conflict within the NDPC, President Roosevelt concluded that the committee structure was unworkable and turned instead to the FPC, which he viewed as staffed by technically competent administrators capable of decisive action.[89]

Over the course of the war, the FPC used its FPA Section 202(c) authority twenty-two times.[90] In June 1941, the FPC found that "an emergency . . . exists in the southeastern area of the United States, resulting from a sudden increase in the demand for electric energy to meet the requirements of national defense production."[91] The Commission followed this declaration with ten separate Section 202(c) orders on the same day.[92] Among other recommendations and mandates, these orders compelled the interconnection of Florida Power & Light Company and the Florida Public Service Company,[93] the construction of a 100,000-volt circuit from a Duke Power Company substation to a Carolina Aluminum Company substation,[94] and the construction of a 110,000-volt circuit interconnecting New Orleans Public Service, Inc. and Mississippi Power Company.[95] Each order recognized the state of emergency due to increased wartime demand and declared that an emergency connection of facilities or increased generation, transmission, or delivery was necessary.[96]

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[83] *Id.*

[84] FUNIGIELLO, *supra* note 81, at 234.

[85] *Id.* at 234–35.

[86] Letter from President Franklin D. Roosevelt to the Sec'y of War (Sep. 3, 1938) (on file with Nat'l Archives, Records of the Federal Energy Regulatory Commission, Record Group 138).

[89] FUNIGIELLO, *supra* note 81, at 251.

[90] Rolsma, *supra* note 27, at 803.

[91] Recommendation for Curtailment of the Use of Elec. Energy in the Se. States, 2 F.P.C. 990, 990 (1941).

[92] *See* Ga. Power & Light Co., 2 F.P.C. 993, 993–94 (1941); Fla. Power Corp., 2 F.P.C. 994, 994–95 (1941); Ga. Power & Light Co., 2 F.P.C. 995, 995–96 (1941); Ala. Elec. Coop., 2 F.P.C. 996, 996–97 (1941); Tenn. Valley Auth., 2 F.P.C. 997, 997–98 (1941); Carolina Aluminum Co., 2 F.P.C. 998, 998–99 (1941).

[93] *See* Fla. Power & Light Co., 2 F.P.C. 991, 991 (1941).

[94] *See* Duke Power Co., 2 F.P.C. 992, 992 (1941).

[95] *See* New Orleans Pub. Serv., Inc., 2 F.P.C. 992, 992–93 (1941).

[96] *See, e.g.*, Fla. Power & Light Co., 2 F.P.C. 991, 991 (1941); Duke Power Co., 2 F.P.C. 992, 992 (1941).

Beyond ordering individual interconnections, the FPC played a key role in creating "power pools," which were arrangements through which private utilities would share power. These pools changed the ways utilities operated, for many of them were unaccustomed to treating power grids as shared resources or working with their competitors, and some had carefully avoided interstate sales to prevent the federal regulation.[97] Soon, major regions of the country were functioning as part of coordinated electricity networks with interties between regions, which meant that power shortages in some areas could be met with electricity from others with excess supply. Later historical accounts have treated these power pools as one of the most important innovations of the United States' World War II energy policies.[98]

In multiple ways, these World War II innovations helped sow the seeds for a more national grid and the complex electricity markets of the present day. As interconnected systems grew larger and remained coupled nearly full-time during the war, the traditional challenges of managing frequency and load became more intricate and demanding, leading to technological innovations that became industry standards.[99] Institutional capacity also grew, as both federal agencies and utilities had to learn how to work across institutional boundaries. More generally, the United States moved quickly away from the prewar world, in which electricity distribution often involved poorly connected or disconnected private fiefs, and toward the efficiencies of an interconnected economy and grid.

II. FEDERAL GRID GOVERNANCE IN THE MODERN ERA

As the prior Part illustrates, the federal government's wartime role in grid management was assertive. But that role also emphasized grid integration and relied on agencies—particularly the FPC—rather than direct presidential control. That emphasis on agencies fits with broader themes of this era, for the early part of the twentieth century saw much of the emergence of the modern administrative state.[100] Regulatory agencies increasingly exercised congressionally delegated authority, often with only modest executive oversight, across a wide range of economic spheres.[101] Electricity, even during wartime, was no exception.

Until recently, that trend continued. This Part surveys the federal electric grid management systems that continued to emerge and evolve from the postwar period through the present, and that trace their roots to the innovations of the interwar period and World War II. These systems and their history are complicated, and no generalization holds entirely true across multiple agencies or over such a long span of time. Nevertheless, throughout this period, management of the nation's electric grid, though heavily influenced by the federal government, was generally not a

[97] *See* COHN, *supra* note 76, at 109.
[98] *Id*. at 117, 120.
[99] *Id.* at 114–117.
[100] *See generally* CASS SUNSTEIN, AFTER THE RIGHTS REVOLUTION (1990) (chronicling the twentieth-century expansion of administrative governance).
[101] *See id.* at 18-24.

sphere of substantial *presidential* influence either through executive orders or DOE actions. Instead, the dominant actor became FERC, an independent agency[102] that operated under legislative delegations conferring sweeping discretion,[103] whose decision-making was steeped in technical expertise,[104] and that showed stable policy commitments even across presidential administrations.[105]

A. The Federal Energy Regulatory Commission: The Electric Grid Regulator

This section picks up where Part I left off and describes the evolution of FERC regulation through the early twenty-first century. After World War II, technologies and challenges evolved, federal regulation of the energy sector continued to develop, and new agencies emerged. For instance, in the 1940s, Congress created the Atomic Energy Commission ("AEC") to regulate the commercial use of nuclear power.[106] It also created new authorities within the executive branch, partly in response to the energy crisis following the 1973 Arab Oil Embargo.[107] In 1977, Congress enacted the Department of Energy Organization Act ("DOE Act"), which split up the FPC's responsibilities.[108] Congress gave some federal energy activities to the newly created DOE, described in more detail in Section II.B, with a Secretary appointed by the President and subject to Senate confirmation.[109] And it assigned the FPC's responsibility for electricity-grid regulation and ratemaking to the newly created FERC.[110]

Subsequent legislation, including the Energy Policy Act of 1992,[112] the Energy Policy Act of 2005,[113] and the Infrastructure Investment and Jobs Act of 2021,[114] among others, expanded FERC's regulatory authority over the electricity sector.

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[102] *See* Kirti Datla & Richard L. Revesz, *Deconstructing Administrative Agencies (and Executive Agencies)*, 98 CORNELL L. REV. 769, 825 (2013).

[103] *See* Jodi L. Short, *In Search of the Public Interest*, 40 YALE J. REG. 759, 804 (2023).

[104] *See* Sharon Jacobs, *The Challenges of Participatory Administration*, 58 UC DAVIS L. REV. 323, 340-45 (2024) (describing the technical and sometimes opaque nature of electricity regulation).

[105] *See* Francisco "A.J." Camacho, *Trump Wants Agencies on a Short Leash. What Does that Mean for FERC?*, E&E NEWS (Dec. 10, 2024), https://www.eenews.net/articles/trump-wants-agencies-on-a-short-leash-what-does-that-mean-for-ferc/.

[106] Atomic Energy Act of 1946, Pub. L. No. 79-585, 60 Stat. 755 (1946).

[107] For discussions of how the Arab Oil Embargo transformed U.S. domestic energy policy, see generally DANIEL YERGIN, THE PRIZE: THE EPIC QUESTION FOR OIL, MONEY & POWER 644-47 (1991); JAY HAKES, ENERGY CRISES: NIXON, FORD, CARTER, AND HARD CHOICES IN THE 1970S 200-201, 217, 224-27, 342-42 (2021).

[108] Department of Energy Organization Act, Pub. L. No. 95-91, 91 Stat. 565 (1977) (codified at 42 U.S.C. §§ 7101–352); *see also A Brief History of the Department of Energy*, DEP'T OF ENERGY, https://www.energy.gov/lm/brief-history-department-energy.

[109] Pub. L. 95-91, 91 Stat. 565 §§ 201–02 (codified at 42 U.S.C. §§ 7131–7132).

[110] Unlike DOE, FERC is a five-member commission supported by a career staff. Each member serves a five-year term, terms are staggered, no more than three commissioners are from the same political party, and each commissioner is appointed by the President and must be confirmed by the U.S. Senate. *Id.* § 401(b)(1) (codified at 42 U.S.C. § 7171).

[112] Energy Policy Act of 1992, Pub. L. No. 102-486, 102 Stat. 2776.

[113] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594.

[114] Infrastructure Investment and Jobs Act, Pub. L. No. 117-58, 135 Stat. 429 (2021).

That authority now includes responsibilities to protect power-grid reliability through creation of mandatory reliability standards, monitoring and investigating energy markets, and penalizing market participants that violate market rules.[115]

FERC has done a lot with that authority. The central story of electricity regulation over the last fifty years has been a movement away from systems built around private monopolies and governmental price regulation, and toward increased market competition.[116] In the 1980s and 1990s, FERC adopted market-based rates for independent power producers,[117] enacted regulations designed to allow utilities to sell power outside their service areas, and required open access transmission, which means that utilities cannot engage in price discrimination against independent power producers or purchasers that wish to use the utilities' power lines.[118] And it encouraged the formation of regional transmission organizations ("RTOs"), which are non-profit, private entities that utilities use to jointly manage the shared grid and oversee wholesale auctions for energy and other grid services.[119]

FERC, together with RTOs and states, also helps maintain "resource adequacy," which means ensuring that there is adequate electricity generation to meet bulk power system needs and avoid brownouts and blackouts.[120] While the FPA left jurisdiction over energy generation plants primarily to states, many states have directed or permitted their utilities to join RTOs, which, subject to FERC review and oversight, impose resource-adequacy requirements on member utilities.[121] Utilities fulfill those obligations through long-term planning and technical analysis, which they complete in cooperation with states, RTOs, and FERC.[122] Likewise, the North American Electric Reliability Corporation ("NERC"), with authorization

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[115] *See What FERC Does,* FED. ENERGY REG. COMM'N, https://www.ferc.gov/what-ferc-does; PAUL W. PARFOMAK, CONG. RSCH. SERV., R48349, THE FEDERAL ENERGY REGULATORY COMMISSION (FERC): AUTHORITIES AND MEMBERSHIP (2026); Sharon Jacobs & Ari Peskoe, *Energy Emergencies vs. Manufactured Crises: The Limits of Federal Authority to Disrupt Power Markets*, 2019 HARV. L. SCH. ENV'T & ENERGY L. PROGRAM 6-7 (2019) (discussing how the Energy Policy Act of 2005 authorized FERC to regulate grid reliability); *see also* Energy Policy Act of 2005, 16 U.S.C. § 825(f), (j) (authorizing FERC to conduct investigations into FPA violations); *id.* § 825*o*–1 (granting FERC authority to assess penalties of up to $1 million per day for each FPA violation).

[116] *See* FERC v. Electric Power Supply Ass'n, 577 U.S. 260, 267 (2016) (describing FERC's evolving role); *see generally* Joseph P. Tomain, *The Past and Future of Electricity Regulation*, 32 ENV'T L. 435 (2002) (describing these changes).

[117] *See Morgan Stanley Capital Group, Inc.*, 554 U.S. at 535 (describing market-based rates, among other regulatory reforms).

[118] *See* New York v. FERC, 535 U.S. 1, 5 (2002).

[119] *See* FERC v. Electric Power Supply Ass'n, 577 U.S. 260, 267-68 (2016); *see also Energy Markets*, FED. ENERGY REG. COMM'N, https://www.ferc.gov/opp/energy-markets.

[120] *Reliability Explainer*, FED. ENERGY REGUL. COMM'N, https://www.ferc.gov/reliability-explainer; *Resource Adequacy for a Clean Energy Grid*, STINSON (Nov. 2021), https://acore.org/wp-content/uploads/2021/11/RA-for-a-Clean-Energy-Grid_Legal-Analysis.pdf; Joshua C. Macey, Shelley Welton & Hannah Wiseman, *Grid Reliability in the Electric Era*, 41 YALE J. REG. 164, 195-96 (2024) (discussing resource adequacy).

[121] *See Resource Adequacy for a Clean Energy Grid*, *supra* note 120.

[122] *See* Macey et al., *supra* note 120, at 194–96.

from Congress in the Energy Policy Act of 2005, sets mandatory standards for grid reliability, subject to FERC review and oversight.[123] Notably, Congress created no role for DOE in addressing long-term resource adequacy or grid reliability.

To what extent these innovations have been successful is one of the central questions of energy law. The debates are broad, rich, and variegated, with scholars arguing whether FERC's reforms have been sufficiently democratic;[124] adequately sensitive to the needs of disadvantaged communities and to emerging concepts of energy justice;[125] aggressive enough in pursuit of decarbonization;[126] and overly solicitous of the roles of traditional vertically integrated private utilities,[127] among many other subjects.

But amid the many debates, some things are relatively clear. Most importantly, these reforms have opened up electricity markets to many new participants, who have brought increased competition and created downward pressure on prices.[128] These reforms also have allowed the market entry of new types of energy generation, including wind and solar.[129] One other feature of FERC's transformation of grid regulation also bears mentioning: presidents didn't have much to do with it. No presidential proclamation spurred FERC's orders creating wholesale electricity markets, RTOs, or approaches to resource adequacy. Nor did the overall trajectory of agency policy shift dramatically from administration to administration. Instead, the agency's direction remained consistent over long periods of time, and its decision-making was largely technocratic, with elected politicians exercising influence through legislation, not presidential directives.[130]

B. The Department of Energy: Electricity Innovator, Research Partner, Funder, and Emergency Responder

In contrast to the FPC and FERC, DOE's origin story comes from the Manhattan Project, the highly-classified effort by the U.S. War Department to work intensely with the scientific community to create the world's first nuclear

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[123] *Id.* at 205.

[124] *See, e.g.*, Jacobs, *supra* note 104, at 345–49, 384–87 (analyzing FERC's efforts to promote democratic participation).

[125] *E.g.* Shalanda H. Baker, *Anti-Resilience: A Roadmap for Transformational Justice within the Energy System*, 54 HARV. C.R.–C.L. L. REV. 1, 36–37 (2019) (arguing that FERC has insufficiently addressed social and racial justice concerns).

[126] *E.g.* Shelley Welton, *Electricity Markets and the Social Project of Decarbonization* 118 COLUM. L. REV. 1067, 1112–13 (2018) (discussing limitations associated with RTO decarbonization efforts requiring FERC approval).

[127] *See, e.g.*, Ari Peskoe, *Is the Utility Transmission Syndicate Forever?*, 42 ENERGY L.J. 1, 45–46, 61 (2021).

[128] *See generally*, FED. ENERGY REGUL. COMM'N, 2024 STATE OF THE MARKETS REPORT (2025) (noting that wholesale prices are declining even as grid additions are dominated by solar, natural gas, wind, and battery storage).

[129] *See id.* at 28-32.

[130] *See* Jacobs, *supra* note 10, at 416–18.

weapon.[131] This initiative required "large, multi-purpose facilities that became the nation's first national laboratories," which today are housed within the Office of Science at DOE.[132] For decades, different offices within DOE have supported many aspects of energy research, development, demonstration, and deployment—including in the electricity sector—through billions of dollars in grants, loans, and other funding.[133]

DOE also acts as a first responder for grid emergencies. But until recently, DOE had understood its emergency-response authority to be limited to short-term responses to genuine emergencies, and it had exercised its powers—mostly—accordingly. As discussed in Part I, in 1935, Congress authorized the FPC to issue temporary orders to require grid-stabilizing actions by private-sector actors in times of war or emergency in Section 202(c) of the FPA.[134] Later, when Congress enacted the Department of Energy Organization Act of 1977 (discussed in more detail in Section II.A) and divided executive branch electricity-related authority among multiple new federal agencies, it transferred the FPC's Section 202(c) authority to DOE.[135]

The FPC and, later, DOE, have exercised 202(c) emergency authority dozens of times, but until recently, both agencies hewed closely to the statutory language limiting its use to wartime conditions and sudden emergencies.[136] As discussed in Part I, the FPC invoked this authority during World War II, primarily to compel grid integration.[137] The FPC also issued orders during and after the Korean War, but issued just seven 202(c) orders from 1944 until DOE assumed authority in 1977.[138] And when a utility challenged the FPC's decision *not* to use 202(c) to address the Arab Oil Embargo in the early 1970s, the D.C. Circuit Court of Appeals sided with the FPC, finding that dependence on foreign oil was a "continuing" emergency and

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[131] *A Brief History of the Department of Energy*, U.S. DEP'T OF ENERGY, https://www.energy.gov/lm/brief-history-department-energy.

[132] *History*, U.S. Dep't of Energy, https://www.energy.gov/science/history.

[133] Zahava Urecki & Tanya Das, *The Department of Energy's Role in Fostering Innovation to Meet America's Energy Needs*, BIPARTISAN POL'Y CTR. (Oct. 2, 2025), https://bipartisanpolicy.org/issue-brief/the-department-of-energys-role-in-fostering-innovation-to-meet-americas-energy-needs/.

[134] 16 U.S.C. § 824a(c).

[135] *See* Department of Energy Organization Act, Pub. L. No. 95-91, 91 Stat. 565 (1977) (codified at 42 U.S.C. §§ 7101–352); *A Brief History of the Department of Energy*, DEP'T OF ENERGY, https://www.energy.gov/lm/brief-history-department-energy.

[136] *See DOE's Use of Federal Power Act Emergency Authorities*, U.S. DEP'T OF ENERGY, https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority.

[137] *See supra* Section I.C; ASHLEY J. LAWSON, CONG. RSCH. SERV., IF12991, FEDERAL POWER ACT: THE DEPARTMENT OF ENERGY'S EMERGENCY AUTHORITY 2 (2026), https://www.congress.gov/crs-product/IF12991; *see also* Rolsma, *supra* note 27, at tbl. 2 (detailing Section 202(c) orders); Appendix (same).

[138] Rolsma, *supra* note 27, at 803-04; Appendix.

that 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances . . . ."[139]

Until recently, DOE itself understood that authority to be highly cabined. In 1981, DOE issued regulations defining an "emergency" for purposes of Section 202(c), and those regulations emphasized the agency's intent that its emergency authority should not be a substitute for long-term utility planning.[140] The regulations also state that "while a utility may rely on these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself."[141] Those regulations remain in place, and in accordance with them, DOE went twenty years before issuing its first 202(c) order.

Around 2000, DOE's practices began to change, but initially only modestly. In 2000, DOE began issuing orders to address (1) grid failures, like the 2003 Northeast blackout and the 2001 California electricity crisis, and (2) weather-related emergencies such as hurricanes, heat waves, and cold waves.[142] The duration of these orders almost always ranged from a few hours to less than ninety days.[143] More importantly, until DOE's orders preventing the retirement of the J.H. Campbell plant in Michigan, DOE had never issued an emergency order on its own initiative. Instead, it had acted only in response to a formal request by the utility, the state, or the regional grid operator.[144] Likewise, it had never pointed to long-

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[139] Richmond Power & Light v. FERC, 574 F.2d 610, 615 (D.C. Cir. 1978); Rolsma, *supra* note 27, at 812 (discussing case).

[140] The regulations defined "emergency" 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. . .

10 C.F.R. § 205.371 ("Definition of emergency"); *see also* U.S. Dep't of Energy, Final Rule, Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Storage of Electric Power, 46 Fed. Reg. 39984, 39985-86 (Aug. 6, 1981), https://archives.federalregister.gov/issue_slice/1981/8/6/39984-39991.pdf#page=2.

[141] U.S. Dep't of Energy, Final Rule, *supra* note 140, at 39985.

[142] *See* Rolsma, *supra* note 23, at 805-06, 839-42; LAWSON, *supra* note 137, at Tbl. 1.

[143] LAWSON, *supra* note 137, at 2-3; *see also* Rolsma, *supra* note 27, at 819–20, 838-42 & tbl. 1; Jacobs & Peskoe, *supra* note 115, at 1, 12.

[144] See Kenneth W. Irvin et al., *Department of Energy Blocks Shutdown of Coal-Fired Power Plant and Oil- and Gas-Fired Generator Units With Federal Emergency Orders*, SIDLEY (June 13, 2025), https://environmentalhealthsafetybrief.sidley.com/2025/06/13/department-of-energy-blocks-shutdown-of-coal-fired-power-plant-and-oil-and-gas-fired-generator-units-with-federal-emergency-orders/ ("[U]nlike other Section 202(c) orders, the Campbell Order was issued by the DOE on its own initiative—not in response to a power plant owner, transmission provider, or grid operator application"); LAWSON, *supra* note 137, at 6 (same). For a table including all section 202(c) orders to date, see Appendix.

term resource adequacy concerns as a justification to use its Section 202(c) authority.[145]

III. THE TRUMP II TRANSFORMATION

Whatever stability federal electricity governance may have enjoyed has come to an end. This Part describes the executive orders and implementation actions that have inserted President Trump's self-described "energy dominance"[146] agenda into aspects of electric grid governance that Congress placed primarily in the FPC's, and then FERC's, control since before World War II.

President Trump's pursuit of what he has termed "energy dominance" began in his first term, with policies designed to promote fossil fuels, particularly coal, and to discourage the development of renewable energy, particularly wind.[147] That agenda mostly failed, as the relatively lower costs of renewable power and natural gas meant that renewable generation and gas continued to grow and coal continued to decline.[148] But upon taking office again in 2025, President Trump revived these efforts, this time with an entirely new level of vigor.

On his first day in office, President Trump declared a "national energy emergency," citing his authority under the National Emergencies Act of 1976 ("NEA").[149] The order declared that the nation had inadequate energy to meet its needs and directed the heads of federal executive departments and agencies to "identify and exercise any lawful emergency authorities available to them" to facilitate the development and use of domestic energy resources.[150] Other executive orders early in the second Trump administration began laying the groundwork for DOE to take control of the electric grid. In April 2025, an order entitled "Strengthening the Reliability and Security of the United States Electric Grid"[151] stated that DOE should conduct its own electric grid resource adequacy analysis and, "to the maximum extent permitted by law, streamline, systemize, and expedite" its procedures for issuing orders under Section 202(c) of the FPA.[152]

In many ways, these directives broke with the past. As discussed in Part II, Congress expressly reserved authority for states to address resource adequacy and

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[145] *See*, *e.g.*, DEP'T OF ENERGY, ORDER NO. 202-25-7 (Aug. 25, 2025), https://www.energy.gov/sites/default/files/2025-08/MISO%20Order%20No.%20202-25-7.pdf, (citing evidence of "a potential longer term resource adequacy emergency in MISO" to justify continued additional dispatch of the Campbell Plant).

[146] *See, e.g.,* Establishing the National Energy Dominance Council, THE WHITE HOUSE, Feb. 14, 2025, https://www.whitehouse.gov/presidential-actions/2025/02/establishing-the-national-energy-dominance-council/.

[147] Lincoln L. Davies, Kiersten Rule Davies & Kathryn Glenn Speckart, *Trump Energy Policy 2.0*, 71 FOUND. FOR NAT. RES. & ENERGY L. INST. 2-1 (2025).

[148] Mickey Francis, *U.S. Renewable Energy Consumption Surpasses Coal for the First Time in Over 130 Years*, U.S. ENERGY INFO. ADMIN. (May 28, 2020), https://www.eia.gov/todayinenergy/detail.php?id=43895.

[149] Exec. Order No. 14,156, 90 Fed. Reg. 8433 (Jan. 20, 2025).

[150] *Id*. at 8434.

[151] Exec Order No. 14,262, 90 Fed. Reg. 15521, 15521 (Apr. 8, 2025).

[152] *Id.*

delegated authority to FERC and FERC-regulated regional entities to ensure grid reliability.[153] With no change in the governing statutory law, the April 2025 electric grid executive order reassigned a dominant role for both authorities to DOE. And nothing in the executive order required or suggested that DOE should or could consult with FERC, RTOs, NERC, or states in conducting its analysis.

DOE wasted no time working to implement these mandates directing it to take control of the electric grid. Among other things, DOE began issuing a barrage of Section 202(c) orders.[154] All of the orders issued in 2025 directed aging and, in some cases, inoperable, coal or oil plants to be made available for dispatch beyond their scheduled retirement dates.[155] Notably, during the first Trump administration, DOE had considered using its Section 202(c) emergency authority to prevent utilities from retiring uneconomic coal and nuclear plants, but the agency was concerned about its legal authority to do so.[156] By 2025, DOE had shed those concerns.

The first of those orders, as discussed in the Introduction, involved the J.H. Campbell coal plant in Michigan.[157] Significantly, neither the plant owner nor the regional grid operator—the Midcontinent Independent System Operator ("MISO")—had sought DOE assistance or expressed any concern about the plant's closure.[158] Consumers Energy had already purchased a gas plant and taken other actions to make up for any reduction in generation capacity arising from the plant closure.[159] It also had received approval for its transition plan from the state and from federal grid reliability regulators.[160] In fact, the utility's transition plan to cleaner and lower-cost energy sources—a plan that state regulators had approved—was expected to save the utility's customers $600 million over the next twenty years.[161] And even after DOE issued its order, MISO affirmed that it had sufficient energy supplies in the region for the next year.[162]

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[153] *See supra* Part II.

[154] *See 2025 DOE 202(c) Orders*, *supra* note 14; Appendix.

[155] *See 2025 DOE 202(c) Orders, supra* note 14.

[156] Jacobs & Peskoe, *supra* note 115, at 21–25; Jeff Horwitz, Michael Biesecker & Matthew Daly, *Despite Earlier Assurance, Trump Denies Coal a Lifeline*, THE CHRISTIAN SCIENCE MONITOR (Aug. 22, 2017), https://www.csmonitor.com/USA/2017/0822/Despite-earlier-assurance-Trump-denies-coal-a-lifeline;

[157] Dep't of Energy, No. 202-25-3, Midcontinent Independent System Operator (MISO) 202(c) Order 1 (2025) https://www.energy.gov/ceser/federal-power-act-section-202c-midcontinent-independent-system-operator-miso.

[158] Dahlberg, *supra* note 5.

[159] *MPSC Approves Consumers Energy Integrated Resource Plan Settlement Agreement, Takes Additional Steps to Boost Electricity Capacity*, MICH. PUB. SERV. COMM'N (June 23, 2022), https://www.michigan.gov/mpsc/commission/news-releases/2022/06/23/mpsc-approves-consumers-irp_takes-steps-improve-capacity; Consumers Energy Co., *supra* note 5, at 35.

[160] Leach, *supra* note 2.

[161] Lavelle, *supra* note 2.

[162] Pet. for Review, Michigan v. Dep't of Energy, No. 25-1159 (D.C. Cir. July 24, 2025), at 18-21, 27-32 (citing MISO actions and auction results).

Beyond erasing those savings, the order created new costs for Consumers Energy and for Michigan consumers. Based on the utility's SEC filings, between the issuance of the first DOE order on May 23, 2025, and December 31, 2025, Consumers Energy had incurred losses of $135 million—the difference between the cost to continue to keep the plant online and the power-sale revenues during that time period.[163] Someone—most likely consumers—will need to pay for those losses.[164]

The DOE's order prompted legal challenges from states, environmental advocacy groups, and other stakeholders. One action—brought by Michigan, other states in the MISO region, and environmental advocacy groups in the U.S. Court of Appeals for the D.C. Circuit—challenged the DOE's orders arguing, among other things, that there were no conditions that justified DOE's exercise of emergency authority under FPA Section 202(c) and that the orders were unlawful.[165]

If the Campbell plant order was just a one-off event, it still would be concerning. Even that one order's costs are huge, not to mention the adverse local health and environmental impacts of continuing to operate the plant.[166] But instead, the Campbell order was the beginning of a pattern. Between May 2025 and March 2026, DOE issued multiple Section 202(c) orders designed to delay the closure of coal-fired power plants.[167] These included: (1) orders requiring a 52-year-old plant in Washington State to keep its last coal-fired boiler online despite longstanding plans to retire it and then convert the plant to run on natural gas;[168] orders requiring a coal plant in Colorado, which was inoperable and set to close in two days at the time of the order, to instead be made available for dispatch;[169] and orders requiring a 60-year-old coal unit in Indiana to remain available for dispatch beyond its retirement date, despite pleas from its owner that the plant would not be able to operate without tens of millions of dollars of unplanned ratepayer costs for

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[163] Larson, *supra* note 5; Consumers Energy Co., *supra* note 5.

[164] Consumers Energy Co., *supra* note 5, at 117-118 (describing allocation of Campbell costs to customers); Lavelle, *supra* note 2.

[165] *See* Initial Opening Brief of the States of Illinois, Michigan, and Minnesota, Michigan v. U.S. Dep't of Energy, No. 25-1159 at 22 (Consolidated with 25-1160 and 25-1162) (D.C. Cir. Dec. 19, 2025).

[166] Teresa Homsi & Alexander Rabin, Opinion, *Keeping Coal Plant Online Isn't Just Costly, It Risks Michiganders' Health*, BRIDGE MI. (Nov. 14, 2025), https://bridgemi.com/guest-commentary/opinion-keeping-coal-plant-online-isnt-just-costly-it-risks-michiganders-health/; Ariel Wittenberg, *Pollution from Coal Plants Was Dropping. Then Came Trump and AI.*, E&E NEWS (Nov. 24, 2025), https://www.eenews.net/articles/ai-gives-coal-plants-a-lifeline-as-trump-makes-them-dirtier/.

[167] *2025 DOE 202(c) Orders*, *supra* note 14; Appendix.

[168] Ethan Howland, *DOE Orders 730-MW TransAlta Coal Plant in Washington to Keep Running*, UTIL. DIVE (Dec. 17, 2025), https://www.utilitydive.com/news/doe-transalta-centralia-emergency-order/808123/.

[169] Ethan Howland, *DOE Orders 446-MW Colorado Coal Unit to Keep Running*, UTIL. DIVE (Jan. 6, 2026), https://www.utilitydive.com/news/doe-colorado-coal-craig-tristate/808849/; Brown & Plumer, *supra* note 14.

maintenance and upgrades.[170] Owners of the coal plants, states, and environmental groups have responded with legal challenges.[171] Nevertheless, utilities in other states have reported that they expect to receive similar emergency orders.[172] Indeed, DOE Secretary Chris Wright declared, at a White House event in January 2026, that he planned to use DOE's Section 202(c) authority to prevent as many coal plant retirements as possible over the next three years.[173]

As with the Campbell plant order, none of the subsequent DOE orders were issued in response to a request by the utilities, grid operators, or states. None of the orders resolve the issue of who beyond the utilities' own ratepayers will bear the costs of maintaining these plants or the costs of the replacement electricity resources utilities had already procured in anticipation of the plants' imminent closures.[174]

Again, all of this was a marked break from the past. The bar graphs below show the Trump administration's significant departure in the use of Section 202(c) orders from Section 202(c)'s historical use. The key point of the charts is simple: orders preventing specific plants from retiring were frequent in 2025 and 2026 but have no historical precedent.

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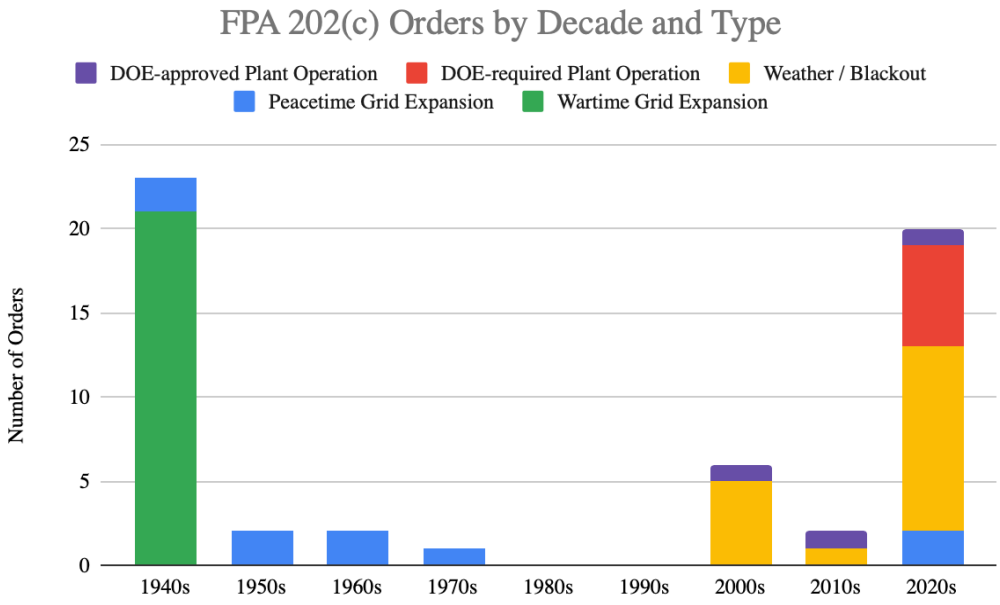
[170] Benjamin Storrow & Hannah Northey, *DOE Orders 2 Indiana Coal Plants to Continue Operating*, GREENWIRE (Dec. 24, 2025), https://www.eenews.net/articles/doe-orders-2-indiana-coal-plants-to-continue-operating/; Tomich, *supra* note 13.

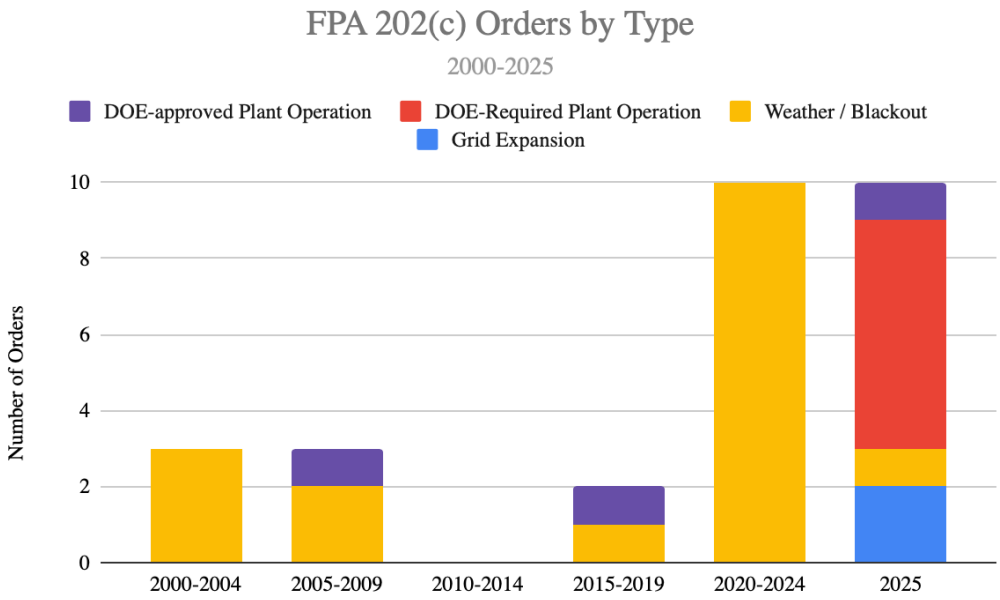
[171] *See*, *e.g.*, Ethan Howland, *Coal Plant DOE Ordered to Stay Online Unlikely to Run Given "Flush" Power Supplies: CEO*, UTIL. DIVE (Mar. 4, 2026), https://www.utilitydive.com/news/washington-earthjustice-sue-doe-centralia-emergency-order-transalta/813754/ (describing litigation over Washington coal plant); *Sam Brasch, The Owners Want to Close This Colorado Coal Plant. The Trump Administration Says No*, NPR (Feb. 23, 2026), https://www.npr.org/2026/02/23/g-s1-110980/trump-coal-energy-colorado (describing litigation over Colorado plant).

[172] Benjamin Storrow, *DOE Orders Washington Coal Plant to Stay Open*, CLIMATEWIRE (Dec. 17, 2025), https://www.eenews.net/articles/doe-orders-washington-state-coal-plant-to-stay-open/.

[173] Brown & Plumer, *supra* note 14.

[174] Howland, *DOE Orders 730-MW TransAlta Coal Plant in Washington to Keep Running*, *supra* note 168; Howland, *DOE Orders 446-MW Colorado Coal Unit to Keep Running*, *supra* note 169.





IV. THE PRESIDENT AND THE POWER GRID

The prior Part described the sharp discontinuity between the second Trump administration's electric grid policies and those of previous administrations. This Part explains two reasons why this discontinuity matters. The first reason relates to important doctrinal questions regarding statutory interpretation and presidential use of emergency authority. The second reason is practical. The grid governance approaches from which the second Trump administration has departed, while far from perfect, gave the United States electricity systems that were strong, evolving,

and improving.[175] Abandoning the lessons of that experience does not bode well for the future of the grid.

A. Presidential Power and Statutory Interpretation

The DOE Section 202(c) orders raise significant questions of statutory interpretation. For instance, since 2022, the Supreme Court has used the major questions doctrine to rein in executive branch agency actions where the perceived absence of a clear statement from Congress raises questions about the "history and breadth of the authority" the agency asserts or where the action is of major "economic and political significance."[176] In 2026, the Court confirmed that statutes delegating emergency authority to the executive branch are not immune from scrutiny under the major questions doctrine.[177] Relatedly, the Court has indicated there are red flags when agencies move outside what the Justices perceive to be those agencies' traditional roles. As Justice Barrett has put it, "[a]nother telltale sign that an agency may have transgressed its statutory authority is when it regulates outside its wheelhouse."[178]

The DOE Section 202(c) orders raise each of these concerns. It would be an understatement to say that Section 202(c) does not provide clear authority to order the indefinite operation of power plants in circumstances where the electric grid is operating normally and no responsible party has requested DOE intervention.[179] While each individual order might not have major economic or political significance, at least outside the specific grid area the affected power plant serves, the collective goal is clearly the kind of reworking of electricity-generation systems that the Court already has treated as raising major questions.[180] And most strikingly, the orders move DOE outside its traditional role; for decades, project-specific decisions about modes of electricity generation have been left to state governments and private ordering within a grid governance framework overseen by FERC.[181] Indeed, outside the narrow and temporally limited context of wartime and short-term, unexpected emergencies, the federal government has not been in the business of directly ordering particular power plants under private ownership to open or

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[175] *See supra* Part II (describing FERC actions).

[176] *See* West Virginia v. EPA, 597 U.S. 697, 723–24 (2022).

[177] *See* Learning Resources v. Trump, 607 U.S. __, 2026 WL 477534 at *9 (U.S. Feb. 20, 2026).

[178] Nebraska v. Biden, 600 U.S. 477, 518 (2023) (Barrett, J., concurring).

[179] *See* 16 U.S.C. § 824a(c) (allowing orders only in response to an "emergency").

[180] *See West Virginia*, 597 U.S. at 728-29 (arguing that choices about the amount of coal-fired power on electricity grids are major questions). In fact, the impact of the Trump administration's Section 202(c) orders might be much greater than that of the Clean Power Plan, for the Clean Power Plan aligned with market trends, while the 202(c) orders attempt to fight those trends. *See id.* at 755 (Kagan, J. dissenting) ("[T]he Clean Power Plan never went into effect. The ensuing years, though, proved the Plan's moderation. Market forces alone caused the power industry to meet the Plan's nationwide emissions target—through exactly the kinds of generation shifting the Plan contemplated.").

[181] *See supra* Part II (describing state authority over power plants).

close.[182] In raising these concerns, we do not endorse the major questions doctrine, which has been subject to extensive and persuasive scholarly criticism.[183] But if the courts wish to apply it in an ideological neutral way, then a Section 202(c) case would be an excellent opportunity.

B. Practical Consequences

Beyond the doctrinal implications, there are practical consequences associated with the DOE's Section 202(c) orders for electric utilities and their customers, and more generally for electric grid governance. As described throughout this Essay, through both research and regulation, the federal government until now has consistently supported the development and deployment of new technologies, helping to build an electricity system that is more diverse than even the most optimistic World War II-era planners would likely have dreamed of. While no one would call it perfect, FERC has created a system of regulated markets overseen by a technically savvy and politically stable bureaucracy.[184] That system has helped produce a variety of good results,[185] and it did so with only light involvement from a series of presidents.

The Trump administration's interventions reflect a very different way of thinking about the role of government in managing the grid. In that alternative way of thinking, use of emergency authorities allows the administration to promote favored energy resources, like fossil fuels, regardless of costs and markets. Conventional and basic-level economic and political theories—including works that once were canonical on the political right—can easily predict the consequences: If business opportunities are allocated by centralized and political authorities who have a limited understanding of, or interest in, the economics of electricity, then consumer costs will rise and quality will drop.[188]

Already, that is exactly what is happening. The Trump administration is embracing the technologies of the past, like decades-old coal plants with poor

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[182] *See supra* Part II (describing history and roles of federal agencies in grid governance).

[183] *See, e.g.*, Jody Freeman & Matthew C. Stephenson, *The Anti-Democratic Major Questions Doctrine*, 2022 SUP. CT. REV. 1, 4 (2022) (describing the major questions doctrine as a "novel clear statement rule that not only ignores but inverts longstanding administrative law principles."); Mila Sohoni, *The Major Questions Quartet*, 136 HARV. L. REV. 262, 266 (2022) ("[T]he new major questions doctrine allows the Court ample leeway to *preserve* major rules when the muse so moves it—even when those rules rest on statutory authority as contestable to the naked eye as the authority that underwrites rules that fail to pass muster.").

[184] Michael Panfil & Rama Zakaria, *Uncovering Wholesale Electricity Market Principles*, 9 MICH. J. ENV'T & ADMIN. L. 145, 149 (2019) ("Although the Commission's makeup itself may change from year to year, the rationale and logic undergirding its work has been remarkably durable and consistent since the introduction of competitive wholesale markets.").

[185] *See supra* notes 128-130 and accompanying text.

[188] *See generally, e.g.*, FRIEDRICH A. HAYEK, THE ROAD TO SERFDOM (1944) (arguing that centralized planning leads to both despotism and poor economic outcomes); MILTON FRIEDMAN, CAPITALISM AND FREEDOM (1962) (advancing similar critiques of centralized economic power).

reliability records, high maintenance costs, and adverse environmental impacts.[189] Many of the plants in question are not even able to operate, undermining the DOE's claim that they are in any position to address "emergency" conditions under the statute.[190] The increased costs associated with the administration's Section 202(c) orders are staggering.[191] One estimate puts the costs to consumers of keeping aging coal plants online at over $3 billion a year.[192]

There is another cost associated with the Section 202(c) orders beyond the immediate excess consumer costs. The DOE orders will inevitably discourage states and power companies from engaging in the type of rational long-term planning that FERC and state public utility commissioners have encouraged and, in some cases, required. Using the J.H. Campbell plant as an example, the electric utility, regional grid operator, and state and federal regulators identified an uneconomic resource that needed to be retired, planned years in advance to replace it with cheaper and cleaner resources, charged ratepayers for carrying out that plan, and then the DOE Secretary upended those plans just days ahead of the plant's retirement.[193] If such actions become expected, no electric utility or state regulator can be confident that resource plans and the commitments they have made to ratepayers will be carried out. The result is deeply destabilizing to the kind of sensible economic decision-making and resource planning that the private sector and state and federal regulators need to be able to engage in.

Moreover, the administration's use of Section 202(c) orders to commandeer long-term grid-planning is uniquely free from the substantive and procedural constraints that usually accompany federal administrative actions, both in the electricity sector and more generally. The orders are issued by the DOE Secretary without notice and comment;[194] the statute does not require consideration of costs

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[189] *See* RICHARD L. REVESZ & JACK LIENKE, STRUGGLING FOR AIR: POWER PLANTS AND THE "WAR ON COAL" 10–12 (2016) (summarizing the environmental costs of coal); *see also* Tomich, *supra* 13 (discussing unreliability of plants subject to the 202(c) orders).

[190] *See* Tomich, *supra* note 13 (discussing operational failure of coal unit in Indiana and quoting utility's president as saying that required maintenance and upgrades "will require substantial investment to support an inefficient and increasingly unreliable asset."); Benjamin Storrow, *3 Coal Turbines Ordered to Stay Open by DOE Have Not Run*, CLIMATEWIRE (Apr. 10, 2026), https://subscriber.politicopro.com/article/eenews/2026/04/10/3-coal-plants-ordered-to-stay-open-by-doe-have-not-run-00866256 (discussing reasons why multiple plants subject to 202(c) orders have not run or have run well below their historic averages either due to maintenance problems or because grid operators did not need them).

[191] *See* Greg Alvarez, *DOE Forces Busted Coal Plant to Stay Online for "Energy Emergency" but Halts 2.5 Million Homes' Worth of New Power*, THE POWER LINE (Jan. 11, 2026), https://thepowerline.substack.com/p/doe-forces-busted-coal-plant-to-stay.

[192] Michael Goggin, *The Cost of Federal Mandates to Retain Fossil-Burning Power Plants*, GRID STRATEGIES (Aug. 2025), https://earthjustice.org/wp-content/uploads/2025/08/grid-strategies_cost-of-federal-mandates-to-retain-fossil-burning-power-plants.pdf; *see also* Brown & Plumer, *supra* note 13 (identifying costs of at least $3 billion per year).

[193] *See supra* notes 2-5, 157-163 and accompanying text (discussing circumstances of DOE's order).

[194] *See* 16 U.S.C. § 824a(c) (allowing orders "with or without notice, hearing, or report").

or other factors that usually are part of utility regulatory decisions;[195] and DOE has taken the position that as "emergency" decisions these actions should be given enormous deference.[196] As such, these actions are uniquely prone to arbitrary, impulsive, politically-driven decisionmaking—a mode of administrative action that is particularly unsuited to expertise-laden technical and policy questions like how best to meet resource adequacy needs over a long-term time horizon.[197] Consumers and the environment both will pay the price.

CONCLUSION

In years to come, grid managers will occasionally face genuine emergencies. Circumstances will arise, suddenly and without warning, that could not have been planned for, and those crises could require quick and short-term federal interventions in management of the grid. When those circumstances arise, the nation may appreciate the wisdom of including Section 202(c) in the Federal Power Act. But that sort of crisis intervention is not what has happened in 2025 and 2026. Instead, DOE has used Section 202(c) in ways that have no historical analog, neither during the crisis years of World War II nor in the decades since, and that are creating problems rather than resolving them. The immediate burdens on consumers will be substantial, and the long-term consequences for grid management may well be worse. Future administrations and present-day courts would do well to return Section 202(c) to its traditional place and, more broadly, to restore systems of grid governance that have served the nation relatively well.

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[195] *See id.*

[196] *See* Respondents' Initial Answering Brief, Michigan v. U.S. Dep't of Energy, No. 25-1159 at 17-18, 47-48, 52, 61 (Consolidated with 25-1160 and 25-1162) (referring multiple times to the "broad discretion" Section 202(c) grants to DOE to determine what constitutes an emergency and the deference the court owes to DOE in exercising its judgment).

[197] *See*, *e.g.*, Ethan Howland, *Coal Plant Owners Say DOE "emergency" Order to Run it Violates Constitution*, UTIL. DIVE (Feb. 2, 2026) (quoting the CEO of Colorado utility that owns the coal plant as stating that the order violates the Federal Power Act and constitutes an unconstitutional taking of private property because it "requires the operation of an uneconomic resource and disrupts ordinary and orderly planning, development, and investment in generation resources.").

Appendix
Federal Power Act § 202(c) Orders (1941-2025) [198]

Order	Date	Subject Matter	Direction	Duration
Order No. 202-25-14	December 2025 (renewed Mar. 2026)	446.4 MW coal plant in Colorado ordered to remain operational despite planned retirement date in Dec. 2025	DOE directed Tri-State Generation and Transmission Association and its co-owners to continue to operate the Craig Station in Colorado.	Continuous since December 30, 2025
Order No. 202-25-13	December 2025 (renewed Mar. 2026)	103.7 MW coal-fired generating unit in Indiana ordered to remain operational despite planned retirement in Dec. 2025	DOE directed CenterPoint Energy and the Midcontinent Independent System Operator, Inc. (MISO) to continue to operate the F.B. Culley Generating Station in Indiana.	Continuous since December 23, 2025
Order No. 202-25-12	December 2025 (renewed Mar. 2026)	Two 423.5 MW coal-fired generation units in Indiana ordered to remain operational despite planned retirement in Dec. 2025	DOE directed Northern Indiana Public Service Company and MISO to continue to operate the R.M. Schahfer Generating Station in Indiana.	Continuous since December 23, 2025
Order No. 202-25-11	December 2025 (renewed Mar. 2026)	729.9 coal-fired generation unit in Washington State ordered to remain operational despite planned retirement in Dec. 2025	DOE directed TransAlta to continue to operate the Centralia Generating Station in Washington.	Continuous since December 16, 2025
Order No. 202-25-6	July 2025 (extended Oct. 2025)	397 MW oil-burning generator unit in Maryland allowed to exceed its yearly operational hour allotment	In response to a request from regional transmission organization PJM, DOE permitted PJM and Talen Energy Corporation to dispatch an oil-burning generator unit beyond its yearly allotment of permitted operational hours when necessary to meet PJM's anticipated demand.	156 days
Order No. 202-25-5	June 2025	Additional generation permitted beyond authorized emissions limits	In response to a request from investor-owned utility Duke Energy Carolinas, DOE authorized utility to use its generating units as needed to meet demand regardless of emission or permit limitations due to expected weather-related energy shortfalls.	42 hours

[198] The information used to create this table is from the following sources: *DOE's Use of Federal Power Act Emergency Authority*, DEP'T OF ENERGY, https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority (last visited Feb. 2, 2025); Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. 789, 839-46 (2025); ASHLEY J. LAWSON, CONG. RSCH. SERV., THE FEDERAL POWER ACT: THE DEPARTMENT OF ENERGY'S EMERGENCY AUTHORITY (Jan. 20, 2026), https://www.congress.gov/crs-product/R48568. The table includes DOE's renewal of orders issued in 2025 through April 1, 2026.

Order	Date	Subject Matter	Direction	Duration
Order No. 202-25-4	May 2025 (renewed Aug. 2025, Nov. 2025, Feb. 2026)	Two 380 MW dual fuel oil-gas generating units in Pennsylvania, ordered to remain operational	DOE directed Constellation Energy and PJM Interconnection to continue to operate two natural gas and oil generating units set to retire on the Eddystone Generating Station in Pennsylvania despite their planned retirement in May 2025.	Continuous since May 30, 2025
Order No. 202-25-3	May 2025 (renewed Aug. 2025, Nov. 2025, Feb. 2026)	1560 MW coal plant in Michigan ordered to remain operational	DOE directed Midcontinent Independent System Operator, Inc. (MISO) and Consumers Energy to continue to operate the coal-fired Campbell Power Plant in Michigan despite its planned retirement in May 2025.	Continuous since May 23, 2025
Order No. 202-25-2	May 2025 (renewed Aug. 2025, Nov. 2025, Feb. 2026)	Vegetation management ordered	DOE directed the Puerto Rico Electric Power Authority to conduct vegetation management to ensure the operate of the generation facilities as demanded by Order No. 202-25-1, below.	Continuous since May 16, 2025
Order No. 202-25-1	May 2025 (renewed Aug. 2025, Nov. 2025, Feb. 2026)	Expanded generation ordered due to chronically weak power grid further damaged by natural disasters in Puerto Rico	DOE directed the Puerto Rico Electric Power Authority to dispatch generation units to expand baseload generation.	Continuous since May 16, 2025
Order No. 202-24-1	October 2024	Additional generation permitted beyond authorized emissions limits	In response to a request from Duke Energy Florida, DOE permitted Duke Energy Florida to dispatch additional generation despite emission and permit limits to meet load requirements due to expected shortfalls caused by Hurricane Milton.	3 days
Order No. 202-23-1	September 2023	Additional generation permitted beyond authorized emissions limits	In response to a request from the Electric Reliability Council of Texas (ERCOT), DOE permitted ERCOT to dispatch additional generation despite emission and permit limits due to weather-related shortfalls caused by an extreme heat wave.	26.5 hours
Order No. 202-22-4	December 2022	Additional generation permitted beyond authorized emissions limits	In response to a request from PJM Interconnection, DOE permitted PJM to operate certain generating units at maximum capacity despite emission and permit limits due to expected shortfalls caused by extreme winter weather.	30.5 hours
Order No. 202-22-3	December 2022	Additional generation permitted beyond authorized emissions limits	In response to a request from the Electric Reliability Council of Texas (ERCOT), DOE permitted ERCOT to operate certain generating units at maximum capacity despite emission and permit limits due to expected shortfalls caused by extreme winter weather.	36.5 hours

Order	Date	Subject Matter	Direction	Duration
Order No. 202-22-2	September 2022	Additional generation permitted beyond authorized emission limits	In response to a request from the Balancing Authority of Northern California (BANC), DOE permitted BANC to dispatch additional generation despite emission and permit limits due to expected shortfalls caused by extreme heat.	7 days
Order No. 202-22-1	September 2022	Additional generation permitted beyond authorized emissions limits	In response to a request from the California Independent System Operator Corporation (CAISO), DOE permitted CAISO to operate certain generating units at maximum capacity despite emission and permit limits due to expected shortfalls caused by extreme heat.	7 days
Order No. 202-21-2	September 2021	Additional generation permitted beyond authorized emissions limits	In response to a request from the California Independent System Operator Corporation (CAISO), DOE permitted CAISO to operate certain generating units at maximum capacity despite emission and permit limits due to expected shortfalls caused by extreme heat.	60 days
Order No. 202-21-1	February 2021	Additional generation permitted beyond authorized emissions limits	In response to a request from the Electric Reliability Council of Texas (ERCOT), DOE permitted ERCOT to operate certain generating units at maximum capacity despite emission and permit limits due to expected shortfalls caused by extreme winter weather.	5 days
Order No. 202-20-2	September 2020	Additional generation permitted beyond authorized emissions limits	In response to a request from the California Independent System Operator Corporation (CAISO), DOE permitted CAISO to operate certain generating units at maximum capacity despite emission and permit limits due to expected shortfalls caused by extreme heat.	8 days
Order No. 202-20-1	August 2020	Temporary interconnection permitted in response to weather-related shortages in Texas	In response to a request from CenterPoint Energy Houston Electric (CEHE), DOE permitted CEHE to utilize a temporary connection to another Texas utility system to restore electric service after Hurricane Laura caused grid outages.	46 days
Order No. 202-17-2	June 2017 (multiple renewals through Dec. 2018)	Use of noncompliant coal-fired generating units in Virginia permitted	In response to a request from PJM Interconnection, DOE permitted continued use of two coal-fired generation units that were noncompliant with the Mercury and Air Toxics Standards initially due to expected shortfalls caused by extreme heat. The order was renewed through December 2018 upon PJM's request to allow for continued use during the construction of a new transmission line that would augment the region's power grid.	630 days

Order	Date	Subject Matter	Direction	Duration
Order No. 202-17-1	April 2017	Use of noncompliant coal generating unit in Oklahoma permitted	In response to a request from Grand River Dam Authority (GRDA) in Oklahoma, DOE permitted GRDA to utilize a coal generating unit that was noncompliant with the Mercury and Air Toxics Standards to meet demand after two other units became inoperative after a local fire and flooding.	90 days
Order No. 202-08-1	September 2008	Temporary interconnection in Texas permitted	DOE authorized CenterPoint Energy to temporarily connect to other Texas utility systems to restore electric service after Hurricane Ike caused grid outages.	48 days
Order No. 202-05-1	September 2005	Temporary interconnection in Texas permitted	DOE authorized CenterPoint Energy to temporality connect to other Texas utility lines to restore power lost as a result of Hurricane Rita.	34 days
Order No. 202-05-3	August 2005 (renewals through Jan. 2007)	Generating station in the DC area ordered to remain operational	In response to a request from the District of Columbia Public Service Commission, DOE required Mirant Corporation to continue operating its Potomac River generating station despite plans to cease operations. DOE found that ceasing operations of the station would likely cause outages.	558 days
Order No. 202-03-1	August 2003	Transmission ordered between New York and Connecticut	DOE ordered the New York Independent System Operator and ISO New England to require Cross-Sound Cable Company to operate between Connecticut and New York to ease shortages causing regional blackouts.	18 days
Order No. 202-02-1	August 2002	Transmission ordered between New York and Connecticut	DOE ordered the New York Independent System Operator and ISO New England to require Cross-Sound Cable Company to operate between Connecticut and New York to ease shortages causing regional blackouts.	47 days
Order No. 202-00-1	December 2000	Services ordered in California to fulfill unexpected shortfalls	DOE ordered certain entities to generate, deliver, and transmit energy when requested by the California Independent System Operator in response to unexpected shortfalls caused by the combined effect of inoperative facilities, water shortages, and market volatility.	7 days
47 F.P.C. 747	March 1972	Interconnection ordered in Ohio	Federal Power Commission ordered interconnection between Cleveland Electric Illuminating Co. and the City of Cleveland's Division of Water and Power due to potential shortages in isolated regions without external connections.	No termination specified
38 F.P.C. 269	August 1967	Interconnection ordered in Kentucky	Federal Power Commission ordered interconnection between Kentucky Utilities Co. and additional electrical systems due to potential shortages in isolated regions without external connections.	No termination specified

Order	Date	Subject Matter	Direction	Duration
35 F.P.C. 629	April 1966	Interconnection ordered in Georgia	Federal Power Commission ordered interconnection between Georgia Power Co. and Crisp County after several outages in the County revealed system inadequacies.	5 years and 9 months
16 F.P.C. 823	August 1956 (extended Sept. 1956)	Interconnection ordered between Wisconsin and Illinois to account for limited reserve generation capacity	Federal Power Commission ordered an increase in the interconnection capacity between Commonwealth Edison Co. and Wisconsin Electric Power Co. without affecting either company's jurisdictional status with the Commission.	4 months
10 F.P.C. 1506 (1951)	November 1951 (extended Aug. 1956)	Interconnection permitted between Wisconsin and Illinois	Federal Power Commission permitted interconnection between Wisconsin Electric Power Co. and Public Service Co. of Northern Illinois without subjecting either company to Commission jurisdiction with interconnection to be utilized during likely shortfalls given the high concentration of defense industries located in the region.	4 years and 9 months
7 F.P.C. 574	April 1948 (extended Feb. 1949, Dec. 1950)	Interconnection permitted in Texas	Federal Power Commission permitted interconnection in Texas without affecting companies' jurisdictional standing with the Commission in response to unexpected construction delays, equipment failures, load forecasts, and reduced hydroelectric output.	4 years and 8 months
6 F.P.C. 320	January 1947	Interconnection permitted in the Pacific Northwest	Federal Power Commission permitted interconnections to support the Pacific Northwest region in response to increased regional demand after returning to peacetime activity after WWII.	8 years
3 F.P.C. 934	February 1943	Increased generation and transmission permitted to support war efforts	Federal Power Commission permitted increased generation and transmission between Dairyland Power Cooperative and Northern States Power Co. to support regions experiencing increased demand caused by the production of farm products needed during wartime.	Wartime order
3 F.P.C. 920	February 1943	Transmission and delivery ordered in the Pacific Northwest to support war efforts	Federal Power Commission ordered the Washington Water Power Co. to deliver and transmit energy to Bonneville Power Administration to supply War Department facilities.	Wartime order
3 F.P.C. 869	November 1942	Interconnection ordered to support war efforts	Federal Power Commission ordered the interconnection of electric facilities in Connecticut in response to increased demand, limitations on supply and transportation, and restrictions on construction and maintenance because of the war effort.	Wartime order
3 F.P.C. 715	May 1942	Interconnection ordered in Florida to support the war effort	Federal Power Commission ordered the interconnection of Florida electric facilities to support increased demand associated with the war effort.	Wartime order

Order	Date	Subject Matter	Direction	Duration
3 F.P.C. 714	May 1942	Interconnection ordered in Florida to support the war effort	Federal Power Commission ordered the Florida Power & Light Co. and the City of Gainesville, Florida to construct transmission facilities and establish interconnections to support increased demand associated with the war effort.	Wartime order
3 F.P.C. 712	May 1942	Interconnection ordered in Florida to support the war effort	Federal Power Commission ordered the Florida Power & Light Co. and the City of Jacksonville, Florida to construct transmission facilities and establish interconnections in response to an increased demand related to war efforts.	Wartime order
2 F.P.C. 1095	December 1941	Interconnection and delivery ordered between Virginia and Maryland to meet increase in demand associated with war-related infrastructure	Federal Power Commission ordered interconnection between Virginia and Maryland to meet a sudden increase in demand resulting, in part, from the construction of a new War Department office building.	Wartime order
2 F.P.C. 1060	November 1941	Transmission and delivery ordered in the Southeast to support the war effort	Federal Power Commission ordered electric companies to transmit and deliver energy up to 10,000 kilowatts for use by the Pittsburgh Metallurgical Co., which was producing products of war.	Wartime order
2 F.P.C. 1055	October 1941	Delivery ordered in the Southeast to support the war effort	Federal Power Commission ordered delivery of electric energy to meet increased demand and correct generation shortages associated with wartime manufacturing, particularly aluminum production.	Wartime order
2 F.P.C. 461	Sept. 16, 1941 (extended Sept. 1942)	Additional water usage permitted on the Niagara River to increase electric generation in support of the war effort	Federal Power Commission permitted the Niagara Falls Power Co. to amend its license to increase the amount of water the company could divert from the Niagara River to increase generation in response to increased demand related to wartime production.	Wartime order
2 F.P.C. 1021	August 1941	Interconnection ordered in the Southeast to meet increased demand and insufficient generation	Federal Power Commission ordered additional interconnection to meet increased demand and insufficient generation.	Wartime order
2 F.P.C. 998	June 1941	Generation and delivery from Carolina Aluminum Company ordered to meet increased demand	Federal Power Commission ordered the Carolina Aluminum Co. to generate and deliver continuous electric supply from its hydroelectric plants to ensure maximum generation of aluminum products to support the war effort.	Wartime order
2 F.P.C. 997	June 1941	Curtailment of nonessential electric supply recommended	Federal Power Commission recommended that all public and private citizens in the southeastern region of the United States curtail the use of electric energy in light of increased demand associated with wartime production and reduced hydroelectric supply.	Wartime recommendation

Order	Date	Subject Matter	Direction	Duration
2 F.P.C. 996	June 1941	Interconnection ordered between Florida and Alabama	Federal Power Commission ordered interconnection between Florida and Alabama to meet increased demand and insufficient generation associated with wartime production.	Wartime order
2 F.P.C. 995	June 1941	Interconnection ordered between Florida and Georgia	Federal Power Commission ordered interconnection between Florida and Georgia to meet increased demand and insufficient generation associated with wartime production.	Wartime order
2 F.P.C. 994	June 1941	Interconnection ordered in Florida	Federal Power Commission ordered the interconnection of two Florida electric utilities to meet increased demand and insufficient generation associated with wartime production.	Wartime order
2 F.P.C. 993	June 1941	Interconnection ordered in Georgia	Federal Power Commission ordered the interconnection of two Georgia electric utilities to meet increased demand and insufficient generation associated with wartime production.	Wartime order
2 F.P.C. 992	June 1941	Interconnection ordered between Georgia and Louisiana	Federal Power Commission ordered the interconnection between Georgia and Louisiana to meet increased demand and insufficient generation associated with wartime production.	Wartime order
2 F.P.C. 992	June 1941	Interconnection ordered in North Carolina	Federal Power Commission ordered the interconnection of two North Carolina electric utilities to meet increased demand and insufficient generation in the southeastern region of the United States associated with wartime production.	Wartime order
2 F.P.C. 991	June 1941	Interconnection ordered in Florida	Federal Power Commission ordered the interconnection of two Florida electric utilities to meet increased demand associated with wartime production.	Wartime order
2 F.P.C. 990	June 1941	Emergency declared in the southeastern region of the United States due to in sufficient generation	Federal Power Commission declared a state of emergency in the southeastern region of the United States given the increased demand for electric supply associated with wartime production and drought limiting hydroelectric generation. This declaration was the basis for all June 1941 FPC 202(c) orders listed above.	Wartime recommend-dation

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Long-Term Reliability Assessment

January 2026



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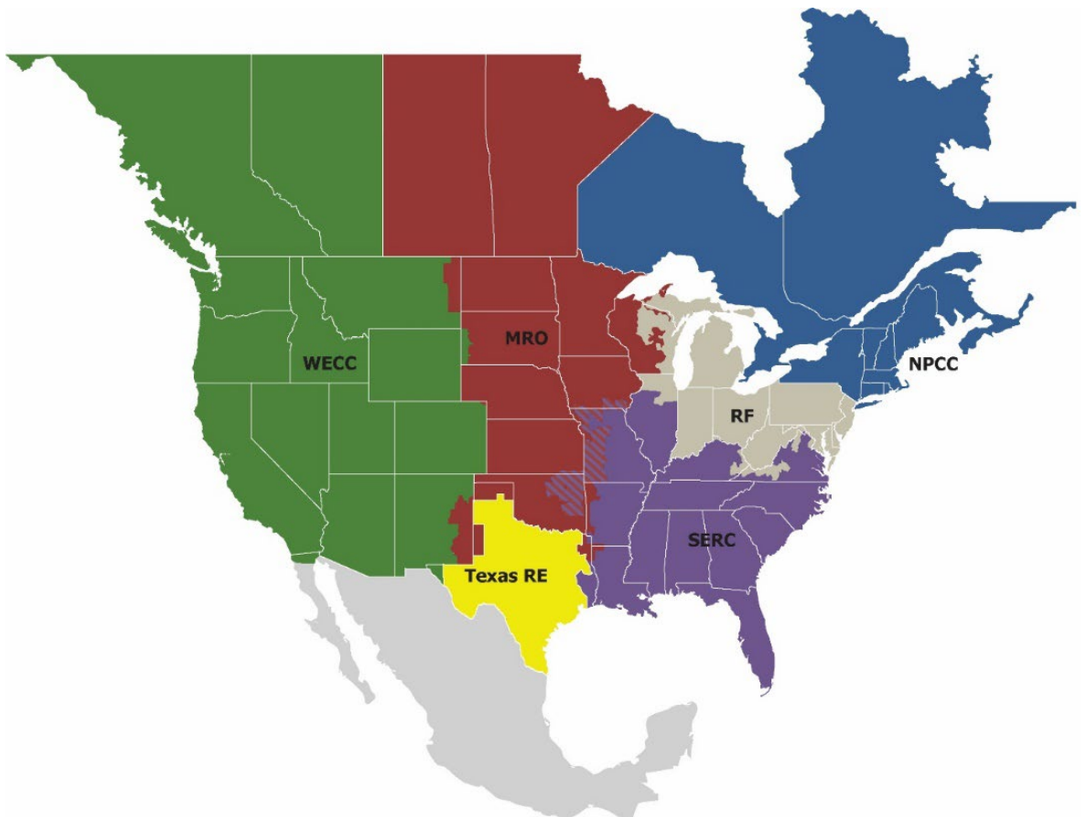
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About This Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

The *Long-Term Reliability Assessment* (LTRA), along with NERC's other reliability assessments and analysis reports, supports the ERO Enterprise vision and mission by providing independent analysis of reliability risks. Other important assessments and reports include the following:

- **Seasonal Reliability Assessments:** The *Summer Reliability Assessment* (SRA) and *Winter Reliability Assessment* (WRA) provide overall perspective on the adequacy of the generation resources and the transmission systems necessary to meet projected seasonal peak demands. They also identify reliability issues of interest and areas of concern for the upcoming season. Seasonal assessments are published annually prior to each respective season.
- **Special Reliability Assessments:** In addition to the long-term and seasonal reliability assessments, NERC also conducts special reliability assessments on a regional, interregional, and Interconnection basis as conditions warrant, or as requested by the NERC Board of Trustees or governmental authorities. Special reliability assessments are performed and published on an as-needed basis.
- ***State of Reliability* Report (SOR):** The SOR contains an unbiased, data-driven look at BPS reliability for the calendar year, identifying ongoing challenges and informing future-looking reliability assessments. It seeks to inform regulators, policymakers, and industry leaders of the most significant reliability risks facing the BPS and describe the actions that the ERO Enterprise has taken, and will take, to address them. The SOR is published annually, containing analysis of BPS performance data from the prior year.
- **Event Analysis Reports:** NERC publishes reports of major system events and off-normal system occurrences as one output of the ERO Event Analysis Program. This program employs rigorous post-event analysis and promotes broad understanding of the causes and effects of reliability events. NERC also publishes Lessons Learned for industry.

Reliability assessments and analysis are published on NERC's website.

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see **Preface**) on an assessment area basis (see **Regional Assessments Dashboards**) to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee (RAS), at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer-review process that leverages the knowledge and experience of system planners, RAS members, NERC staff, and other subject matter experts; this peer-review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees subsequently accepted this assessment and endorsed the key findings.

NERC develops the LTRA annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations;[3] this is also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

[1] NERC Rules of Procedure - Section 803

[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

[3] Title 18, § 39.11 of the Code of Federal Regulations

[4] BPS reliability, as defined in the **How NERC Defines BPS Reliability** section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.

Considerations

This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2025 about known system changes with updates incorporated prior to publication. This *2025 LTRA* assessment period includes projections for 2026–2035; however, some figures and tables examine data and information for the 2025 year. NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in the **Demand Assumptions and Resource Categories** section. Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment, which is primarily focused on resource adequacy and operating reliability. NERC leads a multifaceted approach through its Electricity Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electric industry and government partners.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC's reliability assessments are developed to inform industry, policymakers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

Assumptions

In this *2025 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts that were submitted and validated in July 2025. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame has been included where appropriate.
- Peak demand is based on average peak weather conditions and forecasted economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, known planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading This Report

This report is compiled into two major parts:

1. **A reliability assessment of the North American BPS with the following goals:**
   a. Evaluate industry preparations that are in place to meet projections and maintain reliability, with a special focus on adequacy in the first five years
   b. Identify trends in demand, supply, reserve margins, and probabilistic resource adequacy metrics
   c. Identify emerging reliability issues
   d. Focus the industry, policymakers, and the general public's attention on BPS reliability issues
   e. Make recommendations based on an independent NERC reliability assessment process
2. **A regional reliability assessment that contains the following:**
   a. A 10-year data dashboard
   b. Summary assessments for each assessment area
   c. A focus on specific issues identified through industry data and emerging issues
   d. A description of regional planning processes and methods used to ensure reliability

[5] ERO Reliability Assessment Process Document

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Executive Summary

The overall resource adequacy outlook for the North American BPS is worsening: In the *2025 LTRA*, NERC finds that 13 of 23 assessment areas face resource adequacy challenges over the next 10 years. Projections for resource and transmission growth lag what is needed to support new data centers and other large loads that drive escalating demand forecasts. Most new resources in development to come on-line in the next five years consist of battery storage and solar photovoltaic (PV), which are inverter-based and weather-dependent resources that increase the complexity of planning and operating a reliable grid. Meanwhile, more fossil-fired generator retirements loom in the next five years, reducing the amount of generation that has fuel on site and impacting the system's ability to respond to spikes in demand. The continuing shift in the resource mix toward weather-dependent resources and less fuel diversity increases risks of supply shortfalls during winter months. As Resource Planners, market operators, and regulators grapple with steep increases in demand and swelling resource queues, they face more uncertainty, adding to the already-complex endeavor of planning for resource adequacy during this period of rapid grid transformation. To ensure there are sufficient resources for supplying electricity in the future and to reliably meet the growing electricity needs for North Americans, industry, regulators, and policymakers need to be vigilant for shifting projections, keep plans for deactivating existing generators flexible, expedite system development, and perform robust adequacy assessments of future scenarios. In addition, careful planning and broad cross-sector coordination will be needed to navigate a period of potentially strained electricity resources.

The findings presented here are vitally important to understanding the reliability risks to the North American BPS as it is currently planned and being influenced by government policies, regulations, consumer preferences, and economic factors. Summaries of the report sections are provided below.

Capacity and Energy Risk Assessment

The **Capacity and Energy Risk Assessment** section of this report identifies potential future electricity supply shortfalls under normal and extreme weather conditions based on current BPS planning forecasts. NERC's evaluation of resource adequacy in the LTRA considers both the capacity of the resources and the capability of resources to convert inputs (e.g., fuel, wind, and solar irradiance) into electrical energy. NERC used a probabilistic assessment and a deterministic reserve margin analysis from the LTRA process to identify the risk of future electricity supply shortfall and determine a risk category for each assessment area based on consistent risk criteria.[7] Risk assessment inputs are tied to industry forecasts of electricity supplies, demand, and transmission development, providing a forward-looking snapshot of resource adequacy.

Areas determined to be **High Risk** exceed the upper risk criteria levels. In high-risk areas, planned resources as of July 2025 would result in energy shortfalls that exceed resource adequacy targets or baseline criteria for unserved energy or loss of load.[8] **Elevated-Risk** areas meet resource adequacy criteria, but planned resources are likely to result in energy shortfalls that are expected to be limited to more extreme weather conditions. More extreme conditions can include temperatures that result in above-normal demand levels, low resource output or availability, fuel supply disruptions, and limitations of normal electricity transfers. **Elevated-Risk** areas are identified in the LTRA when unserved energy and load loss metrics are below the **High-Risk** criteria but are not negligible. **Normal-Risk** areas are expected to have sufficient resources under a broad range of assessed conditions and are below the lowest risk criteria level. The results of the risk assessment are summarized for all elevated- and high-risk assessment areas in **Figure 1** and described in **Table 1**.

[7] In some cases, NERC modified the risk category when system studies performed by a system operator or regulator determine that resource adequacy target(s) will not be met. Details of the risk evaluation for each assessment area are in the **Capacity and Energy Risk Assessment**.

[8] The criteria used for risk determination in the LTRA include resource adequacy targets established by regulatory authorities, traditional 1-day-in-10 years load-loss criteria, and probabilistic loss-of-load-hour and expected unserved energy metrics. See **Risk Categories** in this report for a complete description.

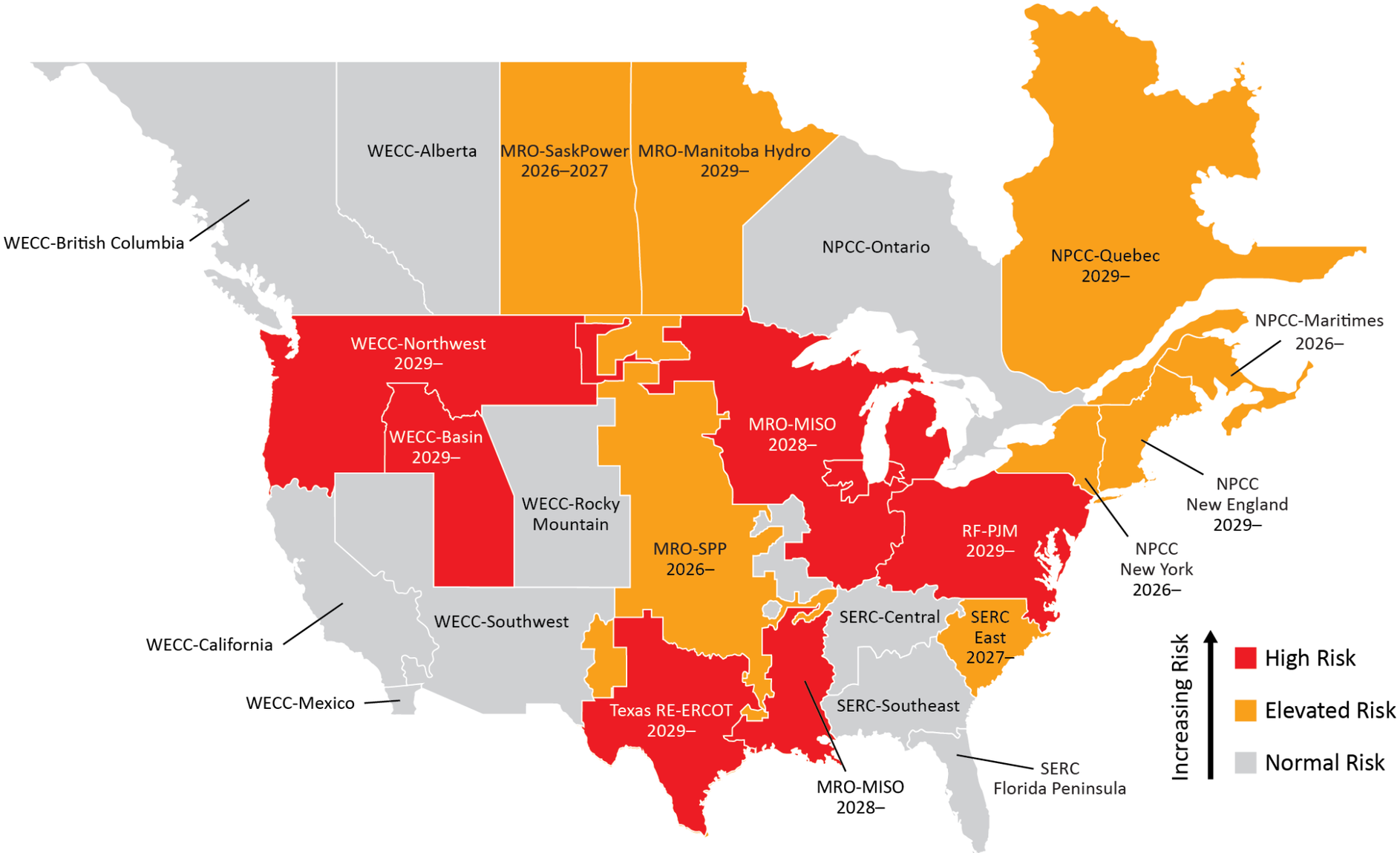


Figure 1: Risk Area Summary 2026–2030

Shows highest risk classification that occurs in the first 5 years and states initial year of occurrence

Table 1: Capacity and Energy Risk Assessment Area Summary

Assessment Area	Risk Level (High, Elevated, or Normal)					Risk Summary
	2026	2027	2028	2029	2030	
MISO						Projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements. The recently approved *Expedited Resource Addition Study* (ERAS) process is expected to result in additional resources in the MISO system beginning in 2028 that are not included in the model for the *2025 LTRA*. Timely implementation of ERAS resources will eliminate reserve margin shortfall and improve expected unserved energy metrics.
MRO-Manitoba						With rising demand, planned reserves are falling, leading to potential resource shortfalls in low-hydro conditions.
MRO-SaskPower						With current resources, there is risk of insufficient generation during fall and spring when more generators are undergoing maintenance. Expected natural-gas-fired generator additions in Winter 2027 will boost planned reserves and reduce risks of unserved energy.
MRO-Southwest Power Pool (SPP)						Demand forecasts outpace resource additions, leading to falling reserve margins. Scenarios with low wind and high generator forced outages identify energy shortfall risks. SPP's *Expedited Resource Adequacy Study* is attracting additional resources.
NPCC-Maritimes						Demand growth forecasts have increased since the *2024 LTRA*, while expected capacity contributions from variable energy resources (VER) have declined, causing resource shortfalls in the near term. New natural-gas-fired generation planned for 2028 will reduce the potential unserved energy, but not below the elevated risk threshold.
NPCC-New England						Strong demand growth and persistent winter natural gas infrastructure limitations pose risks of energy shortfalls in extreme winter conditions.
NPCC-New York						Planned retirements of peaking generators create localized system adequacy needs as described in the New York ISO *2025 Q3 Star Report*.
NPCC-Québec						Demand growth projections are outpacing planned resource additions, leading to projected resource shortfalls in the winter season.
PJM						Current projections for resource additions do not keep pace with escalating demand forecasts and expected generator retirements. The anticipated resource margin falls below the Reference Margin Level starting in 2029. Recently approved new generation projects for expedited interconnection under the PJM Reliability Resource Initiative were not far enough along to include in the LTRA risk analysis.
SERC-East						Current projections for resource additions do not keep pace with escalating demand forecasts and planned generator retirements. With projected resources, supply shortfalls would occur in below-normal winter temperatures, resulting in unserved energy.
Texas RE-ERCOT						Probabilistic unserved energy metrics for 2026–2027 have improved since the *2024 LTRA*, but continued rapid load growth outpaces projected resource additions in later years. To mitigate increasing resource adequacy risks from load growth, Texas lawmakers have granted ERCOT operators additional authority to curtail new large loads if necessary to prevent grid emergencies. Texas lawmakers also established funding programs to expedite new resources that address reliability needs.
WECC-Basin						Demand forecasts outpace resource additions and expected generator retirements, leading to falling reserves. Resource additions nearing completion are predominantly solar PV, leading to a more variable resource mix. Unserved energy risk is in summer.
WECC-Northwest						Rapid forecasted demand growth is driving the need for more resources. Resource additions nearing completion are predominantly solar PV, battery, and wind, leading to a more variable resource mix. Periods of unserved energy are projected for both summer and winter.

Regional Assessments Dashboards

The **Regional Assessments Dashboards** section contains dashboards and summaries for each of the 23 assessment areas, developed from data and narrative information collected by NERC from the six Regional Entities. Probabilistic assessments (ProbA) are presented that identify energy risk periods and describe the contributing demand and resource factors.

Responding to Trends in Resource Adequacy

As resource adequacy concerns have expanded and grown more acute in many parts of the North American BPS, more actions have been taken by industry and regulators to bolster resources.

- Projected retirements have shrunk from the *2024 LTRA*. Growing demand, market signals, and resource plans have highlighted the potential need to keep resources on-line longer than previously anticipated. Though the confirmed and announced potential retirements over the next 10 years remain high and total over 105 GW in peak seasonal capacity, this is roughly 10 GW lower than the 10-year retirement projections last year.
- The initiation of market mechanisms like capacity accreditation has also more precisely highlighted the loss-of-load risks posed by a generation mix that has increasing amounts of variable resources. Market procurements are becoming more effective in procuring resources as a result.
- Expedited resource programs that were approved by FERC in late Summer 2025 for MISO, PJM, and SPP have resulted in acceleration and prioritization for resources that can address identified reliability risks. Most new resources brought in through recently approved expedited resource programs are not included in the *2025 LTRA* risk assessment.
- Lawmakers in Texas have provided ERCOT with curtailment management authority over new large loads to prevent grid emergencies and established funding to speed new generating capacity to the grid.

The **Capacity and Energy Risk Assessment** and **Regional Assessments Dashboards** sections provide details on these examples and initiatives in other assessment areas.

Trends and Reliability Implications

Demand, resource, and transmission trends affect long-term reliability and the sufficiency of electricity supplies. A summary for each is provided below and further discussed within the **Demand Trends and Implications** and **Transmission Development and Interregional Transfer Capability** sections.

Demand Trends and Implications

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades. Over the 10-year period, aggregated assessment area summer peak demand is forecast to rise by over 224 GW. This is 69% higher than last year's 10-year growth projection of 132 GW. Winter peak demand is expected to grow by 245 GW, continuing to outpace summer and exceed prior-year projections. New data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years.

Demand and large-load projections throughout the LTRA are based on load-serving entity (LSE) and BPS system planner forecasts provided to NERC during LTRA development, reflecting mid-2025 plans. LSE load forecasts are based on information from the interconnection process and agreements between utilities and owners of connecting loads, such as facility peak demand, load flexibility, and some operating characteristics. To be counted in load forecasting, data center projects have advanced from speculative and exploratory stages into development commitments necessary to drive grid planning studies. Still, large loads inherently add volatility to load forecasts as project timelines and commitments can vary with factors related to construction, permitting approvals, grid development, and data center owner decisions. ERCOT and PJM, the grid planners and operators for two areas experiencing vigorous large-load and data center development, have each prepared revised load forecasts since the *2025 LTRA* data collection period that, due to timing, is not used in this LTRA. Both forecasts indicate that some large-load projects have slowed or failed to materialize within the shorter-term horizon, while interconnection requests for later years continue to increase. Load forecasts that are revised downward can shrink the energy shortfalls that are projected in this LTRA.

Resource Additions and the Changing Resource Mix

The shift toward a more variable resource mix continues, as battery, solar PV, and hybrid generation lead the most recent and projected near-term additions and as fossil-fired generators retire. From 2024 to 2025, the existing capacity from fossil-fueled generators fell by 21 GW, while BPS capacity for peak demand hours from battery, wind, and solar resources increased by 23 GW.

In a shift from a key insight from the *2024 LTRA*, solar PV is no longer the sole, predominant generation type planned over the next 10 years. New battery resource projects have grown to match solar projections, and, together, solar and battery capacity additions represent two-thirds of the Tier 1 and Tier 2 resources in this year's 10-year LTRA study period. Natural-gas-fired generator additions represent 15% of the projected capacity additions followed by wind and hybrid at 8% each. While interconnection queues continue to swell, considerable uncertainty surrounds the timing and amount of resource additions. Overall, on-peak resource capacity in Tier 1 and Tier 2 has grown modestly since

the *2024 LTRA* by 7 GW (1.7%). This is slightly less than in the prior year when Tier 1 and Tier 2 capacity grew by 44 GW.

As older fossil-fired generators retire and are replaced by more battery and solar PV resources, the resource mix is becoming increasingly variable and weather-dependent. The share of VERs in the existing BPS on-peak resource capacity increased from 9.5% to 10.2% over the last year. VERs have different physical and operating characteristics from the generators that they are replacing, affecting the essential reliability services (ERS) that the resource mix provides. Frequency response, or the ability of the BPS to maintain stable frequency, is one such ERS that NERC assesses on an Interconnection basis to ensure future resource mix reliability. Battery storage can enhance system frequency response. Other IBRs provide little or no frequency response capability, requiring grid operators to ensure that enough synchronous generators and other facilities are on-line for system stability. This year's LTRA finds that the future resource mix in each Interconnection through 2027 has sufficient resource types to provide for adequate frequency response. As generators are deactivated and replaced by new types of resources, ERSs must still be maintained for the grid to operate reliably.

The thermal generation component of the resource mix is increasingly reliant on natural gas for fuel as new natural-gas-fired generators are added to the BPS and as some existing coal-fired generators undergo fuel conversion. Overall, 13 out of 23 assessment areas are adding capacity to their fleet of natural-gas-fired power plants over the next 10 years: 53 GW of new natural-gas-fired winter capacity is in the planning queues, and new ERAS programs will add more. As new natural-gas-fired generators progress through interconnection processes, Generator Owners, grid planners, and natural gas infrastructure developers need to take steps to ensure that regional natural gas infrastructure can reliably serve the needs of BPS generators.

Transmission Development and Interregional Transfer Capability

Transmission projections reported for the *2025 LTRA* reflect an increase in transmission development, continuing a trend that emerged in the *2024 LTRA*. This year's cumulative level of 41,000 miles (66,000 km) of transmission (>100 kV) under construction or in various stages of development for the next 10 years is substantially higher than the *2024 LTRA* 10-year projections (28,275 miles or 45,504 km). Transmission in construction has yet to increase substantially over past-year levels; rather, the large increase in transmission projects is seen in planning phases. Several Planning Coordinators (PC) have recently approved, or are actively contemplating, expansive extra-high voltage (EHV) overlays on their systems to address new generator additions and a variety of reliability needs, including Hydro-Québec, ERCOT, SPP, MISO, PJM, BC Hydro, and the Independent Electricity System Operator (IESO) in Ontario.

Interregional transmission projects that support energy transfers across Interconnections make up a small but important portion of total BPS transmission development. They can allow entities to take advantage of geographic diversity during extreme weather, such as Winter Storm Elliott,[9] including scenarios identified in the *Interregional Transfer Capability Study* (ITCS) published by NERC in 2024, and the separate ***Interregional Transfer Capability Study (Canadian Analysis)***. About 4% of transmission projects reported for the *2025 LTRA* are for tie-lines that support transfers between neighboring systems, lower than the 6% reported in the *2024 LTRA*.

Transmission development in some areas is hampered by growing risks in procurement and supply chain delays. Other reasons for delays include economic impacts, planning and construction issues, permitting issues, or changing needs. Of nearly 900 projects that were under construction or in planning for the next 10 years, at least 390 projects have been delayed from their originally expected in-service dates.

Recommendations

To address the energy and capacity risks identified in this LTRA, NERC recommends the following priority actions:

1. **Integrated Resource Planners, market operators, and regulators: Expedite new resources to meet growing demand and carefully manage generator deactivations.** BPS planners should develop, implement, or enhance mechanisms to expedite resource additions to the grid that provide the services needed to address anticipated reliability issues related to each area's needs. Independent System Operator/Regional Transmission Organizations (ISO/RTO) should evaluate mechanisms and process enhancements for obtaining information on expected generator retirements that would support early identification of reliability risks. State and provincial regulators and ISO/RTOs need to have mechanisms they can employ to extend the service of generators seeking to retire when they are needed for reliability, including the management of energy shortfall risks. Regulators must support resource development and manage the pace of retirements such that replacement infrastructure can be developed and placed in service to support reliability needs.
2. **NERC, industry, and regulators: Understand and manage reliability risks accompanying large-load growth and leverage potential capabilities in new types of loads to provide flexibility to operators during times of grid stress.** An increasing number of large commercial and industrial

[9] Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022 | Federal Energy Regulatory Commission

loads is rapidly connecting to the BPS. Emerging large loads—such as data centers (including cryptocurrency and artificial intelligence applications) and hydrogen fuel plants—present unique challenges in BPS planning and operations. Stakeholders should support NERC's Large Loads Action Plan[10] and collaborate through NERC's Large Loads Task Force.[11] ISO/RTOs should collectively work to create more uniform requirements to address the emerging reliability issues associated with large data center loads.

3. **NERC, Regional Entities, and industry: Improve the LTRA by incorporating new analysis and criteria to inform stakeholders of future reliability risks.** NERC increased the frequency of the ProbA from biennial to annual and included unserved energy and load-loss metrics as the basis for risk analysis in this year's LTRA. To promote consistency in analysis and develop assessment capabilities, NERC and the Regional Entities piloted Interconnection-wide energy assessments using a common probabilistic resource adequacy tool in 2025. Wide-area energy analysis will support the evaluation of interregional transfer capabilities and the effects of extreme weather and regional fuel supply issues on the BPS at an Interconnection level. Industry should work with NERC through its technical groups to implement ERO energy assessments in the *2026 LTRA* and continue to improve consistency in the annual ProbA. NERC and the Regional Entities, in consultation with the RSTC, should also continue to enhance NERC's LTRA to assess ERSs in the future system and the potential impact of new and evolving electricity market practices, regulations, or legislation on resource adequacy.

4. **Regulators and policymakers: Streamline siting and permitting processes to remove barriers to resource and transmission development.** As ISO/RTOs continue looking for opportunities to speed transmission planning processes, many states are also taking steps to expedite siting and permitting. Siting and permitting issues are among the most common causes for delayed transmission projects. Support from regulators and policymakers at the federal, state, and provincial levels is urgently needed.

5. **Regulators, electric industry, and gas industry member organizations: Continue identifying and implementing solutions for addressing the operating and planning needs of the interconnected natural gas-electric energy system.** As various initiatives launched in past years roll out recommendations for addressing reliability needs, stakeholders should act with urgency on implementation. Continued collaboration through readiness forums and working groups remains a priority. While new regulatory and oversight mechanisms of the natural gas industry have yet to solidify, voluntary actions for managing natural gas production, processing, and delivery risks are needed. NERC, gas and electric industry, and research partners should continue studies and assessments of regional fuel supply risks to BPS generation.

6. **Regional transmission organizations, independent system operators, and FERC: Continue to ensure that ERSs are maintained.** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate ERSs.[12] Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to ERSs. As replacement resources are interconnected, these new resources should be capable of supporting voltage, frequency, ramping, and dispatchability. Many technologies can contribute to ERSs, including VERs; however, policies and market mechanisms need to reflect these requirements to ensure that these services are provided and maintained. ISO/RTOs and FERC have taken steps in this direction, and these positive steps must continue.

In addition to these priorities, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. All recommendations are listed in the **Recommendations and ERO Actions Summary.**

[10] NERC's Large Loads Action Plan: https://www.nerc.com/initiatives/large-loads-action-plan
[11] NERC's Large Loads Task Force webpage: Large Loads Task Force (LLTF)
[12] Essential Reliability Services: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf

Capacity and Energy Risk Assessment

Resource Planners and state and provincial policymakers use resource adequacy criteria to ensure that sufficient resources are available to meet demand and prevent unacceptable levels of energy shortfall. In their application, traditional capacity-based adequacy criteria were not designed to consider the magnitude, frequency, duration, and timing of potential energy shortfalls. Such considerations have become increasingly important as the resource transformation evolves from capacity-based resources with assured and stored energy supplies to energy-constrained resources that are increasingly impacted by weather and environmental conditions. NERC's LTRA includes all-hours probabilistic indices to measure these additional dimensions of risk and provide a more complete analysis to inform system plans.

Assessment Approach

NERC evaluates industry-provided resource adequacy data and credible studies to assess risks of future energy shortfalls as the system is currently planned. Probabilistic and deterministic analyses provide forward-looking snapshots of resource adequacy tied to industry forecasts of electricity supplies, demand, and transmission development. The risk analysis entails these components:

- Assessing load-loss metrics determined from probability-based simulation of projected demand and resource availability over all hours. This approach identifies high risk periods and potential energy constraints resulting in load-loss events. The 2025 ProbA is performed for each assessment area and examines the system as planned for the years 2027 and 2029. Loss-of-load hours (LOLH) and expected normalized unserved energy (NEUE) from NERC's ProbA are used to identify risk levels.
- Comparing the margin between projected resources and peak net demand, or reserve margin, to a reserve margin target (known as the Reference Margin Level (RML)) that represents the accepted level of risk based on a probability-based loss-of-load analysis.

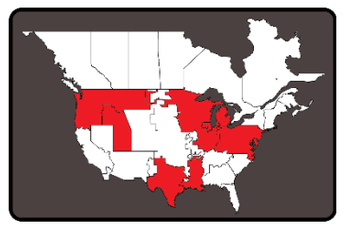
NERC also incorporates other findings from scenarios or information from system studies to address assessment area-specific adequacy risks when needed. See MRO-SPP, NPCC-New England, and NPCC-New York.

The risk determination is based on data and information provided to NERC during LTRA development and represents a snapshot in time. Integrated resource planning and ISO/RTO resource adequacy mechanisms vary across North America and can be implemented to respond to resource adequacy issues on many different timescales.

The **Demand Assumptions and Resource Categories** section provides further details on these approaches. Assessment area dashboards (see **Regional Assessments Dashboards**) provide resource capacity and energy risk assessment results for all areas.

Risk Categories

For the *2025 LTRA*, NERC uses the following three levels of risk category determination for each assessment area and associated years for which there is a risk of energy shortfall during the first five years of the LTRA period (i.e., 2026–2030). The details for the risk criteria determination are shown below for each category of risk.



An assessment area is determined as **High Risk** when established resource adequacy targets or requirements are not met or when probabilistic or deterministic energy analyses find that planned resources produce shortfalls resulting in unserved energy or load loss exceeding criteria for baseline resource adequacy specified below. Regulatory authorities or market operators establish resource adequacy targets. Most targets in North America are currently based on a 1-day/event load loss in a 10-year planning requirement. See **Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area**. Recently, regulators and policymakers in many states and market areas have begun to consider or develop resource adequacy targets based on additional criteria that can better address energy risks and extreme weather-related supply disruption.[13] High risk areas are those where today's demand forecasts and resource projections indicate a shortfall in future planned resources for expected (i.e., most likely, aka 50/50) demand and typical resource performance. More severe operating conditions associated with unusual heat waves or deep-freeze events would further exacerbate shortfalls in planned resources.

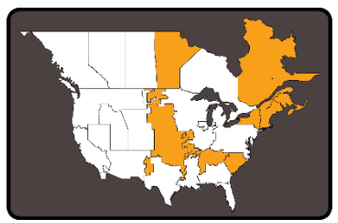
For the *2025 LTRA*, NERC uses the following criteria to determine areas and associated years for which there is high risk of insufficient planned resources during the first five years of the LTRA period (i.e., 2026–2030):

- Annual LOLH exceeds 2.4 hours/year for one or more years in the ProbA; or
- Annual normalized expected unserved energy (EUE) exceeds 0.002% (20 ppm) for one or more years in the ProbA; or

[13] See the NERC-National Academy of Engineering Workshop Report *Evolving Planning Criteria for a Sustainable Power Grid*.

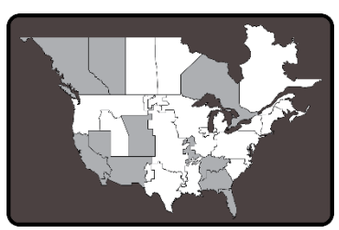
- Resource adequacy target(s) established by regulatory authority or system operator are not met.

Resource Planners, regulators, and market operators in assessment areas identified as having a high risk of resource shortfalls can mitigate these risks through timely actions that address capacity and energy risks.



An assessment area is determined to have **Elevated Risk** when it meets the established resource adequacy targets and baseline criteria specified earlier but does not meet more stringent thresholds of unserved energy and load loss that provide for reliability in more extreme weather conditions. More extreme conditions can include temperatures that result in above-normal demand levels, low resource output or availability, and/or disruption of normal electricity transfers. In the analysis, elevated risk may be found by modeling above-normal demand and low resource availability. The risk can also be identified by examining output data from probabilistic analysis tools to determine the underlying conditions for load-loss events. For the *2025 LTRA*, assessment areas are classified as elevated risk when they meet any one of the following criteria in the first five years of the LTRA period (i.e., 2026–2030):

- Annual LOLH is between 0.1 and 2.4 hours/year for one or more years in the ProbA
- Annual normalized EUE is less than 0.002% (20 ppm) but greater than or equal to 0.0002% (2 ppm) for one or more years in the ProbA
- Resource adequacy target(s) established by regulatory authority or system operator are met, but plausible scenarios of above-normal demand and/or low-resource conditions indicate risk of loss of load



An assessment area is determined to have **Normal Risk** if resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance). Although areas determined as normal risk are expected to have sufficient resources for plausible extreme[14] conditions, they are not immune to the effects of high-impact, low-frequency weather events that affect demand and generation simultaneously. For the *2025 LTRA*, assessment areas are classified as normal risk based on an evaluation of the following criteria for each of the first five years of the LTRA period (i.e., 2026–2030):

- Annual LOLH is below 0.1 hours/year.
- Annual normalized EUE is below 0.0002% (2 ppm).
- Resource adequacy target(s) established by regulatory authority or system operator are met and reserves are expected to be available in plausible scenarios of above normal demand and/or low-resource conditions associated with a once-per-decade event indicate risk of load loss.

Application of the Risk Criteria: NERC uses industry-provided demand and resource information and the results from the ProbA performed by NERC Regional Entities, ISO/RTOs, and regulated utilities to determine risk of energy and capacity shortfalls. The methods, assumptions, and approaches used by entities to perform probabilistic assessments affect the results and outputs. In last year's LTRA, NERC incorporated new probabilistic assessment risk criteria (LOLH and EUE) from the NERC-National Academy of Engineering Workshop Report, *Evolving Planning Criteria for a Sustainable Power Grid*, alongside established reserve margin criteria. In instances where an assessment area's probabilistic assessment results and reserve margins give mixed indications as to the risk category, adherence to resource adequacy targets (e.g., required RML and load-loss criteria) established by regulatory jurisdictions took precedence. Any other apparent contradictions with metrics and criteria were generally assessed according to results of all-hours probabilistic analysis.

A numerical summary of the assessment areas' risk profile measured against the NERC risk criteria is summarized in **Table 2**. A risk description summary for each assessment area at an **Elevated Risk** or a **High Risk** is provided in the **High-Risk Area Details** or **Elevated-Risk Area Details** sections following **Table 2**. Full details about all assessment areas are provided in the **Regional Assessments Dashboards** section.

[14] Plausible extreme conditions considered by NERC in this assessment are similar to those experienced during Winter Storm Elliott, Winter Storm Uri, and the 2020 Western Wide-Area Heat Dome.

Table 2: Capacity and Energy Risk Assessment Numerical Summary														
	NEUE (ppm)		LOLH (hours/year)		Anticipated Reserve Margin					Reference Margin Level[15]				
Summer-Peaking Areas	**2027**	**2029**	**2027**	**2029**	**2026**	**2027**	**2028**	**2029**	**2030**	**2026**	**2027**	**2028**	**2029**	**2030**
MISO	1.13	**42.39**	**0.23**	**6.61**	11.0%	11.2%	9.5%	8.6%	**4.3%**	8.1%	8.3%	8.5%	8.5%	8.5%
MRO-SPP	0.00	0.00	0.00	0.00	32.4%	30.3%	28.4%	25.1%	22.6%	19.0%	19.0%	19.0%	19.0%	19.0%
NPCC-New England	0.00	0.02	0.00	0.00	18.3%	21.7%	24.8%	23.7%	23.6%	13.4%	13.0%	13.0%	13.0%	13.0%
NPCC-New York	0.00	0.08	0.00	0.03	22.3%	24.5%	24.5%	23.6%	22.5%	15.0%	15.0%	15.0%	15.0%	15.0%
NPCC-Ontario	0.00	0.00	0.00	0.00	29.6%	19.8%	28.1%	18.7%	19.7%	16.1%	19.0%	22.6%	15.8%	19.5%
PJM	**3.50**	**65.50**	**0.61**	**9.97**	29.7%	28.3%	24.3%	**18.9%**	**13.9%**	18.6%	20.1%	21.9%	23.9%	26.3%
SERC-Central	0.00	0.00	0.00	0.00	19.1%	20.8%	19.7%	18.5%	16.5%	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-East	0.98	**2.27**	**0.15**	**0.33**	30.6%	30.5%	30.5%	31.5%	34.9%	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-Florida Peninsula	0.00	0.00	0.00	0.00	27.4%	25.2%	24.3%	22.6%	21.1%	15.0%	15.0%	15.0%	15.0%	15.0%
SERC-Southeast	0.00	0.00	0.00	0.00	35.9%	29.5%	29.8%	24.9%	20.9%	15.0%	15.0%	15.0%	15.0%	15.0%
Texas RE-ERCOT	**8.70**	**18.84**	**0.95**	**3.64**	28.2%	30.5%	31.8%	30.8%	29.9%	13.8%	13.8%	13.8%	13.8%	13.8%
WECC-Basin	0.04	**2,250**	**3.00**	**310.00**	36.3%	37.9%	27.4%	19.7%	15.2%	13.5%	14.0%	13.6%	12.4%	12.3%
WECC-California	0.00	0.00	0.00	0.00	53.2%	47.0%	46.1%	45.6%	42.7%	20.3%	19.2%	19.3%	19.7%	19.3%
WECC-Mexico	0.00	0.00	0.00	0.00	14.9%	13.8%	29.9%	27.0%	24.6%	7.8%	8.0%	9.1%	7.2%	7.0%
WECC-Rocky Mountain	0.00	0.00	0.00	0.00	51.3%	60.0%	53.2%	38.1%	30.5%	17.8%	17.0%	16.2%	16.1%	15.7%
WECC-Southwest	0.00	0.00	0.00	0.00	41.1%	39.6%	38.6%	38.4%	36.1%	13.3%	13.7%	13.6%	12.6%	12.2%
Winter-Peaking Areas	**2027**	**2029**	**2027**	**2029**	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**	**2030–2031**	**2026–2027**	**2027–2028**	**2028–2029**	**2029–2030**	**2030–2031**
MRO-Manitoba Hydro	0.12	0.23	0.03	0.06	13.9%	16.7%	15.4%	13.6%	**1.2%**	12.0%	12.0%	12.0%	12.0%	12.0%
MRO-SaskPower	**5.24**	0.19	**1.09**	0.05	25.9%	35.0%	33.4%	32.3%	31.2%	15.0%	15.0%	15.0%	15.0%	15.0%
NPCC-Maritimes	0.52	0.25	**0.25**	0.10	**17.2%**	**18.5%**	25.6%	23.0%	21.7%	20.0%	20.0%	20.0%	20.0%	20.0%
NPCC-Québec	0.00	0.29	0.00	**0.11**	15.6%	16.7%	14.7%	13.0%	**11.5%**	11.9%	12.2%	12.2%	12.2%	12.2%
WECC-Alberta	0.00	0.00	0.00	0.00	36.2%	45.3%	40.7%	38.0%	33.0%	11.8%	17.6%	14.3%	15.6%	11.6%
WECC-British Columbia	0.00	0.00	0.00	0.00	23.4%	19.1%	19.5%	24.1%	24.2%	11.7%	12.1%	12.1%	11.6%	11.6%
WECC-Northwest	0.00	**36.64**	0.00	**85.00**	30.2%	29.3%	23.3%	19.1%	15.7%	17.8%	17.4%	16.1%	15.8%	15.5%

[15] Refer to the Regional Assessments Dashboards and the Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area table.

High-Risk Area Details

The assessment areas below exceed the highest level of risk criteria for the **High-Risk** classification during one or more years of the 2026–2030 period. Areas are listed in order of appearance in the **Regional Assessments Dashboards** section.

MISO (Normal Risk 2026| Elevated Risk 2027| High Risk 2028–)

Escalating demand forecasts and uncertainty around new resource commercialization timing contribute to heightened resource adequacy concerns in the MISO area. MISO forecasts its peak total internal demand at 127 GW during the 2026 summer season (up over 2.6 GW since the same year's projection in the *2024 LTRA*) and expects that summer demand will grow to 143.7 GW by 2035. The largest contributor to this accelerated demand growth is data center additions with 18 GW of data center loads projected by 2035. MISO's accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements. New solar PV resources contribute to a 5.7 GW increase in MISO's accredited non-thermal capacity since last year.

As of July 2025, MISO has more than 54 GW nameplate capacity of generation—predominantly solar and battery—with signed generation interconnection agreements that are projected to come on-line over the next few years. As of December 2025, that figure increased to more than 70 GW of nameplate capacity. In addition to these resources, MISO instituted the ERAS process to respond to generation needs. The ERAS process provides a framework for the accelerated study of generation projects that address urgent resource adequacy and reliability needs in the near term. ERAS projects are not in the model for the *2025 LTRA*. If ERAS projects come in as currently planned, the projected reserve margin shortfall would be eliminated.

Based on the current resource and demand forecasts, MISO begins to meet elevated-risk criteria in 2027 (see **Table 3**). While resources are adequate for regulatory requirements, the ProbA results show load loss and unserved energy exceeding the elevated-risk threshold. The Summer season makes up the bulk of annual risk in this region and is seen to materialize during late afternoon and evening hours when demand is high and solar resource output begins to decline. The ProbA also identifies winter risk periods during early morning and hours after 7:00 p.m. Additionally, shortfall risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high.

As the demand forecast rises in subsequent years, and with currently projected generator retirements and planned resource additions, the ProbA shows worsening results. While resources are adequate for regulatory requirements (i.e., loss of load expectation (LOLE) of 0.1 day in a year), the ProbA results show load loss and unserved energy exceeding the elevated risk threshold criteria.

For the 2029 ProbA study, MISO assumed 14 GW of generator retirements that are uncertain to occur by 2029.

Table 3: MISO Base-Case Summary of Results

	2027	2029
EUE (MWh)	797	31,654
NEUE (ppm)	1.13	42.39
LOLH (hours per Year)	0.23	6.61
Category	Elevated	High

With model assumptions, MISO would exceed load-loss and unserved energy criteria and fall below reserve margin targets to become a high-risk area beginning in Winter 2028 (see **Figure 2**). Projections for resource additions are predominantly solar PV, with some battery and wind resources. The small amounts of natural-gas-fired generation in signed interconnection agreements do not offset planned generator retirements, and, as a result, MISO is projecting shortfalls in planned resources for winter peak periods.

These results offer a point-in-time snapshot of risk based on the data available during the time of this year's analysis. The regulatory structure within MISO provides utilities and regulators with many tools to ensure alignment of large-load additions, generator retirements, and generator additions. Regulators and utilities in the MISO region are statutorily required to ensure reliability and can work to address uncertainties associated with these three phenomena.

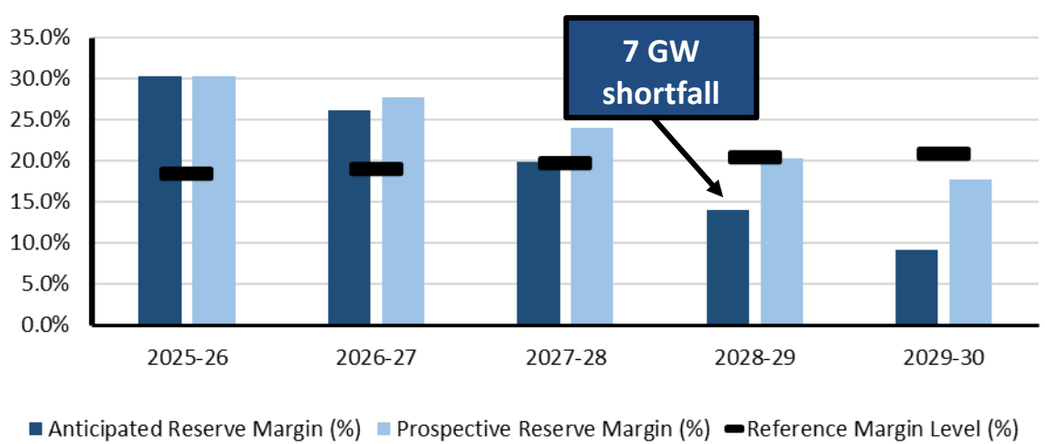
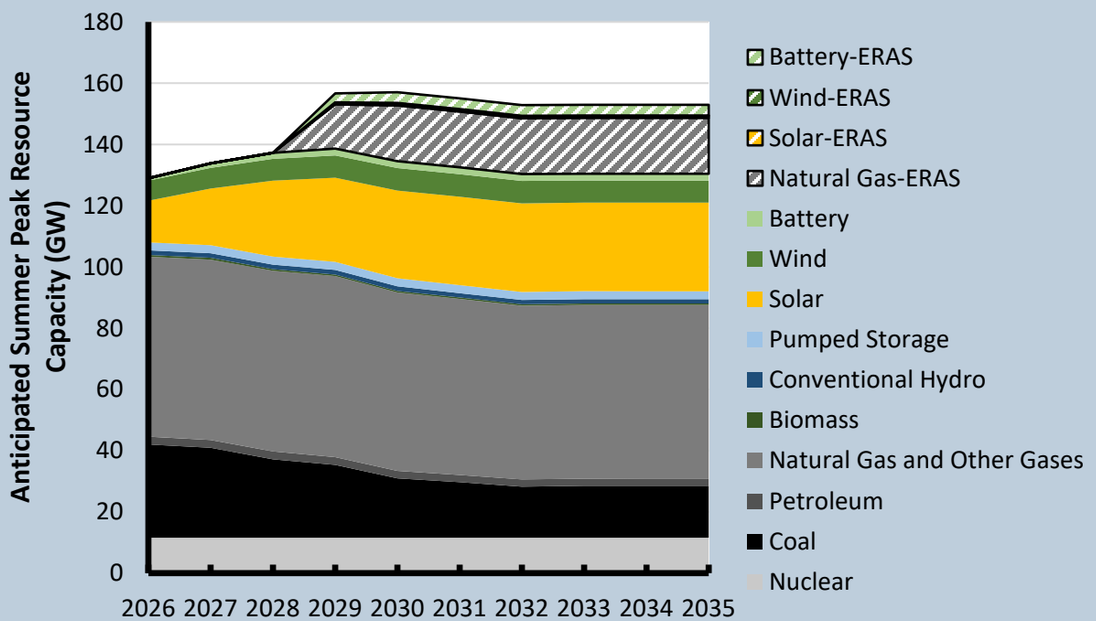


Figure 2: MISO Winter Planning Reserve Margins

Currently, MISO has surplus transfer capacity within its assessment area, but transfers between subregions have been historically constrained by a transmission limitation between the northern and southern MISO subregions.

The timing of FERC's approval of MISO's ERAS process in July meant that the generator additions that MISO plans as part of that process were not included in the resource adequacy modeling for the *2025 LTRA*. ERAS is already expected to result in considerable new resource additions to the MISO system in the near term. The additional summer on-peak capacity from ERAS is expected to grow to over 20 GW by summer 2030. These expedited resource additions are expected to reduce the shortfall risk identified in this year's ProbA. Furthermore, the timing of the ERAS additions would mitigate an identified winter ARM shortfall if the approximately 8.6 GW of winter on-peak capacity anticipated by 2028–29 reaches operation as projected. The latest ERAS projects, along with current load forecasts and resource projections as of July 2026, will be included in the input data for the *2026 LTRA*, and ERAS summer capacity additions are summarized by the diagonal hatched stacked areas in plot below.



The Potential Effect of MISO's ERAS Process on Anticipated Summer Capacity

PJM (Elevated Risk 2026–2028| High Risk 2029–)

Demand for electricity in PJM is growing at its fastest pace in years, driven primarily by data centers, followed by electrification and manufacturing loads. PJM expects its summer peak demand to grow by 56 GW to a total of 210 GW in 2035, and its winter peak demand is expected to climb by 62 GW to reach 198 GW by winter 2034–35. PJM's annual net energy for load growth rate is projected to average 4.8% per year over the next 10 years, up from 2.3% in last year's projections.

At the same time, PJM faces an extreme and rapid tightening of capacity resources in the near term because of generator retirements and project delays. A large share of PJM's new interconnection requests is from VERs, approximately 40% of which are solar, and dispatchable resources are currently leaving the system faster than they can be replaced with other dispatchable technologies. These factors, paired with PJM's limited reliance on transfers from neighboring areas to meet resource adequacy targets (maximum total transmission interchange capability is <2% of PJM's internal generation capacity), have led to a projection that PJM's ARM may fall below its Installed Reserve Requirement (or RML) in 2029 (see **Figure 3**).

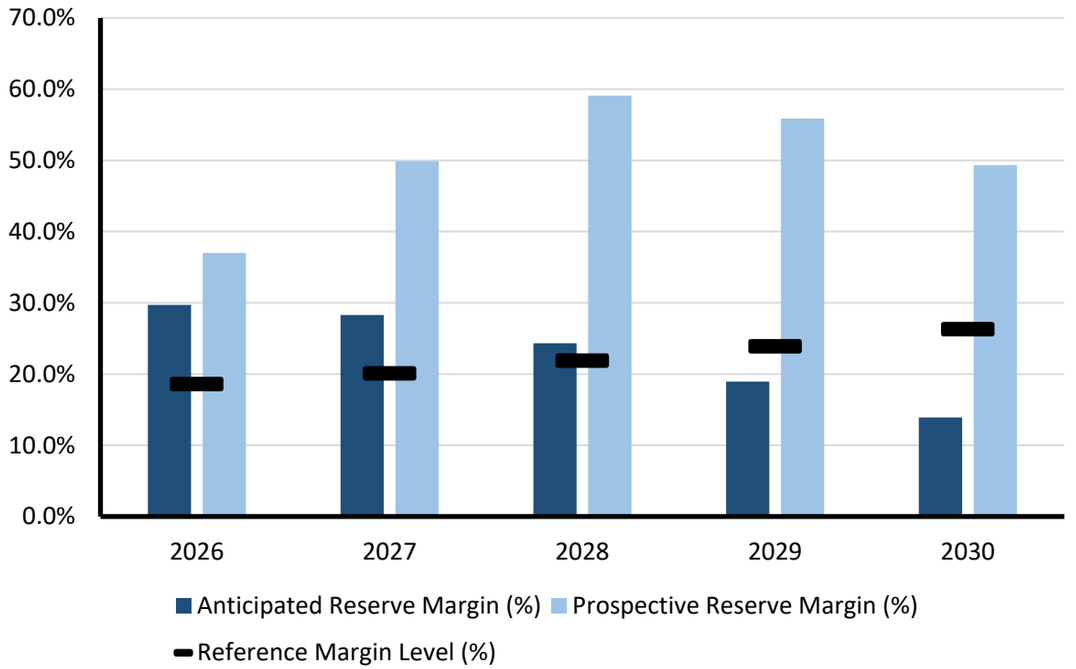


Figure 3: PJM Summer Planning Reserve Margins

As part of its reforms to speed interconnection with the system, PJM has approximately 30,000 MW of generation projections in the transitional interconnection queue to be processed in 2026. PJM's new cycle process opens in April with a one- to two-year timeline for reviews, depending on the impact to the system. From the time of the original *2025 LTRA* data submittal to recent evaluation, PJM projected an additional 8.3 GW of Tier 1 summer resource capacity over the next seven years. Tier 1 resource additions will provide 3.4 GW of winter capacity. However, many of these projects continue to be slowed or stopped by factors affecting multiple regions across the continent, including local opposition, state/local permitting delays, supply chain challenges or financing.

In 2025, FERC approved a PJM-proposed expansion of Surplus Interconnection Service to augment the operating efficiency and availability of existing resources, and the Reliability Resource Initiative (RRI), which attracted 11,000 MW of nameplate capacity in proposed, shovel-ready generation projects. Such initiatives also impacted Tier 2 resources from 2026 to 2031, netting an additional 8.2 GW in summer capacity from the original *2025 LTRA* data submittal and 4.1 GW in winter capacity. This net increase factors resources that transitioned from Tier 2 to Tier 1, the Reliability Resource Initiative, and any recently withdrawn projects.

Setting aside the impact of such initiatives, results of the ProbA using PJM's current resource and demand forecasts indicate that the area is at an elevated risk of resource shortfalls at the beginning of the 10-year horizon (see **Table 4**). Because this year's ProbA does not study years earlier than 2027, the elevated-risk determination is based on results of the 2024 ProbA and consideration of the declining ARM in PJM since last year's LTRA (2026 Summer ARM has fallen from 35.7% to 29.7%). The greatest risk of resource shortfalls leading to unserved energy or load loss in PJM occurs in the winter months during the early morning and evening hours. The risk is associated with generator availability and performance issues that can arise from equipment freezing and fuel supply issues during extreme winter conditions. PJM falls into the high-risk category beginning in 2029 as demand forecasts continue to climb, generators reach planned retirement dates, and the projected resources become less certain. The winter risk profile indicates that new resources will need to be capable of reliably serving winter load.

Table 4: PJM Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	538	3,251	67,581
NEUE (ppm)	0.00	3.50	65.50
LOLH (hours per Year)	0.1	0.61	9.97
Category	Elevated	Elevated	High

***Provides the 2024 ProbA Results for Comparison**

Texas RE-ERCOT (Elevated Risk 2026–2028| High Risk 2029–)

The Texas RE-ERCOT assessment area is forecast to experience continued rapid electric demand growth over the next 5–7 years. ERCOT forecasts summer peak total internal demand to increase from 94,650 MW for 2026 to 154,077 MW for 2035, an average annual increase of 5.6%. This load growth is mainly driven by forecasted interconnections of large loads totaling 45 GW by 2030, of which 23 GW are data centers.

ERCOT continues to evolve its planning methods as fluctuations in recent large interconnections activity continue to affect both near- and long-term demand expectations. Several projects have slowed or failed to materialize within the shorter-term horizon, while interconnection requests for later years continue to increase. Such fluctuations do not, however, undercut the significance of demand growth attributable to large loads.

Responding to rapidly escalating demand from data centers and other large industrial loads, ERCOT, regulators, and lawmakers in Texas are adapting with policy and planning approaches to address emerging supply risks. Actions provide ERCOT with new curtailment management tools for large loads, establish criteria for when to incorporate new large loads in system planning, and help fund and speed new generating capacity to the grid. Furthermore, the first reliability assessment for the Public Utility Commission of Texas (PUCT)-approved Reliability Standard, and potential approval of market design changes to address deficiencies, is scheduled for completion by year-end 2026. Such market design changes would further mitigate energy risk.

Signed into law in June 2025, Texas Senate Bill 6 directs the PUCT to establish uniform large-load interconnection standards that, among other things, provide ERCOT with new large-load curtailment management tools and provide ERCOT authority to direct (or require transmission service providers to direct) large loads to curtail their load prior to and during declared energy emergency situations. For the *2025 LTRA*, ERCOT's DR contributions have increased substantially to reflect the authority and capability to curtail new large loads during energy emergencies. For Summer 2026, DR contributes 13.3 GW to resource adequacy (up from the 2.7 GW projection in the *2024 LTRA*), and contributions from DR rise to 53.1 GW by 2030. Because new large loads can be curtailed during energy emergencies, the rapid rise in projected large loads has substantially less effect on Planning Reserve Margins in ERCOT than in the 2024 LTRA.

The ARM is above the 13.75% RML for all years (see **Figure 4**).

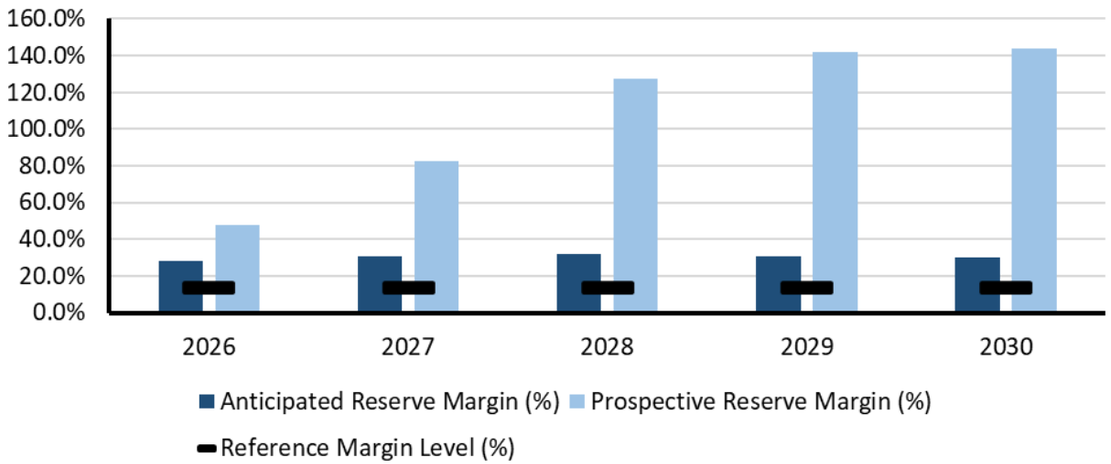


Figure 4: TEXAS RE-ERCOT Summer Planning Reserve Margins

ERCOT's Planning Reserve Margins in the *2025 LTRA* are also being affected by the implementation of new capacity contribution methods. ERCOT has switched from using historical average on-peak capacity factors to average effective load carrying capabilities (ELCC) for VERs, and the resulting capacity derates largely offset the gains that load management programs have on ARM. In the case of solar, ELCCs are significantly lower than prior years. ELCC values are probabilistically derived and reflect resource reliability value, and in the case of solar, this value has been decreasing as reserve scarcity risk shifts to the evening hours when solar availability is low.

The ProbA results for Texas RE-ERCOT reveal some improvement in near-term resource adequacy when compared to the *2024 LTRA*, but the area remains an elevated risk through 2027 before forecasted load growth drives the area to high risk (see **Table 5**). ERCOT's ProbA modeling includes demand-side management protocols that reasonably reflect large load curtailments described above, and other programs used in ERCOT's market. This modeling contributes to the improved unserved energy and load-loss hour metrics that are observed between the 2024 ProbA and the current ProbA. Battery resource additions since last year and improved modeling in the resource adequacy analysis tool also contribute to these improved metrics.

Table 5: Texas RE-ERCOT Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	11,090	5,865	17,053
NEUE (ppm)	18.95	8.70	18.84
LOLH (hours per Year)	1.57	0.95	3.64
Category	Elevated	Elevated	High
***Provides the 2024 ProbA Results for Comparison**			

ERCOT's ProbA study results show that most resource adequacy risk is in the winter, and this is mainly driven by the large demand variability associated with winter temperatures. By 2029, there is significant risk in the summer and slight risk in the shoulder seasons, driven by the considerable growth of large loads across the year. For non-winter months, ERCOT continues to experience the highest reserve scarcity risk during the early evening hours (peaking at hour ending (HE) 9:00 p.m.) based on probabilistic capacity reserve modeling for monthly peak load days. During these periods, the drop-off in solar generation causes margins to decrease when load remains high. Battery storage helps reduce these short-duration energy risks. ERCOT expects battery energy storage capacity to reach 18.9 GW by Summer 2026 (Existing and Tier 1 resource categories) and grow to 25.2 GW by 2029. ERCOT typically sees the greatest energy provided by energy storage during net load peaks when solar is ramping off in the evening, or during early morning hours prior to solar ramping up.

In response to the rapid and unprecedented load growth, the PUCT in April 2025 approved three 765 kV import paths identified in the *Permian Basin Reliability Study*, which introduced the new 765 kV voltage class into the ERCOT region after six decades since the introduction of the 345 kV voltage class. The Texas 765-kV Strategic Transmission Expansion Plan (TX 765-kV STEP) tackles the unprecedented load growth expected by 2030 and enhances transfer capability by an additional 600 MW to 3,000 MW. This 765 kV addition enables power to flow more efficiently through long-distance transmission from resource-rich regions to load centers.

WECC-Basin (Elevated Risk 2026–2028/High Risk 2029–)

Forecasted load growth and planned generator retirements in the Great Basin (WECC-Basin assessment area) present resource adequacy challenges. Over the next 10 years, the summer demand forecast will rise by over 1.7 GW (17%, or 1.8% compounded annually), while at the same time the capacity from currently existing resources will decline by nearly 2.3 GW through generator retirements and other capacity changes. Solar resources are the predominant type nearing project completion: There is 3.5 GW of nameplate solar capacity (capable of providing 2.3 GW to summer capacity) in Tier 1 resources for the assessment period, making up nearly half of all resources in the

Tier 1 and Tier 2 planning.[16] The projected resources, with planned retirements and additions, are not sufficient for forecasted demand, resulting in some unserved energy and load-loss hours in the future-year energy analysis. While the ARM does not fall below the RML during the 2026–2035 time frame and indicates substantial surplus, the ProbA results indicate significant EUE and LOLH (see Table 6).

Table 6: WECC Basin Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	N/A	3	200,892
NEUE (ppm)	N/A	0.04	2,250.70
LOLH (hours per Year)	N/A	3.00	310.00
Category	-	High	High
***No prior results as the assessment area is new for the *2025 LTRA*.**			

The risk of shortfall in the WECC-Basin area is concentrated in the summer months when seasonal electricity demand is highest. ProbA results for 2027 indicate that risk is most concentrated to the month of peak demand and the hours around sunset as solar output declines. The LOLH in 2027 and 2029 coincides with the evening solar down ramp and the persistence of elevated demand after peak. For 2029, as planned retirements of coal-fired generation and all currently projected resource additions are reflected in the resource mix, risk periods expand across all summer months, and the hours of risk extend from midday to nighttime. In WECC's ProbA modeling, energy transfers from neighboring areas are helping WECC-Basin meet supply deficits, but at times they are insufficient, resulting in unserved energy and load-loss hours.

Unlike the ProbA results from other areas, WECC's probabilistic model produces values higher values for load loss and EUE because the results are not probabilistic weighted averages. Taking this into account, NERC assesses WECC Basin as an elevated risk through 2029 even though the reported load-loss hours from the simulations exceed high-risk criteria

WECC-Northwest (Normal Risk 2026–2028| High Risk 2029–)

Peak load in the WECC-Northwest assessment area is forecast to increase by 6.6 GW (19%) over the next 10 years, driven by an influx of data centers into the Pacific Northwest. There are over 10 GW of new wind, solar, and battery projects expected to connect over the next five years (nameplate capacity) and provide an expected on-peak capacity contribution in winter of 3.2 GW. Additional resources will be needed to avoid shortfalls in planning reserves and prevent energy risks from emerging. While the ARM does not fall below the RML during the 2026–2030 time frame, the ProbA results based on current resource projections and demand forecasts indicate significant EUE and LOLH by 2029 (see Table 7).

Table 7: WECC Northwest Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	N/A	0	8,080
NEUE (ppm)	N/A	0.00	36.64
LOLH (hours per Year)	N/A	0.00	85.00
Category	N/A	Normal	High
***No prior results as the assessment area is new for the *2025 LTRA*.**			

Resource adequacy concerns in the U.S. Northwest can arise in the summer and winter seasons. Peak demand occurs in the winter months. In the ProbA results, load-loss hours occur at a greater frequency during winter high-demand periods. The summer months also have an emerging risk of shortfalls according to the ProbA: The 2029 study year had approximately 85% of identified unserved energy occurring between the afternoon-to-evening hours of mid to late summer.

Elevated-Risk Area Details

The below areas are classified as Elevated Risk as they are projected to meet resource adequacy criteria and have energy and capacity for normal forecasted conditions but are at risk of supply shortfall in extreme conditions. Areas are listed in order of appearance in the Regional Assessments Dashboards section.

MRO-Manitoba Hydro (Normal 2026–2028| Elevated 2029–)

The Winter 2026–2027 peak demand forecast grew by 127 MW, exceeding the projected 29 MW growth from the *2024 LTRA*. Demand growth is driven primarily by population growth and expected economic activity. Conversely, the forecasted annual peak demand growth rate for the next 10 years has fallen to almost 1.4%, down from around 1.8% projected in the *2024 LTRA*. Generating resources are projected to remain largely the same over the 10-year planning period.

Similar to prior probabilistic assessments, Manitoba Hydro's 2025 ProbA indicates elevated-risk levels of load loss in the later (year 4) study year (see Table 8). Resource adequacy concerns and load-loss risk in the ProbA arise from studied very low hydro conditions. Although the Manitoba system is

[16] Tier 1 resources in the LTRA are those resources in the interconnection process that have high confidence of being realized and generally under construction or have signed interconnection agreements. Tier 2 resources have more uncertainty in being realized and are in earlier development stages such as undergoing interconnection planning study.

winter-peaking, the risk is primarily present during the summer season, with some risk also identified in the spring shoulder season. Planned electricity supply resources could fall short during an extreme and prolonged drought, affecting the predominantly hydroelectric system.

Table 8: MRO-Manitoba ProbA Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	5	3	6
NEUE (ppm)	0.18	0.12	0.23
LOLH (hours per Year)	0.06	0.03	0.06
Category	Normal	Normal	Elevated
*** Provides the 2024 ProbA Results for Comparison**			

MRO-SaskPower (Elevated 2026–2027| Normal 2028–)

Large industrial loads in Saskatchewan are driving average annual peak demand growth of 1.0% compounded annually over the next 10 years, down slightly from the *2024 LTRA*'s projection (1.35%). To respond to demand growth, SaskPower recently added 370 MW of natural-gas-fired generation, 220 MW of VERs, and a 20 MW/20 MWh battery storage system to its system and is projecting on-peak resource additions of 700 MW over the next 10 years—a slight decrease from last year's projection (~1 GW). Nameplate additions include 400 MW of wind, 300 MW of solar, and 525 MW of natural gas to offset ~32 MW of confirmed waste heat recovery and wind generation retirements. Saskatchewan is also deferring generator retirements and reactivating recently deactivated coal units and is bolstering both its intra-regional and interregional transmission system to diversify its current portfolio that relies heavily on firm transfers with Manitoba. Reserve margins are expected to remain above SaskPower's RML for the entire 10-year period of the *2025 LTRA*.

SaskPower is a winter-peaking system, but MRO-Saskatchewan's probabilistic studies concluded that LOLH and EUE could occur during planned outages of large generators during peak demand hours in the spring and fall seasons. The ProbA reveals load-loss risk during the months of May, August, September, and October in 2027 based on current planned resources and load forecasts. Monthly and annual results improve in 2029 with SaskPower's projected resource additions (see **Table 9)**.

Table 9: MRO-SaskPower Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	76	145	5
NEUE (ppm)	2.81	5.24	0.19
LOLH (hours per Year)	0.55	1.09	0.05
	Elevated	Elevated	Normal
***Provides the 2024 ProbA Results for Comparison**			

MRO-SPP (Elevated 2026–)

Resource additions and delays in generator retirements since the *2024 LTRA* are improving the resource adequacy outlook for 2026, while higher demand forecasts and less capacity projects in development are causing lower planned reserves in later years. SPP's ARMs are projected to remain above RMLs until after 2030 (see **Figure 5**). Additionally, ProbA results of the planned resources and demand forecast did not identify EUE or load-loss hours in studied years. Seasonal resource adequacy assessments by NERC have identified risks of insufficient operating reserves during periods of low wind and high generator outages.[17] SPP is an elevated risk because it is projected to have lower planned reserves with a similar mix of VERs and dispatchable thermal generation in the future.

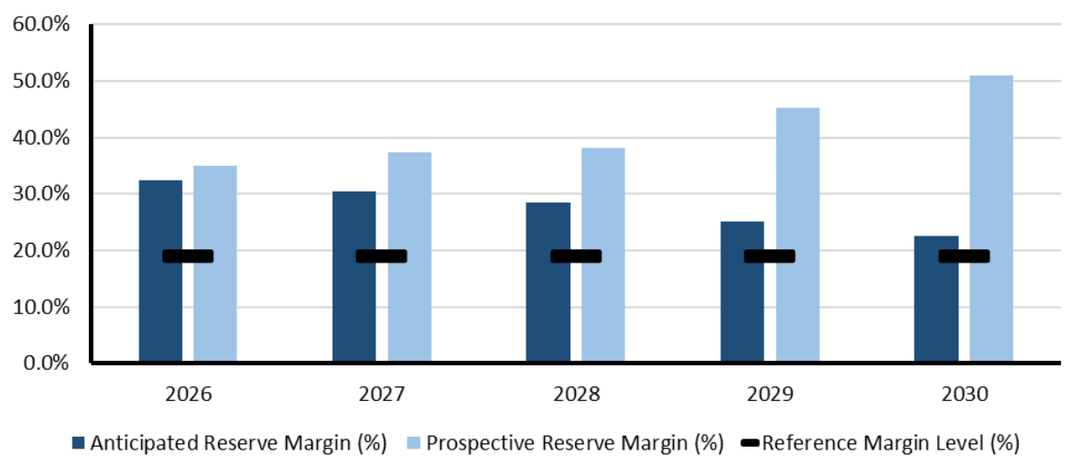


Figure 5: MRO-SPP Five-Year Planning Reserve Margin—Summer

[17] See NERC *2025 Summer Reliability Assessment*

Recent and newly approved resource adequacy initiatives in SPP are aimed at addressing demand growth and energy challenges associated with the evolving resource mix. SPP has approved higher Planning Reserve Margin requirements for LSEs that take effect beginning in the summer of 2026, along with a new winter reserve margin requirement starting later that year. These reserve margin requirements respond to growing resource adequacy challenges by obligating LSEs to obtain more firm resources for the summer and winter seasons. New performance-based resource accreditation will more accurately account for generator contributions to serving area demand during times of greatest need. The *Expedited Resource Adequacy Study* process, approved by FERC in July, is providing an accelerated pathway to interconnection for generation that supports identified resource adequacy needs.

NPCC-Maritimes (Elevated 2026–)

The Maritimes area peak loads are expected to increase by 8% during summer and by 10% during winter seasons over the 10-year assessment period (see **Table 10**). This translates to compound average growth rates of 0.8% in summer and 1% in winter, which are higher than the *2024 LTRA* projections (0.4% in summer and 0.6% in winter). Resource projections for Maritimes have diminished slightly since the *2024 LTRA* due to smaller peak capacity contributions from certain VERs through most of the planning period.

Firm capacity transfers in the first two years of the assessment period (2026–2027 and 2027–2028) decreased significantly from the *2024 LTRA* (322 MWs to -32MWs in 2026 and 215 MWs to 75 MWs in 2027). As a result, the ARM is below the 20% RML in those years, 17.2% and 18.5%, respectively. Beginning in 2028, the capacity transfers for the remaining assessment period are consistent with those in the *2024 LTRA*, and ARMs are projected to remain above the RML of 20% until 2032 when the ARM dips to 18.2%.

Table 10: NPCC-Maritimes Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	5	15	7
EUE (ppm)	0.17	0.52	0.25
LOLH (hours per Year)	0.09	0.25	0.10
***Results from the 2024 The ProbA simulations**			

The ProbA for 2027 indicates elevated levels of unserved energy in the peak winter month of February. Load growth projections and resource mix characteristics are the primary driver. A few hours of risk occur in other winter months. Resource additions contribute to the improved EUE and LOLH metrics for the 2029 study year.

NPCC-New England (Normal 2026 –2028| Elevated 2029–)

Since the *2024 LTRA*, 650 MW of fossil-fired generation has retired in New England, while wind, battery, and solar projects and uprating to an oil-fired power plant are projected to increase summer capacity by 1 GW in Summer 2026. Winter capacity is also increasing by a similar amount due to the expected contribution of offshore wind by winter 2026–2027. New England is among the areas projecting the highest growth in winter electricity demand, with winter peak demand forecast to increase by 7.1 GW (36%) from the Winter 2025–2026 forecast over the next 10 years. This demand forecast has changed little since the *2024 LTRA*.

ProbA results and reserve margin assessment for the NPCC-New England Assessment Area indicate that the risk of unserved energy in New England is small (see **Table 11**). Unserved energy risk is concentrated in the summer months when area demand currently peaks. However, escalating winter electricity demand and the performance challenges faced by the current and future resource mix in extreme, long-duration cold weather events is a persistent reliability concern. New England has already experienced constraints on electric energy production due to the availability of natural gas during winter. Interstate natural gas pipelines serving New England run at full capacity with (firm) gas utility contracts serving their residential, commercial, and industrial (RCI) customers. An extended cold spell or a series of cold spells can threaten regional natural gas fuel delivery infrastructure and result in insufficient fuel for electric generators. Dual-fueled generation provides crucial alternative energy to maintain electric system reliability. In scenarios of extended extreme cold, stored liquid fuels can become depleted and result in insufficient generation for demand.

Table 11: NPCC New England Base-Case Summary of Results

	2026*	2027	2029
EUE (MWh)	11	<1	2
NEUE (ppm)	0.10	0.00	0.02
LOLH (hours per Year)	0.10	0.00	0.00
Category	Normal	Normal	Normal
*** Provides the 2024 ProbA results for Comparison**			

NPCC-New York (Elevated 2026–)

The LTRA anticipated and Prospective Reserve Margins are above RML of 15% for all 10 years. However, the system margins are narrowing throughout the assessment period. Although expected resource contribution is great enough to meet expected demand, there is risk due to the variability in the demand forecast with a greater risk added due to the variability in resource contribution. Demand could be 10–13% higher than expected, which could cause strain on the system.

This impact is shown in the increasing LOLH and EUE shown in **Table 12.**

Table 12: NPCC New York Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	2	<1	12
NEUE (ppm)	0.01	0.00	0.08
LOLH (hours per Year)	0.01	0.00	0.03
Category	Normal	Normal	Normal
*** Provides the 2024 ProbA results for Comparison**			

While NPCC's ProbA results and reserve margin assessment for the New York assessment area indicate that the risk of unserved energy in New York is relatively small, an assessment performed by NYISO, the ***2025 Quarter 3 Short-Term Assessment of Reliability*** **(STAR)**,[18] identified transmission security reliability needs in the New York City and Long Island parts of the system to ensure summer reliability. With little reliability margin, plausible futures point to system issues within the next 10 years. Depending on demand growth and retirement patterns, the system may need several thousand megawatts of new dispatchable generation over that time frame.

Due to the reliability needs identified in the STAR report, NERC assesses that NPCC-New York is an elevated risk area and that, with current resource and transmission system projections, localized supply shortfalls are likely in extreme conditions.

NPCC-Québec (Normal 2026–2028| Elevated 2029–)

Québec's demand forecast has increased since the *2024 LTRA*, driven by electrification of transportation, industrial decarbonization, and electric heating. New sectors such as hydrogen production, battery manufacturing, and data centers are also contributing to demand growth. Québec's demand peaks at 41.4 GW in 2026–2027, rising to 49.6 GWs by 2035–2036, an increase of 8.2 GWs compared to the assessment period growth of 7.5 GWs projected in the *2024 LTRA*.

With stable resources over the 10-year assessment period, Québec's ARMs remain above the 12.2% RML for the first four years, falling below in 2030–2031 and all subsequent years. Québec and Ontario have a firm seasonal capacity exchange agreement through 2030–2031 that allows Québec to import 600 MW in winter.

Hydro-Québec's Action Plan 2035 and a memorandum of understanding with Newfoundland and Labrador outline major new capacity additions, including hydro upgrades, new large hydro power plants, wind and solar development, and potential battery storage and natural-gas-fired generation. These resources are not included in the present assessment due to their early development stage but are expected to be incorporated gradually into future assessments.

Hydro Québec is a winter-peaking area. There were no significant LOLH or EUE estimated for Winter 2027–2028. For Winter 2029–2030, EUE and LOLH are above the elevated risk criteria See **Table 13**.

Table 13: NPCC Québec Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	8	8	63
NEUE (ppm)	0.04	0.00	0.29
LOLH (hours per Year)	0.01	0.00	0.11
Category	Normal	Normal	Elevated
*** Provides the 2024 ProbA results for Comparison**			

SERC-East (Normal 2026| Elevated 2027–)

SERC-East is projecting over 5.7 GW of coal unit retirements over the 10-year assessment horizon. These continued retirements from prior years continue to trigger reserve margin targets and ProbA thresholds for elevated risk. To offset the upcoming retirements, SERC-East has planned 2 GW of solar resources and 8.9 GW of gas additions over the next 10 years. The 2025 ProbA reveals elevated levels of risk occurring in both the 2027 and 2029 study years, as shown in **Table 14** below.

Table 14: SERC-East ProbA Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	143	232	539
NEUE (ppm)	0.60	0.98	2.27
LOLH (hours per Year)	0.09	0.15	0.33
Category	Normal	Elevated	Elevated
*** Provides the 2024 ProbA Results for Comparison**			

[18] Additional details available in the report: https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf/

Normal-Risk Area Details

All other assessment areas (see Figure 1) are classified as normal risk. In these areas, resource adequacy criteria are met, and there is a low likelihood of electricity supply shortfall even when demand is above forecasts or resource performance is abnormally low (e.g., above-normal forced outages or low VER performance).

Resource and Demand Projections

The **Capacity and Energy Risk Assessment** section is a forward-looking snapshot of resource adequacy that is tied to industry forecasts of electricity supplies, demand, and transmission development. Later sections in this report describe important trends in each of these forecast areas. The future electricity supply will come from a resource mix that is more variable, weather-dependent, and reliant on natural gas for fuel, requiring broad coordination and careful attention to manage reliability risks. Future electricity demand is being shaped by many factors that collectively influence peak demand forecast levels, peak seasons, and hourly profiles. Peak demand and energy forecasts are projected to continue rising dramatically over the *2025 LTRA* assessment period, exceeding their highest rates in recent years. Ongoing challenges with resource and transmission development and the continued pace of generator retirements raise concerns that the risk assessment map will expand with more elevated- and high risk areas in the future.

Risk from Additional Generator Retirements

Accelerated retirements of the existing coal, natural gas, petroleum, and nuclear generators can negatively affect the resource adequacy and reliability of the BPS in the next 10 years. In the preceding **Capacity and Energy Risk Assessment**, NERC accounted for nearly 92GW of nameplate of fossil-fired and nuclear generator retirements that are anticipated through 2035. NERC's risk analysis did not include an additional 65 GW of nameplate fossil-fired generators that have announced plans to retire over the decade but have yet to enter deactivation processing with the planning authorities. Combined, the confirmed and announced-potential retirements over the next 10 years total over 105 GW in peak seasonal capacity, roughly 10 GW lower than the 10-year retirement projections in the *2024 LTRA* (see **Figure 6**). Projected retirements overall, both confirmed and unconfirmed, have shrunk from the prior year's LTRA as reliability needs have expanded with the continued growth in anticipated large-load interconnections. The initiation of market mechanisms like capacity accreditation has also more precisely highlighted the loss-of-load risks posed by a generation mix that has increasing amounts of variable resources. Growing demand and evolving planning methodologies have highlighted the potential need to keep resources, particularly non-variable resources, on-line longer than previously anticipated.

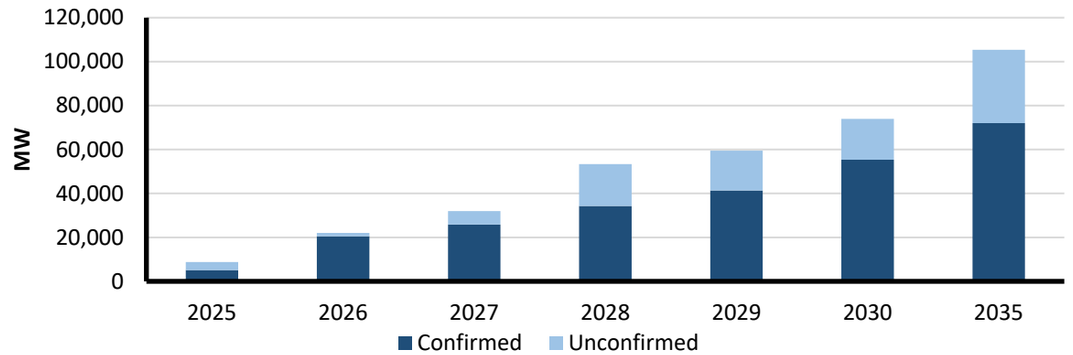


Figure 6: Projected Generation Retirement Capacity Through 2035

Figure 7 shows the total capacity of reported retirements (i.e., reported to ISO/RTOs and planning entities) as well as owner-announced, unconfirmed retirements of fossil-fueled and nuclear generators across the BPS over the next 10 years in each assessment area.[19] MISO continues to lead the assessment areas in the amount of projected retiring capacity at roughly 35 GW.

The yearly projections of future retirements and an assessment area view are provided in the **Risk from Additional Generator Retirements** section.

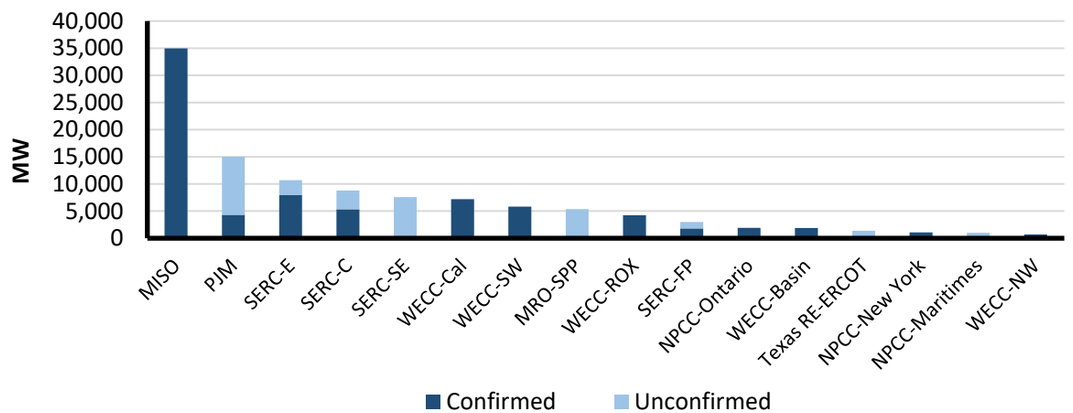


Figure 7: Projected Capacity Retirements of Nuclear and Fossil Generation 2025–2035

[19] Confirmed generator retirements are reported to NERC by each assessment area in this *2025 LTRA* development process. NERC obtained data on announced, unconfirmed generator retirements from Energy Ventures Analysis, Inc. and from each assessment area. Some sources of information on announced generator retirements include EIA 860 data, trade press, and utility integrated resource plans.

Reducing Resource Capacity and Energy Risk

The risk of electricity supply shortfalls in the assessment period can be lowered through the concerted efforts of resource and system planning stakeholders. The actions taken in electricity markets and regulatory jurisdictions with the improving trends noted previously provide examples of what can work: obtaining additional firm resources to meet resource adequacy targets, delaying generation retirements when reliability needs dictate, and using capacity targets and energy risk metrics based on better resource and demand models. Specific and actionable recommendations are contained in the **Executive Summary**.

Resource Adequacy Program Attributes

Utilities, market operators, and regulators across North America are adapting their resource adequacy programs to address mounting challenges, including load growth, changing load behavior, resource mix transition, extreme weather, and evolving end-use need for electricity. NERC and industry stakeholders have recognized key resource adequacy program attributes that may become needed to address specific challenges faced by system planners and operators. **Table 15** includes five of these attributes and a brief description of how the attribute can be implemented. Assuring an adequate supply of electricity requires modernizing planning approaches. NERC encourages each assessment area to evaluate the program attributes needed to plan effectively for current and future challenges and implement those identified as essential.

Table 15: Resource Adequacy Program Attributes

Attributes	Objective	Implementation
1. Uses Energy Risk Criteria	To ensure energy adequacy in systems with VER and fuel limitations, resource planners and markets need to augment existing 1-day-in-10 load-loss criteria with additional energy risk metrics.	Establish criteria based on EUE or similar energy risk metric(s).
2. Evaluates Resource Contributions at Risk Periods	As periods of shortfall risk on the system change with changing resource and demand characteristics (e.g., risks during winter and summer, peak net demand, and shoulder seasons), methods for assigning resource contributions in resource procurement and assessments must evolve.	Adopt effective load-carrying capability or other probabilistic methods for determining resource contributions during risk periods.
3. Load Forecasting Accounts for Growth Uncertainty	Future electricity demand is being influenced by the pace of electrification, industrialization, data center development, and DER adoption. Load forecasts for adequacy assessment and resource planning need to account for new growth patterns and uncertainty.	Capture the forecast drivers needed for the area and address uncertainties.
4. Considers Effect of Extreme Scenarios on Adequacy	To reduce the unique resource adequacy risks from wide-area extreme weather events, resource adequacy programs should evaluate potential system impacts and weather scenarios to mitigate risk to the BPS.	Analysis considers low-probability energy events (e.g., drought, multi-day weather patterns) and adequacy criteria include load-loss event magnitude and duration.
5. Includes Coordinated Interregional Transfer Capability	Interregional transfer capability can provide enhanced reliability and resilience and is most effective when resource adequacy programs include coordination with neighbors.	Model transfer limits and deliverability; implement processes for seams coordination.

Demand Trends and Implications

Demand and Energy Projections

Electricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb higher than at any point in the past two decades. See **Figure 8** for seasonal peak demand growth over the current and prior assessment periods and **Figure 9** for net energy growth. Over the 10-year period, aggregated assessment area summer peak demand is forecast to rise by over 224 GW. This is 69% higher than last year's 10-year growth projection of 132 GW. Winter demand growth continues to outpace summer demand growth: The 10-year aggregated winter peak demand is forecast to rise by over 245 GW, a 65% increase from last year's 149 GW growth projection. Compound annual growth rates (CAGR) for summer and winter peak demand are the highest since NERC's tracking started in 1995. A map of the primary demand drivers for the North American BPS is illustrated for each assessment area in **Figure 10.**

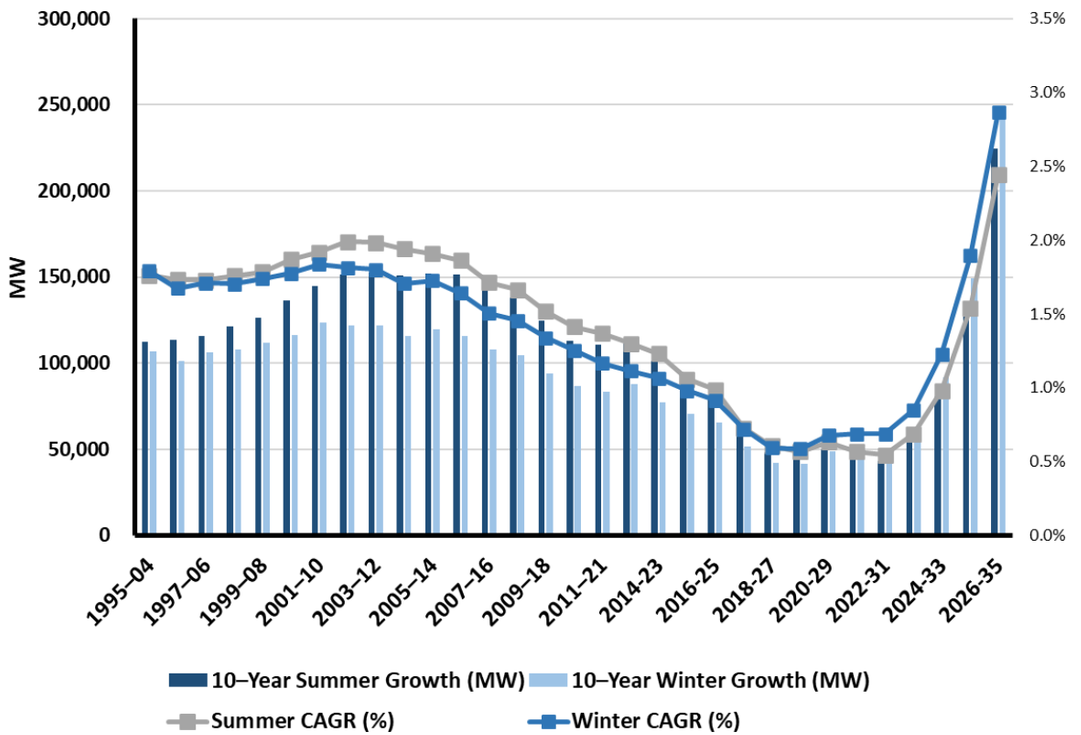


Figure 8: 10-Year Summer and Winter Peak Demand Growth and Rate Trends

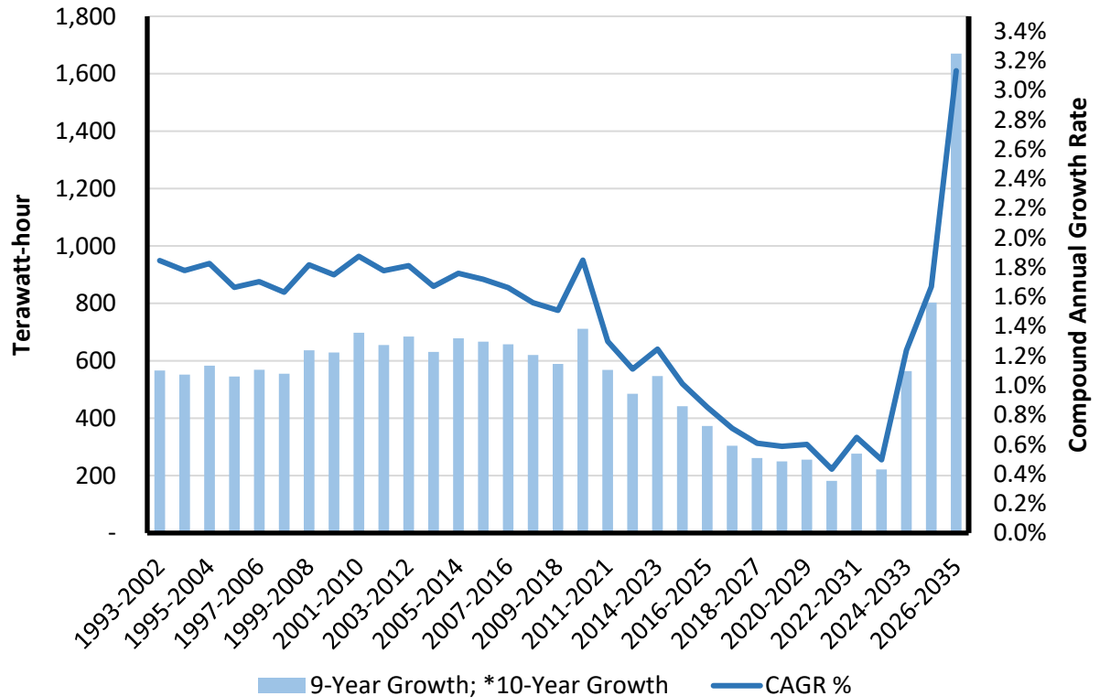


Figure 9: Net Energy for Load Growth and Rate Projections

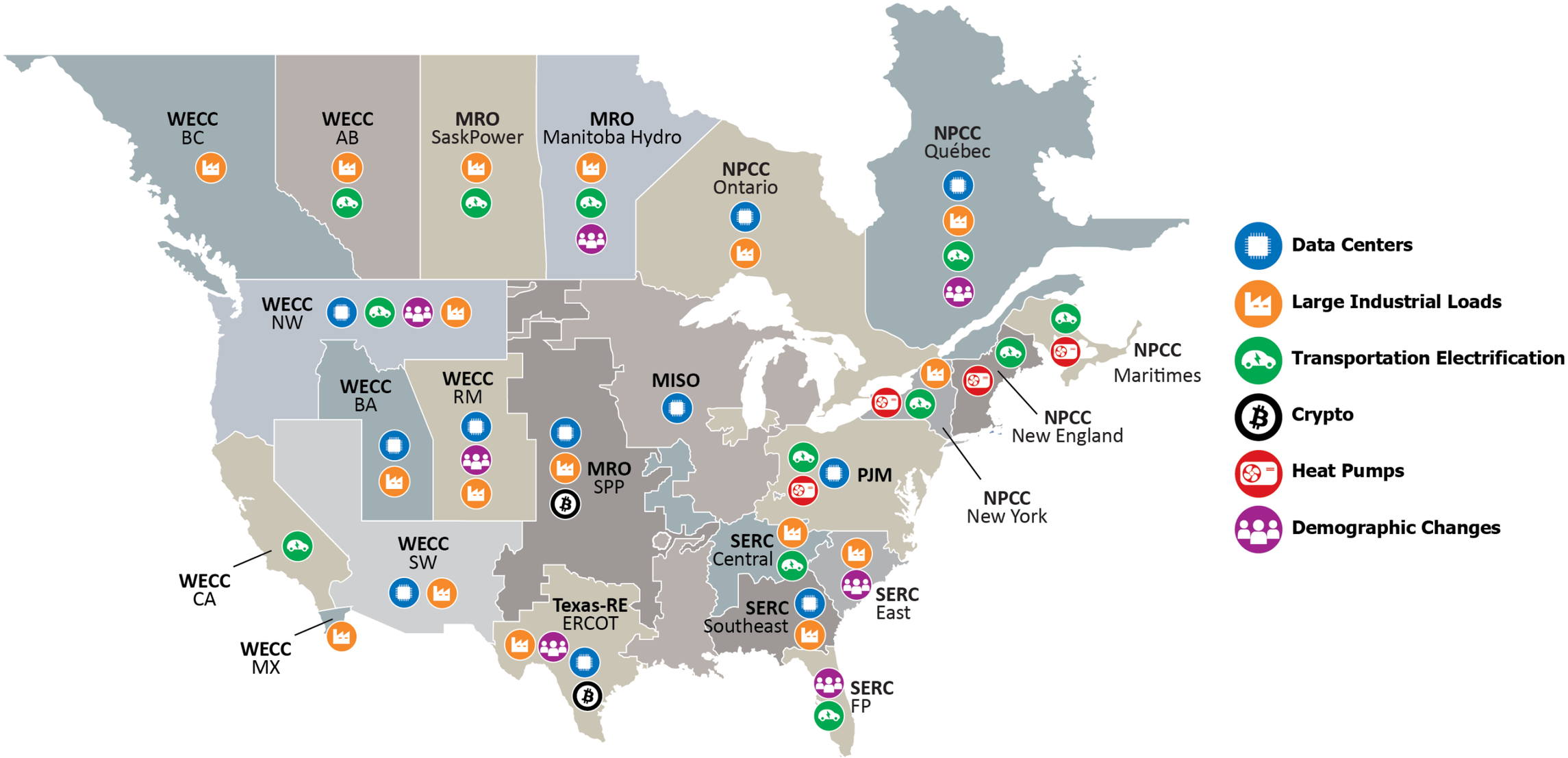


Figure 10: Primary Demand Drivers by Assessment Area

Data Centers and Large Commercial and Industrial Loads

New data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years. These and other large commercial and industrial loads are connecting rapidly to the BPS. The emerging large loads present unique challenges to forecasting and planning for increased demand.

Load forecasts collected by NERC for the *2025 LTRA* reveal the massive build-out of data centers in many parts of North America. Texas, PJM, and the WECC assessment areas are reporting steep demand increases due primarily to new data centers and large loads. BAs within WECC reported that planned data centers account for an average of 10% of demand, with some BAs reporting as high as 40% of the demand forecast. See **Figure 11** and **Figure 12** for projections in ERCOT and most WECC assessment areas, respectively.

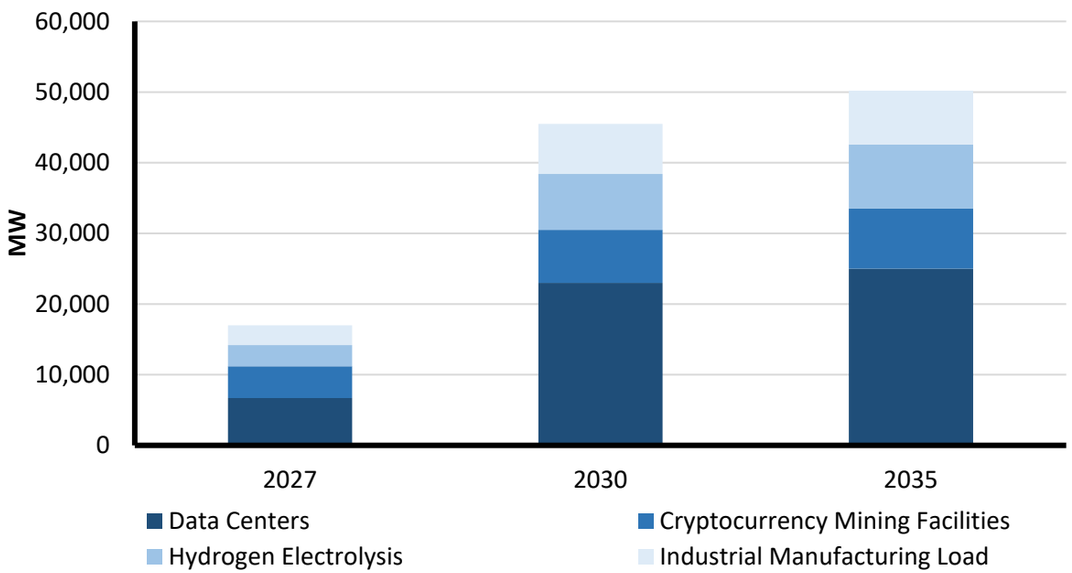


Figure 11: Large-Load Projection Breakdown in ERCOT

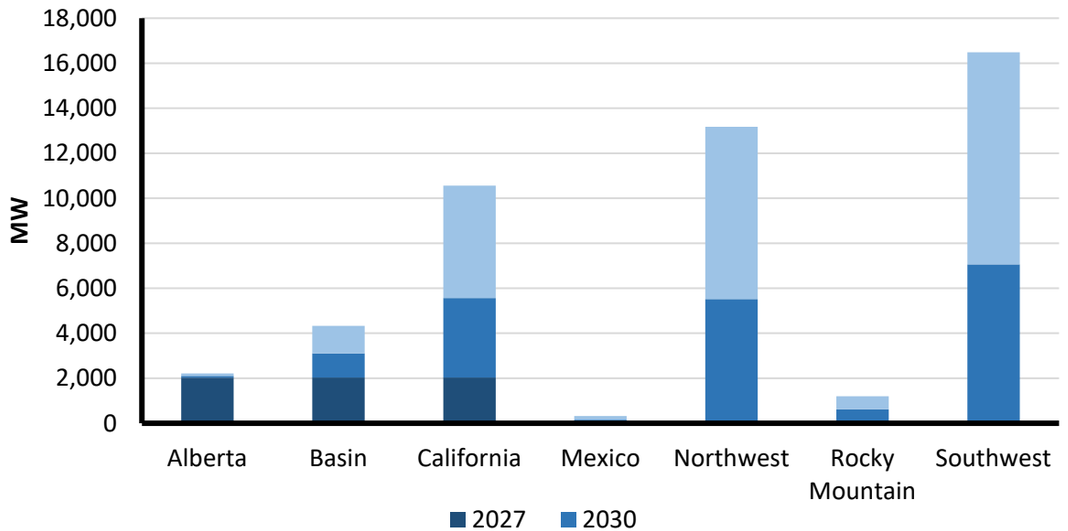


Figure 12: Large-Load Projection by Year in WECC Assessment Areas

Demand forecasts and large load projections throughout the LTRA are based on LSE and BPS system planner forecasts. LSE load forecasts are based on information from the interconnection process and agreements between utilities and owners of connecting loads, such as facility peak demand, load flexibility, and some operating characteristics. To be counted in load forecasting, data center projects have advanced from speculative and exploratory stages into development commitments necessary to drive grid planning studies. Consequently, data center and large load growth forecasts in the LTRA are likely to be more conservative than predictions from the technology industry or from economic, research, academic, and policy organizations.

In Texas, fluctuations in recent large-load interconnections activity continue to affect both near- and long-term demand expectations. Utilities and system operators are also gaining insights from large-load development and operating behaviors and applying them to future forecasts. Several projects have slowed or failed to materialize within the shorter-term horizon, while interconnection requests for later years continue to increase. New data center demand projections in Texas are reduced by almost 50% of their original requested load level to reflect the observed consumption behavior of existing data center sites during their initial operations. ERCOT also slashes most new large loads that have yet to enter a contract for transmission service from its long-term demand forecast and adjusts

expected in-service dates to account for historical delays. Similarly, PJM is refining processes for large load forecasting starting with its 2026 load forecast.[20]

There is already evidence that large loads impact BPS reliability. For example, the Eastern and ERCOT Interconnections have observed load-reduction events[21] with each Interconnection experiencing approximately 1,500 MW of voltage-sensitive load reduction. The event in the Eastern Interconnection was primarily attributed to data centers and other power electronic loads (PEL) transferring load to backup generation and caused frequency overshoot and high voltages. The ERCOT Interconnection event involved many different types of loads of varying size reducing consumption during an extended low-voltage period in West Texas due to a protection system misoperation. These load-reduction events highlight some of the potential risks posed by large loads utilizing the BPS and why NERC is closely examining this issue. NERC's RSTC established a Large Loads Task Force (LLTF)[22] to better understand the reliability implications of growth in large loads and develop solutions. The LLTF published the white paper *Characteristics and Risks of Emerging Large Loads*[23] in 2025, and another white paper, *Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads*, is forthcoming.[24]

Electrification and Demand Growth

Electrification of household appliances (e.g., heat pumps for household heating) and projections for electric vehicle growth over this assessment period are components of the demand and energy estimates provided by each assessment area. Since the *2024 LTRA*, peak season CAGR has risen in all assessment areas except five: MRO-Manitoba Hydro's winter CAGR fell from 1.79% to 1.37%, MRO-SaskPower's winter CAGR fell from 1.32% to 0.89%, NPCC-New England's summer CAGR from 1.28% to 1.05%, NPCC-New York's summer CAGR from 0.87% to 0.84%, and SERC-East's summer CAGR fell from 1.88% to 1.17%. Rising peak demand forecasts are contributing to the lower reserve margins projected for nearly all assessment areas.

Peak Season Transition

Some of the sharpest peak demand forecast increases and growth rates can be seen in winter seasons as electrification in heating systems and transportation influence forecasts. Dual-peaking or changing from summer to winter peaking is anticipated in several areas, including the U.S. Southeast and Northeast. Electrification of heating systems and the anticipated growth of electric vehicles (which are expected to charge overnight and coincide with periods of electricity demand for heating) are driving factors. Such changes have wide-ranging implications for how the grid and resources are planned and operated. For example, resource output and fuel risks are significantly different in winter, requiring the focus of resource adequacy processes to change. The following are the areas that anticipate a change from summer-peaking systems to winter-peaking (or dual-season peaking) systems and the approximate year of the transition:

- NPCC-New England (mid-2030s)
- NPCC-New York (late-2030s)
- NPCC-Ontario (2030; dual-season peaking)
- Texas RE-ERCOT (2035)

In the U.S. Southeast, SERC-Central and SERC-East became dual-peaking systems in recent years. SERC-Southeast recently began experiencing slightly higher peak demand in winter compared to summer. In Canada, WECC-Alberta has been operating as a dual-peaking system.

Demand Response

Demand-side management programs are growing for many assessments areas. DR is one form of demand-side management. It consists of mainly commercial and industrial end users that have entered into agreements with load-serving entities to curtail demand when needed by grid operators. DR can assist with reducing load during critical periods of increased demand, such as heat waves or winter storms. **Figure 13**, **Figure 14**, and **Figure 15** show the increasing projections for DR in the first year of the forecast for the past five LTRA reports in Texas RE-ERCOT, NPCC-Québec, and NPCC-New York, respectively. Other forms of demand-side management include EE and conservation programs administered by utilities. The reported contributions from DR, EE, and conservation programs reduce total electricity demand in load forecasts and provide reliability benefits that are accounted in LTRA reserve margin calculations and the ProbAs.

[20] Planned revisions to PJM's treatment of large load forecasts from PJM's Load Analysis Subcommittee: 20250613-item-03--large-load-adjustment-process-improvement-discussion.pdf

[21] "Incident Review - Considering Simultaneous Voltage-Sensitive Load Reductions," NERC, Jan. 2025. Available: https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf

[22] NERC Large Loads Task Force webpage: Large Loads Task Force (LLTF)

[23] The LLTF's *Characteristics and Risks of Emerging Large Loads* White Paper

[24] The LLTF's action plan is updated regularly and contains links to white papers, guidance, and presentations.

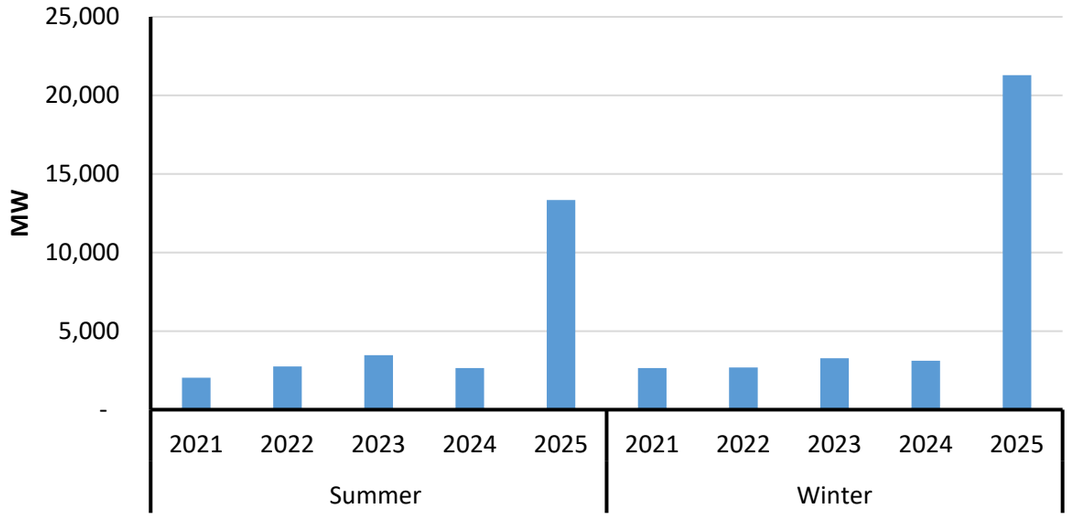


Figure 13: Texas RE-ERCOT Demand-Response Trend in Past Five LTRAs (Year 1)

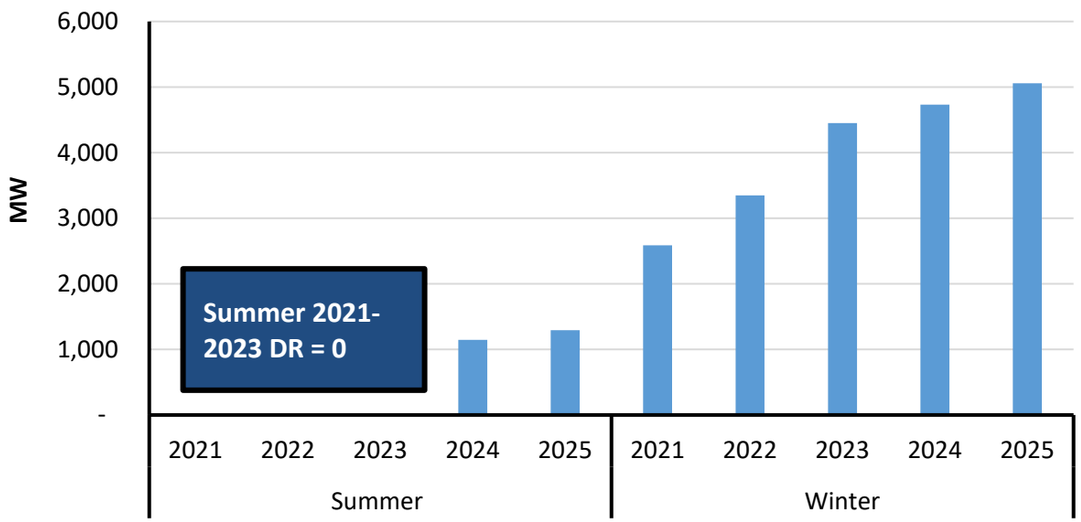


Figure 14: NPCC-Québec Demand-Response Trend in Past Five LTRAs (Year 1)

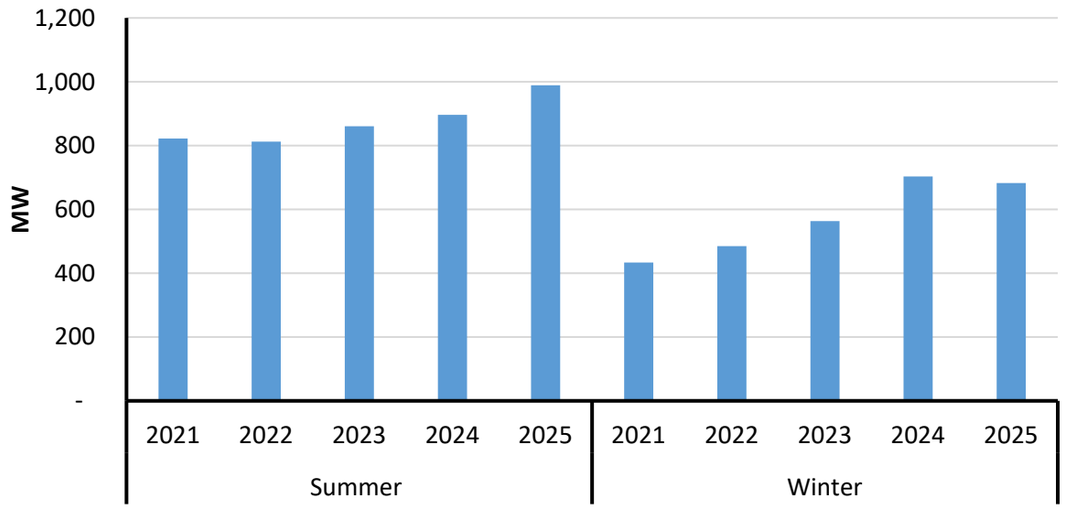


Figure 15: NPCC-New York Demand-Response Trend in Past Five LTRAs (Year 1)

Reliability Implications

Demand and energy growth projections in this assessment period provide both challenges and opportunities for electric grid reliability. Planning for resource and transmission adequacy requires accurate long-term forecasting, but future demand and energy use will be influenced by many factors, including the economy, energy policies, technology development, weather, and consumer preferences. Changing patterns in electricity use, load behavior, and DER performance affect the accuracy of operational load forecasts that are essential to grid operators. Large flexible loads and demand-side management programs hold promise for peak load management capabilities that can reduce the risk of firm load interruption.

Anticipating large commercial and industrial loads, electrification, electric vehicle adoption, and the impacts of energy transition programs on future demand and energy needs will require even more focus for planners and operators. Peak demand forecast changes in the past year noticeably affected resource adequacy for many areas. A confluence of factors (economic, energy policies, technology development, and consumer preferences) has the potential to fuel continued growth.

Resource Mix Changes

On-peak resource capacity increased approximately 6.2 GW across the interconnected North American BPS over the last year. This is down from approximately 8.3 GW of net on-peak capacity additions reported a year ago in the *2024 LTRA*. Net capacity from fossil-fueled generators continued to decline at a rapid pace over the last year with approximately 21 GW leaving the system. Continent-wide, net BPS additions of battery, wind, and solar resources totaled 23 GW over the last year (see Table 16).

Table 16: Existing BPS Resource On-Peak Capacity

Resource Type	2024 Capacity (MW)	2025 Capacity (MW)	Difference (MW)
Coal	180,402	166,799	– 13,603
Petroleum	30,987	27,931	– 3,056
Natural Gas	484,148	479,901	– 4,247
Biomass	7,381	7,181	– 200
Solar	66,293	70,723	+ 4,430
Wind	31,370	35,121	+ 3,751
Geothermal	3,881	2,932	– 949
Conventional Hydro	105,792	111,117	+ 5,325
Run-of-River Hydro	2,047	2,017	– 30
Pumped Storage	19,422	19,734	+ 312
Nuclear	105,384	105,389	+ 5
Hybrid	1,322	1,102	– 220
Other	774	830	+ 56
Battery	8,587	23,267	+ 14,680
Total	1,047,790	1,068,514	+ 6,254

Like last year, the anticipated BPS generating capacity (i.e., capacity from existing generation + expected additions – expected generator retirements) fell short of industry projections reported in the LTRA, furthering the concerns that accelerating peak demand growth is continuing to outpace the supply resources.

Figure 16 compares this year's existing and Tier 1 nameplate and on-peak capacity against the actual current capacities derived from data collected for this year's LTRA. Bars that cross the 100% line represent resources with actual additions exceeding projections from 2024, and bars that fall to the left of the 100% line represent resource types with actual additions less than projected in 2024.

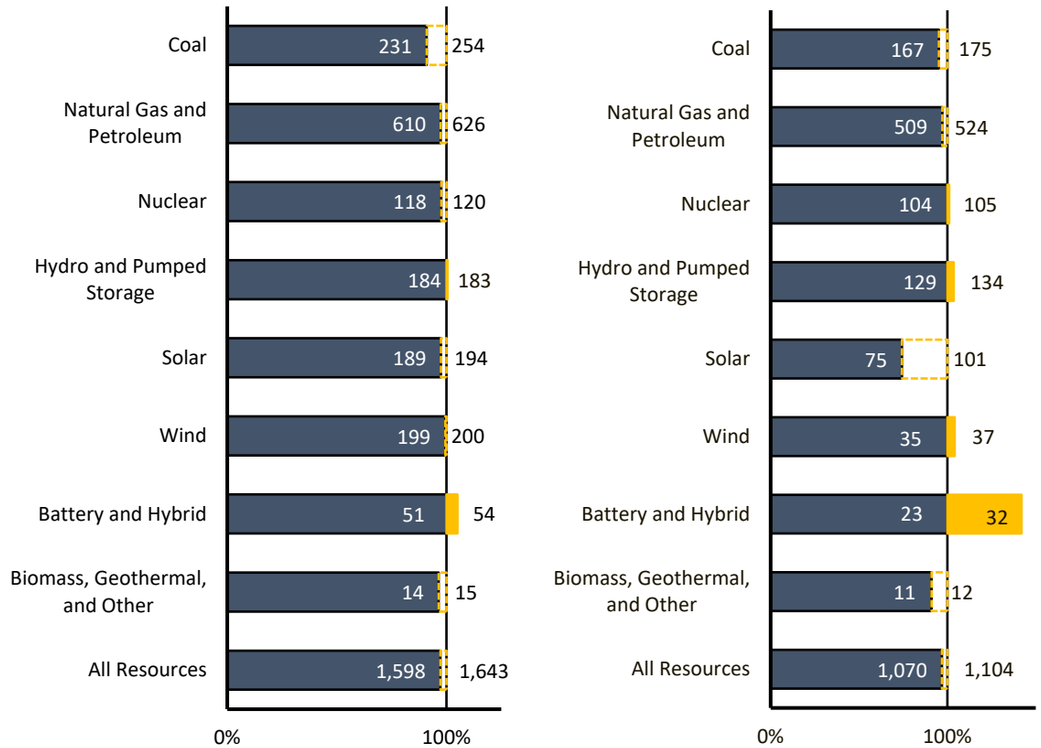


Figure 16: Comparison of North America's 2025 Existing and Tier 1 Nameplate (Left) and On-Peak (Right) Capacities in GW to *2024 LTRA* Projections

Continuing the trend from last year, battery energy storage systems were added to the system faster than expected, while coal, natural gas and petroleum, and solar resources were once again over-projected. As coal capacity continued its decline because of plant retirements and age-related derating, its over-projection from last year means that it left the system faster than anticipated in 2025.

Notably, the capacity contribution of VERs, including solar, wind, battery, and some types of hydroelectric generation, to serving load at peak demand differs from the nameplate, or installed capacity. The right plot in Figure 16 above includes a complementary view to the on-peak projections using nameplate capacity to accommodate different capacity accounting methods. Both 2025 on-peak and nameplate solar was over-projected across the North American BPS last year. These over-

projections continue to support electric industry reports of construction delays and project withdrawals prior to commercial operations that prevented the expected interconnection of new resources.

Planned On-Peak Capacity Additions

New resources are added to the BPS through each area's interconnection planning process. Entities have expressed concerns that the pace of resource additions has been too slow to meet demand growth and future retirements in the existing generator fleet. **Figure 16** above highlights that industry participants are expecting peak demand growth of nearly 250 GW over the next 10 years because of accelerating demand for a variety of electricity users. Planning for such explosive growth and the uncertainty about its magnitude and timing is a complicated challenge for system planners.

Figure 17 illustrates the planned on-peak capacity additions and subtractions across the North American BPS over the next 10 years. Additions are illustrated by the positive portions of the stacked columns and include both Tier 1 and Tier 2 additions. In general, Tier 1 resources are in the final stages for connection, while Tier 2 resources are further from completion (see **Demand Assumptions and Resource Categories**). Some projects that are in the earlier stages of the interconnection queue process will be withdrawn before completion due to supply chain issues, planning and siting challenges, and business or economic factors. Deratings and retirements of the existing fleet are stacked in the negative Y direction with diagonal hatching patterns.

To keep up with forecasted demand growth and generator retirements, planned resources with interconnection agreements will need to come in on time, and additional resources in development must mature through the interconnection process quickly (see **Figure 18**). The on-peak capacity of approved resource additions found in integrated resource plans (IRP) and ISO/RTO expansion plans through 2028 is able to keep pace with the aggregated peak demand forecasts of all NERC assessment areas. Beyond 2028, new approvals for resource additions are required to maintain robust growth. Furthermore, additional generation is needed to make up for capacity lost to generator retirements. Considering the generator retirements depicted in **Figure 17**, there are only approximately 60 GW of net additions planned in the most certain Tier 1 category over the next 10 years. Another 190 GW of Tier 2 or other resources (70% of Tier 2's 10-year total) would need to complete the interconnection planning process and reach commercial operations to meet the expected demand growth, illustrating the pressure on resource and system planning to rapidly add resources. DR programs, EE improvements, and transmission development to enable interregional transfers that take advantage of geographic diversity can also support growing demand.

To respond to this urgent need for new resources, independent system operators and regional transmission organizations have been developing new market structures and products to retain capacity and expedite interconnection of new generation and storage. Three such programs established by ISO/RTOs are PJM's Reliability Resource Initiative, MISO's ERAS process, and SPP's *Expedited Resource Adequacy Study*.

In a shift from a key insight from the *2024 LTRA*, solar PV is no longer the sole, predominant generation type planned over the next 10 years. New battery resource projects have grown to match solar projections, and together, solar and battery capacity additions represent two-thirds of the Tier 1 and Tier 2 resources in this year's 10-year LTRA study period. Natural-gas-fired generator additions represent 15% of the projected capacity additions followed by wind and hybrid at 8% each. While interconnection queues continue to swell, considerable uncertainty surrounds the timing and amount of resource additions. Overall, on-peak resource capacity in Tier 1 and Tier 2 has grown only modestly since the 2024 LTRA by 7 GW (1.7%) as compared to a year-over-year growth of 44 GW last year.

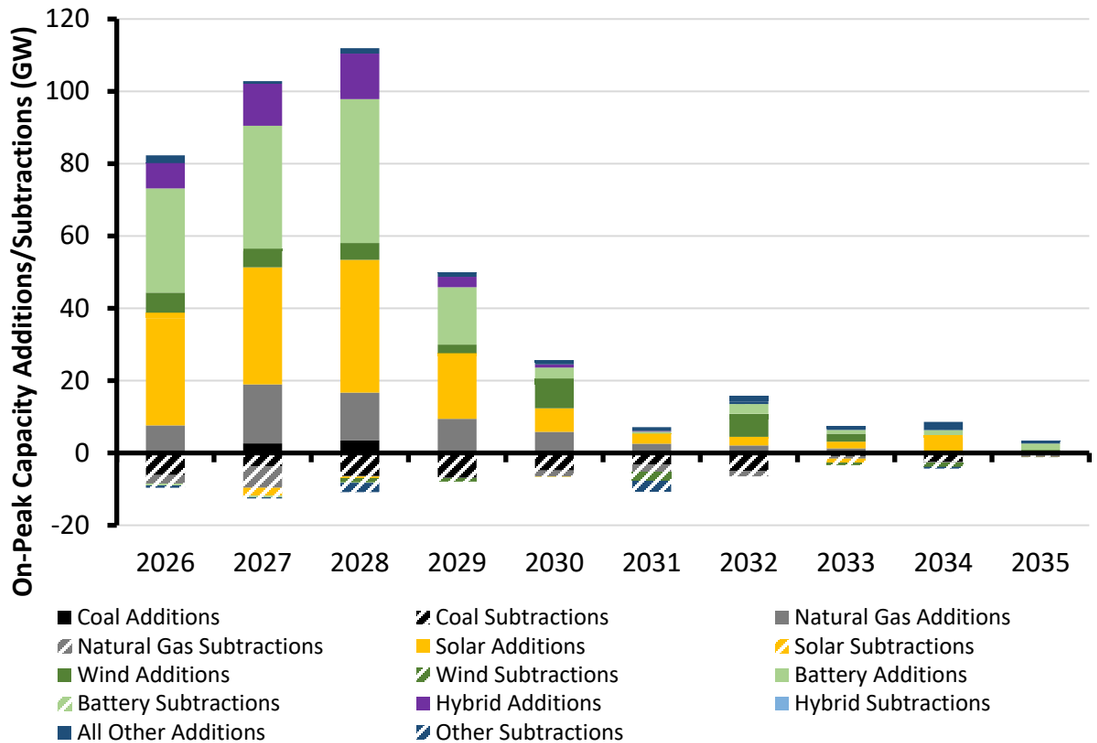


Figure 17: Projected Annual On-Peak Capacity Additions and Subtractions by Resource Type and Net Cumulative Capacity Changes

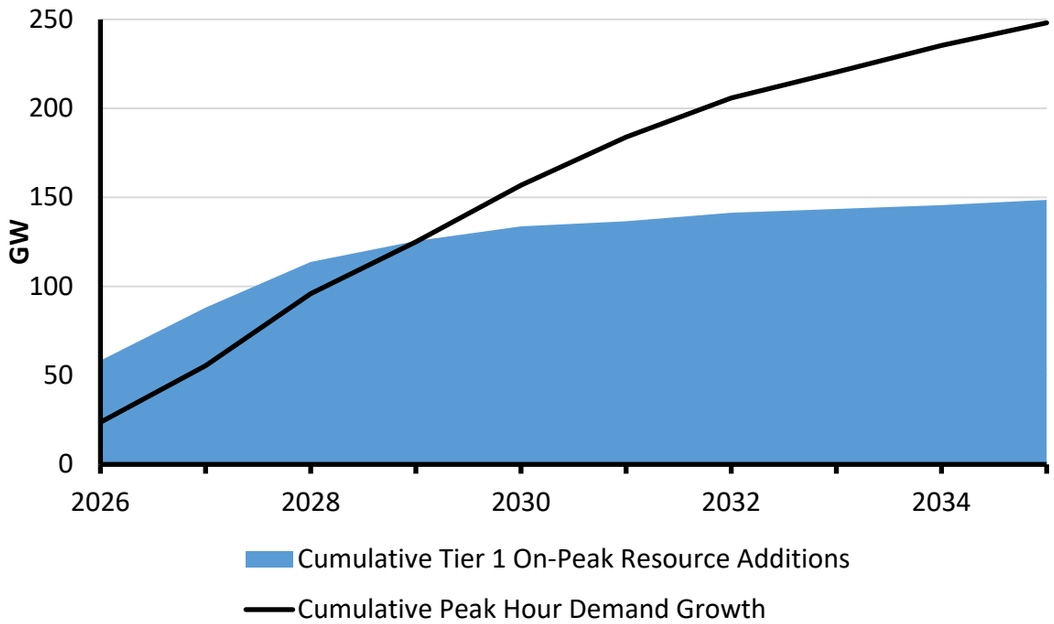


Figure 18: Expected BPS Resource Additions (Tier 1) and Aggregated BPS Peak Demand Growth Through 2035

Increasing On-Peak Share of Variable Resources

Year-over-year increases in the fraction of on-peak capacity provided by VERs—run-of-river hydro, solar, and wind—have continued since the 2024 LTRA with VER on-peak contributions increasing from 9.5% to 10.2%. This observed trend is projected to continue through 2035 with shares of on-peak VER capacity projected to rise to between 15% and 20% depending on the completion and interconnection of Tier 1 and Tier 2 resources. **Figure 19** shows existing on-peak capacity by resource type for 2024 and 2025 along with projected on-peak capacity by resource type for 2035 with Tier 1 and Tier 2 additions. Resource types with on-peak shares less than 5% are not labeled with their contribution fraction but are stacked in the graphic.

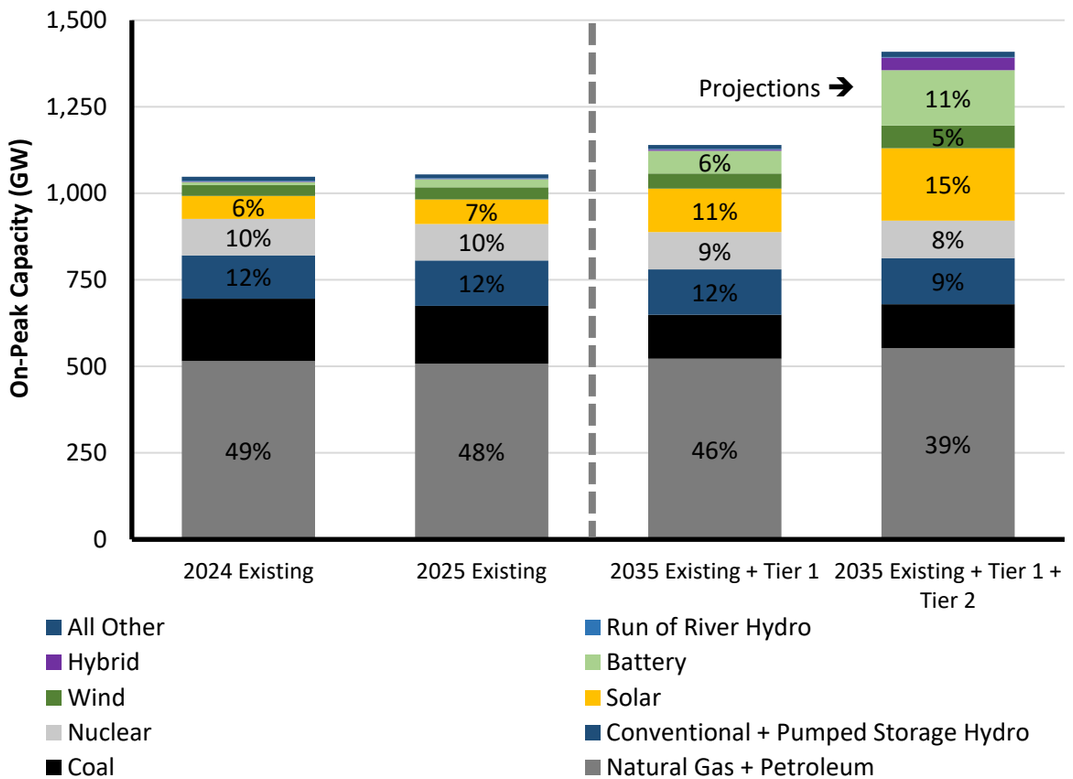


Figure 19: North America On-Peak Capacity Shares by Resource Type

Like last year, a relatively small change in total on-peak capacity was observed, but the continued trend of increasing VER share highlights that important reliability attributes continue to leave the system. Non-variable generation—including coal, petroleum, natural gas, biomass, geothermal, conventional hydro, and nuclear—as well as hybrid or storage systems can ramp up or down in response to demand. Non-variable resources can also provide other ERSs like system inertia, dynamic reactive support, and frequency response for stable grid operation. Many of the variable resources that are being added to the grid to replace non-variable resources cannot provide the same ERSs in their current configuration. This deficiency is amplified in the winter when on-peak contributions from variable resources are diminished by changing weather and environmental conditions.

System Frequency Response Analysis

Despite lower inertia from retiring synchronous generators and greater penetration of inverter-based resources, all four Interconnections expect adequate, diverse frequency response capabilities and a low risk of under-frequency load shedding (UFLS) activation. In preparing the *2025 LTRA*, NERC worked with the Regional Entities and system planners to assess the frequency response capability of the projected resource mix through 2027 on an Interconnection basis. The findings are summarized in Table 17.

Table 17: Measures of Frequency Response

Measure	What it Measures	Summary Assessment Findings
Synchronous Inertial Response (Measure 1)	The minimum inertial response amount (total stored kinetic energy) projected in each Interconnection	Despite the retirement of synchronous generation over the past eight years, there appears to be more than sufficient inertia within all Interconnections. ERCOT's use of load response to respond to frequency disruptions is effective in supporting low-inertia conditions.
Rate of Change of Frequency (Measure 2)	The calculated rate of frequency decline within the first 0.5 seconds following the largest credible contingency	No negative trends identified. Texas RE-ERCOT studies show that load response is extremely effective in arresting frequency due to its ability to perform very quickly.
Frequency Response Performance (Measure 4)	Simulated dynamic behavior of an Interconnection's response to the largest credible contingency	Simulations in both the Eastern and Western Interconnection show sufficient frequency response in future planning cases.

The results of analysis for each Interconnection are in Table 18. Non-synchronous resources have increased in all Interconnections since the last LTRA frequency response analysis in 2022. Each interconnection continues to project sufficient frequency response ERSs in the near term and have low likelihood of UFLS activation during a disturbance. These results were determined by dynamic studies performed for the Eastern, Western, and Québec Interconnections and analysis of operational procedures for the Texas Interconnection.

Table 18: Summary of the Results of NERC Frequency Response Sufficiency Assessment

Interconnection	Highest Non-Synchronous Penetration at Minimum Inertia Studied	Number of Critical Inertia Conditions Reached?	Lowest Frequency Nadir Observed in Planning Studies	Likelihood of Credible Disturbance Resulting in UFLS Activation
Eastern Interconnection	17.9%[25]	0	59.93 Hz	Low
Western Interconnection	42.9%[26]	0	59.65 Hz	Low
Texas Interconnection	65.7%	0	N/A	Low[27]
Québec Interconnection	37%	0	N/A	Low

Increasing Natural Gas Reliance

In 2024, natural-gas-fired power plants generated approximately 43.4% of all electricity generated in the United States, according to the U.S. Energy Information Administration, up from 43.2% in 2023. As of August 2025, natural-gas-fired power plants in the United States are on track to generate a slightly smaller share of electricity this year in comparison to last year, but accelerating energy demand through the remainder of the year and projected increases in net energy for load over the next 10 years indicate that natural-gas-fired generators will remain critical resources for BPS reliability in many areas.

Natural-gas-fired generators are especially important during the winter. Winter peak electricity demand in most areas occurs during early morning hours when unavailability of weather-dependent resources leads to a surge in natural-gas-fired generation's share of the resource mix. Severe winter weather events in 2021 and 2022 provide stark evidence of the critical nature of natural gas as a generator fuel and the importance of secure fuel supplies during times of extreme electricity demand.

[25] EIPC Frequency Response Report

[26] 42.9% is the penetration of utility-scale non-synchronous generation. The Western Interconnection has a significant amount of DERs that are also non-synchronous. When DERs are included, the non-synchronous penetration was 54.9%.

[27] ERCOT procures responsive reserve service to protect from involuntary under frequency load shed after loss of two largest generating units at a single plant (2,805 MW). In March 2020, a new subproduct of responsive reserve service was introduced, FFR, which is triggered at 59.85 Hz within 0.25 seconds. Up to 450 MW of FFR can be procured as a part of responsive reserve service. This product is still going through implementation stages due to required changes to ERCOT systems.

Overall, 13 out of 23 assessment areas are adding capacity to their fleet of natural-gas-fired power plants over the next 10 years, amounting to slightly more than 12 GW of new natural-gas-fired winter capacity if only the most certain Tier 1 resources come on-line. That number jumps to 41 GW of new natural-gas-fired winter capacity if both Tier 1 and Tier 2 resources come on-line (see **Figure 20**). Importantly, the vast majority of natural-gas-fired Tier 1 and Tier 2 additions—11 to 39 GW—are projected to come on-line in the next five years.

The timing and magnitude of natural-gas-fired generator additions remains uncertain in today's energy system planning environment. Multiple areas are conducting expedited resource assessments and interconnection process reforms with goals of adding more generator capacity to the grid over the next few years to meet rapidly accelerating electricity demands, particularly due to large-load addition. The early project submissions and selections from these programs indicate that actual natural-gas-fired additions may exceed previous industry projections in some areas. For instance, PJM Interconnection's Reliability Resource Initiative has led to the selection of approximately 8 GW of natural-gas-fired generator uprates and additions out of the nearly 17 GW of natural-gas-fired projects submitted for consideration. Round one selections for MISO's ERAS include approximately 4 GW of natural-gas-fired additions out of the 20 GW submitted to date, and SPP's *Expedited Resource Adequacy Study* includes approximately 9 GW of natural-gas-fired winter capacity additions in its interconnection queue. Most of these expedited additions that have been selected across all three programs have applied to come on-line before 2030.

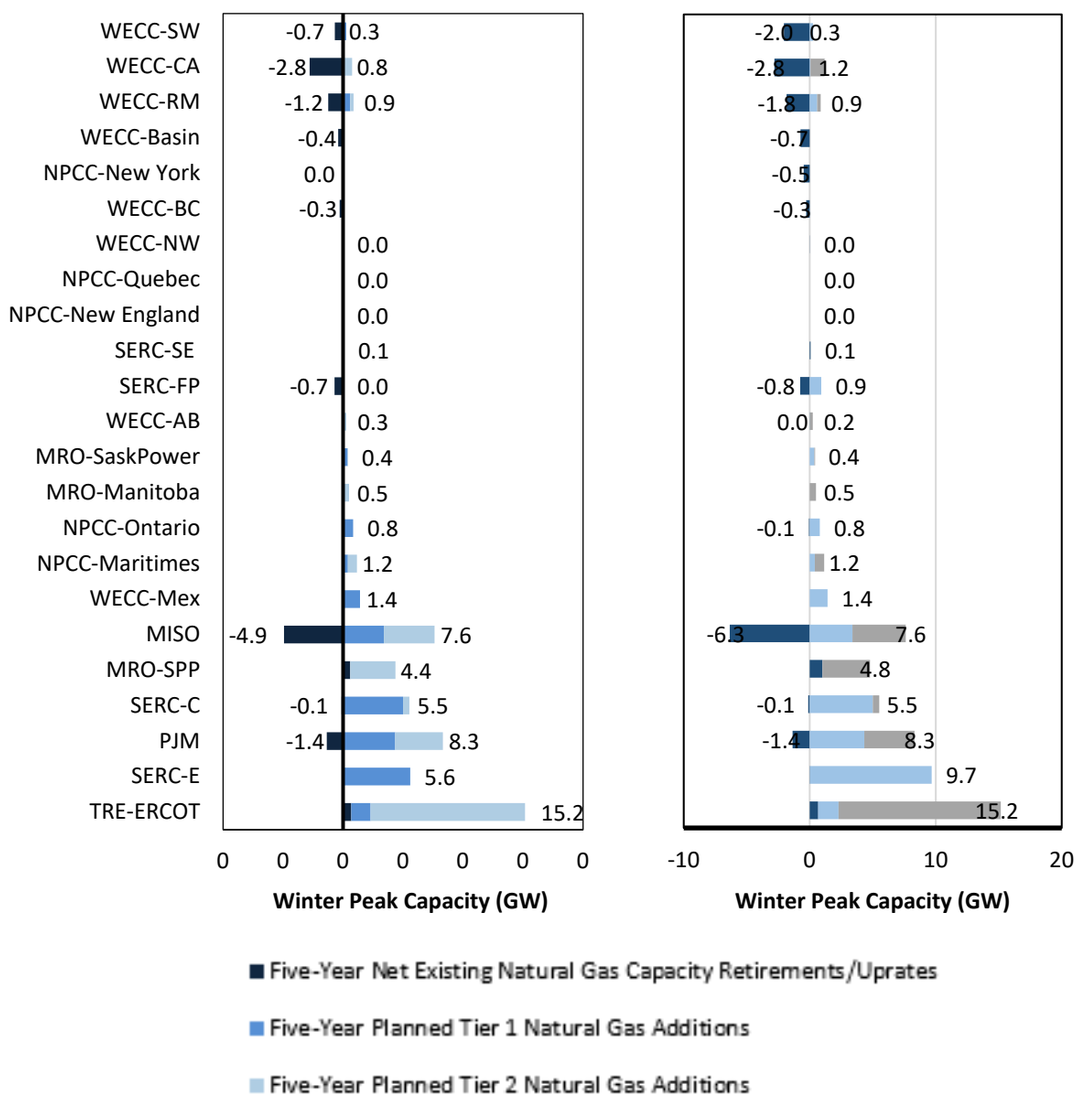


Figure 20: 5-Year (Left) and 10-Year (Right) Projected Natural-Gas-Fired Winter Capacity Additions by NERC Assessment Area

Natural Gas Infrastructure Development

Natural gas system planners have increasingly been coordinating with electric system planners to prepare for large additions to the natural-gas-fired power plant fleet. However, processes, regulations, and financial mechanisms that underpin capital investments and expansion of the natural gas pipeline and production system at times do not align with the variable operations of critical natural-gas-fired generators. For these reasons, among others, a significant percentage of natural-gas-fired power plants continue to rely on interruptible, or non-firm, supply and transportation arrangements. Non-firm natural gas supply and transportation is generally sufficient for electric generators most of the year. However, during extreme cold weather, demand for natural gas for both electricity generation and space heating can both dramatically increase. In these instances, generators that lack firm supply and transport arrangements are at risk of fuel unavailability. When winter weather also impacts gas production facilities, the resulting imbalance in pipeline injections and withdrawals can imperil even firm pipeline customers' supply as preparatory linepack is rapidly depleted.

There is a possibility that generators in the areas that are adding the most gas resources—MISO, MRO-SPP, PJM, SERC-C, SERC-E, and TRE-ERCOT—could secure additional firm fuel supplies from natural gas system projects planned or proposed over the next decade. **Figure 21** shows the amount of incremental natural gas pipeline capacity with in-service dates spanning the next five years. In total, S&P Global Energy projects that roughly 45 BCF/day of incremental natural gas pipeline capacity created by additional compression, expansions, pipeline repurposing, new pipelines, or reversal of flow directions will be built over the next decade. About one-third of this incremental capacity has gained regulatory approval and moved into the more formal stages of project development. Of the 15 BCF/day of regulatory approved gas pipeline capacity additions, only 5 BCF/day is planned to serve natural gas demand in the states outside of the Gulf Coast region.

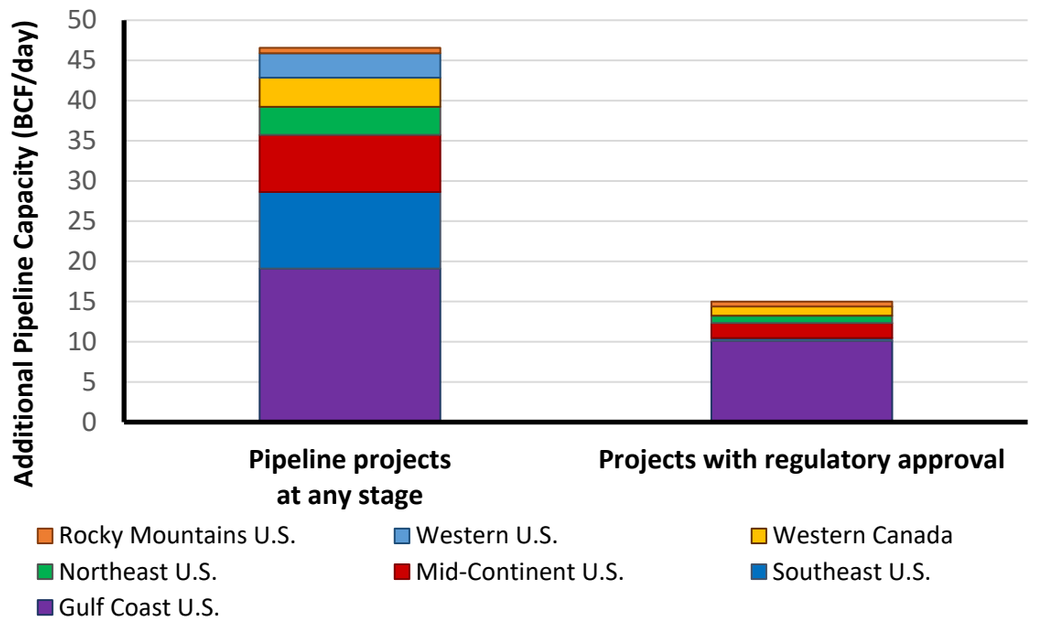


Figure 21: Projected Natural Gas Pipeline Capacity Expansion Projects by Project Stage (Source: S&P Global Energy)

The nearly 40 GW of natural-gas-fired winter capacity additions in the six areas adding the most gas resources could consume as much as 6–11 BCF/day of natural gas during a peak winter day after factoring plant type, efficiency, and whether the generator designated by its grid operator as a critical on-peak resource. While enough incremental pipeline additions to support this anticipated increase in gas demand seem to be moving through the natural gas project development process in those regions (see **Figure 22**), generators will need to compete with other pipeline customers for firm supply and delivery during periods of high gas demand. The magnitude of gas pipeline capacity additions suggests that there may be promising opportunities for generators to procure firm gas pipeline and supply contracts, but regulatory approval does not assure construction or commercial operation. In addition, if firm gas contracts cannot be secured for coincident high gas and electricity demand periods, like winter, ongoing critical generator projects might need to consider backup fuel capabilities so that they can assure fuel availability.

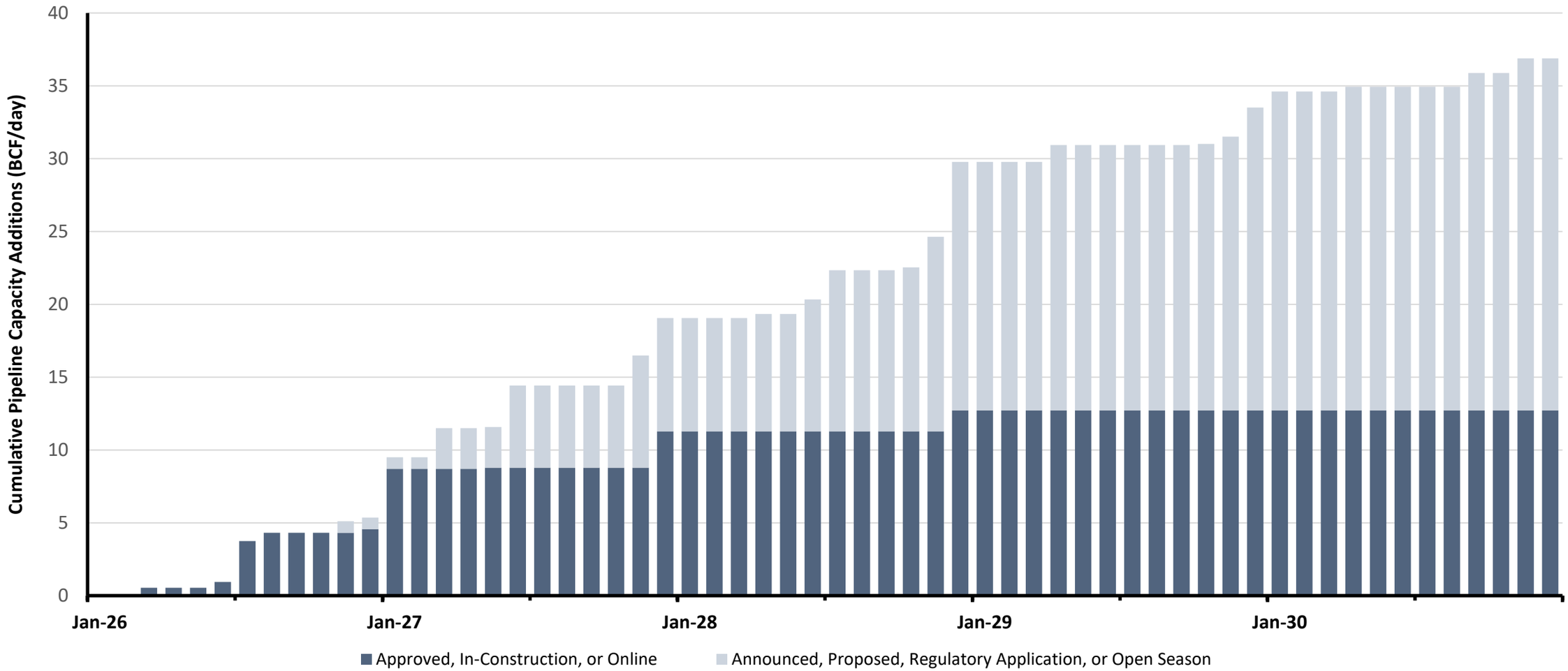


Figure 22: Projected Natural Gas Pipeline Capacity Expansion Projects Ending in MISO, PJM, SERC-C, SERC-E, SPP, and TRE-ERCOT Areas (Source: S&P Global Energy)

Transmission Development and Interregional Transfer Capability

Transmission Projects

This year's cumulative level of 41,000 miles (66,000 km) of transmission (>100 kV) under construction or in various stages of development for the next 10 years (see **Figure 23**) is substantially higher than the *2024 LTRA* 10-year projections (28,275 miles or 45,504 km). Transmission in construction has yet to increase substantially; rather, the large increase in transmission projects is seen in planning phases.

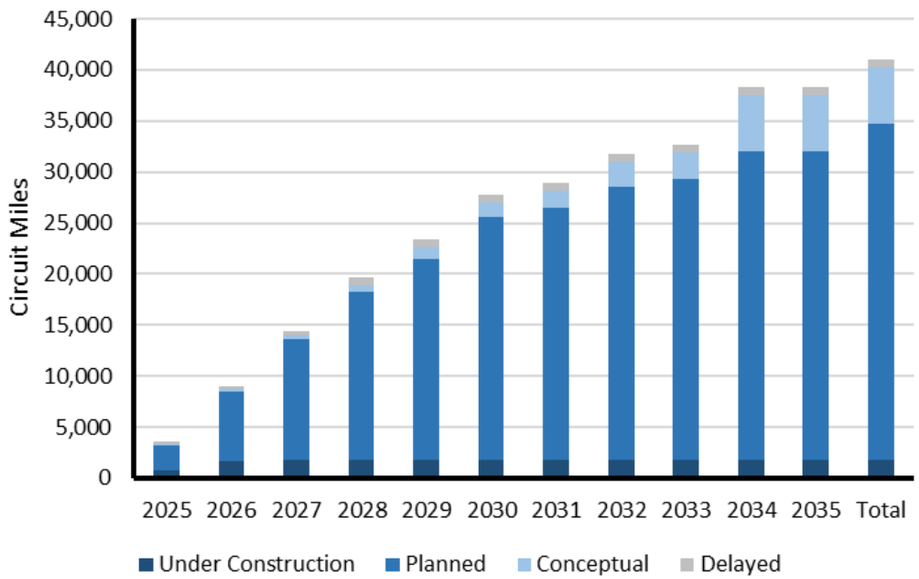


Figure 23: Future Transmission Circuit Miles >100 kV by Project Status[28]

Transmission flow patterns are changing and becoming more dynamic with resource shifts. New transmission projects are being driven by reliability, which includes efforts to replace aging infrastructure, integrate renewable generation, retire existing power plants, or meet increased demand forecasts. One such example is Hydro-Québec's plan to add significant new generating capacity by 2035, which necessitates several major EHV transmission projects. Similarly, several PCs have recently approved, or are actively contemplating, expansive EHV overlays on their systems to address a variety of needs, including ERCOT, SPP, MISO, PJM, British Columbia, and IESO. **Figure 24** shows the percentage of future transmission circuit miles by primary driver. Most projects reported this year have been initiated for the purpose of grid reliability, which generally includes transmission projects that are needed to ensure that the BPS operates within established limits and design criteria.

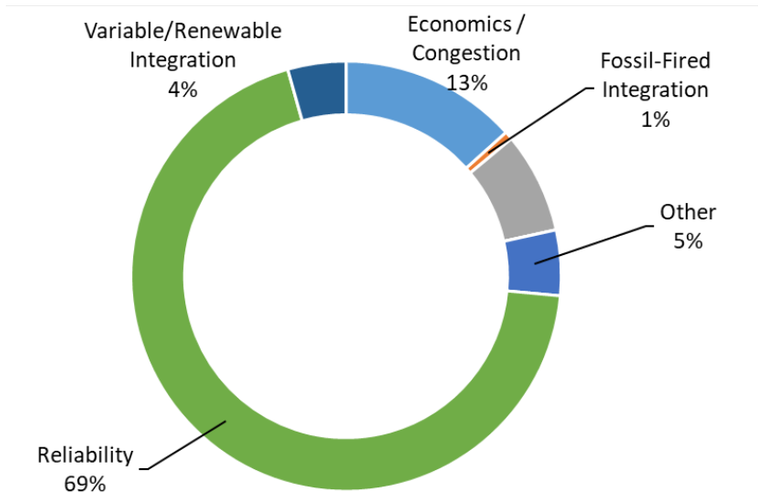


Figure 24: Future Transmission Circuit Miles by Primary Driver

There were 14,150 circuit miles (22,775 km) of reported transmission in development with an operating class greater than 400 kV (about 35% of the total miles in development). Nevertheless, intraregional transmission projects continue to greatly outnumber interregional transmission expansion. These interregional transmission projects can allow entities to take advantage of geographic diversity during extreme weather, such as Winter Storm Elliott,[29] including scenarios identified in the ITCS. Only 38 of the 863 transmission projects in development are for tie-lines and tie-line upgrades (down from 70 in last year's LTRA), which can support transfer capability between neighboring BA areas, including high-capacity dc interconnections, such as the 1,200 MW Appalaches-Maine (NECEC) and the 1,250 MW Hertel-New York (CHPE) projects. NYISO has identified a reliability risk if the CHPE project is not completed in a timely fashion. See the transmission summaries at the end of each assessment area's pages (in the **Regional Assessments Dashboards**) for current transmission development details.

[28] The column at right is the total transmission projects reported to NERC and includes projects that did not specify an expected in-service date.

[29] *Winter Storm Elliott Report: Inquiry into Bulk-Power System Operations During December 2022* | Federal Energy Regulatory Commission

Transmission development in some areas is hampered by growing risks in procurement and supply chain delays as well as regulatory obstacles, such as siting and permitting. Other reasons for delays include economic impacts, planning and construction issues, or changing needs. Of nearly 900 projects that were under construction or in planning for the next 10 years, at least 390 projects have been delayed from their originally expected in-service dates.

Interregional Transfer Capability Study (Canadian Analysis)

In the *2024 LTRA*, NERC provided a summary of the ITCS, a comprehensive study of existing and future interregional transfer capability undertaken by NERC in response to the Fiscal Responsibility Act of 2023. In addressing this legislation, NERC identified additions to transfer capability[30] for U.S. transmission planning regions (TPR) that could support energy adequacy.[31] NERC filed the completed study report with FERC on November 19, 2024.[32] Due to the interconnected nature of the BPS, NERC extended the study beyond the congressional mandate to identify and make recommendations to transfer capabilities from the United States to Canada and among Canadian provinces. The *ITCS Canadian Analysis* (Canadian Analysis) was published in April 2025.

The Canadian Analysis was the first-of-its-kind assessment of transfer capability and hourly energy margin analysis in Canada under a common set of assumptions but did not represent a transmission plan or blueprint. Transmission assessments, like the Canadian Analysis, are crucial to understanding potential options to mitigate future risks; however, alternative approaches other than transmission, such as local generation or demand-side solutions, can also mitigate future energy risks. The study results should be considered as an input into subsequent planning discussions that will consider broader objectives and the cost effectiveness of different alternatives to meet long-term needs.

Transfer Capability Analysis

The current transfer capability analysis between each pair of neighboring TPRs focused on 2024 Summer and 2024/25 Winter cases, with results shown in **Figure 25** and **Figure 26**, respectively. These transfer capabilities represent the ability of the entire network to move energy from one TPR to another TPR[33] but are not synonymous with path ratings, which calculate the maximum flow that can be reliably attained over a selected set of transmission facilities.

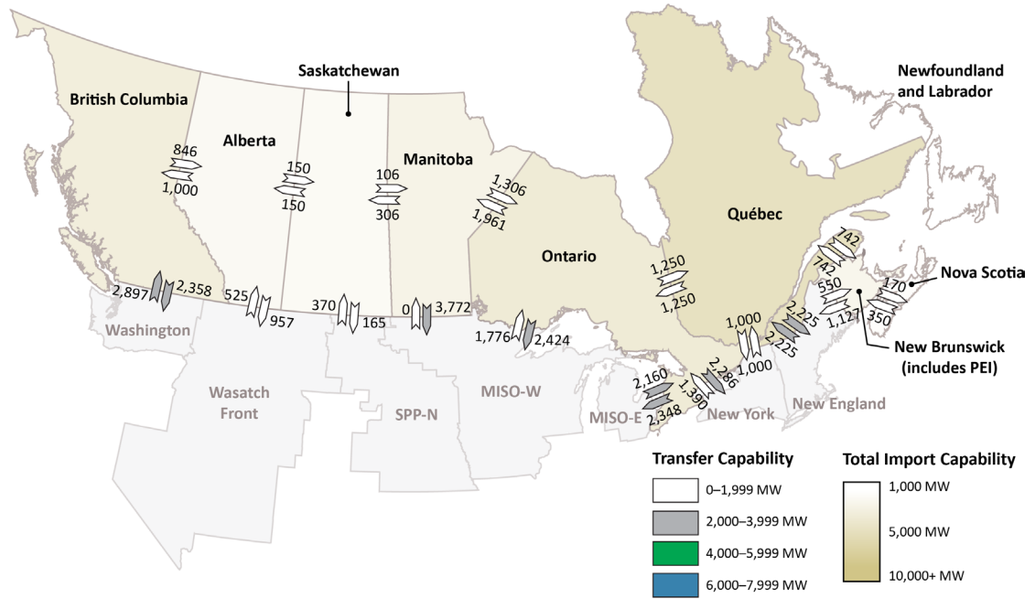


Figure 25: Transfer Capabilities (Summer)

[30] Transfer capability is the measure of the ability of interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all transmission lines (or paths) between those areas under specific system conditions.

[31] As evidenced during recent operational events including Western Interconnection Heatwave (2020), Winter Storm Uri (2021) and Winter Storm Elliott (2022), more needs to be done to support energy adequacy to be able to continuously meet customer demand. This is the reliability risk that the ITCS seeks to identify and mitigate through additions to transfer capability.

[32] NERC filing of the *Interregional Transfer Capability Study*, FERC Docket AD25-4-000.

[33] Transfer capability is not synonymous with path ratings, which calculate the maximum flow that can be reliably attained over a selected set of transmission facilities. Since this study did not follow a path-based calculation method used by many TPRs, results generally do not match individual facility ratings.

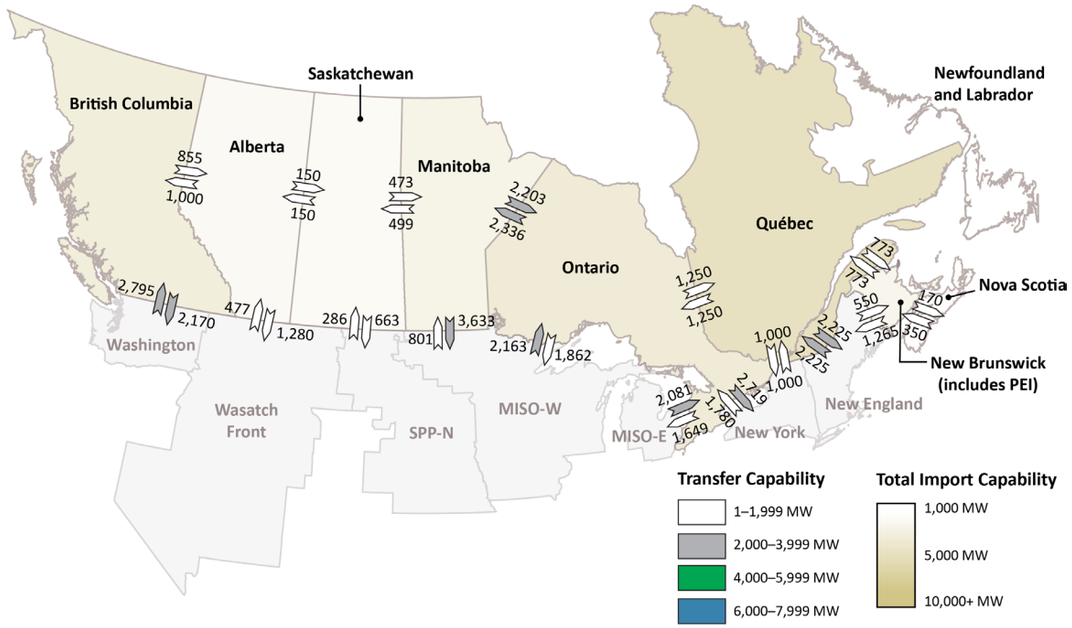


Figure 26: Transfer Capabilities (Winter)

The transfer capability results reflect the conditions studied and are not an exhaustive evaluation of the potential for energy transfers. The results are highly dependent on the assumptions, including load levels and dispatch of resources, which can vary significantly between seasons.

Key Findings–Transfer Analysis

- Transfer capability varies seasonally and under different system conditions that limit transmission loading; it cannot be represented by a single number.
- Transfer capability is highly dependent on coordinated phase angle regulator settings, particularly in Saskatchewan, Manitoba, and Ontario.
- Prince Edward Island load impacts the transfer capability from New Brunswick to Nova Scotia.
- Transfer capability differs across Canada, with total import capability varying between 5% and 80% of peak load.
- Observed transfer capabilities are generally higher between Canada and the United States but relatively lower between provinces.
- The magnitude of transfer capability is not itself a measure of energy adequacy.
- Interregional transfer capability, as studied in this analysis, is not synonymous with path ratings.

Transfer Capability Additions

The Canadian Analysis also evaluated the future energy adequacy of the BPS if historical extreme weather conditions occurred again.[34] Specifically, the study applied 12 past weather years to the 2033 load and resource mix projection reported in the *2023 LTRA* using the current transfer capabilities.[35] The study then evaluated the impact of additional transfer capability in mitigating the identified resource deficiencies during extreme events, thereby helping to improve energy adequacy. While there are several factors that Transmission Planners consider (including reliability, economics, and policy objectives) given NERC's role, the Canadian Analysis focused solely on reliability, specifically in terms of energy adequacy and reserve optimization.

[34] This study did not incorporate climate change models.

[35] The transfer capability analysis calculated current transfer capabilities for summer and winter based on 2024/25 projected system conditions using the area interchange method. Identified additions to transfer capability do not account for any changes to the transmission network that are planned after Winter 2024/25.

Key Findings–Energy Margin Analysis (2033)

- Canadian systems, like U.S. systems, were found to be increasingly vulnerable during extreme weather due to anticipated load increases and the changing resource mix. Transmission limitations, and potential for energy inadequacy, were identified in all 12 weather years studied. Enhancing transmission interfaces could reduce the likelihood of energy deficits during extreme conditions.
- Reliability risks are highly dependent on regional weather conditions. The import capability that could be beneficial during extreme conditions varied significantly across the country. An additional 12–14 GW of transfer capability may be an effective vehicle to strengthen energy adequacy under extreme conditions.
- More recent industry forecasts reflected in *2024 LTRA* data generally result in considerable improvement, particularly in Ontario and Québec, as resource projections catch up to demand forecasts. Ongoing studies will capture future changes.
- Weather-related outages were not found to be a major contributor to deficiency events, as Canadian systems are generally designed to handle extreme cold conditions. However, high winter peak loads can still challenge the available energy supply.
- Some identified transmission additions could be addressed by projects already in the planning, permitting, or construction phases. Likewise, existing system capability to switch resources or load between provinces, which was not accounted for in this study, may help reduce the identified shortfalls.
- The importance of maintaining sufficient generating resources underpins the study's assumptions. Higher-than-expected retirements (without replacement capacity) would lead to increased energy deficiencies and potentially more transfer capability additions if surplus energy is available from neighbors.
- A broad set of solutions should be considered, including transmission, local resource, demand-side, and storage solutions. A diverse and flexible approach allows tailored solutions specific to each province's vulnerabilities, risk tolerance, economics, and policies.

Just as in the U.S. ITCS, the Canadian Analysis found potential for energy deficiency in all 12 weather years evaluated. The results identified the potential for energy deficiency in six provinces, with a maximum resource deficiency of 10 GW in Québec based on *2023 LTRA* data. A sensitivity study using more recent forecasts, based on *2024 LTRA* data, generally resulted in considerable improvement, particularly in Ontario and Québec, as resource projections catch up to demand forecasts.

The Canadian Analysis used these results to develop a list of additions to transfer capability from neighboring TPRs, including geographic neighbors without existing electrical connections. The analysis identified 14 GW of additional transfer capability that would improve energy adequacy under the studied extreme conditions throughout Canada. In the U.S. analysis reported last year, 35 GW of additional transfer capability was recommended across the U.S. to improve energy adequacy under extreme conditions. Figure 27 shows the existing and potential new interfaces for Canadian TPRs where beneficial additional transfer capability is identified.

Transfer capability additions are based on 2033 resource mix and other study assumptions

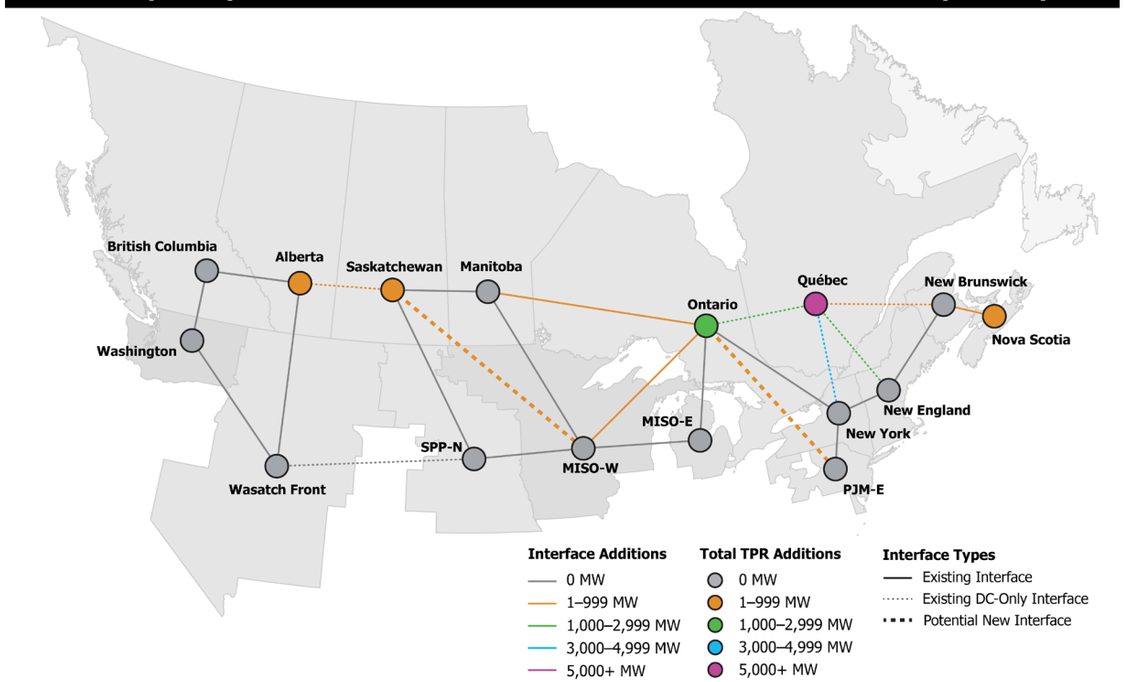
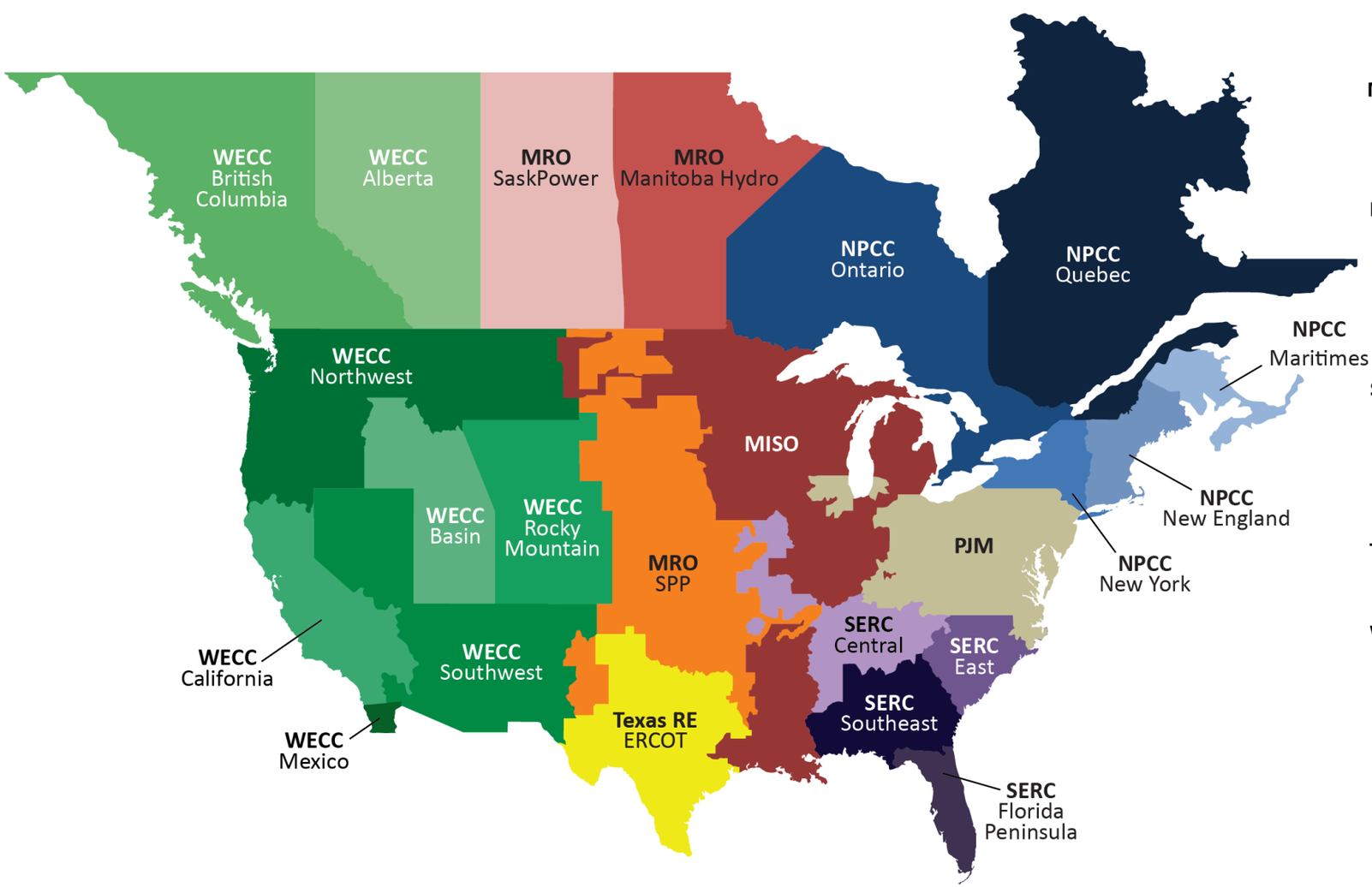


Figure 27: Transfer Capability Additions

Regional Assessments Dashboards

The following regional assessments were developed based on data and narrative information collected by NERC from the Regional Entities on an assessment area basis. The Reliability Assessment Subcommittee, at the direction of NERC's RSTC, supported the development of this assessment through a comprehensive and transparent peer review process that leveraged the knowledge and experience of system planners, Reliability Assessment Subcommittee members, NERC staff, and other subject matter experts. This peer review process promotes the accuracy and completeness of all data and information.



- MISO *(Midcontinent Independent System Operator)*
- PJM

MRO – Midwest Reliability Organization
- MRO-Manitoba Hydro
- MRO-SaskPower
- MRO-SPP *(Southwest Power Pool)*

NPCC – Northeast Power Coordinating Council
- NPCC-Maritimes
- NPCC-New England
- NPCC-New York
- NPCC-Ontario
- NPCC-Québec

SERC – SERC Reliability Corporation
- SERC-Central
- SERC-East
- SERC-Florida Peninsula
- SERC-Southeast

Texas RE – Texas Reliability Entity
- Texas RE-ERCOT *(Electric Reliability Council of Texas)*

WECC – Western Electricity Coordinating Council
- WECC-Alberta
- WECC-Basin
- WECC-British Columbia
- WECC-California
- WECC-Mexico
- WECC-Northwest
- WECC-Rocky Mountain
- WECC-Southwest

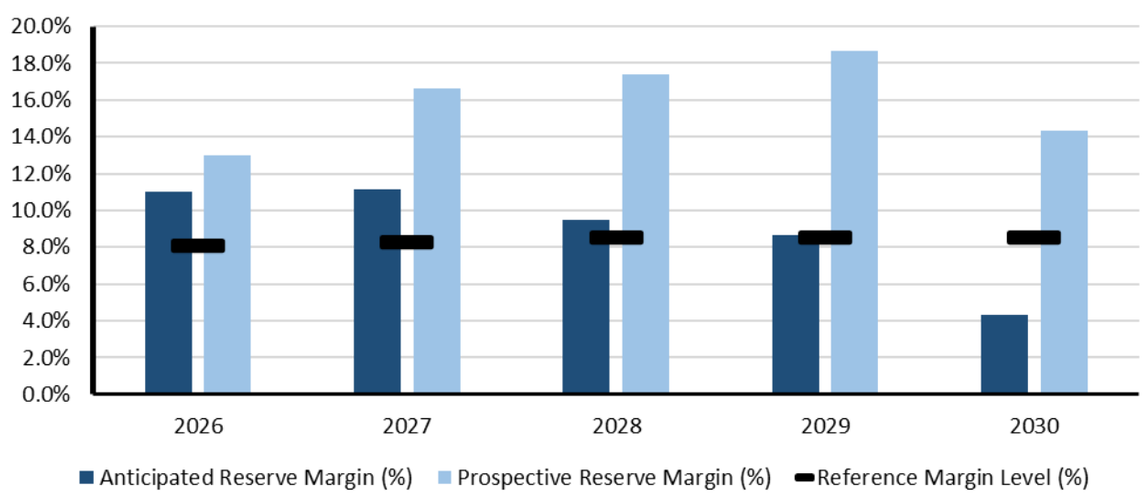


MISO

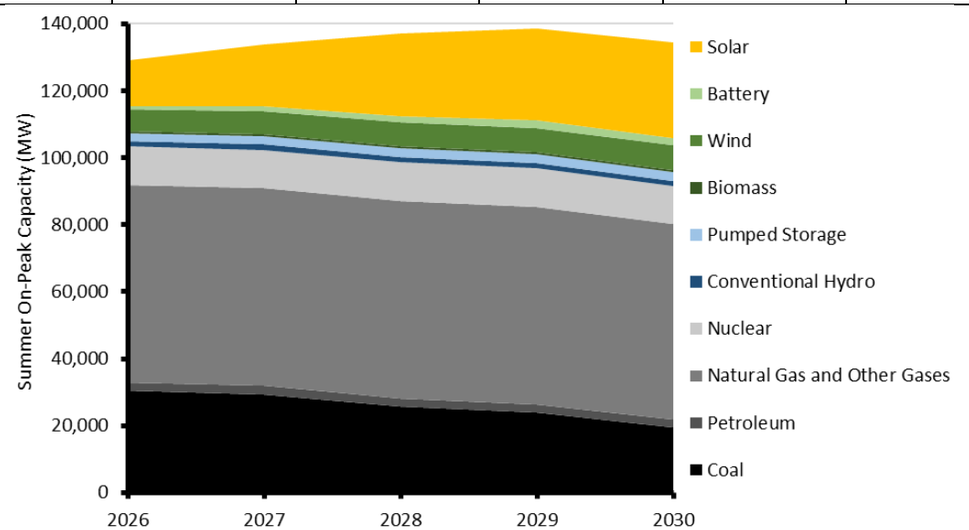
The Midcontinent Independent System Operator, Inc. (MISO) is an independent, not-for-profit organization responsible for operating the bulk electric power system and administering wholesale electricity markets across 15 U.S. states and the Canadian province of Manitoba. MISO ensures the reliable delivery of electricity to approximately 45 million people by managing regional transmission operations and energy and ancillary services markets and advising on long-term resource planning. The MISO footprint includes 39 local BAs and more than 550 market participants. MISO operates one of the world's largest organized electricity markets, with its members operating a system that consists of over 79,000 miles of transmission lines and approximately 1,979 generating units. The peak electricity demand on the MISO system currently occurs during the summer season. MISO's footprint lies across three regional entities (MRO, RF, and SERC), but MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Demand, Resources, and Reserve Margins (Summer)

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	127,071	131,107	135,998	138,286	139,631	140,959	142,003	142,789	143,754	143,754
Demand Response	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280	8,280
Net Internal Demand	118,791	122,827	127,718	130,006	131,351	132,679	133,723	134,509	135,474	135,474
Additions: Tier 1	5,576	13,339	21,350	24,631	26,027	26,320	26,366	26,366	26,366	26,366
Additions: Tier 2	2,403	6,723	10,072	13,056	13,116	13,260	13,364	13,466	13,466	13,466
Additions: Tier 3	1,632	4,459	9,395	14,474	19,823	23,820	27,983	27,858	27,915	28,077
Net Firm Capacity Transfers	2,809	2,661	2,509	2,509	2,419	2,419	2,419	2,419	2,419	2,419
Existing-Certain and Net Firm Transfers	126,263	123,205	118,481	116,593	110,996	108,686	106,448	106,568	106,553	106,553
Anticipated Reserve Margin (%)	11.0%	11.2%	9.5%	8.6%	4.3%	1.8%	-0.7%	-1.2%	-1.9%	-1.9%
Prospective Reserve Margin (%)	13.0%	16.6%	17.4%	18.7%	14.3%	11.7%	9.3%	8.8%	8.1%	8.1%
Reference Margin Level (%)	8.1%	8.3%	8.5%	8.5%	8.5%	8.6%	8.7%	8.8%	8.9%	8.9%



Planning Reserve Margins



Existing and Tier 1 Resources

MISO Highlights

- For Summer 2026, MISO projects a prospective resource surplus ranging from 3.4 to 5.8 GW, but, if historical rates of resource additions continue, a deficit of resources beginning in Summer 2030 may be realized. The recently approved ERAS is expected to result in a considerable amount of new resource additions to the MISO system by 2029, which was not included in this year's assessment due to the timing of FERC approval. As of December 2025, around 30 GW of new capacity is being studied through the ERAS process.
- MISO forecasts that the coincident total internal demand will peak at 127.1 GW during the 2026 Summer season and will grow to 143.7 GW by 2035. The largest contributor to this demand growth is data center additions.
- MISO's accredited thermal capacity has decreased by 8.8 GW, primarily driven by reductions in accredited capacity of existing resources, and accredited non-thermal capacity has increased by 5.7 GW since last year, primarily driven by solar additions.
- In July 2025, MISO had more than 54 GW nameplate capacity of generation—predominantly solar and battery—with signed generation interconnection agreements that were projected to come on-line over the next few years. As of December 2025, that figure increased to more than 70 GW of nameplate capacity.
- Currently, MISO has surplus transfer capacity within its subregions, but transfers between subregions have been historically constrained by a transmission limitation between the two subregions. MISO members plan to invest $30 billion to install nearly 5,000 miles of 345 kV and 1,750 miles of 765 kV transmission lines to address local, regional, and interregional transmission needs.

MISO Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	30,442	29,376	25,620	23,780	19,384
Petroleum	2,551	2,551	2,551	2,551	2,428
Natural Gas	58,748	58,892	58,984	59,099	58,262
Biomass	585	580	516	515	512
Solar	13,586	18,496	24,792	27,499	28,629
Wind	6,576	6,757	7,139	7,258	7,379
Conventional Hydro	1,521	1,523	1,524	1,524	1,524
Pumped Storage	2,608	2,608	2,608	2,608	2,608
Nuclear	11,571	11,571	11,571	11,571	11,571
Other	68	68	68	68	63
Battery	774	1,462	1,950	2,243	2,243
Total MW	**129,031**	**133,883**	**137,322**	**138,715**	**134,604**

MISO Assessment

MISO's guiding principles for its planning process include six key objectives: reliability and resilience; economic efficiency/lowest total electric system cost; support of federal, state, and local energy policy and member goals for their respective resource mixes; appropriate cost allocation for transfer-enabling assets; analysis of an appropriate range of system scenarios and dissemination of results to relevant decisionmakers; and coordinated planning processes among neighbors to eliminate barriers to reliable and efficient operations. See MISO's Statement of Guiding Principles for more information.

Planning Reserve Margins

Every year, MISO coordinates with its stakeholders to calculate the minimum amount of capacity above coincident peak demand required such that the LOLE equals one-day-in-10 years, or 0.1 days per year. For the MISO-wide analysis, generating units were modeled as part of their appropriate local resource zone as a subset of a larger MISO system. The MISO system was modeled with no internal transmission limitations between zones. To meet the LOLE reliability criteria, capacity is either added or removed from the MISO system within the model. The minimum amount of capacity above the MISO system coincident peak demand forecast required to meet the LOLE reliability criteria was used to establish seasonal Planning Reserve Margin (PRM) values. This minimum PRM is based on a probabilistic analysis and is expressed for each season as an unforced capacity (UCAP) requirement based on the modeled availability of resources in the MISO system. UCAP represents an adjustment from installed capacity (ICAP) that accounts for a generator's equivalent forced outage rate demand, a measure of the probability that a generating unit will not be available due to forced outages, which MISO further adjusts to exclude events outside management control.

MISO's LOLE Study for PY 2025–2026 estimated the minimum seasonal PRM values (in UCAP) as follows:

- Summer 2026: 8.1%
- Fall 2026: 14.9%
- Winter 2026-2027: 19.1%
- Spring 2027: 26.2%

The study that produced these PRM values included a probabilistic risk modeling and power flow transfer analysis to also determine zonal local reliability requirements (LRR), zonal import ability (ZIA), zonal export ability (ZEA), capacity import limits (CIL), and capacity export limits (CEL). A software program called Strategic Energy & Risk Valuation Model (SERVM) was used to calculate LOLE for the applicable planning year.

The results of the LOLE Study for PY2 5-26 serve as inputs to the MISO Planning Resource Auction (PRA). The computed PRMs are used in area adequacy assessments unless an area includes an entity that falls under a state regulatory body's purview, in which case a state-mandated PRM may be used in MISO's analysis in place of the computed PRM.

In most of the MISO footprint, LSEs with oversight by the applicable state or local regulators are responsible for resource adequacy. Every year, MISO collaborates with the Organization of MISO States (OMS) to survey its members about their plans to maintain resource adequacy in the coming years. The OMS-MISO survey provides a resource adequacy view for the MISO region over a five-year horizon based on the latest information available at the time of survey. The 2025 OMS-MISO Survey indicated that LSEs are expected to have adequate resources to meet load reserve requirements; however, various projected capacity scenarios and large spot-load additions highlight the increasing uncertainty and evolving risk.

For Summer 2026, MISO projects a prospective surplus ranging from 3.4 to 5.8 GW. Moving beyond the short term, if historical rates of resource additions continue in MISO as reflected in the anticipated resources projection for the NERC LTRA, a deficit of resources beginning in summer 2030 may be realized. This potential shortage is due to accelerated load growth and inadequate build rates for new resources. Interconnection of additional identified resources in Tier 2 and potential resources in Tier 3 could present an opportunity to retain a resource surplus through the entirety of the LTRA study time frame.

In anticipation of resource shortages beginning in Summer 2030, MISO has initiated the following processes and reforms:

1. Implement the interim ERAS process to facilitate the accelerated rollout of new resources to meet increased demand growth. This process has yielded nearly 30 GW of potential new capacity as of December 2025.
2. Move to a direct loss of load (DLOL) marginal accreditation model for the 2028–2029 planning year, which is intended to better reflect the true value of the next megawatt of resources during critical hours
3. Enhance resource adequacy risk assessment and communication like aligning solar representations between the PRA and LOLE model, properly represent non-firm imports between neighboring regions, and investigate the relationship between solar and battery installations and how their capacity might impact one another.
4. Reduce queue cycle times through automation

5. Establish a more robust DR and emergency resource process moving forward to ensure non-market units are being appropriately accredited.
6. Enhance allocation of resource adequacy requirements.

Energy Risk

MISO uses a seasonal PRA and conducts seasonal resource assessments to evaluate generation availability, outage rates, and forecasted load. Based on outcomes of these processes, MISO has also initiated a change to its capacity market construct, in part, to ensure energy adequacy by evaluating how classes of resources and each individual resource help serve load during periods of the year that demonstrate the most reliability risk to the MISO system.

Beyond the probabilistic energy risk assessments associated with MISO's LOLE Study for PY 25–26, MISO has also performed additional assessments for renewable integration and regional resource evolution that touch on the topic of energy risk but are not a formal part of MISO's resource adequacy and resource planning processes.

ProbA Results

The results of the ProbA simulations show normal risk for the MISO system in study year 2027 and more pronounced, elevated risk in study year 2029 wherein MISO assumed approximately 14 GW of potential retirements that are uncertain to occur by 2029. The results offer a point-in-time snapshot of risk based on the data available during the time of this year's analysis. The regulatory structure within MISO provides utilities and regulators with many tools to ensure alignment of large-load additions, generator retirements, and generator additions. Regulators and utilities in the MISO region are statutorily required to ensure reliability and have the ability to address uncertainties associated with these three variables.

MISO initiatives like ERAS and joint collaborative efforts between MISO, its membership, regulators, and neighboring regions will be critical to ensuring resource adequacy in the coming years.

While overall installed nameplate capacity across the system is expected to increase in the coming years, system risk can be expected as the aging thermal fleet in MISO's system continues to retire and is replaced with more intermittent, less available generation. Significant demand growth, in part due to large data center loads, has been forecasted by MISO's LSEs. It is important to note that a substantial number of large-load customers continue to evaluate their options for participation in the markets, including the potential to participate as DR resources during emergency conditions. The construction delays for new resources due to supply chain and other issues, as well as the ongoing evaluation of large-load customers, contribute to continued uncertainty regarding both overall resource availability and the prospective participation of large loads as DR resources in the markets. This substantiates that MISO, its membership, and regulators must continue to monitor retirements and large-load additions and increase resource additions to ensure future resource adequacy.

The ProbA simulations for study year 2029 resulted LOLE of 2.4 days in 1 year compared to the target of 0.1 day in 1 year. The primary drivers for the expected risks in 2029 include the following:

- Load growth increases: Peak demand for winter is expected to grow considerably—approximately 9–10 GW in 2029.
- Nameplate capacity changes: To align with MISO's annual LOLE studies and proactively send the right signals, member-submitted low certainty resources from the most recent OMS-MISO Survey were assumed to be unavailable in study year and amounted to approximately 14 GW of additional unconfirmed retirements by Winter 2029.
- Summer risk shifts to later in the day: An increased reliance on solar generation as the resource mix evolves results in summer risk appearing as solar generation ramps down.
- In Winter 2029, risk is emerging in morning and twilight hours: Shifting winter risk is driven by a combination of increased reliance on solar generation, an increase in member-submitted load forecasts, elevated thermal forced outages induced by extreme cold temperatures, and a larger generation deficit than in prior years.

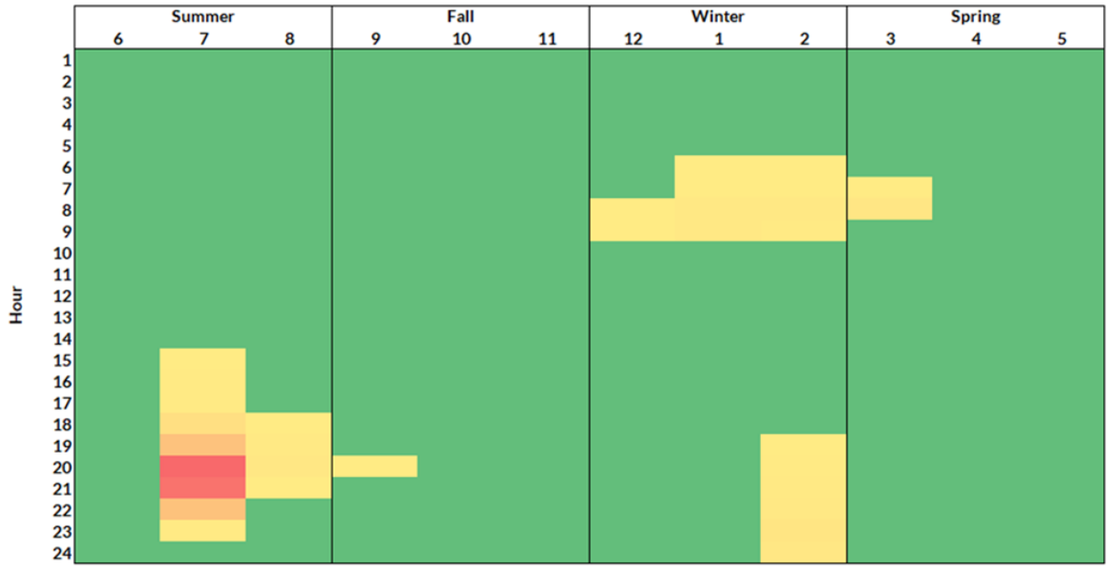
Base-Case Summary of Results

	2026*	2027	2029**
EUE (MWh)	0	797	31,654
NEUE (ppm)	0	1.13	42.4
LOLH (hours per Year)	0	0.23	6.61

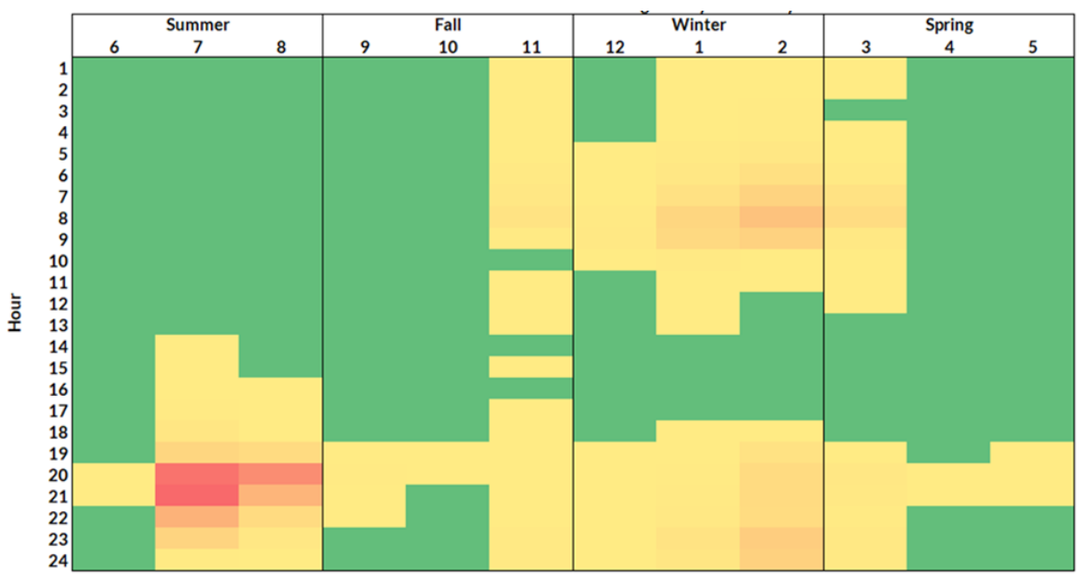
*Provides the 2024 ProbA Results for Comparison

**The 2029 ProbA study assumed approximately 14 GW of potential retirements that are uncertain to occur by 2029. The results offer a point-in-time snapshot of risk based on the data available during the time of this year's analysis.

The following EUE heat maps show the distribution of unserved energy events from the probA simulations across hours and seasons. Green cells indicate no unserved energy events, while yellow and red cells indicate increasing numbers of simulations with unserved energy.



2027-2028 ProbA Heat Map



2029-2030 ProbA Heat Map

Demand

LSEs within MISO's footprint report two sets of seasonal peak demand projections, coincident with the entire MISO system and coincident with their applicable local resource zone. LSEs also submit their non-coincident peak demand projections for the next 10 years, monthly for the first two years and seasonally for the remaining eight years. Coincident peak demand forecasts are based on factors including average historical weather conditions, economic conditions, and expected demand changes. For the *2025 LTRA*, MISO used its LSE demand submissions to create non-coincident and coincident peak demand projections on a regional basis by summing the annual peak demand forecasts for the individual LSEs in the larger region of study. In MISO's normal process, the coincident peak demand forecast is used to determine each LSE's PRM requirement.

MISO forecasts the coincident total internal demand to peak at 127,071 MW during the 2026 Summer season. Since the *2024 LTRA*, MISO has increased its 10-year forecast peak demand from 132 GW to 143.7 GW. This rate of increase is expected to continue.

The largest increases in demand in the MISO footprint are related to data centers. These large load additions are projected to result in significant increases in the demand for energy in all hours and would not conform to typical residential or industrial load patterns. In total, MISO projects approximately 6 GW of data center load additions by 2027, accumulating to 14 GW by 2030, and 18 GW by 2035. MISO published a *Long-Term Load Forecast* white paper in December 2024. This white paper comes to similar conclusions around the load growth rate based upon member submissions by way of the MOD-031/FERC 714 data pathway.

Demand-Side Management

A combination of peak demand hour performance, forecasting, and baseline scenarios help MISO to determine the amount of DR capacity available during peak demand hours. DR programs continue to play a significant role in providing capacity for MISO. For the 2025/26 planning year, DR is steady around 9 GW in the summer and 8 GW in the winter and is projected to remain constant during the LTRA study horizon. MISO's latest reforms for demand-side resources focus on accrediting such resources based on their availability and performance during the highest-risk hours (in and near emergency conditions).

Distributed Energy Resources

Behind-the-meter-generation (BTMG) resources contribute about 4.4 GW of capacity across the study horizon, of which approximately 1.3 GW are distributed photovoltaics. MISO's transition to seasonal auctions highlights the variability of DERs across the four seasons, and it is working with stakeholders to derive adequate methods of aggregating, reporting and allowing DER participation in MISO markets.

Generation

Because of the size of MISO's interconnection queue, in the 2025 NERC LTRA, generation in the queue is multiplied by a reduction factor based on the study phase and likelihood of that resource coming on-line and the timing of those additions. MISO notes that the recent 2025 OMS-MISO survey used a slightly different resource addition cadence than what is reported for the LTRA that factors in both planned utility/member-specific generation addition rates and historical addition cadences. Specifically, the LTRA's existing resource capacities come directly from the 2025–2026 MISO Planning Resource Auction (PRA), based on the amount of confirmed seasonal accredited capacity. Tier 1 resources describe the expected integration rate of currently signed generator interconnection agreements (GIA) over a three-year delay ramp to represent the fact that many GIAs experience delays on their path to installation in MISO. Tier 2 resources are based on active replacement projects and Phase 3 GIAs. Tier 3 resources are based on a 15% completion rate of all non-signed GIAs with the three-year delay schedule in line with Tier 1 resources.

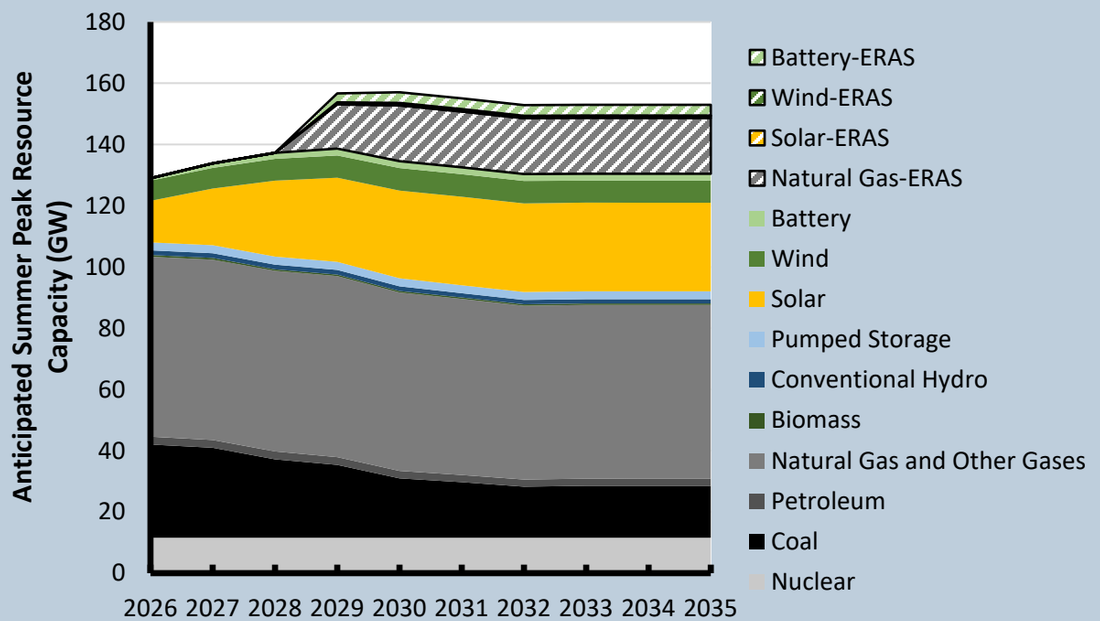
As of December 2025, MISO had more than 70 GW nameplate capacity of generation—predominantly solar and battery—with signed generation interconnection agreements that are projected to come on-line over the next few years. Since the 2024 NERC LTRA, MISO has observed an 8.8 GW reduction in thermal accredited capacity, driven primarily by aging existing facilities, unit suspensions, and retirements. However, suspensions and retirements in MISO have recently been followed by replacement facilities that re-utilize the interconnection service with new units. More than 75% of the units pursuing cessation in MISO are also pursuing replacement projects. Non-thermal accreditation has increased by 5.7 GW since the 2024 NERC LTRA report.

MISO's accreditation of battery resources is tied to the mandatory 4-hour energy offer window, resulting in most storage resources pursuing the ratio of 1 MW/h for 4 hours. Battery storage resources receive a 95% class-wide accreditation (relative to nameplate capacity) in the MISO PRA and NERC LTRA for their first year in operation in lieu of historical output data. Wind ELCC analyses have been performed for all seasons. Wind capacity is given the following seasonal accreditations: Summer: 20.8%; Fall: 30.7%; Winter: 29.0%; Spring: 25.3%. The effective capacity for existing solar resources is based on historical performance during typical seasonal peak hours. New solar resources get 50% accreditation relative to nameplate capacity in the summer, fall, and spring seasons and 5% in the winter season. Hydro resources accredited capacity is calculated based on historical performance during seasonal peak hours.

Energy Storage

MISO is experiencing increased interest by members for battery energy storage, with more than 500 MW currently on-line, and queue projects identifying more than 100 GW of battery or hybrid fuel type projects. MISO's anticipated installations include an addition of more than 2.4 GW by Summer 2030 and a prospective battery fleet of nearly 7 GW by 2035. The primary expected usage for batteries is for reliability, providing significant capacity capability with the variable nature of MISO's growing solar and wind fleet. MISO performs risk modeling with advanced storage representations to ensure that battery capacity is characterized appropriately.

The timing of FERC's approval of MISO's ERAS process in July meant that the generator additions that MISO plans as part of that process were not included in the resource adequacy modeling for the 2025 LTRA. ERAS is already expected to result in considerable new resource additions to the MISO system in the near term. The additional summer on-peak capacity from the ERAS program is expected to grow to over 20 GW by Summer 2030. These expedited resource additions are expected to reduce the shortfall risk identified in this year's ProbA. Furthermore, the timing of the ERAS additions would mitigate an identified winter ARM shortfall if the approximately 8.6 GW of winter on-peak capacity anticipated by 2028–29 reaches operation as projected. The latest ERAS projects, along with current load forecasts and resource projections as of July 2026, will be included in the input data for the *2026 LTRA* and ERAS summer capacity additions are summarized by the diagonal hatched stacked areas in plot below.



The Potential Effect of MISO's ERAS Process on Anticipated Summer Capacity

Energy Transfers
In the PRA, MISO accredits several power purchase agreements known as diversity contracts between Manitoba Hydro and MISO internal generation owners, wherein energy flows from Manitoba to the MISO system in the summer when Manitoba has excess hydro power vice-versa in the winter. Currently, MISO has surplus capacity in both the MISO North/Central and MISO South subregions, but imports and exports between them have been historically constrained by a transmission limitation.

A key input to MISO's probabilistic risk modeling that determines the system-wide seasonal PRM values is how much non-firm energy support MISO can reasonably expect from neighboring external areas. Every year, MISO performs an analysis of recent year trends in seasonal non-firm energy support to develop a range for each season that the probabilistic model will randomly draw from mid-simulation. Additionally, MISO found this year that there was not a significant difference in the amount of non-firm energy support MISO received from its neighbors during hours and days with tight operating margins when compared to normal operating conditions.

Transmission
MISO, in collaboration with its transmission-owning members and stakeholders, performs annual reliability assessments to identify transmission infrastructure upgrades needed to ensure system reliability. Many factors are considered during MISO's transmission expansion planning process, including urgency of need, suitability of alternatives to address identified issues, cost effectiveness, performance of alternatives, development time frame, right-of-way or substation impacts, expandability, and operational flexibility. To learn more about MISO's transmission expansion plan, see information and reports posted on MISO's MTEP page.

MISO has 488 transmission projects totaling $30 billion planned across MTEP24, its Long Range Transmission Planning (LRTP) Tranche 2.1, and the SPP-MISO Joint Targeted Interconnection Queue (JTIQ). In total, these three programs include nearly 5,000 miles of 345 kV and 1,750 miles of 765 kV transmission lines in their project portfolios. These projects aim to address local, regional, and interregional needs across the area's large geographic footprint by enabling reliability in response to accelerating load growth. In fact, most of the demand increases reported by LSEs in the MISO footprint can be tracked to transmission projects either in the Expedited Project Review (EPR) or normal MTEP project pathway. Specifically, MISO's Tranche 2.1 Portfolio seeks to establish a transmission system backbone for the whole MISO system, and the JTIQ portfolio is being undertaken with the potential to unlock approximately 28 GW of generator interconnections, eliminating barriers to new capacity at the SPP-MISO seam.

As of December 1, 2025, MISO identified 63 projects comprising 12.8 GW of additional load through the EPR process.

Reliability Issues
Load growth and additions are increasing. A spike in large, single-site load additions from manufacturing resurgence and incremental load growth from electric vehicles and other electrification trends pose new challenges for the grid. Continued high numbers of MTEP projects submitted through the expedited project review request, which are urgent projects that cannot wait for the next full MTEP cycle to proceed, are evidence of this faster paced load growth and additions.

Maintaining resource capacity margins will require accelerated resource additions to outpace retirements and the forecasted load growth. Recent reforms have helped to reduce the volume of requests and to process them more efficiently. As of December 1st, 2025, MISO has 1,127 Active interconnection queue projects that total 215 GW of nameplate capacity. This is in addition to the 444 projects and 70 GW of signed GIAs.

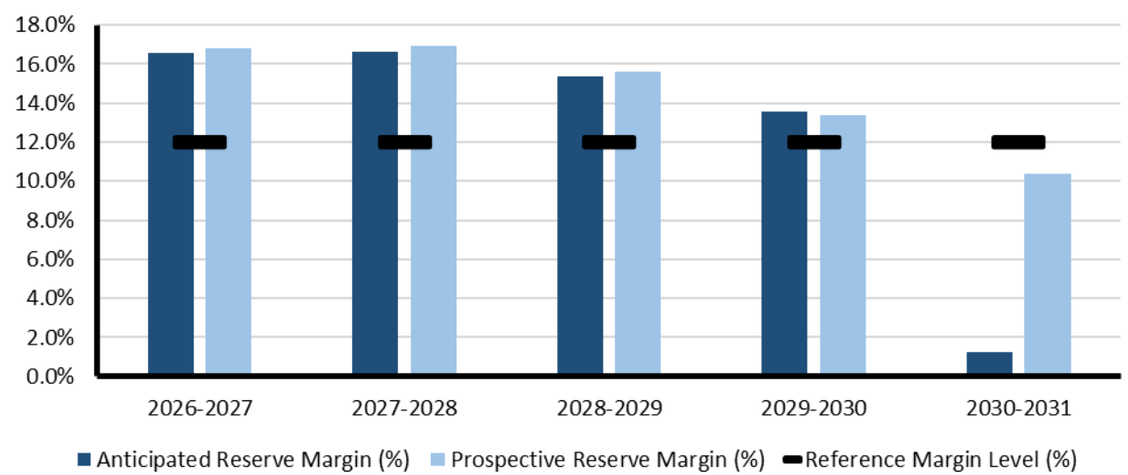


MRO-Manitoba Hydro

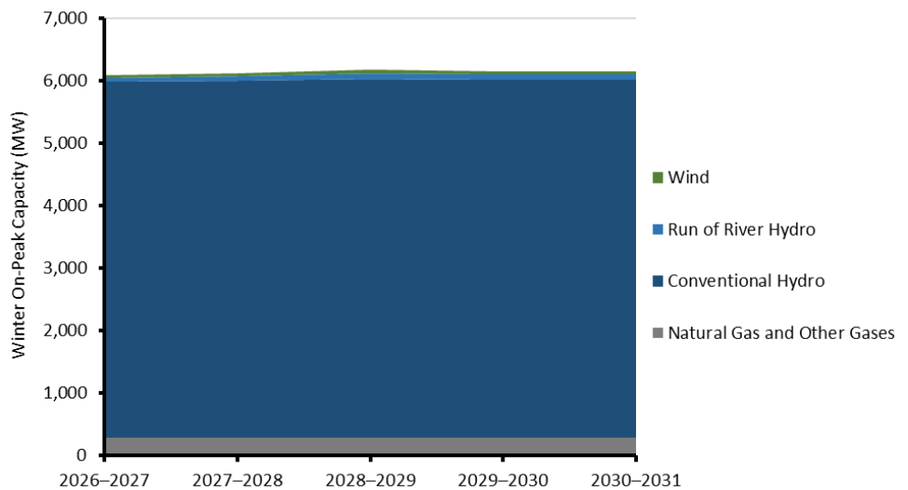
Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro provides electricity to approximately 601,000 electric customers in Manitoba and provides approximately 291,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is a provincial crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is winter-peaking. Manitoba Hydro is its own PC and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the Reliability Coordinator for Manitoba Hydro.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	5,002	5,041	5,081	5,137	5,374	5,412	5,447	5,507	5,580	5,655
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	5,002	5,041	5,081	5,137	5,374	5,412	5,447	5,507	5,580	5,655
Additions: Tier 1	36	50	63	63	63	63	63	63	63	63
Additions: Tier 2	0	0	0	0	500	500	500	500	500	500
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-113	-93	-167	-172	-565	-565	-565	-565	-565	-315
Existing-Certain and Net Firm Transfers	5,794	5,831	5,799	5,770	5,377	5,377	5,377	5,377	5,377	5,627
Anticipated Reserve Margin (%)	16.6%	16.7%	15.4%	13.6%	1.2%	0.5%	-0.1%	-1.2%	-2.5%	0.6%
Prospective Reserve Margin (%)	16.8%	16.9%	15.6%	13.4%	10.4%	9.6%	8.9%	7.7%	6.3%	9.3%
Reference Margin Level (%)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%



Planning Reserve Margins



Existing and Tier 1 Resources

MRO-Manitoba Hydro Highlights

- Manitoba projects a shortfall in anticipated resources starting in the winter of 2030–2031.
- The demand is projected to grow over 13% through the assessment period.
- The Province of Manitoba paused cryptocurrency interconnection requests until April 2026 to prepare a long-term solution to limit reliability impacts to the system.[36]

MRO-Manitoba Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	**2027–2028**	**2028–2029**	**2029–2030**	**2030–2031**
Natural Gas	278	278	278	278	278
Wind	52	52	52	52	52
Conventional Hydro	5,705	5,723	5,758	5,735	5,735
Run of River Hydro	59	71	90	90	90
Total MW	**6,094**	**6,124**	**6,179**	**6,155**	**6,155**

[36] Province directs Manitoba Hydro to continue pause on new cryptocurrency connections

MRO-Manitoba Hydro Assessment

Planning Reserve Margins
The ARM for the summer season does not fall below the RML of 12% during the 10-year assessment period. The ARM for the winter season falls below the RML of 12% beginning in Winter 2030–2031 due to a combination load growth and reduced resources due to an ending of winter capacity import contracts ("diversity capacity") in 2030, as well as an assumed reduction of the Curtailable Rate load management program.

Demand
Manitoba Hydro is anticipating load growth of 1.5% (net of demand side management) over the assessment period. In order to limit load growth, Manitoba Hydro has been directed by the Province of Manitoba to suspend processing of cryptocurrency load connections until 2026.

Demand-Side Management
Manitoba Hydro currently does not have any form of directly controllable and dispatchable DR programs. Manitoba Hydro does have an indirectly controllable and dispatchable DR program called the Curtailable Rate Program.

The Curtailable Rate Program provides approximately 160 MW of load reduction through up to 16 load curtailments of 4¼ hours each on five-minutes notice. The program is intended for peak load management. In addition, one product of the Curtailable Rate Program provides 50 MW of contingency reserves, also on five-minutes notice.

The terms and conditions of the Curtailable Rate Program were updated in August 2023 to require an annual curtailment test, increase the number of possible curtailments, extend the notice period for conversion to firm service, and make minor editorial changes.

Manitoba Hydro is in the process of developing a new industrial rate pilot, with the combined goal of reducing winter peak and providing additional rate options for customers that both assist customer profitability and help keep costs low for all Manitobans. The rate pilot is being developed to leverage existing technology and programming with the intent of introducing the program on a pilot basis.

Manitoba Hydro, in collaboration with Efficiency Manitoba, is looking to develop a DR pilot program aimed initially at targeting smart thermostats with the focus on reducing Manitoba's winter peak. The pilot program is targeting to launch for the winter of 2025.

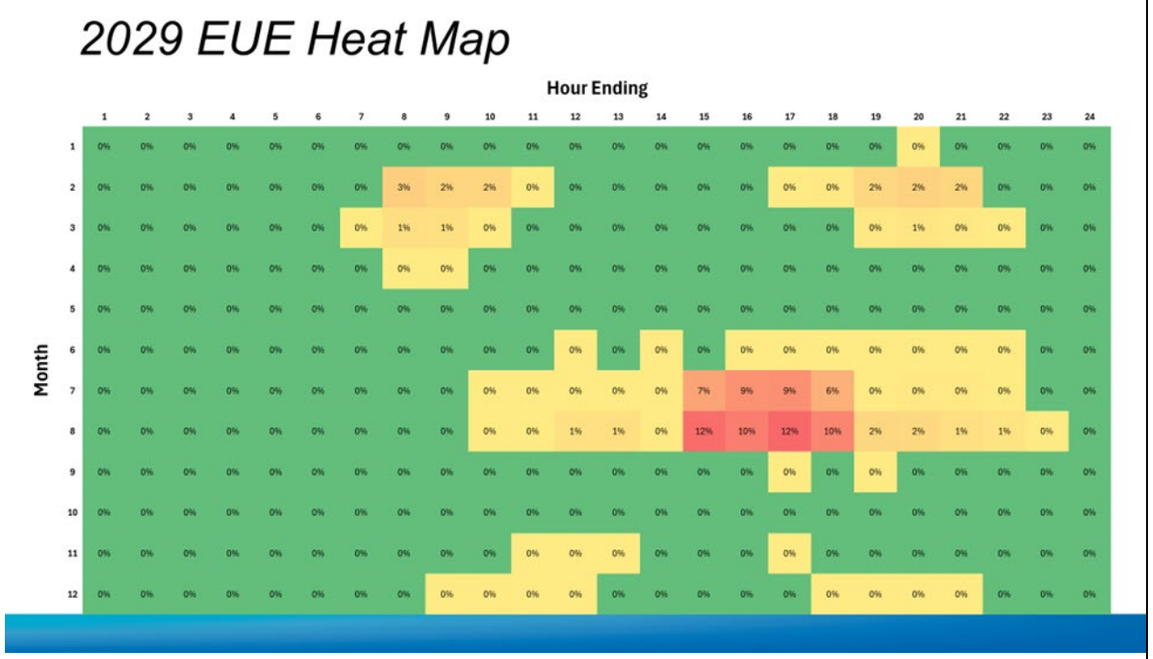
Energy Risk
As the operator of a predominantly hydro system, weekly at a minimum, Manitoba Hydro performs an all-hours season-ahead energy adequacy analysis as required to manage near-term to seasonal-ahead reservoir energy storage while meeting system demands. Additionally, Manitoba Hydro conducts specific analyses to determine short-term storage and minimum flow requirements that would be required to maintain Manitoba and extra-provincial resource adequacy obligations. As there are modest levels of wind and solar on the Manitoba Hydro system, the resource adequacy risk on the Manitoba Hydro system over the next five years and under normal water conditions is expected to fall at or very near the peak demand hours.

Probabilistic Assessment (ProbA)
Every year, Manitoba Hydro prepares a probabilistic assessment for the Manitoba system, most recently in 2024. The 2024 probabilistic assessment was supportive of a 12% PRM for the Manitoba system being sufficient to provide an LOLE of less than 0.1 days per year under the study assumptions. Results of the 2025 ProbA prepared for the LTRA are as follows.

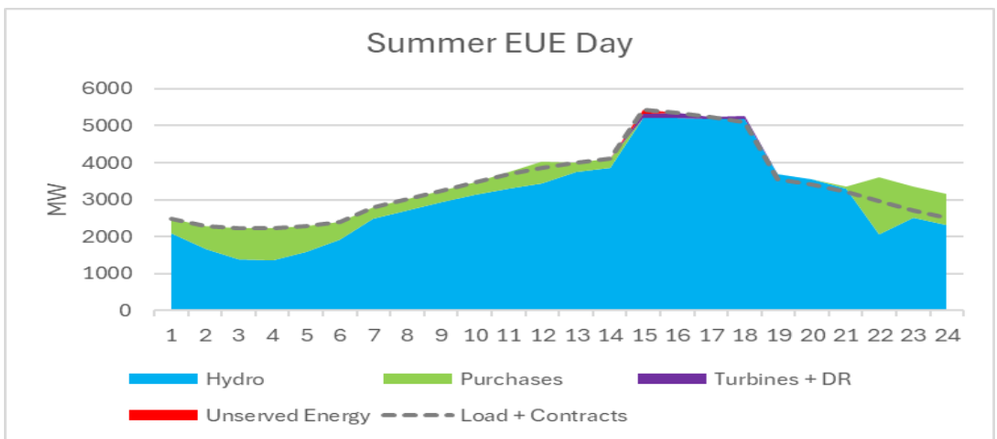
Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	4	3	6
NEUE (ppm)	0.17	0.12	0.23
LOLH (hours per Year)	0.05	0.03	0.06
* Provides the 2024 ProbA Results for Comparison			

There were no appreciable Manitoba loss-of-load events seen in winter or in the summer for 37 of the 44 weather/ flow years studied. Manitoba loss-of-load events that were seen in summer occurred during the lowest flow years with upwards of 80% of the risk of loss of load occurring in the two worst flow years (1988 and 2003) of the 44 years studied. The Manitoba loss-of-load events that were seen in summer were driven by very low hydro flow conditions combined with both very high summer loads in Manitoba and very high summer loads on the MISO system.

The annual EUE heat map for 2029 is provided below.



A sample summer EUE day with very high loads on the Manitoba and MISO systems during extreme drought is shown in the illustration below. For much of the day, Manitoba is a net importer of power.



Distributed Energy Resources

There is a potential for significant solar DER resources in the latter half of the assessment period, and plans are being developed to study the impacts on the Manitoba Hydro system. The potential for future solar DERs may be dependent on solar PV subsidies and/or incentives.

Generation

Under normal water conditions, over 95% of the generation in Manitoba Hydro's system is from renewable energy—primarily hydro generation and wind generation. A Tier 1 project to replace eight older and smaller hydro units is in progress for the Pointe du Bois Generating Station. The Pointe du Bois Renewable Energy Project (PREP), approximately 50 MW, replaces the original hydro units that were mothballed or retired based on economics/end of life after about 100 years of operation.

On February 25, 2025, Manitoba Hydro filed with its regulator the preliminary estimate for a 500 MW gas capacity resource entering service in 2030. While not yet approved, this proposed plant was included as Tier 2 capacity resource. Manitoba is not currently experiencing the large additions of wind and solar resources seen in other regions, and hence, emerging reliability issues arising from such large wind and solar resource additions are not anticipated over the next five years. Manitoba Hydro is working on an Integrated Resource Plan that will support future investment decisions. The Government of Canada is further regulating carbon dioxide emissions from the electric generation sector, finalizing the Clean Electricity Regulations in December 2024. These regulations begin to restrict fossil fuel generation in 2035 and direct Canadian electric generation to achieve net-zero greenhouse gas emissions by 2050. Manitoba Hydro does not anticipate that meeting the Clean Electricity will have a negative impact on system reliability or modify the operation of Manitoba's electricity system. The Province of Manitoba provided energy policy direction with the publication of the Affordable Energy Plan in September 2024. Energy conservation, wind generation, and dispatchable back-up generation, such as natural gas combustion turbines, form the basis of the plan. Manitoba Hydro's forthcoming 2025 Integrated Resource Plan will be consistent with the policy direction.

Energy Storage

Additions of battery energy storage system (BESS) resources in the next 10 years are not anticipated at this time. The hydro generation resources, while not storing electricity directly, do store water in a reservoir for conversion to electricity and have been in use for over 100 years. For most hours of the year, the only dispatchable resources on-line are hydro generation resources, which therefore serve most operational, reliability, and economic functions. In the longer term, there may be a role for energy storage resources in Manitoba in areas that may become transmission constrained. Preliminary long-term studies of a modest amount of energy storage resources have not identified

operational challenges and have not required modification to planning assumptions since the 2024 LTRA.

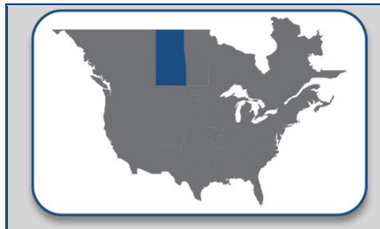
Energy Transfers

The Manitoba Hydro system is winter-peaking and is interconnected to the MISO Zone 1 Local Resource zone (which includes Minnesota and North Dakota), which as a whole is summer-peaking. Significant capacity transfer limitations from MISO into Manitoba may have the potential to cause reliability impacts, but only if the following conditions occur simultaneously: extreme Manitoba winter loads, unusually high forced generation/transmission outages, and a simultaneous emergency in the northern MISO footprint. In the unlikely event of such a situation, Manitoba Hydro would implement plans developed in accordance with emergency operating procedures for capacity and energy emergencies, including calling on emergency energy from Adjacent Balancing Authority Coordination Agreements, if available. Transmission planning studies consider maximum firm winter import and N-1 and N-2 contingencies. The completion of the Manitoba–Minnesota 500 kV transmission line on June 1, 2020, increased import capability from 700 MW to 1,400 MW and firm export capability from 2,100 MW to 2,983 MW. This new 500 kV line also improved the resilience of the network in the event of transmission contingencies. The 500 kV line is equipped with single pole trip and reclose capability, which results in only one phase being out for one second during common single-phase faults.

The expiration of existing winter capacity import contracts ("diversity capacity") in 2030 is contributing to overall lower firm resources from winter 2030–2031 through the remainder of the assessment period.

Transmission

Manitoba Hydro has identified aging components of its HVdc system as a potential reliability issue, which is unique to the assessment area. The concern is that the oldest HVdc system components could be approaching end-of-life. Studies have been initiated to study/evaluate modernization options and alternatives. The studies and procurement of replacement equipment could take up to 10 years to implement based on the current HVdc market capability. There is currently spare capacity on the HVdc system, and the end-of-life failure of a single pole would not create reliability issues. The further end-of-life failure of a second pole, while believed to be a very low probability, has the potential to create reliability concerns under peak winter loads if mitigation measures are not implemented. Mitigation measures to minimize the likelihood of experiencing this quantity of long-term outages are being actively pursued.

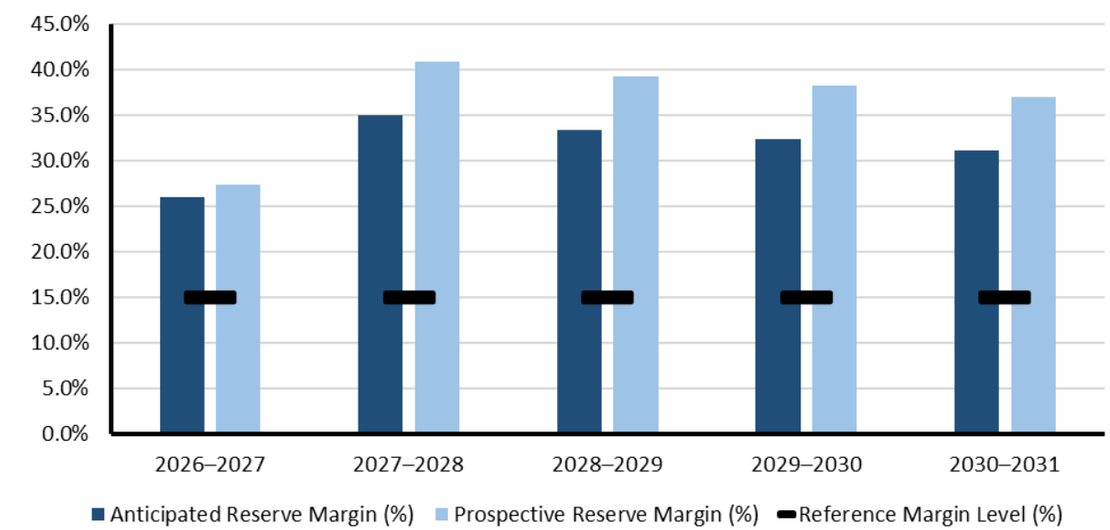


MRO-SaskPower

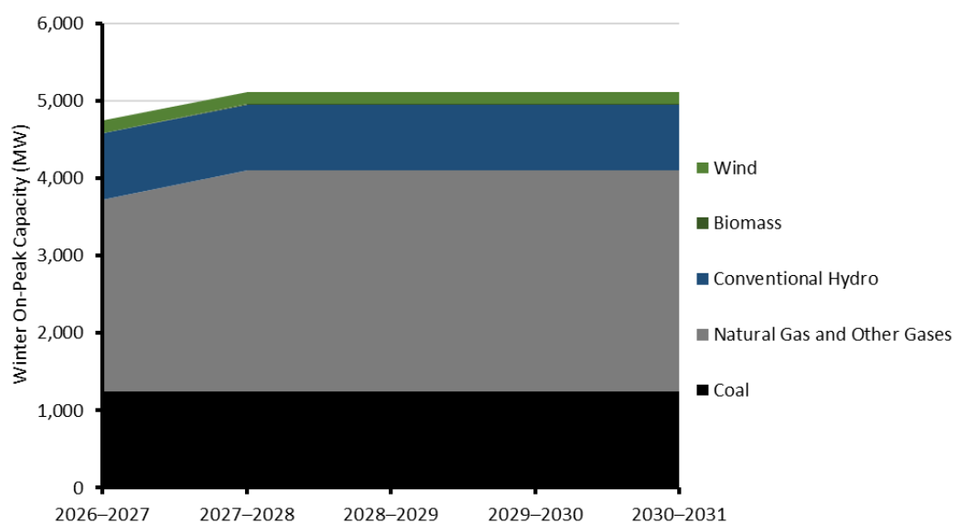
MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. The Saskatchewan Power Corporation (SaskPower) is the PC and Reliability Coordinator for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan Bulk Electric System and its interconnections. Overall, SaskPower operates nearly 14,816 circuit-km of transmission lines, 65 high-voltage switching stations, and 191 distribution substations. Peak electricity demand on the SaskPower system currently occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	4,040	4,112	4,148	4,180	4,205	4,230	4,278	4,314	4,347	4,375
Demand Response	72	72	72	72	72	72	72	72	72	72
Net Internal Demand	3,968	4,040	4,076	4,108	4,133	4,158	4,206	4,242	4,275	4,303
Additions: Tier 1	90	460	460	460	460	460	460	460	460	460
Additions: Tier 2	55	241	241	241	241	241	241	241	241	241
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	290	315	315	315	315	315	315	315	315	315
Existing-Certain and Net Firm Transfers	4,907	4,992	4,976	4,976	4,961	4,962	4,900	4,962	4,976	4,892
Anticipated Reserve Margin (%)	25.9%	35.0%	33.4%	32.3%	31.2%	30.4%	27.4%	27.8%	27.2%	24.4%
Prospective Reserve Margin (%)	27.3%	40.9%	39.3%	38.2%	37.0%	35.5%	32.5%	32.8%	32.1%	29.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

MRO-SaskPower Highlights

- Over the next 10 years, MRO-SaskPower's ARM ranges from approximately 24% to 35% and does not fall below the RML in any year. SaskPower's recent probabilistic studies concluded that the largest contribution to EUE occurs during peak hours because of planned outages. Rescheduling maintenance can help avoid these issues.
- Saskatchewan's average annual summer and winter peak demand growth is expected to be approximately 1.0% throughout the assessment period. Large industrial loads are the primary driver for both growth and uncertainty in SaskPower's forecast.
- SaskPower is projected to increase its wind and solar capacity to 1,550 MW in the next three years. Natural-gas-fired generation is being added to the system to offset VERs with plans to add 525 MW nameplate of new gas-fired generation—460 MW of Tier 1 and 65 MW of Tier 2—over the next 10 years. Life extensions and repowers for coal units are in process as directed by the Saskatchewan government. SaskPower is anticipating 31.8 MW of confirmed retirements, both waste heat and wind. 174 MW of unconfirmed wind retirements may also occur over the next 10 years.
- Driven by load growth, new generation, and reliability, SaskPower is planning to expand its interconnection with SPP and add 500 MW of new transmission service over the next five years, increasing tie-line capacity to 650 MW total. Internal transmission projects totaling 180 km of new 230 kV lines are being added and an additional ~410 circuit km of transmission projects are in planning and conceptual phases over the next 5 to 10 years.
- SaskPower's primary reliability issues include growing supply chain issues that may potentially affect their significant transmission project plans and an interdependence between Southeast Saskatchewan's power generators and natural gas production fields. SaskPower has been managing these issues by scheduling long-lead-time components as early as possible in transmission project timelines and by working with Saskatchewan's gas pipeline utility to coordinate and study gas system responses to losses of production receipts during power outages as incremental demand is added.

MRO-SaskPower Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	**2027–2028**	**2028–2029**	**2029–2030**	**2030–2031**
Coal	1,249	1,249	1,249	1,249	1,249
Natural Gas	2,480	2,850	2,850	2,850	2,850
Biomass	3	3	3	3	3
Wind	164	162	162	162	162
Conventional Hydro	856	856	856	856	856
Other	17	17	1	1	1
Total MW	**4,769**	**5,137**	**5,121**	**5,121**	**5,121**

MRO-SaskPower Assessment

Planning Reserve Margins

Saskatchewan uses two criteria for determining adequate generating capabilities. The first method is to calculate EUE through probabilistic modeling and maintain it within an acceptable level as determined through resource adequacy analysis. The second method employs a deterministic criterion in which the reserve margin for the Saskatchewan system must not fall below the RML.

Saskatchewan uses a RML of 15% and has assessed its PRM for the upcoming 10 years considering summer and winter peak hour loads, available existing and anticipated generation resources, firm capacity transfers, and available DR for each year. During the 10-year assessment period, Saskatchewan's ARM ranges from approximately 24% to 35% and does not fall below the RML in any year.

Energy Assessment, Including Non-Peak Hour Risk

Saskatchewan performs energy assessments using probabilistic methods to inform the area's resource adequacy requirements. A detailed representation of the SaskPower system that includes load forecasts, capacity expansion sequences, individual unit characteristics, maintenance, and outages are included in the model. For VERs, SaskPower uses the ELCC methodology to periodically update capacity credits in the model. The model simultaneously considers many types of randomly occurring events, such as forced outages of generating units. Uncertainty in assumptions is addressed through scenario work based on the likelihood of occurrence (e.g. high/low hydro energy forecast, high/low load forecast).

These studies conclude that the majority contribution to the EUE is typically planned outages with unserved energy occurring mainly during peak hours. These short-term reliability issues, when identified, can be mitigated by rescheduling maintenance.

ProbA Results

Saskatchewan does not anticipate resource adequacy issues during its off-peak hours. Currently, its resource mix majorly consists of baseload and fast-ramping generation resources, and it does not have a considerable penetration level of intermittent energy resources.

The major contribution to the EUE is planned outages. The contribution to EUE in these months occurs mainly during peak hours. These short-term reliability issues when identified can be mitigated by rescheduling the maintenance.

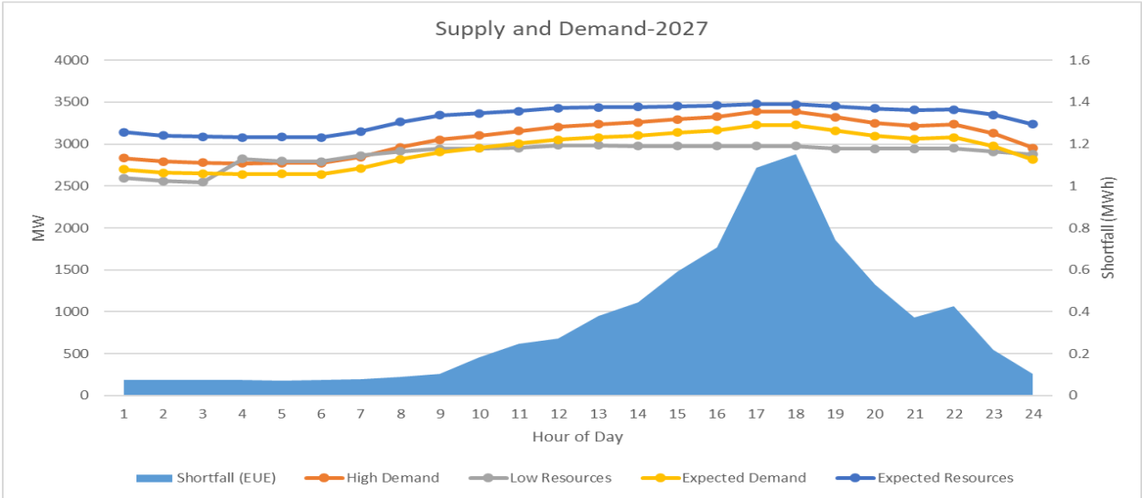
Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	75	145	5
NEUE (ppm)	2.807	5.242	0.190
LOLH (hours per Year)	0.547	1.094	0.046
*** Provides the 2024 ProbA Results for Comparison**			

The annual EUE heat map for 2027 is provided below.

Hourly EUE Heat Map : 2027

EUE	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Jan-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Feb-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%
Mar-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Apr-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
May-27	1%	1%	1%	1%	1%	1%	1%	1%	1%	2%	2%	3%	3%	3%	3%	4%	5%	5%	3%	3%	2%	3%	2%	1%
Jun-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Jul-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%
Aug-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	2%	2%	1%	1%	1%	1%	0%	0%
Sep-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%
Oct-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	0%	0%	0%
Nov-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Dec-27	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Hourly demand and resource projections for the highest EUE day in 2027 are shown in the figure below. Expected resource contributions are observed to cover expected demand on the risk day. However, there is a risk of supply shortfalls if demand is higher than expected and resource availability is lower than expected.



Demand

Saskatchewan experiences its peak season in the winter. Saskatchewan's system peak load forecast is based on econometric variables, weather normalization, and individual level forecasts for large industrial customers. SaskPower computes a coincident peak by customer category based on a combination of historical data and other factors and aggregates the coincident peaks across classes to compute the system peak.

Large industrial loads continue to be the primary reason for both growth and uncertainty in the forecast. The average annual summer and winter peak demand growth is expected to be approximately 1.0% throughout the assessment period, down slightly from the *2024 LTRA*'s projection of 1.35% average annual peak demand growth.

Demand-Side Management

Saskatchewan's DR consists of contracts with industrial customers for interruptible load based on conditions specified in established DR programs. The first of these programs provides a curtailable load, with up to 72 MW enrolled currently, with a 12-minute event response time. Other programs are in place providing access to additional curtailable load requiring up to two hours' notification, but those loads are not included in PRM calculations.

Distributed Energy Resources

The current behind-the-meter DER installed capacity in Saskatchewan is approximately 57 MW, which includes approximately 55 MW of solar PV and approximately 2 MW of distributed wind projects. An additional 25 MW of DER solar PV are expected to be added in the next five years. Additional behind-the-meter DER installations are incorporated into load forecast models used for supply and transmission planning studies.

Small power producers contribute an additional 5 MW installed DER capacity (in front of the meter) in Saskatchewan. There is currently an existing 14 MW and a potential for up to 6.5 MW of DERs being added in the next year based on the currently approved Power Generation Partner program. These projects are included as generation additions, but their capacity is not currently considered in reliability planning.

Generation

Saskatchewan prepares a 10-year supply plan annually that outlines its generation plan to meet the province's future resource needs. It considers retirements, planned and major overhauls, degradation of unit performance, escalating fuel prices, increasing capital costs, unit operating costs, and regulatory requirements. The installed capacity of non-synchronous/inverter-based generation has recently risen to 845 MW and is expected to increase to approximately 1,550 MW in the near-term planning horizon through the addition of 400 MW of wind and 300 MW of solar in the next three years. SaskPower added 370 MW of natural-gas-fired generation in 2024, which served to offset the increased net demand variations from the 220 MW of VERs added in the same year. This resulted in a slight improvement in ramping performance as compared to the last ramping assessment in 2022. SaskPower plans to add approximately 525 MW of new natural-gas-fired generation over the next 10 years and is also working to extend the life of its operational and recently deactivated coal units as directed by the Saskatchewan government.

Saskatchewan is projecting 31.8 MW (nameplate) of confirmed retirements consisting of 21.2 MW of waste heat recovery generation and 10.6 MW of wind generation. These retirements are driven by the units approaching the ends of their lifespans and terminations of power contracts. An additional 174 MW of unconfirmed wind retirements may also materialize during the 10-year assessment period.

Energy Storage

SaskPower's first battery storage system, a 20 MW/20 MWh unit, came on-line in 2024. The prevalent use for the planned energy storage is to provide regulating reserve, peak capacity and energy reduction, net demand ramping control, reactive power/ voltage control, primary frequency control, and blackstart.

Energy Transfers

SaskPower has three interfaces with its neighboring areas. The interface with Manitoba is currently the largest of the three interfaces and is the only interface with long-term firm contracts. Capacity

transfers from Manitoba would be limited in the event of a prior outage of tie lines between SaskPower and Manitoba Hydro as well as nearby transmission facilities supporting the interface. This could only impact reliability if it is coincident with the extreme winter or summer peak demand and a prior outage of one or more larger generating units in Saskatchewan. Risk mitigation measures are in place through SaskPower's emergency operating procedure that will allow measures such as short-term imports from available interfaces, initiating DR, and short-term load shedding.

According to the NERC's *ITCS Canadian Analysis*, the total simultaneous transfer capability into the Saskatchewan transmission planning region from all its neighbors, including dc-only interties, is 904 MW in the 2024 Summer and 893 MW in the 2024–2025 Winter. These values translate to approximately 25% of peak summer load and 22% of peak winter load in the analysis years. The interfaces include connections with MRO-SPP, MRO-Manitoba Hydro, and WECC-Alberta.

Transmission

SaskPower's major transmission projects in the first five years of the assessment period are related to the interconnection expansion with SPP and the 500 MW of new transmission service. This includes two new international power lines between Saskatchewan and North Dakota. Within Saskatchewan, a total of approximately 180 km of new 230 kV lines, a new 230 kV transmission station, expansion of several existing transmission stations, installation of two phase-shifting transformer interfaces, and two STATCOMs are being added. The remaining transmission projects (approximately 410 circuit km) will be in the planning or conceptual phases in the 5-to-10-year timeframe. These projects are driven by load growth, new generation additions, and reliability needs. SaskPower has historically experienced transmission limitations for existing generation deliverability in the southwest part of the province during prior outages of major transmission facilities.

Transmission infrastructure is being developed to reinforce the Northern Transmission System. SaskPower's Northern System is not directly connected to the Southern grid, so significant load growth in the North will also require additional generation to supply the additional loads. SaskPower is looking at different ways to supply the generation to this load, including wheeling power from the South to the North through adjacent areas and temporary generation until a more permanent solution can be implemented. Planning for these projects is being driven, in part, by a projected increase in mining activity and associated development in Saskatchewan's remote northern region. Reliable power supplies for new loads in the north will require significant transmission development.

Reliability Issues

As SaskPower is planning on constructing a significant number of transmission facilities, growing supply chain issues may affect project schedules because of long lead times for major system components. SaskPower is identifying and initiating projects earlier that may require longer lead time and is advancing procurement as necessary.

It has been noted that there is an interdependency between Southeast Saskatchewan's power generation and natural gas production. Saskatchewan's pipeline utility, SaskEnergy, has completed analysis on how its system will respond to a loss of natural gas receipts during a power outage in this region as potential incremental demand is added. Both SaskPower and SaskEnergy have incorporated the potential challenges identified by that analysis into long-term planning and mitigation efforts.

SaskPower has been recently observing increasing instances of unscheduled flows on its interface with SPP and Manitoba Hydro. SaskPower is coordinating this on a regional basis with Manitoba Hydro, SPP and MISO to monitor and address the impact.

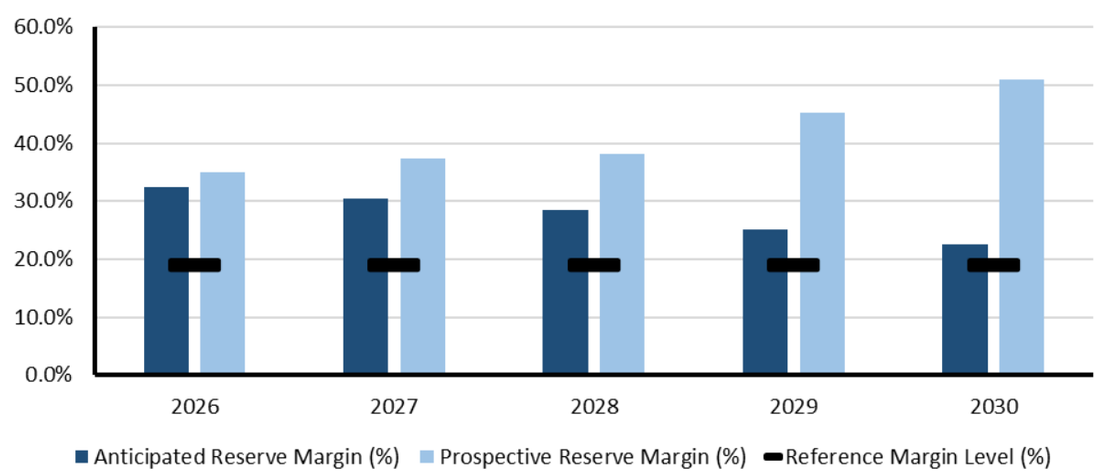


MRO-SPP

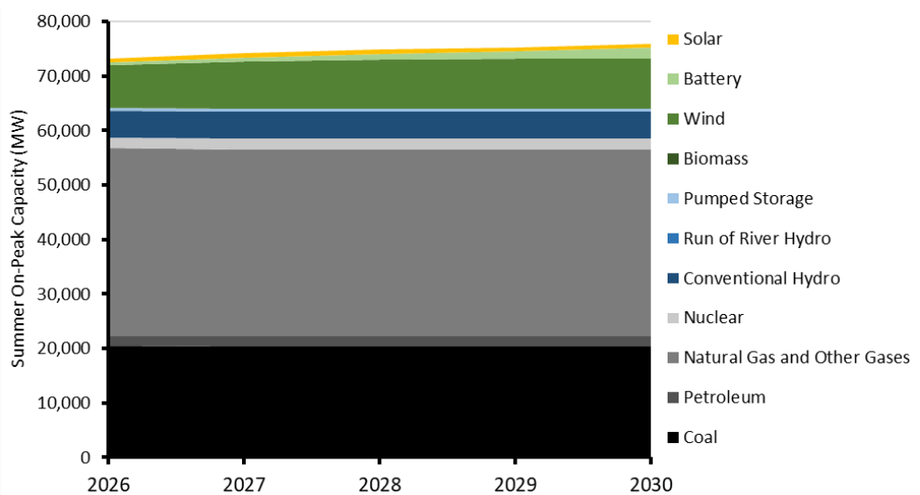
The Southwest Power Pool (SPP) PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	57,479	59,121	60,689	62,766	64,475	66,283	66,982	67,570	68,049	68,622
Demand Response	2,138	2,162	2,332	2,508	2,509	2,511	2,513	2,514	2,718	2,720
Net Internal Demand	55,340	56,959	58,357	60,258	61,966	63,772	64,469	65,056	65,331	65,902
Additions: Tier 1	1,808	3,020	3,685	4,251	4,815	4,866	5,344	5,344	5,344	5,344
Additions: Tier 2	2,436	6,104	8,948	15,659	21,487	23,345	25,664	27,277	27,877	28,627
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-18	-78	-78	-78	-78	-79	-79	-79	-79	-79
Existing-Certain and Net Firm Transfers	71,475	71,224	71,232	71,127	71,146	71,115	71,135	71,106	71,105	71,106
Anticipated Reserve Margin (%)	32.4%	30.3%	28.4%	25.1%	22.6%	19.1%	18.6%	17.5%	17.0%	16.0%
Prospective Reserve Margin (%)	34.9%	37.3%	38.2%	45.2%	50.9%	48.7%	51.5%	51.8%	51.8%	50.6%
Reference Margin Level (%)	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%	19.0%



Planning Reserve Margins



Existing and Tier 1 Resources

MRO-SPP Highlights

- The SPP assessment area peak demand occurs during the summer season; the 2025 net internal demand forecast over the 10-year time frame is projected to peak at 65,902 MW, which is a 16% increase to the all-time summer peak that SPP saw in 2023.
- SPP is seeing a slowing in retirements due to the projected PRM increases along with the separate seasonal PRM and accreditation requirements that are planned to be implemented in 2026.
- The existing-certain and net firm transfers reserve margin for the SPP assessment area is projected to fall below the current summer season PRM requirement in 2029.

MRO-SPP Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	20,473	20,440	20,440	20,428	20,428
Coal*	19,187	19,154	18,086	18,075	18,075
Petroleum	1,824	1,827	1,827	1,827	1,829
Petroleum*	1,824	1,771	1,771	1,771	1,774
Natural Gas	34,525	34,303	34,303	34,265	34,265
Natural Gas*	34,363	33,662	33,550	33,512	33,268
Biomass	35	35	35	35	35
Solar	700	700	700	700	700
Wind	7,831	8,581	9,044	9,134	9,191
Conventional Hydro	4,925	4,993	5,009	5,026	5,030
Pumped Storage	456	456	456	415	460
Nuclear	1,945	1,945	1,945	1,945	1,945
Other	281	281	281	281	281
Battery	379	833	1,027	1,472	1,949
Total MW	73,429	74,450	75,123	75,584	76,168
Total MW*	71,981	72,467	71,960	72,422	72,762
***Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to give formal notice to SPP are removed from the resource projection where marked.					

MRO-SPP Assessment

Planning Reserve Margins

The existing-certain and net firm transfers reserve margin for the SPP assessment area is projected to fall below the current summer season PRM requirement in 2029. SPP has approved a non-coincident 16% PRM for the 2026 Summer season and a 36% PRM for the 2026–2027 Winter season. Additionally, a non-coincident 17% PRM for the 2029 Summer season and 38% PRM for the winter season was approved as well. The PRM increases are not reflected in the *2025 LTRA* as they are tied to policies that are still before FERC. Based on resources submitted in the ARM calculation, including the impact of retirements, SPP is forecasted to drop below the current 19% RML in 2032 and remain below that RML for the remainder of the 10-year horizon.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

SPP is performing a yearly energy adequacy assessment and assessment of adequacy of reliability attributes, which will be presented to SPP stakeholders. The results will also be used to perform for all reliability attributes a biennial assessment of the need for new market products, changes to market functionality, and changes to resource adequacy policies or requirements. Results of the biennial reassessment will be provided to impacted SPP stakeholder groups and the Regional State Committee (RSC).

Southwest Power Pool (SPP) performs an LOLE analysis every two years to determine the adequate amount of planning reserves needed to maintain a reliability metric of one day (or less) in ten years. SPP's 2023 LOLE study supported much of the demand forecast presented in NERC's *2024 LTRA* and demonstrated how the PRM could be impacted materially depending upon how much loss of demand risk was planned for each season (winter or summer). Directed by the RTO's Resource and Energy Adequacy Leadership Team, SPP completed an out-of-cycle 2024 LOLE analysis published in April 2025 to develop a recommendation for 2029 seasonal PRMs. This study and its results are based on the 2024 member-submitted forecast for the resource mix and demand, using the 2023 LOLE study assumptions. Member-submitted demand forecast increased approximately 5% in summer and 6% in winter for planning year 2029.

ProbA Results

The 2025 ProbA study was performed on assumptions, and the accompanying methodology reflects methods used in SPP's LOLE studies, which have been thoroughly vetted through the SPP stakeholder process. Study improvements include additional weather years, seasonal forced outage modeling from the previous NERC probabilistic study, and incremental cold weather outages. More information on improvement and methodology can be found in SPP's LOLE study reports.

There was no observed unserved energy for years two and four of the base-case analysis for the SPP assessment area. This is most likely attributed to an increase of conventional thermal generations more than that of renewable resources and the delayed retirements of other thermal resources to meet the increasing projected demand needs. Since there are no observed load-loss events, additional reporting is not provided.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	0	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
***Provides the 2024 ProbA Results for Comparison**			

Demand

The SPP assessment area is a summer-peaking region and currently relies on the forecast submitted by the load responsible entities in the annual resource adequacy process. The 2025 net internal demand forecast over the 10-year time frame is projected to peak at 65,902 MW, which is a 16% increase to the all-time summer peak that SPP saw in 2023. Although actual demand is very dependent on weather conditions and typically includes the effects of interruptible loads, forecasted net internal demands are based on a 10-to-30-year average of summer weather, or 50/50 weather. Some SPP RTO members base their peak load forecasts on a 50% confidence level, as approved by their respective state commission(s). This means the actual weather on the peak summer day is expected to have a 50% likelihood of being hotter and a 50% likelihood of being cooler than the weather assumed in deriving the load forecast. SPP RTO members make economic assumptions in their individual forecasting methods as well consider the effects of non-controllable or dispatchable programs and resources within their area. One risk that SPP has noted is that the aggregated noncoincident demand forecast submitted by members in recent years, which is based on a 50/50 forecast and is weather normalized, is tracking at a lower demand level than what the BA has seen in recent peak season.

Although SPP's energy projections for resource adequacy purposes differ from load interconnection process set forth in the SPP OATT, the SPP Assessment Area has received new load requests for data center, pipeline, oil and gas, irrigation and industrial load. While these loads represent above average load growth in areas, some of the load due to oil and gas exploration have decreased. Of current concern is the projected growth in the crypto load area and how much of that will turn into demand growth outside of the DR arena.

Demand-Side Management
SPP RTO members track dispatchable and controllable DR programs, which are used as peak load shaving programs. For resource adequacy purposes, the peak demand can be reduced by the impacts of the programs to determine an appropriate net peak demand for each member. SPP's tariff requires each Load Responsible Entity (LRE) to qualify and test their programs to prove they can meet and maintain the level of reduction submitted annually in the resource adequacy compliance window. SPP is constructing new policy to more appropriately categorize DR based on the flexibility of the program, which will ultimately be reflected in the accreditation process.

Distributed Energy Resources
The SPP assessment area is forecasting ~70 MWs of DERs in the 5–10-year planning horizon. The impacts and assumptions may differ across the planning processes, for instance in some studies they may be used to reduce the load impacts whereas in other studies they may be modeled as a resource that has a high cost associated with it. SPP does not consider the impacts of BTM resource as a load reduction for purposes on resource adequacy compliance.

Generation
In general, SPP is seeing a slowing in retirements due to the projected PRM increases along with the separate seasonal PRM and accreditation requirements that are planned to be implemented in 2026. There has been minimal retirement reported since the *2024 LTRA*, and a number of resources identified in 2024 as being set to retire are now being converted to new fuel, mostly coal to gas.

The *Expedited Resource Adequacy Study* process, approved by FERC in July 2025, is providing an accelerated pathway to interconnection for generation that supports identified resource adequacy needs. The program is yielding additional natural-gas-fired, solar, and battery resource projects in SPP's Tier 2 development queue. Nearly 8 GW of natural-gas-fired generator capacity, 2.2 GW nameplate in solar, and 1.8 GW nameplate in batteries have been added to SPP's Tier 2 queue since July and are not reflected in this year's LTRA. SPP anticipates the first interconnection agreements for *Expedited Resource Adequacy Study* projects will be signed in early 2026, which will qualify these resources for Tier 1 in NERC's reliability assessments and ProbA and count toward ARM.

Energy Storage
There are approximately 57,000 MWs of energy storage and hybrid resources in generator interconnection queues. There are about 50 MWs that are under contract by members across the SPP assessment area and 230 MW of nameplate capacity forecasted for the assessment timeframe. These resources are being modeled as generation in the planning assumptions both near and long term. Due to this limited amount of storage, limited operational impacts have been identified.

Capacity Transfers
Over the assessment time frame, SPP is forecasting, based on submitted member data, to be a net exporter of capacity. In the resource adequacy process, SPP only relies on the imports that have firm transmission service, which is ~2,000 MWs. SPP and ERCOT executed a Coordination Plan, which addresses operational issues for coordination of the dc ties between the Texas Interconnection and Eastern Interconnection, block load transfers (BLT), and switchable generation resources (SWGR). Under the terms of the Coordination Plan, SPP has priority to recall the capacity of any SWGRs that have been committed to satisfying the resource adequacy requirements contained in Attachment AA of the SPP Open Access Transmission Tariff. Annually, SPP and ERCOT update the Coordination Plan based on the latest discussions and business decisions related to resource priority.

Transmission
SPP's 2024 Integrated Transmission Plan (ITP) is the single largest portfolio, in terms of size and value, that SPP has proposed for construction in its 20-year history as a transmission PC. The approved plan includes 89 transmission upgrades needed to address increasing electricity consumption and changes in the region's generating fleet.

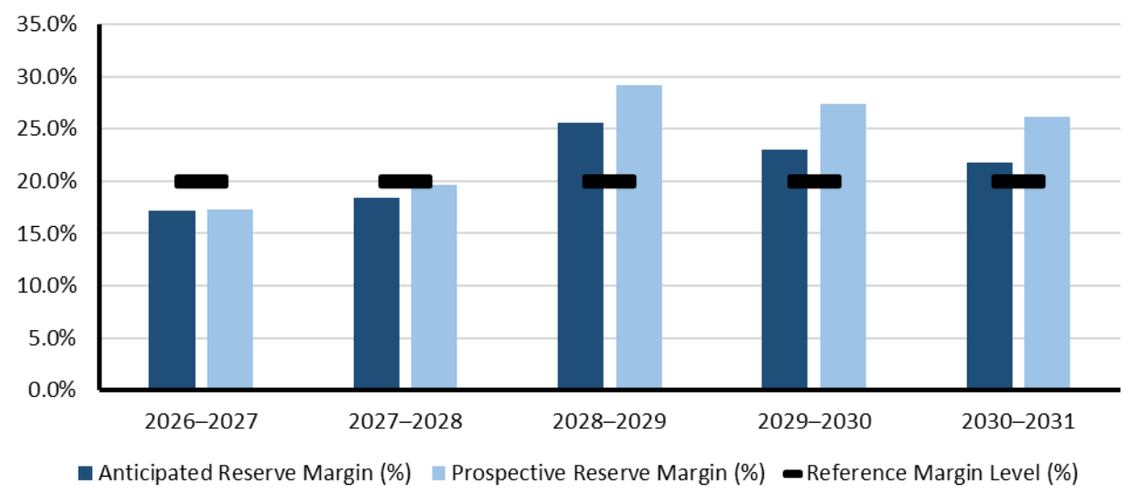


NPCC-Maritimes

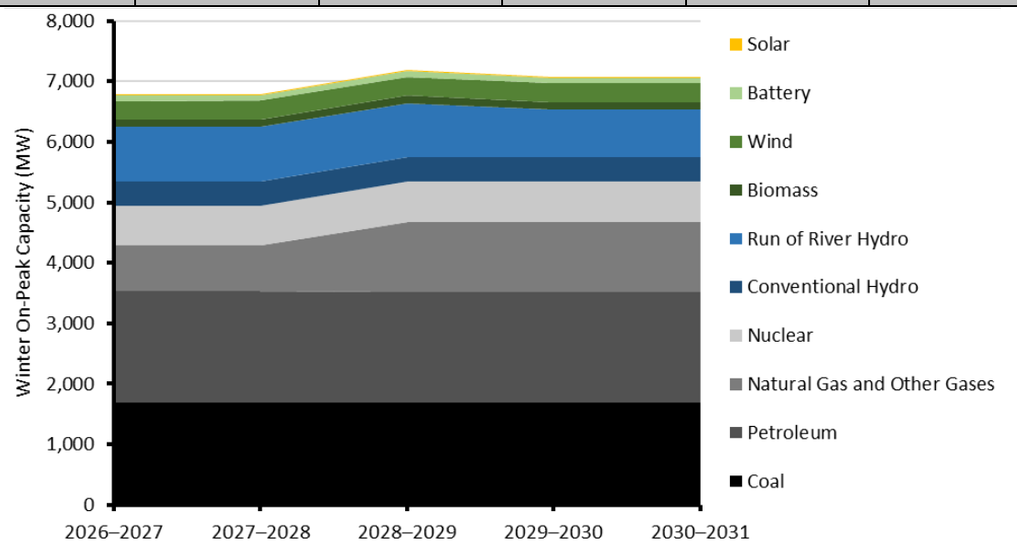
NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. State of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly 1.9 million people. The New Brunswick Power Corporation (NB Power) is the BA for New Brunswick, Prince Edward Island, and the northern portion of Maine. Nova Scotia Power Inc. (NSPI) is the BA for Nova Scotia. NB Power's system is electrically interconnected with NPCC-Québec and NPCC-New England, and the electric systems in the provinces of Nova Scotia and Prince Edward Island have ties with New Brunswick but no direct ties with other assessment areas. Peak electricity demand in NPCC-Maritimes occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	6,107	6,157	6,194	6,231	6,292	6,346	6,380	6,493	6,579	6,669
Demand Response	264	283	290	291	290	291	290	291	290	290
Net Internal Demand	5,843	5,875	5,904	5,940	6,001	6,055	6,089	6,202	6,289	6,380
Additions: Tier 1	173	179	579	579	579	579	579	579	579	579
Additions: Tier 2	6	367	656	1,492	1,492	1,492	1,492	1,492	1,492	1,492
Additions: Tier 3	0	0	23	101	215	227	239	251	260	260
Net Firm Capacity Transfers	-32	75	145	145	145	145	145	145	145	145
Existing-Certain and Net Firm Transfers	6,673	6,780	6,838	6,727	6,727	6,727	6,621	6,621	6,596	6,707
Anticipated Reserve Margin (%)	17.2%	18.5%	25.6%	23.0%	21.7%	20.7%	18.2%	16.1%	14.1%	14.2%
Prospective Reserve Margin (%)	17.3%	19.6%	29.2%	27.4%	26.1%	25.0%	22.6%	20.3%	18.3%	18.3%
Reference Margin Level (%)	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-Maritimes Highlights

- Since the *2024 LTRA*, the overall resource outlook has diminished slightly with smaller peak capacity contributions from certain wind, hydro, and biomass resources through most of the planning period. Starting in 2026, winter peak demand forecasts for this assessment area have risen slightly from the previous year's projection through most years of the planning horizon; however, ARMs are currently projected to remain above the RML of 20% until 2032 when the ARM dips to 18.2%.

NPCC-Maritimes Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	**2027–2028**	**2028–2029**	**2029–2030**	**2030–2031**
Coal	1,696	1,696	1,696	1,696	1,696
Coal*	1,696	1,696	1,410	1,003	691
Petroleum	1,831	1,831	1,820	1,820	1,820
Natural Gas	757	757	1,157	1,157	1,157
Biomass	129	129	129	129	129
Solar	10	10	10	10	10
Wind	300	306	306	306	306
Conventional Hydro	395	395	395	395	395
Run of River Hydro	901	901	901	790	790
Nuclear	663	663	671	671	671
Other	98	98	89	89	89
Battery	99	99	99	99	99
Total MW	6,878	6,884	7,272	7,161	7,161
Total MW*	6,878	6,884	6,986	6,468	6,156
*** Capacity with additional generator retirements.** Generators that are being considered for retirement but have not been confirmed are removed from the resource projection where marked.					

NPCC-Maritimes Assessment

Planning Reserve Margins

The RML that is used for evaluating the New Brunswick (NB), Nova Scotia (NS), Prince Edward Island (PEI), and Northern Maine (NM) sub-areas comprising the Maritimes area is 20% of firm load. The 20% criterion is not a mandated requirement. The ARM over the study period for the Maritimes area ranges between 14% to 26% during the winter period and between 74% to 90% during the summer period.

The ARM level during off-peak season for the Maritimes areas ranges between 74% to 90%. During off-peak hours, the Maritimes area has surplus generation available to meet the area's energy needs and hence there are no constraints with converting the capacity to energy during these times.

The two BAs within the Maritimes area, as members of the NPCC, jointly prepare annual interim or comprehensive probabilistic assessment reviews that cover three to five-year forward-looking periods for both the area's transmission system and resource adequacy evaluations. In addition, the Maritimes area also supports NERC's annual seasonal probabilistic assessments which provides an evaluation of generation resource and transmission system adequacy that will be necessary to meet projected seasonal peak demands and operating reserves.

Energy Risk

During off-peak hours, the Maritimes area has surplus generation available to meet the area's energy, needs and hence there are no constraints with converting the capacity to energy during these times.

The two Balancing Authorities within the Maritimes Area as members of the Northeast Power Coordinating Council (NPCC) jointly prepare annual interim or comprehensive probabilistic assessment reviews that cover three- to five-year forward-looking periods for both the area's transmission system and resource adequacy evaluations. In addition, the Maritimes area also supports NERC's annual and seasonal ProbAs, which provide an evaluation of generation resource and transmission system adequacy that will be necessary to meet projected seasonal peak demands and operating reserves.

ProbA

For the Maritimes area, the ProbA indicates elevated levels of unserved energy in February 2028 due to load growth projections and the characteristics of the resource mix during that period and with a few hours of risk in the shoulder months of December and January.

Annual metrics and requested enhancements including EUE heat maps, loss of load event analysis, and risk period visualizations for both 2027 and 2029 are included in the ProbA appendix.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	**5**	**15**	**7**
NEUE (ppm)	**0.17**	**0.52**	**0.25**
LOLH (hours/year)	**0.09**	**0.25**	**0.10**
*Results from the 2024 ProbA simulations			

Resource additions described in the Generation section below contribute to the improved EUE and LOLH metrics for study year 2029.

Demand

There is no regulatory requirement for a single authority to produce a forecast for the whole Maritimes area. The peak area demand occurs in winter and is highly reliant on the forecasts of the two largest sub-areas of NB and NS, which are historically highly coincidental. Demand for the Maritimes area is determined to be the non-coincident sum of the peak loads forecasted by the individual sub-areas. The aggregated growth of both demand and energy for the combined sub-areas see an upward trend over summer and winter seasonal periods of the LTRA assessment period.

The Maritimes area peak loads are expected to increase by 8% during summer and by 10% during winter seasons over the 10-year assessment period. This translates to compound average growth rates of 0.8% in summer and 1% in winter. The Maritimes area annual energy forecasts are expected to increase by a total of 6.6% during the 10-year assessment period for an average growth of 0.7% per year. Demand and energy forecasts have risen since the *2024 LTRA*, due in large part to rural-to-metropolitan population migration and the proliferation of heat pump technology in local areas previously heated by fossil fuels, primarily in the PEI region.

Demand-Side Management

Plans to develop up to 100 MW by 2030–2031 of controllable direct load control programs using smart grid technology to selectively interrupt space and/or water heater systems in residential and commercial facilities are underway but no specific annual demand and energy saving targets currently exist. During the 10-year LTRA assessment period in the Maritimes area, annual amounts for summer peak demand reductions associated with EE and conservation programs rise from 21 MW to 147 MW

while the annual amounts for winter peak demand reductions rise from 177 MW to 652 MW. [37] The total controllable and dispatchable DR increases from 328 MW to 337 MW in the summer period while increasing from 248 MW to 290 MW in the winter period.

Distributed Energy Resources

The DER installed capacity in NS is approximately 300 MW at present, including distribution-connected wind projects under purchase power agreements, small community wind projects under a feed-in tariff and BTM solar.

LTRA wind capacity for NB, NS, and PEI is de-rated between 18% and 33% using probabilistic methods to calculate equivalent perfect capacities for each sub-area excluding NM, which uses seasonal capacity factors. Behind-the-meter (BTM) solar is assumed to have an ELCC of 0% during the winter period. The Maritimes area has shown embedded BTM solar PV projections of 204 MW in 2025 rising to 1,261 MW by 2035. These projects include distributed small-scale solar (mainly rooftop) projects that fall under the net metering program and serve as a reduction in load mainly in the residential class. The forecasted increase in solar installations in the coming years is a result of initiatives including municipal and provincial incentive programs. There is no capacity contribution from solar generation due to the timing of area's system peak which occurs either before sunrise or after sunset in the winter period.

Generation

NB plans to extend 28 MW diesel fired generator starting in 2025 and recently upgraded 277 MW of natural-gas-fueled resource completed in 2023. An anticipated replacement PPA contract, a long-term firm energy contract from neighboring jurisdiction, and opportunities to buy in day-ahead and real-time markets will be utilized to maintain the overall resource adequacy.

In New Brunswick, Tier 1 resources include 63 MW (installed capacity) of wind and 400 MW of combustion turbines. Tier 2 resources include 546 MW of wind resources and 72 MW of biomass.

In Nova Scotia, Tier 1 resources include wind projects with a total installed capacity of 635MW phased-in from 2025–2027. These projects include 306 MW as part of the provincial Rate Base Procurement program, a 168 MW wind project, a 12.5 MW wind project, and a 148 MW wind project under the Renewable to Retail tariffs. Tier 1 resources in NS also include a 150 MW battery (2025–2026). Tier 2 resources in NS include 600 MW of combustion turbines (2027–2029); a 150 MW conversion of a coal-fired unit to natural gas (2028); 459 MW conversion of coal-fire units to oil (2030); 250 MW of batteries (2027–2029); 262 MW of wind projects as part of the provincial Green Choice Program (2028–2029); and approximately 100 MW of solar independent power producer (IPP) projects (2026-2029) with an ELCC of 0%. Tier 3 resources in NS include new wind generation with a nameplate capacity of 1400 MW phased in from 2029-2034.

PEI has 30 MW installed capacity of tier 2 wind, 111 MW tier 3 wind, 140 MW of tier 3 Petroleum based generation and 10 MW of tier 3 batteries.

NB de-rates its wind capacity using a calculated year-round equivalent capacity of 22%. NS and PEI de-rate wind capacity to 18% and 17% respectively of nameplate based on year-round calculated equivalent load carrying capabilities for their respective individual sub areas. The peak capacity contribution of grid based solar is estimated at zero since the Maritimes Area peak occurs in the winter either before sunrise or after sunset.

Energy Storage

NS Power includes a 150 MW (4-hour duration) nameplate standalone battery resource as a Tier 1 resource (2025–2026) and a 250 MW (4-hour duration) nameplate capacity standalone battery resource added as a Tier 2 resource (2027–2029). These grid scale projects will support the integration of new renewable generation, provide energy arbitrage and resiliency services, and provide firm capacity and fuel savings.

PEI includes a 10 MW nameplate capacity hybrid energy storage as a Tier 3 resource starting summer of 2028.

NB Power has not included any energy storage resources in the *2025 LTRA* submission; however, the value of energy storage options is expected to increase as the technology improves and as NB's smart grid network develops. NB Power issued a request for expressions of interest (REOI) for new renewable generation sources, including 200 MW wind, 15 MW solar, 5 MW tidal, and 50 MW 4-hour duration battery storage in February 2023. Under this program, NB Power expects uptake in new energy storage projects in the coming years. Internal pilot projects and studies are underway to understand the economics, application, and performance of battery storage resources. Ongoing internal analyses are conducted by NB Power to determine the cost and benefit associated with battery storage options and dispatching these resources to reduce/shift peaks and/or balance intermittent resources such as wind to provide additional flexibility to the system.

[37] Current and projected EE effects based on actual and forecasted customer adoption of various DSM programs with differing levels of impact are incorporated directly into the load forecast for each of the areas but are not separately itemized in the forecasts. Since controllable space and water heaters will be interrupted via smart meters, the savings attributed to these programs will be directly and immediately measurable.

Capacity Transfers
Probabilistic studies show that Maritimes area is not reliant on inter-area capacity transfers to meet NPCC resource adequacy criteria.

Transmission
NS has multiple new transmission line projects compared to the 2025 LTRA, most being shorter runs to enable the connection of renewable resources, with one major project of 165 miles designed to improve the reliability of the existing tie between NS and NB.

Reliability Issues
The Maritimes area has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind (de-rated), dual fuel oil/gas, tie benefits, and biomass with no one type feeding more than about 32% of the total capacity in the area. The Maritimes area does not anticipate fuel disruptions that pose significant challenges to resource during the assessment period.



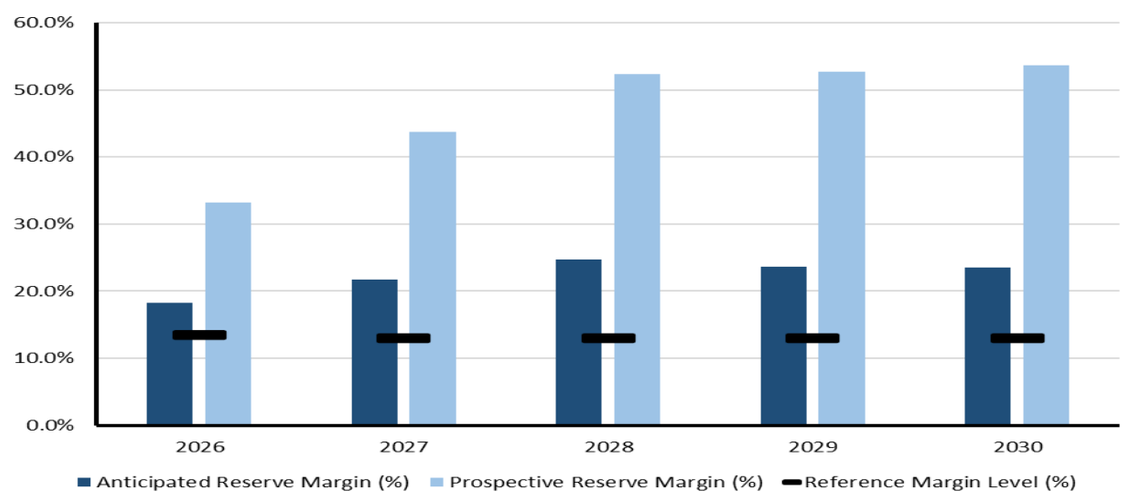
NPCC-New England

NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont served by ISO New England Inc. (ISO-NE). ISO-NE is a regional transmission organization responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

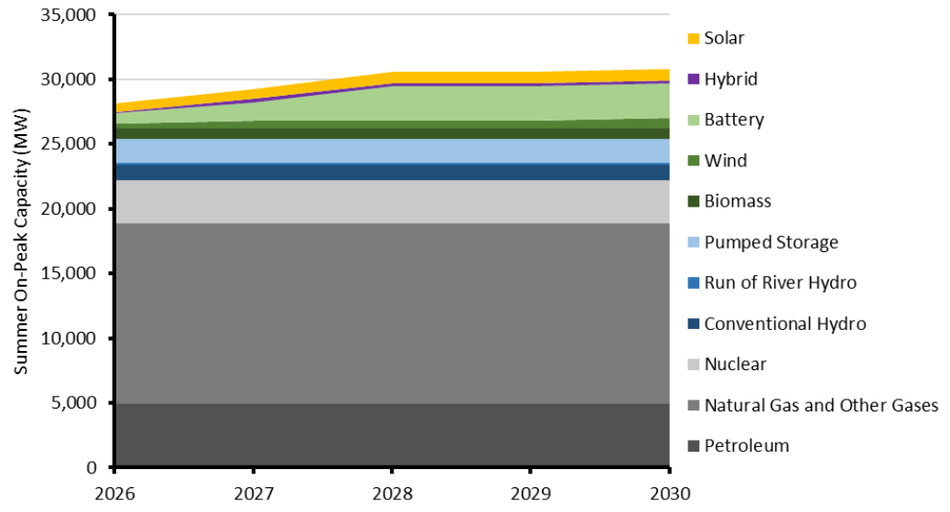
The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	24,877	24,945	25,124	25,347	25,557	25,821	26,123	26,486	26,897	27,331
Demand Response	623	544	544	544	544	544	544	544	544	544
Net Internal Demand	24,254	24,401	24,580	24,803	25,013	25,277	25,579	25,942	26,353	26,787
Additions: Tier 1	1,081	2,183	3,543	3,551	3,781	3,781	3,913	3,913	4,263	4,263
Additions: Tier 2	1,113	2,871	4,274	4,687	5,037	5,037	5,037	5,387	5,387	5,387
Additions: Tier 3	872	4,129	10,335	11,426	11,830	12,924	12,924	12,924	12,924	12,924
Net Firm Capacity Transfers	567	465	84	84	84	84	84	0	0	0
Existing-Certain and Net Firm Transfers	27,607	27,505	27,124	27,124	27,124	27,124	27,124	27,040	27,040	27,040
Anticipated Reserve Margin (%)	18.3%	21.7%	24.8%	23.7%	23.6%	22.3%	21.3%	19.3%	18.8%	16.9%
Prospective Reserve Margin (%)	33.2%	43.7%	52.3%	52.7%	53.7%	52.1%	50.8%	49.7%	48.7%	46.3%
Reference Margin Level (%)	13.4%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-New England Highlights

- New England is forecast to have sufficient seasonal ARMs needed to meet consumer demand for electric energy for the entire assessment period (2026–2035) and not require any Tier 2 resources.
- Ongoing developments of wind facilities and a new interregional tie with Canada (the New England Clean Energy Connect) as well as new technologies (such as longer-duration electricity storage) will likely continue the trend toward a cleaner, albeit more complex, power system. ISO-NE is addressing the issues brought on by grid transformation through a number of planning, operational, and market measures.
- The summer ARMs do not fall below the annual RMLs for the entire assessment period. The summer ARMs range from a surplus high of 3,213 MW (26% ARM) in Summer 2028 and then decrease each year to a low of 1,356 MW (18% ARM) in 2035.

NPCC-New England Projected Generating Capacity by Energy Source in Megawatts (MW)[38]					
	2026	2027	2028	2029	2030
Petroleum	4,899	4,899	4,899	4,899	4,899
Natural Gas	13,939	13,939	13,939	13,939	13,939
Biomass	776	776	776	776	776
Solar	645	726	864	872	872
Wind	416	622	622	622	852
Conventional Hydro	1,165	1,165	1,165	1,165	1,165
Run of River Hydro	179	179	179	179	179
Pumped Storage	1,864	1,864	1,864	1,864	1,864
Nuclear	3,351	3,351	3,351	3,351	3,351
Hybrid	96	287	287	287	287
Battery	791	1,416	2,638	2,638	2,638
Total MW	28,121	29,223	30,584	30,591	30,821

- The winter ARMs do not fall below the annual RMLs for the entire assessment period.

[38] MW totals reflect existing and Tier 1 generation. Generator retirements in this timeframe would be captured if a resource submits a retirement request through the ISO-NE capacity market.

NPCC-New England Assessment

The summer ARMs do not fall below the annual RMLs for the entire assessment period. The summer ARMs range from a surplus high of 3,213 MW (26% ARM) in Summer 2028 and then decrease each year to a low of 1,356 MW (18% ARM) in 2035.

The winter ARMs do not fall below the annual RMLs for the entire assessment period. The winter ARMs range from a surplus high of 10,651 MW (66% ARM) in winter 2027–28 and then decrease each year to a surplus low of 4,522 MW (30% ARM) in winter 2035–36. The larger surpluses during winter (vs. summer) reflect the fact that New England is currently summer-peaking.

With the continued development of renewable and clean energy resources, the system will continue to emit lower air emissions.

Planning Reserve Margins

ISO-NE's installed capacity requirement (ICR) is based on the capacity needed to meet NPCC's resource adequacy reliability criterion. The ICR varies from year to year depending on projected system conditions. The ICR is calculated on an annual basis, in advance of the capacity auctions for each Capacity Commitment Period (CCP). The latest ICR calculations result in an LTRA annual RML of 13% in 2026 and 2027, expressed in terms of the annual 50/50 peak demand forecast. For the years 2028 through 2035, ISO-NE continued to use the last available RML value of 13%.

Energy Risks (Including Non-Peak Hour Risk)

ISO-NE routinely prepares a 21-day energy assessment forecast and report. These forecasts incorporate weather, transmission topology, resource capability and availability, fuel inventories and constraints, and projected imports/exports. If the regional supply/demand balance is projected to be negative, then projected energy deficiencies can trigger energy alerts or energy emergencies that are then disseminated to market participants and federal and state regulators. This early notification of potential electricity shortages should incentivize market participants to procure whatever is necessary (fuel) to follow future ISO dispatch orders. ISO-NE publishes its 21-day energy assessments every 2 weeks during spring, summer, and fall and then increases these publications to weekly (and/or daily if necessary) during the winter.

ISO-NE worked with the Electric Power Research Institute (EPRI) to develop the Probabilistic Energy Adequacy Tool (PEAT) framework. The modeling results for the near-term PEAT assessments show for Summer 2027 that no energy shortfalls were observed in any of the events. One operating reserve shortfall was observed within a long-duration heat wave coincident with low wind scenario. For Winter 2027, a range of energy shortfall risks and associated probabilities were observed:

- The energy shortfall risk appears manageable over a 21-day period.
- These modeling results are consistent with the significant quantities of PV (BTM and utility scale), wind, and energy/electricity storage expected while experiencing minimal load growth.
- Operating risks may be mitigated by incremental imports from large inter-area transmission interconnects.

The modeling results for Summer 2032 also show that no energy shortfalls were observed in any of the hours of the 21-day period and only 1 hour of 30-minute reserve shortfall was observed. Baseline studies of Summer 2032 events indicate an energy shortfall risk similar to that of Summer 2027 events.

The modeling results for Winter 2032 show that the energy adequacy risk profile is dynamic and will be a function of the evolution of both supply and demand profiles. These results also reveal the range of energy shortfall risk under a variety of resource mix and demand assumptions. In terms of magnitude and probability, baseline studies of Winter 2032 events indicate an energy shortfall risk profile akin to that of Winter 2027 event studies.

Probabilistic Assessments (ProbA and Other Studies)

In conjunction with NPCC, ISO-NE conducts annual probabilistic resource adequacy assessments to identify regional capacity resource needs and to comply with NPCC/NERC reliability criterion/requirements. In the transmission assessment domain, revisions to ISO-NE planning processes reflect the changing resource characteristics, probabilistic study assumptions, and changes to national and regional criteria. Coordinated transmission planning activities with neighboring systems will continue in support of the New England states' policy objectives of providing access to a greater diversity of clean energy resources and to comply with environmental regulations.

New England is a summer-peaking area. For the ProbA years, New England presents negligible risks in 2027 and very low risk in 2029 based on the ProbA results shown below.

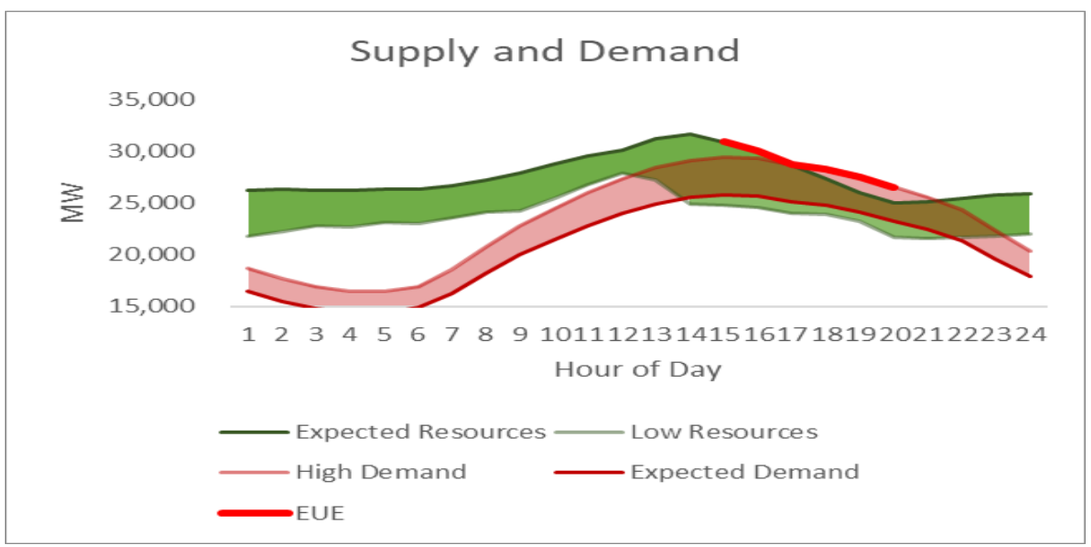
NPCC New England Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	10.7	0.1	1.8
NEUE (ppm)	0.1	0.0	0.0
LOLH (hours per Year)	0.1	0.0	<0.1
* Provides the 2024 ProbA results for Comparison			

EUE Heat Map – 2029

For the 2029 summer season, the highest EUE risks are driven by high demand and low resources availability.

Month \ Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	10%	33%	24%	1%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	19%	5%	0%	0%	0%	0%	0%
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11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
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2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

The figure below illustrates hourly demand and resource projections for the highest EUE day in 2029.



Demand

For its 2025 forecast, ISO-NE has updated its long-term forecast methodology to include hourly modeling of all load components, incorporation of climate-adjusted weather in forecast simulation, redefinition of gross load to reflect reconstitution for BTM solar PV (BTM PV) only, and an expanded forecast horizon that extends to 2045. This new base load forecast also already implicitly accounts for the load reduction from EE.

Over the 10-year LTRA planning horizon, the forecast net internal summer peak demand increases by 2,094 MW from 24,803 MW in 2025 to 26,897 MW in 2034. The corresponding net internal winter peak demand increases by 5,964 MW from 20,056 MW in 2025–26 to 26,020 in 2034–35. Net energy for load is forecast to grow by 13,403 GWh from 117,262 GWh in 2025 to 130,665 GWh in 2034. These peak growth projections have not changed significantly since the *2024 LTRA*. The energy growth projection has decreased as well since the *2024 LTRA*.

The higher winter peak growth rate due to anticipated electrification results in convergence with summer peak projections by the end of the 10-year period, such that New England's transition to a winter-peaking system is currently anticipated by the mid-2030s. It is also expected that the timing of the peaks will likely occur in the morning by that time, with heating electrification in particular inducing a greater tendency for morning peaks due to electrified residential and commercial heating.

Demand-Side Management (DR/DSM)/Distributed Energy Resources (DER)

For Summer 2026, ISO-NE forecasts 623 MW of controllable and dispatchable DR/DSM resources, which is projected to decrease to 544 MW by the summer of 2027. That value is then held constant through the rest of the assessment period.

For summer months, the results of the BTM PV forecast are incorporated into the ISO-NE gross demand forecast as estimated reductions in demand. In the summer of 2026, New England is expected to have 1,759 MW (5,093 MW nameplate) of BTM PV. BTM PV is forecast to grow to 1,942 MW (7,359 MW nameplate) by 2031. The winter capacity contribution for BTM PV resources is currently 7 MW (5,372 MW nameplate) in the winter of 2026–27 and increases to 521 MW (9,360 MW nameplate) in the winter of 2035–36.

In 2024, ISO-NE developed a new Planning Procedure 12 entitled *Data Collection for Distributed Energy Resources* to formalize and standardize data collection for DERs. Under this new planning procedure, distribution providers are responsible for providing installation-level data on DERs connected to their system (these DERs do not include DR, controllable loads, or other load modifiers). Additionally, transmission providers are responsible for providing data to translate feeder IDs into substation names and other useful identifying information. Among the other benefits, this planning procedure will allow for proper accounting of the location, size, and type of DER, which will lead to more accurate operational and planning studies.

Generation

The two largest changes that will impact New England's generation fleet are the changes to the methodology for capacity accreditation and the development of a seasonal, prompt capacity market. Efforts are underway to change the timing and commitment horizons of capacity auctions to

seasonal/prompt in preparation for the evolving resource mix the Capacity Auction Reforms Key Project.

While ISO-NE does not expect any reliability impacts due to the retirement of any one single unit or station, the past and future retirements of dispatchable, fossil-fueled capacity, with on-site fuel inventories, as well as potential nuclear plant retirements, continue to exacerbate known winter reliability issues related to natural gas availability.

Energy Storage

New England has a total of 2,331 MW/2,110 MW (summer/winter rating) of energy storage capacity. Among the largest energy storage resource(s) in New England are three pumped-storage hydro-electric facilities that can supply a combined 1,864 MW / 1,861 MW (summer/winter rating) of quick-start 10-minute operating reserve capability, and with full reservoirs, can produce over 11,800 MWh of energy.

New England currently has 467 MW/249 MW (summer/winter rating) of electricity storage, including traditional battery storage along with integrated hybrid and co-located hybrid electricity storage.

As of April 1, 2025, there were 16,885 MW (summer ratings) of electricity storage devices (batteries, integrated-hybrid, and co-located-hybrid) that have submitted interconnection requests for installation over the next five years under the combined resource categories of Tier 1 at 2,658 MW, Tier 2 at 3,258 MW, and Tier 3 at 10,969 MW.

No new pumped-storage facilities are planned for the region. Over the next 10 years, those total Tier 1–3 capacities do not increase/decrease from their 5-year projection.

Capacity Transfers (Reliance on Assistance)

New England is interconnected to three BAs: Québec, Maritimes, and New York. ISO-NE considers the tie benefits associated with these BAs within its capacity market methodology to meet the regional resource adequacy criterion while preventing over-reliance on such assistance. Assumed assistance from tie benefits ranges from 2,100 MW in 2026 to 2,115 MW in 2027. Aside from such assistance, ISO-NE's firm capacity imports are projected to range from a maximum of 567 MW in the summer of 2026 to 84 MW in the summer of 2028. There is one long-term firm import contract of 84 MW that extends from Summer 2028 through Summer 2032.

Within the *2025 LTRA* Prospective Resources (and Prospective Reserve Margin in the Demand, Resources, and Reserve Margins table), a summer and winter, energy-only contract is identified (i.e., expected imports). These numbers reflect the upcoming commercialization (in late 2025) of the New England Clean Energy Connect (NECEC), a new 1,200 MW tie line connecting Québec to Lewiston, Maine. An off-take 1,090 MW energy-only contract into Maine/New England has been executed. This import of 1,090 MW reflects the average hourly rate of the total annual energy in the contract.

In addition, there are no firm exports identified over the 10-year LTRA summer or winter assessment periods.

Transmission

Transmission expansion in New England has improved the overall level of reliability and resiliency, reduced air emissions, and lowered wholesale market costs by nearly eliminating congestion. Generator retirements, off-peak system needs, the growth of DERs and VERs that use inverter-based technology and changes to mandatory planning criteria promulgated by NERC and NPCC have driven the need for increasingly complex transmission assessments.

The future reliable and economic performance of the system is expected to continue to improve because of planned transmission upgrades over the next 10 years. Generator retirements, the integration of many DERs and VERs, the use of inverter-based technologies, and issues arising from minimum load assessments and high-voltage conditions are changing the needs for reliability-based transmission upgrades. In addition, transmission improvements will also be needed to support state policies to access remotely located sources of clean energy and serve increased load as transportation and heating are electrified. ISO-NE's longer-term transmission planning process was developed through coordination with NESCOE to create an additional path toward meeting these future system needs.

Reliability Issues

New England's power system is transitioning to a system with unprecedented projected demand growth and a growing number of renewables, clean energy resources, VERs, and DERs. ISO-NE has been engaged in the implementation of revised interconnection standards for VERs and DERs that will ensure overall power system reliability and facilitate the economic development of IBRs.

ISO-NE has observed some delays in projected "in-service" dates for transmission system upgrades due to supply chain issues. In these cases, ISO-NE develops special operating plans to work around any issues caused by these commercialization delays.

New England has already experienced constraints on electric energy production due to the availability of natural gas during winter. In winter, the interstate natural gas pipelines serving New England run full with (firm) gas utility contracts serving their residential, commercial, and industrial (RCI) customers. In response, ISO-NE has been a key player at the national level in promoting electric/gas

communications/coordination, sharing of lessons learned, best practices, and more recently, through the performance of more detailed and in-depth deterministic and probabilistic energy assessments.

The just-in-time delivery of a generator's fuel supply, whether natural gas, wind, or solar, is creating the need for the electric sector to quickly develop ways to retain access to flexible, stored energy/electricity—either through long-term energy/electricity storage solutions that can capture and store renewable power or through the use of flexible, dispatchable resources.

ISO-NE is actively working on numerous major projects as part of its energy transition while ensuring continued reliability. The following is a short list of major projects in which ISO-NE has engaged:

- Capacity Auction Reforms
- Operational Impacts of Extreme Weather Events
- Day-Ahead Ancillary Services Initiative
- 2024 Economic Study
- Extended-Term Transmission Planning Tariff Changes (aka Longer-Term Transmission Planning (LTTP) Tariff Changes)
- Longer-Term Transmission Studies
- Storage As Transmission Only Asset
- FERC Order No. 1920 Project
- FERC Order No. 2023 Project
- FERC Order No. 2222 Project

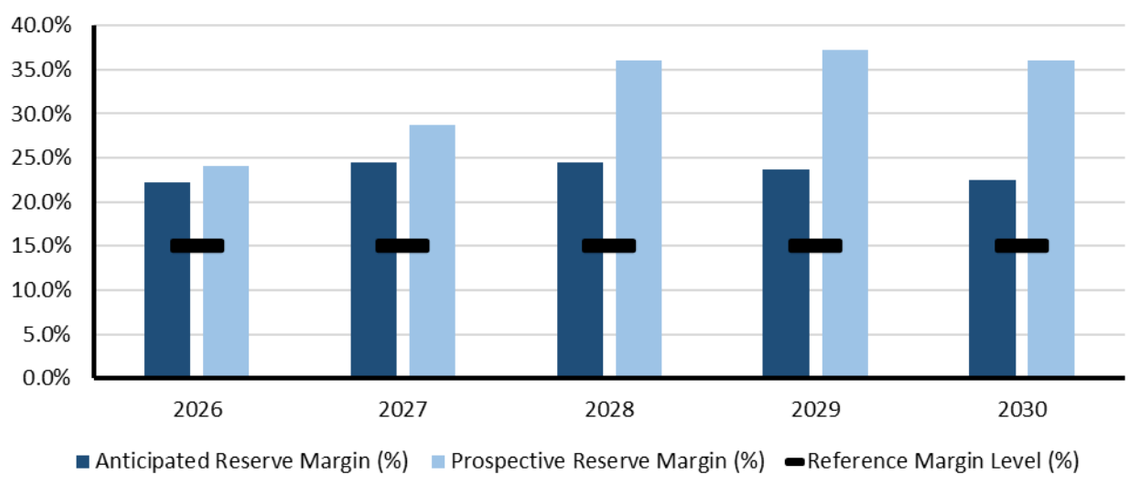


NPCC-New York

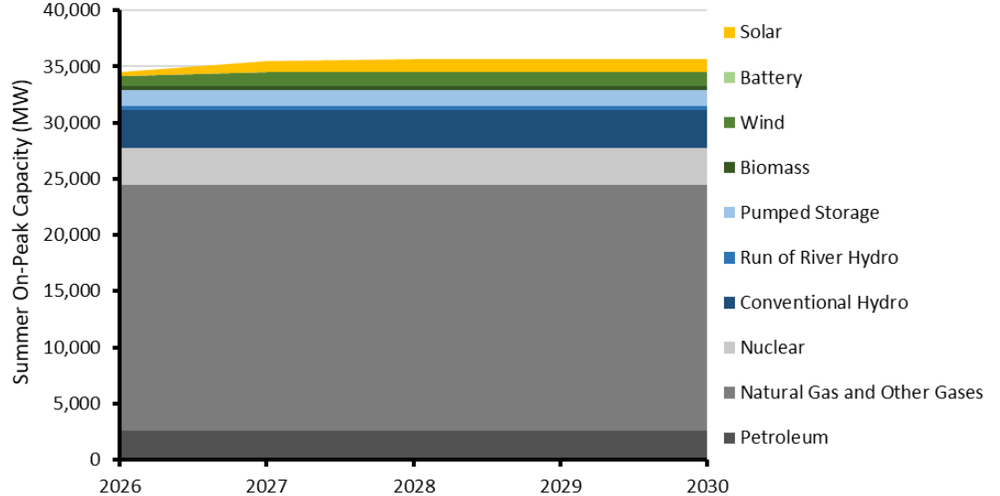
NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this LTRA, the established RML is 15%. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). The NYSRC approved the 2025–2026 IRM at 24.4%.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	31,990	32,280	32,410	32,620	32,910	33,190	33,520	33,870	34,170	34,500
Demand Response	989	989	989	989	989	989	989	989	989	989
Net Internal Demand	31,001	31,291	31,421	31,631	31,921	32,201	32,531	32,881	33,181	33,511
Additions: Tier 1	532	1,509	1,660	1,660	1,660	1,660	1,660	1,660	1,660	1,660
Additions: Tier 2	574	1,317	3,642	4,313	4,313	4,313	4,313	4,313	4,313	4,313
Additions: Tier 3	150	1,516	9,280	19,034	25,847	28,035	28,035	28,526	29,009	29,009
Net Firm Capacity Transfers	3,405	3,486	3,486	3,486	3,486	3,486	3,486	3,486	3,486	3,486
Existing-Certain and Net Firm Transfers	37,368	37,449	37,450	37,450	37,450	36,995	36,995	36,995	36,995	36,995
Anticipated Reserve Margin (%)	22.3%	24.5%	24.5%	23.6%	22.5%	20.0%	18.8%	17.6%	16.5%	15.4%
Prospective Reserve Margin (%)	24.1%	28.7%	36.1%	37.3%	36.0%	33.4%	32.1%	30.7%	29.5%	28.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-New York Highlights

- Generator deactivations are outpacing new supply additions. Electrification programs and new large-load customers associated with economic development initiatives are pushing projected demand higher. Together, these forces are also narrowing reliability margins across New York and increasing the risk of future reliability needs.
- As public policy goals seek to decarbonize the grid, fossil-fired generation will be needed for reliable power system operations until the capabilities it offers can be supplied by other resources. EE and demand-side management (DSM) will continue to play a key role in reducing energy consumption, lowering costs, and mitigating environmental impacts.
- Some of the risks can be mitigated by repowering. Repowering aging power plants can lower emissions, meet rising consumer demand, and provide reliability benefits to the grid that are needed to integrate additional clean energy resources.
- New York is projected to become a winter-peaking electric system by the 2040s, driven primarily by electrification of space heating and transportation. On the coldest days, the availability of natural gas for power generation can be limited, and interruptions to natural gas supply will introduce further challenges for reliable electric grid operations.
- Driven by public policies, new supply, load, and transmission projects are seeking to interconnect to the grid at record levels. NYISO's interconnection processes continue to evolve to balance developer flexibility with the need to manage the process to more stringent time frames. New processes have been implemented to accelerate the process while protecting grid reliability.
- The competitive wholesale electricity markets administered by NYISO support reliability while minimizing costs to consumers. Competitive wholesale markets are essential to a reliable, affordable, and cleaner grid of the future.
- NYISO's *2025 Quarter 3 Short-Term Assessment of Reliability* (STAR)[39] report identified short-term reliability needs in New York City and Long Island due to generation deactivations.

NPCC-New York Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Petroleum	2,597	2,597	2,597	2,597	2,597
Natural Gas	21,858	21,858	21,858	21,858	21,858
Biomass	334	334	334	334	334
Solar	345	931	1,083	1,083	1,083
Wind	850	1,221	1,221	1,221	1,221
Geothermal	0	0	0	0	0
Conventional Hydro	3,324	3,324	3,324	3,324	3,324
Run of River Hydro	418	418	418	418	418
Pumped Storage	1,411	1,411	1,411	1,411	1,411
Nuclear	3,326	3,326	3,326	3,326	3,326
Hybrid	0	0	0	0	0
Other	0	0	0	0	0
Battery	32	52	52	52	52
Unknown	0	0	0	0	0
Total MW	34,495	35,472	35,623	35,623	35,623

[39] NYISO's *2025 Q3 STAR Report*: https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf; Explanatory Statement: https://www.nyiso.com/documents/20142/54553125/03_2025Q3STAR_NearTermReliabilityNeedExplanatoryStatement.pdf; and Solutions Solicitation: https://www.nyiso.com/documents/20142/15930765/STRP-Q3-2025-Solicitation-Letter-Final.pdf

NPCC-New York Assessment

Planning Reserve Margins

The LTRA anticipated and prospective margins are above 15% for all 10 years. However, the system margins are narrowing throughout the assessment period. Wind, grid-connected solar, and run-of-river totals were derated for the LTRA calculation. Under its reliability planning processes, NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of no greater than 0.1 event-days/year probability of unplanned load loss. NYISO's *2024 Reliability Needs Assessment*[40] found reliability margins decrease over time as load increases to the point that New York is nearly at the 0.1 even-days/year criteria by 2034.

NYISO also provides support to the New York State Reliability Council (NYSRC) in conducting an annual IRM study. This study determines the IRM for the upcoming capability year (May 1 through April 30). The IRM is used to quantify the capacity required to meet the Northeast Power Coordinating Council (NPCC) and NYSRC's resource adequacy criterion of "one day in 10 years." The current IRM for the 2025–2026 capability year is 24.4% of the forecasted NYCA peak load. All values in the IRM calculation are based upon full installed capacity values of resources. The IRM has varied historically from 15% to 24.4%. Additionally, NYISO performs an annual study to identify the Locational Minimum Installed Capacity Requirements (LCRs) for the upcoming capability year.

Energy Assessment, Including Non-Peak Hour Risk

New York State's Climate Leadership and Community Protection Act (CLCPA) decarbonization mandates to decarbonize span all major industries and are the main drivers of change to the electric system NYISO staff in system operations, planning, and markets will continue to assess the system changes to prepare for the grid's transformation.

With high penetration of renewable intermittent resources, the system will need dispatchable emission-free resources (DEFR) and long-duration resources to balance intermittent supply with demand. These types of resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. Additionally, although new transmission is being built, more investment is necessary to support the delivery of future offshore wind energy and to connect new resources upstate to downstate load centers where demand is greatest.

NYISO performs long-range assessments (10-year and beyond planning horizon), and certain energy aspects are accounted for in the hourly modeling and simulations performed under the resource adequacy studies through NYISO's reliability planning processes along with the production cost simulations performed under its System and Resource Outlook.

NYISO performs and supports energy assessments a fuel and energy security study, a study assessing potential impacts related to climate change, and weekly analysis of fuel and energy security based on load profiles and fuel inventories reported through NYISO's Generator and Fuel Emissions Reporting (GFER) data portal. These assessments are based on data and information provided by resources on an annual, weekly, and as-needed basis considering system operating conditions. These assessments have the capability to analyze the impact of changes in stored fuel inventory, resource outages, fuel supply disruptions, transmission constraints, and other relevant conditions that may adversely impact fuel and energy security. Additionally, the New York City and Long Island areas have a loss of gas supply dual-fuel requirement, and certain combined-cycle gas units participate in a "Minimum Oil Burn" program. While oil accounts for a relatively small percentage of the total energy production in New York, it is often called during critical periods, such as when severe cold weather limits access to natural gas.

Probabilistic Assessments (NERC ProbA and Other Studies)

NYISO performs probabilistic assessments using GE's Multi-Area Reliability Simulation (MARS) as part of its reliability planning processes, as well as supporting the calculation of the annual IRM, LCRs, and capacity accreditation. The new capacity accreditation market rules align compensation for capacity suppliers with an individual resource's expected reliability benefit to consumers and uses the probabilistic models from the LCR process to define capacity accreditation factors (CAF) for various capacity accreditation resource classes. The CAFs will reflect the marginal reliability contribution of the ICAP suppliers within each capacity accreditation resource class toward meeting NYSRC resource adequacy requirements for the upcoming capability year, starting with the capability year that began in May 2024.

Additionally, every year, each Regional Entity (e.g., NPCC) provides results into NERC's ProbA process under the LTRA. The results from the ProbA performed in 2025 by the NPCC Regional Entity are shown below.

ProbA Results

New York is a summer-peaking area with negligible risks as shown in the low values in the following table of annual metrics.

[40] https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf

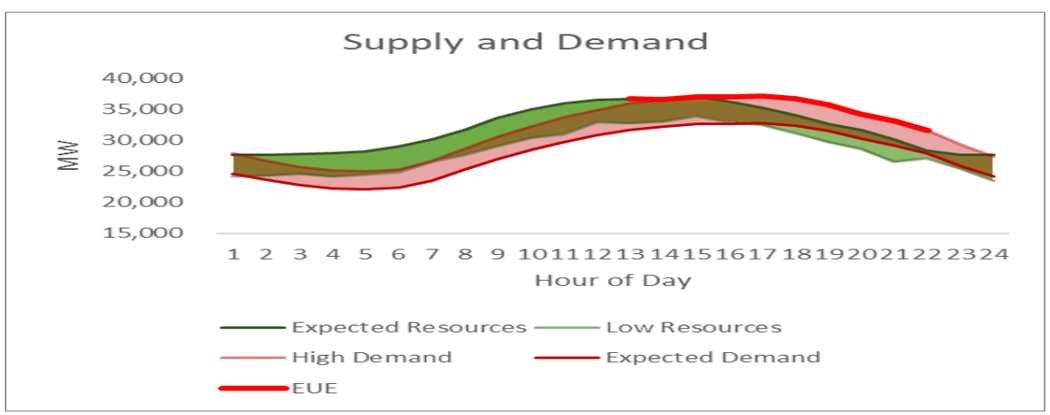
NPCC New York Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	1.909	0.466	12.478
NEUE (ppm)	0.012	0.003	0.078
LOLH (hours per Year)	0.011	0.002	0.035
* Provides the 2024 ProbA results for Comparison			

EUE Heat Maps – 2029

Negligible risk presented for Summer 2029, with occurrences clustered in July and August around hours 16 to 18.

Month \ Hour	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	7%	24%	25%	7%	3%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	8%	16%	6%	1%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Hourly demand and resource projections for the highest EUE day in 2029 are shown in the figure below.



Although expected resource contribution is great enough to meet expected demand, there is risk due to the variability in the higher net demand levels from LFU compounded with a greater risk added due to the variability in resource contribution. The higher net demand LFU levels could be 10–13% higher than expected, which could strain the system as modeled in the ProbA.

Demand

NYISO employs a multi-stage process to develop load forecasts for each of the 11 zones within the New York Control Area (NYCA). The impacts of net electricity consumption of energy storage resources due to charging and discharging are added to the energy forecasts, while the peak-reducing impacts of BTM energy storage resources are deducted from the peak forecasts.

Currently, the NYCA summer peak typically occurs in late afternoon. The NYCA summer peak is projected to shift into the evening as additional BTM solar is added to the system and as electric vehicle charging impacts increase during the evening hours. Because the hour of the summer peak shifts into the evening over the course of the forecast horizon, BTM solar generation becomes less coincident with the NYCA peak hour, and BTM solar coincident peak reductions are forecasted to decrease in later years. The forecast of solar PV-related reductions to the winter peak is zero because the system typically peaks after sunset.

Trended weather conditions from the Climate Impact Study Phase I report are included in NYISO's end-use models and are reflected in the baseline, scenario, and percentile forecasts. NYISO develops 90th and 99th percentile forecasts to account for the impacts of extreme weather on seasonal peak demand and calculates 10th percentile forecasts to represent milder seasonal peak conditions.

The 10-year annual average energy (+1.7%) and summer peak demand (+1.0%) growth rates are similar to last year's forecast. Throughout the 30-year forecast period, baseline energy and seasonal peak demand increase significantly due to New York State electrification and decarbonization policies, principally the CLCPA. The baseline forecast includes significant electrification via conversion to electric heating and electric non-weather sensitive appliances, along with significant growth in EV adoption. In the early forecast years, large-load projects add significant growth to the annual energy and peak demand forecasts. To account for forecast uncertainty during winter due to electrification and large loads, NYISO implemented a winter dynamic load forecast uncertainty in the resource adequacy models for its 2024 RNA.

Demand-Side Management

NYISO has been working on developing market concepts to encourage the participation of flexible load, which participation will become increasingly important as the levels of weather-dependent intermittent resources on New York's grid increase in response to the state's climate and clean energy

policies. New York utilities are piloting several load management programs (e.g., smart electric vehicle charging, home-thermostat use, and integration of BTM storage for local peak demand modulation). As part of NYISO's annual long-term forecasting process, the impacts of these programs are discussed and significant impacts on demand are included in the load forecast.

For the 2025 LTRA, the DR participation for the summer capability period has increased slightly from 1,294 MW to 1,487 MW. These values are nameplate and are derated for reserve margin calculations. For example, the 1,487 MW is derated to 989 MW. There are currently 433 MW of DR participating in ancillary services programs (not included in reserve margin calculations) and providing either 10-minute spinning reserves or 30-minute non-synchronous reserves.

Distributed Energy Resources

In 2024, NYISO implemented a plan to integrate DERs, including DR resources, into its markets. The DER Participation Model project aims to enhance participation of DERs in the competitive wholesale markets. These measures closely align the bidding and performance measurements for DERs with the rules for generators. The measures establish a state-of-the-art model that is largely consistent with the market design envisioned by FERC in its Order 2222. This project, which began in 2017, provides a single-participation model for DER DR resources to provide energy, ancillary services, and installed capacity through an aggregation. The market rules for the DER and aggregation participation model were accepted by FERC in January 2020. NYISO filed additional proposed tariff revisions with FERC in June 2023 to clarify and enhance these market rules. NYISO deployed its DER participation model in 2024.

Generation

Significant new resource development will be required to achieve New York's energy targets under the CLCPA. According to the 2023–2042 System and Resource Outlook the total installed generation capacity to meet policy objectives within New York is projected to range between 111 GW and 124 GW by 2040. At least 95 GW of this capacity will consist of new generation projects and/or modifications to existing plants. Even with these additions, New York still may not be sufficient to maintain the reliable electricity supply and meet policy requirements within the next 20 years.

Currently, NYISO's interconnection process[41] contains a significant number of proposed projects in various stages of development with only a fraction in more advanced stages included in the reliability planning models. However, the grid will evolve to achieve the policy mandates, and those changes will affect the nature and amount of resources.

Coordination of project additions and retirements is essential to maintaining reliability and achieving policy. The New York system relies on fossil-fuel, synchronous generation. ERSs usually provided to the system by synchronous fossil generation will remain necessary. As New York's public policies seek to decarbonize the grid, fossil-fuel, synchronous generation will be needed for reliable power system operations until the capabilities it offers can be supplied by other resources. New technology is being developed to allow for a reliable transition to a clean grid. Grid-forming inverter capabilities, as well as DEFRs, will likely be part of this transformation.

On June 23, 2025,[42] New York's governor directed the New York Power Authority to develop and construct a zero-emission advanced nuclear power plant in upstate New York to support a reliable and affordable electric grid while providing the necessary zero-emission electricity to achieve a clean energy economy.

Energy Storage

Storage resources can help to fill in voids created by reduced output from renewable resources. However, sustained periods of reduced renewable generation can rapidly deplete storage capabilities. NYISO has implemented its Co-Located Storage Resources model to allow wind or solar resources that are interconnected with an energy storage resource the ability to participate in the markets while respecting a shared interconnection limitation. NYISO is preparing the implementation of a model for hybrid storage resources to allow multiple technologies at the same point of interconnection to participate in the market as a single resource. Additionally, the resource adequacy simulation tools (such as GE's MARS) used in system planning by NYISO and for setting the IRMs were enhanced to include energy-limited resource models that allow for charging and discharging and also include temporal constraints (e.g., hours/days or hours/month).

Capacity Transfers

The models used for NYISO's reliability planning studies include firm capacity transactions (purchases and sales) with its neighboring systems as a base-case assumption. Proposed projects that are in a more advanced stage are included. One such project is the 1,250 MW HVdc line from Québec to New York City, which is reflected in the LTRA summer total transfers starting in 2026. Additionally, the probabilistic model that NYISO uses to assess the adequacy of resources in the reliability planning processes employs several methods aimed at preventing overreliance on the external systems support. For example, NYISO limits emergency assistance from neighboring systems by modeling a total limit of 3,500 MW, modeling five simultaneous peak days, modeling the long-term purchases and sales with neighboring control areas, and not modeling emergency operating procedure steps for the neighboring systems.

[41] https://www.nyiso.com/documents/20142/1407078/NYISO-Interconnection-Queue.xlsx

[42] https://www.governor.ny.gov/news/governor-hochul-directs-new-york-power-authority-develop-zero-emission-advanced-nuclear-energy

New York is fortunate to have strong interconnections with neighboring regions and has enjoyed reliability and economic benefits from such connections. As the energy policies in neighboring regions evolve, New York's imports and exports of energy could vary significantly due to the resulting changes in neighboring systems. The availability of energy for interchange is predicted to shift fundamentally as policy achievement progresses. As New York's and other regions' grids evolve, continuous monitoring and collaboration with our neighboring systems will be required.

Transmission

Significant new transmission is being built across New York, but more investment is necessary to support, among other things, the delivery of offshore wind energy to connect new resources upstate to downstate load centers where demand is greatest.

Key transmission projects under development and accounted for in the reliability models include the following:

- The Northern New York Priority Transmission Project upgrading the transmission corridors from the renewable generation pocket in the north country to central New York
- The 1,250 MW Champlain-Hudson Power Express HVdc line from Hydro-Québec to New York City, and
- The transmission project selected to address the Long Island Offshore Wind Expert Public Policy Transmission Need and that adds three new ac tie lines and a 345 kV backbone across western/central Long Island with an in-service date in 2030
- Con Edison's proposed Brooklyn Clean Energy Hub project, including a new 345 kV load-serving substation with the goal of addressing local electric reliability needs in the boroughs of Brooklyn and Queens as well as the goal of serving as a point of interconnection for new clean-energy resources

Additionally, there are significant transmission projects either recently selected or under study that have not yet met the criteria to be in the reliability model. For instance, the PSC recently identified a new public policy transmission planning need for NYISO to solicit proposed solutions and that is intended to support the integration of 4.7 GW of wind resources in New York City.

Furthermore, in 2020, the PSC ordered the New York utilities to undertake planning assessments and make investment proposals to facilitate the cost-effective development of renewable and emission-free resources while maintaining the reliability of New York's electric grid. The Coordinated Grid Planning Process (CGPP) was approved by the PSC in August 2023. The process is designed to assess the state's electric grid using a 20-year planning horizon. The CGPP is intended to identify electric grid expansions that can aid in unlocking renewable generation capacity and provide energy headroom for the purpose of meeting New York's clean energy goals while providing value to customers. Moreover, the CGPP is designed to identify opportunities for expansion of the bulk transmission system to advance the mandates of CLCPA. This provides another opportunity to inform the PSC's consideration of whether to establish a public policy transmission need for NYISO to solicit and evaluate proposed solutions.

Reliability Issues

NYISO's *2024 Reliability Needs Assessment*[43] (RNA) and subsequent analysis[44] identified very tight transmission security margins in New York City (Zone J) by 2034. The narrowing of the reliability margin continues to be a major concern. Most recently, NYISO's 2025 Quarter 3 STAR report[45] identified short-term reliability needs in New York City and Long Island due to generation deactivations.

The transition to a cleaner grid in New York is leading to an electric system that is increasingly dynamic, decentralized, and reliant on weather-dependent renewable generation and may lead to increasing reliability issues on the New York system. Reliability margins are shrinking. Generators needed for ERSs are planning to retire. Delays in the construction of new supply and transmission, higher-than-expected demand, and extreme weather could threaten reliability and resilience in the future. The system is projected to become winter-peaking in the next decade due to electrification and decarbonization policies. Large loads are being proposed to interconnect to the system. New York's current reliance on neighboring systems is expected to continue through the next 10 years. A successful transition of the electric system requires replacing the reliability attributes of existing fossil-fueled generation with clean resources with similar capabilities. Such resources must be significant in capacity and have attributes such as the ability to come on-line quickly, stay on-line for as long as needed, maintain the system's balance and stability, and adapt to meet rapid, steep ramping needs. New transmission is being built, but more investment is necessary to support the delivery of offshore wind energy to connect new resources located in upstate to downstate load centers where demand is greatest.

[43] https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf
[44] https://www.nyiso.com/documents/20142/51270164/CRP_KeyTopics_TPAS_050625.pdf
[45] NYISO's 2025 Q3 STAR Report: https://www.nyiso.com/documents/20142/16004172/2025-Q3-STAR-Report-Final.pdf and Explanatory Statement: https://www.nyiso.com/documents/20142/54553125/03_2025Q3STAR_NearTermReliabilityNeedExplanatoryStatement.pdf; Solutions Solicitation: https://www.nyiso.com/documents/20142/15930765/STRP-Q3-2025-Solicitation-Letter-Final.pdf

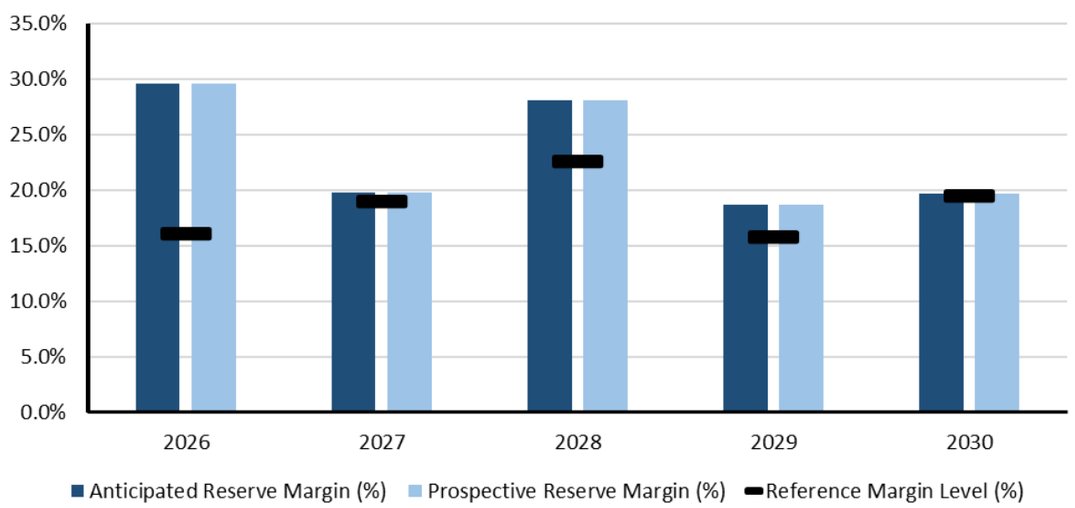


NPCC-Ontario

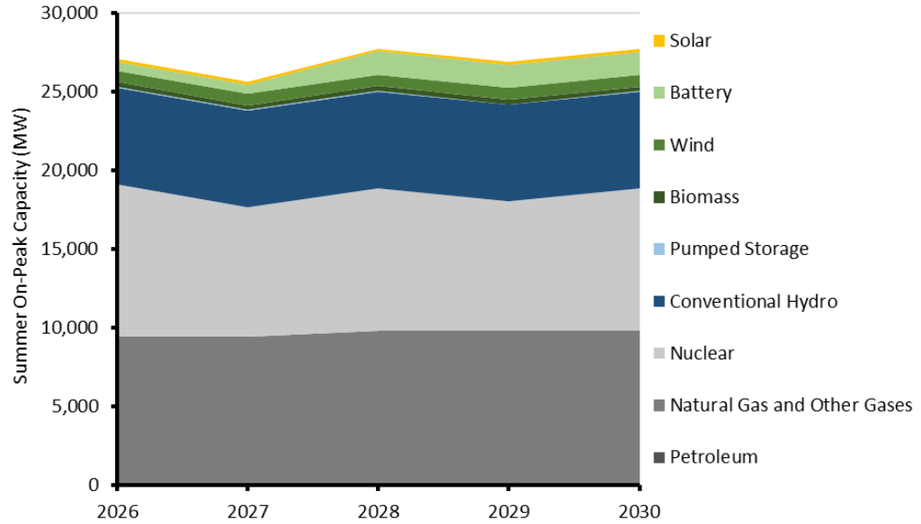
NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of over 16 million people. The Independent Electricity System Operator (IESO) is the balancing authority for the province of Ontario. NPCC-Ontario is electrically interconnected with NPCC-Québec, MRO-Manitoba, MISO, and NPCC-New York. Peak electricity demand in NPCC-Ontario occurs during the summer season.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	23,403	24,023	24,514	25,587	26,443	26,927	27,747	28,621	29,202	29,974
Demand Response	2,046	1,998	2,090	2,092	2,093	2,095	2,096	2,098	2,099	2,101
Net Internal Demand	21,357	22,025	22,424	23,495	24,350	24,832	25,651	26,523	27,103	27,873
Additions: Tier 1	853	853	2,156	2,156	2,156	2,964	3,507	4,051	4,579	5,387
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	600	600	600	1,233	1,324	1,324
Net Firm Capacity Transfers	602	772	1,002	1,002	1,432	1,002	302	302	302	302
Existing-Certain and Net Firm Transfers	26,833	25,541	26,577	25,737	26,999	25,623	25,767	25,767	26,611	26,611
Anticipated Reserve Margin (%)	29.6%	19.8%	28.1%	18.7%	19.7%	15.1%	14.1%	12.4%	15.1%	14.8%
Prospective Reserve Margin (%)	29.6%	19.8%	28.1%	18.7%	19.7%	15.1%	14.1%	12.4%	15.1%	14.8%
Reference Margin Level (%)	16.1%	19.0%	22.6%	15.8%	19.5%	13.9%	14.7%	9.6%	14.3%	13.2%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-Ontario Highlights

- Ontario's ARMs remain above the RML for the first five years of the 2025 LTRA outlook. Only one year within the 10-year horizon shows a minor shortfall, which is mitigated through a combination of capacity swap agreements with Hydro-Québec and the expected contribution of Tier 3 resources, including those from the Long-Term 2 (LT2) procurement expected to be on-line in 2030.
- Ontario's 2025 Annual Planning Outlook (APO) identified a growing energy gap beginning in 2029, with a more pronounced shortfall expected by 2035. This is primarily driven by expiring contracts, increasing demand from electrification, and the emergence of large industrial loads. Different to last year's LTRA, the IESO assumes generation resources are expected to be re-contracted (through the IESO's reacquisition mechanisms) after those contracts expire. This has improved the resource outlook for the IESO when compared to last year while aligning the methodology to forecast supply with the methodology used by other NERC assessment areas.
- For demand, Ontario projects compound annual growth rates of 2.37% for summer peak and 2.93% for winter peak over the 2026–2035 period. As a result, total internal demand is projected to grow by 31% over the next 10 years to nearly 30 GW by 2035.
- Ontario's generation landscape is undergoing a significant transformation, driven by the integration of IBRs, expansion of energy storage, nuclear refurbishments, and new nuclear projects. Ontario's planning assumptions now reflect a more realistic view of generator retirements, assuming continued operation unless explicitly declared otherwise. This aligns with two recently completed procurements to re-contract existing resources.
- Ontario is undergoing a significant expansion in energy storage capacity. As of April 2025, the Oneida battery storage facility (250 MW/1,000 MWh) entered commercial operation, marking a major milestone. By May 2028, Ontario expects over 2,700 MW (installed capacity) of BESS to come on-line, with discharge durations of four hours.
- Ontario is attentively monitoring reliability risks due to large industrial and commercial load additions, including data centers, EV production facilities, hydrogen electrolyzers, and electrified heating systems. These loads introduce uncertainty in peak and hourly demand forecasting and challenge transmission development. Additional reliability risks include nuclear refurbishment delays, aging infrastructure, supply chain constraints, and policy uncertainty. The IESO incorporates these risks into long-term planning by maintaining additional reserves and using probabilistic assessments.

NPCC-Ontario Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Petroleum	3	3	3	3	3
Natural Gas	9,385	9,385	9,790	9,790	9,790
Biomass	299	304	310	310	310
Solar	150	150	150	150	150
Wind	724	725	728	732	732
Conventional Hydro	6,163	6,163	6,163	6,163	6,163
Pumped Storage	38	38	38	38	38
Nuclear	9,724	8,256	9,059	8,214	9,047
Battery	597	597	1,489	1,489	1,489
Total MW	27,084	25,622	27,731	26,891	27,723

NPCC-Ontario Assessment

Planning Reserve Margins

Ontario's ARMs remain above the RML for the first five years of the *2025 LTRA* outlook. Only one year within the 10-year horizon shows a minor shortfall, which is mitigated through a combination of capacity swap agreements with Hydro-Québec and the expected contribution of Tier 3 resources, including those from the Long-Term 2 (LT2) procurement expected to be on-line in 2030. No Tier 2 resources have been identified for this year's publication.

The IESO calculates Ontario's reserve margin annually using the GE MARS model and applies a more stringent reserve criterion than the NPCC standard of 0.1 days/year LOLE, incorporating additional reserves to manage risks associated with nuclear refurbishments and new nuclear builds. For example, over the LTRA outlook, the 2025 Annual Planning Outlook (APO) includes reserves of nearly 800 MW in some summers and nearly 1,100 MW in some winters to account for uncertainties in nuclear project timelines. If these additional reserves were excluded, Ontario would meet or exceed the RML in all years of the assessment. MARS inputs include resource availability, outages, refurbishment schedules, interface limits, and demand uncertainty. The model uses probabilistic simulations and Monte Carlo analysis for wind and solar and historical data for hydro and thermal units. The assessment evaluates system adequacy across all hours, not just peak periods.

For the *2025 LTRA*, the IESO applied NERC's definitions for Tier 1 and Tier 3 resources. The IESO's Resource Adequacy Framework (RAF) enables reacquisition of existing resources nearing contract expiry. It's important to distinguish between off-contract resources and those that have reached end of life or retired. Many existing Ontario resources remain operational and can be upgraded or re-contracted, with the RAF providing competitive mechanisms to secure capacity from these resources. The *2025 LTRA* assesses reliability independent of contractual status, unlike the 2025 APO, which aims to determine the resource adequacy needs in order to inform future reacquisitions of existing and new resources. As a result, the *2025 LTRA* outlook will differ from the 2025 APO, especially regarding off-contract resources that are likely to continue to be operational.

The RAF remains unchanged since the *2024 LTRA* and continues to guide the reacquisition of existing resources and the procurement of new capacity. The RAF supports a flexible, multi-pronged approach to resource adequacy, including capacity auctions, medium- and long-term procurements, and targeted programs for re-contracting or upgrading existing facilities and securing new resources.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Ontario conducts annual energy adequacy assessments using Energy Exemplar's Plexos software, which models the province's nodal transmission network and simulates dispatch under expected system conditions. These deterministic assessments evaluate energy sufficiency over a 20-plus-year horizon and are supplemented by sensitivity analyses to identify periods of heightened risk.

The 2025 APO identified a growing energy gap beginning in 2029, with a more pronounced shortfall expected by 2035. This is primarily driven by expiring contracts, increasing demand from electrification, and the emergence of large industrial loads. It should be reinforced that the APO presents an energy adequacy assessment used to inform future procurements, whereas the LTRA's purpose is to inform reliability of the system, where contractual end dates are not incorporated into the assessment

Shorter-term energy assessments are conducted quarterly through the Reliability Outlook (RO), which evaluates energy adequacy over an 18-month horizon. These assessments use probabilistic demand forecasts and outage data to identify seasonal and weekly risks. While the RO time frame is too short to secure new resources, the IESO uses operational tools such as capacity auctions, coordination with market participants on outage scheduling, and DR programs to mitigate risks.

Ontario's energy adequacy assessments do not assume economic imports or exports, reflecting a self-sufficiency planning approach. However, in practice, intertie capacity and capacity-sharing agreements (e.g., with Hydro-Québec) provide additional flexibility during periods of stress.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	0.043	0.001	0.066
NEUE (ppm)	0.000	0.000	0.000
LOLH (hours per Year)	0.000	0.000	0.000
***Provides the 2024 ProbA Results for Comparison**			

Demand

Ontario's demand forecast is shaped by a combination of econometric modeling for the near-term and sectoral/end-use modeling for the long term. The 2025 APO projects compound annual growth rates of 2.37% for summer peak and 2.93% for winter peak over the 2026–2035 period. Growth projections in the *2024 LTRA* were 2.34% for summer and 2.75% for winter. Marginal increases in demand growth since the 2024 LTRA are attributed to data center growth and EV production. Incremental 2025 APO forecasted growth is driven by the following:

- Electrification of buildings, transportation, and industry
- Expansion of electric vehicle (EV) production and supply chains

- Rapid development of commercial data centers
- Population growth and household formation

Offsetting factors include increased EE, DSM programs, and a plateau in agricultural greenhouse expansion.

The 2025 APO forecasted Ontario to become a dual-peaking jurisdiction by 2030, with winter and summer peaks converging due to increased electrification of heating. The IESO's demand forecast incorporates updated assumptions on immigration, economic growth, and sector-specific developments, including hydrogen production, steel decarbonization, and data center expansion. Additional large loads in planning but not yet included in the forecast are assessed based on their development stage, funding, and likelihood of materialization.

Ontario anticipates significant changes in load behavior, including increased demand from building electrification, EV charging (shifting peaks), data centers, hydrogen electrolyzers, and large industrial loads. These trends introduce variability and new reliability challenges. The IESO conducts System Impact Assessments (SIA) for large loads, evaluating impacts such as voltage flicker and transient stability. Enhancements to the assessment process are underway. Additionally, annual regulation needs assessments project up to 110 MW of incremental regulation by 2035 to manage fluctuating loads, with procurement strategies in place to meet these needs.

Demand-Side Management

The IESO has implemented a capacity qualification process that applies performance-based derates to DR resources, ensuring more reliable capacity contributions. Since the *2024 LTRA*, the Peak Perks program has expanded to small businesses, helping the program deliver more than 152 MW of summer peak demand reduction in 2024, growing to over 200 MW in 2025. A new DR program targeting HVAC loads in the commercial and institutional sector is in development. These programs, as well as the Industrial Conservation Initiative (ICI), also contribute to peak demand reduction. A new electric demand side management (eDSM) framework spanning the next 12 years commenced with a $1.8 billion budget for years 2025–2027 targeting 4.6 TWh of energy savings and 900 MW of peak demand savings.

Distributed Energy Resources

Ontario's DER landscape includes both contracted embedded generation and uncontracted BTM resources. In 2024, contracted DERs totaled over 3,400 MW, with about 60% from solar, 20% from wind, and 15% from hydro and biomass. Uncontracted DERs contributed an estimated 2.7 TWh of energy.

DERs are integrated into planning through the Enabling Resources Program (ERP), which is developing participation models for standalone DERs, hybrid resources, and aggregations. The IESO is also advancing coordination protocols through the Transmission-Distribution Coordination Working Group (TDWG), which has proposed tools for real-time coordination and visibility. The group wrapped up work during Summer 2025 and has posted final reports on their findings.

DERs are considered in transmission planning as non-wires alternatives and are increasingly included in regional planning processes. The IESO's DER Potential Study and Local Generation Program aim to further integrate DERs into Ontario's RAF.

Generation

Ontario's generation landscape is undergoing a significant transformation, driven by the integration of IBRs, expansion of energy storage, nuclear refurbishments, and new nuclear projects. To maintain system reliability, the IESO continues to monitor key operational parameters such as primary frequency response and system inertia, both of which are currently sufficient but require reassessment as the resource mix evolves. Ramping needs can be provided by over 11,100 MW of natural gas generation with 600 MW able to be online and ramp within 20 minutes. Supply to the majority of Ontario's gas fleet is robust and supported by significant firm supply and transportation contracts. The IESO does not expect any material gas supply or delivery issues under extreme winter conditions. The day-ahead market, established through the IESO's Market Renewal's Program, allows for firm gas supply to be scheduled.

Deliverability testing is a core component of Ontario's long-term procurement process, ensuring that new resources can connect without causing congestion or reliability issues. For the IESO's second long-term procurement, testing will be expanded to include inverter-based resource screening for sub-synchronous control interactions.

Ontario has updated its Market Rules to align with IEEE 2800 and now requires synchrophasor data from generators and transmitters to improve situational awareness and IBR performance. The IESO is also conducting system-wide electromagnetic transient (EMT) studies and validating models for battery storage projects to proactively address sub-synchronous control interaction risks.

For Ontario's adequacy assessments, capacity contribution values for thermal resources are calculated using historical performance and probabilistic modeling. Wind and solar contributions are based on seasonal capacity factors, while hydroelectric values are derived from historical output. Energy storage contributions are based on a four-hour discharge duration.

Ontario's planning assumptions now reflect a more realistic view of generator retirements, assuming continued operation unless explicitly declared otherwise. This aligns with two recently completed medium-term procurements, which re-contracted existing resources for five-year terms. In addition to medium-term procurements, the IESO also maintains mechanisms such as Reliability Must Run agreements and capacity auctions to mitigate retirement risks. The IESO is currently conducting assessments for operating reserve and frequency response for the next 10 years, intended to be included in the 2026 APO.

Overall, Ontario's generation planning is increasingly focused on flexibility, resilience, and integration of emerging technologies, with a strong emphasis on ensuring deliverability, maintaining operability, and adapting to evolving reliability challenges.

Energy Storage

Ontario is undergoing a significant expansion in energy storage capacity. As of April 2025, the Oneida battery storage facility (250 MW/1,000 MWh) entered commercial operation, marking a major milestone. By May 2028, Ontario expects over 2,700 MW of new BESS to come on-line, with discharge durations of four hours. These resources were secured through the Expedited Long-Term 1 (E-LT1) and LT1 procurements.

New storage projects may also participate in the second long-term procurement and long-lead time procurement, which aim to support system reliability during periods of high demand and low renewable output, particularly in the 2029–2035 time frame.

Energy storage resources are currently modeled as generators and loads at the same location, which presents operational challenges. The IESO is working to enhance its market tools and participation models through the ERP, which includes co-located and hybrid resource integration. Storage resources are also being incorporated into resource adequacy assessments using GE MARS software, which optimizes dispatch and accounts for energy reservoir size.

While operational experience with transmission-connected storage is still limited, the IESO is actively monitoring performance and refining planning assumptions. The integration of nearly 3 GW of new storage capacity over the next four years is expected to significantly improve Ontario's ability to manage variability and meet ramping needs.

Capacity Transfers

Ontario maintains robust intertie connections with neighboring jurisdictions, including Québec, New York, Michigan, Manitoba, and Minnesota. These interconnections play a critical role in supporting reliability, particularly during peak demand periods and resource shortfalls.

Two key capacity swap agreements with Hydro-Québec provide Ontario with firm summer capacity. The 2016 agreement allows for a 500 MW swap, while the 2024 agreement enables a 600 MW per year exchange over a seven-year period. These agreements are designed to be flexible, allowing Ontario to bank capacity and use it in future summers as needed.

Ontario's planning assessments assume self-sufficiency for the purpose of reserve margin calculations. However, in practice, these intertie agreements provide a valuable reliability backstop. The IESO coordinates closely with Hydro-Québec to align assumptions and ensure deliverability across the interties.

The refurbishment of Pickering NGS as well as new small modular reactors (SMR) scheduled to come on-line in the 2030s necessitated the review of flows across the province to maintain reliable operations. As a result, several new transmission projects have been proposed.

The IESO also participates in regional and interregional transmission planning processes, including NPCC area Transmission reviews and NERC planning assessments. These reviews ensure that Ontario's transmission system can support capacity transfers and maintain reliability under a range of scenarios.

Firm capacity transfers have appeared to increase in this LTRA publication compared to 2024 due to a review of NERCs definitions, allowing modeled and coordinated capacity to be treated as firm. This process aligns with the IESO's internal studies.

Transmission

Ontario is undertaking a significant expansion of its transmission system to support growing demand, resource integration, and system reliability. Key projects include the Waasigan Transmission Line, Etobicoke Greenway, and Flow East Towards Toronto (FETT) upgrade, which will collectively enhance capacity and resilience across the province. Additional reinforcements in London, Windsor-Essex, and northeastern Ontario address regional growth and industrial development. Voltage support devices, such as shunt reactors and STATCOMs, are being deployed to manage high voltages and support new transmission lines.

Transmission planning studies have identified constrained areas, particularly in the Greater Toronto Area (GTA), Essa (Barrie area), and eastern Ontario. These constraints are being addressed through the South and Central Ontario Bulk Plan and corridor studies to secure future transmission routes.

The IESO is also planning a new 500 kV double-circuit transmission line from Bowmanville to Toronto to support the connection of SMRs at Darlington NGS. This line is expected to be in service by the early 2030s.

To streamline transmission development and integrate Tier 2 resource deliverability insights, the IESO is designing a Transmitter Selection Framework (TSF) and enhancing its evaluation of non-wires alternatives (NWA). These initiatives aim to accelerate project delivery and improve coordination among stakeholders.

Reliability Issues

Ontario is attentively monitoring reliability risks due to large industrial and commercial load additions, including data centers, EV production facilities, hydrogen electrolyzers, and electrified heating systems. These loads introduce uncertainty in peak and hourly demand forecasting and challenge transmission development. The IESO is actively monitoring these trends and has published technical papers to better understand their implications. SIAs are conducted for large loads to evaluate impacts on voltage, stability, and power quality, with future enhancements planned to address sub-synchronous oscillation and ramp rate concerns.

Interdependencies with critical infrastructure sectors—such as natural gas, telecommunications, and transportation—are also being assessed. Ontario's gas supply is considered robust, with most generators located near the Dawn storage hub and supported by firm contracts. Dual-fuel capabilities of some generators and coordination protocols with gas pipeline operators further mitigate risks during extreme weather. The IESO's Market Renewal Program enhances gas-electric coordination through improved day-ahead scheduling.

Additional reliability risks include nuclear refurbishment delays, aging infrastructure, supply chain constraints, and policy uncertainty. The IESO incorporates these risks into long-term planning by maintaining additional reserves and using probabilistic assessments. Emerging technologies like battery storage and SMRs also present integration challenges. To address these, Ontario's planning processes prioritize flexibility, resilience, and proactive mitigation strategies, including outage planning that accounts for extreme weather scenarios.

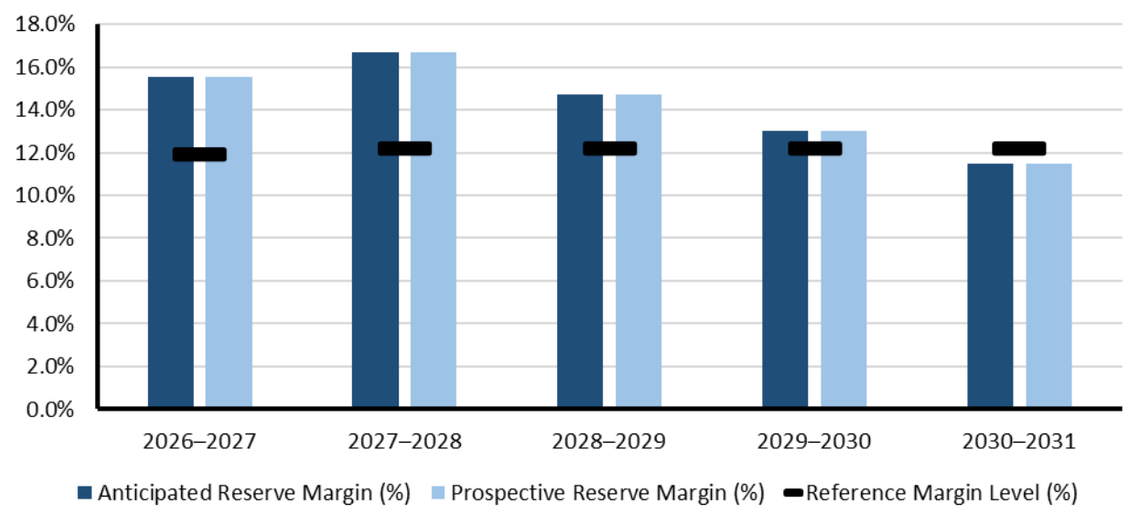


NPCC-Québec

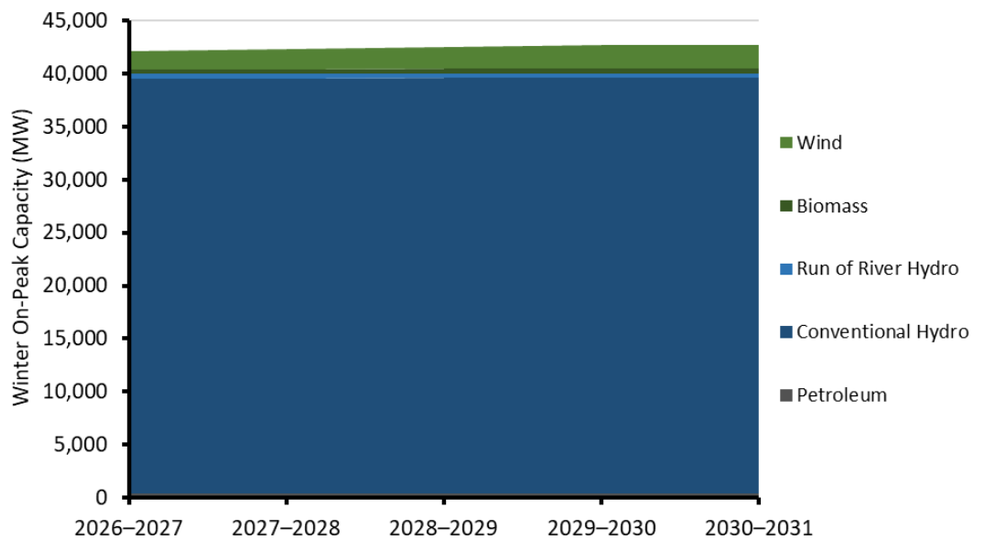
NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of nearly 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the four electric Interconnections in North America. It is a predominantly hydroelectric-generation-based system that is electrically interconnected with NPCC-Ontario, NPCC-New York, NPCC-New England, and NPCC-Maritimes. Peak electricity demand in NPCC-Québec occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	41,405	41,901	42,833	43,635	44,392	45,116	46,053	47,148	48,164	49,613
Demand Response	5,058	5,224	5,367	5,445	5,533	5,587	5,618	5,606	5,562	5,562
Net Internal Demand	36,347	36,677	37,465	38,191	38,859	39,529	40,435	41,542	42,602	44,051
Additions: Tier 1	412	566	710	891	891	891	891	891	891	891
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	-145	455	455	455	600	0	0	0	0	0
Existing-Certain and Net Firm Transfers	41,591	42,231	42,269	42,272	42,421	41,825	41,830	41,834	41,838	41,842
Anticipated Reserve Margin (%)	15.6%	16.7%	14.7%	13.0%	11.5%	8.1%	5.7%	2.9%	0.3%	-3.0%
Prospective Reserve Margin (%)	15.6%	16.7%	14.7%	13.0%	11.5%	8.1%	5.7%	2.9%	0.3%	-3.0%
Reference Margin Level (%)	11.9%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%	12.2%



Planning Reserve Margins



Existing and Tier 1 Resources

NPCC-Québec Highlights

- ARMs remain above the RML for the first four years of the assessment period.
- Over 4,000 MW of new wind installed capacity is expected to be in service by 2030, with additional wind projects in development.
- Hydro-Québec's Action Plan 2035 and a memorandum of understanding with Newfoundland and Labrador outline major new capacity additions, including hydro upgrades, new large hydro power plants, wind and solar development, and potential battery storage and gas-fired generation. These projects are not included in Tier 1–3 categories in the present assessment due to their early development stage or ongoing stakeholder consultations but are expected to be incorporated gradually into future assessments.
- Major transmission projects, including the Appalaches–Maine (NECEC) and Hertel–New York (CHPE) interconnections, are expected to be in service by the end of 2025 and May 2026, respectively.

NPCC-Québec Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Petroleum	429	429	429	429	429
Biomass	405	405	405	405	405
Wind[46]	1,778	1,931	2,076	2,257	2,257
Conventional Hydro	39,091	39,129	39,167	39,170	39,175
Run of River Hydro	445	447	447	447	447
Total MW	42,148	42,342	42,524	42,708	42,712

[46] Expected at-peak capacity.

NPCC-Québec Assessment

Planning Reserve Margins
ARMs remain above the RML for the first five winters of the assessment period (2025–26 to 2029–30), supported by existing and anticipated capacity and firm imports. Margins fall below the RML starting in 2030–31 due to sustained demand growth from electrification. Several large-scale projects are under development but are not included in the reserve margin calculation due to their early-stage status. The RML is based on the 2024 NPCC Interim Review of Resource Adequacy and accounts for weather and economic uncertainty, generator outages, and DR constraints.

The assumptions used for this assessment, including demand forecast and resources, are consistent with the Hydro-Québec 2024 Supply Plan update, which was filed with the Régie de l'énergie on November 1, 2024, and the 2024 Québec Interim Review of Resource Adequacy filed with the NPCC in December 2024.

Over 90% of Québec's installed capacity comes from large hydroelectric reservoirs, enabling flexible and reliable energy delivery. The system is designed to withstand multi-year droughts, with planning criteria requiring sufficient reserves to cover inflow deficits of 64 TWh over two years and 98 TWh over four years. No off-peak or seasonal energy risks have been identified.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
Québec is a winter-peaking area. There were no significant LOLH or EUE estimated for Winter 2027–2028. For Winter 2029–2030, the EUE is 62.99 MWh with an expected LOLE of 0.106 hours per year.[47]

ProbA Summary of Results			
	2026*	**2027-2028**	**2029-2030**
EUE (MWh)	8.205	0.01	62.99
NEUE (ppm)	0.040	0.000	0.29
LOLH (hours per Year)	0.014	0.000	0.11
***Provides the 2024 ProbA Results for Comparison**			

Demand
Québec's demand forecast is driven by electrification of transportation, industrial decarbonization, and electric heating. New sectors such as hydrogen production, battery manufacturing, and data centers are also contributing to demand growth. Forecasts are developed using sector-level modeling and include high and low scenarios to reflect uncertainty.

Demand-Side Management
Hydro-Québec operates a broad portfolio of DR programs, including interruptible load contracts for industrial and commercial customers, and smart heating and dynamic pricing for residential users. These programs are expected to provide 5,600 MW of peak reduction by 2034–2035. Reported capacities reflect actual observed reductions during events. EE and conservation programs are integrated into demand forecasts.

Distributed Energy Resources
BTM solar PV is expected to reach 705 MW by 2035. However, due to Québec's winter-peaking profile, the on-peak contribution of DERs remains below 5 MW. No operational impacts are expected, and no DER aggregators are currently active in the area.

Generation
4,000 MW of wind installed capacity is under development or construction, including the Apuiat project (204 MW), three 400 MW phases of Des Neiges, and two procurement rounds totaling 2,700 MW. Hydro-Québec is also pursuing:

- Up to 2,000 MW from hydro unit upgrades;
- 5,000 MW of wind installed capacity through new community partnerships;
- 3,440 MW from Churchill Falls upgrades and the Gull Island project;
- 3,000 MW of solar installed capacity by 2035, including 300 MW of front-of-the-meter PV by 2029;
- Potential battery storage and natural gas generation.

Except for the 4,000 MW of wind capacity in construction, these projects are not included in the Tier 1–3 categories due to their early development stage or ongoing stakeholder consultations.

Energy Storage
No energy storage resources are currently planned for commissioning during the assessment period.

[47] 2025 Probabilistic Assessment results cover the period from March of the first year to February of the second year.

Capacity Transfers
Québec maintains firm seasonal capacity exchange agreements with Ontario (600 MW imports in winter, exports in summer). Québec has several firm capacity export agreements during the summer season.

Transmission
Hydro-Québec plans to add 5,000 km of new transmission lines and several major substations by 2035 to support regional development and renewable integration. Key projects include the following:

- NECEC (1,200 MW to Maine) – expected in service by December 2025
- CHPE (1,250 MW to New York) – expected in service by May 2026
- Three new 735 or 315 kV corridors in Québec
- Jean-Jacques-Archambault substation – planned for 2029

No long-term transmission constraints have been identified.

Reliability Issues
Large industrial loads are screened and approved by the Québec government and Hydro-Québec based on available supply. A moratorium is in place for new blockchain clients. The system's winter peak is primarily driven by residential heating, and industrial additions are not expected to significantly affect peak uncertainty. To mitigate the impact of rising demand, Hydro-Québec is expanding its DSM programs and studying multiple new generation projects. In addition, Québec's large hydro reservoirs provide strong protection against the impacts of drought. The system is planned to meet a regulatory energy reliability criterion requiring sufficient reserves to withstand inflow deficits of 64 TWh over two years and 98 TWh over four years.

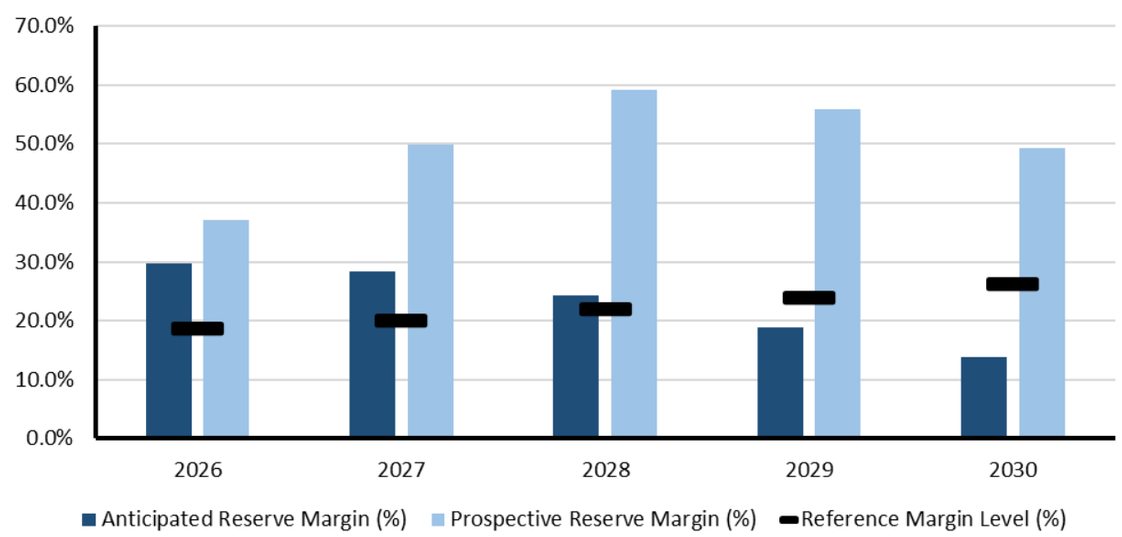


PJM

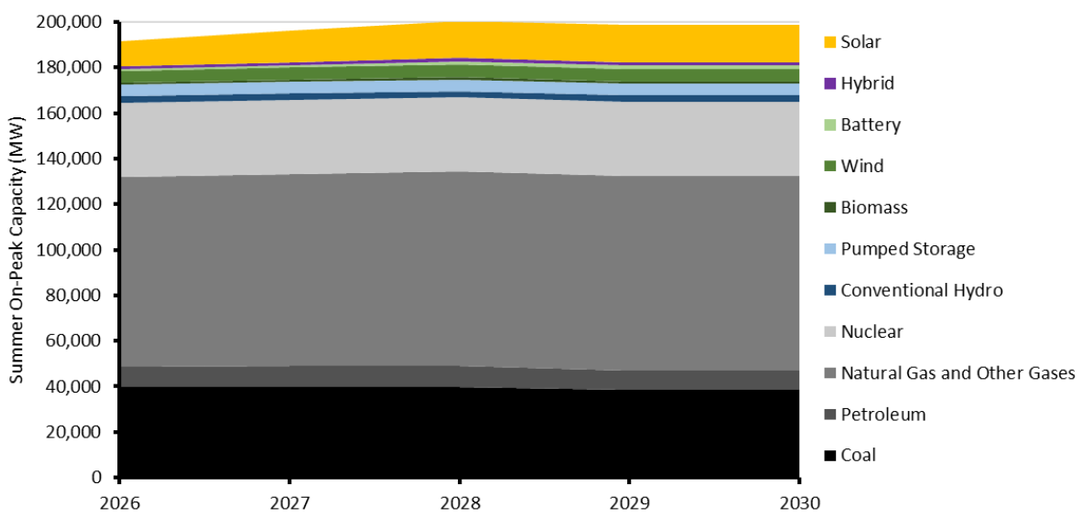
PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM's footprint covers approximately 369,054 square miles and has an approximate population of 67 million people. PJM is the area's BA, Transmission and Resource Planner, Interchange Authority, Transmission Operator, Transmission Service Provider, and Reliability Coordinator. PJM is electrically interconnected with MISO, NPCC-New York, SERC-Central, and SERC-East. Peak electricity demand in PJM occurs during the summer season.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	158,937	164,186	169,981	176,094	183,883	192,647	200,507	204,197	207,253	209,923
Demand Response	8,184	8,439	8,703	9,002	9,398	9,845	10,250	10,409	10,533	10,629
Net Internal Demand	150,753	155,747	161,278	167,092	174,485	182,802	190,257	193,788	196,720	199,294
Additions: Tier 1	5,861	10,177	14,521	14,709	14,709	14,709	14,709	14,709	14,709	14,709
Additions: Tier 2	12,410	38,519	65,315	71,119	75,116	75,290	77,655	77,655	77,655	77,655
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	3,840	3,818	0	0	0	0	0	0	0	0
Existing-Certain and Net Firm Transfers	189,693	189,644	186,005	184,030	184,030	184,030	184,030	184,030	184,030	184,030
Anticipated Reserve Margin (%)	29.7%	28.3%	24.3%	18.9%	13.9%	8.7%	4.5%	2.6%	1.0%	-0.3%
Prospective Reserve Margin (%)	37.0%	49.9%	59.1%	55.9%	49.3%	42.6%	27.7%	25.4%	23.5%	20.0%
Reference Margin Level (%)	18.6%	20.1%	21.9%	23.9%	26.3%	28.9%	30.8%	33.0%	35.1%	35.1%



Planning Reserve Margins



Existing and Tier 1 Resources

PJM Highlights

- Load forecasts have increased year over year due to data center and economic growth as well as increased electrification in the PJM footprint.
- Available generation capacity has decreased due to retirements and delays in new additions to the fleet.
- Based on the load increase and generation decrease, PJM is projecting potential reserve margin shortages during peak operating periods. As a result, there is an increased risk that emergency procedures may be required to meet load and reserve requirements.
- PJM will be heavily reliant on good generation performance from both fossil and inverter-based generation to avoid/minimize the need for emergency procedures.

PJM Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	39,866	39,866	39,866	38,288	38,288
Coal*	39,866	37,738	27,448	28,002	26,464
Petroleum	8,952	9,163	9,163	8,766	8,766
Natural Gas	83,210	84,150	85,385	85,385	85,385
Natural Gas*	82,589	83,443	84,678	84,678	84,678
Biomass	857	907	907	907	907
Solar	11,282	13,616	16,141	16,328	16,328
Wind	5,251	5,496	5,622	5,622	5,622
Conventional Hydro	2,807	2,829	2,829	2,829	2,829
Pumped Storage	5,068	5,068	5,068	5,068	5,068
Nuclear	32,508	32,508	32,508	32,508	32,508
Hybrid	1,187	1,504	1,504	1,504	1,504
Battery	703	895	1,531	1,531	1,531
Total MW	191,712	196,002	200,524	198,737	198,737
Total MW*	191,091	193,166	187,399	187,743	186,205
***Capacity with additional generator retirements.** Generators that are forecasted to retire by PJM are removed from the resource projection where marked.					

PJM Assessment

Planning Reserve Margins
The PJM ARM falls below the Installed Reserve Requirement (RML) in 2029 when the ARM dips just below 19% as the RML reaches 24%.

- Accelerated retirements, driven by unit age and environmental public policy, of generators that provide necessary attributes needed to maintain reliability are outpacing new, mainly IBR additions. PJM received over 30 deactivation notifications totaling over 2 GW in 2024.
- Approximately 40% of new interconnection requests to the PJM grid are solar resources.

PJM faces an extreme and rapid tightening of supply and demand for capacity resources in the near term and needs additional resources to rapidly address its near-term reliability challenges.

PJM is in a transition year as the determination is based on the Reserve Requirement Study (RRS) and Effective Load Carrying Capability (ELCC) Study via PJM Manual 20A Resource Adequacy Analysis.[48]

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
Based on the load increase and generation decrease, PJM is projecting a potential reserve margin shortages during peak operating periods. As a result, there is an increased risk that emergency procedures may be required to meet load and reserve requirements.

PJM will be heavily reliant on good generation performance from both fossil and inverter-based generation to avoid or minimize the need for such emergency procedures. The greatest risk is still during the summer peak period.

Probabilistic Assessments (NERC ProbA and Other Studies)
LOLH and EUE values for 2027 are 0.61 hours/year and 3,251 MWh/year, respectively, which are values consistent with PJM having a 2027 LOLE slightly worse than the 1 day in 10-year target. For 2029, the metrics significantly increase (LOLH = 9.97 hours/year and EUE = 67,581 MWh/year) due to significant forecasted peak load increases (i.e., more than 12,000 MW in summer and more than 14,000 MW in winter, driven by large load additions in the PJM footprint) and the changing resource portfolio mix (i.e., the retirement of thermal resources and the addition of wind, solar and storage, that do not provide an expected commensurate resource adequacy value when compared to the retired thermal resources).

In both studied years, large shares of the annual EUE and LOLH are concentrated in the winter months (especially January). In such winter days, the loss-of-load events identified by the model are driven by low temperatures, which result in high loads and the potential for high correlated outages from gas resources as well as poor performance from solar resources. These winter events tend to occur during both morning and evening peaks.

The smaller shares of EUE and LOLH observed in the summer period for 2027 and 2029 are driven by events in the evening (hours ending 19 and 20), during days with high temperature, high loads, and declining performance of BTM and front-of-the-meter solar resources, low performance of wind resources, and to a lesser extent by slightly worse performance of thermal resources.

The ProbA results differ from the LTRA results in that the ProbA models the following:

- Fewer additions: Resources that are identified as Tier 1 in the LTRA may not reach the in-service status on their targeted in-service date.
- More retirements: The current number of announced retirements does not reflect all the environmental policies that states in the PJM footprint are targeting for future years.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	538	3,251	67,580
NEUE (ppm)	0.00	3.50	65.50
LOLH (hours per Year)	0.11	0.61	9.97
* **Provides the 202**4 ProbA Results for Comparison			

Demand
The demand for electricity is growing at the fastest pace in years, primarily from the proliferation of data centers, electrification of buildings and vehicles, and manufacturing.

PJM expects its summer peak to climb by 55,779 MW to 209,923 MW in 2035, while winter peaks are expected to grow by 62,048 MW to reach 198,175 MW by winter 2034–35.

Sector models are a key part of the load forecast process, providing insights into why load trends are happening. Sector models also incorporate the independent assumptions on economic trends and

[48] https://www.pjm.com/-/media/DotCom/documents/manuals/m20a.pdf

end-use adoption and efficiency. The PJM load forecast process considers three sectors: residential, commercial, and industrial. Each sector has its own set of models and inputs.

The load forecast is constructed using 24 hourly models for each zone. In each model, load is the dependent variable. In the history, we start with metered load and then re-constitute with load management addbacks, load drops associated with peak shaving programs, load related to load adjustments (where applicable), and distributed solar generation estimates.

PJM's projected load indicators in many instances have doubled from the *2024 LTRA* projections. For example, net energy for load growth for PJM is projected to average 4.8%, up from 2.3% in last year's projections, per year over the next 10-year period and 2.9% over the next 20 years. Total PJM energy is forecasted to be 1,328,045 GWh in 2035, a 10-year increase of 495,264 GWh, and reaches 1,482,068 GWh in 2045, a 20-year increase of 649,287 GWh. Annualized 10-year growth rates for individual zones range from 0.2% to 8.4% with a median of 1.6%.

Demand-Side Management

As in past years, DR resources can participate in all PJM markets—capacity, energy, and ancillary services. DR is forecast to grow during the summer peak season from 8,184 MW in 2026 to 10,629 MW in 2035. PJM's probabilistic resource adequacy modeling accounts for observed DR availability variations by season and hour.

Distributed Energy Resources

PJM expects 4,810 MW of solar DERs at the time of summer peak demand in 2030 and 5,165 MW in 2035. The effects of solar DERs are included in the load forecast for PJM. No effect of solar DERs is incorporated in the winter load forecast since winter expected peak occurs after sundown.

PJM also expects 3,652 MW of contributions from plug-in EVs to load at the time of summer peak demand in 2030 and 8,250 MW in 2035, with additional contributions from distributed battery storage ranging from 300–900 MW over the same five-year period.

The net effect of DERs is included in the load forecast as the models utilize recent historical data, which implicitly include DERs.

Generation

PJM added 560 MW of new on-peak generation capacity since the 2024 LTRA. The new projects include one wind project at 24.5 MW and 19 solar projects totaling 535.5 MW. An additional 70 MW in capacity was connecting in late 2025.

Substituting thermal resources (coal, natural gas, and oil) with renewable generation (wind, solar, storage, and hybrid resources) may get significantly more challenging as the energy transition progresses and flexible thermal resources are still needed to maintain resource adequacy at one-in 10 LOLE.

Maintaining an adequate level of generation resources with the right operational and physical characteristics is essential for PJM's ability to serve consumer demand through the energy transition. The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain reliability. Today, thermal resources supply ERSs. Until a different technology can provide a reliable substitute at scale, an adequate supply of thermal resources will be needed to maintain grid stability.

Increasing levels of intermittent resources create significant variability and uncertainty to be managed by flexible resources. If the gas fleet of today remains as is, or decreases due to regulatory pressures, but additional storage resources do not get built at pace, immense pressure will be placed on natural gas to supply the ramping needs for the system. Changes to market mechanisms will be evaluated to ensure that adequate resources are incentivized to help PJM manage increasing system uncertainty and volatility.

For example, in 2025, FERC approved a PJM-proposed expansion of Surplus Interconnection Service to augment the operating efficiency and availability of existing resources, and the Reliability Resource Initiative, which attracted 11,000 MW of nameplate capacity in proposed, shovel-ready generation projects. PJM projects that the initiatives will boost Tier 1 resources by an additional 8.3 GW in summer periods and 3.4 GW in winter periods from the original *2025 LTRA* data submittal.

Such initiatives also impacted Tier 2 resources from 2026 to 2031, netting an additional 8.2 GW in summer capacity from the original *2025 LTRA* data submittal and 4.1 GW in winter capacity. These net increases factor resources that transitioned from Tier 2 to Tier 1, the Reliability Resource Initiative, and any recently withdrawn projects.

However, many of these projects continue to be slowed or stopped by factors that extend beyond PJM and affect multiple regions across the continent, including local opposition, state/local permitting delays, supply chain challenges, and financing.

PJM uses some differing capacity assumptions between the LTRA and ProbA. The LTRA counts more resource additions, mainly new solar and gas combined-cycle units, which may not actually become operational. In contrast, the ProbA is more conservative, excluding some Tier 1 resources that might not reach the in-service date as planned. Additionally, the LTRA only accounts for officially announced

retirements, while the ProbA also factors in potential retirements caused by state environmental policies, particularly affecting coal resources projected to retire by 2029.

As of June 2025, all generation capacity resources, with the exception of VERs, that are committed in PJM's Reliability Pricing Model or committed in a PJM Fixed Resource Requirement Plan shall be subject to operational testing initiated by PJM up to two times in each of the summer and winter seasons during the relevant delivery year. (Seasons are defined as: summer (May–October) and winter (November–April). Generation operational tests will be unannounced tests. The tests are being conducted to verify that generating resources can reliably operate when needed.

Energy Storage

Energy storage development continues in PJM. As solar generation increases in PJM, growth of storage is expected to follow since storage devices are frequently co-located with solar projects. Efficient grid operations in an era of rapid renewable energy resource growth will require greater system flexibility. Energy storage can offer grid operators another tool to maintain stable power supply under varying wind and solar power output driven by weather conditions or unit outages. Storage can also improve grid efficiency by increasing utilization of existing transmission lines. PJM continues to work with members, Department of Energy DOE national laboratories, and other industry entities to advance the use of energy storage and, in particular, enable its participation in PJM markets.

There is approximately 162 GWs of solar, wind, battery and hybrid in the PJM interconnection queue requesting capacity injection rights. Hybrid resources make up approximately 20 GWs and standalone storage makes up approximately 40 GWs.

To address the limited-duration issue, some developers are pairing storage with variable, renewable generation, such as solar or wind, to create opportunistic revenue streams. The pairing is either co-located (in which the storage facility and the generator facility are sited on the same parcel of land, but each has its own connection to the grid) or is hybrid (in which the storage facility and generator share a common connection to the grid).

Currently new storage is dispatched similar to other generators in economic order. No more specific operation has been considered due to the small penetration. Many older batteries are used for regulation.

Capacity Transfers

PJM does not rely on significant transfers to meet resource adequacy requirements. Maximum transfer (total transmission interchange capability) into PJM would amount to less than 2% of PJM's internal generation capability. At no time within this assessment period does the ARM get anywhere near 2%. PJM reliability would not be negatively affected if its transfers were dropped to zero.

Transmission

Beginning in 2023, PJM began to identify trends encompassing large load increases in specific areas, driven primarily by the construction of new data centers, and these were incorporated in PJM's 2024 RTEP cycle analyses for five-year (2029) and eight-year (2032) study year models. The large load increases are driving heavier, increased regional transfers and the consequent need for significant system reinforcement. PJM's load forecasting process incorporates methods by which it solicits and applies large load adjustments by transmission zone. Electrification itself is the process of converting conventional end-use load that uses fossil fuels (e.g., gas stoves and oil-burning furnaces) to use electricity instead, as well as the increased use of EVs. This is having a significant impact on the magnitude of the load forecast and load shape. Notably, additional electric heating will narrow the gap between summer and winter peaks.

Most transmission additions are related to local load deliverability problems and not new generation enhancement in Tier 2. Each generator is responsible for transmission enhancements associated with its interconnection and network enhancements if necessary. PJM does not use Tier 3 resources.

PJM's analysis of 2029 and 2032 summer, winter and light load conditions identified 8,520 thermal and voltage criteria flowgate violations across PJM, of which 1,609 were ineligible from competitive windows. The 6,911 remaining violations were addressed in 2024 RTEP Proposal Window No. 1

The large number of violations observed in the 2024 RTEP were driven by heavy west-to-east transmission interface flows caused by large load increases in the Dominion zone and in eastern PJM: 10 GW and 15 GW load increase for 2029 and 2032 between the load forecasts used for the 2022 and 2024 RTEP study cycles, respectively. The significant load growth is attributed primarily to data centers, electrification, and electric vehicle developments.

From PJM's 2024 RTEP Proposal Window No. 1 (July–September 2024), 94 competitive proposals to solve the 6,911 NERC reliability criteria violations identified in the RTEP 2029 model year analysis as well as those identified in the 2032 model year requiring long-lead-time transmission solutions. The PJM board approved $5.9 billion worth of regional and local projects to address the reliability criteria violations.

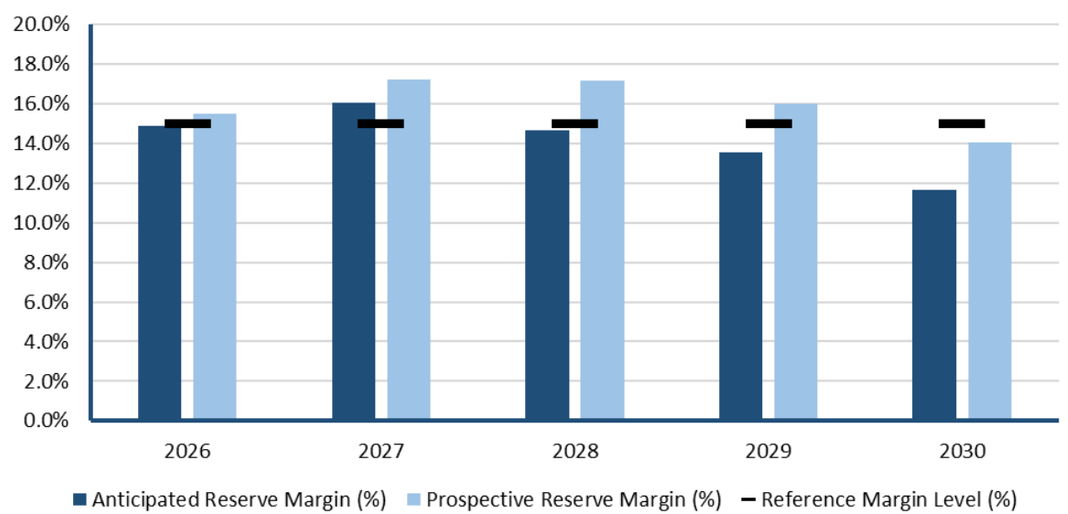


SERC-Central

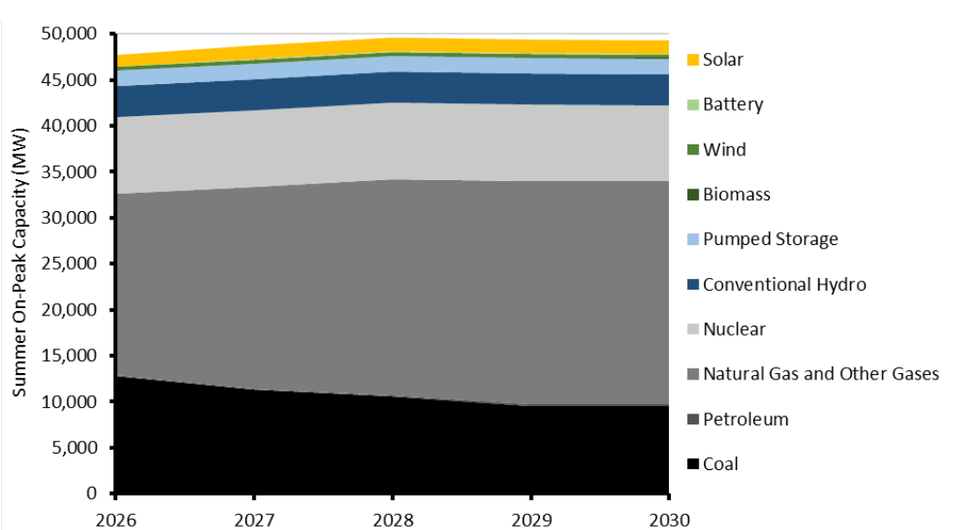
SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	43,066	43,512	44,298	44,616	45,280	45,975	46,034	46,168	46,412	46,619
Demand Response	2,818	3,047	3,287	3,356	3,364	3,377	3,392	3,367	3,323	3,301
Net Internal Demand	40,248	40,465	41,011	41,260	41,916	42,598	42,642	42,801	43,089	43,317
Additions: Tier 1	518	492	4,567	5,435	5,435	5,435	5,435	5,435	5,435	5,735
Additions: Tier 2	20	245	837	837	837	837	837	837	837	837
Additions: Tier 3	178	234	300	362	743	795	2,107	3,293	5,539	5,591
Net Firm Capacity Transfers	460	391	-288	-287	-287	-221	-221	-220	-220	-157
Existing-Certain and Net Firm Transfers	47,859	47,438	45,895	44,503	43,474	43,382	43,448	42,484	42,485	41,414
Anticipated Reserve Margin (%)	19.1%	20.8%	19.7%	18.5%	16.5%	14.8%	12.4%	12.0%	8.7%	9.0%
Prospective Reserve Margin (%)	19.7%	22.0%	22.3%	21.1%	19.0%	17.3%	14.9%	14.5%	11.2%	11.5%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-Central Highlights

- SERC-Central is projected to remain above its RML through 2030. The ProbA shows no loss of load over the 2027 and 2029 study years.

SERC-Central Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	12,782	11,308	10,595	9,565	9,565
Coal*	**12,782**	**11,308**	**9,944**	**8,914**	**8,914**
Petroleum	128	128	128	128	128
Natural Gas	19,706	21,956	23,483	24,341	24,249
Natural Gas*	**19,279**	**21,529**	**22,585**	**23,443**	**23,443**
Biomass	37	37	37	37	37
Solar	1,181	1,408	1,445	1,455	1,455
Wind	370	370	370	370	370
Conventional Hydro	3,405	3,405	3,405	3,405	3,405
Pumped Storage	1,247	1,247	1,247	1,247	1,247
Nuclear	8,280	8,280	8,280	8,280	8,280
Battery	100	135	135	135	135
Total MW	47,236	48,274	49,124	48,963	48,871
Total MW*	**47,256**	**48,267**	**47,996**	**47,835**	**47,835**
***Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Central Assessment

Planning Reserve Margins

PRMs are crucial for ensuring the reliability and adequacy of electric transmission systems in the Central assessment area, with various entities employing different methodologies and targets. The concept of LOLE, often aiming for a standard of one day in 10 years (0.1 LOLE annually), is a critical metric used to establish these targets.

Several entities establish reserve margin levels based on resource adequacy study results. For instance, one entity sets target reserve margins at 29% in winter and 23% in summer, determined using a 1-in-10 LOLE study, a change from its previous economic reserve margin approach, which resulted in lower targets. Another entity performs a reserve margin study using the Astrapé Strategic Energy and Risk Valuation Model (SERVM) to establish summer (18%) and winter (25%) planning targets, balancing seasonal risk and cost, which also aligns with a 1-in-10-year expected probability of a loss-of-load event. Another entity uses the NERC/SERC-accepted 15% reserve margin for predominantly thermal systems, which is generally consistent with a one-day-in-10-year loss of load. Methodologies for determining these margins often involve probabilistic modeling using extensive weather data (e.g., 40 years of weather data with Astrapé SERVM) and simulations of hourly forced outages, load, market availability, and renewable resources. Key drivers of risk often include extreme weather, low renewable generation, forced outages, and limited import capability.

Since the *2024 LTRA*, some significant changes have occurred or are underway. One entity recently updated its minimum reserve margin constraints from economic reserve margin targets to a resource adequacy standard of one day in 10 years LOLE. This entity also conducted a LOLE study that incorporated improvements such as enhanced peak demand modeling and additional sensitivities, including temperature-dependent outage probabilities. Load forecasting is also updated annually to meet NERC MOD-32 requirements, aiming to maintain reserve margins at minimal cost while balancing risk, reliability, environmental responsibility, and flexibility.

Currently, most entities' ARMs are not expected to fall below their RMLs. However, challenges stemming from load growth and increased load sensitivity to weather, particularly in winter, have led to a reduction in reserve margin levels over the next 10 years for some. To address potential shortfalls and future needs, resource additions are being planned, including solar facilities, natural gas combined-cycle units, and battery storage. Utilities also account for uncertainty and variability in assumptions through quantitative scenario modeling and probabilistic weighting of key assumptions. The results of energy risk assessments are used to establish or confirm PRM targets based on simulations and scenario analyses, which account for variability in load, weather, and unit outages to ensure system reliability.

Non-Peak Hour Risk, Energy Assurance, Probabilistic Based Assessments

Energy risk assessments are an evolving aspect of grid reliability planning, moving beyond traditional peak-demand analyses to encompass all potential hours of the year, including non-peak periods in the Central subregion. These comprehensive assessments are vital due to the increasing variability and uncertainty in system demand and resource mix. Utilities employ a range of methods for these assessments, often including detailed LOLE studies that simulate hourly conditions over a 10-year horizon, incorporating extensive historical weather data and system flexibility. Some entities adopt a holistic, year-round planning approach that integrates scenario-based reserve margin analysis and robust fuel inventory management to handle supply and demand uncertainties. Probabilistic modeling is commonly used, leveraging extensive weather data (e.g., 40 years of weather data), and simulating hourly forced outages, load, market availability, and renewable resources to identify risks across a wide range of conditions.

Key drivers of risk examined in these assessments include extreme weather (both highly unexpected demand impacts and unseasonable conditions), low renewable generation, forced outages, and limited import capability. Other factors considered are low water conditions, fuel availability (such as natural gas pipelines and their interdependencies), resource outages, transmission constraints, common mode failures, correlated and dependent outages (derations), ramping limitations, and flexibility requirements. The results of these energy risk assessments are directly used to establish or confirm PRM targets, which are designed to account for variability in load, weather, and unit outages to ensure overall system reliability. These assessments also emphasize the importance of a balanced and diversified generation portfolio to reduce dependency on single sources and to hedge against supply disruptions. Furthermore, they support detailed operational planning, such as maintaining higher reserve margins during shoulder months to mitigate risks from maintenance outages and unpredictable weather, and implementing fuel security measures like firm transportation contracts and fuel inventory targets. Ultimately, the outcomes of energy assessments inform and guide a broad spectrum of strategic, operational, and planning decisions, ensuring that utilities can build robust, adaptive plans to provide consistent and reliable service despite external uncertainties and the evolving conditions of the electricity system.

ProbA Results

In the SERC model, based on data and assumptions, SERC-Central does not show any loss of load risk for 2027 nor 2029 for any of the 5375 cases. The annual metrics are shown below.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0.10	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
*Provides the 2024 ProbA Results for Comparison			

However, the study shows overall reliance on imports from neighboring areas with the potential of insufficient local generation to meet the demand. The month of April in particular shows the risk of low hydro generation, which can coincide with planned maintenance outages. The summer load forecast is expected to grow by 1,005 MW and winter load forecast is expected to grow by 781 MW from 2027 to 2029. At the same time, there is an expected retirement of approximately coal generation in 2028, leading to tighter margins. Close to 2,600 MW of gas generation is expected to be added in the same period. Based on the ProbA, overall margins get tighter in 2029.

Demand growth, planned generator retirements, fuel diversity and reliance on imports contribute to growing energy risks. SERC and the SERC Central entities will need to continue to monitor the resource adequacy studies.

Demand

Utilities in the Central assessment area employ comprehensive and evolving methodologies to project future energy and demand needs, crucial for accurate system planning. Load forecasts are regularly updated, typically every one to two years, drawing heavily on historical data including hourly load profiles, economic indicators, demographic trends, and weather patterns. Many entities utilize econometric or regression-based models to capture the relationship between energy usage and variables like temperature, population, and housing. To account for uncertainty and variability, some utilities develop multiple forecast scenarios, employing historical weather extremes or probabilistic modeling to capture a range of potential outcomes. Forecasts also integrate emerging factors such as DERs, EVs, and end-use efficiency trends. Advanced modeling techniques include shaping system forecasts with hourly load profiles by customer class and DER type, with adjustments for anticipated industrial or commercial growth. Load forecast uncertainty (LFU) is managed through both quantitative scenario modeling and probabilistic weighting of key assumptions. Forecasts beyond a 10-year horizon, while highly uncertain, provide insights into potential long-term drivers such as the addition of data centers and large commercial/industrial loads, which can substantially increase demand and are often modeled as sensitivities in reliability studies. Electrification trends, particularly in home heating, contribute to increased winter peak sensitivity, and transportation electrification is expected to become a more significant driver beyond the 10-year horizon. While climate change and extreme weather impacts often are not pronounced in probabilistic load models, some models are refined to reflect more frequent cold weather patterns, and load impacts are often addressed through scenario planning rather than directly embedded in long-range forecasts.

Demand-Side Management

DR and other DSM programs vary significantly across utilities in the Central assessment area, playing a role in managing demand and enhancing system flexibility. Some entities model their DR programs as dispatchable supply-side resources, meaning their contribution is not reflected as load reductions in forecasts, with available capacity often estimated based on historical performance and being highly weather-dependent. Plans are in place for significant expansion of DR capacity over the next five years by some entities. Specific programs include legacy Interruptible Power, the newer PowerFlex offering greater flexibility in response times, and the relaunched dispatchable voltage regulation (DVR) program, which provides enhanced credits for both emergency and capacity events. Conservation voltage reduction (CVR) is employed as a 24/7 energy-efficiency tool, and Peak Rewards is an aggregator-based DR program for large commercial and industrial customers. Capacity from these programs is estimated based on historical reactivity to voltage changes and forecasted load, with some having specific use limitations, such as 400 event hours per year for DVR. While some smaller entities in Central report no current or planned dispatchable DR programs or note that DR is not a significant factor in their resource planning, other entities are actively growing this resource class, particularly for DR and peak load management. These aggregator-based programs are included in IRP inputs and modeled through semi-annually updated Power Supply Plan processes. The development and refinement of these programs help utilities ensure consistent and reliable service by balancing supply and demand, especially during critical periods.

Distributed Energy Resources

DERs, primarily solar PV, are generally incorporated into net load forecasts by most entities within the Central assessment area, though the specific methodologies and extent of integration vary. Some entities utilize historical data and national laboratory research to integrate distributed generation and EVs into their peak demand and energy forecasts. For example, one entity projects solar PV to reach approximately 1% of summer peak demand by 2028, with total DER capacity anticipated to be 153 MW by 2032. Another entity, which incorporates both BTM and front-of-meter DERs, forecasts solar PV penetration to grow from 250 MW by 2029 to 350 MW by 2034. They model BTM resources using irradiance-based hourly shapes and treat program-based solar as a fixed energy supply with simulated profiles. Future DER growth is projected using adoption curves based on economic payback periods and market trends, also accounting for local self-generation programs that allow up to 5% of annual energy needs.

However, some entities in the region either do not currently utilize or separately account for DERs due to minimal penetration or a lack of utility-sponsored programs. One entity has implemented a

cap on DER penetration at 10% of peak demand, expecting to reach this limit within five years, and models DERs at 80% of capacity during system peaks. IBRs, which include many DERs, are subject to rigorous modeling and verification processes, including fault ride-through testing, oscillation monitoring, and the enforcement of a minimum short-circuit ratio (SCR) to maintain system reliability.

The contribution of DER aggregators is currently limited but is actively expanding in the assessment area, with select entities integrating them into planning and demand-side management strategies. These aggregator-based programs are included in the entity's Integrated Resource Plan (IRP) inputs and are modeled through its semi-annually updated Power Supply Plan process. While some smaller entities report no current or planned dispatchable DR programs or note that DR is not a significant factor in their resource planning, others with minimal DER participation do not account for them separately in resource planning. The capacity from DER aggregators, where applicable, is generally reflected as part of DR resources and modeled as dispatchable or embedded in the net load forecast, depending on the entity. Overall, the assessment area sees a proactive effort by leading entities to grow this resource class for DR and peak load management as the energy landscape evolves.

Generation

Utilities in the Central assessment area are actively engaged in managing their generation portfolios, which are undergoing significant transformation, primarily driven by the integration of IBRs and a focus on flexible, dispatchable capacity. Planning entities have mechanisms to prevent the retirement of reliability-critical units, such as state laws mandating replacement with dispatchable capacity or ensuring replacement generation is established before retirement. Reliability and reserve margin studies are used to assess the impacts of retirements. One entity maintains its plan to retire a 297 MW coal-fired unit in 2027 due to economic and environmental factors, though the timing is under reassessment. There have been no changes to confirmed or unconfirmed retirements since the *2024 LTRA*, with entities projecting no new retirements.

Changing Resource Mix and Operational Considerations: Entities are addressing potential operational issues stemming from this evolving resource mix, particularly due to the increased penetration of solar, BESS, natural gas, and hydro resources. For instance, one entity is retiring a 297 MW coal-fired unit and adding approximately 240 MW of utility-owned solar, a 645 MW natural gas combined-cycle (NGCC) unit, and a 125 MW battery storage facility to enhance system ramping flexibility and absorb more intermittent generation. While annual stability assessments generally show no transmission stability issues, some entities have observed operational challenges related to IBR controls, tuning, and power oscillations. To mitigate these, advanced testing and commissioning processes for new IBRs are being implemented, including a "burn-in" period, and utilities require utility-scale solar resources to operate on automatic generation control (AGC) and allow for automated, proportional output reductions during surplus conditions. Planning activities regularly assess system inertia with IBRs, finding no critical issues related to low system inertia so far.

Addressing Net Demand Ramping Needs: Planners are proactively ensuring sufficient flexible resources are available for long-term net demand ramping needs. Some entities maintain a diverse mix of flexible, dispatchable resources with no planned thermal asset retirements, ensuring adequate inertia and system stability. One larger entity is preparing for the potential integration of up to 11,000 MW of solar over the next 15 years. Proactive measures include replacing 1,400 MW of aging combustion turbines (CTs) with 1,500 MW of modern Frame-type CTs, refurbishing older peakers, and planning for at least 500 MW of new aeroderivative CTs to support flexibility. Exploration of **long-duration energy storage technologies**, such as pumped hydro, gravity-based systems, and flow batteries, is also underway to provide future flexibility. A contractual ability to curtail solar output during times of low demand and high solar output, particularly in spring, serves as a backup measure.

Capacity Contribution Values for Various Resources: Capacity contribution values for different generation types vary based on resource characteristics and available data:

- **Thermal resources** typically use historical performance data, with planned additions relying on vendor guarantees. Forced outage rates for thermal units are generally not reflected in the reported values.
- **VERs** like wind and solar utilize seasonal or monthly net dependable capacity (NDC) values based on historical performance or modeled solar irradiance at peak times. For example, one entity uses 84% of nameplate capacity for solar in summer and 0% in winter, while another uses a 50% confidence level for monthly wind and solar contributions, accounting for inverter risk.
- **Energy storage** contributions vary by duration and reliability benefit; one entity assigns 93% for 8-hour storage and 85% for 4-hour storage, considering 4-hour duration sufficient for reliability.
- **Hydroelectric resources** are evaluated using historical seasonal performance. Most methodologies have remained consistent since the previous LTRA, with updates primarily to assumptions for loads, outages, and transmission imports. Probabilistic modeling, such as ELCC, is used to ensure resource adequacy.

IBR Performance and Reliability: Entities are actively addressing reliability risks from IBRs through various study requirements and operational protocols. Some require EMT models as part of the interconnection study process. Rigorous modeling and validation practices are implemented, including mandating PSSE and PSCAD models for interconnection, enforcing quality control, and evaluating harmonic distortion. A key focus is on inverter control systems that prevent momentary cessation and ensure inverters remain on-line during voltage and frequency excursions. While no

protection schemes or ancillary service needs have explicitly emerged, increased regulation demand has been observed with growing IBR penetration. AGC capability is being mandated for all new utility-scale solar facilities, and legacy plants are being retrofitted to allow system-wide output reductions for flexibility during surplus generation events. The primary challenges with IBRs relate to system stability and control rather than resource adequacy.

Generator Retirements

Natural Gas Fuel Supply Risk: Natural gas fuel supply risk is mitigated through various strategies, including **on-site fuel oil backup** at key generation sites and contingency-based studies simulating pipeline disruptions. One entity estimates that approximately **87% of its gas-fired winter peak capacity will have firm gas transportation or fuel oil backup** within the next five years. Following a 2022 winter event, reliability improvements were implemented by an affected pipeline operator. Strategies also include 100% storage-backed firm transportation for combined cycle units, diverse procurement and scheduling, and embedding fuels personnel in system operations for real-time communication with pipeline operators during contingency events. Long-term planning considers natural gas infrastructure limitations when evaluating new generation resource locations, ensuring fuel supply adequacy and construction timelines.

Energy Storage

Energy storage, primarily BESS, is being added to the system and is expected to contribute to reliability and flexibility. Expected uses include economic operation, reliability enhancements, peak shaving, and frequency response. The capacity contribution of energy storage is factored in based on its supply duration, with entities considering different minimum durations (e.g., 4-hour or 8-hour discharge capability). One entity is adding a 125 MW battery storage facility. These resources are incorporated into long-term planning through IRPs and power supply processes.

Capacity Transfers

The Central assessment area is proactively managing capacity transfers and ensuring transmission adequacy through a variety of studies, strategic investments, and coordinated efforts to maintain system reliability amidst an evolving resource mix and load growth.

The assessment area's ability to transfer capacity is continuously evaluated and is evolving:

- **Evaluation Methods:** Transfer capabilities are assessed through biennial resource adequacy studies that account for firm contracts and probabilistic delivery expectations, showing a positive contribution from increased firm contractual capacity to overall reliability. Seasonal assessments are also conducted to identify surplus transfer capacity across different times of the year, allowing for more accurate planning of bidirectional flows and optimizing the scheduling and delivery of transfers.
- **Observed Impacts and Trends:** One entity has seen an increased reliance on external generation resources, with over 6% of its firm capacity sourced from outside its immediate footprint, driven by fossil unit retirements, load growth, and shifts in its generation portfolio. While no significant changes in power flow patterns have been identified overall, the ongoing transition in the resource mix, along with planned retirements and new additions, is anticipated to influence future transfer scheduling, surplus availability, and bi-directional flow characteristics.
- **Coordinated Efforts:** Entities are implementing various coordination efforts to ensure reliable capacity transfers:
- **Seasonal Capacity Transfer Studies** analyze how different system conditions (e.g., summer and winter peaks, shoulder months) impact import/export capabilities.
  - A transfer monitoring process tracks firm capacity from external generators, ensuring their reliable availability during peak conditions.
  - Coordination with neighboring balancing authorities is undertaken to secure contractual commitments and physical transfer capability.
  - Some entities embed transfer analysis into their long-term planning documents (e.g., IRPs) to evaluate how future firm transfers impact transmission constraints and local reliability.

Transmission

Entities in Central are maintaining transmission adequacy, with significant projects and planning processes in place to address limitations and ensure reliability.

- **Major Transmission Projects:** The assessment area is undertaking numerous projects to support reliability and accommodate changing load and generation patterns. These include the following:
  - **New Line Construction:** Approximately 158 miles of new 345 kV lines and 18 miles of 161 kV lines, along with new 56 MVA 161/69 kV stations
  - **Substation Construction and Expansion:** Three new 345/161 kV stations and one new 161 kV switching station
  - **Transformer Additions/Upgrades:** Various upgrades to 345/161 kV and 161/69 kV transformers to increase capacity
  - **Line Rebuilds and Voltage Conversions:** Over 227 miles of 161 kV lines are being rebuilt, and nearly 20 miles of 69 kV lines are being converted to 161 kV

- **Voltage and Stability Projects:** Installation of a 60 MVAR capacitor bank (by 2025) and planned Statcoms to address voltage reliability
- **Regional Reinforcements:** Projects like a new 161 kV Line and Apalachia Area Improvements are critical to mitigate thermal overload, voltage collapse, and support native load reliability

- **Identified Transmission Limitations:** Planning studies have identified constraints often associated with transformer overloads, line loading issues, or high-voltage conditions.
- **Mitigation Planning and Actions:** To address identified limitations, utilities employ the following:
  - **Operating Guides and Real-Time Controls:** Providing generation dispatch limits or specific switching actions for constrained locations
  - **Infrastructure Expansion:** Planning multiple long-term system reinforcements
  - **Congestion Management Processes:** Using system operator tools and protocols to re-dispatch generation or adjust flows
  - **Annual Transmission Assessments:** Identifying and addressing long-term transmission constraints, including new service requests and interconnections
- **Changes to Transmission Planning Processes:** Since the 2024 LTRA, several enhancements are being implemented or considered:
  - Expanding the biennial Long-Range Plan to incorporate power transfers and extreme weather events
  - Updating generator interconnection and affected system procedures to comply with FERC Order No. 2023, with one entity transitioning to a cluster study approach (transitional cluster in 2025, full cluster in January 2026) to streamline interconnection requests and reduce backlogs
  - Evaluating multi-value projects through resource and capacity assessments to proactively address long-term transmission needs

Reliability Issues

The Central assessment area is actively managing and addressing a range of reliability issues stemming from evolving system conditions, including changes in resource mix, load growth, and extreme weather.

- **Reduced Reserve Margins and Challenges from Load Growth:** Entities in the SERC-Central region are confronting challenges due to load growth and an increased sensitivity of load to weather, especially in winter, which has resulted in a reduction in reserve margin levels over the next 10 years. While some entities anticipate their ARMs will not fall below their RMLs, one entity projects that without replacement resources, its reserve margin would fall below its target range due to a unit retirement in 2027, necessitating further resource additions for increasing economic development load beyond 2027. Underlying reliability issues include increasing winter peak demand sensitivity to weather and the potential for new large commercial loads. To address this, resource additions are being planned, and some entities are shifting their minimum reserve margin constraints to a resource adequacy standard of one day in 10 years LOLE, moving away from prior economic reserve margin targets that resulted in lower targets. Large industrial or commercial load additions, such as data centers and manufacturing centers, are actively monitored as they can introduce reliability risks due to short lead times and uncertain scalability, potentially challenging load forecasting and transmission development.
- **Operational Issues and System Stability with the Changing Resource Mix, Particularly IBRs:** The assessment area is actively addressing potential operational issues stemming from the increasing integration of IBRs like solar and BESS. Some entities have experienced operational challenges related to IBR controls, tuning, and power oscillations, including instances where solar generation contributed to over-generation events. While annual stability assessments have not yet identified transmission stability issues or critical issues related to low system inertia, increased regulation demand has been observed with growing IBR penetration. To manage these risks, entities are implementing proactive measures such as advanced testing and commissioning processes for new IBRs, requiring them to demonstrate stable performance. New utility-scale solar facilities are being mandated to operate on AGC, and legacy plants are being retrofitted for system-wide output reductions to provide flexibility during surplus generation events. The primary challenges related to inverter risks in the assessment area are system stability and control, rather than resource adequacy.
- **Natural Gas Fuel Supply Risk:** The reliability of the BPS faces risks from natural gas generator fuel supply issues, including production or transportation curtailments and limitations during both normal and extreme weather conditions. To mitigate these risks, various strategies have been developed.

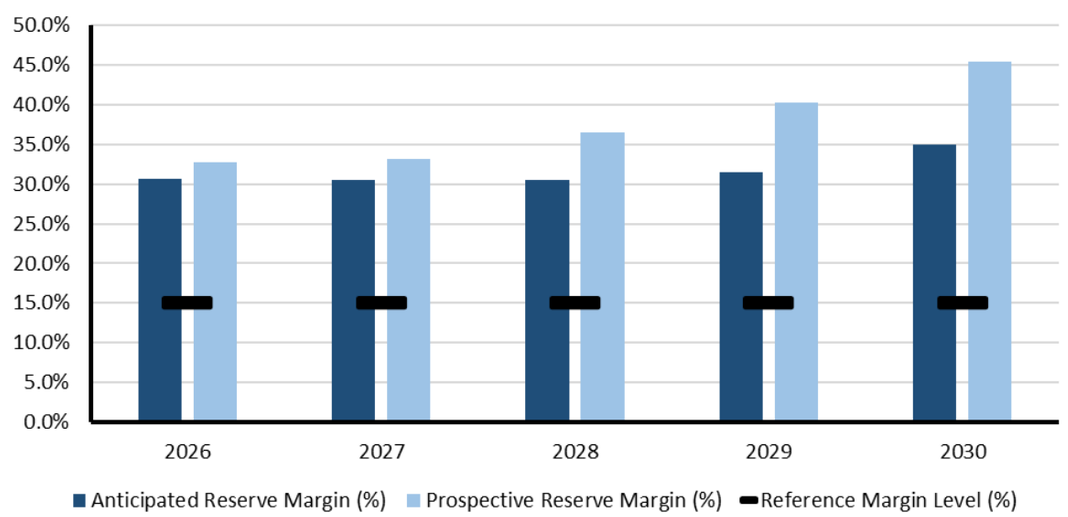


SERC-East

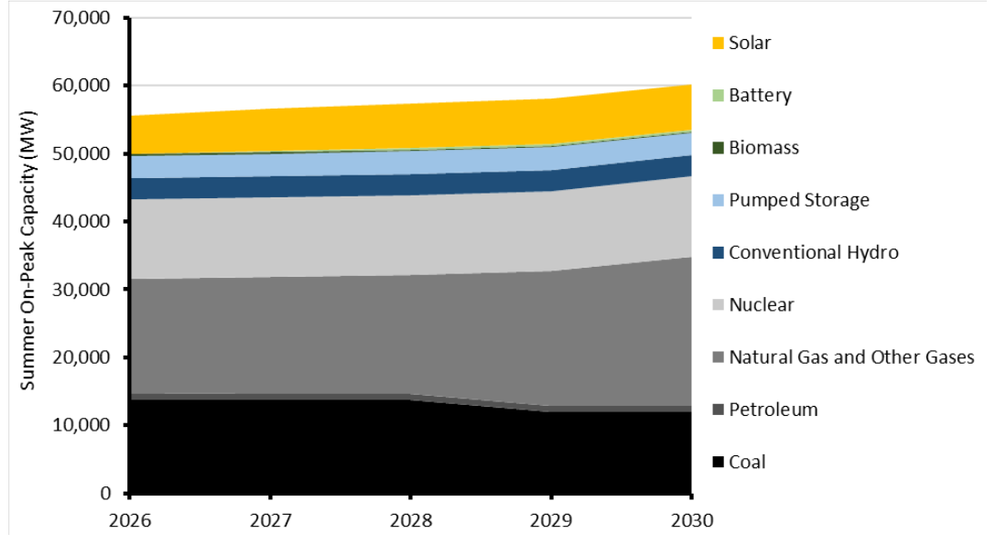
SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	44,414	45,289	45,893	46,128	46,646	47,256	47,776	48,445	48,870	49,313
Demand Response	1,608	1,620	1,621	1,652	1,679	1,702	1,726	1,751	1,773	1,795
Net Internal Demand	42,806	43,669	44,272	44,476	44,967	45,554	46,050	46,694	47,097	47,518
Additions: Tier 1	959	2,109	2,817	5,282	7,348	8,656	9,921	11,186	11,186	11,186
Additions: Tier 2	215	484	2,009	3,231	4,045	4,551	5,114	6,232	9,022	9,022
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	150	150	150	236	236	236	236	236	236	236
Existing-Certain and Net Firm Transfers	54,964	54,880	54,953	53,222	53,316	52,237	50,919	50,919	49,557	49,557
Anticipated Reserve Margin (%)	30.6%	30.5%	30.5%	31.5%	34.9%	33.7%	32.1%	33.0%	29.0%	27.8%
Prospective Reserve Margin (%)	32.7%	33.1%	36.5%	40.3%	45.4%	45.1%	44.7%	47.8%	49.5%	48.2%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-East Highlights

- The 2025 ProbA reveals elevated levels of risk occurring in both the 2027 and 2029 study years.
- To offset the upcoming retirements, SERC-East has planned 2 GW of solar resources and 8.9 GW of gas additions over the next 10 years.

SERC-East Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	13,715	13,715	13,715	11,898	11,898
Petroleum	1,044	992	992	992	992
Petroleum*	1,044	868	868	868	868
Natural Gas	16,737	17,081	17,396	19,816	21,851
Biomass	176	176	176	176	176
Solar	5,649	6,223	6,626	6,671	6,702
Conventional Hydro	3,094	3,094	3,094	3,094	3,094
Pumped Storage	3,324	3,324	3,324	3,324	3,324
Nuclear	11,795	11,795	11,808	11,808	11,902
Battery	8	208	258	258	258
Total MW	**55,540**	**56,606**	**57,388**	**58,035**	**60,196**
Total MW*	**55,540**	**56,482**	**57,264**	**57,911**	**60,072**
***Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-East Assessment

Planning Reserve Margins

PRMs in the assessment area are generally expected to remain above reference levels over the next five years, indicating no immediate system-wide resource adequacy concerns. However, there are variations among entities. For instance, one generation-only BA with an all-hydro portfolio finds reserve margin requirements inapplicable, while another entity reports sufficient margins. A third entity anticipates potential reserve margin challenges starting in Winter 2027 due to significant new load additions and its targeted 18% winter reserve margin. To address this, it has issued requests for proposals for new capacity resources, including battery energy storage, and is evaluating longer-term options.

Other entities expect their reserve margins to remain above the 15% reference level for both near-term (0–5 years) and longer-term (6–10 years) outlooks, despite significant projected winter load growth of approximately 2% annually, which is expected to increase winter peak demand by about 6,500 MW by 2035. Their IRPs identify substantial new resources through 2035, including thousands of megawatts of solar, battery storage, wind, combustion turbines, combined-cycle units, and small modular nuclear reactors. They also plan to implement uprates to existing units. These entities aim to achieve a 22% winter PRM by 2031. Approximately 5,800 MW of coal generation is slated for retirement over the next decade, but these retirements are contingent on securing sufficient replacement capacity to maintain reliability and meet the 22% winter reserve margin target. Without firm replacement resources, coal retirements would be deferred to preserve system reliability.

Since the *2024 LTRA*, most entities have not significantly changed their resource adequacy planning or procurement processes. One entity, operating hydro-only resources, has not made any changes, nor has another entity that is replacing coal-fired generation with natural gas combined-cycle units, though this shift indirectly enhances reliability. However, a third entity, based on its 2022 LOLE study, increased its winter reference PRM from 12% to 18% by 2026, while maintaining the summer reserve margin at 15%. This adjustment reflects heightened concern over winter reliability risks due to electrification trends and potential load increases. Other companies continue to refine strategies for load growth, resource additions, unit uprates, and retirements, maintaining an "all-of-the-above" strategy.

The RML is typically determined by each entity using probabilistic reliability metrics, commonly targeting a LOLE of no more than 1 day in 10 years, or to comply with state requirements. Entities establish separate summer and winter RMLs, considering factors such as load forecast uncertainty, generator availability, and extreme weather impacts. Planning relies on detailed statistical modeling and ELCC studies to assess resource contributions, particularly for variable energy resources like solar, batteries, and wind. The capacity contribution values for variable energy resources and energy storage are determined by ELCC analyses, which discount nameplate capacity to firm, dependable capacity to meet LOLE standards, while non-variable resources like thermal units are counted at their nameplate capacity. Uncertainty and variability in assumptions are accounted for through "High" and "Low" load forecast scenarios that vary demographic and economic growth, large-load adoption rates, rooftop solar penetration, and EV uptake, which in turn drive planning reserve and resource-adequacy sensitivity cases. Although no major methodological changes occurred over the past year, there is a clear trend toward higher winter margins and an emphasis on flexible, dispatchable resources. A reliability verification step within the IRP process ensures that any developed portfolio meets reliability criteria, regardless of its stated installed capacity (ICAP) margin.

Energy Risk, Probabilistic-Based Assessments

Entities within the assessment area exhibit varying approaches to assessing energy risk, with some currently in the early stages of implementation or lacking formal processes. For instance, one generation-only BA with an all-hydro portfolio has not identified any energy risks to date. Another entity has yet to establish a formal energy risk assessment process but is preparing for the forthcoming implementation of NERC's BAL-007-1 standard, which will mandate the development of such procedures and assessments. A third entity also acknowledges the importance of developing these capabilities but currently has no established process or results to report.

Despite the current limitations in formal assessments, the sources indicate that key drivers of energy risk expected to be considered in future evaluations include the following:

- Fuel availability constraints, particularly concerning natural gas supply and delivery
- Impacts from unseasonable extreme weather
- Limitations of variable energy resources
- Transmission or interchange constraints
- Correlated outages
- Other factors such as low water conditions, resource outages, and ramping limitations

Entities within the assessment area extensively employ probabilistic reliability metrics and studies as fundamental tools in their transmission and resource planning processes. These assessments are primarily centered on determining resource adequacy and PRMs, with a common objective of achieving a LOLE of no more than 1 day in 10 years. This probabilistic standard is a cornerstone for establishing the reliability needed to meet anticipated demand.

Key probabilistic assessments and their applications include the following:

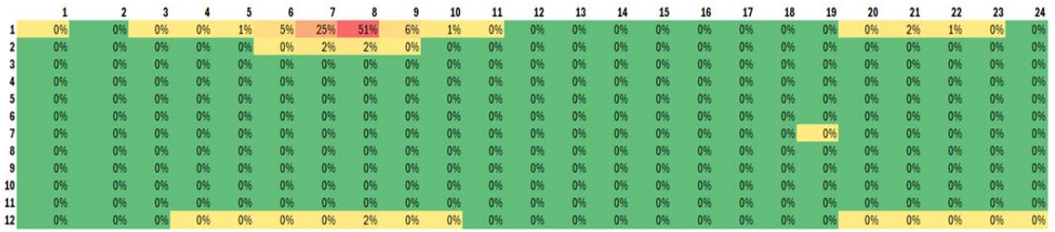
- LOLE Studies: These studies are crucial for setting PRMs. For example, one entity increased its winter reference PRM from 12% to 18% by 2026 following a 2022 LOLE study, reflecting heightened concern over winter reliability risks due to electrification trends. The results from LOLE models are also used in a reliability verification step within IRPs to ensure that proposed resource portfolios can meet reliability thresholds year-round, including accounting for net demand ramping and energy adequacy needs.
- ELCC Studies: These are a specific type of probabilistic assessment used to determine the capacity contributions of VERs such as solar, wind, and battery storage. Unlike non-variable resources like thermal units, which are typically counted at their nameplate capacity, VERs and energy storage undergo ELCC analyses to discount their nameplate capacity to firm, dependable capacity that effectively contributes to meeting LOLE reliability standards. ELCC studies account for factors such as the intermittent, diurnal nature of solar output, especially noting that solar output is minimal during typical winter peak loads (early morning and late evening).
- Statistical Modeling: Entities use detailed statistical modeling to establish separate summer and winter RMLs, considering factors like load forecast uncertainty, generator availability, and extreme weather impacts. While no major methodological changes occurred over the past year, there is a clear trend toward higher winter margins and an emphasis on flexible, dispatchable resources.
- Stochastic Analysis in Load Forecasting: To account for the inherent uncertainties in demand, especially with the addition of large industrial customers like data centers, entities employ stochastic analyses. For instance, one entity uses a 50,000-trial stochastic analysis to capture the probability and timing of prospective data center and manufacturing projects.
- Load Forecast Uncertainty (LFU) Scenarios: Planning processes integrate “High” and “Low” load forecast scenarios that vary demographic and economic growth, large-load adoption rates, rooftop solar penetration, and EV uptake. These scenarios directly drive planning reserve and resource-adequacy sensitivity cases, allowing planners to assess system resilience under different conditions.

Regarding non-peak hour risk and energy assessments, entities are in varied stages of implementing formal processes. While some currently lack established procedures, they acknowledge the forthcoming implementation of NERC’s BAL-007-1 standard, which will mandate the development of such assessments. As these formal energy risk assessments are initiated, future reports are expected to include risk quantification tied to specific drivers (e.g., fuel supply constraints, weather-driven demand volatility, system flexibility limitations) using probabilistic metrics across operational time frames, beyond just peak demand hours. These formal energy risk assessments, once fully implemented, are intended to be essential tools for informing strategic planning and operational decisions to ensure resource capacity is available across a broad range of conditions.

ProbA Results

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	143	231	538
NEUE (ppm)	0.60	0.98	2.27
LOLH (hours per Year)	0.09	0.16	0.33
*Provides the 2024 ProbA Results for Comparison			

The ProbA results for the year 2027 indicate some risk for SERC-East in the winter months of January and February. This is in line with the risk findings of previous ProbA studies. The annual EUE is 231.75 MWh but for a very short, expected duration of 0.15 hours. As shown in the 2027 EUE Heat Map below, the risk occurs during winter morning hours around 7:00-8:00 a.m. due to a combination of higher loads and solar resources not yet ramped up. The risk is seen mainly in January but on a smaller scale in the other winter months of February and December. The major contributing weather-years to the EUE in the model are 1982 and 1985, which experienced one of the worst winters throughout the SERC Region, limiting the amount of imports from neighboring subregions.



2027 EUE Heat Map

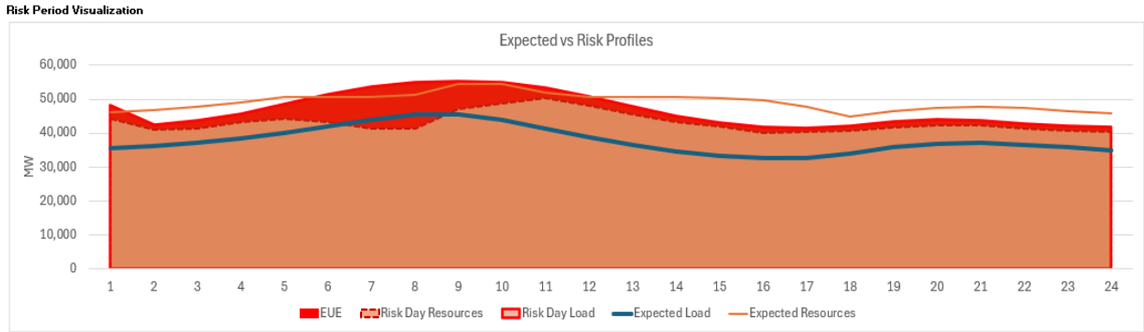
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	1%	7%	23%	41%	9%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	1%	3%	5%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
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6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
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9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
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11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	1%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

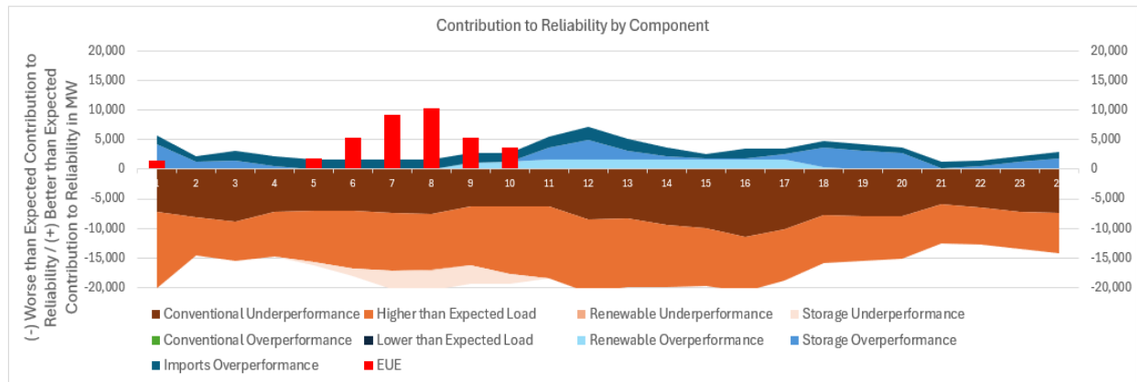
2029 EUE Heat Map

For the year 2029, SERC-East risk continues to grow with 538.48 MWh of EUE and 0.33 hours of LOLH. As is shown in the 2029 EUE Heat Map above, the trends of risk are similar to the findings of 2027, with risk is expected to occur primarily in January, but other winter months of February and December as well. The expected duration of risk is still very short, occurs around 7:00-8:00 a.m. Load is expected to grow in SERC-East. In 2028, more than 1800 MW of coal is expected to retire. While there are some replacements with battery, solar generation, and DR, they are limited in the winter morning risk hours as seen in the study and contribute to the increase in EUE in 2029.

Between 2027 and 2029, the is an expected addition of 683 MW summer load and 985 MW winter load. In the last stages of the ProbA, SERC worked with its entities to identify an error in winter load forecast reporting. We are unable to rerun the model in time for the submission however, we are working with the entities to make the correction to the LTRA. For SERC-East, the overall 2029 winter load forecast should be 1932 MW than is currently reported. The expected risk would be higher along the same trends as is seen in the present study for the year 2029

In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1,000 event or higher probability. The following charts show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2027.

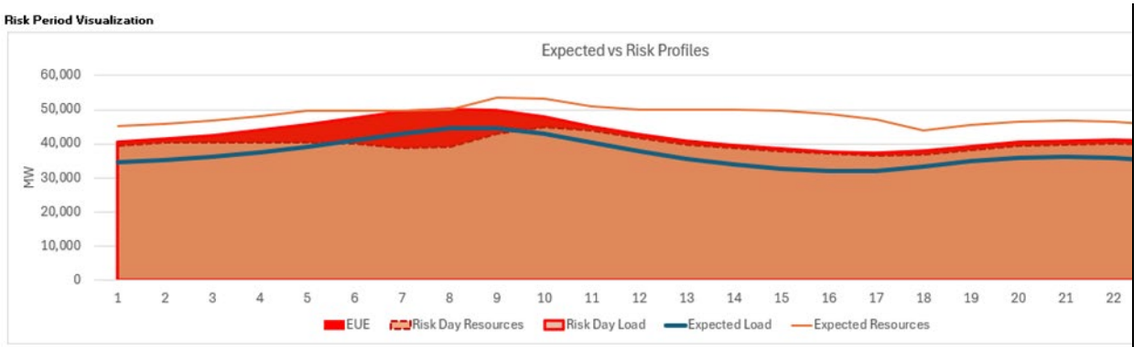


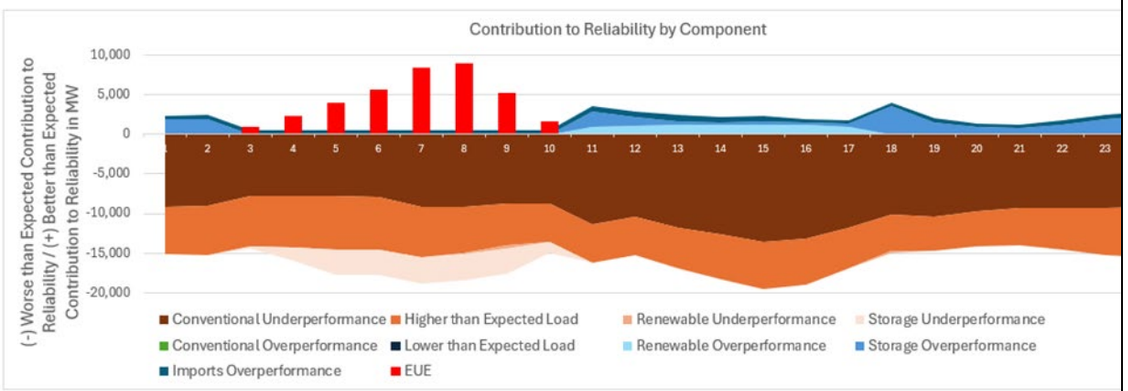


Expected vs. Risk Profiles and Contribution to Reliability by Component

The event day with the worst case EUE hour was chosen for reference (load forecast error +4%, weather year 1985, winter). The chart shows risk during winter morning hours from 4:00-10:00 a.m. and 12:00-1:00 a.m. In this event, the risk is driven by the load forecast higher than expected, unavailability of storage, unavailable or limited solar generation, and some conventional generation on outage. Some imports from neighboring areas are available.

The following charts show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2029. The event day with the worst case EUE hour was chosen for reference (load forecast error +2%, weather year 1985, winter).





Similar to the 2027 event, there is risk during winter morning hours from 3:00-11:00 a.m. In this event, the risk is driven by the load forecast higher than expected, unavailability of storage, unavailable or limited solar generation, and some conventional generation on outage. While there are some imports from neighboring areas available, it is much lower in this event.

Demand growth and planned generator retirements contribute to growing energy risks. SERC and the SERC East entities will need to continue to monitor the resource adequacy studies.

Demand

The assessment area develops its load forecasts using a combination of short-run and long-run econometric techniques, which are then aggregated into a coincident system peak outlook. One entity uses statistically adjusted end-use (SAE) models for customer classes, supplemented by adjustments for energy-efficiency programs, rooftop solar, and EV forecasts from external consultants. Another entity applies SAE regression for residential and commercial classes, a consultation-based approach for large industrial customers, and a 50,000-trial stochastic analysis to capture the probability and timing of prospective data center and manufacturing projects. Municipal and wholesale sub-area forecasts are integrated to form the coincident peak, with contracts having defined end dates removed to prevent overstatement of future demand. Load forecast uncertainty (LFU) is addressed through "High" and "Low" scenarios that vary demographic and economic growth, large-load adoption rates, rooftop solar penetration, and EV uptake, driving planning reserve and resource-adequacy sensitivity cases. Since the 2024 LTRA, key refinements include the explicit addition of an EV demand component starting in 2025, more frequent updates for large industrial prospects, and expanded stochastic modeling to capture rising volatility from electrification and BTM generation.

Changes in the 10-year forecasted demand and energy growth rates since the *2024 LTRA* are primarily driven by the anticipated addition of large new loads, especially data centers and other industrial facilities. These loads are accounted for via a post-modeling stochastic adjustment from active projects and are a significant driver, contributing approximately 1,100 MW by 2034. Electrification trends, particularly EV adoption, are also included, projected to increase residential and commercial summer peak demand by 33 MW and winter demand by 3 MW by 2034. Rooftop solar is forecast to offset summer demand by 3 MW, with no winter peak impact. Other potential drivers like geographic/demographic shifts, economic outlook, EE (beyond standard modeling), flexible loads, extreme weather, and climate change are currently not considered significant contributors to forecast changes. Beyond the 10-year window, electrification and industrial expansion are expected to continue influencing demand, though uncertainty increases.

Demand-Side Management

DR programs are actively monitored and managed through contractual agreements, control technologies, and performance metrics. DR capacity primarily supports the grid during peak periods, with one entity's capacity mainly from interruptible loads and customer standby generation based on contracted firm demand. Programs focus on winter peak capacity support with some summer use but do not currently address ancillary services. Recent initiatives include a residential DR program (smart thermostat rewards, peak time rebates, time-of-use education) and a residential DR program with load control switches on HVAC units and water heaters, contributing about 2.3 MW based on industry benchmarks. However, efforts to develop more precise baselines for measuring performance have yielded inconsistent results, especially in winter, leading to continued reliance on industry averages. Plans include piloting a "Bring Your Own Thermostat" initiative and transitioning to smart thermostat and other grid-edge technologies due to limitations of current switch-based programs.

Since the *2024 LTRA*, regulatory approvals have expanded incentives for most residential controllable programs (heat strip control, thermostats, water heaters, batteries, except the newer battery program) and increased program coverage. This includes a statewide water heater switch program

launching in 2025, adding November as a winter control month, and enabling year-round water heater control. Emerging technologies like EV batteries, smart panels, home automation, and smart inverters are being monitored for future inclusion. A multi-year initiative has been approved to quantify broader value streams from DR, potentially including energy, regulation, and ancillary services. For non-residential customers, a "Bring Your Own kW" winter load curtailment program is expanding, and two new 2025 programs offer an economic curtailment option and a shorter emergency curtailment program. A planned retirement of one large customer DR program aims to streamline offerings into a unified portfolio called PowerShare.

No major changes have been reported for EE and conservation since the *2024 LTRA*, but refinements are being considered. EE impacts are integrated into load forecast models as post-modeling adjustments, reflecting incremental improvements and new program designs. EE is embedded within customer class forecasts and refined through stakeholder input and ongoing evaluation. Looking ahead, increased focus is expected on load-modifying technologies, smart home integration, and more dynamic EE measurement approaches, potentially through real-time metering data or integration with distributed energy resource management systems (DERMS).

Distributed Energy Resources

DERs, particularly BTM solar PV, are anticipated to experience gradual growth within the assessment area over the next 5 and 10 years, although their current penetration levels remain low. Forecasts project residential solar installations to grow by approximately 8% in 2025, tapering slightly to 7% in 2026 and 2027, and then stabilizing around 6% annually thereafter. These projections are informed by local adoption trends, national market dynamics, and regression models that consider economic payback factors such as installation costs, incentives, and bill savings. Historical metering data also shows a recent decline in new BTM installations due to the expiration of DER incentive programs, which influences future projections.

In terms of integration into planning, BTM solar generation is primarily treated as a load modifier, effectively reducing net load through hourly profiles consistent with prior methodologies. Transmission planning similarly incorporates DER generation as a load reduction rather than a supply resource. For generation planning, the capacity value of solar is assessed through ELCC studies due to its intermittent and diurnal nature. Unlike fully dispatchable thermal resources, which are counted at their full nameplate capacity, solar output varies and typically yields minimal output during early morning and late evening winter peak loads. Summer peak loads align better with solar generation, but its capacity contribution still requires careful assessment through ELCC to discount nameplate capacity to firm, dependable capacity to meet LOLE reliability standards.

The system-level impact of current BTM solar on peak demand and load shapes has been minimal, with no significant operational issues identified from existing penetration levels. BTM solar output is projected to represent only 1% to 1.5% of system load over the planning horizons. While no DER-related reliability risks are anticipated for summer 2025, entities are monitoring for potential localized impacts on midday load in areas with higher solar density. Aside from solar PV, no other types of BTM DERs are currently known to materially affect demand-side profiles.

Regarding DER aggregators, there are currently no active or projected aggregators contributing to electricity demand management within the assessment area, and no such capacity is included in forecasts for the next 5 or 10 years. No formal programs are in place to involve DER aggregators in wholesale electricity markets or Integrated Resource Plans, and no virtual power plants operate within the system. While broader grid reliability studies, particularly concerning IBRs, have been conducted through collaborations like the Eastern Interconnection Planning Collaborative, these efforts have not yet extended to DER aggregation. However, if DER aggregator participation increases in the future, planning practices will be adjusted accordingly.

Since the *2024 LTRA*, there have been no major modifications to DER monitoring or modeling methods. However, future updates aim to distinguish between solar-only and solar-plus-storage DERs. Load forecast uncertainty (LFU) scenarios do account for rooftop solar penetration and BTM generation, reflecting the rising volatility introduced by electrification.

Generation

Generation planning and management within the assessment area involve a comprehensive set of studies and strategies to ensure reliability amidst an evolving resource mix and increasing load growth.

Overall Planning and Resource Mix Evolution

Entities in the assessment area conduct extensive reliability studies as part of their resource planning, including resource adequacy and LOLE studies, typically targeting a reliability standard of no more than 1 day in 10 years. These studies inform integrated resource planning (IRP) processes, which evaluate new generation scenarios and resource transitions.

The resource mix is undergoing significant changes, driven by the following:

- **Retirements:** Approximately 5,800 MW of coal generation is slated for retirement over the next decade. However, these retirements are contingent on securing sufficient replacement capacity to maintain reliability and a target winter reserve margin. For instance, Roxboro units are expected to retire 1,156 MW by 2028 and 1,402 MW by 2033, and Mayo 763 MW by 2030, all dependent on replacement capacity being online. Planning entities proactively manage

these risks through transmission impact studies and will delay retirements if replacement resources are not operational.

- **New Additions:** To meet growing demand and replace retiring capacity, IRPs identify substantial new resources through 2035. These include thousands of megawatts of solar, battery storage, wind, combustion turbines (CT), combined cycle (CC) units, and small modular nuclear reactors (SMR). Some entities are also replacing coal-fired generation with natural gas combined-cycle (NGCC) units to introduce more flexible, dual-fuel generation that supports VER integration.
- **Load Growth:** Significant winter load growth of around 2% annually is projected between 2025/2026 and 2034/2035, increasing winter peak demand by approximately 6,500 MW. This growth is primarily driven by the anticipated addition of large new loads, especially data centers and other industrial facilities. These high-load, high-duty-factor customers require resource portfolios capable of sustaining elevated energy demand beyond typical seasonal peaks.

Capacity Valuation and Reliability
For resource adequacy, entities determine PRMs to meet reliability standards.

Capacity Contribution Values: Capacity contributions for different generation types are assigned using a mix of historical performance data and model-based simulations:

- **Variable Energy Resources (VER):** For intermittent resources like solar, onshore wind, offshore wind, and storage, ELCC studies are essential. ELCC studies discount the nameplate capacity of VERs to determine their firm, dependable capacity to meet LOLE reliability standards. Solar output varies and often yields minimal output during early morning and late evening winter peak loads, though summer peak loads align better with solar generation. ELCC values for solar and battery storage are typically updated every three years.
- **Thermal Resources:** Non-solar, wind, and storage resources, such as thermal units, are generally counted at their full nameplate capacity.
- **Hydro Resources:** For hydro-only entities, capacity contributions are based on hydro capacity and remain stable.

Reserve Margins: Reserve margins are generally expected to remain above reference levels over the next five years, indicating no immediate system-wide resource adequacy concerns. One entity, however, anticipates potential reserve margin challenges starting in Winter 2027 due to significant new load additions and has increased its winter reference PRM from 12% to 18%. Another entity plans to adopt a 22% winter reserve margin by 2031.

Operational Considerations
Planning activities are actively underway to address potential operational issues from the evolving resource mix:

- **Ramping Needs:** Planning entities estimate ancillary service needs, such as regulation, balancing, and contingency reserves, to ensure operational reliability amid high penetrations of VERs. While some entities with hydro-based or dispatchable, fast-ramping units have no immediate ramping concerns, and others conduct triennial integration studies aligned with their IRPs to assess the system's ability to integrate intermittent generation.
- **Inertia and Stability:** Stability assessments are conducted as part of TPL-001 compliance and interconnection cluster studies. These studies account for new generators and evaluate the growing share of VERs. Results thus far have not revealed significant stability concerns. If a weaker area with lower inertia is identified, further analysis like EMT modeling may be conducted, and adjustments to IBR performance settings or transmission system upgrades are considered.
- **IBRs:** As solar PV integration grows, interconnection studies now mandate the use of EMT models to evaluate IBR performance during disturbances, addressing issues like momentary cessation and fault ride-through. These studies ensure inverter settings comply with NERC standards (e.g., PRC-024) and FERC Order 827. Efforts focus on maintaining network reliability and system stability. While no new ancillary service needs have emerged in the near five-year horizon, entities are considering adopting IEEE 2800 standards.
- **Natural Gas Fuel Supply Risk:** Planning entities have implemented measures to mitigate risks from natural gas fuel supply disruptions, especially during extreme weather. All natural-gas-fired combined cycle and simple cycle units have dual-fuel capability or firm gas transportation contracts. Future resource planning assumes on-site backup fuel or dual-fuel capability. Long-term studies factor in fuel supply constraints and infrastructure bottlenecks.

Energy Storage
Energy storage (ES) systems, particularly BESS, are anticipated to see significant capacity installations over the coming decade.

Purpose: Much of the planned BESS will be paired with solar facilities to store excess solar generation and enhance system flexibility. The region also operates substantial pumped hydro storage, used to meet load economically and manage generation ramping requirements.

Integration: Energy storage projects are evaluated through generator interconnection studies, modeling both charging and discharging behaviors. Both standalone and hybrid (paired with renewable generation) storage systems are planned for deployment.

Modeling: BESS are modeled assuming a four-hour discharge duration, with capacity contributions varying based on system conditions and resource mix. Hybrid and standalone battery systems are evaluated using ELCC to capture their effective capacity contribution during peak demand periods.

Capacity Transfers

Energy transfer needs and capabilities are undergoing changes, primarily driven by anticipated load growth and the potential retirement of generation resources.

While one generation-only BA does not foresee any changes to its transfer capabilities, other entities acknowledge that the potential retirement of coal plants could constrain transfer capability. To address these potential constraints, new transmission projects are being evaluated and planned. In response to increasing load demands, particularly within specific BAs, multiple active transmission projects are underway to enhance near-term transfer capabilities. Firm transmission service contracts have been secured to support future transfer needs tied to generator retirements, indicating a reliance on these transfers to maintain reliability. Long-term transmission and resource adequacy planning efforts, including IRPs and coordination with neighboring utilities, are ongoing to ensure the region maintains sufficient capacity and transfer reliability. Planning entities model projected resource additions and retirements and incorporate these into transmission models to identify and address any negative impacts through reliability assessments. Long-term firm imports have been requested from neighboring regions to assess whether external capacity transfers might be more cost-effective than developing new local resources, highlighting a consideration for reliance on external capacity for reliability and economic reasons. Potential organizational changes, such as merging BAs, are also being modeled and assessed to ensure system reliability is maintained.

Transmission

Major transmission projects are identified through annual planning assessments to support and maintain system reliability. These projects include new transmission lines (including HVdc), reconductor projects, and power electronic devices like static var compensators (SVC). For instance, a new 230 kV line and synchronous condensers are planned to improve reliability and reduce congestion in coastal areas, and an additional circuit in South Carolina will address low-country congestion. Transmission limitations and constrained areas are identified through annual assessments, but no widespread transmission-constrained areas have been identified in recent planning studies. However, an operating guide exists to manage potential overloads on a specific transmission line. Interconnection study processes are crucial for detecting and resolving potential constraints before new generation is brought online, which helps prevent congestion during real-time operations. Since the *2024 LTRA*, there have not been major changes to transmission planning processes, but entities are actively responding to evolving regulatory requirements, such as FERC Order No. 2023. This includes developing new processes for interconnection heat maps, implementing updated interconnection and affected system processes (including cluster studies), and evaluating grid-enhancing technologies (GET). A business practice is being developed to formalize how GETs will be assessed in both transmission planning and interconnection analyses.

In summary, capacity transfers are important for reliability in this assessment area. System adequacy is maintained through proactive planning for new transmission projects, securing firm transfer contracts, evaluating external imports, and continually refining planning processes to accommodate evolving load and resource dynamics.

Reliability Issues

Entities in East have identified several key reliability issues primarily stemming from projected load growth, an evolving resource mix, and critical infrastructure interdependencies. These challenges necessitate proactive planning and operational adjustments to maintain BPS reliability.

Firstly, large, new load additions, particularly data centers and other industrial facilities, are the primary drivers of significant changes in the 10-year forecasted demand and energy growth rates. These high-load, high-duty-factor customers could strain both generation and transmission resources if not adequately planned for. One entity anticipates potential reserve margin challenges starting in Winter 2027 due to these significant new load additions and is proactively issuing requests for proposals for new capacity resources. All substantial new loads are subjected to interconnection studies to assess their reliability impacts and determine necessary transmission upgrades.

Secondly, the management of generator retirements and the assurance of sufficient replacement capacity pose a significant reliability concern. Approximately 5,800 MW of coal generation is slated for retirement over the next decade. However, these retirements are strictly contingent on securing firm replacement capacity to maintain reliability and meet a target winter reserve margin (e.g., 22%). If firm replacement resources are not in place, coal retirements would be deferred to preserve system reliability. Planning entities actively manage these risks by conducting thorough transmission impact studies to evaluate the effects of retirements on system reliability and to determine required transmission upgrades and replacement generation before allowing retirements to proceed.

Thirdly, the evolving interdependencies with other critical infrastructure sectors, especially natural gas fuel supply, are a major reliability issue, particularly during extreme weather conditions. The risk to BPS reliability from natural gas generator fuel supply issues, such as production or transportation

curtailments, is a recognized concern. Mitigation measures include ensuring that natural-gas-fired combined-cycle and simple cycle units have dual-fuel capability or firm gas transportation contracts. Coordination protocols exist between electric and natural gas operators for both routine operations and emergency response, including maintaining electric service to critical gas infrastructure like compressor stations. Long-term studies also factor in fuel supply constraints and infrastructure bottlenecks, drawing insights from past events.

Fourthly, the operational impacts of the changing resource mix, particularly the increasing penetration of VERs and IBRs, are actively being addressed. Stability assessments are routinely conducted as part of TPL-001 compliance and interconnection cluster studies to evaluate inertia and transmission stability. While results so far have not revealed significant stability concerns, further analysis, such as EMT modeling, may be conducted in identified weaker areas with lower inertia. Interconnection studies for IBRs now mandate the use of EMT models to evaluate their performance during disturbances (e.g., momentary cessation, fault ride-through) and ensure compliance with NERC standards and FERC Order 827. Additionally, ensuring sufficient flexible resources are available to meet expected system ramping needs is a key planning consideration, with triennial integration studies assessing the system's ability to integrate intermittent generation.

Finally, one entity highlighted that its southern system, which is closely interconnected with neighboring utilities, may face import constraints during the spring and fall shoulder seasons when generation outages are common. To mitigate this, the entity proactively coordinates major generation outages with neighboring utilities and prioritizes reliance on internal generation rather than market purchases during these vulnerable periods. For extreme cold weather, a specific temperature threshold triggers the inclusion of additional operational reserves in its planning process, supported by enhanced forecasting tools. While no widespread transmission-constrained areas have been identified in recent planning studies, new transmission projects are being evaluated and planned to enhance transfer capabilities in response to increasing load demands and potential coal plant retirements, indicating ongoing efforts to prevent future transmission-related reliability issues.

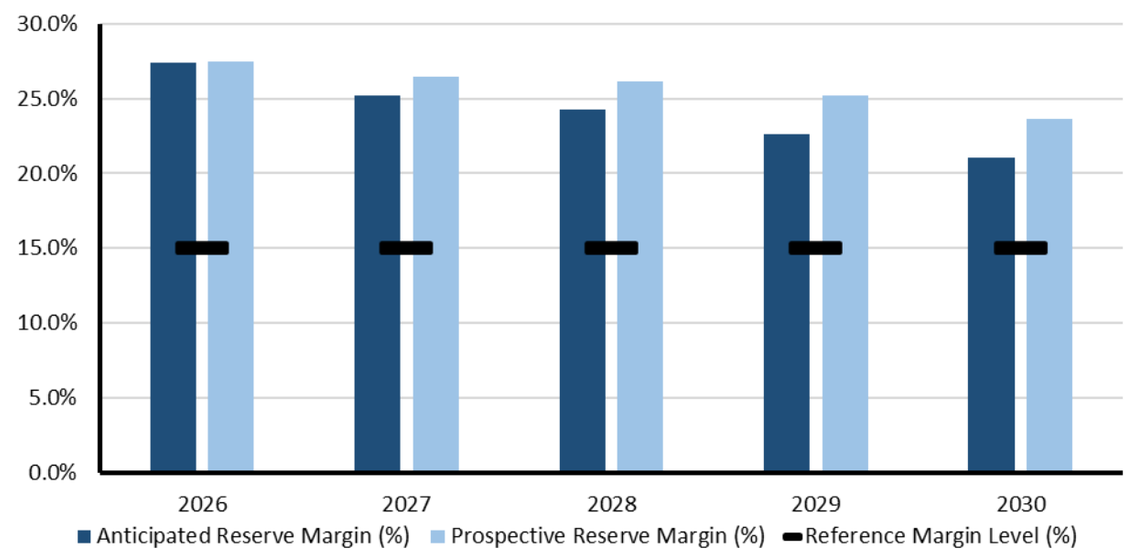


SERC-Florida Peninsula

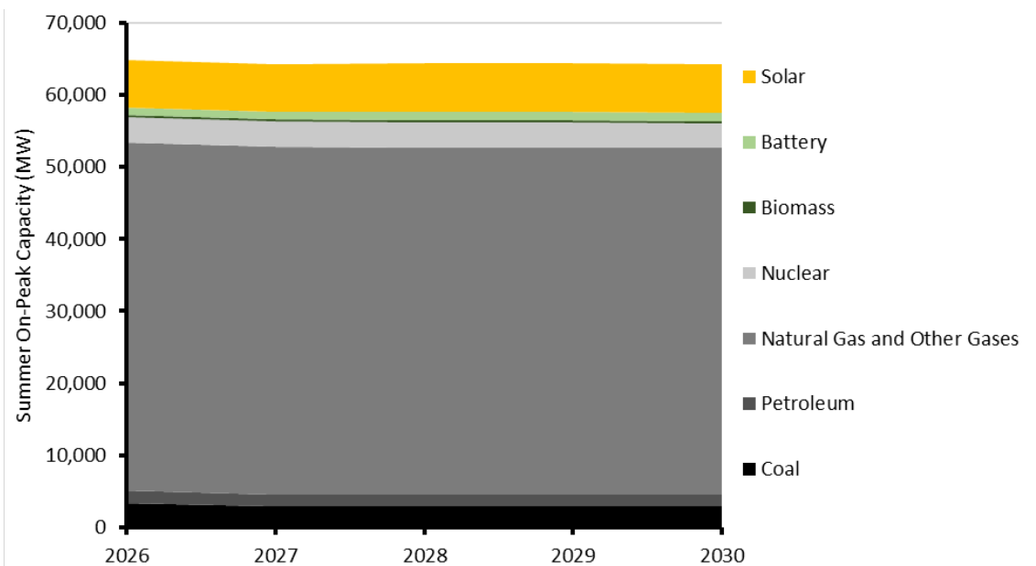
SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	54,477	54,933	55,377	56,099	56,666	57,414	58,267	58,972	59,724	60,415
Demand Response	3,345	3,345	3,357	3,360	3,368	3,379	3,388	3,400	3,412	3,418
Net Internal Demand	51,132	51,588	52,020	52,739	53,298	54,035	54,879	55,572	56,312	56,997
Additions: Tier 1	754	800	997	1,000	1,001	1,801	1,801	1,802	1,803	1,803
Additions: Tier 2	32	620	962	1,375	1,375	1,375	1,375	1,375	1,375	1,375
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Firm Capacity Transfers	293	293	200	200	200	200	200	200	200	200
Existing-Certain and Net Firm Transfers	64,393	63,795	63,659	63,659	63,525	63,001	62,966	62,966	62,966	62,966
Anticipated Reserve Margin (%)	27.4%	25.2%	24.3%	22.6%	21.1%	19.9%	18.0%	16.5%	15.0%	13.6%
Prospective Reserve Margin (%)	27.5%	26.4%	26.2%	25.2%	23.7%	22.5%	20.5%	19.0%	17.5%	16.1%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-Florida Peninsula Highlights

- SERC-Florida Peninsula's ARM falls below the RML during the 2035 time frame.
- SERC-Florida Peninsula's ProbA results for the study years 2027 and 2029 indicate a normal level of risk.

SERC-Florida Peninsula Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	3,361	2,902	2,902	2,902	2,902
Coal*	3,346	2,418	2,418	2,418	2,418
Petroleum	1,795	1,667	1,667	1,667	1,667
Petroleum*	1,768	1,459	1,459	1,459	1,459
Natural Gas	48,214	48,202	48,159	48,159	48,025
Biomass	310	310	310	310	310
Solar	6,666	6,712	6,814	6,817	6,818
Nuclear	3,502	3,502	3,502	3,502	3,502
Battery	1,000	1,000	1,095	1,095	1,095
Total MW	64,849	64,297	64,450	64,453	64,321
Total MW*	**64,806**	**63,604**	**63,757**	**63,760**	**63,628**
*Capacity with additional generator retirements. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

SERC-Florida Peninsula Assessment

Planning Reserve Margins

The Florida Peninsula subregion annually assesses its PRMs to ensure the regional total reserve margin (TRM) requirement is met over a 10-year projected period, considering summer and winter peak loads, generating resources, and firm DSM resources. The State of Florida's Public Service Commission (FPSC) reliability criterion of a 15% reserve margin serves as the general TRM for entities in the subregion. Notably, investor-owned utilities (IOU) in the subregion voluntarily maintain a higher 20% reserve margin, which also functions as their RML based on firm load. These subregional TRM calculations incorporate merchant plant capacity that is under firm contract to load-serving entities.

Currently, the ARM for the Florida Peninsula subregion is projected to remain above the RML throughout the entire assessment period, indicating no present concerns regarding resource adequacy due to reserve margin deficiencies. Specifically, the projected Regional TRM is above the NERC RML of 15%, and Florida Peninsula subregion reserve margins are anticipated to stay at or above 20% for all summer and winter seasons during the assessment period. This healthy reserve level, coupled with excess import capability, means that the subregion does not foresee changes to its energy transfer needs or capabilities.

Probabilistic analyses confirm that the Florida Peninsula subregion continues to operate below this 0.1 loss of load probability (LOLP) standard. The methods used to calculate the Florida Peninsula RML have remained consistent since the prior LTRA. While individual planners account for uncertainty and variability before submitting their data, which is then aggregated, energy adequacy concerns are not directly addressed within the immediate calculation of ARM/RML. Instead, energy adequacy is reviewed through a biennial Loss of Load Probability Study, which assesses all hours of the year, as well as through transmission and fuel reliability study work. Although no formal changes have been made to existing resource adequacy planning or procurement processes since the *2024 LTRA*, the Florida Reliability Coordinating Council (FRCC) and individual entities are actively considering enhancements, particularly focusing on the increasing penetration of IBRs to ensure sufficient dispatchable generation for potential energy assurance concerns. The FRCC is also continuing to develop its analysis of the 24-hour load and resource outlook around peak days to better understand the impact of increased solar penetration and energy storage charging/discharging on ARM/RML.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

The Florida Peninsula Subregion undertakes energy risk assessments to understand its ability to meet uncertain forecasted system demand, particularly as traditional resource adequacy approaches face shortcomings with increasing variability. These assessments are primarily conducted through biennial loss-of-load probabilistic (LOLP) assessments, which are distinct from NERC's ProbA and are designed to assess energy adequacy across every hour of a five-year study period, rather than solely focusing on seasonal peaks. Inputs for these studies include projected generating unit information (current and future capacity), seasonal demand values, projected DR availability, generation maintenance schedules, and Forced Outage Rates (FOR). The FRCC utilizes Astrapé's SERVM Software for multiple base case and sensitivity LOLP studies, with scenarios often examining conditions like no firm import availability, no DR availability, or a 90/10 load case.

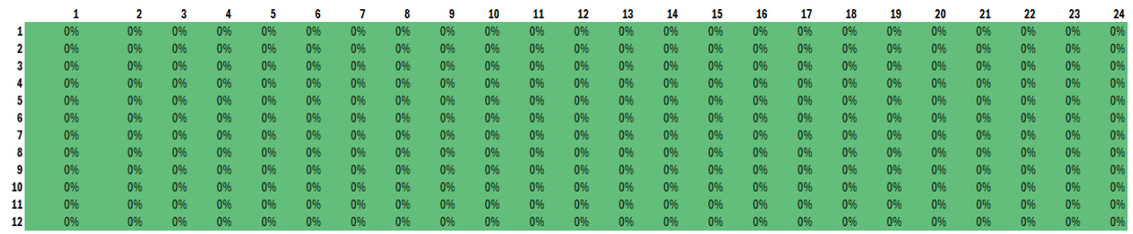
These assessments review a 24-hour load and resource outlook centered around the peak day for both the summer and winter seasons. This effort helps entities fully comprehend the impact of increasing solar penetration levels and energy storage charging/discharging across all hours on the ARM and RML. The analysis has indicated no expected hours of shortfall in adequacy through 2034, though it has observed that increasing solar levels tend to shift the hours of thinnest reserve margins in the summer to later in the day (specifically, HE 18–19).

The FL-Peninsula subregion assesses system adequacy against the industry standard metric of 0.1 LOLP, which equates to approximately one event every 10 years, and currently remains under this standard. Although no significant adequacy impacts have been identified for off-peak hours and shoulder periods, the subregion entities are continuously working to improve their probabilistic analysis methodologies and enhance the robustness of their assessments for these periods. The results of these energy risk assessments are foundational for proactive planning, risk mitigation, and regulatory compliance, guiding long-term strategic decisions like infrastructure development and resource procurement, as well as short-term operational preparedness. The FRCC and its members are also actively considering enhancements to these processes, particularly focusing on the increasing penetration of inverter-based resources (IBR) to ensure sufficient dispatchable generation for potential energy assurance concerns.

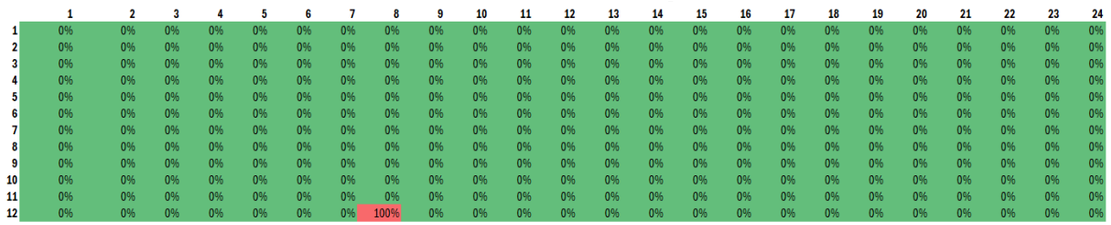
ProbA Results

Based on the data and assumptions of SERC's ProbA model, SERC-Florida Peninsula does not show any loss of load in 2027. For 2029, the annual, probability weighted risk is 0.094 MWh and the LOLH is 0.0001 hours. This is summarized in the table below.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	2	0	0.094
NEUE (ppm)	0.01	0.00	0.00
LOLH (hours per Year)	0.01	0.00	0.00
* Provides the 2024 ProbA Results for Comparison			



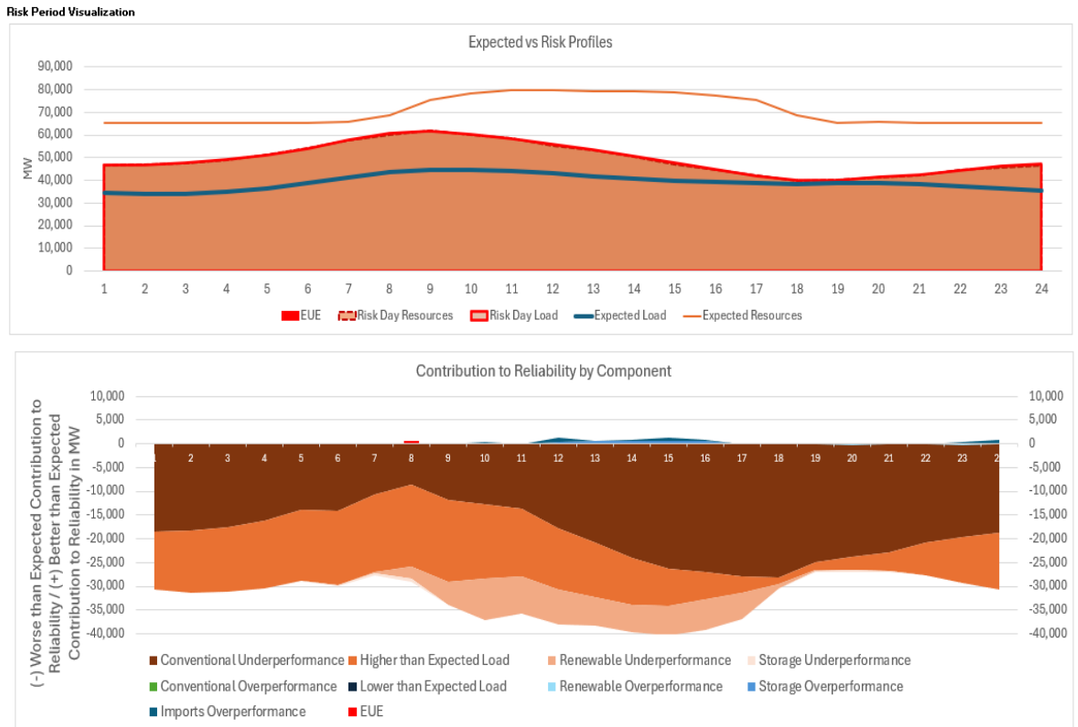
2027 EUE Heat Map



2029 EUE Heat Map

As seen above, the 2027 EUE heat map does not show any risk hours. For study year 2029, there is only one out of 5,375 cases that show risk, which is for a load forecast error of +4%, and weather years 1985 which was an extreme winter year. For that one case, SERC-Florida Peninsula shows an EUE of 720 MWh, with all the risk in December at 7:00-8:00 a.m.

In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1,000 event or higher probability. Figures below show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2029 show event details for one risk event for 2029.



Expected vs. Risk Profiles and Contribution to Reliability by Component

Above, the event day as higher than expected load (extreme winter 1985, 4% load forecast error) and resources available are less than expected. The above shows the risk hour to be between 7:00-8:00 a.m. when solar generation is limited, storage and imports are limited. There is some conventional generation on outage.

SERC-Florida Peninsula is also seeing load growth, with an addition of 1,551 MW winter load and 1,146 MW summer load between 2027 and 2029. While the subregion continues to add solar generation, this study indicates that it would not help alleviate risk in cases of extreme winter mornings when solar generation would be very limited.

With the heavy dependence on natural gas in the SERC-Florida Peninsula subregion, fuel diversity could become an area of future concern. Entities in FL-Peninsula have reported a high number of dual-fuel units to mitigate potential disruptions in the natural gas pipelines. Additionally, a new gas pipeline and connection hubs were constructed in the past few years to provide additional gas to the SERC-Florida Peninsula units. The growing penetration of renewable energy means that SERC and the SERC-Florida Peninsula entities will need to continue to monitor the resource adequacy studies and the impact that renewable resources will have. As solar generation continues to grow, the need to ensure the availability of quick start generating units to meet the ramp in demand will increase.

Demand

The Florida Peninsula subregion's approach to demand forecasting involves individual entities developing their own load forecasts, which are then aggregated by the FRCC to calculate a non-coincident seasonal peak for the subregion. These individual entities annually adjust their forecasts to account for factors such as actual peak demands, updated economic outlooks, population growth, weather patterns, conservation and EE efforts, and electric appliance usage patterns.

The net energy for load (NEL) as well as summer and winter peak demands are forecasted to grow, with the current average annual growth rate for NEL at 1.1% per year, and firm summer and winter peak demand growth expected to increase to 1.34% and 1.45%, respectively, implying a declining trend for the regional load factor. While some larger utilities account for load profile modifiers like DERs and EVs, smaller utilities either lack sufficient data or deem their current impacts as minimal. The penetration of dependable ac solar capacity and EVs is currently low but expected to grow steadily. LFU is assessed at the individual entity level but is incorporated in FRCC and SERC probabilistic analyses for determining potential Loss-of-Load metrics, though not at the subregional level for Total Demand calculation.

Overall, demand and energy growth rates are projected to increase slightly (between 0.15% and 0.3%) compared to the previous LTRA, driven by population growth, economic performance, electricity prices, changing technology and consumption patterns, and more-efficient building codes. Higher-than-normal temperatures have played a noticeable role in higher average consumption per customer. The impact of data centers or similar large loads is currently minimal and not anticipated to create reliability concerns within the planning horizon, and insights beyond the 10-year forecast are not provided.

Demand-Side Management

DSM programs, controllable and dispatchable DR programs within the Florida Peninsula subregion are treated as a load modifier, projected to remain constant at approximately 6% of the summer and winter total peak demands throughout the assessment period. Each reporting entity independently develops its forecast of firm controllable and dispatchable DR values based on their specific methodologies and program policies, with the FRCC aggregating these impacts for regional analytical purposes. In addition to utility-sponsored EE programs, many utilities also include forecasts of EE associated with the impact from governmental codes and standards. Trends in both utility-sponsored EE and EE from governmental codes and standards remain consistent with prior years, and no modifications have been made to these methods or assumptions since the previous LTRA. Looking forward over the next 10 years, while no changes to how EE and conservation are measured or accounted for have been implemented since the 2024 LTRA, enhancements are actively being considered. These considerations include improved hourly granularity, standardized methodologies, advanced measurement and verification techniques, and better integration of EE into long-term resource planning to support system reliability amidst growing energy demands and increasing renewable integration.

Distributed Energy Resources

The Florida Peninsula subregion systematically monitors and integrates DERs into its planning processes, primarily focusing on BTM solar PV as the most significant type of DER currently identified.

Penetration and Trends: The FRCC conducts an annual collection of DER data across its membership, as reflected in the Load and Resource Plan. While DER penetration levels, particularly for private dependable ac solar capacity and EVs, are currently relatively low, they are forecast to increase steadily over the planning horizon. This includes observed and anticipated year-over-year increases in BTM PV penetration, though these levels remain low compared to the total demand of the Florida Peninsula subregion.

Accounting and Integration in Planning: Entities within the subregion utilize NERC-published definitions for DERs. In general, DERs are modeled as being netted out with the actual customer demand, as their impacts are implicitly accounted for within the load forecasts developed by individual entities. Some larger utilities specifically account for DERs and EVs as load profile modifiers in their forecasts.

Monitoring and Studies: The FRCC's Load Forecast Working Group (LFWG) meets annually to monitor trends in demand sensitivities related to DERs and coordinates on best practices. Additionally, resource planning, transmission planning, and stability analysis subcommittees annually review DER penetration levels to assess whether further study work or sensitivities are required.

Challenges and Reliability Impacts: No additional challenges or significant operational issues have been identified by PCs and Transmission Planners in the assessment area stemming from increased

DER penetration levels at this time. The subregion has not identified any significant BTM resources other than solar PV.

DER Aggregators: Currently, the FRCC and its members do not collect additional data from third-party DER aggregators beyond what is already included in the members' integrated resource plans via their annual data collection process.

Generation

The Florida Peninsula subregion is actively managing its generation fleet to maintain reliability amidst an evolving resource mix, with a particular focus on the increasing integration of IBRs like solar and battery installations, and its continued reliance on natural gas.

Here are the key details regarding generation in the subregion:

- Changing Resource Mix and Operational Considerations:
  - While no significant operational issues have been identified at this time due to the changing resource mix, FRCC subcommittees and working groups are collaboratively learning about potential operational considerations associated with increased IBR penetration levels (solar and battery installations).
  - The FRCC Operating Committee (OC) monitors actual output of solar units and tracks how much additional solar capacity will be online within the next 18 months, discussing any operational issues at monthly meetings.
  - Transmission planning studies, including short-circuit ratios and transient stability analyses, have been conducted to assess the performance of existing and planned IBR installations. These studies indicate that the FRCC system is anticipated to maintain reliable stability performance under expected IBR penetration levels in the five-year planning horizon, with no TPL performance issues identified.
  - Additional study sensitivities include light load conditions with solar modeled at projected output and system strength evaluations.
  - IBR performance issue risks are not considered significant in the near term for the assessment area relative to synchronous capacity.
  - The FRCC Planning Committee reviews IBR interconnection studies to ensure transmission system reliability.
- Natural Gas Reliance and Fuel Supply Risk
  - The Florida Peninsula subregion is not expecting any long-term reliability impacts resulting from an increased reliance on natural gas-fired generation.
  - The Fuel Reliability Working Group (FRWG) and Resource Subcommittee (RS) periodically study current and projected natural-gas-fired generation levels, including analyses of long-term infrastructure requirements, potential loss of compressor stations, availability of alternate fuel, and extreme weather analyses.
  - Entities in the subregion do not anticipate natural gas supply issues to create reliability risk.
  - Members are projected to hold the vast majority (approximately 90%) of firm pipeline capacity delivering into Florida, supporting increasing gas generation requirements.
  - In the event of a short-term failure of gas delivery infrastructure, there is sufficient back-up fuel capability to meet projected demand. Approximately 55–57% of natural gas generation has alternate fuel capability.
  - Communication protocols include fuel data status reporting by Operating Entities (OE) to the FRCC State Capacity Emergency Coordinator (SCEC) and FRCC RC during threats to fuel availability, integrating this data into enhanced daily capacity assessments.

Net Demand Ramping

No entity has identified any potential issues with net demand ramping within the 10-year planning horizon, as sufficient flexible resources are available. Potential ramping changes are not seen as emerging given current IBR penetration levels and the availability of dispatchable resources. FRCC planning and operating subcommittees plan to further evaluate aggregate system ramping needs over the next few years.

Capacity Contribution Values

Estimates for VERs, including wind, solar, and hydro, and energy storage, are determined by individual members based on actual performance of existing resources and projected performance using industry standard modeling tools (e.g., PVsyst).

Generator Retirements

Confirmed retirements are incorporated into the *Load and Resource Reliability Assessment Report*, while unconfirmed retirements are not tracked. Retirement decisions are made by each entity based on factors such as unit end of lifespan, operating costs vs. new alternatives, environmental regulations, and local sustainability targets. The subregion is not anticipating any negative impacts on reliability from retirements. Confirmed retirements projected have decreased from approximately 3,400 MW in the prior LTRA to 2,150 MW in the current analysis. Entities analyze projected resource

needs in their annual 10-year site plans (TYSP), which include planned retirements and new generation facilities.

Energy Storage

ES is increasingly being integrated into the planning processes within the Florida Peninsula subregion, with methodologies continuously evolving as entities gain more experience in their planning and operation. While entities are modifying their planning processes based on this accumulating experience, no significant modifications have been made to the core VER methods or assumptions, which include ES, since the previous LTRA.

For deterministic analyses, energy storage units are anticipated to be available to provide energy at the time of peak at their full capacity, effectively contributing to peak capacity. However, for probabilistic analyses and energy adequacy assessments, entities are continuing to discuss methodologies to incorporate supply duration and charging time to better reflect the resource's characteristics over time. The FRCC's biennial loss-of-load probabilistic assessments, which review every hour of a five-year study period, help assess energy adequacy and can include considerations for ES.

The impact of energy storage on system adequacy is also evaluated through the FRCC's "2x24 Hour Analysis." This analysis reviews the 24-hour load and resource outlook, helping entities understand more completely the impact of increased solar penetration levels and energy storage charging and discharging across all hours of the peak days on the ARM and RML. This detailed hourly assessment helps observe how ES operations influence system adequacy throughout the day and has indicated no expected hours of shortfall through 2034.

The capacity contribution values for energy storage are determined by individual members, generally based on a combination of actual performance of existing resources and projected performance using industry standard modeling tools. The basis for the percentage capacity contribution considers the nameplate rating of each facility.

Energy storage installations, particularly battery installations, are considered alongside other IBRs. FRCC subcommittees and working groups are collaboratively learning about potential operational considerations associated with increased IBR penetration levels, including these battery installations. The FRCC Planning Committee reviews IBR interconnection studies to ensure transmission system reliability.

Currently, PCs and Transmission Planners in the assessment area have not identified any additional challenges or significant operational issues specifically stemming from increased DER penetration levels, including ES.

Capacity Transfers

In the Florida Peninsula subregion, capacity transfers primarily refer to anticipated firm import and export values with neighboring assessment areas, particularly the Southern Balancing Authority. While these transfers are an integral part of regional planning, Florida is generally not reliant on external capacity transfers for its core reliability, due to its robust internal generation and healthy reserve margins.

The FRCC Load and Resource Plan (LRP) annually incorporates anticipated firm import and export values reported by member utilities. Recent projections indicate a decline in firm imports for the region over the past few years.

To ensure effective capacity transfers and assess their sufficiency, the Florida–Southern Interface owners conduct an annual transfer capability assessment. This assessment determines the available transfer capability between Peninsular Florida and the Southern Balancing Authority and between the Southern Balancing Authority and FPL Northwest. The results of the most recent analysis project that the interface capability is sufficient to meet anticipated firm import needs.

Transmission

The Florida Peninsula subregion has not identified any specific major transmission projects that impact or are needed to maintain reliability during the planning horizon that are not already identified in the Annual Regional Plan. The individual entities have planned projects that are primarily related to system expansion in order to serve their forecasted growing demand and resource integration and to ensure long-term reliability (beyond the planning horizon). At this time, there have been no changes made to the transmission planning process since last year's reporting.

Reliability Issues

The Florida Peninsula subregion generally maintains a strong reliability outlook, with no other significant emerging reliability issues identified at this time. The ARM is expected to remain above the RML throughout the entire assessment period, meaning there are no current concerns regarding resource adequacy related to reserve margin deficiencies and thus no reliance on Tier 2 resources or supplemental options. Similarly, no potential issues with net demand ramping have been identified within the 10-year planning horizon, and no additional challenges from increased penetration levels of DERs have been identified by PCs and Transmission Planners. Large industrial or commercial load additions, such as data centers, are not anticipated to create reliability risk in the subregion, nor have

any transmission-constrained areas been identified in planning studies. The subregion is also not reliant on external capacity transfers for its core reliability due to robust internal generation and healthy reserve margins.

Even though the Florida Peninsula subregion is not projecting any significant emerging reliability issues, there are areas that the assessment area continues to monitor closely and actively consider for future enhancements or reassessments, indicating underlying risks or concerns that could impact long-term reliability:

- **Increasing Penetration of IBRs and Associated Energy Assurance/Operational Flexibility Concerns:** Although IBR performance issues are "not considered significant in the near-term" for the Florida assessment area at current penetration levels, the increasing integration of IBRs (such as solar and battery installations) is a "key area of focus."
- **Risks of Extreme Weather:** While the Florida-specific energy risk assessments note "no expected hours of shortfall," scenario cases are run that include altered projected load to reflect extreme conditions (e.g., a 90/10 case), demonstrating an awareness of these potential risks.
- **Dependency on Natural Gas as a Fuel Resource:** Despite that Florida does not anticipate any natural gas supply issues that may create risk to reliability and has developed robust mitigation strategies (such as holding approximately 90% of firm pipeline capacity and having 55%–57% of natural gas generation with alternate fuel capability), the area's "dependency on natural gas as a fuel resource" is still factor where possible impacts on the long-term reliability of the BES are continuously monitored.

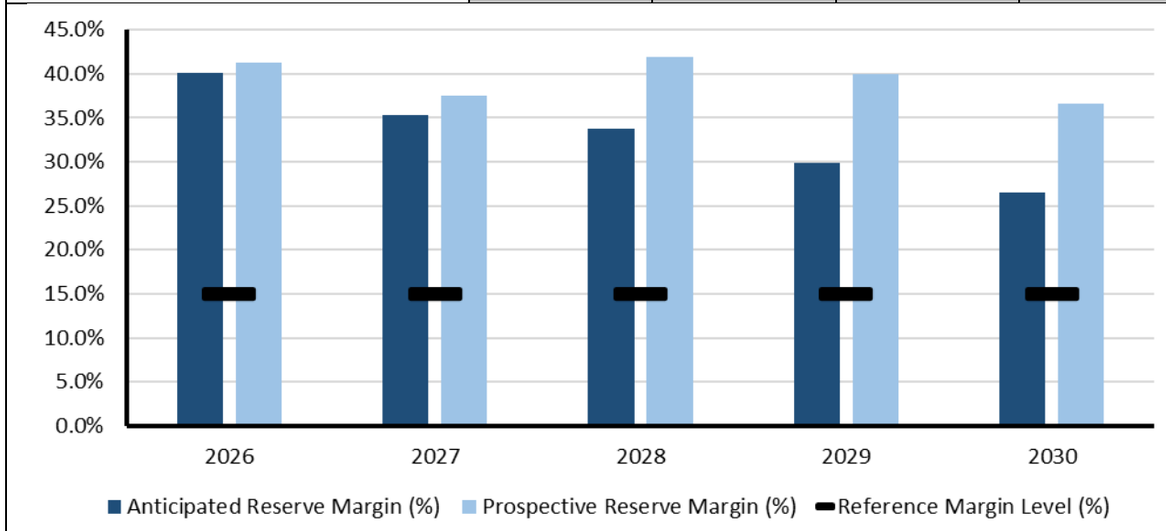


SERC-Southeast

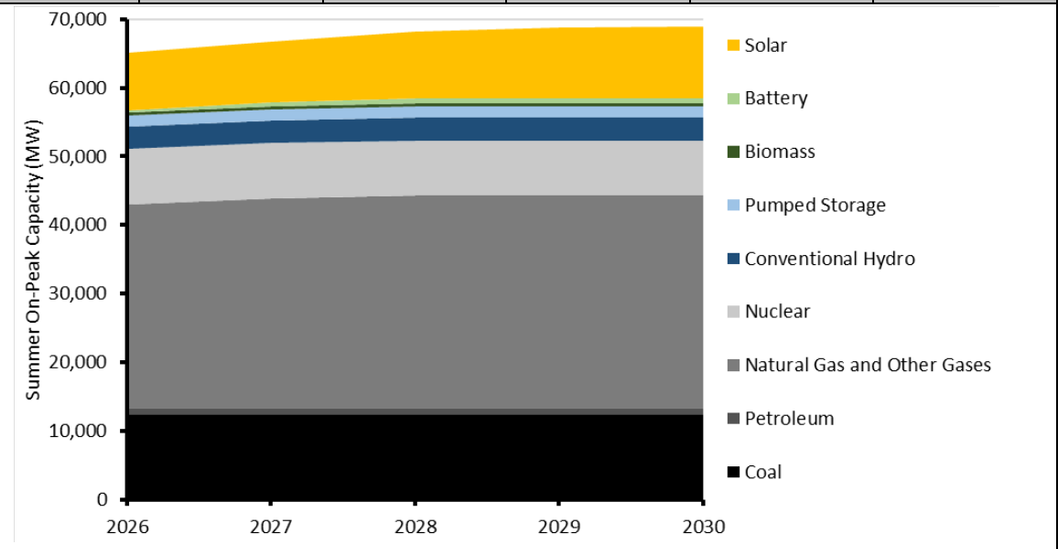
SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 Reliability Coordinators.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	48,386	50,648	52,900	55,127	56,624	57,544	57,978	58,552	59,004	59,166
Demand Response	1,358	1,391	1,623	1,634	1,640	1,650	1,656	1,664	1,671	1,677
Net Internal Demand	47,028	49,257	51,277	53,493	54,984	55,894	56,322	56,888	57,333	57,489
Additions: Tier 1	684	2,262	3,704	4,395	4,474	4,474	4,474	4,474	4,474	4,474
Additions: Tier 2	0	516	3,687	4,889	4,989	4,989	4,989	4,989	4,989	4,989
Additions: Tier 3	0	150	250	500	500	500	500	500	500	500
Net Firm Capacity Transfers	814	-53	414	619	619	619	619	619	619	619
Existing-Certain and Net Firm Transfers	65,201	64,393	64,860	65,065	65,065	65,065	65,065	65,065	65,065	65,065
Anticipated Reserve Margin (%)	40.1%	35.3%	33.7%	29.8%	26.5%	24.4%	23.5%	22.2%	21.3%	21.0%
Prospective Reserve Margin (%)	41.3%	37.5%	42.0%	40.0%	36.5%	34.3%	33.3%	32.0%	30.9%	30.6%
Reference Margin Level (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%



Planning Reserve Margins



Existing and Tier 1 Resources

SERC-Southeast Highlights

- SERC-Southeast's ARM does not fall below the RML during the 2025–2035 time frame.
- SERC-Southeast's ProbA results for the study years 2027 and 2029 indicate a normal level of risk.

SERC-Southeast Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	12,403	12,403	12,403	12,403	12,403
Coal*	12,403	12,403	11,145	11,145	11,145
Petroleum	866	866	866	866	866
Natural Gas	29,765	30,646	31,057	31,057	31,057
Natural Gas*	29,751	30,632	31,043	31,043	31,043
Biomass	428	428	428	428	428
Solar	8,358	8,836	9,667	10,358	10,358
Conventional Hydro	3,292	3,292	3,292	3,292	3,292
Pumped Storage	1,632	1,632	1,632	1,632	1,632
Nuclear	8,018	8,018	8,018	8,018	8,018
Battery	279	557	757	757	836
Total MW	65,042	66,678	68,120	68,811	68,890
Total MW*	65,042	66,678	66,862	67,553	67,632
***Capacity with additional generator retirements.** Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

Planning Reserve Margins

PRMs in the Southeast assessment area highlight a proactive and stable approach to ensuring grid reliability, with ARMs projected to remain above reference or target levels throughout the long-term assessment period. Utilities in the region typically plan for a 15% reserve margin, a target that has remained unchanged from prior years. Capacity plans are specifically designed to maintain 15% reserve margins in summer and 25% in winter, consistent with previous long-term assessments. The annual IRP process is crucial, as it addresses resource adequacy well in advance, ensuring that reserve margins consistently stay above these required levels, considering both primary and secondary generation resources.

The methodologies for determining these RMLs are robust and comprehensive. A LOLP analysis is conducted to ascertain if adjustments are necessary to maintain a 1-in-10-year LOLE. This analysis relies on assumptions concerning system loads, potential outages, transfer capabilities, and resource plans, drawing from historical and forecasted data. To account for uncertainties, these assumptions are stress-tested through Monte Carlo simulations across a range of best- and worst-case scenarios, calculating EUE at current RMLs. One utility, which operates independently of state regulatory oversight, conducts its own triennial reserve margin study (RMS) to pinpoint an economically optimal reserve level. This RMS balances capacity costs, production costs, and the costs associated with unserved energy, utilizing a wide array of data including weather variability, unit reliability, fuel availability, and market conditions to model hourly system operations and assess the risk and cost of potential capacity shortfalls. Furthermore, resource adequacy assessments are evolving to include advanced capacity accreditation methods like perfect capacity (PCAP) and ELCC, which more accurately reflect the reliability contributions of VERs. For instance, one ELCC study increased solar peak credit from 50% to 89% for certain solar capacity. No significant changes have been made to reserve margin modeling or resource procurement processes since the previous LTRA, and none are planned for the next decade regarding resource adequacy planning, though input assumptions are regularly updated.

Despite maintaining adequate reserve margins, energy risk assessments highlight an important nuance: reserve margins alone do not guarantee reliability; energy deliverability and fuel sufficiency are also crucial. Results from these assessments may prompt policy updates or recalibrated targets for PRM policies to better align with actual risk levels identified across the year, including non-peak hours. To address identified capacity needs or potential shortfalls, the IRP process leads to procurement actions approved by regulatory commissions. New resource technologies are selected based on their technical, economic, and capacity attributes. For example, one utility intends to maintain its 15% reserve margin by incorporating potential capacity purchases of up to 370 MW to serve anticipated data mining loads over the next four years, alongside plans to add solar and battery resources in 2029. Overall, planning entities consistently update their capacity expansion plans annually to meet load requirements and adhere to these PRMs.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments

Energy risk assessments in the Southeast assessment area utilize a combination of deterministic and probabilistic methods to identify and address potential energy shortfalls across various planning horizons. These assessments incorporate crucial assumptions about fuel availability, generation outages, extreme weather events, and transmission capabilities. Winter peak hours have been identified as the highest-risk period for energy shortfalls, driven primarily by volatile peak demand during extreme cold weather events that exceeds forecasts, and sustained overnight load where demand remains high throughout the evening and early morning, eliminating traditional off-peak troughs. Recent winter events, like Winter Storm Elliott, have led to updates in load shapes used in modeling, reflecting higher and more sustained loads even outside traditional peak hours.

A significant finding from these assessments is that fuel availability, particularly for natural gas, presents a risk, especially in systems with limited renewable penetration. Entities are mitigating this by securing firm pipeline transportation contracts for baseload plants and ensuring onsite fuel storage (natural gas or fuel oil) for peaking units. Probabilistic modeling, including Monte Carlo simulations, evaluates the impact of these drivers, calculating metrics such as LOLE and EUE; these studies show increased risk in winter and significant EUE increases under fuel-constrained scenarios. Crucially, the results underscore that reserve margins alone do not guarantee reliability; energy deliverability and fuel sufficiency are also vital.

Furthermore, scenarios modeling low hydro output and low solar generation during high-demand periods (especially in winter or prolonged cloudy conditions) indicate increased energy risks when variable energy resources (VERs) underperform. While annual production cost simulations performed in an “island” mode (excluding market purchases) have not identified energy deficiencies under base conditions, the RMS provides a comprehensive probabilistic analysis of hourly energy adequacy by simulating thousands of scenarios and considering historical weather, load, solar availability, fuel constraints, and generator outages. The RMS also assesses regional interdependency risks, finding that transmission constraints can hinder economic and emergency imports, exacerbating local energy shortages during widespread events. Energy risk assessments reflect a maturing focus on year-round, all-hour reliability, emphasizing risks from fuel supply chains, weather variability, and the increasing integration of variable renewable energy sources. These findings may lead to policy updates or recalibrated targets for PRM policies (e.g., 15% summer/25% winter) to better align with actual identified risk levels.

ProbA Results

SERC-Southeast does not show any loss of load risk for the year 2027, the EUE is 0.00 MWh and LOLH is also 0.00 hours. For the year 2029, there is a small ANNUAL risk of 0.39 MWh and 0.001 hours.

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	0	0.0	0.4
NEUE (ppm)	0.00	0.00	0.001
LOLH (hours per Year)	0.00	0.00	0.001
* Provides the 2024 ProbA Results for Comparison			

The figure below shows the EUE as a Heat Map for the year 2027.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

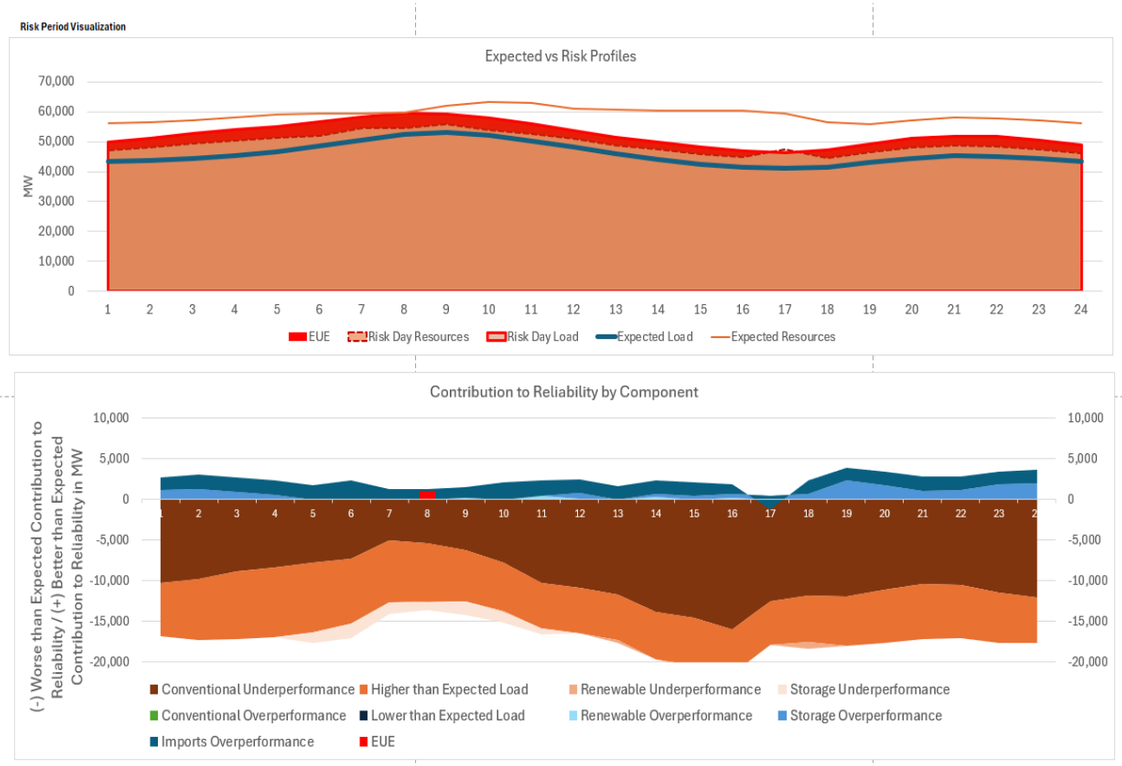
2027 EUE Heat Map

For the year 2029, there is a small annual risk of 0.39 MWh and 0.001 hours. There are some iterations of cases in the 2029 case, for load forecast error +2% and +4%, there is an EUE of up to 1,006 MWh. As shown in the figure below, higher load forecasts, particularly during extreme cold weather events such as weather years 1982, 1985, and 2022, contribute to risk in winter mornings (7:00-8:00 a.m.) and nights (10:00 p.m.-12:00 a.m.). December shows the most risk, followed by January.

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	13%	29%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	0%	0%	0%	0%	0%	0%	1%	35%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	22%	0%

2029 EUE Heat Map

In the SERC SERVM model, there are 5,375 unique cases. There was not a case for the 1 in 1000 event or higher probability, so the event day with the highest EUE in an hour was selected. Figures below show the expected (typical) vs. risk profiles and the contribution to reliability by component for the study year 2029.



The top figure compares the event day to a typical day in December, with weather year 1985, which was an extreme cold event. The lower figure shows the loss of load between 7:00-8:00 a.m. when the load is higher than projected, solar generation is unavailable, energy storage and imports are available during the risk hour.

Between 2027 and 2029, SERC-Southeast is expected to add battery and solar generation Tier 1 resources. The addition of solar generation, however, would not help alleviate risk that occurs in winter morning or winter night hours when solar irradiation is unavailable. Georgia Power Company has publicly filed their intent to build company owned combined cycle, battery energy storage systems, hybrid solar and battery energy storage systems, coming online between 2029 and 2031. However, the commission has yet to vote on approval, expected to do so in December and are not included in the model. SERC-Southeast is not expected to retire additional generation during this time.

SERC-Southeast is seeing high load growth. Between summer 2027 and 2029, there is expected to be an addition of 4,468 MW of summer load and 2,134 MW of winter load.

With the growing dependence on natural gas as the predominant energy source in the SERC Southeast subregion, fuel diversity could become an area of future concern.

Demand

The entities in the Southeast assessment area employ a robust approach to developing their load forecast for the LTRA. This methodology combines econometric modeling, statistically adjusted end-use (SAE) analysis, and hourly bottom-up aggregation across members. Forecasts are annually updated based on historical data and the latest S&P Global economic outlook, using regression models that account for weather, economic indicators, population, appliance efficiency, and load shapes. Both coincident and non-coincident peak demand forecasts are included and refined using specialized tools. LFU is addressed by testing load levels ranging from 80% to 104% of projected peak demand, with weather identified as the primary driver of variability. While DERs like rooftop solar currently have minimal impact, their potential effects are considered in sensitivity scenarios. No major changes have been made to the core forecasting methodology since the prior LTRA, though input assumptions are regularly updated.

Several factors contribute to the 10-year forecasted demand and energy growth rates. Data centers are a significant and highly uncertain consideration, capable of substantially increasing demand when included as a sensitivity in reliability studies, with nearly 400 MW of data mining load expected by 2025. These loads often exhibit unpredictable behavior, with some shifting to 24/7 operation, flattening the overnight load curve and extending peak periods, which complicates traditional peak-centric planning. Large commercial and industrial loads are expected to contribute to energy growth in specific economic development areas. Electrification trends are emerging slowly, with limited current impact on forecasts, though home heating electrification is notably contributing to increased winter peak sensitivity. Beyond the 10-year horizon, transportation electrification is anticipated to become a more significant driver of load growth. The influence of climate change and extreme weather on load forecasting is modest in most cases, with some utilities refining models to reflect more frequent cold weather patterns. Recent winter events, like Winter Storm Elliott, have led to updates in load shapes used in modeling, reflecting higher and more sustained loads even outside traditional peak hours. EE improvements are occurring but are not yet deemed a significant overall impact, and flexible or price-sensitive loads are typically modeled on the supply side, thus excluded from direct demand forecasts.

Demand-Side Management

Depending on the entity, DSM could be a voluntary DSM water heater program, which allows for limited control of appliance usage during peak demand periods, with the number of installed control switches tracked monthly to forecast future participation. Load research data is used to estimate the diversified load contribution from these devices. While the entity is monitoring how new EE regulations may impact program effectiveness and developing a DSM measurement and verification (M&V) framework, its analysis currently relies on historical load research data. DR resources under contract are monitored and dispatched, and annual ELCC simulations determine the capacity value of each active DR program. BTM DERs are accounted for within annual load forecasts, while front-of-the-meter (FTM) DERs are treated as generation assets. The entity is also exploring new DR and flexibility programs, including pilot efforts in commercial and industrial automated DR and solar-plus-storage, and implementing a DERMS to enable broader coordination. No modifications to DR methodologies or assumptions have been made since the *2024 LTRA*, but new pilot programs and system capabilities are actively being developed. For EE and conservation, no significant changes have occurred in measurement or accounting since the prior LTRA. EE impacts are generally incorporated through adjustments to load forecasts based on federal and state efficiency standards, appliance saturation trends, and building code updates, reflected in econometric models or end-use forecasts that estimate reduced energy consumption over time.

Distributed Energy Resources

The estimated penetration of DERs in the Southeast assessment area remains modest, with forecasts projecting 1–1.5% of peak load over the next five years and staying below 2% over a 10-year horizon. Specifically, BTM solar PV is expected to grow from 57 MW by 2030 to 120 MW by 2035. Currently, DERs and rooftop solar are considered to have minimal impact on overall reliability, with no emerging transmission or resource adequacy issues directly attributed to them anticipated for Summer 2025.

In terms of planning, BTM DERs are accounted for within annual load forecasts and are not explicitly modeled as discrete capacity resources. Instead, they are represented using hourly generation profiles to account for operational factors like ramping, and estimated generation is placed back onto load buses when installations reach or exceed 2 MW. Conversely, FTM DERs are treated as generation assets. While BTM solar is contributing to energy availability and reducing fossil fuel consumption, their limited capacity value and variability are creating challenges, particularly during the sunrise and sunset hours, requiring greater flexibility from non-solar resources. Solar-related ramping concerns and energy adequacy under evolving weather conditions are considered emerging reliability challenges, which are actively being studied through triennial renewable integration studies. Load forecast uncertainty related to DERs is addressed by considering their potential effects in sensitivity scenarios, such as assuming zero DER contribution under stress conditions.

Generation

The Southeast assessment area actively manages its generation portfolio to ensure reliability amid a changing resource mix, with particular focus on the increasing integration of utility-scale solar and other VERs. While current renewable penetration is modest, leading to no significant stability or inertia issues observed to date, future challenges like intra-hour volatility and ramping needs are being proactively evaluated. The Renewable Cost and Benefit (RCB) Framework is utilized to assess integration costs and identify mitigation strategies such as flexible backup resources.

Regarding net demand ramping, the assessment area does not currently identify any emerging issues due to the limited penetration of VERs and a robust, flexible generation portfolio primarily composed of natural gas units. Annual analysis of five-minute ramping data is conducted to inform regulating reserve requirements, and existing natural-gas-fired units, supported by firm fuel supply and fuel-switching capabilities, are deemed sufficient to meet current and projected ramping needs.

Capacity contribution values for VERs like solar and wind are determined using a combination of historical performance data and ELCC analyses via the SERVM reliability and production cost model. For solar, contributions are initially set at 50% of nameplate capacity during May–September, with annual re-evaluation based on actual performance, though no contribution is assigned in winter due to the assessment area's winter peak planning season. An ELCC study in 2024 notably increased solar peak credit for up to 340 MW of solar capacity. While energy storage resources are evaluated through ELCC, with a preferred minimum duration of two hours, no operational storage resources are currently on the system. Hydro resources are credited at 100% due to firm delivery contracts.

Efforts to address IBR performance issues include enhanced interconnection studies that assess various factors like thermal loading, voltage stability, and short circuit performance. EMT models are now required from Generator Owners to better simulate and understand IBR behavior during disturbances, and mitigations include adjusting ramp rates and enforcing ride-through requirements. Additional phasor measurement units (PMU) are being deployed to enhance real-time situational awareness, particularly at IBR interconnection points. While current IBR penetration is low, network impacts and protection coordination are identified as the primary reliability concerns being addressed.

Generator retirements have seen no changes to confirmed or unconfirmed projections since the *2024 LTRA*, with no unit retirements currently projected over the 10-year planning horizon. All native generation, including coal, natural gas, and nuclear resources, is expected to remain available to meet peak demands. Planning entities have established processes involving detailed studies over a 10- to 20-year horizon to assess potential reliability impacts of retirements, considering mitigations such as transmission infrastructure capital improvements or dynamic VAR support. The IRP process coordinates retirement schedules with the addition of replacement capacity to prevent reliability gaps.

Natural gas fuel supply risk is actively managed, with approximately 78% of winter on-peak natural gas generation capacity having either firm fuel supply arrangements or backup fuel options like oil or dual-fuel capability. Annual gas pipeline failure studies are conducted ahead of each summer and winter season to assess impacts under various curtailment scenarios. Communication protocols between electric system operators and natural gas operators are maintained for coordinated responses. Long-term planning processes incorporate fuel risk through load capability analysis and production cost modeling over a 20-year horizon, ensuring capacity plans meet PRMs.

Energy Storage

While there are currently no operational energy storage resources on the system in the Southeast assessment area, future plans do include the addition of solar and battery resources by 2029. BESS are recognized as IBRs that, like solar, require different modeling and analysis techniques compared to traditional synchronous generation. The uncertainty surrounding the future locations and generation outputs of new BESS is noted as a factor that complicates proactive planning.

For planning purposes, energy storage resources are primarily evaluated for their capacity contribution through ELCC analyses. A preferred minimum duration of two hours is considered for operational reliability when evaluating energy storage resources, although there is no formal duration requirement currently enforced. Pilot programs are also being explored, specifically solar-plus-storage initiatives, as new DR and flexibility programs. These programs aim to provide flexible capacity and fast-start capabilities to the system.

No major methodology modifications have been made to the methods or assumptions for incorporating energy storage since the *2024 LTRA*.

Capacity Transfers

Capacity transfers are important for reliability in the Southeast assessment area and the SERC Region. System adequacy is maintained through planning studies and coordination with neighbors to manage evolving energy needs and maintain regional reliability.

Currently, surplus capacity for transfer and delivery is anticipated to remain available to meet reliability margins and support marketing opportunities. Transmission flow patterns are becoming more dynamic due to shifts in internal and external resource portfolios, retirements, additions, and system topology adjustments, but no significant impacts to firm transmission contracts have been

identified to date. Furthermore, recent reserve margin studies suggest that current transmission capabilities do not pose a constraint on resource adequacy within the assessment area.

To facilitate and ensure reliable capacity transfers, the assessment area engages in extensive coordinated efforts, studies, and protocols with neighboring assessment areas for both peak and non-peak hours. These coordinated efforts include:

- **Joint Transmission Planning Studies**, such as the Southeast Regional Transmission Planning (SERTP) process, which evaluate the BPS's ability to support transfers under various seasonal and system conditions, accounting for projected load growth, generation changes, and transmission upgrades.
- **Firm Transfer Agreements and Modeling**, which are integrated into seasonal and long-range planning studies to ensure deliverability under normal and contingency conditions. These agreements are regularly reviewed and updated.
- **Seasonal Coordination Studies**, including power flow, stability, and transfer capability analyses, conducted prior to each summer and winter season to assess the ability to maintain reliability and meet transfer obligations under expected and extreme conditions.
- **Contingency and Emergency Protocols** with neighboring BA and Reliability Coordinators to support emergency situations and real-time transfers. These protocols are exercised through reliability drills and supported by tools like dynamic line ratings and real-time data sharing.
- **Reserve Sharing and Balancing Arrangements** that enable entities within the assessment area to share generation reserves during system events or peak demand periods, supporting both operational reliability and economic efficiency.
- **Real-Time Operational Coordination** where neighboring areas monitor real-time flows and manage congestion through dynamic scheduling, redispatch strategies, and curtailment procedures as necessary.
- **Coordinated use of the Open Access Same-Time Information System (OASIS)** to ensure transparency and proper scheduling of transfers, preventing violations of reliability standards or operational issues.

Despite these robust coordination mechanisms, energy risk assessments have highlighted certain limitations regarding external reliance, particularly during extreme conditions. Studies, including the RMS, have modeled interactions with 13 neighboring systems to understand the limits of market support during high risk periods. These assessments indicate that regional transmission constraints can hinder economic and emergency imports, potentially exacerbating local energy shortages during widespread events. Furthermore, studies suggest limited excess market generation availability during extreme weather events in the Southeast, underscoring the critical importance of internal resource adequacy planning.

In terms of future reliance, while the overall trend suggests sufficient internal capacity, one utility expects to potentially make capacity purchases of up to 370 MW to serve possible data mining loads over the next four years. This indicates a willingness to utilize external purchases to meet specific, potentially high-density and unpredictable, new loads. The results of energy risk assessments are used to inform capacity expansion plans and determine the need for additional capacity purchases.

Transmission

Entities within the assessment area have numerous transmission projects planned or underway over the next 10 years to support system reliability and address evolving load and generation needs. These projects include approximately 1,308 miles of new transmission lines above 100 kV, 1,322 miles of line rebuilds, around 20 reactive compensation installations, 50 new transmission stations, and various upgrades to increase the capacity of existing infrastructure. One entity plans to retire a 46 kV transmission path and convert affected delivery points to 115 kV service, constructing a new network line to address localized thermal constraints and improve contingency performance. Power electronic devices such as reactive compensation systems are being installed to enhance voltage stability and system performance. While no major transmission adequacy issues have been identified, there are risks of project delays due to supply chain disruptions and contractor availability. Mitigation measures include staggered project timelines, strategic inventory management, and evaluation of interim technologies like variable line impedance devices. Overall, the assessment area maintains a coordinated and proactive transmission planning approach to ensure continued reliability across the region. Since the *2024 LTRA*, planning entities across the assessment area have begun implementing or exploring several enhancements to their transmission planning processes in response to evolving reliability, resource mix, and regulatory conditions. One key area of focus is the growing presence of IBRs, such as solar and battery storage, which require different modeling and analysis techniques compared to traditional synchronous generation. Entities are now incorporating additional scenarios into their long-term planning to assess the adequacy of the transmission system under various levels of IBR penetration, particularly in areas experiencing rapid deployment of utility-scale renewables.

Another significant development involves planning for large data center loads, which present unique challenges due to their high energy consumption and sensitivity to power quality. Entities are preparing to implement new technical studies—such as dynamic modeling and harmonic analysis—to ensure that these loads can be reliably served without compromising grid stability. These studies are expected to become increasingly important over the next 10 years as data centers proliferate across the region. While there have been no wholesale changes to core transmission planning methodologies, adjustments are being made to better reflect recent operating experiences. For

example, entities have refined the load levels used in extreme case scenarios to align more closely with observed peak events. There is also growing interest in performing comprehensive gas-electric interdependency studies to assess the risks posed by natural gas supply disruptions to gas-fired generation resources.

For non-FERC-jurisdictional entities, FERC Order No. 2023 is being monitored, and although compliance is not mandatory, potential alignment with its principles—such as improved generator interconnection procedures and enhanced transparency in queue management—is being considered.

Regional coordination remains a critical component of transmission planning. Entities continue to work closely with first-tier neighbors through long-term, quarterly, and weekly coordination protocols. Interface transfer capabilities are calculated regularly on monthly and two-day-out bases, with requests managed through the OASIS system. Coordination of transfer capability assessments and planning assumptions is also carried out through interregional forums, such as the SERC Long-Term and Near-Term Working Groups and the Southeastern Regional Transmission Planning process. These efforts ensure that planned projects and operational practices are aligned across the region, helping to maintain reliability as system conditions evolve.

Reliability Issues

The Southeast assessment area actively manages its generation portfolio to ensure reliability amidst a changing resource mix. While no significant stability or inertia issues have been observed to date due to the current modest renewable penetration, several evolving reliability concerns are being proactively addressed:

- **Elevated Winter Energy Risk and Sustained Overnight Loads**: Energy risk assessments consistently identify winter peak hours as the highest-risk period for energy shortfalls. This increased risk is driven by two primary factors: volatile peak demand due to extreme cold weather events exceeding forecasts, and sustained overnight load where demand remains high throughout the evening and early morning. Recent winter events, such as Winter Storm Elliott, have led to updated load shapes that reflect higher and more sustained loads, underscoring the importance of energy adequacy beyond just peak periods. This indicates a shift requiring more continuous energy coverage rather than just peak-hour capacity.
- **Natural Gas Fuel Supply Vulnerability**: Fuel availability, particularly for natural gas, has emerged as a significant energy risk. To mitigate this, entities in the assessment area actively manage natural gas fuel supply risk through firm fuel arrangements, backup capabilities like onsite fuel storage or dual-fuel options (e.g., oil), and annual gas pipeline failure studies conducted before each summer and winter season. Communication protocols are also maintained between electric and natural gas system operators for routine and contingency operations. Long-term planning studies also incorporate considerations for gas production limitations and transportation bottlenecks.
- **Challenges Posed by Large Industrial and Commercial Load Additions**: The assessment area is experiencing an increasing demand of large industrial and commercial load additions, such as data centers and crypto mining facilities, which require enhanced coordination, especially with local distribution cooperatives. These loads can “substantially increase demand” and exhibit unpredictable behavior, with some shifting to 24/7 operation and relying on short-term capacity purchases. Entities are proactively developing updated technical interconnection requirements and pursuing regulatory approvals to procure additional generation to serve these new loads.

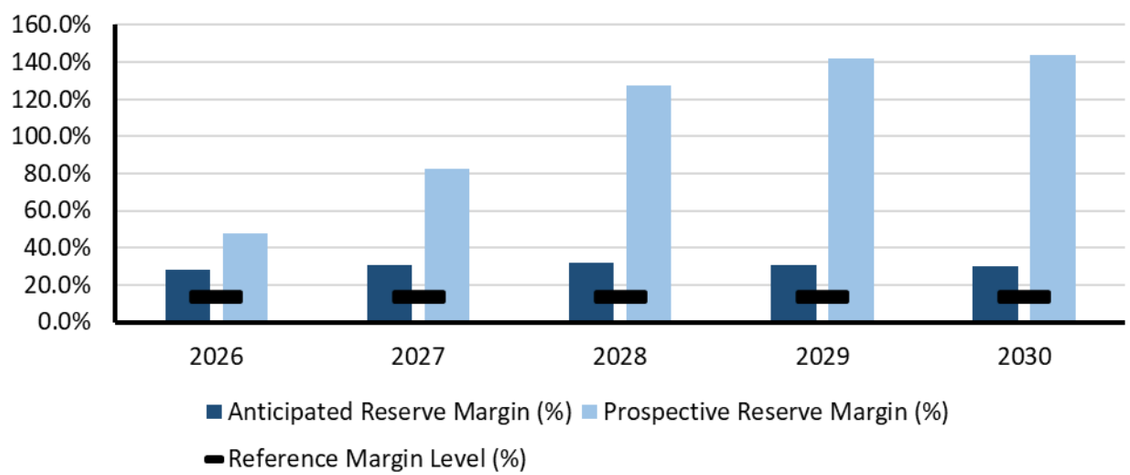


Texas RE-ERCOT

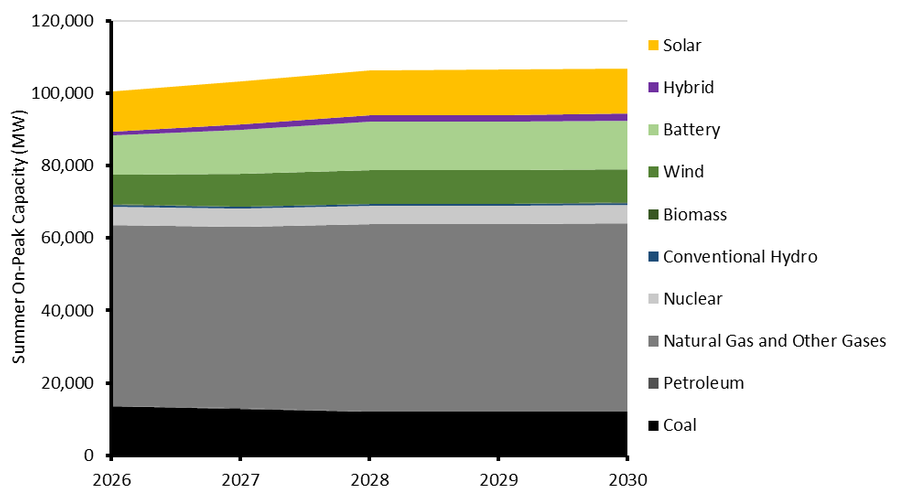
The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the PUCT and the Texas Legislature. ERCOT is summer-peaking. It covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 million people. Lubbock Power & Light joined the ERCOT grid on June 1, 2021. Texas Reliability Entity is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT.

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	94,650	104,295	121,543	128,851	138,944	144,522	148,567	149,846	152,230	154,077
Demand Response	13,346	22,127	37,672	43,888	53,131	57,720	60,942	61,846	62,644	63,321
Net Internal Demand	81,304	82,168	83,871	84,963	85,813	86,802	87,625	88,000	89,586	90,756
Additions: Tier 1	10,377	15,216	18,527	19,037	19,037	19,037	19,037	19,037	19,037	19,037
Additions: Tier 2	15,391	42,413	79,923	95,374	98,707	99,018	99,018	99,018	99,018	99,018
Additions: Tier 3	5,022	17,546	36,405	51,080	58,217	58,217	58,463	58,463	58,463	58,463
Net Firm Capacity Transfers	508	659	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122
Existing-Certain and Net Firm Transfers	93,870	92,008	92,046	92,113	92,401	92,401	92,401	92,401	92,401	92,401
Anticipated Reserve Margin (%)	28.2%	30.5%	31.8%	30.8%	29.9%	28.4%	27.2%	26.6%	24.4%	22.8%
Prospective Reserve Margin (%)	47.9%	82.3%	127.3%	142.1%	143.9%	141.5%	139.2%	138.2%	134.0%	131.0%
Reference Margin Level (%)	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%	13.75%



Planning Reserve Margins



Existing and Tier 1 Resources

Texas RE-ERCOT Highlights

- The ARM is above the 13.75% RML for all years and seasons and reflects the inclusion of provisional forecast estimates of large-load curtailment potential, applicable before and during ERCOT emergency conditions.
- ERCOT forecasts total internal demand to increase from 94,650 MW for 2026 to 154,077 MW for 2035, an average annual increase of 5.6%.
- Texas Senate Bill 6, signed into law in June 2025, provides ERCOT with new large-load curtailment management tools and the authority to direct large loads to curtail their load both prior to and during declared energy emergency situations.
  - Offsetting the positive ARM impact of these load management programs is the switch from using historical average on-peak capacity factors to average ELCC for IBRs.
- ERCOT expects battery energy storage capacity to reach 18.9 GW by Summer 2026, growing to 25.2 GW by 2029, which reflects the furthest future year for reported planned commercial operations dates.
- ERCOT's 2024 Regional Transmission Plan (RTP) includes a 345 kV plan and the Texas 765 kV Strategic Transmission Expansion Plan (TX 765-kV STEP), which addresses unprecedented load growth expected by 2030.

Texas RE-ERCOT Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	13,596	12,941	12,156	12,156	12,156
Coal*	13,596	12,550	11,205	11,205	11,205
Petroleum	30	30	30	30	30
Natural Gas	50,032	50,122	51,689	51,689	51,977
Natural Gas*	50,032	49,764	51,331	51,331	51,619
Biomass	131	131	131	131	131
Solar	11,049	11,923	12,305	12,534	12,534
Wind	8,303	8,900	9,215	9,219	9,219
Conventional Hydro	570	570	570	570	570
Nuclear	4,973	4,973	4,973	4,973	4,973
Hybrid	1,127	1,497	1,813	1,909	1,909
Battery	10,734	12,285	13,375	13,374	13,374
Total MW	**100,545**	**103,372**	**106,257**	**106,584**	**106,872**
Total MW*	**100,545**	102,203	104,528	104,855	105,143

***Capacity with additional generator retirements**. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.
**Wind, solar, and battery capacities are based on their projected effective load carrying capabilities during peak load conditions.

Planning Reserve Margins

The ARM is above the 13.75% RML only for summers 2026 and 2027, and winters 2025–26 and 2026–27. The main contributing factor for lower ARMs relative to last year's LTRA is the switch from using historical average on-peak capacity factors to average ELCC for IBRs. In the case of solar, ELCCs are significantly lower than on-peak capacity factors since ELCCs reflect resource reliability value, and in the case of solar, this value has been decreasing as reserve scarcity risk shifts to the evening hours when solar availability is low. Partially offsetting the reduction in solar contribution was the shift from assigning 0% on-peak capacity contribution for battery energy storage to using average ELCCs based on design duration. For example, battery storage systems with a duration of one hour or less are assigned an ELCC of 36%, whereas the ELCC for systems greater than one hour and less than two hours is 69%.

Energy Risk, Including Non-Peak Hour Risk

For non-winter months, ERCOT continues to experience the highest reserve scarcity risk during the early evening hours—peaking at HE 9:00 p.m.—based on probabilistic capacity reserve modeling for monthly peak load days. The elevated risk is due to the drop-off in solar generation and continued higher loads during those hours. However, the large growth in battery energy storage resources and associated changes in state of charge management have mitigated the capacity reserve scarcity risk relative to previous years. For winter, risk modeling indicates elevated reserve scarcity risk for the morning hours (HE 7:00 to 9:00 a.m.) as well as the early evening hours.

Probabilistic Assessments (NERC ProbA and Other Studies)

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	11,090	5,864	17,053
NEUE (ppm)	18.95	8.70	18.84
LOLH (hours per Year)	1.57	0.94	3.64
*** Provides the 2024 ProbA Results for Comparison**			

Like the 2024 ProbA Study, most risk is in the winter, and this is mainly driven by the large demand variability modeled in the winter. By 2029, there is significant risk in the summer and slight risk in the shoulder seasons, driven by the considerable growth of large loads across the year.

12x24 EUE Heat maps (months for the vertical axis, hours for the horizontal axis) for 2027 and 2029 are provided below. Note that as the numbers are given in percentages, the lower winter values in 2029 relative to 2027 do not indicate a decrease in winter risk, just a smaller portion of the annual total.

2027

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	4%	3%	2%	2%	3%	5%	8%	11%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	4%	7%	5%	4%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	2%	2%	2%	2%	2%	3%	4%	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	3%	4%	4%	4%

2029

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	3%	2%	2%	2%	3%	4%	6%	7%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	3%	4%	4%	4%	3%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	0%	0%	0%	0%
7	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	4%	1%	0%	0%
8	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	6%	5%	1%	0%	0%
9	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12	1%	1%	1%	1%	1%	2%	2%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	3%	2%	2%	2%	2%

Demand

ERCOT forecasts summer peak total internal demand to increase from 94,650 MW for 2026 to 154,077 MW for 2035, an average annual increase of 5.6%. This load growth is mainly driven by forecasted interconnections of large loads, comprised mostly of data centers. The breakdown of new large loads added by 2030 by customer classification is as follows:

Load Additions in the Load Forecast (MW) (Cumulative)			
Load Type	**End of Year 2 (2027)**	**End of Year 5 (2030)**	**End of Year 10 (2035)**
Data Centers	**6,700**	**23,000**	**25,000**
Cryptocurrency Mining Facilities	**4,500**	**7,500**	**8,500**
Hydrogen Electrolysis	**3,000**	**7,902**	**9,100**
Industrial Manufacturing Load	**2,800**	**7,100**	**7,600**

For 2025, the ERCOT transmission service providers (TSP) had once again reported a significantly larger-than-normal amount of contracted large loads that they asked to be included in the *2025 Long-Term Load Forecast* and *Regional Transmission Planning Study*. Due to the large amount of large-load requests for 2025, ERCOT has applied adjustment factors to these requests. ERCOT has adjusted the large-load projections provided by the TSPs based on the patterns observed by recent projects. The first adjustment was based on the average project delay of 180 days from the original project requested energization date for projects with in-service dates in 2022 through 2024. The next adjustment was applied to Data Centers. ERCOT studied requested MWs versus the peak consumption by data center site for data centers with in-service dates in 2022 through 2024. The average peak consumption per site was 49.8% of the requested MW. This factor was applied to all non-crypto data center load additions. The final adjustment used the percentage of previously filed officer letter projects with in-service dates in 2024 that have energized (55.4%). This percentage is based on percentage of loads energized.

The PUCT is developing criteria for including large loads in ERCOT's load forecasts along the lines of criteria applicable to generation projects (for example, the large-load customer has executed and securitized an interconnection agreement or meets other criteria demonstrating a firm commitment to interconnecting the load).

Demand-Side Management

Signed into law in June 2025, Texas Senate Bill 6 directs the PUCT to establish uniform large-load interconnection standards that, among other things, provide ERCOT with new large-load curtailment management tools and ERCOT's authority to direct (or require transmission service providers to direct) large loads to curtail their load prior to and during declared energy emergency situations. The following table shows the total large loads and their curtailment amounts included in the "Controllable and Dispatchable Demand Response" line items.

Summer	Total LL (MW)	LL Curtailment (MW)		Winter	Total LL (MW)	LL Curtailment (MW)
2025 (S)	3864.4	1,313.9		2025-26 (W)	9112.9	8,227.7
2026 (S)	12355.4	8,853.5		2026-27 (W)	17289.8	15,909.3
2027 (S)	21665.7	17,171.5		2027-28 (W)	31590.8	29,408.9
2028 (S)	38583.3	32,716.5		2028-29 (W)	45249.3	42,298.1
2029 (S)	45681.1	38,932.6		2029-30 (W)	55533.1	51,981.4
2030 (S)	55964.9	48,175.5		2030-31 (W)	60917.9	57,010.6
2031 (S)	61349.7	52,764.3		2031-32 (W)	64863.6	60,672.7
2032 (S)	65295.4	55,985.9		2032-33 (W)	66370.5	62,017.8
2033 (S)	66802.3	56,890.6		2033-34 (W)	67764.7	63,256.0
2034 (S)	68196.5	57,688.4		2034-35 (W)	69032.1	64,373.6
2035 (S)	69463.9	58,365.6		2035-36 (W)	69805.1	65,043.3

Distributed Energy Resources

DERs that register with ERCOT to participate in wholesale energy and/or ancillary services markets are modeled and dispatched in ERCOT transmission planning studies similarly to transmission-connected resources participating in those markets. For DERs not participating in those markets, ERCOT relies on member Transmission and Distribution Service Providers (TDSPs) to provide information about individual DERs on their systems for shorter-term reliability and economic impact studies, typically a one-to-six-year time frame.

ERCOT has proposed rule changes mandated by the Texas Legislature to establish a process to collect comprehensive data from Distribution Service Providers for so called "Unregistered Distributed Generators" (primarily rooftop solar systems). The data will be collected on a substation level and will include information to be used for network modeling and analysis, including aggregate reactive power capability and status of PUCT voltage/frequency ride-through requirements.

Generation

In 2024, ERCOT received notices of suspension of operations for three gas-steam units in the San Antonio area. Reliability impact studies indicated that all three were needed to manage the South Texas Interconnection Reliability Operating Limit (IROL) established in 2024. As a result, ERCOT signed

a two-year "Reliability Must Run" (RMR) agreement with CPS energy for one of the three generators (Unit 3). This generator, as part of its RMR service obligation, would only operate when necessary to provide voltage support, stability, or management of localized transmission constraints when a market solution does not exist. ERCOT also signed a contract in June 2025 to use 15 mobile generators that are being relocated from Houston to the San Antonio area. The contract ends in March 2027 when transmission solutions are expected to be in place to offset the loss of the mothballed CPS generating units.

New rules became effective in October 2024 to improve IBR ride-through performance and monitoring and mitigation efforts. The rules were developed in response to NERC recommendations following IBR failures during system disturbances in West Texas. The new ride-through requirements align with the specifications of the updated IEEE 2800-2022 standard, which addresses the interconnection and interoperability of IBRs. As part of the new rules, IBR entities are required to maximize their IBR ride-through capabilities, which includes making software, firmware, and settings adjustments, and potentially physical modifications to ensure that they can remain connected to the grid during frequency and voltage disturbances. The rules also establish a process for investigating, reporting, and mitigating ride-through performance failures, requiring resource entities to develop mitigation plans within a defined timeline. IBR entities must meet the new requirements by December 31, 2025, or their synchronization date, subject to an extension/exemption process.

During 2024, units totaling 18.6 MW were retired, comprising a 9.6 MW biomass facility, a 7 MW wind site, and 2 MW battery storage system. So far in 2025, a 62 MW gas combined-cycle unit was retired.

Energy Storage

ERCOT expects battery energy storage capacity to reach 18.9 GW by summer 2026 (Existing and Tier 1 resource categories). The capacity grows to 25.2 GW by 2029, which reflects the furthest future year for planned commercial operations dates reported by project developers.

ERCOT is moving away from a dual to an integrated single model of an energy storage resource for operational and transmission planning studies. Under the dual approach, an energy storage resource is composed of a generator with a negative minimum power to represent consumption and a generator with a positive maximum power to represent injection. The single "integrated" generator model, along with other system enhancements for battery energy storage, is being implemented as part of ERCOT's "Real Time Co-Optimization + Battery" project, expected to be implemented by December 2025. Since each resource receives independent dispatch instructions and ancillary service deployments in the dual model approach, moving to a single integrated resource model will eliminate current performance monitoring issues. The discharging behavior for all energy storage resources is considered for peak cases in transmission planning studies. The charging behavior for all energy storage resources is considered for minimum load cases in transmission planning studies. Energy storage resources, if required to provide voltage support, need to have the reactive power capability be available at all MW levels when charging or discharging and meet the voltage ride-through requirements to remain connected to the system. To support larger penetration levels of energy storage resources, new rules have been implemented to improve state-of-charge monitoring in energy dispatch and Reliability Unit Commitment.

Capacity Transfers (Reliance on Assistance)

ERCOT has coordination plans in place with neighboring grids. These plans cover DC tie emergency operations, procedures for generators that can switch between grids, and temporary block load transfers. For its transmission planning studies, ERCOT tests the outage of each of the ERCOT-SPP DC ties, plus a contingency on top of that, to ensure no reliability issues post-contingency. There are no severe scenarios studied where multiple DC ties are assumed to be unavailable.

Transmission

ERCOT's 2024 RTP includes a 345 kV plan and a 765 kV plan, called the Texas 765-kV Strategic Transmission Expansion Plan (TX 765-kV STEP). The 765-kV plan tackles the unprecedented load growth expected by 2030 and associated regional planning challenges and addresses existing congestion issues. TX 765-kV STEP enhances transfer capability by an additional 600 to 3,000 MW across various scenarios evaluated in the analysis and would also increase the West Texas export stability constraints. The 765 kV addition enables power to flow more efficiently through long-distance transmission from resource-rich regions to load centers. Overall, 274 reliability projects were identified in the 2024 RTP's 345 kV plan to address all reliability violations compared with 173 projects in the 2023 RTP, 89 projects in the 2022 RTP, 67 projects in the 2021 RTP, and 50 projects in the 2020 RTP. This upward trend reflects grid infrastructure needed to support rapidly growing power demands and an evolving generation resource mix.

ERCOT is adopting changes to its planning processes to address the long-term transmission challenges. Examples of the major changes include establishment of a new congestion cost savings test for economic project evaluation, establishment of resiliency criteria for the ERCOT region, and development of new multi-value criteria to address the process for determining whether a project that addresses a resiliency issue provides sufficient benefit balanced with economic savings or reliability benefits.

Reliability Issues

There are several reliability concerns associated with the rapid growth in large loads:

Loss of Load: Due to the amount of large electronic-based load projected to energize in upcoming years (mainly from cryptocurrency mining facilities), ERCOT is concerned that potentially thousands of megawatts of load can instantly drop or switch to backup generation during normally cleared system faults, thereby posing significant risks to system reliability. To address this concern, ERCOT has proposed a change to its Reliability Performance Criteria to limit load loss for any single contingency and to specify how loss of load is calculated for this criterion. ERCOT recently completed a Load Loss Threshold Analysis that indicates that the load loss should be limited to 2,600 MW.

Load Forecasting Challenges: The flexible operation of large loads also presents challenges for accurate load forecasting and monitoring. ERCOT has observed increasing errors in its load forecasts, which is problematic during extreme or unusual operating days when having an accurate forecast is most critical for maintaining reliability. New approved rules include standards for the identification and classification of a site with an aggregate peak demand of 25 MW or more at a common substation in ERCOT's Network Operations Model. Such information will provide ERCOT visibility of the locations of these loads for operational, modeling, and planning purposes.

Potential Subsynchronous Oscillation Vulnerabilities: Large loads, particularly those with high reactive power consumption, can cause subsynchronous oscillation (SSO) that can damage generation and other equipment and ultimately destabilize the grid. This vulnerability is highest in areas with a weak grid, such as West Texas. To address SSO issues, ERCOT is implementing new rules that require SSO vulnerability assessments for large-load customers seeking grid interconnection as well as for transmission projects.

Need for a Large Load Interconnection Study Process: ERCOT identified the need for a Large Load Interconnection Study (LLIS) process several years ago due to the emerging reliability impacts. An interim process was estimated in March 2022. A final interconnection process was approved by the PUCT in May 2025.

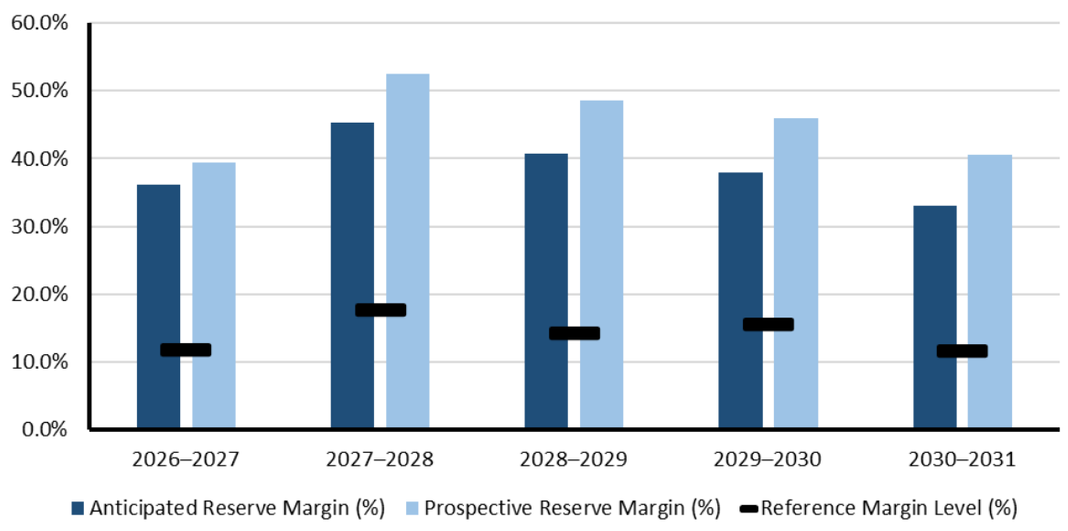


WECC-Alberta

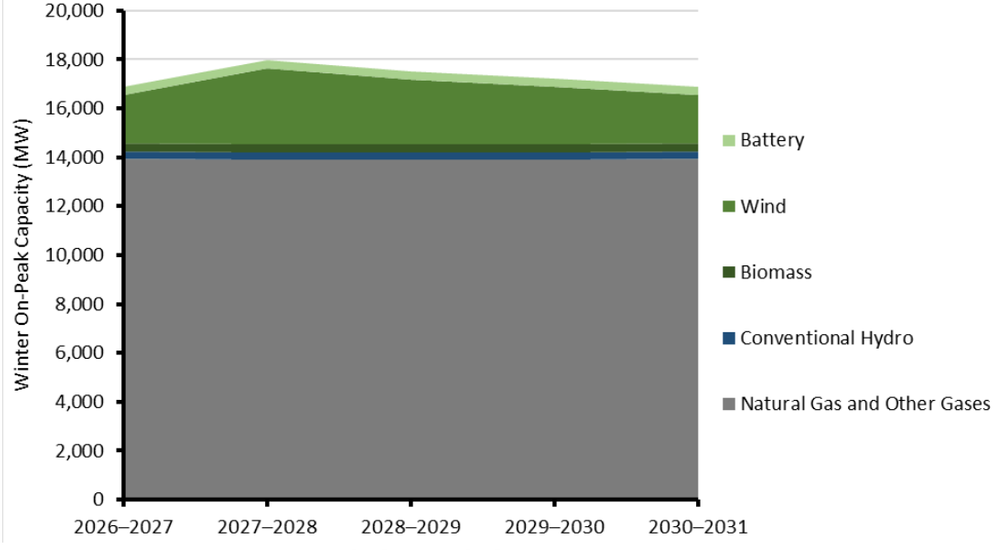
WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province's Planning Entity and Reliability Coordinator responsible for safe, reliable, and economic operation of the Alberta Interconnected Electric System. AESO is a non-profit corporation that operates a system that includes approximately 26,000 kilometers of transmission lines and connects approximately 426 qualified generating units and nearly 250 market participants through a wholesale market. Alberta's transmission system has three interties with neighboring areas—Saskatchewan (see MRO-SaskPower), British Columbia (see WECC-British Columbia), and Montana (see WECC-Northwest). Peak electricity demand on the AESO system currently occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076	13,470
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	12,463	12,434	12,510	12,528	12,759	12,831	12,956	12,992	13,076	13,470
Additions: Tier 1	209	209	209	209	209	209	209	209	209	209
Additions: Tier 2	393	889	983	1,009	959	1,009	921	971	971	971
Additions: Tier 3	392	658	917	1,297	1,334	1,631	1,635	1,751	1,751	1,751
Net Capacity Transfers (WECC Model)	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Transfers	16,764	17,856	17,394	17,074	16,764	17,074	16,502	16,820	16,820	16,820
Anticipated Reserve Margin (%)	36.2%	45.3%	40.7%	38.0%	33.0%	34.7%	29.0%	31.1%	30.2%	26.4%
Prospective Reserve Margin (%)	39.3%	52.4%	48.6%	46.0%	40.5%	42.6%	36.1%	38.5%	37.7%	33.6%
Reference Margin Level (%)	11.8%	17.6%	14.3%	15.6%	11.6%	15.2%	12.2%	14.3%	13.9%	13.5%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Alberta Highlights

- WECC-Alberta's ARM does not fall below the RML during the 2025–2035 time frame.
- WECC-Alberta's total electricity demand is projected to grow by 10% over the next 10 years. Summer peak hour demand is projected to grow by 7%, and winter peak hour demand is projected to grow by 11% over the same period.
- Alberta is anticipated to add 556 MW of Tier 1 gas, solar, and battery resources over the next 10 years. Alberta's thermal power generation fleet is aging, and significant additions of Tier 2 and 3 variable renewable energy resources are being proposed to make up for forthcoming thermal retirements while meeting Alberta's 30% renewable by 2030 policy requirement. On top of the 250 MW of existing storage, 88 MW are anticipated Tier 1 and 370 MW are Tier 2 additions over the next 10 years. Still, rapid declines in solar and wind output could cause ramping issues in the future and require the use of contingent reserves and assistance from the NWPP Reserve Sharing Group.
- AESO has recently added two transmission lines to its system to increase reliability and integrate fossil-fired generation additions.
- Under a different set of assumptions and with a different vintage of data from the LTRA, the NERC ITCS for Canada concluded that WECC-Alberta may have winter energy deficiencies that could be alleviated by increased transfer capabilities.

WECC-AB Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Natural Gas	13,932	13,908	13,890	13,900	13,932
Biomass	336	336	335	336	336
Wind	2,000	3,109	2,665	2,327	2,000
Conventional Hydro	293	301	301	310	293
Other	81	81	81	81	81
Battery	330	330	329	330	330
Total MW	16,973	18,065	17,602	17,283	16,973

WECC-Alberta Assessment

Planning Reserve Margins
WECC-Alberta's ARM does not fall below the RML during the 2025-2035 time frame. WECC continues to use a probabilistic approach for determining RMLs, holding a LOLP less than or equal to 0.02% (approximately a 1 day in 10 years loss of load). The model determines what reserve margin must be held to maintain a fixed LOLP. Using this technique, a target reserve margin is evaluated for every hour of every year of the full forecast period.

There have, however, been changes to policies that might affect planning and procurement over the next 10 years. The Canada Clean Electricity Regulations (CER) were finalized in December 2024, which delayed the nationwide net-zero electricity target from 2035 to 2050. Alberta has recently entered into an agreement with the Canadian federal government to pursue alternative policies to achieve a net-zero power grid by 2050.

Energy Risk, Including Non-Peak Hour Risk
AESO uses an hourly probabilistic model to quantify uncertainties around unit availability, dispatch economics, load variability, and weather impact on load and generation in operational time frames.

ProbA Results

Alberta does not show any LOLH or EUE in 2027 or 2029 and therefore does not have any further reporting or visualizations.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	0	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
*** Provides the 2024 ProbA Results for Comparison**			

Demand
Alberta's annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 7% and winter peak hour demand is projected to grow 11% over the same period. The primary driver for demand growth in Alberta is transportation electrification. Large-load additions in the forecast total 80 MW over the next five years and 105 MW through 2035. Additional large loads that may materialize and are not included in the forecast amount to 1,600 MW by 2030 and 2,100 by 2035.

Seasonally, the region is becoming more dual-peaking with summers almost matching winters.

Demand-Side Management
AESO factors in approximately 250 MW of DSM in its load forecast and this is projected to remain steady across the 10-year assessment period.

Generation
Alberta is anticipated to add 556 MW (nameplate capacity) of Tier 1 gas, solar, and battery resources over the next 10 years. Tier 2 additions include nearly 5 GW of gas, solar, wind and batteries and Tier 3 additions include just over 5 GW of gas, solar, wind, conventional hydro, and batteries. Operational and planning issues related to generation in WECC-Alberta include the following:

- Aging Thermal Resource Fleet: There is ongoing analysis of potentially mothballing aging coal-to-gas boilers. Alberta has five natural gas steam sites over 35 years old, which total 1,745 MW of capacity. Alberta shows significant additions of Tier 2 and Tier 3 solar and wind to make up the difference. Supply shortfalls are addressed using the protocols in AESO's ISO Rules. These protocols include directives such as instructing available assets and long-lead-time assets to deliver energy up to their maximum capability, calling upon DR, and maximizing import capability.
- Solar and Wind Variability: Rapid decline in solar and wind output coupled with off-line thermal resources can create situations in which thermal resources cannot be ramped up in time to counter the loss of renewable generation. The use of contingency reserves coupled with a subsequent grid alert declaration to receive assistance from the NWPP Reserve Sharing Group (NWPPRSG) are options for addressing these situations.
- Electric-Gas Coordination: As a part of WECC's load and resources data request, members were asked to provide a conservative estimate of the percentage of natural gas generating capacity that is likely to have firm supply for 2025 and 2030 for both the summer and winter season. Results indicated that all natural-gas-fired generators connected to AESO's system are fueled through firm gas supply contracts during both the summer and winter seasons but do not report any dual-fuel capacity. To enhance operational reliability of natural gas fuel supplies for the province, Alberta's natural gas operators are part of the Northwest Mutual Assistance Agreement. This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to one another when unplanned events impact the gas supply and transportation system. There is frequent communication between system operators regarding gas resources

that are planned for operation and pipeline representatives regarding the status of pipelines serving the jurisdictions covered by the agreement.

- Resource Portfolio, Clean Electricity, and Development Policies: The Canadian province of Alberta is required to ensure its electricity supply is 30% renewable by 2030. Alberta has also issued a ban on renewable energy project development on prime agricultural land and a buffer zone around pristine views, both of which could limit siting for wind and solar. This followed a temporary moratorium from August 2023 to March 2024 on new renewable approvals, creating investment uncertainty. In January 2025, Alberta lifted a previous 2022 moratorium on coal exploration, reopening 190,000 hectares of land to new coal development.

Energy Storage

In addition to the 250 MW of existing energy storage in Alberta, 88 MW are anticipated Tier 1 additions, and 370 MW are projected Tier 2 additions of energy storage over the next 10 years. Storage in the west is generally being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar.

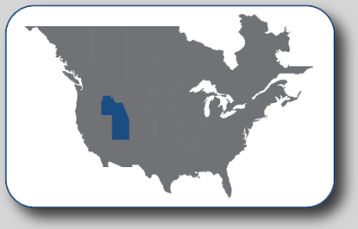
Energy Transfers

According to the NERC's *ITCS Canadian Analysis*, the total simultaneous transfer capability into the Alberta transmission planning region from all its neighbors, including dc-only interties, is 1,096 MW in 2024 Summer and 1,005 MW in 2024–25 Winter. These values translate to approximately 10% of peak summer load and 9% of peak winter load in the analysis years. The two interfaces include connections with the U.S. state of Montana (see WECC-Northwest) and British Columbia (see WECC-British Columbia).

The ITCS for Canada further showed that WECC-Alberta may have winter energy deficiencies that can be alleviated with increased transfer capabilities.

Transmission

In 2024, Alberta added two transmission lines for fossil-fired integration. The reported primary driver for transmission expansion in Alberta is reliability.

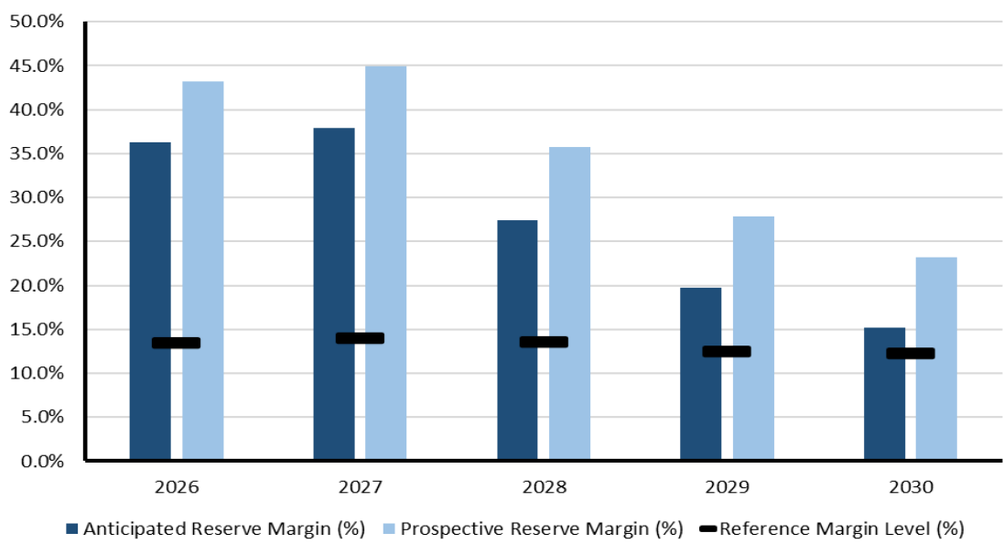


WECC-Basin

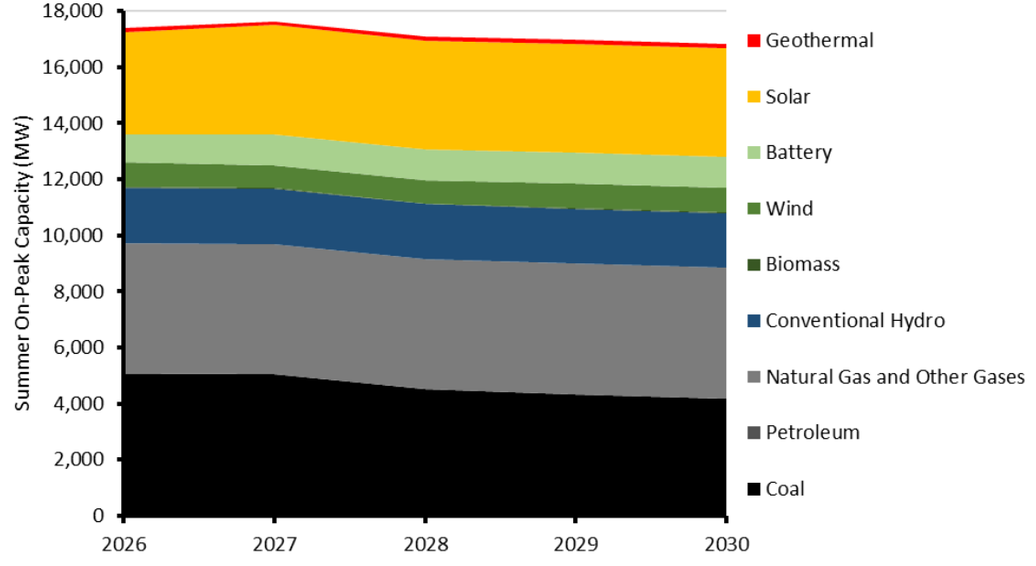
WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern BA area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	14,794	15,326	16,012	16,396	16,762	17,099	17,202	17,268	17,344	17,467
Demand Response	670	670	670	670	670	670	670	670	670	670
Net Internal Demand	14,124	14,656	15,342	15,726	16,092	16,429	16,532	16,598	16,674	16,797
Additions: Tier 1	2,125	2,453	2,453	2,466	2,466	2,466	2,466	2,453	2,466	2,466
Additions: Tier 2	973	1,018	1,270	1,279	1,279	1,279	1,279	1,270	1,279	1,279
Additions: Tier 3	127	1,162	2,024	2,616	4,209	4,726	5,665	6,203	6,332	6,332
Net Capacity Transfers (WECC Model)	1,822	2,545	2,420	1,820	1,698	1,400	1,400	1,400	1,400	1,400
Existing-Certain and Net Transfers	17,125	17,763	17,097	16,357	16,071	15,736	15,729	15,315	15,288	15,280
Anticipated Reserve Margin (%)	36.3%	37.9%	27.4%	19.7%	15.2%	10.8%	10.1%	7.1%	6.5%	5.7%
Prospective Reserve Margin (%)	43.2%	44.9%	35.7%	27.8%	23.1%	18.6%	17.8%	14.7%	14.2%	13.3%
Reference Margin Level (%)	13.5%	14.0%	13.6%	12.4%	12.3%	12.1%	12.1%	12.5%	11.8%	11.8%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Basin Highlights

- The ARM does not fall below the RML during the 2025–2035 time frame. IPCO and PACE participate in the Western Resource Adequacy Program (WRAP).
- The Basin subregion shows three LOLH in 2027 totaling approximately 3 MWh of EUE in June and July at hours beginning 18:00 and 19:00. In 2029, the subregion shows 310 LOLH totaling approximately 200,892 MWh of unserved energy. Over 90% of the EUE occurs between the hours of 17:00–22:00 from June to September.
- For 2027 and 2029, the peak hour is projected to occur in July at hour beginning 15:00.
- The LOLH in 2027 and 2029 coincides with the evening solar down ramp and the persistence of elevated demand after peak.

WECC-Basin Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	5,068	5,041	4,508	4,326	4,177
Petroleum	5	5	5	5	5
Natural Gas	4,655	4,634	4,634	4,655	4,655
Biomass	31	31	31	31	31
Solar	3,668	3,899	3,899	3,884	3,884
Wind	900	826	826	897	882
Geothermal	139	139	139	139	139
Conventional Hydro	1,962	1,976	1,968	1,954	1,954
Other	31	31	31	19	19
Battery	967	1,090	1,090	1,092	1,092
Total MW	**17,428**	**17,672**	**17,130**	**17,003**	**16,839**

WECC-Basin Assessment

Planning Reserve Margins

The ARM does not fall below the RML during the 2026–2035 time frame. The Idaho Power and PacificCorp East balancing areas both participate in WRAP, the first regional reliability planning and compliance program in the West.

Energy Assessment, Including Non-Peak Hour Risk

WECC performs a probabilistic resource adequacy analysis using the Multiple Area Variable Resource Integration Convolution model (MAVRIC). MAVRIC is WECC's internally developed modeling tool that performs energy based ProbAs that support NERC's LTRA and seasonal assessments, as well as WECC's Western Assessment of Resource Adequacy (WARA).

Although the WECC-Basin assessment area's ARM does not fall below the RML during the 2026–2035 time frame and indicates substantial surplus, the ProbA results indicate significant EUE and LOLH. As resource additions struggle to keep up with rising demand and expected generator retirements, reflected in falling ARMs after 2027, unserved energy and load-loss increase in the ProbA results. The LOLH in 2027 and 2029 coincides with the evening solar down ramp and the persistence of elevated demand after peak.

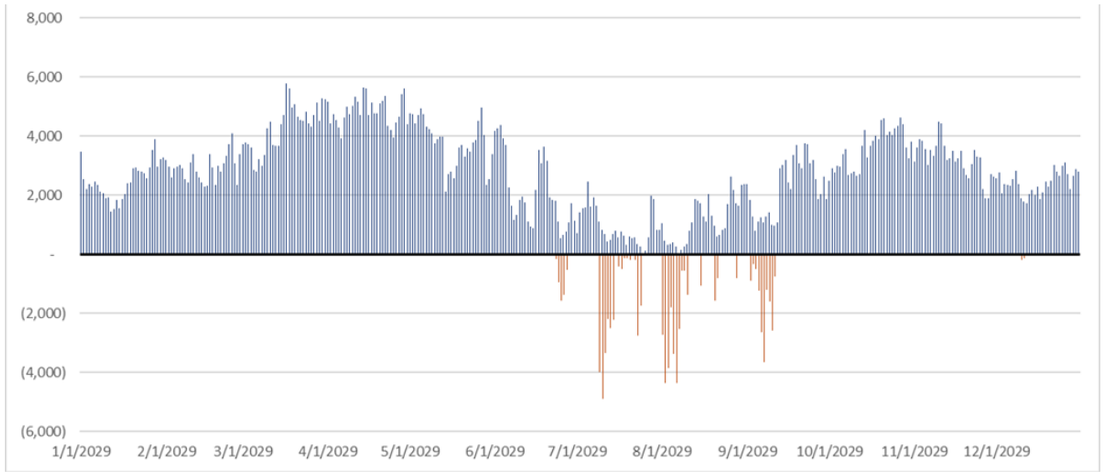
Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	N/A	3	200,892
NEUE (ppm)	N/A	0.04	2250.70
LOLH (hours per Year)	N/A	3.00	310.00
*** No prior results as the assessment area is new for the 2025 LTRA.**			

The risk of shortfall in the WECC-Basin area is concentrated in the summer months when seasonal electricity demand is highest. In the ProbA results illustrated in the following heat map figure, risk is most concentrated to the month of peak demand (June) and the hours around sunset as solar output declines. The values in the heat map are the number of hours from the MAVRIC simulations that resources fall short of demand and reliability margins in the study year. For 2029, as planned retirements of coal-fired generation and all currently projected resource additions are reflected in the resource mix, risk periods expand across all summer months, and the hours of risk extend from midday to nighttime.

Basin - 2027		Months												Basin - 2029		Months											
Existing + Tier 1		1	2	3	4	5	6	7	8	9	10	11	12	Existing + Tier 1		1	2	3	4	5	6	7	8	9	10	11	12
Hour Beginning	0	0	0	0	0	0	0	0	0	0	0	0	0	Hour Beginning	0	0	0	0	0	0	0	0	0	0	0	0	0
	1	0	0	0	0	0	0	0	0	0	0	0	0		1	0	0	0	0	0	0	0	0	0	0	0	0
	2	0	0	0	0	0	0	0	0	0	0	0	0		2	0	0	0	0	0	0	0	0	0	0	0	0
	3	0	0	0	0	0	0	0	0	0	0	0	0		3	0	0	0	0	0	0	0	0	0	0	0	0
	4	0	0	0	0	0	0	0	0	0	0	0	0		4	0	0	0	0	0	0	0	0	0	0	0	0
	5	0	0	0	0	0	0	0	0	0	0	0	0		5	0	0	0	0	0	0	0	0	0	0	0	0
	6	0	0	0	0	0	0	0	0	0	0	0	0		6	0	0	0	0	0	0	0	0	0	0	0	1
	7	0	0	0	0	0	0	0	0	0	0	0	0		7	0	0	0	0	0	0	0	1	0	0	0	2
	8	0	0	0	0	0	0	0	0	0	0	0	0		8	0	0	0	0	0	0	0	1	0	0	0	2
	9	0	0	0	0	0	0	0	0	0	0	0	0		9	0	0	0	0	0	0	0	0	0	0	0	0
	10	0	0	0	0	0	0	0	0	0	0	0	0		10	0	0	0	0	0	0	0	0	0	0	0	0
	11	0	0	0	0	0	0	0	0	0	0	0	0		11	0	0	0	0	0	0	2	0	0	0	0	0
	12	0	0	0	0	0	0	0	0	0	0	0	0		12	0	0	0	0	0	0	8	1	0	0	0	0
	13	0	0	0	0	0	0	0	0	0	0	0	0		13	0	0	0	0	0	1	9	2	0	0	0	0
	14	0	0	0	0	0	0	0	0	0	0	0	0		14	0	0	0	0	0	2	8	2	1	0	0	0
	15	0	0	0	0	0	0	0	0	0	0	0	0		15	0	0	0	0	0	3	8	3	1	0	0	0
	16	0	0	0	0	0	0	0	0	0	0	0	0		16	0	0	0	0	0	2	8	4	6	0	0	3
	17	0	0	0	0	0	0	0	0	0	0	0	0		17	2	0	0	0	0	4	11	14	8	0	0	5
	18	0	0	0	0	0	1	0	0	0	0	0	0		18	0	0	0	0	0	6	16	20	12	0	0	4
	19	0	0	0	0	0	1	1	0	0	0	0	0		19	0	0	0	0	0	7	17	22	9	0	0	3
	20	0	0	0	0	0	0	0	0	0	0	0	0		20	0	0	0	0	0	5	16	13	8	0	0	2
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	22	0	0	0	0	0	0	0	0	0	0	0	0		22	0	0	0	0	0	0	0	5	0	0	0	0
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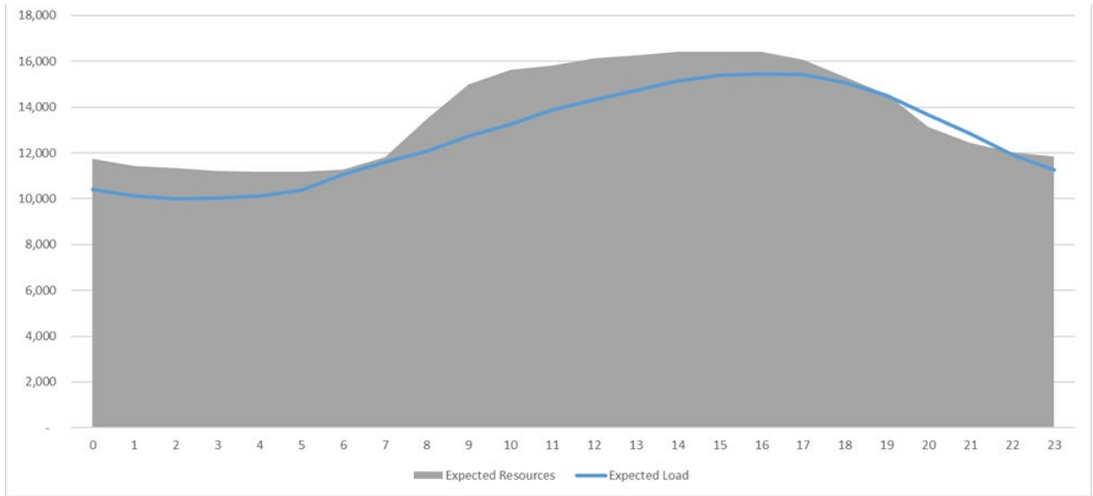
Heat Map Showing Months and Hours Where LOLH is Projected for the WECC-Basin Assessment Area in 2027 and 2029

In WECC's ProbA modeling, energy transfers from neighboring areas are helping WECC-Basin meet supply deficits, but at times they are insufficient, resulting in the unserved energy and load-loss hours. The chart below shows energy surplus and deficit results from the ProbA 2029 study year. For most of the year, WECC-Basin has excess energy that can be transferred to neighboring areas. During peak summer months, however, more of WECC-Basin's resources are needed for its own internal demand and, at times, energy deficits that must be met by importing energy from neighbors can exceed 4,000 MW.



Hourly Energy Surplus and Deficits in MW for ProbA 2029 Study Year

The chart below shows a 24-hour look at expected resources and imports versus expected load for ProbA days with the greatest amount of EUE in 2029. LOLH occurs at hour of 17:00 to 21:00 in 2029. This coincides with the evening solar down ramp and the persistence of elevated demand after the peak hour. The profile for the 2027 study year is similar but limited to the 18:00 to 19:00 hour. It should be noted that it is possible for a day to not show the expected load greater than expected resources on an area-wide basis and still have LOLH. This is because the WECC-Basin assessment area includes a conglomerate of BAs, and one of the BAs within the subregion can encounter energy shortfalls in the ProbA that could not be satisfied by imports due to nearby entities not having sufficient surplus energy to transfer.



Load and Resource Profile in MW on an Unserved Energy Day for ProbA 2029 Study Year

Demand

Average annual growth rate for Basin is 2.5%. The primary drivers are data centers and semiconductor manufacturing. Large-load additions in the forecast are 1,223 MW through 2035.

Idaho Power implements a substantial dispatchable DR program focused on the agricultural sector with its Irrigation Peak Rewards Programs. This allows the utility to remotely turn off specific irrigation pumps a minimum of four times during the summer. Participation varies year-to-year based on factors such as the availability of water and program parameters. PacifiCorp states in its most recent IRP that it plans to reach more than 1,100 MW of dispatchable DR by 2042, a 21% increase from its previous plan. The company's dispatchable DR programs include residential and small commercial air-conditioner load control programs, irrigation load management programs, and approximately 200 MW of evergreen interruptible contracts.

Distributed Energy Resources

BTM DER impacts are reflected in the demand forecasts (net of the DERs). BAs did not report a forecast for BTM resources.

Generation

Operational and planning issues related to generation in WECC-Basin include the following:

- **Aging Thermal Resource Fleet:** An aging thermal resource fleet is a year-round concern for this subregion. Older resources require additional maintenance and can be more prone to forced outages or partial derates. Maintenance is planned years in advance and avoided during summer peak season as much as possible. Quarterly evaluations are done to adjust maintenance schedules as needed.
- **Gas Fleet Derates:** During the winter, gas resources may be derated during extreme cold and precipitation events for equipment issues such as snow-clogged inlet filters. This issue is remedied by monitoring filters and changing them out as needed.
- **Hydro Variability:** Hydro resources in this subregion are subject to seasonal and multi-year fluctuations in water supply. This is a year-round concern that requires persistent monitoring. Regular updates to near-term hydro forecasts ensure system operators can be ready for a range of potential hydro output.
- **Solar Variability:** As the solar capacity in this subregion grows, solar ramps are becoming a concern on summer evenings. Large declines in solar output require the dispatch of flexible resources to meet demand. In addition, during the winter solar generation tends to be significantly lower. BESS that typically charge from solar must charge from other resources. Wind and solar forecasts are used to estimate energy availability to serve load versus the amount available for BESS charging, and other resources are dispatched accordingly.
- **Wind Variability:** Particularly during the winter, the timing and volume of wind generation can vary significantly between forecasts and actuals. This is due to the unpredictable behavior of winter storms that may overspeed turbines, or cold temperatures mixed with moisture that may result in the icing of turbine blades.

Electric-Gas Coordination

Electric-gas coordination in long-term planning studies is considered for at least one Basin entity. For integrated resource planning assumptions, Resource Planners reach out to gas traders to confirm pipeline capability to serve existing and future generating asset needs. Gas supply constraints are not explicitly modeled but are inherently reflected in the GADs data used to develop long-term models.

Maintaining gas supplier diversity is one strategy implemented to reduce the risk of fuel shortages and delivery issues in this subregion. In addition, at least one entity in this subregion participates in the Northwest Mutual Assistance Agreement (NWMAA). This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to one another when unplanned events occur impacting the gas supply and transportation system. There is frequent communication between system operators regarding gas resources that are planned for operation and pipeline representatives regarding the status of pipelines serving those resources.

Renewable Portfolio, Clean Electricity, and Emissions Standards

Idaho Power serves ~63% of the state's electricity load and is targeting 100% clean electricity by 2045; Idaho has no state Renewable Portfolio Standard (RPS) or other clean energy target. Utah has enacted a voluntary renewable portfolio goal of 20% renewable energy by 2025. As of 2023, 15.5% of electricity generated in the state was renewable, putting the state on a path to meet the goal.

Transmission

PacifiCorp's Energy Gateway Transmission Plan addresses future transmission requirements necessary to serve PacifiCorp's Network Load customer needs. In total, the Energy Gateway Transmission plan, initiated in May 2007, adds approximately 2,000 miles of new transmission lines. Segments A, B, C, F, G and parts of Segment D have been completed. Segment D.3 Bridger/Anticline to Populus has a planned in-service date of 2034; Segment E Populus to Hemingway is beyond the 10-year planning horizon.

The 500 kV Boardman to Hemingway transmission line was first proposed in 2007 and has faced multiple delays. Now, as a joint project between Idaho Power and PacifiCorp (represented as Segment H in PacifiCorp's Energy Gateway transmission plan), the companies intend to break ground this year, with a planned in-service date of 2027. This ~295-mile 500 kV transmission line provides ~1,000 MW of bidirectional capacity increase between the Northwest and Idaho.

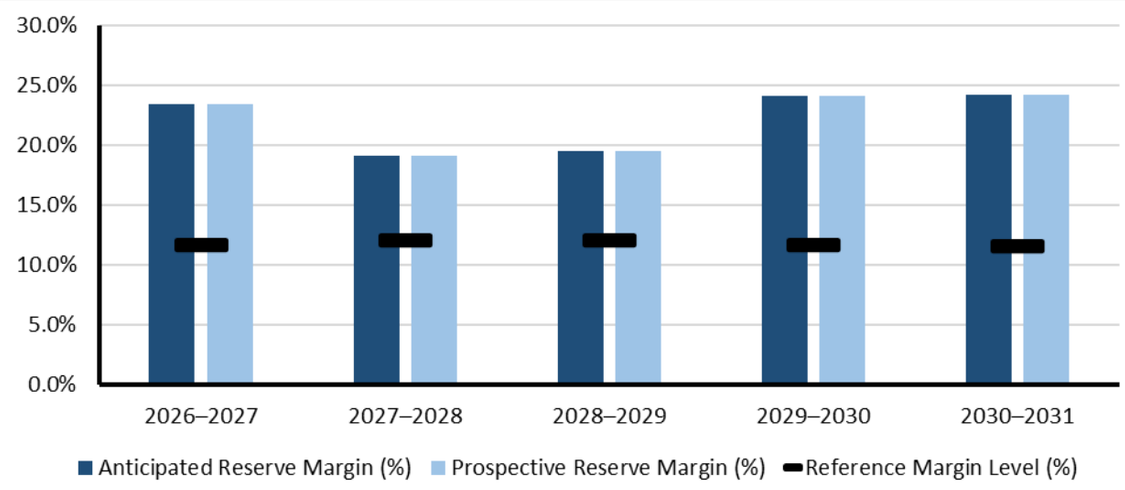


WECC-British Columbia

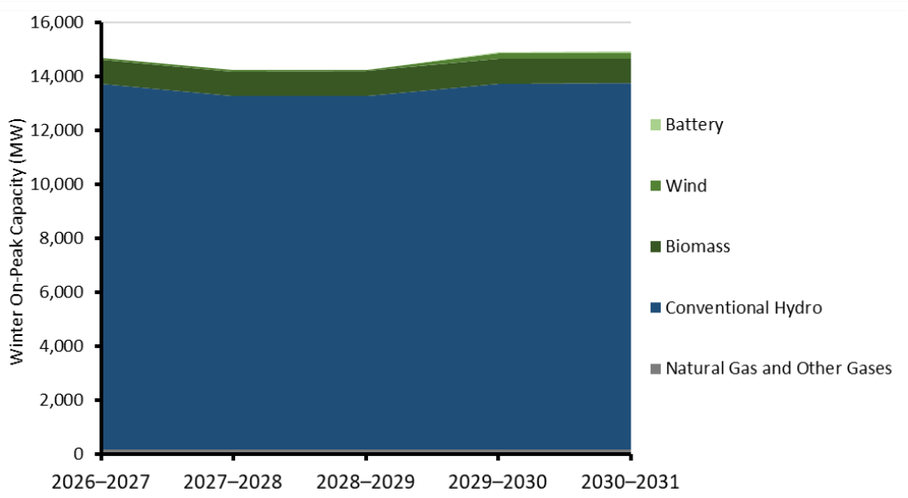
WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and Reliability Coordinator for the province of British Columbia and is the principal supplier of electricity for the province. BC Hydro is a provincial Crown corporation and, under provincial legislation, is responsible for the oversight of the British Columbia Bulk Electric System and its interconnections. BC Hydro operates an integrated system supported by 30 hydroelectric plants, approximately 80,000 kilometers of transmission and distribution lines, and 125 contracts with independent power producers. BC Hydro's transmission system has two interties with neighboring areas—the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta). Peak electricity demand on the BC Hydro system currently occurs during the winter season.

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	11,915	11,970	11,932	12,022	12,028	12,074	12,116	12,177	12,243	12,320
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	11,915	11,970	11,932	12,022	12,028	12,074	12,116	12,177	12,243	12,320
Additions: Tier 1	636	620	625	850	863	863	863	814	863	863
Additions: Tier 2	0	0	0	0	0	0	0	0	0	0
Additions: Tier 3	0	0	0	0	0	0	381	369	381	381
Net Capacity Transfers (WECC Model)	0	0	0	0	0	0	0	0	0	0
Existing-Certain and Net Transfers	14,072	13,638	13,638	14,072	14,072	14,072	14,072	13,638	14,072	14,072
Anticipated Reserve Margin (%)	23.4%	19.1%	19.5%	24.1%	24.2%	23.7%	23.3%	18.7%	22.0%	21.2%
Prospective Reserve Margin (%)	23.4%	19.1%	19.5%	24.1%	24.2%	23.7%	23.3%	18.7%	22.0%	21.2%
Reference Margin Level (%)	11.7%	12.1%	12.1%	11.6%	11.6%	11.6%	11.5%	11.9%	11.5%	11.4%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-British Columbia Highlights

- WECC-British Columbia's anticipated reserve margin does not fall below the RML during the 2025–2035 timeframe.
- British Columbia's annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 4% and winter peak hour demand is projected to grow 3% over the same period.
- British Columbia is anticipated to add 2.6 GW nameplate capacity of Tier 1 solar, wind, conventional hydro, and battery resources over the next 10 years. Hydro variability is the biggest operational issue related to generation in WECC-British Columbia.
- BC Hydro's most recent 10-year capital plan allocates $36 billion (CAD) for infrastructure investments across BC to address load growth and increased customer connections, dam safety, reliability, and the sustainment of existing assets.

WECC-BC Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Natural Gas	170	170	170	170	170
Biomass	900	903	903	900	900
Wind	73	59	59	222	222
Conventional Hydro	13,544	13,104	13,109	13,560	13,573
Other	22	22	22	22	22
Battery	0	0	0	49	49
Total MW	14,708	14,258	14,263	14,922	14,935

WECC-British Columbia Assessment

Planning Reserve Margins

BC Hydro has used the one-day-in-10-years LOLE standard since 1975. Using a probabilistic model, BC Hydro concluded in its updated 2021 IRP that a 12% PRM of dependable generating capacity was required to ensure system resource adequacy. WECC-British Columbia's ARM does not fall below the RML during the 2025–2035 time frame.

There have, however, been changes to policies that might affect planning and procurement over the next 10 years. The Clean Electricity Regulations were finalized in December 2024, which delayed the nationwide net-zero electricity target from 2035 to 2050. Provincial policies in BC that might affect resource planning and procurement include the Renewable Energy Projects Act (May 2025), (which streamlines permitting and grants the BC Energy Regulator broader approval powers for wind, solar, and transmission projects) and the BC Clean Power Action Plan (which aims to double clean electricity supply by 2050 and includes a new biennial procurement cycle for renewable resources).

BC Hydro is included in the Powerex footprint in WRAP. The WRAP defines an adequate reserve margin for its footprint for an 18-month forward period based on a loss of load expectation reliability threshold of one event day in 10 years. WRAP uses an ELCC methodology to determine capacity contribution in its analysis. The WRAP is a non-binding program for Winter 2025–26 but is currently planned to transition to a fully binding program with deficiency charges sometime in 2027. For 2025–2026 Winter, monthly PRMs for the Northwest WRAP subregion (called Mid-Columbia) range between 11.7% and 27.2%. For 2026 Summer, a PRM range between 14.2% and 22.3% is reported.

Energy Assessment, including non-peak hour risk

ProbA Results

British Columbia does not show any LOLH or EUE in 2027 or 2029.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	0	0	0
NEUE (ppm)	0.00	0.00	0.00
LOLH (hours per Year)	0.00	0.00	0.00
* Provides the 2024 ProbA Results for Comparison			

British Columbia did not have LOLH in 2027 or 2029; therefore, no additional reporting or visualizations are provided.

Demand

British Columbia's annual demand is projected to grow 10% over the next 10 years. Summer peak hour demand is projected to grow 4% and winter peak hour demand is projected to grow 3% over the same period. The primary driver for demand growth in British Columbia is natural gas processing. Significant, but uncertain, effects on demand are also expected because of commercial and residential electrification and simultaneous advances in EE in those two sectors.

Distributed Energy Resources

BC Hydro has a net metering program. Net metering for residential and commercial customer projects are up to 100 kW. The net metering program has no annual energy volume target.

Generation

With its abundant hydro, British Columbia is already approximately 95% carbon free. The CleanBC Roadmap states, "By 2030, BC will phase out BC Hydro's last gas-powered facility so the electricity we make is 100% clean."

British Columbia is anticipated to add 2.6 GW nameplate capacity of Tier 1 solar, wind, conventional hydro, and battery resources over the next 10 years. Tier 3 additions include 500 MW of conventional hydro.

Hydro variability is the main operational and planning issue related to generation in WECC-British Columbia. Over 80% of British Columbia's capacity is comprised of hydro resources, making hydro variability a concern year-round. While parts of British Columbia remain in drought classification as of the end of October 2025, many of the province's basins have recovered and conditions are now better for this time of year than in the prior two years. Drought indices for 2026–2027 remain dependent on this year's snowpack accumulation and subsequent seasonal rain. At this time, it is too soon to forecast whether drought conditions will persist or continue easing into next season for the BC Hydro integrated system. Power imports from the United States to British Columbia assist in maintaining water storage levels. More than a fifth of the power in the province was imported from the United States in 2024. Increasing electrification trends coupled with potential continued drought conditions may exacerbate the need for imports to the region in the future.

As BC is working to phase out its last natural-gas-fired power generation units over the next five years, electric-gas coordination issues are not anticipated for power supply. However, BC's natural gas operators are part of the Northwest Mutual Assistance Agreement. This is a voluntary collaboration amongst entities controlling natural gas resources in British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho to cooperate and provide aid to each other when unplanned events occur impacting the gas supply and transportation system. There is frequent communication between system operators regarding gas resources that are planned for operation and pipeline representatives regarding the status of pipelines serving the jurisdictions covered by the agreement.

Energy Storage

BC Hydro is expected to add 50 MW of Tier 1 battery energy storage over the next 10 years. Battery storage in the West is generally being relied on to help mitigate ramping risk from afternoon net demand due to increasing penetrations of solar.

Energy Transfers

According to NERC's *ITCS Canadian Analysis*, the total simultaneous transfer capability into the British Columbia transmission planning regions from all its neighbors is 2,897 MW in 2024 Summer and 3,078 MW in 2024/25 Winter. These values translate to approximately 31% of peak summer load and 27% of peak winter load in the analysis years. The two interfaces include connections with the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta).

Transmission

BC Hydro's most recent 10-Year Capital Plan allocates $36 billion (CAD) for infrastructure investments across BC to address load growth and increased customer connections, dam safety, reliability, and the sustainment of existing assets. These changes are expected to shorten development lead-times, boost renewable energy procurement, and enhance grid infrastructure planning.

Reliability Issues

Congestion of the transmission systems supplying high-growth areas of the Lower Mainland and Vancouver Island could be a potential future emerging reliability issue. Load growth due to electrification, expected population increases, and industrial expansion could couple with increased variability in load caused by extreme weather, wildfires, atmospheric rivers, and heat waves or cold snaps, to add stress to the transmission network. Lastly, aging infrastructure could add to higher forced outage risk if supply chain disruptions create project delays, as has been occurring across the Western Interconnection in recent years.

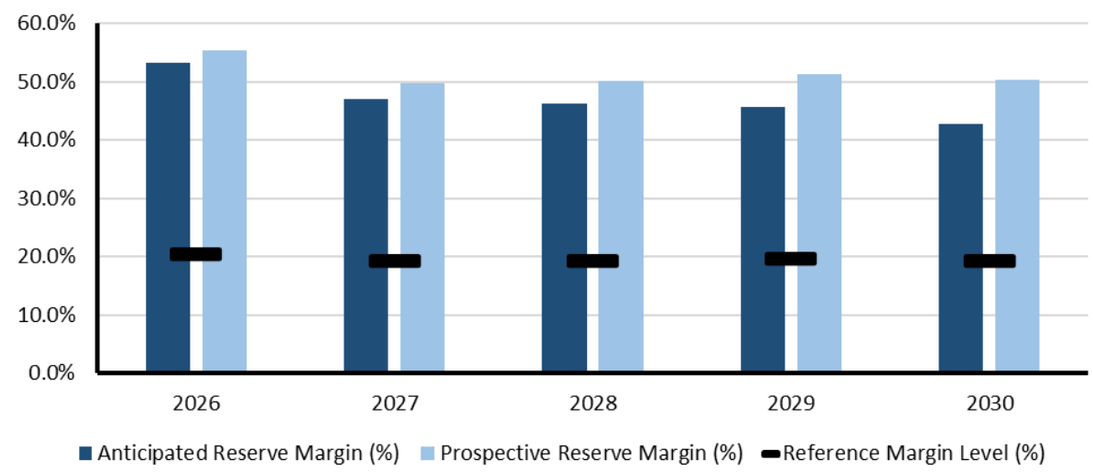


WECC-California

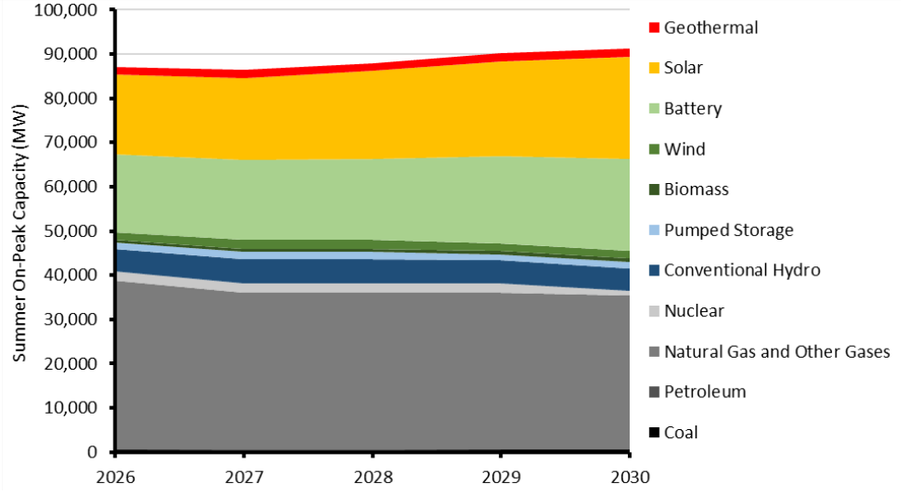
WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, Los Angeles Department of Water and Power, Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-California is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	58,165	60,060	61,547	63,261	65,221	66,879	68,315	69,759	71,373	73,017
Demand Response	756	764	775	783	795	799	812	823	836	836
Net Internal Demand	57,409	59,296	60,772	62,478	64,426	66,079	67,504	68,936	70,537	72,182
Additions: Tier 1	11,558	13,202	14,765	17,206	19,945	19,945	21,532	22,541	23,771	25,622
Additions: Tier 2	1,288	1,552	2,388	3,489	4,974	4,974	6,509	8,475	9,208	9,244
Additions: Tier 3	10	10	10	10	557	557	557	562	557	557
Net Capacity Transfers (WECC Model)	561	583	651	639	541	234	310	314	298	287
Existing-Certain and Net Transfers	76,371	73,982	74,050	73,773	71,969	70,585	70,661	70,925	70,649	70,613
Anticipated Reserve Margin (%)	53.2%	47.0%	46.1%	45.6%	42.7%	37.0%	36.6%	35.6%	33.9%	33.3%
Prospective Reserve Margin (%)	55.4%	49.6%	50.1%	51.2%	50.4%	44.5%	46.2%	47.9%	46.9%	46.1%
Reference Margin Level (%)	20.3%	19.2%	19.3%	19.7%	19.3%	19.1%	18.9%	17.8%	18.3%	18.0%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-California Highlights

- The ARM does not fall below the RML. Further, ProbA results indicate that planned resources can reliably meet demand during the studied years of 2027 and 2029.
- The California Public Utilities Commission (CPUC) recently increased the PRM requirement for 2026 and 2027 from 17% to 18%. CPUC's ruling also maintains procurement targets that provide additional summer reliability resources by ordering IOUs to procure resources of 1,260 to 2,300 MW for the months of June through October in 2026 and 2027.

WECC-California Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	466	466	466	466	466
Coal*	16	16	16	16	16
Petroleum	103	103	103	103	103
Natural Gas	38,144	35,507	35,507	35,468	34,837
Natural Gas*	38,144	34,994	34,994	35,468	34,837
Biomass	734	745	749	749	749
Solar	18,126	18,574	19,936	21,506	23,065
Wind	1,643	1,991	2,000	1,650	1,650
Geothermal	1,809	1,808	1,808	1,809	1,809
Conventional Hydro	5,112	5,426	5,426	5,112	5,112
Pumped Storage	1,401	1,549	1,549	1,401	1,401
Nuclear	2,152	2,151	2,151	2,152	1,076
Other	194	194	194	194	194
Battery	17,486	18,088	18,275	19,731	20,911
Total MW	87,368	86,601	88,164	90,340	91,372
Total MW*	86,918	85,637	87,200	89,890	90,922

***Capacity with additional generator retirements**. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.

WECC-California Assessment

Planning Reserve Margins
The ARM does not fall below the RML. The California Public Utilities Commission (PUC) recently released a PRM increase for 2026 and 2027 from 17% to 18%. The ruling also increases the PRM procurement target from 1,260 to 2,300 MW for the months of June through October for 2026 and 2027 (divided across the IOUs). Note, the CPUC's reserve margins are not used in WECC's methodology for the LTRA.

Energy Assessment, including non-peak hour risk
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

ProbA Results
The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
* No prior results as the assessment area is new for the 2025 LTRA.			

For 2027 and 2029, the peak hour is projected to occur in early September at hour beginning 16:00. California does not show any LOLH or EUE in either 2027 or 2029. No risk period visualizations are included for this subregion as there were no identified risk hours.

Demand
Average annual demand growth rate for WECC-CA is 2.4%. The primary drivers are transportation electrification and incremental load for extreme heat events. Large-load additions in the forecast are 4,993 MW through 2035.

Demand-Side Management
DR accounted for about 2.6% (1,400 MW) of total system resource adequacy capacity in the summer of 2024 compared to about 3 to 4% in the previous four summers. This drop is mainly due to a change in CPUC rules removing the PRM and transmission adders totaling over 11% previously applied to DR capacity.

DR was supplied by CPUC-regulated utility programs, non-utility third-party programs, and non-CPUC jurisdictional load-serving entities (municipal utilities, etc.). Utility DR accounts for about 76% of DR used to meet resource adequacy requirements. About 85% of this capacity was bid into the real-time market during the most critical hours of summer 2024. When dispatched, this category reported curtailing about 81% of scheduled load reductions.

Non-utility (third party) DR accounts for about 18% of DR used as resource adequacy capacity requirements, with actual load reductions of about 54% of scheduled. However, during some hours, this sector exceeded the scheduled level.

Non-CPUC jurisdictional load serving entities (municipal utilities, etc.) utilize an average of about 75 MW of DR—or about 6% of DR used to meet total ISO system resource adequacy requirements. Since this capacity is not bid or scheduled into the ISO market, its performance cannot be verified.

Distributed Energy Resources
A recent policy change in California significantly increased the payback period for residential BTM PV. As predicted, installations of residential rooftop solar systems have fallen to near three-year lows over the past year; existing systems were grandfathered in. Now, the California legislature is considering a bill to undo that grandfathering by reducing those existing net metering contracts with IOUs from 20 years to 10. AB 942 would impact the value of solar on the nearly 2 million homes that have installed panels years ago by shifting them to the "net billing tariff" that pays approximately 75% lower rates for energy sent back to the grid. Given California's shifting policy environment, it is difficult to predict future adoption of BTM PV solar.

Generation

- **Aging Thermal Resource Fleet:** During the summer, aging thermal resources can become a concern for this subregion. Older resources require additional maintenance and can be more prone to forced outages or partial derates. In addition, thermal plant and system operators are becoming increasingly hard to replace, as there appears to be difficulty in finding personnel with the necessary experience to fill these rolls. Succession planning is becoming an integral part of successful thermal plant operation.
- **Behind-the-Meter Variability:** BTM output variability can be an operational concern for this subregion year-round. BTM resource generation can be masked from the transmission operator and BA. For example, localized cloud coverage limiting BTM output has been seen to increase demand by 200 MW, requiring unplanned additional resources to be dispatched.

Flexible operating reserves remain on standby to address the uncertainty associated with BTM output.

- **BESS Fires:** BESS fires have occurred in California. These are isolated events that can render a BESS inoperable. Electrical faults, manufacturing defects, degradation due to aging, and gas buildup can all lead to fires. New technologies for passive fire suppression, such as immersion cooling, are being developed to reduce the occurrence of BESS fires.
- **Gas Fleet Derates:** Gas resources in this subregion can be derated during extremely hot weather in the summer due to ambient conditions. Quantifying gas fleet limitations and ensuring there are alternative resources available to meet demand is paramount.
- **Hydro Variability:** Primarily during the summer season, variations in annual precipitation can have a significant impact on water supply. Extended droughts can reduce head pressure, directly resulting in the reduction of hydro capacity. Improvements in hydro models for run off and precipitation are in progress to address these concerns. For resource adequacy models, a 1-in-5 dry-year planning scenario is used.
- **Inertia Decline on System:** Local and federal regulations have driven a reduction in traditional spinning mass generators, which has exacerbated frequency deviations in California. Operating plans are being updated with the necessary steps to mitigate this issue. This issue is observed year round.
- **Solar Variability:** Solar output variability is a concern year round. Spring, fall, and winter often have overcast cloud coverage in California, which can make solar output difficult to forecast. Summer evenings tend to be a time of day when demand is elevated but solar output declines. Weather forecasts are heavily monitored, and net load uncertainty is accounted for with regulation, flexible ramp, and future imbalance reserve requirements.
- **Wind Variability:** Wind variability is an operational concern year round. Toward the end of summer, the beginning of winter, and the beginning of spring, Santa Ana Winds can create overspeed conditions for wind turbines, limiting their output. Weather forecasts are heavily monitored, and net load uncertainty is accounted for with regulation, flexible ramp, and future imbalance reserve requirements.

Electric-Gas Coordination

Most entities in California consider electric-gas coordination in long-term planning studies. Resource Planners collaborate with gas supply teams to gather assumptions on forecasted gas deliveries and pricing. Constraints are not directly incorporated in resource planning studies.

Operating Procedure 4120 ensures that CAISO provides daily estimated gas usage reports to gas transmission operators (GTO). These are used as the basis for gas curtailment event planning. This procedure helps mitigate risks associated with gas supply limitations that may impact generation resources and applies to both real-time and day-ahead operations. In addition, participants of RC West have formed the Real-Time Working Group (RTWG). This group convenes prior to extreme weather events to prepare for potential gas supply interruptions. California entities that are part of RC West also participate in the Northwest Mutual Assistance Agreement (NWMMA). Communication protocols include following NERC Reliability Standard COM-002-4 which contains predefined communication procedures. In addition, plant operators work directly with power supply and gas schedulers to coordinate scheduling and dispatch of gas generating resources.

Renewable Portfolio, Clean Electricity, and Emissions Standards

California has a mandate for its electricity supply to be 60% carbon free by 2030 and is currently on track to meet that level. The requirement for 100% carbon free is set at 2045.

Transmission

The ITCS report showed that in a heat wave Northern California may be energy-deficient.

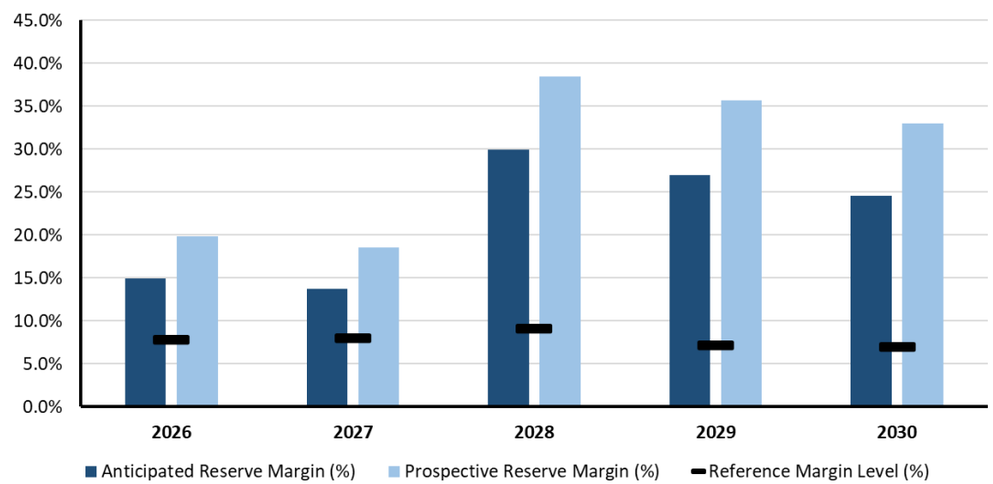


WECC-Mexico

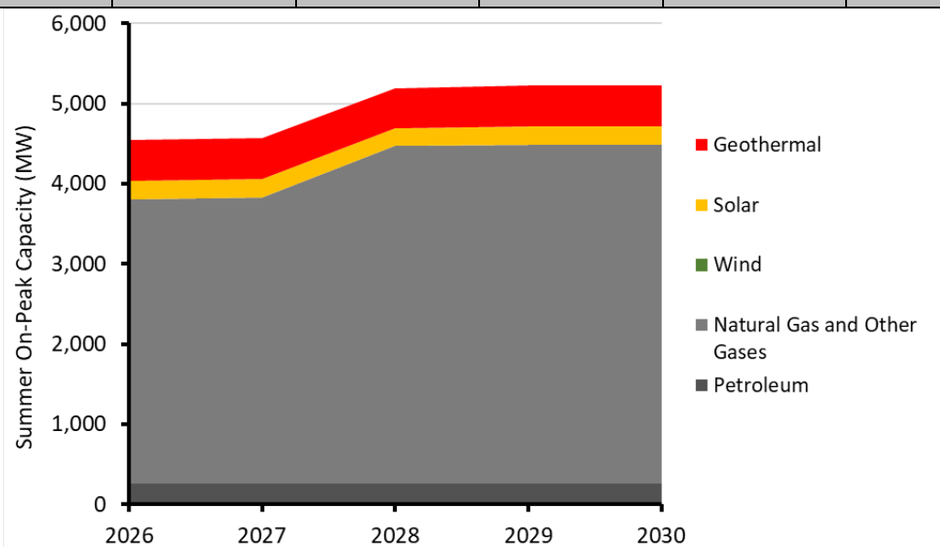
WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Mexico is a new assessment area in 2025 that was part of WECC-CA/MX in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	3,953	4,135	4,315	4,495	4,675	4,855	5,035	5,215	5,395	5,575
Demand Response	0	0	0	0	0	0	0	0	0	0
Net Internal Demand	3,953	4,135	4,315	4,495	4,675	4,855	5,035	5,215	5,395	5,575
Additions: Tier 1	717	722	1,396	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Additions: Tier 2	196	198	367	392	392	392	392	367	392	392
Additions: Tier 3	0	0	0	0	0	0	0	0	0	0
Net Capacity Transfers (WECC Model)	0	131	410	482	600	600	600	600	600	600
Existing-Certain and Net Transfers	3,825	3,982	4,209	4,307	4,425	4,425	4,425	4,409	4,425	4,425
Anticipated Reserve Margin (%)	14.9%	13.8%	29.9%	27.0%	24.6%	20.0%	15.7%	11.4%	8.0%	4.5%
Prospective Reserve Margin (%)	19.9%	18.6%	38.4%	35.7%	33.0%	28.1%	23.5%	18.4%	15.2%	11.5%
Reference Margin Level (%)	7.8%	8.0%	9.1%	7.2%	7.0%	6.8%	6.7%	7.4%	6.4%	6.3%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Mexico Highlights

- Centro Nacional de Control de Energía (CENACE) is adding three natural-gas-fired combustion turbine generators (totaling 780 MW in summer capacity) by Summer 2026, increasing planned reserves to above RMLs. An additional 740 MW of natural-gas-fired capacity is in development between 2026 and 2027.

WECC-Mexico Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	**2027**	**2028**	**2029**	**2030**
Coal	0	0	0	0	0
Petroleum	259	261	258	259	259
Natural Gas	3,540	3,566	4,212	4,224	4,224
Biomass	0	0	0	0	0
Solar	229	231	214	229	229
Wind	7	5	6	7	7
Geothermal	506	510	505	506	506
Conventional Hydro	0	0	0	0	0
Nuclear	0	0	0	0	0
Other	0	0	0	0	0
Battery	0	0	0	0	0
Total MW	4,542	4,573	5,195	5,225	5,225

WECC-Mexico Assessment

Planning Reserve Margins
The ARM is above the RML until 2035, the last year of the assessment period.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
* No prior results as the assessment area is new for the *2025 LTRA*.			

Demand
Average annual demand growth rate for WECC-Mexico is 4.3%. Large-load additions in the forecast are 161 MW through 2035.

Generation
Operational and planning issues related to generation in WECC-Mexico include the following:

- Unplanned Outages of Thermal Sites: High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this assessment area can result in the declaration of an EAA and a request for assistance from RC West. This risk is amplified in the summer when demand is highest.
- Electric-Gas Coordination: Electric-gas coordination is considered in long-term planning studies for the WECC-Mexico area. Current and future gas projects and constraints that could compromise supply to generators are incorporated in planning studies. Constant gas supply monitoring is conducted to ensure generating assets remain reliable throughout the year. Multiple suppliers are also available to generators in WECC-Mexico. This allows for supply redundancy if one supplier is experiencing limitations. Communication between gas suppliers and system operators includes the sharing of gas infrastructure maintenance information and consumption forecasts which are provided on a weekly, monthly, and annual cadence.

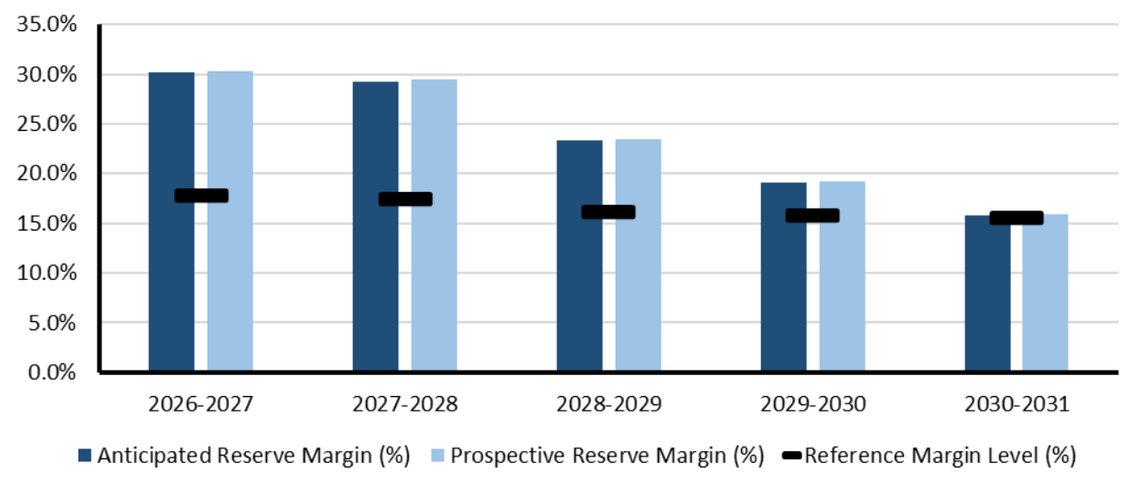


WECC-Northwest

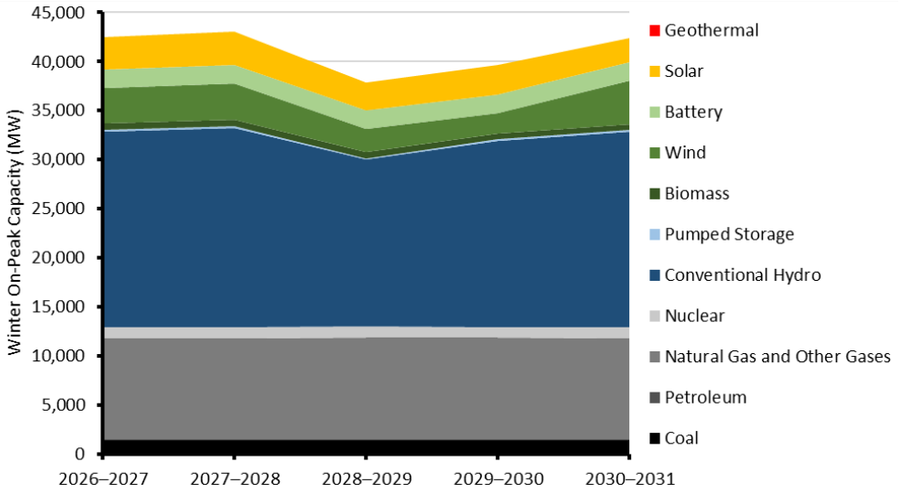
WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Northwest is a new assessment area in 2025 that was part of a larger WECC-NW footprint in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031	2031–2032	2032–2033	2033–2034	2034–2035	2035–2036
Total Internal Demand	34,426	34,930	36,038	37,017	37,939	38,821	39,455	40,083	40,563	41,064
Demand Response	30	30	30	30	30	30	30	30	30	30
Net Internal Demand	34,396	34,900	36,008	36,987	37,909	38,791	39,425	40,053	40,533	41,034
Additions: Tier 1	3,463	3,463	3,219	3,219	3,219	3,219	3,463	3,232	3,221	3,217
Additions: Tier 2	10	49	56	56	56	56	49	56	56	56
Additions: Tier 3	697	830	939	4,958	5,389	5,605	6,267	5,963	5,921	5,903
Net Capacity Transfers (WECC Model)	7,242	7,630	7,316	7,066	6,896	6,825	6,825	6,825	6,630	5,841
Existing-Certain and Net Transfers	41,332	41,653	41,169	40,828	40,652	40,564	40,724	40,558	40,360	39,573
Anticipated Reserve Margin (%)	30.2%	29.3%	23.3%	19.1%	15.7%	12.9%	12.1%	9.3%	7.5%	4.3%
Prospective Reserve Margin (%)	30.3%	29.4%	23.4%	19.2%	15.9%	13.0%	12.2%	9.5%	7.7%	4.4%
Reference Margin Level (%)	17.8%	17.4%	16.1%	15.8%	15.5%	15.3%	15.9%	15.0%	14.9%	14.8%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Northwest Highlights

- The ARM falls below the RML starting in Winter 2031–2032. The assessment area would need additional resources to meet resource adequacy criteria. More details on members participating in the WRAP can be found on the WRAP Area Map.
- For 2027 and 2029, the peak hour is projected to occur in January at hour beginning 10:00.
- Resource adequacy risk is not significant in the Northwest for 2027.
- In 2029, the Northwest subregion shows 8,080 MWh of EUE, with approximately 85% of that occurring between hours beginning 14:00–19:00 in August. Though the magnitude of EUE is greatest in the summer months, LOLH occurs at a greater frequency in the winter months, particularly in January.
- The majority of EUE occurs during the summer from hours beginning 17:00–19:00, during which period demand is elevated but solar output is dissipating.

WECC-Northwest Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026–2027	2027–2028	2028–2029	2029–2030	2030–2031
Coal	1,516	1,516	1,475	1,475	1,475
Petroleum	97	97	95	95	95
Natural Gas	10,539	10,533	10,480	10,480	10,480
Biomass	657	617	615	536	536
Solar	1,545	1,544	1,622	1,622	1,622
Wind	2,149	2,149	1,319	1,311	1,311
Geothermal	4	4	4	4	4
Conventional Hydro	17,855	17,835	18,279	18,275	18,270
Pumped Storage	146	146	149	149	149
Nuclear	1,112	1,112	1,108	1,108	1,108
Battery	1,934	1,934	1,927	1,927	1,927
Total MW	37,553	37,486	37,072	36,981	36,976

WECC-Northwest Assessment

Planning Reserve Margins

The ARM falls below the RML starting in Winter 2031–2032. Additional resources will be needed to avoid shortfalls in planning reserves and prevent energy risks from emerging.

Non-Peak Hour Risk and Energy Assurance

WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

ProbA Results

While the ARM does not fall below the RML during the 2026–2030 time frame, the ProbA results based on current resource projections and demand forecasts indicate significant EUE and LOLH by 2029. As resource additions struggle to keep up with rising demand and expected generator retirements, reflected in falling ARMs over the assessment period, unserved energy and load-loss hours increase in the ProbA results.

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	N/A	0	8,080
NEUE (ppm)	N/A	0	36.64
LOLH (hours per Year)	N/A	0	85.00
* No prior results as the assessment area is new for the 2025 LTRA.			

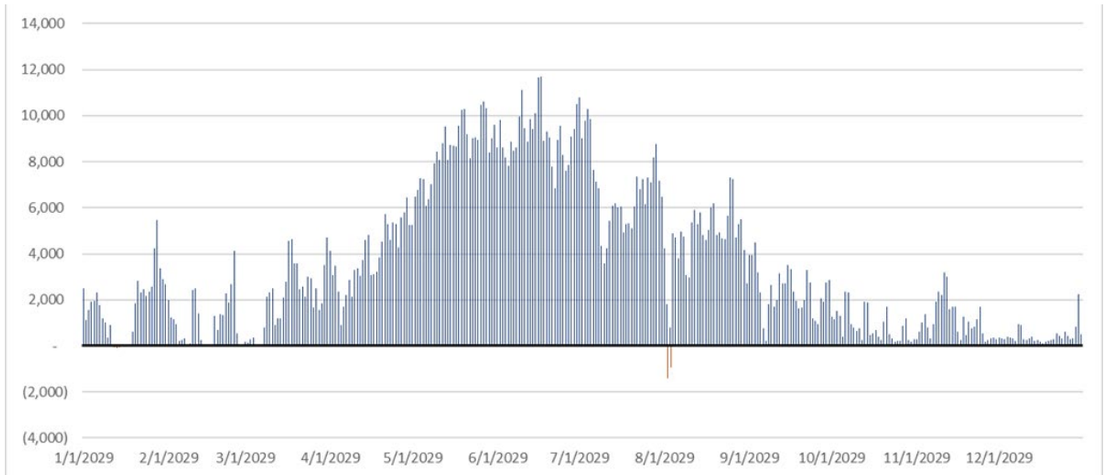
Resource adequacy concerns in the U.S. Northwest can arise in the summer and winter seasons. Peak demand occurs in the winter months. In the ProbA results illustrated in the following heat map figure, load-loss hours occur at a greater frequency during winter high-demand periods. The summer months also have an emerging risk of shortfalls according to the ProbA: The 2029 study year had approximately 85% of identified unserved energy occurring between the afternoon-to-evening hours of mid to late summer. The values in the heat map are the number of hours from the MAVRIC simulations that resources fall short of demand and reliability margins in the study year.

Northwest - 2027	Months											
Existing + Tier 1	1	2	3	4	5	6	7	8	9	10	11	12
Hour Beginning 0	0	0	0	0	0	0	0	0	0	0	0	0
1	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0
22	0	0	0	0	0	0	0	0	0	0	0	0
23	0	0	0	0	0	0	0	0	0	0	0	0

Northwest - 2029	Months											
Existing + Tier 1	1	2	3	4	5	6	7	8	9	10	11	12
Hour Beginning 0	2	0	0	0	0	0	0	0	0	0	0	0
1	2	0	0	0	0	0	0	0	0	0	0	0
2	4	0	0	0	0	0	0	0	0	0	0	0
3	4	0	0	0	0	0	0	0	0	0	0	0
4	4	0	0	0	0	0	0	0	0	0	0	0
5	2	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	1
7	2	0	0	0	0	0	0	0	0	0	0	4
8	3	0	0	0	0	0	0	0	0	0	0	2
9	3	0	0	0	0	0	0	0	0	0	0	0
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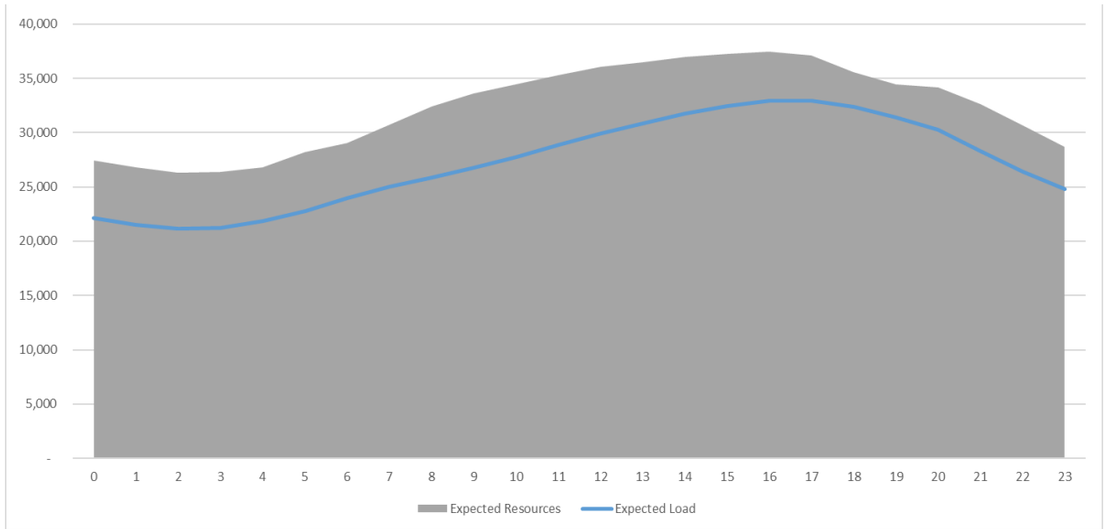
Heat Map Showing Months and Hours Where LOLH is Projected for the WECC-Northwest Assessment Area in 2027 and 2029

In WECC's ProbA modeling, energy transfers from neighboring areas are helping WECC-Northwest meet supply deficits, but at times they are insufficient, resulting in the unserved energy and load-loss hours. The chart below shows energy surplus and deficit results from the ProbA 2029 study year. For most of the year, WECC-Northwest has excess energy that can be transferred to neighboring areas. Winter months are when WECC-Northwest's excess energy is at its lowest, and at times in the 2029 study year internal resources are not sufficient for demand. In summer months, WECC-Northwest is projected to have its highest amount of excess energy, though these supplies can still be insufficient for modeled demand during extreme heat events. Such occurrences can cause deficits represented in the figure below, and energy can go unserved when neighboring areas do not have surplus energy to transfer.



Hourly Energy Surplus and Deficits in MW for ProbA 2029 Study Year

The chart below shows a 24-hour look at expected resources and imports versus expected load for ProbA days with the greatest amount of EUE in 2029. For the Northwest, this occurs in mid-to-late summer. LOLH occurs from hours beginning 14:00 through 19:00. The majority of EUE during these hours occurs from hours beginning 17:00–19:00, during which period demand remains elevated whereas solar output dissipates. There is no LOLH in 2027. It should be noted that it is possible for a day to not show the expected load greater than expected resources on an area-wide basis and still have LOLH. This is because the WECC-Northwest assessment area includes a conglomerate of BAs, and one of the BAs within the subregion can encounter energy shortfalls in the ProbA that could not be satisfied by imports due to nearby entities not having sufficient surplus energy to transfer.



Load and Resource Profile in MW on an Unserved Energy Day for ProbA 2029 Study Year

Demand

Average annual demand growth rate for WECC-Northwest is 2.7%. The primary drivers are data centers, residential electrification, residential customer growth, transportation electrification, and semiconductor manufacturing. Large-load additions in the forecast are 7,652 MW through 2035.

Distributed Energy Resources

In the Northwest, Oregon IOUs continue to offer net metering with carryover credits within a calendar year and annual excess credits going to low-income programs. However, the state's largest IOU has proposed a change that largely mirrors California's revised lower credits; if adopted, this would slow the rate of installations in Oregon as well (where the latitude and climate already lengthen the customer's payback period relative to California).

In Washington, utilities have the option to propose a BTM PV credit that is less than the retail rate once they reach a threshold of 4% of their 1996 peak load. The current program is in effect until at least 2029. However, given the progress toward the 4% penetration rate (below), that year may trigger a slowdown in new installations of BTM PV.

Generation

Operational and planning issues related to generation in WECC-Northwest include the following:

- **Aging Thermal Resource Fleet:** A year-round concern for this subregion is an aging thermal resource fleet. Older resources require additional maintenance and can be prone to forced outages or partial derates. Necessary maintenance and capital expenditures are made to ensure these generators provide reasonable performance when called upon. Planned maintenance outages for these resources may be done at a higher frequency during the shoulder months to avoid unplanned outages during the summer months. However, major upgrades to aging infrastructure reduce system capability for extended periods of time, increasing reliance on imports. Supply chain delays and staffing issues can cause planned outages to extend well beyond their anticipated end date. Staffing shortages have been noted by multiple entities in the Northwest.
- **Hydro Variability:** The Northwest has a large share of hydro resources in its portfolio making hydro generating capability a concern year-round. Seasonal hydro variability and below average inflows observed by some entities in this region from April through November of last year resulted in projects being ran at minimum flow. Underperforming hydro resources can result in entities relying heavily on imports to meet peak load hours. During extreme cold conditions, run of river hydro sites can also be derated due to icing. Performing maintenance during shoulder seasons can help keep hydro on-line during the winter and summer seasons. Improving hydro forecasting for short- and long-term planning models can assist system dispatchers with daily operating plans and resource planners in completing accurate resource adequacy studies.
- **Solar Variability:** Solar output variability due to cloud coverage can be a minor concern year-round in this subregion. Entities in this subregion state there are sufficient flexible resources in their portfolio to address solar output uncertainty.
- **Wind Variability:** Wind variability is of particular concern for this subregion during the winter. Cold weather mixed with moisture can cause icing conditions on wind turbine blades, which can severely derate a wind site. Entities in this subregion state that there are sufficient flexible resources in their portfolio to address wind output uncertainty in the winter.
- **Electric-Gas Coordination:** The Northwest subregion contains entities that consider electric-gas coordination in long-term planning studies, as well as entities that do not. Several gas supply options for future generating assets are evaluated to ensure alternatives exist if one supply point is curtailed. Price certainty from suppliers is also a major consideration in planning studies. Annual natural-gas-load studies are conducted to help identify parts of the gas distribution system that may experience low pressure during peak cold conditions. These areas of the gas system are identified, and recommendations to address this issue are prioritized and completed. If an issue cannot be addressed within a short period of time, contingency plans are developed for these areas during high gas demand or peak cold conditions. Entities in the Northwest subregion are participants in the NWMMA mentioned earlier in the Basin subregion. Status reports and planned resource output forecasts are communicated between electric and gas teams daily to ensure operational needs are met.
- **Renewable Portfolio, Clean Electricity, and Emissions Standards:** Washington is required to have zero coal generation by 2025, be greenhouse gas neutral by 2030 (can use offsets), and be 100% non-emitting by 2045 without using offsets. Oregon passed a requirement for its investor-owned utilities to be 80% below their 2005 emissions baseline by 2030, 90% below by 2035, and 100% below (zero emissions) by 2040. Montana has a 15% renewables target that has been met, with no incremental increases in the out-years.

Transmission: PacifiCorp's Blueprint transmission project will connect major resource and load areas in central and eastern Oregon through construction of approximately 320 miles of new 500 kV transmission line and associated 500 kV and 230 kV system upgrades, in three primary segments planned to be fully in-service in 2028 and 2032. The Blueprint project will largely parallel the existing Northwest AC Intertie 500 kV system, interconnecting at various points and requiring significant coordination with ac Intertie owners and other affected systems. Affected paths include WECC Paths 14, 66 and 75.

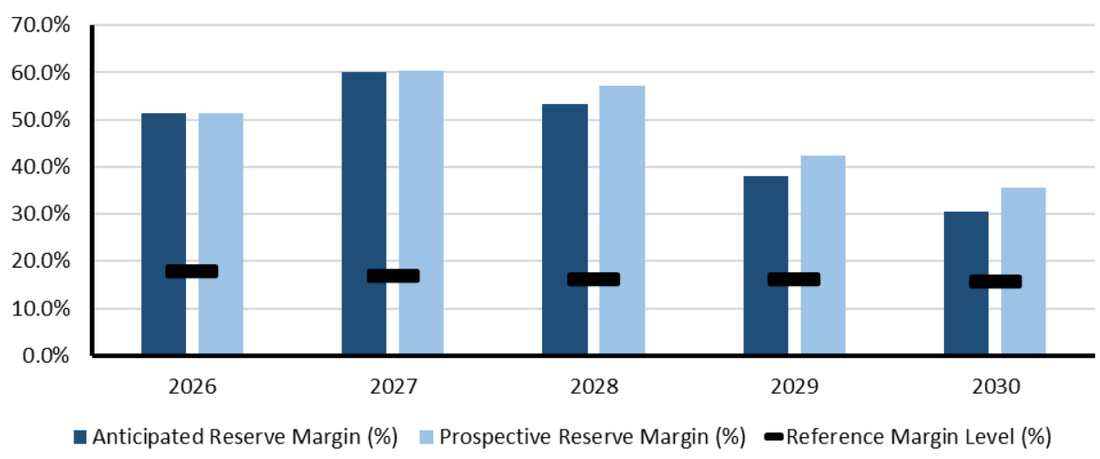


WECC-Rocky Mountain

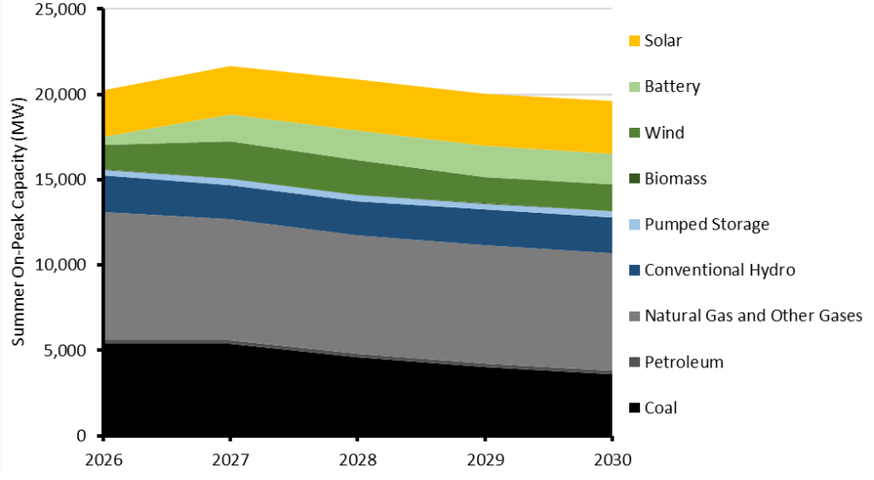
WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Rocky Mountain is a new assessment area in 2025 that was part of WECC-NW in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	14,004	14,338	14,565	15,021	15,442	15,873	16,306	16,764	17,207	17,297
Demand Response	287	290	293	285	287	290	293	296	298	301
Net Internal Demand	13,717	14,048	14,272	14,736	15,154	15,583	16,013	16,468	16,909	16,997
Additions: Tier 1	1,771	3,486	3,979	4,079	4,079	4,079	4,355	4,299	4,079	4,079
Additions: Tier 2	0	45	585	640	761	761	810	810	761	761
Additions: Tier 3	17	178	925	1,160	1,373	3,207	3,276	4,188	4,274	4,370
Net Capacity Transfers (WECC Model)	391	661	852	179	50	23	0	0	0	0
Existing-Certain and Net Transfers	18,979	18,995	17,884	16,278	15,696	14,882	14,721	14,329	14,143	14,098
Anticipated Reserve Margin (%)	51.3%	60.0%	53.2%	38.1%	30.5%	21.7%	19.1%	13.1%	7.8%	6.9%
Prospective Reserve Margin (%)	51.3%	60.3%	57.3%	42.5%	35.5%	26.6%	24.2%	18.0%	12.3%	11.4%
Reference Margin Level (%)	17.8%	17.0%	16.2%	16.1%	15.7%	15.2%	13.5%	11.9%	14.1%	13.9%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Rocky Mountain Highlights

- ARM remains above the RML through 2033. Furthermore, ProbA results indicate that planned resources can reliably meet demand during the studied years of 2027 and 2029.
- The ARM and PRM fall below the RML in Summer 2034 and 2035 and Winter 2034–35, indicating that not enough resources have progressed into the interconnection queue for these later years in the assessment period.

WECC-Rocky Mountain Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	5,383	5,376	4,623	4,034	3,585
Coal*	5,053	5,376	4,429	3,379	2,180
Petroleum	204	204	204	204	204
Natural Gas	7,522	7,083	6,897	6,902	6,902
Biomass	6	6	6	3	3
Solar	2,695	2,873	3,002	3,071	3,071
Wind	1,437	2,218	2,054	1,555	1,550
Conventional Hydro	2,139	2,043	2,029	2,116	2,116
Pumped Storage	346	340	340	346	346
Other	126	126	126	126	126
Battery	496	1,547	1,726	1,817	1,817
Unknown	6	5	5	6	6
Total MW	20,359	21,820	21,011	20,178	19,725
Total MW*	20,029	21,820	20,817	19,523	18,320
***Capacity with additional generator retirements**. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

WECC-Rocky Mountain

Planning Reserve Margins
The ARM and PRM fall below the RML in Summer 2034 and 2035 and Winter 2034–35, indicating that not enough resources have progressed into the interconnection queue for these later years in the assessment period. In Winter 2033–34, the ARM falls below the RML, but the prospective resources are expected to sufficiently cover a shortfall. No BAs in this region are WRAP participants.

The Public Service Company of Colorado (PSCo), a subsidiary of Xcel Energy, has used a 16.3% long-term PRM requirement in its Electric Resource Plan (2021), based on a loss of load probability of 1-day every 10 years. PSCo's reserve margin is not used in WECC's methodology for the LTRA.

Non-Peak Hour Risk, Energy Assurance, Probabilistic-Based Assessments
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

ProbA Results

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
*No prior results as the assessment area is new for the 2025 LTRA.			

Since WECC-Rocky Mountain does not show any LOLH or EUE in 2027 or 2029, no additional reporting of results or visualizations are provided.

Demand
Average annual demand growth rate for WECC-Rocky Mountain is 2.5%. The primary drivers are data centers, commercial customer growth, and industrial customer growth. Large-load additions in the forecast are 574 MW through 2035.

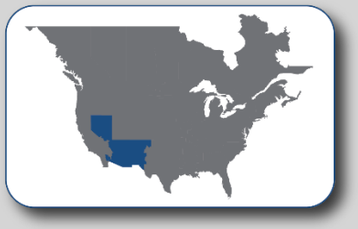
Demand-Side Management
PSCo offers a wide array of DR programs. Total summer demand-reduction estimates for controllable programs for can be found in its Demand Side Management & Beneficial Electrification Plan.

Distributed Energy Resources
BAs did not report a forecast for BTM resources. Some information is available through the EIA on both historical and forecast data. BTM DER impacts are reflected in the demand data (net of the DERs).

Generation
Operational and planning issues related to generation in WECC-Rocky Mountain include the following:

- **Unplanned Outage Extensions:** Supply chain issues, unplanned discovery work, and vendor availability have driven unplanned extensions of resource outages in the Rocky Mountain area. Difficulty in boiler feed pump procurement has resulted in at least one generating asset being unavailable for over nine months. Another thermal site was undergoing a rotor swap and piping inspection, which revealed significant weld defects and pipe cracks. This resulted in a two-month outage being extended into the following year. A hydro site has been unavailable for much of 2024 due to a penstock leak which has been unable to be repaired due to vendor unavailability. Alternative vendors are being sought after for hydro repair work, and contracts to expedite the procurement of equipment will be in place going forward to mitigate these issues.
- **Solar and Wind Variability:** Smaller entities in the Rocky Mountain area have stated that wind and solar variability is a concern year-round due to a lack of geographic diversity. These entities are pursuing advancement into RTOs to leverage the advantages of a wider footprint and additional resources.
- **Electric-Gas Coordination:** The Rocky Mountain area contains entities that consider electric-gas coordination in long-term planning studies as well as entities that do not. For entities that do consider electric-gas coordination, peak capacity requirements for the local distribution company (LDC) and generating assets are inputs into long term planning models. Peak capacity requirements define the pipeline capacity and contractual volumes needed to fulfill LDC and electric needs. In addition, known and historical constraints on pipelines are considered in resource planning studies. Gas suppliers in this subregion have multiple delivery points to resources. This allows for an alternative location for delivery if one delivery point is inaccessible. In addition, gas supply teams provide an email with natural gas price information and constraints to generation dispatchers and marketers daily. During times of cold weather, this communication stream can be expanded to include interstate gas control and commercial operations.

- **Renewable Portfolio, Clean Electricity, and Emissions Standards:** Colorado requires investor-owned utilities to adopt plans to reduce greenhouse gas emissions by at least 80% by 2030, using a 2005 baseline. While the state is on track to achieve this, the additional goal of being 100% carbon free by 2040 is being discussed by utilities, regulators, and legislators, with a proposal to extend the out-year to 2050 in light of the upward pressure on the cost of renewables caused by potential repeal of tax credits and higher tariffs on imports.

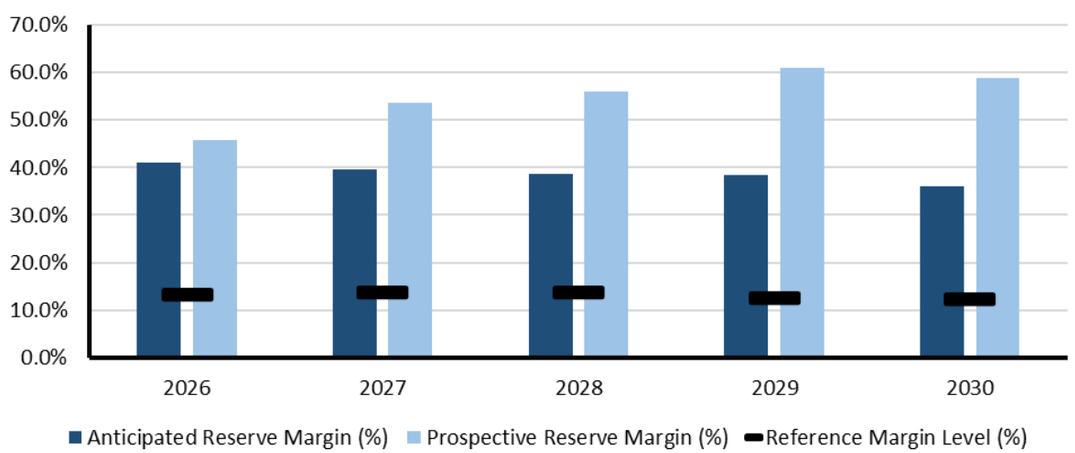


WECC-Southwest

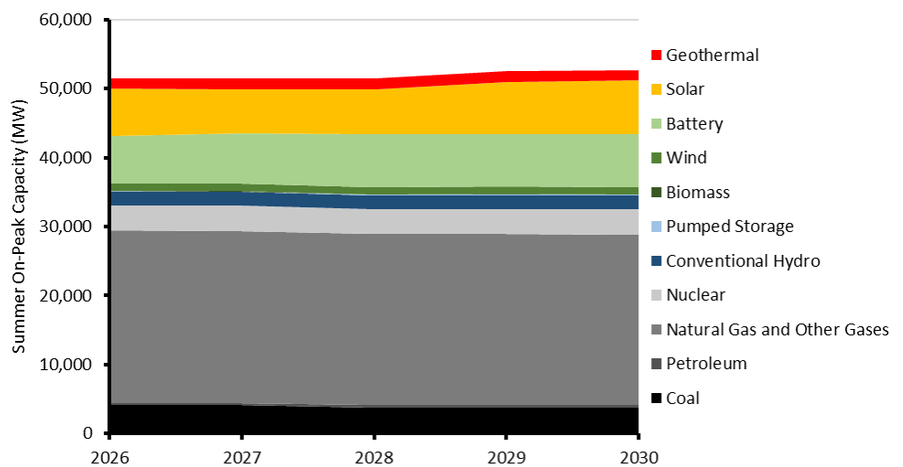
WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025 LTRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability information. WECC-Southwest is a new, larger assessment area in 2025 that now includes a portion of WECC-NW in the 2024 LTRA.*

Demand, Resources, and Reserve Margins

Quantity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Total Internal Demand	37,407	38,911	40,429	41,887	43,551	44,772	45,664	46,317	47,226	47,988
Demand Response	237	258	264	272	282	237	258	264	272	282
Net Internal Demand	37,169	38,653	40,165	41,615	43,269	44,535	45,405	46,053	46,953	47,706
Additions: Tier 1	6,639	7,501	8,155	8,562	8,914	8,914	8,914	8,396	8,852	8,852
Additions: Tier 2	1,771	5,410	6,994	9,369	9,872	11,263	11,286	10,468	11,286	11,252
Additions: Tier 3	2,502	3,899	5,242	7,562	9,710	12,409	14,804	14,801	24,521	24,571
Net Capacity Transfers (WECC Model)	902	2,544	4,162	5,101	6,301	5,895	5,570	4,880	5,030	4,715
Existing-Certain and Net Transfers	45,794	46,457	47,523	49,023	49,986	49,308	47,432	44,294	44,948	43,944
Anticipated Reserve Margin (%)	41.1%	39.6%	38.6%	38.4%	36.1%	30.7%	24.1%	14.4%	14.6%	10.7%
Prospective Reserve Margin (%)	45.8%	53.6%	56.0%	60.9%	58.9%	56.0%	49.0%	37.1%	38.6%	34.3%
Reference Margin Level (%)	13.3%	13.7%	13.6%	12.6%	12.2%	12.0%	11.7%	12.3%	11.3%	11.1%



Planning Reserve Margins



Existing and Tier 1 Resources

WECC-Southwest Highlights

- ARM remains above the RML through 2034. Furthermore, ProbA results indicate that planned resources can reliably meet demand during the studied years of 2027 and 2029.
- The ARM falls below the RML in Summer 2034. With the addition of Prospective Resources, the area can remain above RML.

WECC-Southwest Projected Generating Capacity by Energy Source in Megawatts (MW)					
	2026	2027	2028	2029	2030
Coal	4,121	4,116	3,749	3,754	3,754
Coal*	3,761	4,116	3,749	3,754	2,576
Petroleum	341	340	340	336	336
Natural Gas	24,978	24,887	24,817	24,837	24,750
Biomass	46	46	46	46	46
Solar	6,867	6,349	6,503	7,474	7,804
Wind	1,059	1,055	1,055	1,059	1,050
Geothermal	1,555	1,555	1,607	1,572	1,454
Conventional Hydro	1,984	1,989	1,989	1,982	1,981
Pumped Storage	113	113	113	113	113
Nuclear	3,641	3,640	3,640	3,641	3,641
Battery	6,824	7,325	7,657	7,671	7,671
Total MW	51,530	51,414	51,516	52,484	52,598
Total MW*	51,170	51,414	51,516	52,484	51,421
***Capacity with additional generator retirements**. Generators that have announced plans to retire but have yet to be included in system plans are removed from the resource projection where marked.					

WECC-Southwest

Planning Reserve Margins
The ARM falls below the RML in Summer 2034 but is covered by the PRM. Arizona Public Service and Public Service Company of New Mexico (PNM) are participants in the WRAP.

Energy Assessment, Including Non-Peak Hour Risk
WECC performs a probabilistic resource adequacy analysis using the MAVRIC model. MAVRIC is WECC's internally developed modeling tool that performs energy based probabilistic assessments that support NERC's LTRA and seasonal assessments, as well as WECC's WARA.

ProbA Results

The ProbA found that planned resources meet demand and reliability margins for all hours (no EUE or LOLH).

Base-Case Summary of Results			
	2026*	**2027**	**2029**
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
* No prior results as the assessment area is new for the 2025 LTRA.			

WECC-Southwest does not show any LOLH or EUE in 2027 or 2029; therefore, no additional visualizations are provided.

Demand
The average annual demand growth rate for WECC-Southwest is 3.9%. The primary drivers are data centers, industrial electrification, residential electrification, and residential customer growth. Large-load additions in the forecast are 9,422 MW through 2035.

Demand-Side Management
In the Southwest, Arizona Public Service is in the process of implementing numerous DSM pilots and programs such as the Residential Energy Storage Pilot and Commercial Advanced Rooftop Controls. The Residential Energy Storage Pilot enables the company to dispatch a small battery energy storage system up to 20% of the system's capacity.

Salt River Project (SRP) continues to leverage approximately 87 MW of DR capability through more than 75,000 residential smart thermostats, and 41 MW from over 500 businesses enrolled as interruptible customers. SRP intends to achieve 300 MW of dispatchable DR capability by 2035.

PNM programs reduce peak demand by an average of 45 MW per summer event from its two primary programs enrolling the ability to call on commercial customers and residential air conditioners up to 100 hours with a four-hour limit per curtailment.

Distributed Energy Resources
BAs did not report a forecast for BTM resources. Some information is available through the EIA on both historical and forecast data. BTM DER impacts are reflected in the demand data (net of the DER).

Generation
Operational and planning issues related to generation in WECC-Southwest include the following:

- **Aging Thermal Resource Fleet**: A year-round concern for this subregion is an aging thermal resource fleet. Hundreds of MW of capacity in this region have been operational for over 60 years. During the winter, certain thermal resources are unable to cycle below 40°F due to freezing issues. Older sites also require extensive overhauls such as generator rewinds that can keep resources out of service for extended periods of time and potentially longer than planned as discovery work manifests into additional maintenance. To reduce the risk of age-related forced outages, plant staff adhere to a strict maintenance schedule with frequent inspections, and unit performance is routinely monitored.
- **Behind-the-Meter Variability:** BTM output variability can be an operational concern for this subregion year-round as BTM solar can supply a large amount of energy to the system. Unanticipated loss of BTM generation is addressed through activation of DR programs, peaking power plants, and maintaining sufficient BESS charge. Near-term forecasts for BTM output are also made available to system operators so they can pre-emptively dispatch the system as needed.
- **Coal Inventory Shortages:** In-progress fuel conversions of coal to gas create a balancing act of maintaining coal on-site to operate resources while also avoiding excess coal post conversion. This can limit coal resources to minimum output prior to the fuel conversion outage. In addition, site-specific challenges at coal mines have delayed coal deliveries to resources in this subregion. Active management of on-site inventory and procurement of fuel from other sources can mitigate these issues.

- **Gas Fleet Derates:** Gas resources in this subregion can be derated during hot weather in the summer due to ambient conditions. During the winter, gas supply has been cut to plants in this subregion during cold snaps. Near-term monitoring of gas availability along with additional market purchases or fuel switching for capable resources can assist in mitigating supply issues.
- **Solar Variability:** Solar output variability is a concern year-round for this subregion. It is a primary concern on summer evenings as solar output rapidly declines whereas load increases or remains elevated. Activation of DR programs, peaking/flexible power plants, and maintaining sufficient BESS charge are all potential strategies to mitigate this issue. Large changes in solar output can also cause extreme ACE fluctuations, which are addressed using BESS.
- **Electric-Gas Coordination:** Most entities in the area consider electric-gas coordination in long-term planning studies. Resource planning models compare forecasted gas usage on both daily and hourly intervals to firm contractual rights. Gas usage exceeding firm obligations results in unserved energy, which can then be addressed via spot market purchases, short-term gas transport capacity purchases, or the dispatching of other resources. Entities also account for forecasted LDC usage and reduce the available natural gas for electric use by this amount. Resource adequacy models do not yet incorporate gas pipeline constraints, but consideration is being given to how to incorporate these into modeling efforts.

  Procedures to mitigate gas supply issues include anticipating losses of scheduled gas from the supply side, ensuring scheduled pipeline maintenance is accounted for in operations, and maximizing the availability of dual fuel resources. Planning teams also coordinate with operations teams for gas supply issues on a season-ahead basis, and operations can re-dispatch the system as needed to manage fuel shortages. During times of potential freeze-offs, trading practices may also be changed to not overextended firm load requirements. Entities maintain winter and summer readiness plans that are shared between electric system operators and gas pipeline operators to ensure maintenance schedules are aligned. Gas system limitations are made known to electric system operators through routine meetings between system operators and pipeline operators.
- **Renewable Portfolio, Clean Electricity & Emissions Standards:** In the Southwest region, Arizona has an RPS mandate for its electric supply to be 15% renewable by 2025. Separately, APS has committed to ending the use of coal-fired generation after 2031, and the company set a 100% carbon free by 2050 goal. SRP has goals to reduce CO2 emissions per MWh by 62% from 2005 levels by 2035 and 90% by 2050; TEP will stop using coal by 2032 and plans to reduce carbon emissions by 80% by 2035. New Mexico has set more aggressive mandates, requiring 50% renewable by 2030, 80% by 2040, and 100% by 2045.

Demand Assumptions and Resource Categories

Demand (Load Forecast)	
Total Internal Demand	This is the peak hourly load[49] for the summer and winter of each year.[50] Projected total internal demand is based on normal weather (50/50 distribution)[51] and includes the impacts of distributed resources, EE, and conservation programs.
Net Internal Demand	This is the total internal demand reduced by the amount of controllable and dispatchable DR projected to be available during the peak hour. Net internal demand is used in all reserve margin calculations.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[52]**	**Load Forecasting Entity**
MISO	Summer	Coincident	MISO LSEs
MRO-Manitoba Hydro	Winter	Coincident	Manitoba Hydro
MRO-SaskPower	Winter	Coincident	SaskPower
MRO-SPP	Summer	Noncoincident	SPP LSEs
NPCC-Maritimes	Winter	Noncoincident	Maritimes sub-areas
NPCC-New England	Summer	Coincident	ISO-NE
NPCC-New York	Summer	Coincident	NYISO
NPCC-Ontario	Summer	Coincident	IESO
NPCC-Québec	Winter	Coincident	Hydro-Québec
PJM	Summer	Coincident	PJM
SERC-East	Summer	Noncoincident	SERC LSEs
SERC-Florida Peninsula	Summer	Noncoincident	
SERC-Central	Summer	Noncoincident	
SERC-Southeast	Summer	Noncoincident	
Texas RE-ERCOT	Summer	Coincident	ERCOT
WECC-Alberta	Winter	Noncoincident	WECC BAs, aggregated by WECC
WECC-Basin	Summer	Noncoincident	
WECC-British Columbia	Winter	Noncoincident	
WECC-California	Summer	Noncoincident	
WECC-Mexico	Summer	Noncoincident	

[49] Glossary of Terms Used in NERC Reliability Standards.
[50] The summer season represents June–September and the winter season represents December–February. In this assessment, the year of a winter period is referred to by the year of the month of December (e.g., Winter 2025 is December 2025 – February 2026).
[51] Essentially, this means that there is a 50% probability that actual peak demand will be higher and a 50% probability that actual peak demand will be lower than the value provided for a given season/year.
[52] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval. This is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year.

Load Forecasting Assumptions by Assessment Area			
Assessment Area	**Peak Season**	**Coincident / Noncoincident[52]**	**Load Forecasting Entity**
WECC-Northwest	Winter	Noncoincident	
WECC-Rocky Mountain	Summer	Noncoincident	
WECC-SW	Summer	Noncoincident	

Resource Categories

NERC collects projections for the amount of existing and planned capacity and net capacity transfers (between assessment areas) that will be available during the forecast hour of peak demand for the summer and winter seasons of each year. Resource planning methods vary throughout the North American BPS. NERC uses the following categories to provide a consistent approach for collecting and presenting resource adequacy.

Anticipated Resources[53]

- Existing-certain generating capacity: includes capacity to serve load during period of peak demand from commercially operable generating units with firm transmission or other qualifying provisions specified in the market construct.
- Tier 1 capacity additions: includes capacity that is either under construction or has received approved planning requirements
- Firm capacity transfers (Imports minus Exports): transfers with firm contracts
- Less confirmed retirements[54]

Prospective Resources: Includes all "anticipated resources" plus the following:

- Existing-other capacity: includes capacity to serve load during period of peak demand from commercially operable generating units without firm transmission or other qualifying provision specified in the market construct. Existing-other capacity could be unavailable during the peak for a number of reasons.
- Tier 2 capacity additions: includes capacity that has been requested but not received approval for planning requirements
- Expected (non-firm) capacity transfers (imports minus exports): transfers without firm contracts but a high probability of future implementation.
- Less unconfirmed retirements.[55]

[53] Projected capacities are inputs to reserve margin calculations and probabilistic assessments. Projections are dependent on official retirement notices to system operators. If no notice is given, capacity projections assume no retirements, even if established trends for resource retirements show declines over past years

[54] Generators that have formally announced retirement plans. These units must have an approved generator deactivation request where applicable.

[55] Capacity that is expected to retire based on the result of an assessment area generator survey or analysis. This capacity is aggregated by fuel type.

Resource Categories

Generating Unit Status: Status at time of reporting:

- Existing: It is in commercial operation.
- Retired: It is permanently removed from commercial operation.
- Mothballed: It is currently inactive or on standby but capable for return to commercial operation. Units that meet this status must have a definite plan to return to service before changing the status to "Existing" with capacity contributions entered in "Expected-Other." Once a "mothballed" unit is confirmed to be capable for commercial operation, capacity contributions should be entered in "Expected-Certain."
- Cancelled: planned unit (previously reported as Tier 1, 2, or 3) that has been cancelled/removed from an interconnection queue.
- Tier 1: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[56]
  - Construction complete (not in commercial operation)
  - Under construction
  - Signed/approved Interconnection Service Agreement (ISA)
  - Signed/approved Power Purchase Agreement (PPA) has been approved
  - Signed/approved Interconnection Construction Service Agreement (CSA)
  - Signed/approved Wholesale Market Participant Agreement (WMPA)
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to Vertically Integrated Entities)
- Tier 2: A unit that meets at least one of the following guidelines (with consideration for an area's planning processes):[57]
  - Signed/approved Completion of a feasibility study
  - Signed/approved Completion of a system impact study
  - Signed/approved Completion of a facilities study
  - Requested Interconnection Service Agreement
  - Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)
- Tier 3: A units in an interconnection queue that do not meet the Tier 2 requirement.

[56] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)
[57] AESO: Project has completed Stage 4: the Alberta Utilities Commission (AUC) has issued a Permit and License (AESO-specific)

Reserve Margin Descriptions
Planning Reserve Margins: The primary metric used to measure resource adequacy defined as the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile
Anticipated Reserve Margin (ARM): The amount of anticipated resources less net internal demand calculated as a percentage of net internal demand
Prospective Reserve Margin (PRM): The amount of prospective resources less net internal demand calculated as a percentage of net internal demand
Reference Margin Level (RML): The assumptions and naming convention of this metric vary by assessment area. The RML can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, system planners use this metric is to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing an RML is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increased demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the RML is a requirement. RMLs can fluctuate over the duration of this assessment period or may be different for the summer and winter seasons. If an RML is not provided by a given assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Methods and Assumptions

How NERC Defines BPS Reliability

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:

- **Adequacy:** The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components
- **Operating Reliability:** The ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system components

When extreme or otherwise unanticipated conditions result in a resource shortfall, system operators take controlling actions or implement procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area); these actions include the following:

- Public appeals
- Interruptible demand that the end-use customer makes available to its LSEs via contract or agreement for curtailment[58]
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5%)
- Rotating blackouts (The term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, rotating the outages among individual feeders.)

System disturbances affect operating reliability when they cause the unplanned and/or uncontrolled interruption of customer demand. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When interruptions spread over a wide area of the grid, they are referred to as "cascading blackouts," the uncontrolled successive loss of system elements triggered by an incident at any location.

The BES is a defined subset of the BPS that includes all facilities necessary for the reliable operation and planning of the BPS.[59] NERC Reliability Standards are intended to establish requirements for BPS owners and operators so that the BES delivers an adequate level of reliability (ALR),[60] which is defined by the following characteristics.

- **Adequate Level of Reliability:** It is the state that the design, planning, and operation of the BES will achieve when the following reliability performance objectives are met:
  - The BES does not experience instability, uncontrolled separation, cascading,[61] and/or voltage collapse under normal operating conditions or when subject to predefined disturbances.[62]
  - BES frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - BES voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.

[58] Interruptible demand (or interruptible load) is a term used in NERC Reliability Standards. See Glossary of Terms used in Reliability Standards: NERC Glossary of Terms
[59] BES Definition
[60] NERC Informational Filing (to FERC) on the Definition of Adequate Level of Reliability, Docket Number RR06-1, May 10, 2013.
[61] NERC's Glossary of Terms defines Cascading: "Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."
[62] NERC's Glossary of Terms defines Disturbance: "1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load."

- Adverse reliability impacts on the BES following low-probability disturbances (e.g., multiple BES contingences, unplanned/uncontrolled equipment outages, cyber security events, malicious acts) are managed.

Restoration of the BES after major system disturbances that result in blackouts and widespread outages of BES elements is performed in a coordinated and controlled manner.

How NERC Evaluates Reserve Margins in Assessing Resource Adequacy

PRMs are calculated by finding the difference between the amount of projected on-peak capacity and the forecasted peak demand and then dividing this difference by the forecasted peak demand. Each assessment area has a peak season, summer or winter, for which its peak demand is higher. PRMs used throughout this LTRA are for each assessment area's peak season listed in the load forecasting table of the **Demand Assumptions and Resource Categories**.

NERC assesses resource adequacy by evaluating each assessment area's PRMs relative to its RML—a "target" or requirement based on traditional capacity planning criteria. The projected resource capacity used in the evaluations is reduced by known operating limitations (e.g., fuel availability, transmission limitations, environmental limitations) and compared to the RML, which represents the desired level of risk based on a probability-based loss-of-load analysis. On-peak resource capacity reflects expected output at the hour of peak demand. Because the electrical output of VERs (e.g., wind and solar) depend on weather conditions, on-peak capacity contributions are less than nameplate capacity. Based on the five-year projected reserves compared to the established RMLs, NERC determines the risk associated with the projected level of reserve and concludes in terms of the following:

- **Adequate:** The ARM is greater than RML.
- **Marginal:** The ARM is lower than the RML and the PRM is higher than RML.
- **Inadequate:** The ARM and PRMs are less than the RML and Tier 3 resources are unlikely to advance.

Metrics for Probabilistic Evaluation Used in this Assessment

Probabilistic Assessment: Biennially, NERC conducts a probabilistic evaluation as part of its resource adequacy assessment and publishes results in the LTRA.

Loss-of-Load Hours: LOLH is generally defined as the expected number of hours per time period (often one year) when a system's hourly demand is projected to exceed the generating capacity. This metric is calculated by using each hourly load in the given period (or the load duration curve).

LOLH is evaluated using all hours rather than just peak periods. It can be evaluated over seasonal, monthly, or weekly study periods. LOLH does not inform of the magnitude or the frequency of loss-of-load events, but it is used as a measure of their combined duration. LOLH is applicable to both small and large systems and is relevant for assessments covering all hours (compared to only the peak demand hour of each season). LOLH provides insight to the impact of energy limited resources on a system's reliability, particularly in systems with growing penetration of such resources. Examples of such energy limited resources include the following:

- DR programs that can be modeled as resources with specific contract limits, including hours per year, days per week, and hours per day constraints
- EE programs that can be modeled as reductions to load with an hourly load shape impact
- Distributed resources (e.g., BTM solar PV) that can be modeled as reductions to load with an hourly load shape impact
- VERs can be modeled probabilistically with multiple hourly profiles

Expected Unserved Energy: EUE is the summation of the expected number of megawatt hours of demand that will not be served in a given time period as a result of demand exceeding the available capacity across all hours. EUE is an energy-centric metric that considers the magnitude and duration for all hours of the time period and is calculated in MWhs. This measure can be normalized based on various components of an assessment area (e.g., total of peak demand, net energy for load). Normalizing the EUE provides a measure relative to the size of a given assessment area (generally in terms of parts per million or ppm).

EUE is the only metric that considers magnitude of loss-of-load events. With the changing generation mix, to make EUE a more effective metric, hourly EUE for each month provides insights on potential adequacy risk during shoulder and nonpeak hours. EUE is useful for estimating the size of loss-of-load events so the planners can estimate the cost and impact. EUE can be used as a basis for reference reserve margin to determine capacity credits for VERs. In addition, EUE can be used to quantify the impacts of extreme weather, common mode failure, etc.

NERC is not aware of any planning criteria in North America based on EUE; however, in Australia, the Australian Energy Market Operator is responsible for planning using 0.002% (20 ppm) EUE as their energy adequacy requirement.[63] This requirement incorporates economic factors based on the risk of load shedding and the value of load loss along with the load-loss reliability component.

On the basis of the two years of the ProbA results, NERC determines the risk in terms of the following:

- **Normal Risk:** Negligible amounts of LOLH and EUE.
- **Periods of Risk:** LOLH < 2 Hours and EUE < 0.002% of total annual net energy.
- **Significant Risk:** LOLH > 2 Hours and EUE > 0.002% of total annual net energy.

Understanding Demand Forecasts

Future electricity requirements cannot be predicted precisely. Peak demand and annual energy use are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities. Therefore, the electric industry continues to monitor electricity use and generally revise its forecasts on an annual basis or as its resource planning requires. In recent years, the difference between forecast and actual peak demands have decreased, reflecting a trend toward improving forecasting accuracy.

The peak demand and annual net energy for load projections are aggregates of the forecasts of the individual planning entities and LSEs. These resulting forecasts reported in this LTRA are typically “equal probability” forecasts. That is, there is a 50% chance that the forecast will be exceeded and a 50% chance that the forecast will not be reached.

Forecast peak demands, or total internal demand, are electricity demands that have already been reduced to reflect the effects of DSM programs, such as conservation, EE, and time-of-use rates; it is equal to the sum of metered (net) power outputs of all generators within a system and the metered line flows into the system less the metered line flows out of the system. Thus, total internal demand is the maximum (hourly integrated) demand of all customer demands plus losses. The effects of DR resources that are dispatchable and controllable by the system operator, such as utility-controlled water heaters and contractually interruptible customers, are not included in total internal demand. Rather, the effects of dispatchable and controllable DR are included in net internal demand.
Future Transmission Project Categories

- **Under Construction:** Construction of the line has begun.
  - Planned (any of the following):
  - Permits have been approved to proceed

[63] https://wa.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf

- Design is complete
- Needed in order to meet a regulatory requirement

- **Conceptual** (any of the following):
  - A line projected in the transmission plan
  - A line that is required to meet a NERC TPL standard or power-flow model and cannot be categorized as “Under Construction” or “Planned”
  - Other projected lines that do not meet requirements of “Under Construction” or “Planned”

Summary of Planning Reserve Margins and Reference Margin Levels by Assessment Area

Reference Margin Levels for Each Assessment Area (2026–2030)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
MISO	2025-2026 Summer: 8.1% Fall: 14.9% Winter: 19.1% Spring (2027): 26.2%	Planning Reserve Margin	Yes: Established Annually[64]	0.1 day/Year Loss of Load Expectation (LOLE)	MISO
MRO-Manitoba Hydro	12.0%	Reference Margin Level	No	0.1 day/Year LOLE	Reviewed by the Manitoba Public Utilities Board
MRO-SaskPower	15.0%	Reference Margin Level	No	EUE and Deterministic Criteria	SaskPower
MRO-SPP	19.0%	Resource Adequacy Requirement	Yes: studied on Biennial Basis	0.1 day/Year LOLE	SPP Staff, Stakeholders, SPP Regional State Committee.
NPCC-Maritimes	20.0%[65]	Reference Margin Level	No	0.1 day/Year LOLE	Maritimes Sub-areas; NPCC
NPCC-New England	13.0–13.4%	Installed Capacity Requirement	Yes: three year requirement established annually	0.1 day/Year LOLE	ISO-NE, NPCC Criteria
NPCC-New York	15.0%[66]	Installed Reserve Margin	Yes: one year requirement, established annually by NYSRC based on full installed capacity values of resources	0.1 day/Year LOLE	NYSRC, NPCC Criteria
NPCC-Ontario	15.8–22.6%	Reserve Margin Requirement	Yes: established annually for all years	0.1 day/Year LOLE	IESO, NPCC Criteria
NPCC-Québec	11.9–12.2%	Reference Margin Level	No: established Annually	0.1 day/Year LOLE	Hydro-Québec, NPCC Reliability Coordinating Committee
PJM	18.6–26.3%	Installed Reserve Margin	Yes: established Annually for each of three future years	0.1 day/Year LOLE	PJM Board of Managers, ReliabilityFirst BAL-502-RFC-02 Standard
SERC-Central	15.0%[67]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities

[64] In MISO, the states can override the MISO PRM.

[65] The 20% RML is used by the individual jurisdictions in the Maritimes area with the exception of Prince Edward Island, which uses a margin of 15%. Accordingly, 20% is applied for the entire area.

[66] The NERC LTRA RML for NY is 15%; however, there is no PRM criteria in New York. Wind, grid-connected solar, and run-of-river totals were derated for this calculation. Additionally, the NYISO uses probabilistic assessments to evaluate its system's resource adequacy against the LOLE resource adequacy criterion of 0.1 days/year. However, New York requires LSEs to procure capacity for their loads equal to their peak demand plus an IRM. The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council (NYSRC). NYSRC approved the 2025/2026 IRM at 24.4%. All values in the IRM calculation are based upon full installed capacity (ICAP) MW values of resources, and it is identified based on annual probabilistic assessments and models for the upcoming capability year.

[67] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.

Reference Margin Levels for Each Assessment Area (2026–2030)					
Assessment Area	**Reference Margin Level**	**Assessment Area Terminology**	**Requirement?**	**Methodology**	**Reviewing or Approving Body**
SERC-East	15.0%[68]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
SERC-Florida Peninsula	15.0%[69]	Reliability Criterion	No: Guideline	0.1 day/Year LOLP	Florida Public Service Commission
SERC-Southeast	15.0%[70]	Reference Margin Level	No: NERC-Applied 15%	SERC Performs 0.1 day/Year LOLE	Reviewed by Member Utilities
Texas RE-ERCOT	13.75%	Target Reserve Margin	No	0.1 day/Year LOLE plus adjustent for non-modeled market considerations	ERCOT Board of Directors
WECC-Alberta	11.6–17.6%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[71]
WECC-Basin	12.3–14.0%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]
WECC-British Columbia	11.6–12.1%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]
WECC-California[72]	19.2–20.3%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]
WECC-Mexico	7.0–9.1%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]
WECC-Northwest	15.5–17.8%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]
WECC-Rocky Mountain	15.7–17.8%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]
WECC-Southwest	12.2–13.7%	Reference Margin Level	No: Guideline	Based on a conservative .02% threshold	WECC[58]

[68] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[69] SERC-FP uses a 15% reference reserve margin as approved by the Florida Public Service Commission for non-IOUs and recognized as a voluntary 20% reserve margin criteria for IOUs; individual utilities may also use additional reliability criteria.
[70] SERC does not provide RMLs or resource requirements for its sub-areas. However, SERC members perform individual assessments to comply with any state requirements.
[71] WECC's RML in this table is for the hour of peak demand. Some hours in the year require a higher reserve margin to meet the 0.02% reliability criteria due to the variability in resource availability and resource performance characteristics.
[72] California is the only state in the Western Interconnection that has a wide-area RML, currently 17.5%: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage,

Recommendations and ERO Actions Summary

In addition to the recommendations in the Executive Summary, NERC recommends continued progress in areas identified previously in NERC's LTRA and other assessment reports. The ERO, industry, vendors/manufacturers, and stakeholders should continue acting on the following recommendations to inform system and operations planning, develop the transmission network, and address resource performance issues attributed to IBR characteristics, cold weather, and fuel supply limitations. The ERO has a range of activities underway to monitor, assess, and reduce long-term BPS reliability risks. The selected ERO activities summarized below will result in new or enhanced Reliability Standards requirements, reliability guidelines, resources, or significant findings and actionable steps for stakeholders to address reliability risks.

LTRA Recommendations and Ongoing ERO Actions

Add new resources with needed reliability attributes and make existing resources more dependable.

1. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric criteria applied to results from probabilistic studies that include load loss, unserved energy, event magnitude, and event duration will support achieving the levels of reliability that are required for modern society.

2. **Address performance deficiencies with existing and future inverter-based resources:** Reliably integrating IBRs onto the grid is paramount, and evidence indicates that the risk of grid vulnerabilities from interconnection practices and IBR performance issues are growing. IBRs include most solar and wind generation as well as new BESS or hybrid generation and account for 85% of the new generation in development for connecting to the BPS. IBRs respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused sudden loss of generation resources (over wide areas in some cases). Industry experience with unexpected tripping of BPS-connected solar PV generation units can be traced back to the 2016 Blue Cut fire in California, and similar events have occurred in new geographic areas as recently as the summer of 2023.[73] A common thread with these events is the lack of IBR ride-through capability that causes a minor system disturbance to become a major disturbance. Based on the findings of a recent NERC alert, more ride-through and ERS capabilities can be enabled within existing solar PV resources to improve performance and support the reliable operation of the BPS.[74] Industry adoption of the recommended practices set forth in NERC reliability guidelines and the NERC alert will reduce risks from IBR performance issues to the grid as NERC also develops mandatory Reliability Standards based on those reliability guidelines. It is also critically important for interconnection processes to include accurate modeling and studies requirements.[75] Guided by NERC's comprehensive Inverter-Based Resources Strategy and in response to FERC Order No. 901, the ERO, industry, and manufacturers should take additional steps to ensure that IBRs operate reliably and that the system is planned with due consideration for their characteristics.[76,77]

3. **Improve the performance of the generating fleet in extreme cold temperatures:** The ERO and industry need to complete enhanced requirements for generator cold weather performance to address reliability related findings from the FERC, NERC, and Regional Entity joint staff inquiry into the February 2021 cold weather grid outages.[78] Revisions to Reliability Standard EOP-012-2 will improve the effectiveness of the standard and speed the implementation of corrective actions necessary to address unacceptable freezing issues. Findings of the inquiry into Winter Storm Elliott (December 2022) reinforce the urgency of this effort.[79]

[73] See the ERO's extensive IBR event reporting here: NERC Major Event Reports
[74] The NERC Level 2 alert to gather data from solar PV resource owners and issue recommendations can be found here: *Industry Recommendation: Inverter-Based Resource Performance Issues*.
[75] NERC's comprehensive initiatives to reduce IBR risks are detailed here: IBR Quick Reference Guide
[76] NERC IBR Activities
[77] Order No. 901 Work Plan
[78] *The February 2021 Cold Weather Outages in Texas and the South Central United States | FERC, NERC and Regional Entity Staff Report*
[79] *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott*

LTRA Recommendations and Ongoing ERO Actions

4. **Mitigate fuel-related risks to electricity generation (fuel assurance):** In addition to serving as base and intermediate-load plants, natural-gas-fired generation has become a necessary balancing resource that enables reliable integration of VERs into the dispatch. As a result, the BES has never been more dependent upon the round-the-clock continuity of just-in-time natural gas delivery. The past two winters have seen interruptions of natural gas delivery to generators that resulted in energy deficiencies. Collaborative assessments involving NERC, the Regional Entities, the National Labs, and natural gas and electric power industry participants are needed to identify natural gas fuel supply needs for reliable operation of the BPS. NERC strongly endorses actions to establish reliability rules for the natural gas infrastructure necessary to support the grid as recommended in the Winter Storm Elliott report. Additionally, as part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electricity reliability. The NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System,* provides planning guidance.[80]

Initiative	Description	Product/Reliability Solution
Cold Weather Reliability Standards and Activities	Cold weather Reliability Standards adopted by the NERC Board of Trustees in June 2021 went into effect in the United States in 2023. Generator Owners and Generator Operators are required to implement plans for cold weather preparedness and provide cold weather operating parameters to their Reliability Coordinators, Transmission Operators, and BAs for use in operating plans. Additional Reliability Standard requirements were developed by NERC and industry to address further recommendations of the *FERC-NERC-Regional Entity Staff Report—The February 2021 Cold Weather Outages in Texas and the South Central United States* and respond to FERC directives.[81] In September 2025, FERC approved EOP-012-3 with an effective date of October 1, 2025. The revised standard strengthens generator preparedness by providing clearer and more effective requirements. In the approval order, FERC also directed NERC to make information fillings to FERC every two years beginning in October 2026 and continuing through October 2034, to assess the adequacy of the standard's ability to address reliability concerns and inform potential future modifications.	Reliability Standards NERC Alerts Event Analysis Reports Lessons Learned
Inverter-Based Resources Strategy	NERC's IBR strategy includes four key focus areas: Risk Analysis, Interconnection Process Improvements, Sharing Best Practices and Industry Education, and Regulatory Enhancements. The statuses of NERC's extensive activities in each area are described in detail in the *IBR Activities Reference Guide*.[82] NERC has investigated and analyzed IBR performance issues during grid disturbances dating back to 2016. Since that time, NERC and its technical groups have published a range of reliability guidelines for studying, modeling, controlling, and interconnecting IBRs. In partnership with many experts from across the industry, NERC maintains an active campaign of education, awareness, and outreach to support its strategy and reduce IBR performance risks. NERC and the RSTC recognized that Reliability Standard requirements would be needed as part of a comprehensive approach to reliability and undertook a full review of existing standards to identify gaps. Several reliability standards projects were initiated following this review. In October 2023, FERC issued Order No. 991, which provided clear direction for the industry to develop requirements that address reliability gaps related to IBR in data sharing, model validation, planning and operational studies, and performance requirements.	Reliability Standards NERC Alerts Reliability Guidelines Event Analysis Reports Lessons Learned Educational Webinars

[80] Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised Guideline also identifies as fuel risks requiring evaluation many of the scenarios industry has encountered during recent periods of extreme cold weather and high demand for natural gas. The revised guideline is under review with the Reliability and Security Technical Committee. The approved and revised draft guideline can be found on the RSTC website: NERC Reliability and Security Guidelines

[81] Refer to *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* and *Project 2024-03 Revisions to EOP-012-2* on NERC's standards development page. Project 2021-07

[82] IBR Activities

LTRA Recommendations and Ongoing ERO Actions		
	FERC issued an order in 2022 directing NERC to identify and register owners and operators of currently unregistered BPS-connected IBRs.[83] Working closely with industry and stakeholders, NERC is executing a FERC-approved work plan to achieve the identification and registration directive by 2026. Resources are also posted on the Registration page of the NERC website.	
Natural Gas-Electric Interdependence Initiatives	Informed by severe weather events of the past two winters, the 2023 triennial review of the NERC reliability guideline, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System*, incorporated the *Design Basis for Natural Gas Study* developed by the ERO in 2022. The revised guideline also identifies the fuel risks encountered by industry during recent periods of extreme cold weather and high demand for natural gas. These natural gas supply risks can inform industry's development of planning scenarios. The revised guideline is under review with the RSTC. Refer to the RSTC-Approved Documents page.[84]	Reliability Guideline
Expand the transmission network to deliver supplies from new resources and locations to serve changing loads. 1. **Develop the transmission network:** ISOs and RTOs should continue looking for opportunities to streamline transmission planning processes and reduce the time required for transmission development. However, addressing the siting and permitting challenges that are the most common cause for delayed transmission projects will require regulators and policymakers at the federal, state, and provincial levels to focus attention and provide support.		
Initiative	**Description**	**Product/Reliability Solution**
***Interregional Transfer Capability Study* (ITCS)**	NERC completed the ITCS required by the Fiscal Responsibility Act of 2023 and filed the final report with FERC on November 19, 2024[85]. The ITCS is the first-of-its-kind assessment of transmission transfer capability under a common set of assumptions. However, the ITCS is not a transmission plan or blueprint. Transmission expansion analysis, resource plans, and other inputs must be considered in effective system planning. The ITCS is designed to provide foundational insights that facilitate stakeholder analysis and actions. Due to the interconnected nature of the BPS, NERC extended the study beyond the congressional mandate to identify and make recommendations for transfer capabilities from the United States to Canada and among Canadian provinces. The Canadian analysis was published in 2025.[86] See **Interregional Transfer Capability Study (ITCS) Canadian Analysis**.	ERO Study and Recommendations

[83] FERC Order Issued November 17, 2022
[84] RSTC Approved Documents
[85] NERC's *Interregional Transfer Capability Study* (ITCS) Final Report
[86] NERC's *Interregional Transfer Capability Study (ITCS) Canadian Analysis* Final Report

LTRA Recommendations and Ongoing ERO Actions

Adapt BPS planning, operations, and resource procurement markets and processes to the realities of a more complex power system.

1. **Use enhanced resource adequacy and energy risk assessments for determining resource needs:** PRMs are not sufficient for measuring resource adequacy for most areas because VERs and generator fuel supply issues expose additional energy risks. Resource Planners and wholesale markets need to use enhanced modeling that accounts for energy risks, such as all-hours probabilistic assessments. Multi-metric approaches to resource adequacy using load loss, unserved energy, and event magnitude and duration criteria and results from probabilistic studies will support achieving the levels of reliability that are required for modern society.
2. **Resource contributions must be accurately represented in resource planning, wholesale electricity markets, and operating models:** Resource Planners and wholesale market designers must use appropriate methods for determining the contribution of resources to meeting demand. Weather-dependent resources, fuel supplies, and demand profiles result in seasonal risks. This can be seen in the increasing winter resource adequacy risks observed in the 2024 ProbA for many traditionally summer-peaking areas. ISO/RTOs can help reduce seasonal risks by implementing seasonal resource adequacy procurement (e.g., spring, summer, fall, winter) based on reserve requirements and resource performance that are tailored to each season. The explosive growth of BESS and hybrid resources seen in most areas requires additional details to be incorporated into operating and planning models, such as state of charge, BESS duration, and BESS operating mode.
3. **Maintain sufficient amounts of flexible resources and essential reliability services:** To maintain load-and-supply balance in real-time with higher penetrations of variable supply and less-predictable demand, dispatchable generators must be available and capable of following changing electricity demand. Retirements of fossil-fired generators are reducing the amounts of dispatchable generation in many areas. As more solar PV and wind generation is added, additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. Natural-gas-fired generators and hydro generators have traditionally provided this ERS. Battery resources can provide flexibility during short durations, while new wind and solar PV have minimal assured flexibility. Maintaining ERSs is critically important. Resource Planners and wholesale electricity market operators should ensure resources are procured and made available in the long-range resource portfolio as part of the planning process; markets and other mechanisms need to be in place to deliver weather-ready resources with sufficient energy and ERS capabilities to the operators. [87]
4. **Include energy risks and extreme weather scenarios in resource and system planning:** Industry and regulators need to conduct all-hours analyses for evaluating and establishing resource adequacy and include extreme conditions in integrated resource planning and wholesale market designs. While more sophisticated capabilities for assessing extreme event risk are being developed, scenario planning can be more readily incorporated in resource and system planning. Scenarios should consider the potential effects of wide-area, long-duration extreme weather events, including the impact they can have on natural gas fuel supplies and on the interconnected energy system. NERC and the industry should continue to prioritize completion of new reliability standards supporting energy assurance in operating and planning time horizons, and for the assessment of extreme heat and cold weather events in transmission system planning.
5. **Accommodate the growth of DERs:** Preparing the grid to operate with increasing levels of distributed resources is a priority for most areas. Data sharing, models, and information protocols are needed to support BPS planners and operators. Industry must continue to evaluate potential reliability concerns associated with increasing DER penetration and DER performance and, when necessary, develop reliability standards requirements to address identified gaps. DER aggregators will also play an increasingly important role for BPS reliability in the coming years. ISO/RTOs must consider how the implementation of DER aggregators in the wholesale market will affect BPS planning and operations.[88]

[87] NERC ERS Measure 6 Forward Tech Brief
[88] A comprehensive guide to ERO activities on DERs can be found here: DER Activities

LTRA Recommendations and Ongoing ERO Actions		
Initiative	**Description**	**Product/Reliability Solution**
Energy Assessments Initiatives	NERC conducts seasonal long-term and probabilistic reliability assessments and issues reports like this *2025 LTRA* to advise industry and stakeholders of findings on BPS adequacy, including energy adequacy. In recent years, NERC has enhanced the energy risk analysis in seasonal assessments by incorporating deterministic energy risk scenarios and introducing probability-based assessments. NERC's ProbA uses hourly simulations to examine the ability of resources to meet demand over the entire study year, helping to identify energy risks that could otherwise go unaddressed by peak hour reserve margin resource adequacy analysis. NERC reliability assessments continue to evolve as more sophisticated energy assessment tools, models, and capabilities are developed. The RSTC created the Energy Reliability Assessment Working Group (ERAWG) to support wide adoption of technically sound approaches to energy assessments by BPS planners and operators. Working group projects and activities are described on the ERAWG page.[89] The working group is developing a technical reference document to inform registered entities on approaches and considerations for assessing and reducing the risk of energy shortfalls. New and revised Reliability Standards requirements for BPS planners and operators to address energy risks are in development in Project 2022-03 *Energy Assurance with Energy Constrained Resources.*[90] In other Reliability Standard development work, Project 2023-07 *Transmission System Planning Performance Requirements for Extreme Weather* requirements are being developed that will ensure entities consider extreme heat and cold weather scenarios in BPS planning, including the expected availability of the future resource mix.[91]	Reliability Assessments Reliability Standards
Distributed Energy Resources Strategy	NERC has proactively worked with industry stakeholders to identify BPS reliability risks associated with the increasing DER levels and has initiated actions to support broad awareness and education as well as to provide guidance for industry and enhance Reliability Standards where gaps exist. The statuses of NERC's extensive activities in each area are described in detail in the *DER Activities Reference Guide*.[92]	Reliability Standards Reliability Guidelines Educational Webinars
Strengthen relationships among reliability stakeholders.		
Initiative	**Description**	**Product/Reliability Solution**
Ongoing Strategic Engagements	NERC and the Regional Entities engage in frequent dialogue and conduct outreach with regulators and policymakers at the state/provincial, regional, and federal/national levels.	Constructive Partnerships

[89] ERAWG
[90] Project 2022-03
[91] Project 2023-07
[92] DER Activities

Errata

February 2026

- Resource mix changes: Corrected natural gas, solar, wind, conventional hydro, battery, and total resource capacity for 2025 in Table 16. Corrected the caption of Figure 16 (p. 30).
- WECC British Columbia: Corrected highlights for BC Hydro's most recent 10-year capital plan (p. 144 and 146), corrected the WRAP participation description (p. 145), corrected the DER programs (p. 145), and included a more current drought outlook from October 2025 in the Generation section (p.145)

2026 Summer Energy Market and Electric Reliability Assessment

FEDERAL ENERGY REGULATORY COMMISSION
Staff Report
May 2026

This report is a product of the Federal Energy Regulatory Commission staff. This report does not necessarily reflect the views of the Commission or any Commissioner.

PREFACE

The 2026 Summer Energy Market and Electric Reliability Assessment (2026 Summer Assessment) report provides Commission Staff's outlook for June through September 2026. The report contains five sections: a summary of key findings; anticipated weather and weather-related risks; notable reliability risks for the summer; energy market fundamentals; and regional electric reliability probabilistic assessments.

KEY FINDINGS IN SUMMER 2026 ASSESSMENT

TAKEAWAYS

- **High temperatures and extreme weather events are expected to challenge the electric grid.**
  - Drought and low snowpack could curb hydropower generation.
  - Wildfires and hurricanes may affect some parts of the country.
- **Projected generation and transmission additions will help address forecasted high electricity demand growth.**
- **Natural gas demand and production are both expected to increase.**
- **Resources and operating reserves are adequate in all NERC assessment areas under normal operating conditions.**
  - Possible reliability challenges in NPCC-NE, western ERCOT, and WECC-NW under extreme operating conditions.

Forecasted higher-than-average summer temperatures and uncertainty from extreme weather events are expected to challenge the electric grid this summer. Addressing those stressors may be difficult because several weather conditions build off each other, namely low snowpack, continued drought, and wildfires. The resulting low water levels are also expected to restrict hydropower generation in key regions.

As to market fundamentals, electricity consumption is expected to be higher in summer 2026 than in each of the previous five summers. However, new generator additions and transmission line expansions are expected to help address increased electricity demand. Also, natural gas demand is forecast to increase this summer compared to the previous five summers, while electricity generation is expected to continue to make up the largest share of total natural gas demand.

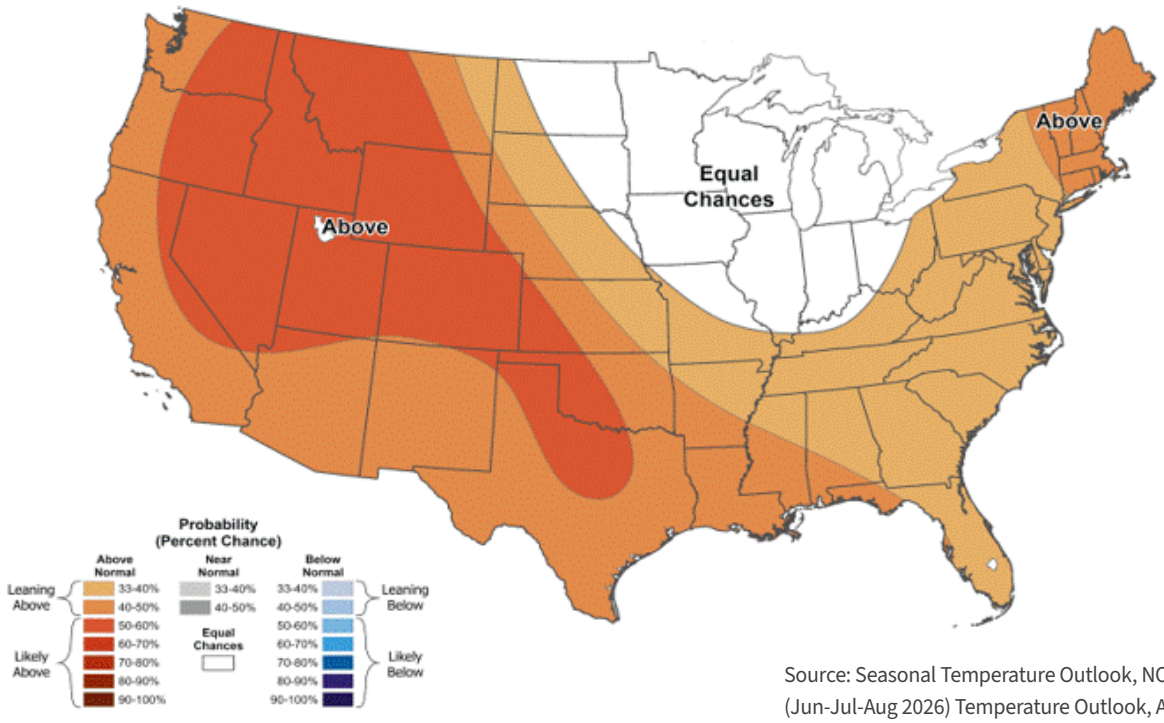
Wholesale electricity prices are expected to vary by region this summer, with the highest prices expected in the Mid-Atlantic (PJM Interconnection LLC), New York (New York Independent System Operator), and New England (ISO New England). Compared to last summer, natural gas prices are also expected to increase at major eastern trading hubs but decrease at most western and midcontinent trading hubs.

Based on data provided by the assessment areas, the North American Electric Reliability Corporation (NERC) has conducted probabilistic assessments that indicate possible challenges this summer for the electric grid. Under normal operating conditions, according to NERC, all assessment areas are expected to have adequate generating resources to meet expected summer electricity demand and operating reserve requirements. However, under

extreme weather conditions, three assessment areas face a higher likelihood of tight generation availability in a range of operating scenarios: the Northeast Power Coordinating Council-New England (NPCC-NE), the western part of the Electric Reliability Council of Texas (ERCOT), and the Western Energy Coordinating Council – Northwest (WECC-NW). These operating scenarios include higher peak load levels, reduced resources conditions, and wide-area extreme weather conditions that may disrupt available transfer and generator availability. If these scenarios occur, operational mitigation may be needed to avoid facing reliability issues.

WEATHER OUTLOOK

Figure 1: Summer Temperatures Likely Higher Than Average with Typical Hurricane Risk Expected



Source: Seasonal Temperature Outlook, NOAA Three Month (Jun-Jul-Aug 2026) Temperature Outlook, April 1, 2026.

Weather risk from extreme heat is elevated this summer with the potential to impact electricity markets and reliability. Forecasts from the National Oceanic and Atmospheric Administration (NOAA) for June to August 2026, shown in the map on **Figure 1**, project above-average temperatures across much of the United States.[1] Additionally, NOAA forecasts a 61% chance of El Niño conditions and a 1-in-4 chance that it will be a 'strong' El Niño later this year, raising the risk of extreme heat events this summer.[2] El Niño conditions typically drive higher temperatures across the northern and central United States and stronger storms in the South. As El Niño strengthens, extreme heat could strain the grid beyond expected operating conditions and result in sharp increases in demand as cooling load increases.

Geographically widespread, high temperatures can intensify stress on the electric grid by reducing the ability of neighboring systems to exchange supply while they are simultaneously facing high demand. High temperatures can also increase transmission line losses and cause conductors to reach operating limits sooner under the combination of high load and high heat conditions, all of which increase the risk of outages and make preparation essential.[3] Extreme heat can also reduce generator capacity, leading to outages or derates.[4]

1 NOAA uses a 30-year climate average in calculating these probabilities along with a range of inputs including the El Niño–Southern Oscillation (ENSO) forecasting data.

2 NOAA, *El Niño/Southern Oscillation (ENSO) Diagnostic Discussion* (Apr. 9, 2026), www.cpc.ncep.noaa.gov/products/analysis_monitoring/enso_advisory/ensodisc.shtml.

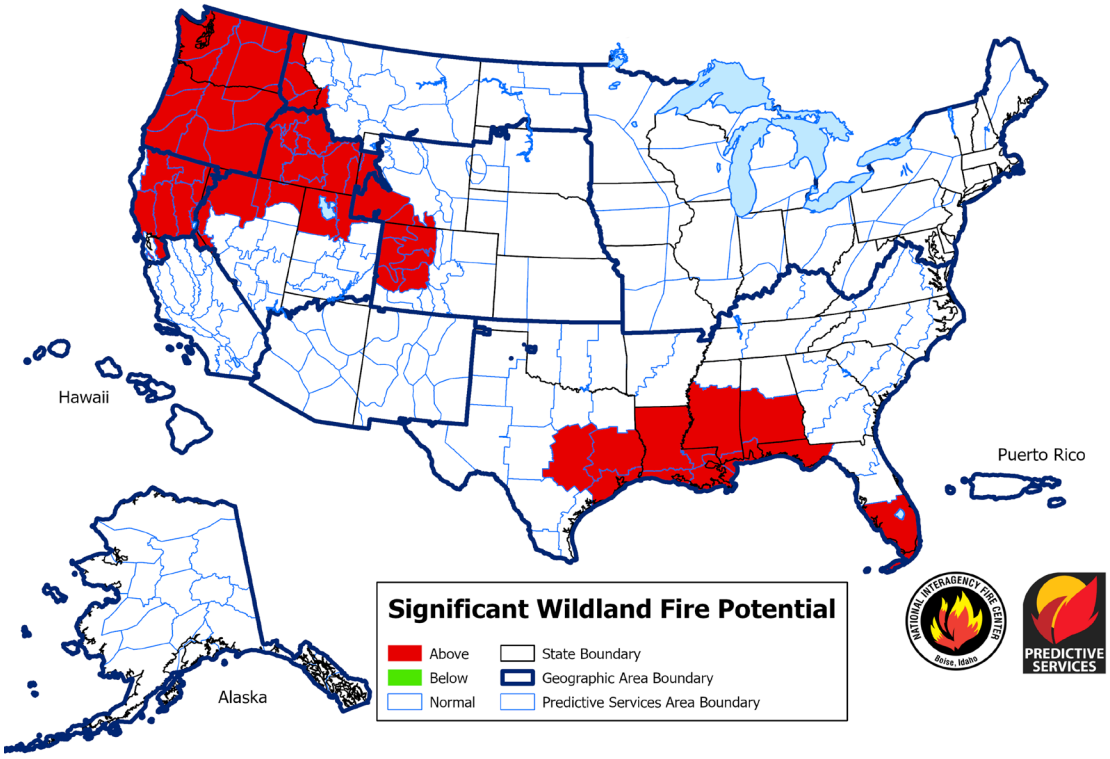
3 Electric Power Research Institute (EPRI), *Extreme Heat Events and Impacts to the Electrical System* at 3 (Sep. 5, 2022), restservice.epri.com/publicdownload/000000003002025522/0/Product.

4 A 2024 Pacific Northwest National Laboratory (PNNL) study concluded that extreme high temperatures can reduce efficiency of some natural gas turbines by 25%. *See PNNL*, *Heatwaves: Less Efficient Power Flow, More Power Demand, press release,* (July 29, 2024), www.pnnl.gov/news-media/extreme-heat-hurricanes-wildfires-how-summers-extremes-disrupt-power-grid.

Finally, higher temperatures forecast for this summer could intensify storm systems and hurricanes.[5] The Atlantic hurricane season runs from June 1 through November 30, typically peaking in late summer or early fall. While the forecasts for this summer anticipate a below-average total of 13 hurricanes, uncertainty remains due to projected weather patterns that produce opposite effects: Projected El Niño conditions typically reduce hurricane formation, but warmer temperatures coupled with warm Atlantic waters can cause hurricanes to form and intensify rapidly.[6]

Wildfire Forecast

Figure 2: Wildfire Risks Elevated across the United States



Above normal significant wildland fire potential indicates a greater than usual likelihood that significant wildland fires will occur. Significant wildland fires should be expected at typical times and intervals during normal significant wildland fire potential conditions. Significant wildland fires are still possible but less likely than usual during forecasted below normal periods.

Source: Significant Wildland Fire Potential Outlook August 2026. National Interagency Coordination Center, Issued: May 1, 2026.

The expansion of wildfire risk from the West to other parts of the country is expected to continue in 2026. The National Interagency Coordination Center's (NICC) map for August 2026, shown in **Figure 2**, shows significant wildfire risk across the West, Southern Plains, and the Southeast regions of the United States, including the risk of fast-moving grass fires. Parts of the Gulf Coast may also experience above-normal fire activity caused by critically dry vegetation, persistent drought, and other conditions.[7]

5 NOAA, *Fuel for the Storm* (Accessed Mar. 9, 2025), oceantoday.noaa.gov/fuelforthestorm/.

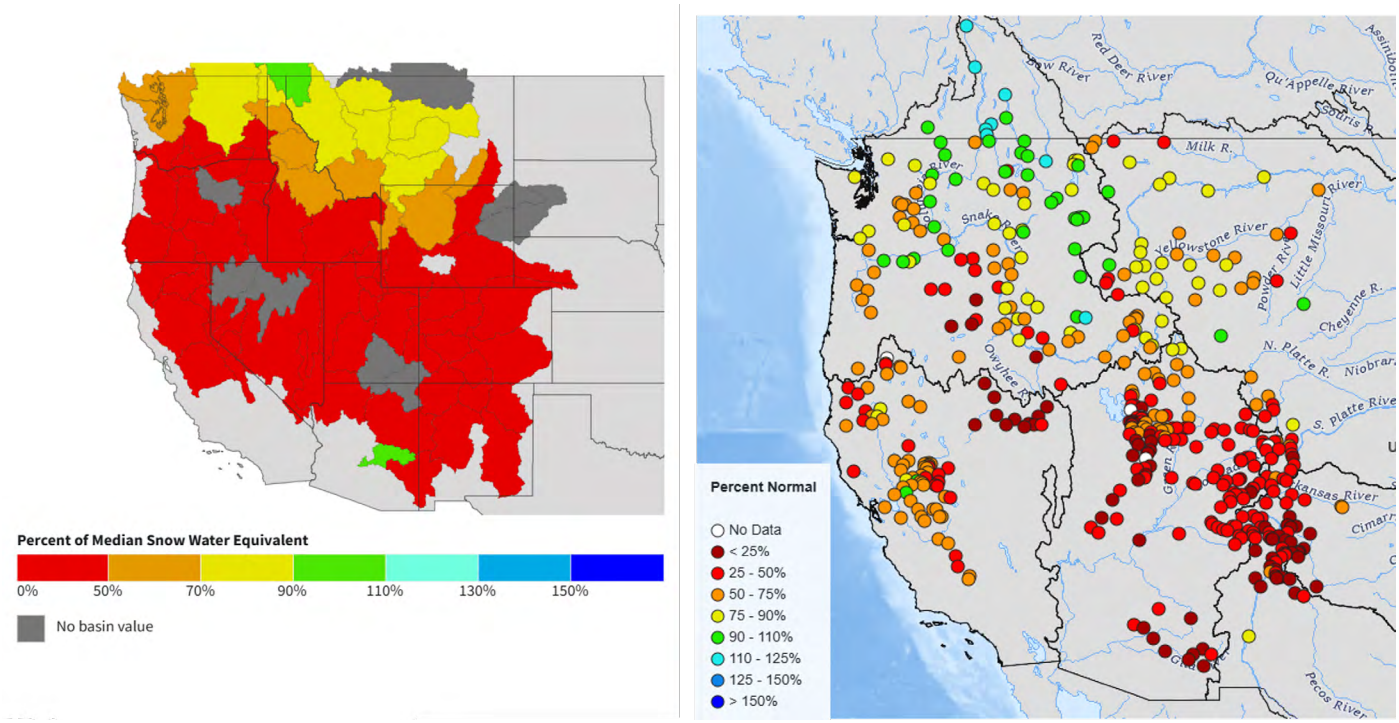
6 Colorado State University, *Forecast for 2026 Hurricane Activity* (Apr. 9, 2026), tropical.colostate.edu/forecasting.html.

7 National Interagency Coordination Center (NICC), *National Significant Wildland Fire Potential Outlook, Outlook Period – March through June 2026* (Mar. 2, 2026), www.nifc.gov/nicc/predictive-services/outlooks.

Since 2019, California utilities have relied on Public Safety Power Shutoffs (PSPSs), or intentional transmission line de-energization, to prevent their equipment from igniting fires. In recent years, PSPSs have been employed as a wildfire mitigation tool more broadly across the West and increasingly in other parts of the United States to counter drought conditions and wildfire risks as they expand eastward.[8]

Western Snowpack and Hydropower Forecast

Figure 3: Record Low Snowpack Impacts Western Hydropower Availability



Source(s): SNOTEL Snow Water Equivalent Percent of Median, USDA Natural Resources Conservation. Service Data Valid End of Day: April 8, 2026; and Western Water Supply Forecast, NWS Colorado Basin River Forecast Center, Valid April 8, 202

Snowpack is important for summer electric system reliability, serving as a natural energy reservoir that gradually releases water during spring and summer and fuels hydropower generation when electricity demand increases with rising temperatures.[9] But across the West this summer, there is record-low snowpack, shown in red, orange and yellow, in **Figure 3**.[10] This could curb production of hydropower throughout the West, where over half of all U.S. utility-scale hydropower generation capacity is concentrated.[11]

8 Pacific Northwest National Laboratory, *Public Safety Power Shutoffs in Wildfire Mitigation Plans* (Feb. 2026), wildfire.pnnl.gov/mitigationPlans/content/analysis/Public%20Safety%20Power%20Shutoffs%20in%20WMPs.pdf.

9 Winter snowpack refers to the depth of water that would theoretically result if the entire snowpack melted instantaneously.

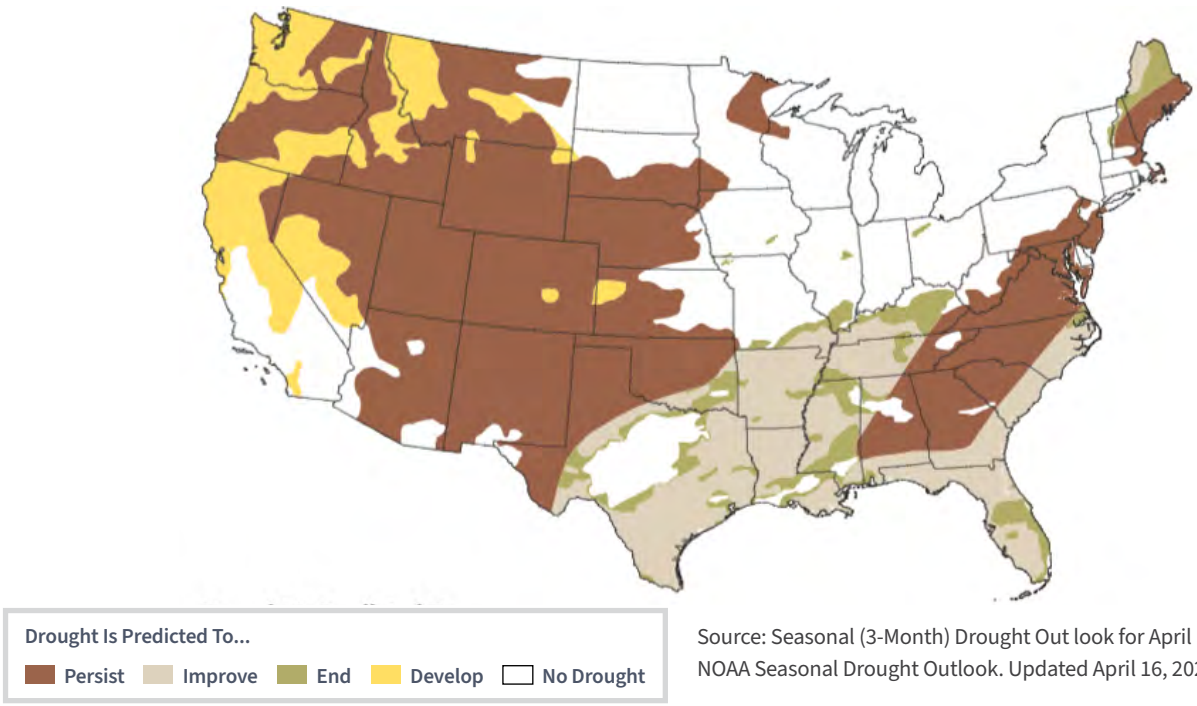
10 National Integrated Drought Information System (NIDIS), *Drought Status Update: Snow Drought Current Conditions and Impacts in the West* (Apr. 9, 2026), www.drought.gov/drought-status-updates/snow-drought-current-conditions-and-impacts-west-2026-04-09.

11 EIA, *Hydropower explained: Where hydropower is generated* (Accessed May 13, 2026), www.eia.gov/energyexplained/hydropower/where-hydropower-is-generated.php.

Meanwhile, low water volumes in summer 2026 in the greater Missouri and Mississippi River basins, following multiple consecutive years of low water flows, increase the risk of disrupted navigation, including for barges carrying coal to power plants. Low water levels, the risk of saltwater intrusion, and increased water temperatures could prompt derating or forced outages of generators with once-through-cooling equipment on the affected rivers.

Drought Conditions

Figure 4: Drought Conditions Impact Western, Central and Eastern Coastal Regions



Source: Seasonal (3-Month) Drought Out look for April 16-July 31, 2026. NOAA Seasonal Drought Outlook. Updated April 16, 2026

Continued drought conditions this summer increase the risks to energy infrastructure, creating challenges for grid reliability. Drought conditions impact 62% of the continental United States and are expected to expand this summer, as shown in **Figure 4**. For example, continued widespread drought conditions could impact energy infrastructure in Texas this summer, as reservoirs along the Gulf Coast are forecast to drop to record lows, putting refineries clustered in Corpus Christi, Texas, and other parts of the region at risk of mandatory water cuts. Refinery capacity in the Corpus Christi region amounts to about 5% of total refinery capacity in the U.S.[12]

To the north, about 53% of Canada was in moderate to extreme drought conditions as of February 2026, and these conditions are projected to persist into summer 2026, particularly in Québec, Manitoba, and British Columbia.[13] That would reduce Canadian hydropower available for export to the United States, potentially affecting thousands

12 Based on a U.S total of refinery capacity of 18,162,000 barrels per day as of January 2026. EIA, *Petroleum and Other Liquids: Refinery Utilization and Capacity* (Accessed Apr. 7, 2026), www.eia.gov/dnav/pet/pet_pnp_unc_dcu_nus_m.htm.

13 Agriculture and Agri-Food Canada, *Canadian Drought Monitor: Current Drought Conditions* (Mar. 6, 2026), agriculture.canada.ca/en/agricultural-production/weather/canadian-drought-monitor/current-drought-conditions.

of megawatts[14] of electricity imports into the New York Independent System Operator, ISO New England, and the Midcontinent Independent System Operator (MISO).[15]

In 2025, 28% less electricity flowed from Canada to the U.S. than in 2024, marking the lowest Canadian export total (35.64 Terawatt hours) since 2004.[16] As of January and February 2026, Canadian electricity exports to the U.S. remained below 2025 levels.

From an operational standpoint, lower Canadian hydropower output will continue to increase U.S.-to-Canada net transfers and potentially strain transmission paths not historically loaded south-to-north.[17] Such strains can lead to further congestion, voltage and loading challenges, or impose limits on power flow management actions during periods of high demand.

14 Canada exported a monthly average 2.6 TWh of electricity to the U.S. in 2025. CER, *Electricity Trade Summary* (Apr. 2, 2026), www.cer-rec.gc.ca/en/data-analysis/energy-commodities/electricity/statistics/electricity-trade-summary/index.html.

15 Canada Energy Regulator (CER), *Electricity Trade Summary* (Apr. 2, 2026), www.cer-rec.gc.ca/en/data-analysis/energy-commodities/electricity/statistics/electricity-trade-summary/index.html.

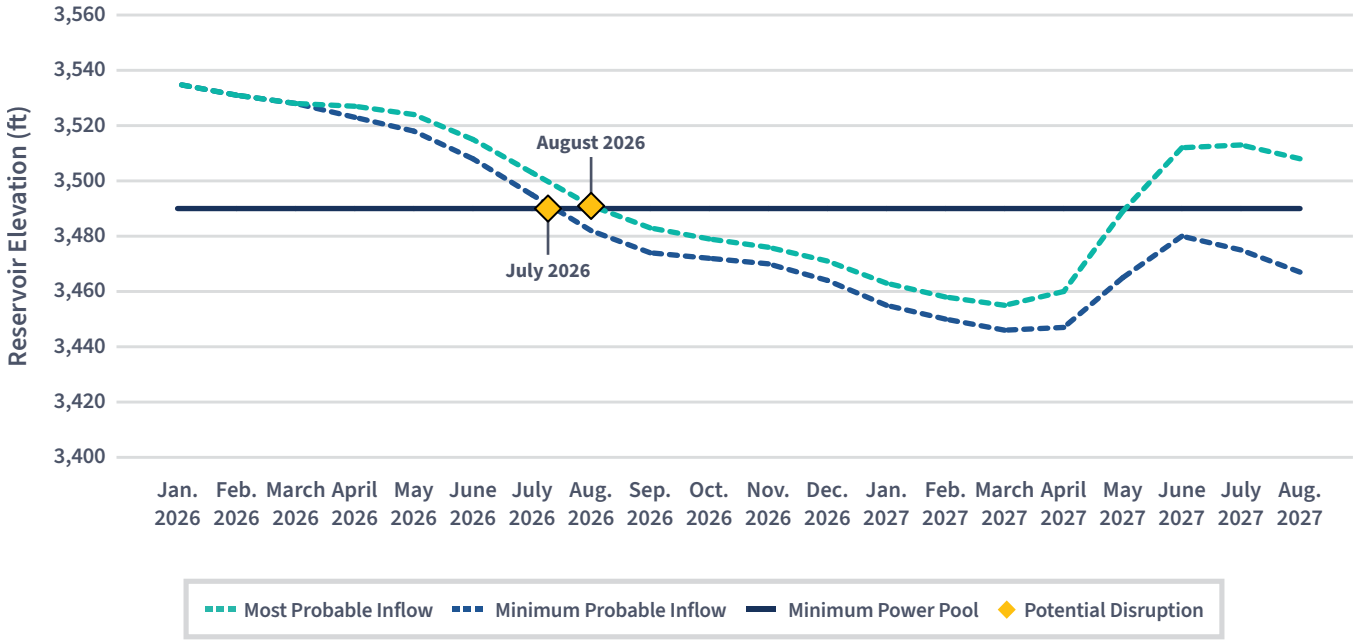
16 CER, *Market Snapshot: Annual Trade Summary – Electricity* (June 25, 2025), www.rec-cer.gc.ca/en/data-analysis/energy-markets/market-snapshots/2025/market-snapshot-annual-trade-summary-electricity.html.

17 EIA, *U.S. Northeast is Relying Less on Electricity Imports from Canada* (Sep. 19, 2025), www.eia.gov/todayinenergy/detail.php?id=66144.

NOTABLE RELIABILITY RISKS AND TRENDS

Colorado River Drought Impacts

Figure 5: Colorado River Expected to Fall to Critical Levels in Summer 2026



Source: Bureau of Reclamation, April 2026 Most Probable 24-Month Study, Bureau of Reclamation Upper and Lower Colorado River Basin Regions, April 16, 2026

Electricity operations in the Colorado River Basin highlight the significant challenges that drought conditions have created across the West. Specifically, Lake Powell at the non-FERC-jurisdictional Glen Canyon Dam is forecast to see the lowest volume of water inflow since the dam began operation in 1964, at only 13% of average inflow volumes.[18]

U.S. Department of Interior's Bureau of Reclamation forecasts indicate that, unless circumstances change, currently under the most probable conditions forecast from April 2026, shown in teal on **Figure 5**, the Glen Canyon dam may reach "minimum power pool," shown as a black line, this summer, below which power generation at the dam is impossible and river flow will be cut off at the dam.[19] However, the Bureau of Reclamation recently announced planned emergency actions it intends to take to preserve operations at Glen Canyon through the summer with emergency releases from upstream reservoirs and significantly reduced water releases from Glen Canyon. Without successful emergency actions or if water releases are reduced significantly, downstream dam operations would be affected, as well as any other municipal, commercial or industrial infrastructure dependent on the river, including the non-FERC jurisdictional Hoover Dam, a 2,000 MW hydropower generator on the Nevada-Arizona border. In total,

18 NOAA Colorado River Basin Forecast Center, *May 2026 Water Supply Briefing* (May 7, 2026) www.cbrfc.noaa.gov/present/2026/cbrfcwsupmay2026.pdf.

19 Bureau of Reclamation, *Reclamation Acts to Protect Colorado River System During Historic Drought*, press release, (Apr. 17, 2026), /www.usbr.gov/newsroom/news-release/5326.

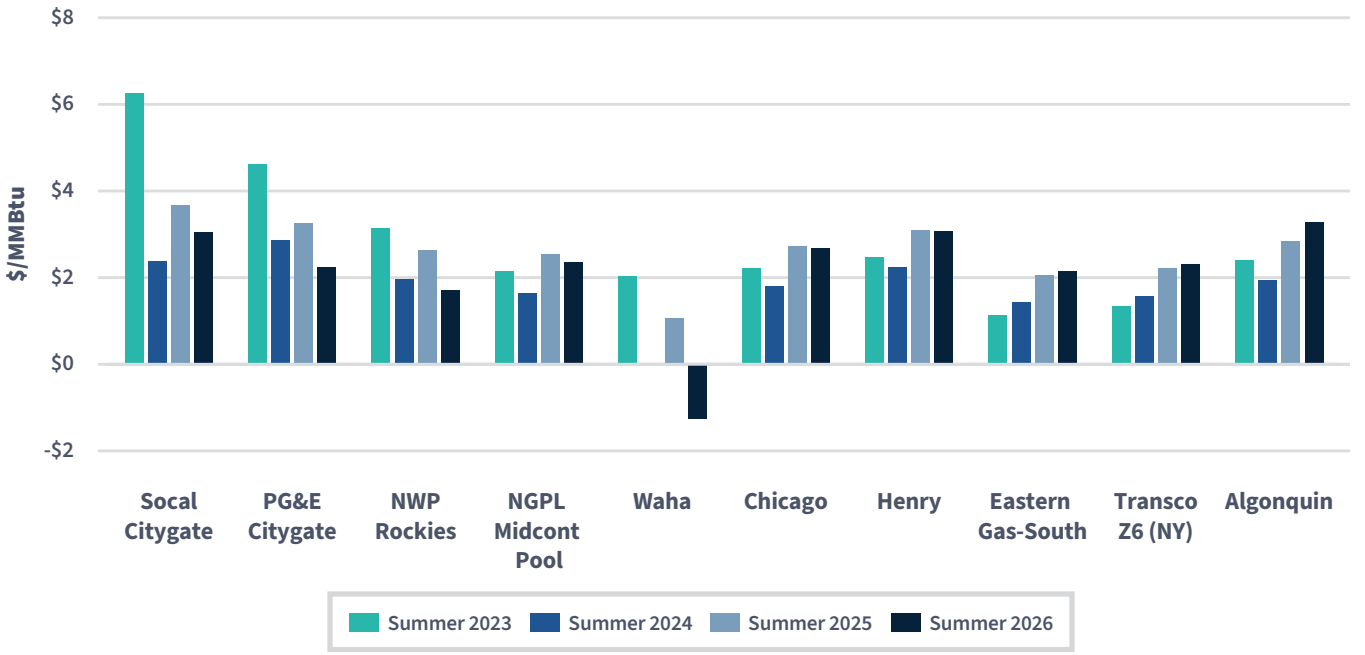
up to 4,500 MW of hydropower capacity on the Colorado River could be impacted by prolonged drought as soon as August 2026, if adverse conditions persist. Such conditions are beyond the region's transmission system design; on a day-to-day basis, they can create congestion and constrain system operators' ability to respond to voltage support challenges, event response mitigation needs, or any additional grid stressors.[20]

20 Bureau of Reclamation, *Technical Appendix – 15 Dams and Electrical Power Resources*, at 15.1.4 (Jan. 2026), www.usbr.gov/ColoradoRiverBasin/post2026/draft-eis/docs/vol-3/P26-DEIS-TA-15.pdf.

NATURAL GAS FUNDAMENTALS

Natural Gas Prices

Figure 6: Natural Gas Prices Expected to Decrease at Western Hubs and Increase at Eastern Hubs



Source: InterContinental Exchange

Natural gas prices are signals of the supply-demand balance in natural gas markets and a significant input in the cost of wholesale electricity. Natural gas prices for summer 2026 are expected to be lower at major western and midcontinent trading hubs and higher at major eastern trading hubs across the United States compared to summer 2025. As of April 10, 2026, the futures contract price for the Henry Hub, located in Louisiana, averaged $3.07 per million British thermal units (MMBtu) for this summer, 1% lower than last summer's settled futures price average of $3.10/MMBtu. Relatively high prices at the Henry Hub, compared to other major U.S. natural gas trading hubs, may be driven by expected growth in demand from LNG exports, the anticipated primary driver for total natural gas demand growth this summer.[21] Despite the projected growth in LNG exports, U.S. natural gas prices this summer are relatively insulated from international events and potential global supply shortages. Most U.S. LNG export terminals are already operating at high utilization rates and do not have significant additional export capacity with which they could respond to near-term international market signals.

In the western United States, elevated natural gas storage levels following the 2025-2026 winter are expected to contribute to a decrease in natural gas prices in the Pacific Northwest and California compared to summer 2025 prices. Prices at the Northwest Rockies hub and the Pacific Gas & Electric Citygate, a northern California trading hub,

21 EIA, *Short-Term Energy Outlook* at Table 5a (Apr. 7, 2026), www.eia.gov/outlooks/steo.

are both expected to decrease by more than 30% year-over-year. Prices at the Southern California Gas Citygate hub are also expected to decrease 17% this summer.

At Northeast hubs, futures prices are expected to be higher this summer, as shown in **Figure 6**, reflecting the need to refill Northeast storage following significant regional storage withdrawals this past winter. The Algonquin Citygate, which serves the Boston area, is expected to average $3.29/MMBtu, 16% higher than last summer's settled futures price of $2.83. The Transco Z6 NY hub, a New York City point, is expected to average $2.30/MMBtu an increase of 4% compared to summer 2025.

At the Waha trading hub, a point that represents the oil- and natural gas-rich Permian Basin production area in West Texas and southeastern New Mexico, average summer futures prices are trading at negative $1.26/MMBtu, a significant reduction to last summer's settled price of $1.06/MMBtu. This negative price reflects the limited availability of pipeline takeaway capacity in the Permian Basin relative to the volume of "associated natural gas," or natural gas that is produced as a byproduct of oil production, in the basin. Higher crude oil prices also are expected to incentivize additional crude oil and associated natural gas production in the Permian Basin this summer to help meet the global demand for crude oil, further exacerbating pipeline takeaway constraints in the area.[22]

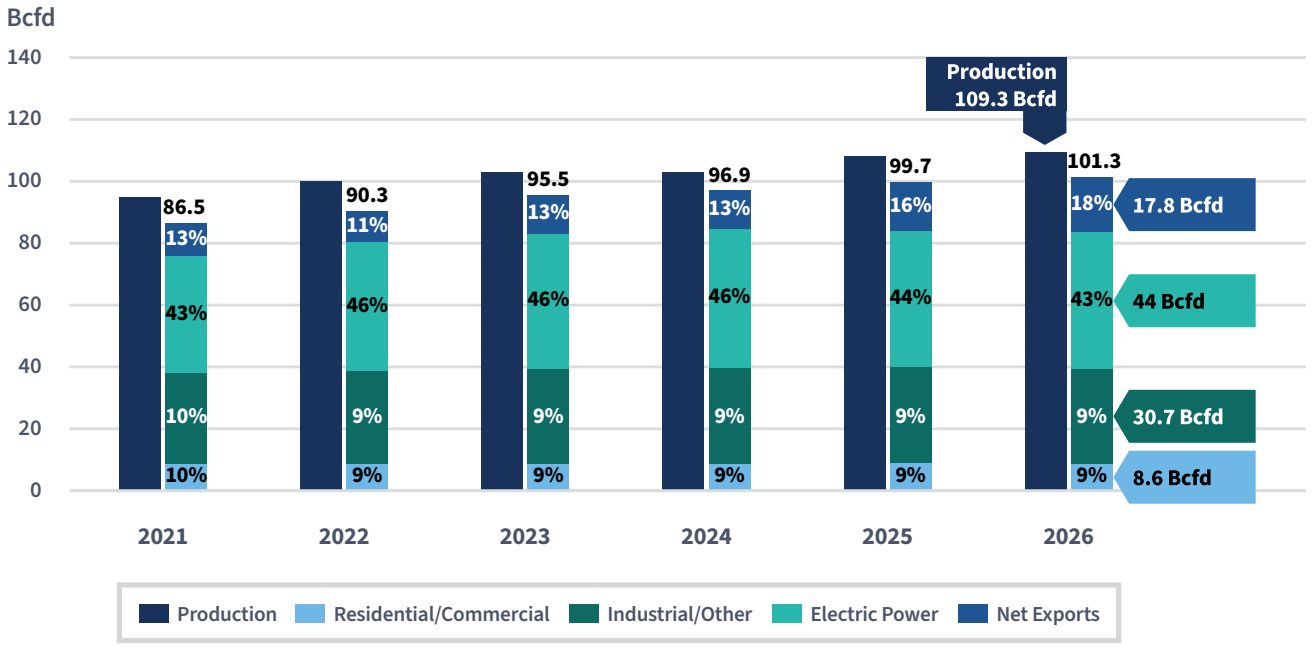
Three natural gas pipeline projects — the Gulf Coast Express Expansion project, the Blackcomb Pipeline project, and Phase 1 of the Hugh Brinson Pipeline project — are expected to add 4.6 Bcfd of pipeline capacity in the second half of 2026. These projects may help to alleviate the constraints in pipeline takeaway capacity for the Permian Basin region and increase natural gas prices at the Waha trading hub towards the end of the year.[23]

22 EIA, *Short-Term Energy Outlook: Global Oil Markets* (Apr. 7, 2026), www.eia.gov/outlooks/steo/report/global_oil.php

23 Chris Newman, *Permian Prompt-Month Natural Gas Forwards Sink to All-Time Lows,* Natural Gas Intelligence, Sep. 25, 2025, naturalgasintel.com/news/permian-prompt-month-natural-gas-forwards-sink-to-all-time-lows/.

Natural Gas Demand

Figure 7: Natural Gas Demand Expected to Continue Growth



Source: U.S. EIA STEO Table 5a

U.S. demand for natural gas continues to grow. As depicted in **Figure 7**, EIA projects total U.S. natural gas demand to average 101.3 Bcfd in summer 2026, 1.6 Bcfd more than summer 2025 levels and 8% more than the previous five-year summer average of 93.8 Bcfd. While electricity generation (also known as power burn) is expected to continue to make up the largest share of natural gas demand, net exports are the largest contributors to the expected growth in overall natural gas demand for summer 2026, consistent with previous summers. Net exports are expected to average 17.8 Bcfd in summer 2026, up 2 Bcfd from summer 2025 and 44% above the previous five-year average.[24] Total domestic natural gas consumption, which includes the residential/commercial, industrial, and power burn sectors but excludes net exports, is expected to average 83.3 Bcfd in summer 2026, a 0.5% decrease from summer 2025 levels but 2.5% above the previous five-year average.

Natural gas demand from the residential/commercial sector is forecast to average 8.6 Bcfd, slightly below summer 2025's level and slightly above the previous five-year average. Natural gas demand in the industrial/other sector is forecast to average 30.7 Bcfd in summer 2026, down slightly from summer 2025's level but 0.7% above the previous five-year average.[25] Industrial demand is mainly concentrated near the Gulf Coast due to the numerous petrochemical and other types of industrial facilities located in that region.

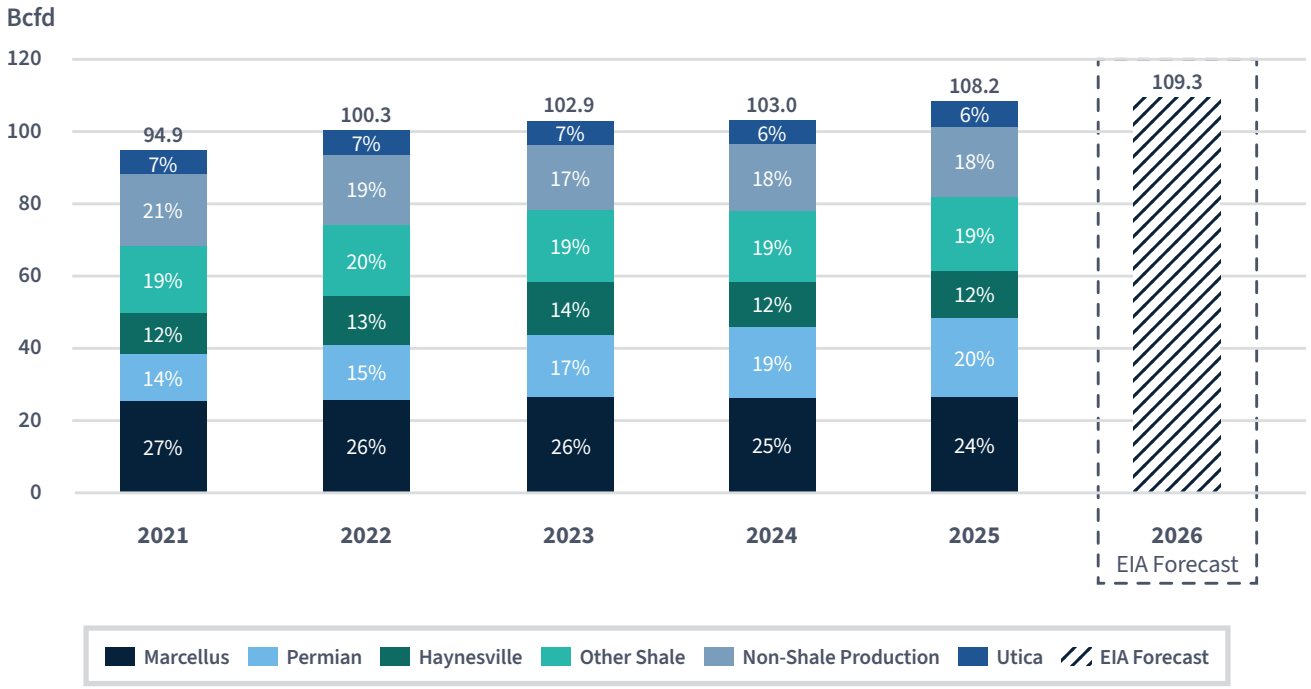
24 EIA, *Short-Term Energy Outlook* at Table 5a (Apr. 7, 2025), www.eia.gov/outlooks/steo.

25 *Ibid.*

EIA projects power burn to average 44 Bcfd in summer 2026, up 0.7% from summer 2025 and 4.2% above the previous five-year average. The average share of electricity generation from natural gas-fired power plants during summer 2026 is forecast to be 43%, down from 44% in summer 2025 and below the previous five-year average of 44%. Consistent with past summers, power burn in 2026 is forecast to peak during the typically hottest months of July and August, averaging 47.9 Bcfd between the two months, up 2.1% from summer 2025.

Natural Gas Production

Figure 8: Natural Gas Production Expected to Increase to All-Time High



Source: U.S. EIA STEO Tables 5a and 10b

Natural gas production is expected to be slightly higher this summer than last, driven by continued strong production from major shale fields. EIA forecasts U.S. dry natural gas production to average 109.3 Bcfd during summer 2026.[26] This represents a 1% increase from the summer 2025 average of 108.2 Bcfd and is 7% above the previous five-year average of 101.8 Bcfd.[27] The different colored segments within each bar in **Figure 8** break down the total production by region, illustrating how various shale plays contribute to overall production volume. Dry gas production remains concentrated across three regions. Collectively, Appalachia, the Permian, and the Haynesville accounted for 63% of total U.S. dry gas production for summer 2025.

26 *Ibid;* Dry natural gas is consumer-grade natural gas that is almost entirely composed of methane, with little to no hydrocarbon liquids or impurities.

27 EIA, *Short-Term Energy Outlook* at Table 5a (Apr. 7, 2026), www.eia.gov/outlooks/steo.

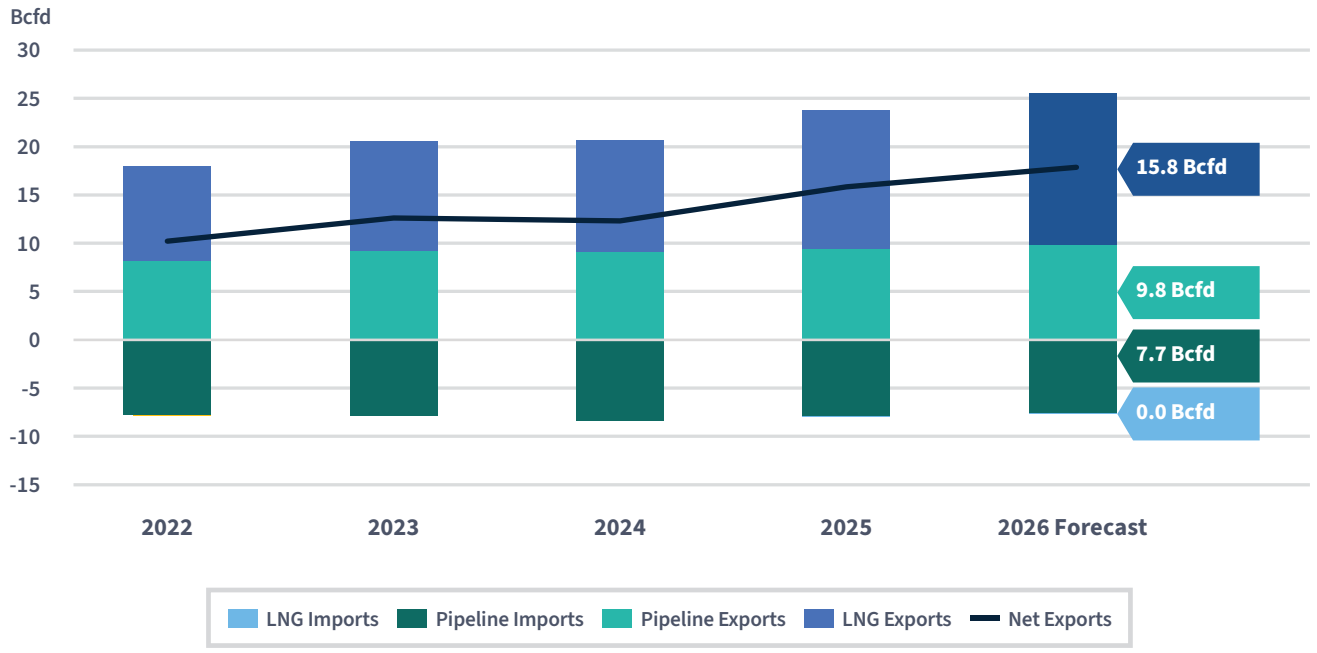
Appalachia remains the largest natural gas-producing region with the Marcellus and Utica shales combining for 33.3 Bcfd, approximately 31% of total U.S. dry natural gas production in 2025. Appalachian natural gas production is primarily located in Pennsylvania, West Virginia, and Ohio. Production growth in Appalachia has slowed in recent years due to pipeline capacity constraints, though recent pipeline capacity additions are expected to support modest growth in 2026.[28]

The Permian Basin, located in West Texas and southeast New Mexico, produced approximately 22 Bcfd of dry natural gas over summer 2025, representing 20% of the total U.S. dry gas production. Growth in Permian natural gas production is driven largely by crude oil market dynamics rather than gas-specific investment. Elevated oil prices are expected to drive more oil-directed drilling for summer 2026, leading to production of more associated natural gas.

The Haynesville formation, located in northwest Louisiana and East Texas, produced 13.3 Bcfd in summer 2025. While production dipped from its all-time peak of 14.7 Bcfd in 2023, the basin is positioned for a rebound in summer 2026. EIA forecasts that Haynesville production will grow 1.2 Bcfd in 2026, partly in response to growing demand from expanding Gulf Coast LNG export capacity.

Natural Gas Exports and Imports

Figure 9: Natural Gas Exports Expected to Increase



Source: U.S. EIA STEO Table 5a

Projected U.S. net natural gas exports show continued growth in summer 2026, as shown in **Figure 9**, increasing by 2 Bcfd as new LNG terminal capacity begins commercial service. According to EIA projections, gross exports via

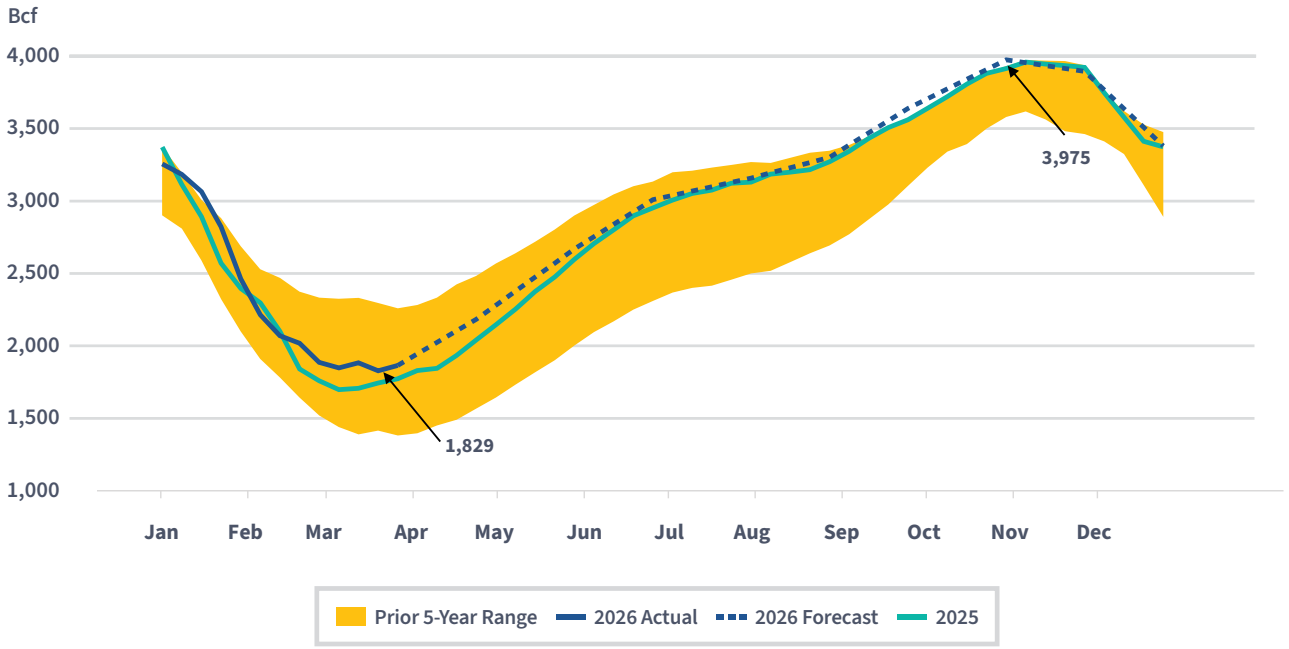
28 EIA, *U.S. Natural Gas Production to Reach Record Highs in 2026 and 2027* (Feb. 13, 2026), www.eia.gov/todayinenergy/detail.php?id=67166.

pipeline and LNG will rise to 25.6 Bcfd in summer 2026, a 7.4% increase from summer 2025. Gross LNG exports for this summer are forecast to average 15.8 Bcfd, up from 14.3 Bcfd in summer 2025 – an increase of 10%.[29] U.S. LNG cargoes continue to face strong demand – particularly from Europe, Japan, and South Korea – which supports additional liquefaction and export capacity growth in the future. The EIA anticipates that U.S. LNG export facilities will operate at high utilization levels this summer, as ongoing geopolitical developments in the Middle East limit global LNG supply.[30]

Gross pipeline exports are forecast to average 9.8 Bcfd this summer, up 0.3 Bcfd from summer 2025. Mexico remains the primary pipeline export destination, driven by growth in demand from Mexico's industrial and electric generation sectors and by expanding pipeline capacity along the U.S.-Mexican border.[31] Gross pipeline imports, primarily from Canada, are forecast to average 7.7 Bcfd in summer 2026, slightly below the 7.9 Bcfd seen in summer 2025.

Natural Gas Storage Inventories

Figure 10: Historical and Forecast U.S. Natural Gas Storage Inventories



Source: U.S. EIA Form 912

29 As of April 2026, FERC-authorized LNG export liquefaction capacity stood at approximately 14.5 Bcfd across eight export facilities. In addition, three facilities are exporting LNG while commissioning. FERC, *North American LNG Export Terminals – Existing, Approved not Yet Built, and Proposed* (Accessed Apr. 7, 2026), www.ferc.gov/media/us-lng-export-terminals-existing-approved-not-yet-built-and-proposed.

30 EIA, *Short-Term Energy Outlook: Natural Gas Market Update*, (Apr. 7, 2026), www.eia.gov/outlooks/steo/report/natgas.php#:~:text=In%20our%20forecast,%20the%20Henry,to%20come%20online%20this%20month.

31 Mexico also began exporting LNG in 2024 from its Fast LNG Altamira LNG production vessel. *See* EIA, *Initial Cargo of Liquefied Natural Gas Ships from Mexico* (Aug. 16, 2024), www.eia.gov/todayinenergy/detail.php?id=62844#:~:text=The%20developer%20of%20the%20first,Tuxpan%20pipeline%20supplies%20the%20project.

Natural gas storage inventories help to balance natural gas demand and supply and are fundamental to price formation in natural gas markets.[32] The 2026 U.S. natural gas storage injection season began in late March with 1,829 Bcf stored in working gas inventories, an inventory level 2.5% above the previous five-year average.[33] The starting inventory level for the 2026 injection season was 131 Bcf (8%) higher than at the start of the 2025 injection season.[34] EIA expects total injections of approximately 2,146 Bcf throughout the 2026 injection season, 5% less than the 2025 injection season but 6% more than the previous five-year average. EIA forecasts a total of 3,975 Bcf of natural gas in storage by the end of October 2026, which would be slightly above the 2021-2025 five-year range.[35]

Regionally, the Mountain and the Pacific regions started the injection season with elevated levels of storage.[36] The Mountain region started with 198 Bcf, 22% higher than the 2025 injection season and 64% more than the 2021-2025 five-year average. The Pacific region started with 257 Bcf, 34% higher than the 2025 storage level and 56% more than the five-year average. Elevated storage levels in these two regions would put downward pressure on prices in the West as the available natural gas supply increases.

Natural Gas Infrastructure

Natural gas infrastructure additions since summer 2025 further increased pipeline transportation capacity available in summer 2026 relative to prior summers, which should ease constraints in some regions. Between September 1, 2025, and April 17, 2026, staff calculates a combined 152 miles of new, enhanced, or expanded interstate natural gas pipelines, adding approximately 1.6 Bcfd in transportation capacity. These capacity additions are distributed across the Northeast, Midwest, and South Central regions. Capacity additions for both interstate and intrastate pipelines continue to support LNG export growth in the South Central region. For example, two large intrastate pipeline projects in Louisiana completed in mid-2025—the 1.7 Bcfd Louisiana Energy Gateway project and the 1.8 Bcfd New Generation Gas Gathering project—will increase access to the Haynesville Shale and expand capacity serving Gulf Coast demand, including LNG facilities, this summer.

32 U.S. natural gas storage inventory data listed in this section is for the Lower 48 states.

33 EIA, *Weekly Natural Gas Storage Report* (Apr. 9, 2026), www.eia.gov/naturalgas/storage/. The natural gas storage injection season typically spans from the first week of April to the last week of October. The start of the season is determined by the lowest natural gas storage level of the year and the winter withdrawal season by the highest storage level of the year.

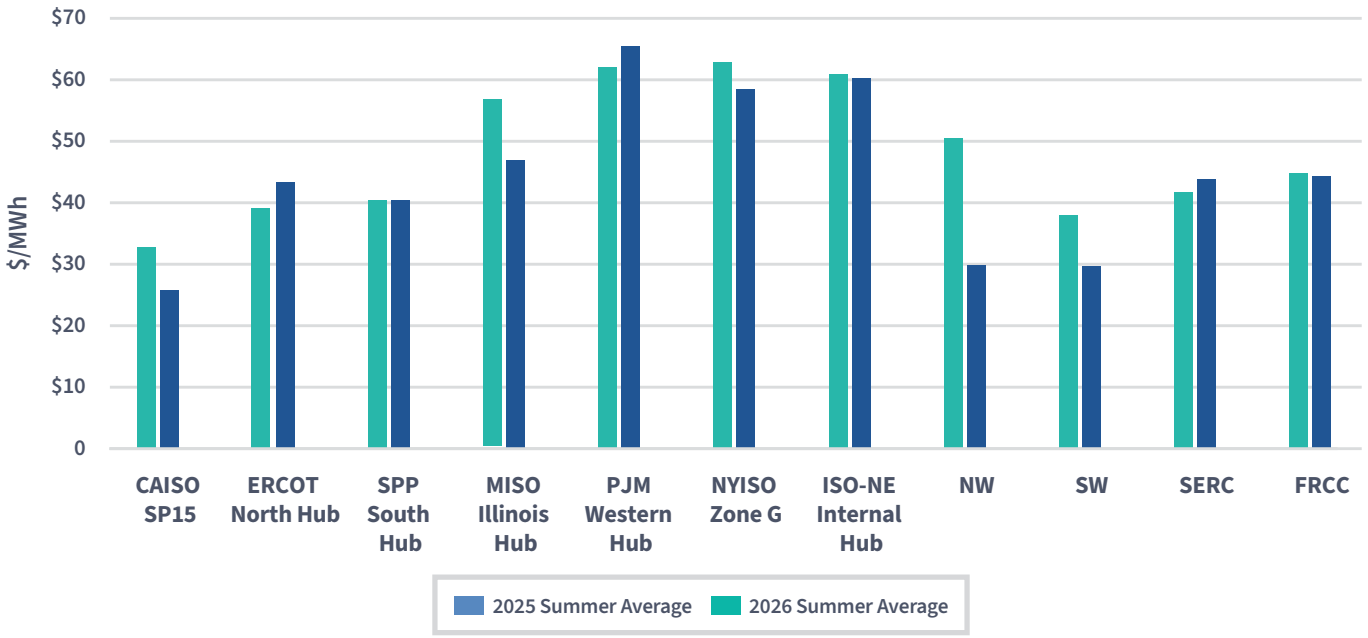
34 *Ibid.*

35 EIA, *Short-Term Energy Outlook* (Apr. 7, 2026), www.eia.gov/outlooks/steo.

36 EIA, *Weekly Natural Gas Storage Report* (Apr. 9, 2026), www.eia.gov/naturalgas/storage/.

Electricity Prices

Figure 11: Summary Average Wholesale Electricity Price Expected to Decrease



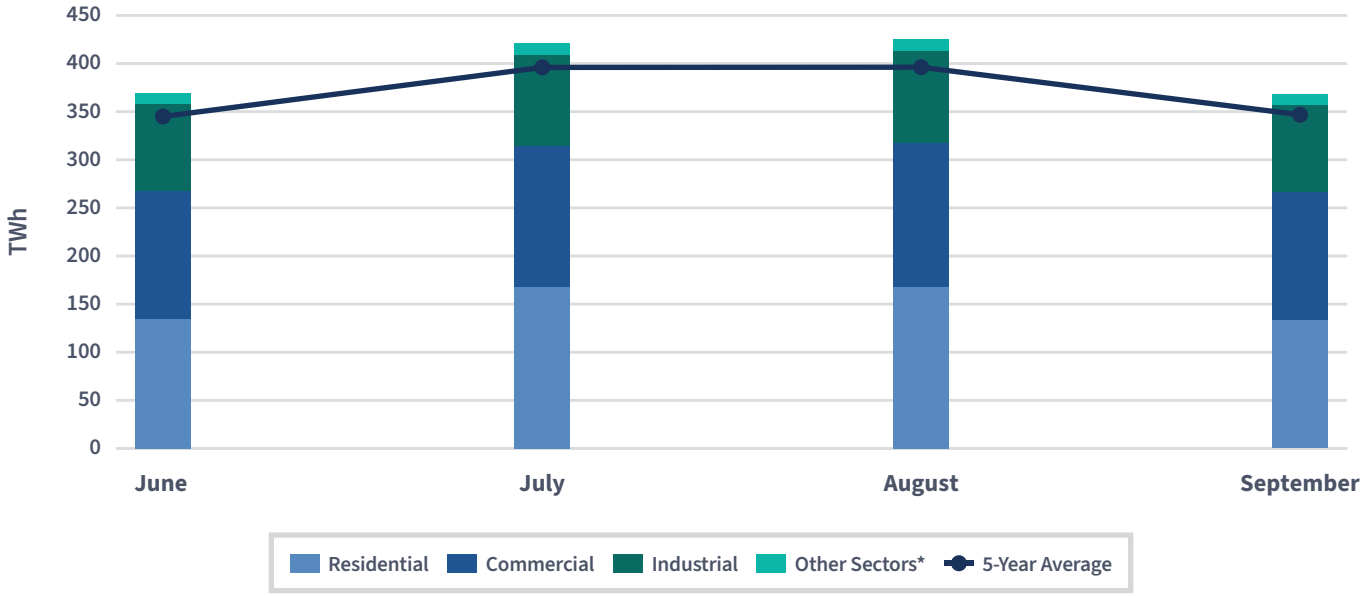
Source: U.S. EIA STEO Table 7a

Overall, the nationwide, wholesale, average electricity price is expected to fall this summer; however, prices will vary by region, reflecting differences in generation additions, shifts in the resource mix, natural gas prices, and regional demand. EIA forecasts that the load-weighted, wholesale electricity prices at benchmark trading hubs for summer 2026 will average $46.81 per megawatt-hour (MWh), a 5% decrease from summer 2025. Most of the regions are expected to see a decline in prices compared to the previous summer, with the greatest price decreases expected in the Northwest (-41%), the Southwest (-22%), and MISO (-17%). ERCOT, PJM, and SERC are the only regions projected to see increases in prices, with ERCOT up by 11%, PJM by 5%, and SERC by 5%.

The price trends align with EIA forecasts for net summer capacity additions in RTOs/ISOs this summer, as described in more detail in the *Electric Generation Additions, Retirements, and Outages* section. Nationwide, EIA projects more generation additions than retirements in 2026, easing supply-demand tension. Regions are also expected to have larger shares of solar capacity that will contribute more energy and help reduce summer electricity prices. Further, as described in the *Natural Gas Prices* section, lower summer natural gas prices in the West may help lower electricity prices in CAISO, the Northwest, and the Southwest.

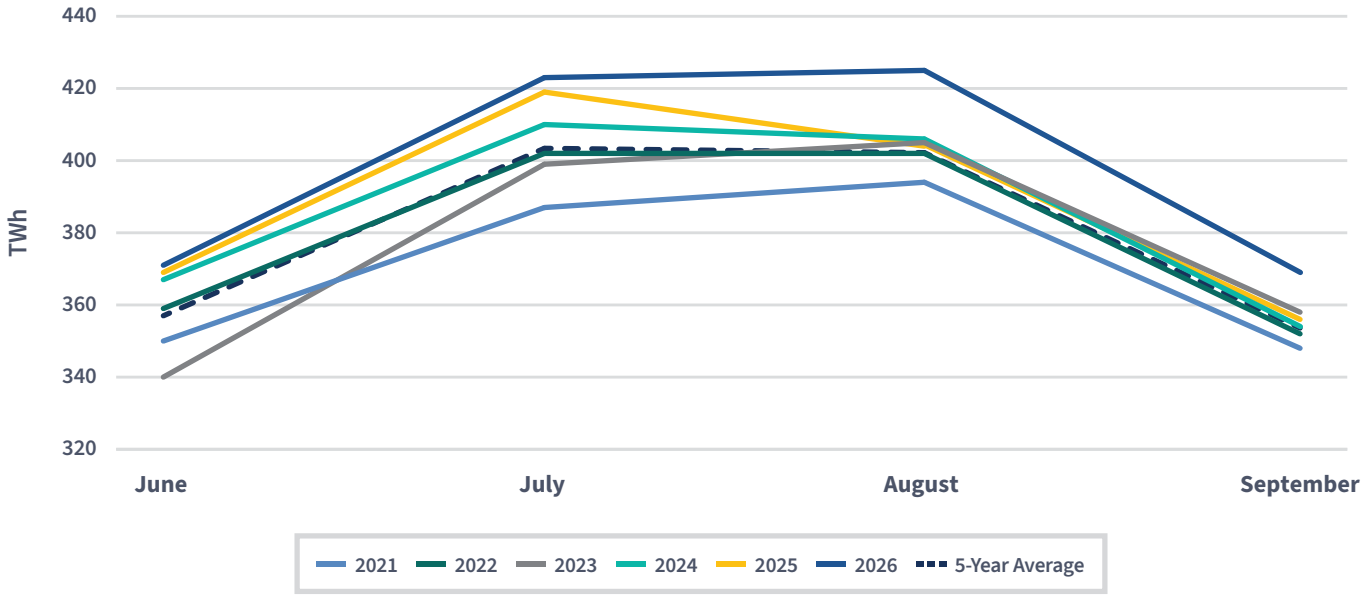
Electricity Consumption

Figure 12: 2026 Summer Electricity Consumption by End User



*Other sectors includes direct use and transportation Source: U.S. EIA Form 912

Figure 13: Summer Electricty Consumption by Year (2021-2026)



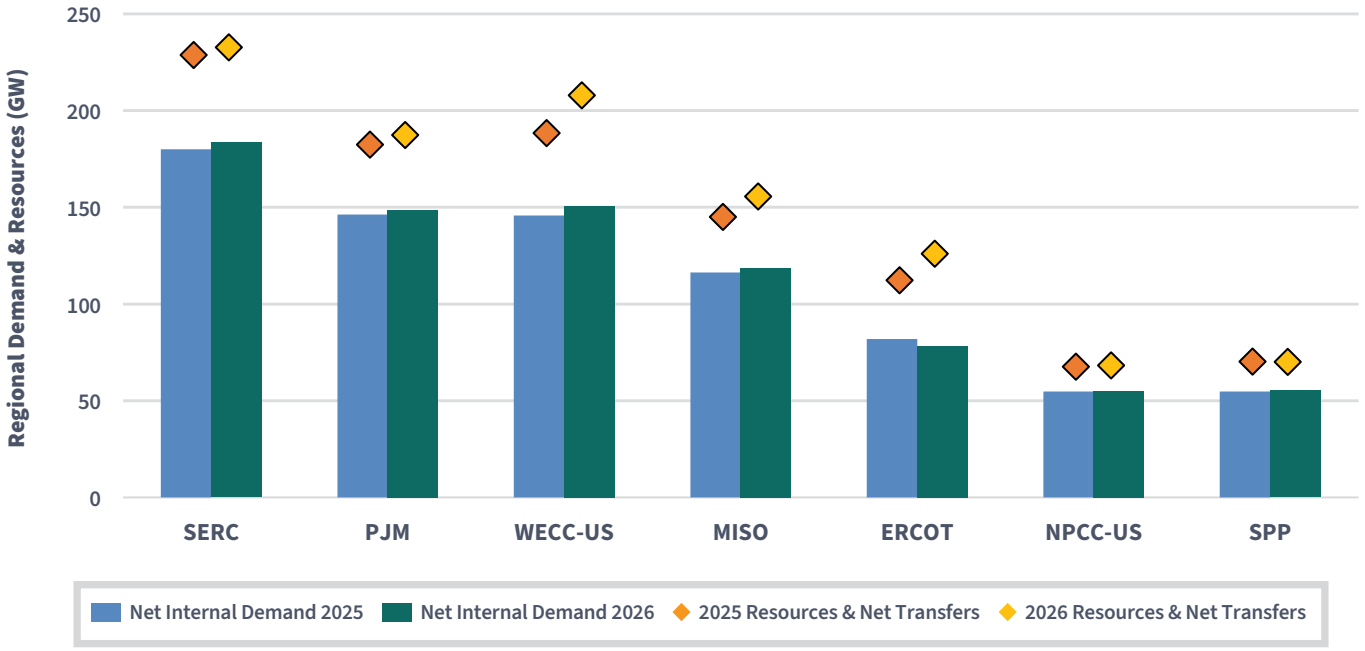
Source: U.S. EIA STEO Table 7a

Electricity consumption is projected to continue to increase in 2026 as it has since 2021. **Figure 12** illustrates electricity consumption across customer classes for summer 2026, with the dark blue line with blue markers showing the previous 5-year average summer consumption. The residential sector's projected 2026 summer consumption of 604 TWh would surpass its 2021-2025 average of 580 TWh by 4.1%, with particularly strong growth in August (6% above the five-year average). The commercial sector shows the most pronounced departure from its historical pattern, with projected 2026 summer consumption of 561 TWh exceeding its 2021-2025 five-year average of 523 TWh, a 7% increase. For the industrial sector, EIA projects 2026 summer consumption of 372 TWh—3% above the previous five-year average of 361 TWh.

Figure 13 illustrates that electricity consumption in summer 2026, represented by the dark blue line, is expected to exceed total consumption levels over each of the previous five summers. Total electricity consumption is projected to reach 1,587 TWh during summer 2026. EIA forecasts that electricity consumption from June to September 2026 will increase by 106 TWh from summer of 2021. This represents a 7% increase from summer 2021 to summer 2026, with summer 2026 projected to have 3% year -over-year growth compared to summer 2025, which is projected to be the most significant year-over-year growth since summer 2022 and 4.5% above the previous five-year average of 1,518 TWh. EIA's projections for monthly total consumption in summer 2026 suggest that demand will peak in August, when EIA forecasts electricity demand will be 426 TWh, a 5% increase from August 2025.

NERC ELECTRICITY DEMAND & RESOURCES

Figure 14: NERC Forecasted Electricity Demand and Resources Summer 2025 and 2026



Source: NERC, 2026 Summer Reliability Assessment

Each summer, NERC projects electricity demand and resources to gauge resource adequacy for each assessment area and the regions. Nationwide, electricity demand is expected to be higher this summer compared to last summer, except in ERCOT. NERC forecasts net internal demand for electricity to increase by approximately 1.3%, or 10 GW, from 780 GW in summer 2025 to 790 GW in summer 2026. However, electricity demand could vary depending on the number of extreme weather events and the characteristics and duration of those events.

Figure 14 compares the net internal demand shown as solid bars and the resources and net transfer values shown as diamonds.[37] This figure compares summer 2025 and summer 2026 and shows that all 15 NERC assessment areas are expected to have sufficient available generation resources and net transfers to meet their expected loads under normal summer conditions,[38] with all areas' planning reserve margins[39] exceeding the reference margins levels.[40] However, extreme weather conditions can create reliability problems even for a region that has achieved its target

37 Resources and Net Transfers refers to the addition of "Existing-Certain Capacity" and "Net Firm Capacity Transfers." NERC, *2025 Long Term Reliability Assessment* at 167-168 (Jan. 2026), www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

38 NERC, 2026 *Summer Reliability Assessment* at 2-3 (May 19, 2026), www.nerc.com/our-work/assessments.

39 The planning reserve margin measures the difference in resources (anticipated or prospective) and net internal demand divided by net internal demand, shown as a percentile. NERC, *2025 Long Term Reliability Assessment* (Jan. 2026), at 170, www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

40 The reference margin level (RML) can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. If an RML is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydropower systems. NERC, *2025 Long Term Reliability Assessment* at 170 (Jan. 2026), www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

reserve margin. Those conditions can limit fuel availability for generators, reduce power transfers and cause derates of electric generators, unexpected outages and other problems. A variety of factors affect reliable operation and are managed by system operators to help maintain electric supply and reliability. More comprehensive reliability assessments for three of these assessment areas are in the *Regional Highlights and NERC Probabilistic Assessments* section of this report.

To serve demand in summer 2026, NERC forecasts a national increase of 5%, or approximately 52 GW, in total electric generation capacity compared to summer 2025 and expects net energy transfers to increase from approximately 995 GW to approximately 1,048 GW over the same period, illustrated as diamonds in **Figure 14**.[41] This increase is for all areas except NPCC-US and SPP, where total capacity remains about the same as the prior year.

Three trends could challenge resource adequacy in summer 2026: (1) rapid load growth from data centers, electrification, and industrial expansion; (2) supporting increasing transfers; and (3) possible retirements of coal and natural gas generators.

On the demand side, NERC projects that summer peak demand across North America will grow by about 224 GW over the next decade, a 69% increase over the previous year's ten-year forecast and roughly a 24% increase from 2025 peak demand.[42] NERC attributes most of the expected new load to an increasing number of new data centers.[43] On the supply side, operators are deploying tools and technologies to increase effective transfer capability. For example, the Commission's Order No. 881 requires transmission providers to use ambient-adjusted ratings, potentially increasing available transmission capacity, though implementation is ongoing.[44] For this summer, across the U.S., many transmission providers will have begun using hourly ambient adjusted ratings for their line ratings pursuant to Order No. 881.[45] Among the RTO/ISOs, PJM Interconnection LLC (PJM) has adopted the use of ambient adjusted ratings, and SPP expects to implement them on September 1.[46]

Additionally, in several regions, coal and natural gas-fired plants that were slated to retire are continuing operations pursuant to DOE Orders under section 202 (c) of the Federal Power Act (FPA).[47] These units total more than 4,300 MW

41 NERC, *2026 Summer Reliability Assessment* at 45-50 (May 19, 2026), www.nerc.com/our-work/assessments..

42 NERC, *Long Term Reliability Assessment, January 2026*, T*rends and Reliability Implications* at 9, (Jan. 23, 2026), prod.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

43 *Ibid;* Robert Walton, *NERC Forecasts Peak Demand to Rise 24% on New Data Center Loads*, Utility Dive, Jan. 30, 2026, www.utilitydive.com/news/nerc-10-year-peak-demand-forecast-jumps-24-on-new-data-center-loads/810955/#:~:text=Dive%20Brief%3A&text=Summer%20peak%20demand%20across%20the,most%20of%20the%20projected%20increase.

44 *Managing Transmission Line Ratings,* Order No. 881, 177 FERC ¶ 61,179 (2021). Ambient adjusted ratings are designed to more accurately reflect the transfer capability of the transmission system than seasonal and static transmission line ratings, and in some cases may identify more transfer capacity.

45 Transmission providers using AARs this summer include Tampa Electric Co., Duke Energy Florida, Southern Companies, Dominion Energy South Carolina, Louisville Gas and Electric Co. and Kentucky Utilities, Avista, Idaho Power Co., Public Service Company of New Mexico, and Portland General Electric Co.

46 PJM Inside Lines, *PJM Becomes First RTO to Implement Ambient-Air Ratings for Transmission under FERC Order 881* (Mar. 9, 2026), insidelines.pjm.com/pjm-becomes-first-rto-to-implement-ambient-air-ratings-for-transmission-under-ferc-order-881/. Ethan Howland, *PJM is Now Using Ambient-Adjusted Transmission Ratings. Other Grid Operators Will Soon Follow,* Utility Dive, Mar. 12, 2026, www.utilitydive.com/news/pjm-ambient-adjusted-transmission-ratings-ferc-881/814534/.

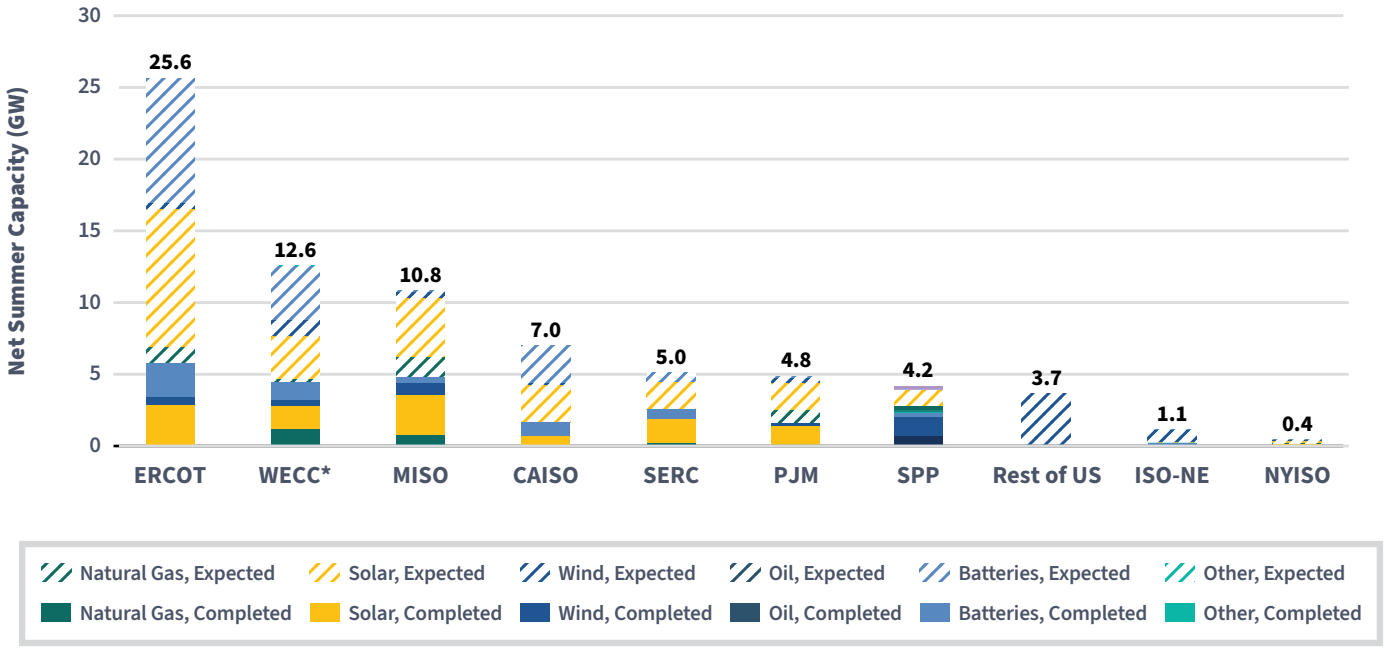
47 Pursuant to FPA section 202(c) and section 301(b) of the Department of Energy Organization Act, the Secretary of Energy may direct a plant to continue running to address an emergency and to serve the public interest. 16 U.S.C. § 824a(c); 42 U.S.C. § 7151(b).

of firm capacity that may be able to support reliability during peak demand.[48] A detailed list of other notable thermal plant retirements that are not subject to the DOE emergency orders can be found in the *Electric Generation Additions, Retirements, and Outages* section of this report.

48 Units directed to continue operations by the Secretary of Energy under FPA 202(c) include: Eddystone Units 3 and 4 (760 MW) in Pennsylvania through May 2026; the Centralia Generating Station Unit 2 (729 MW) in Washington, the R.M. Schahfer Units 17 and 18 (722 MW) in Indiana, the Craig Station Unit 1 (427 MW) in Colorado, and the F.B. Culley Generating Station Unit 2 (360 MW) in Indiana will remain in operation through June 2026. Also, J.H. Campbell (1,331 MW) in Michigan through August 2026. DOE, *2026 DOE 202(c) Orders* (Accessed May 18, 2026), www.energy.gov/ceser/2026-doe-202c-orders; *EIA, Retirement Delays of U.S. Electric Generating Capacity May Continue in 2026* (Feb. 23, 2026), www.eia.gov/todayinenergy/detail.php?id=67206.

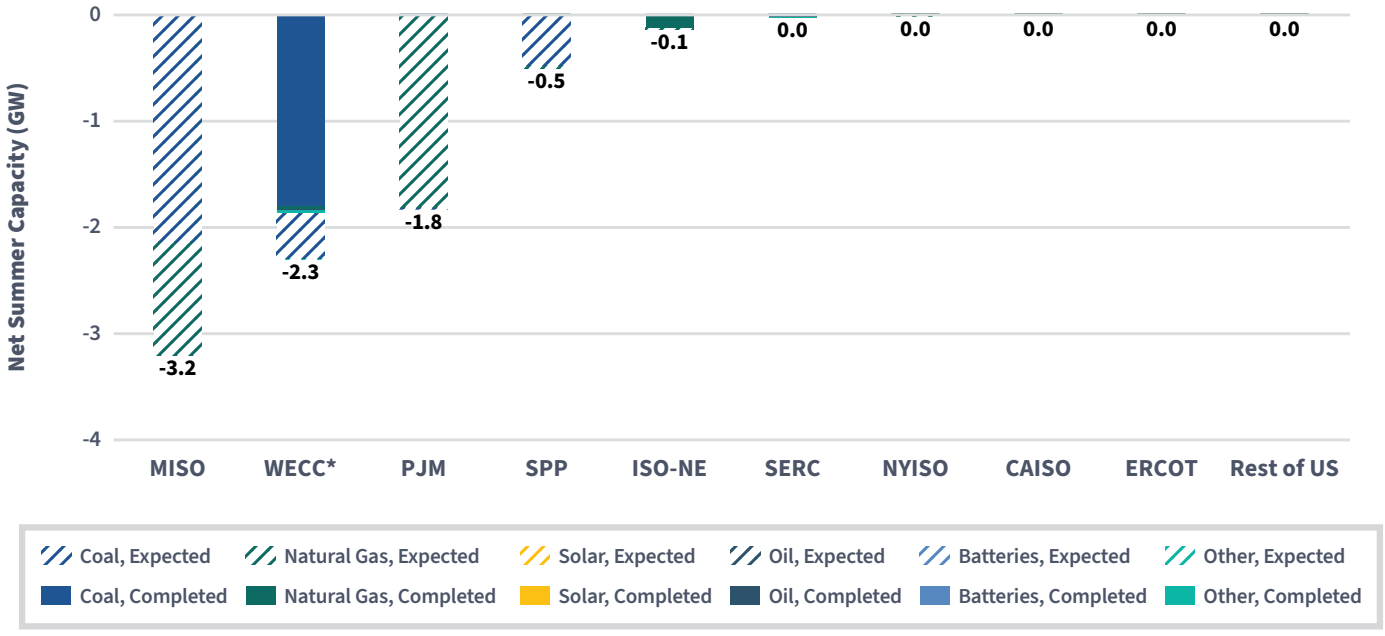
ELECTRIC GENERATION ADDITIONS, RETIREMENTS, & OUTAGES

Figure 15: Electricity Capacity Additions (Oct 2025 - Sep 2026)



NOTE: Completed (from Oct 2025-Jan 2026); Expected (from Feb 2026-Sep 2026) Source: U.S. EIA. Form 860M. *WECC* refers to WECC without CAISO.*

Figure 16: Electricity Capacity Retirements (Oct 2025 - Sep 2026)



NOTE: Completed (from Oct 2025-Jan 2026); Expected (from Feb 2026-Sep 2026) Source: U.S. EIA. Form 860M. *WECC* refers to WECC without CAISO.*

In this section of the assessment, we take a closer look at recent and expected generator additions and retirements heading into summer, including how the resource mix is changing and where plants are being built and retired.

Figure 15 and **Figure 16** show solid bars for completed electric capacity additions and retirements from October 2025 to January 2026, and stripe patterned bars show expected electric capacity additions and retirements from February 2026 to September 2026.[49] These figures reflect net summer capacity[50] across different regions and resource types. Based on EIA data, during this time period net summer capacity additions are expected to total about 75 GW, which is 78% higher than the average net summer capacity additions seen in the last five years.[51] ERCOT is expected to add the most net summer electric capacity, 25.6 GW, which is a 16% increase from its 2025 net summer electric capacity of 158 GW. Other regions expected to add significant net summer electric capacity are the non-CAISO WECC (12.6 GW, a 7% increase to its 2025 capacity) and MISO (10.8 GW, a 6% increase to its 2025 capacity).

Most of these new capacity additions are from solar, battery, and wind facilities, while the expected 8.1 GW of retirements are almost all (98%) coal and natural gas facilities.[52] Given their operating characteristics, new capacity from solar, battery, and wind facilities does not replace the thermal capacity from coal and natural gas facilities on a one-for-one basis.[53]

Meanwhile, across all regions, natural gas generators will continue to provide the largest share (39%) of net summer generation capacity, followed by solar at 14%, coal at 13%, wind at 12%, and nuclear and hydropower both at 7%.[54]

Natural gas resources will remain the dominant source of net summer capacity even while that capacity will decrease more than that of any other fuel type this summer compared to last. Meanwhile, the share of solar net summer capacity will increase the most.

Specifically, generators are expected to retire 3.1 GW of natural gas net summer capacity and to add 35.9 GW of solar capacity, which would decrease the share of natural gas net summer capacity from 41% to 39% and increase the share of solar net summer capacity from 11% to 14%. Generators are also expected to add 22.3 GW of battery net summer capacity, which would increase the share of battery net summer capacity from 3% to 4.5%. All other resource types are expected to see installed capacity share changes of one percent or less.

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49 Of the units directed to continue operations by the Secretary of Energy under FPA 202(c), J.H. Campbell, Eddystone Units 3 and 4, R.M. Schahfer Units 17 and 18, and the Craig Station Unit 1 are included in the expected electric capacity retirements in Figure 16. FPA 202(c) order status changes statuses change every three months, and EIA updates their data accordingly.

50 In this report, net summer capacity refers to the maximum output that generating equipment can supply to system load at the time of peak summer demand. EIA, *Glossary* (Accessed Mar. 18, 2026), www.eia.gov/tools/glossary/index.php/.

51 EIA, *Preliminary Monthly Electric Generator Inventory* (Mar. 24, 2026), www.eia.gov/electricity/data/eia860m/.

52 The WECC amounts include two coal-fired units at the Intermountain Power Plant that are not operating but have not been decommissioned. *See Alixel Cabrera, IPP Coal-fired Units are no Longer Operating as State Government Searches for Buyers,* Utah News Dispatch, Dec. 5, 2025, utahnewsdispatch.com/2025/12/05/intermountain-power-plant-coal-fired-units-no-longer-operating/.

53 For example, Bolson et al. estimate replacing 1 MW of thermal electricity generation requires 2 MW of wind generation or 4 MW of solar generation. *See* N. Bolson, P. Prieto, & T. Patzek, *Capacity Factors for Electrical Power Generation from Renewable and Nonrenewable Sources, Proc. Natl. Acad. Sci. U.S.A. 119 (52) e2205429119*, doi.org/10.1073/pnas.2205429119 (2022).

54 Note that these installed summer capacity estimates capture expected capacity retirements and planned capacity through September 2026 and do not imply that generation output will match the summer capacity of a resource type. *See* EIA, *Preliminary Monthly Electric Generator Inventory* (Mar. 2026), www.eia.gov/electricity/data/eia860m/.

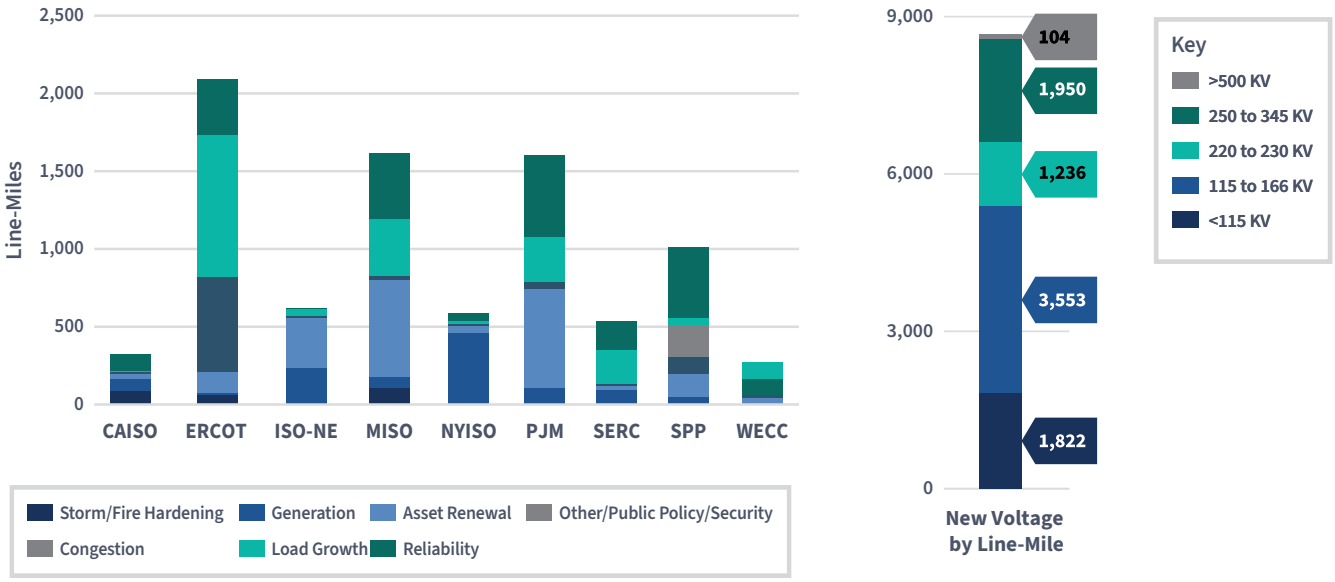
Electricity generators plan to retire 8.1 GW of nameplate capacity between summer 2025 and summer 2026, accelerating by 55% the previous-year pace of retirement. Between summer 2024 and summer 2025, 5.2 GW were retired from the U.S. power grid, the smallest amount of generation capacity retired since 2008. Coal generating capacity accounts for the largest share of planned capacity retirements (60%), followed by natural gas (38%).

Some notable large thermal plants slated for retirement include: the Elwood Energy Power Station (1,344 MW) in Illinois; Grand River Energy Center (594 MW) in Oklahoma; Sabine Power Plant (1,304 MW) in Texas; Oak Creek Units 7 and 8 (616 MW) in Wisconsin; and the AES Alamitos (1,142 MW) and Huntington Beach (226 MW) plants in California.[55]

Generally, planned outages for conventional units tend to decline into the summer from a peak in April and rise again in September to a peak in October or November. As a result, total coincident capacity on outage generally declines in the summer. During July and August, forced outages and derates make up the majority or plurality of unavailable capacity.[56] Proactive grid management strategies are important to maintain grid reliability during extended planned outages as well as when unexpected, forced outages occur.

Electricity Transmission

Figure 17: New Line and Line Upgrades in Summer 2026 by Project Driver (Left) and Voltage (Right)



Source: North American Electric Transmission and Distribution Project Database, The C Three Group L.L.C.

New and upgraded transmission infrastructure supports summer reliability by alleviating constraints, connecting new generation resources, and reinforcing the grid to meet growing electricity demand. Across the country, there are 2,202 new transmission projects in service supporting grid reliability this summer, including 1,136 substation-only projects,

55 EIA, *Preliminary Monthly Electric Generator Inventory* (Mar. 2026), www.eia.gov/electricity/data/eia860m/.

56 Staff analysis of NERC's Generating Availability Data System data from 2021 to 2025.

662 transmission line projects, and 404 combined projects. These projects total 8,665 line-miles, including both projects in regional transmission plans developed by RTOs and ISOs and local projects planned by individual transmission owners within those regions. Of these, 6,476 miles were completed and placed in service between October 2025 and May 2026, and 2,189 miles are expected to enter service between June and September 2026.[57] **Figure 17** breaks down new and upgraded line-miles by region and project driver. Nationwide, the primary drivers for these projects are system reliability (2,244 line-miles), asset renewal (2,019 line-miles), and load growth (1,997 line-miles).

By transmission project count, ERCOT (684), PJM (481), and MISO (450) are the most active regions for transmission development. **Figure 17** illustrates that the top drivers vary by region: ERCOT is primarily focused on load growth (44% of its line-miles) and other/policy/grid security drivers (29%); MISO is driven by a combination of asset renewal (39%) and system reliability (26%); PJM's transmission expansion is concentrated on asset renewal (39%) and system reliability (33%); and CAISO's new mileage is led by system reliability (35%) and storm and fire hardening (27%). SERC is driven by load growth (40%) and system reliability (36%). SPP and MISO are the only regions with new transmission projects developed during this period to relieve congestion, totaling 209 line-miles.

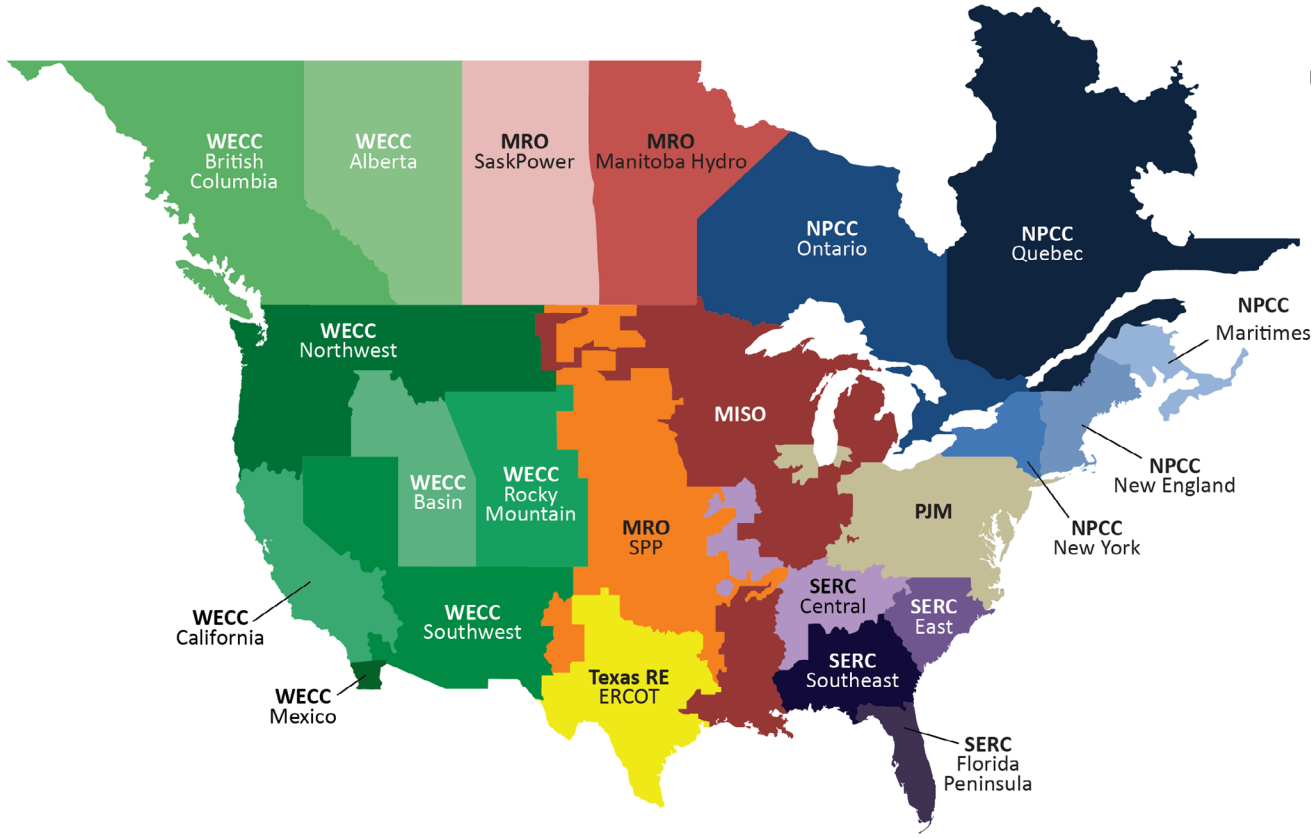
Most projects involve lines below 230 kV, accounting for 62% (or 5,375 line-miles) of new line-miles. The highest voltage lines of 500 kV or more account for 104 line-miles.

57 Transmission line-mile data is from Yes Energy's Electric Transmission and Distribution database. Projects listed include those completed between October 2025 and May 2026 and those expected to enter service between June and Sept. 2026.

REGIONAL HIGHLIGHTS & NERC PROBABILISTIC ASSESSMENTS

NERC Regional Probabilistic Assessments

Figure 18: Regional Highlights and Probabilistic Assessments



Source: NERC

Regions may face energy shortfalls even if planning reserve margins exceed the reference margin levels.[58] To better understand this possibility, NERC assessment areas undertake probabilistic risk analysis[59] to study expected system performance and uncertainty under region-specific scenarios. In doing so, they evaluate the risk of resource adequacy shortfalls for each assessment area this summer. This section relies on the probabilistic risk analyses from NERC's summer 2026 seasonal assessment and supporting reports to assess resource adequacy. NERC's analysis shows that all assessment areas, shown in **Figure 18**, anticipate adequate supplies and reserve margins under normal conditions, but the NPCC-NE, the western part of ERCOT, and the WECC-NW may face a higher likelihood of tight supply and reliability issues during extreme conditions.[60] Below, we focus on the assessments for these three areas.

58 NERC, *2026 Summer Reliability Assessment* at 10-11 (May 19, 2026), www.nerc.com/our-work/assessments.

59 A probabilistic risk analysis assesses a range of scenarios, including potential variations in resources and load that can affect grid operations and can include model parameters to mimic operator actions that could help to mitigate shortfalls in operating reserves.

60 All Regional Entities and assessment areas provide a probability-based resource adequacy risk assessment for the summer season. *See* NERC, *2026 Summer Reliability Assessment* (May 19, 2026), www.nerc.com/our-work/assessments.

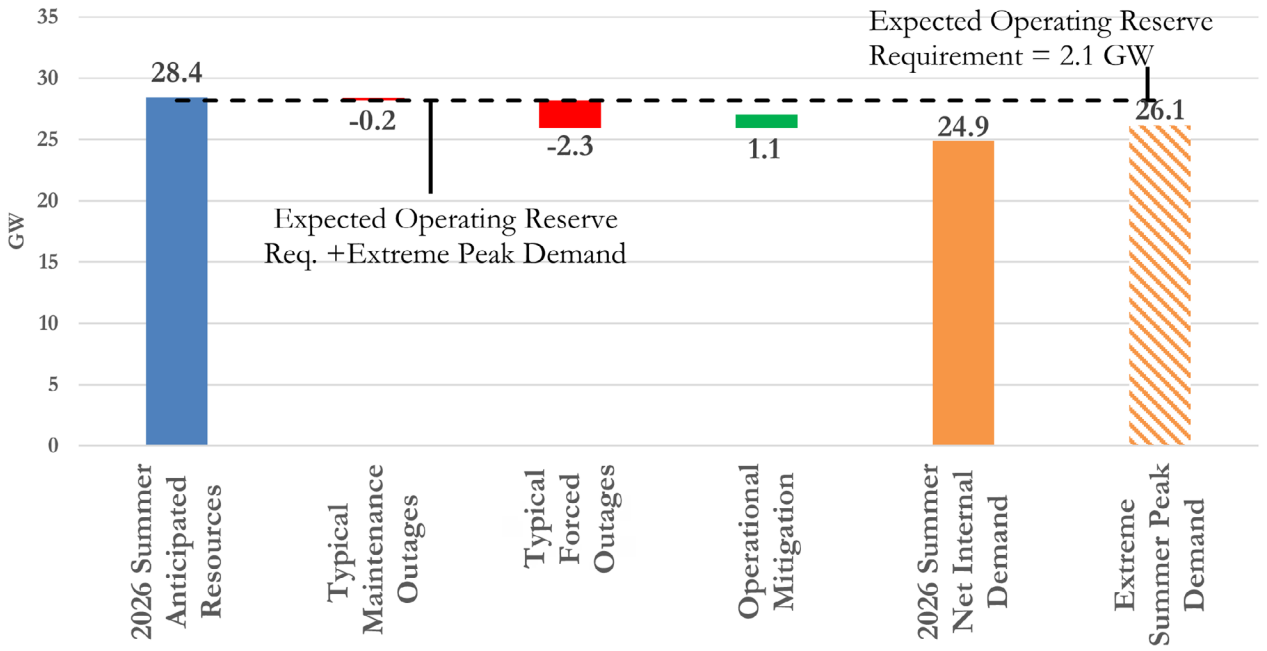
Across all assessment areas, above-normal summer peak load and resource outages could require operational mitigation measures. System operators may call on demand response resources, cancel or postpone non-critical maintenance outages of generation and transmission, and request voluntary conservation measures. If system conditions deteriorate substantially, Reliability Coordinators would declare an Energy Emergency Alert (EEA), allowing system operators to activate emergency demand response measures and increase generation imports from neighboring regions during scarcity conditions.

Regional Highlights

As noted above, NERC's probabilistic assessments evaluate the risk of resource adequacy shortfalls for each assessment area this summer.

Assessment areas set seasonal risk scenarios to provide insight into unexpected events in normal or extreme conditions, but not all unique risks are captured. The scenarios generally assess the greatest risk hour(s) for Expected Unserved Energy,[61] along with the varying demand and available resource profiles. The methods, scenarios considered, and assumptions differ by assessment area and may not be comparable. While all areas are expected to have adequate anticipated resources under normal summer conditions, NPCC-NE, western ERCOT, and WECC-NW assessment areas may experience challenges during extreme summer conditions.

Figure 19: NPCC-NE'S Seasonal Risk Assessment



Source: NERC, 2026 Summer Reliability Assessment

61 Expected Unserved Energy is the sum of the expected number of MWhs that will not be served in a given time period when demand exceeds available capacity. NERC, *Long Term Reliability Assessment, January 2026, Metrics for Probabilistic Evaluation Used in this Assessment* at 172-173, prod.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

NPCC-NE. NERC's *2026 Summer Reliability Assessment* uses "waterfall" charts to illustrate probabilistic assessments for each region. **Figure 19** shows the seasonal risk assessment for NPCC-NE. The left blue column shows anticipated resources of 28.4 GW and the two orange columns on the right show the demand scenarios with normal summer peak of 24.9 GW (50/50) and the extreme summer peak of 26.1 GW (90/10).[62] The middle red bars show the factors that can reduce resource availability, including maintenance outages (0.2 GW less available) and forced outages (2.3 GW), which are not already accounted for in anticipated resources. The middle green bar depicts potential additions of 1.1 GW in resource availability from operational mitigation actions that are available during scarcity conditions but have not been accounted for in the reserve margins. The dotted, horizontal line represents the expected operating reserve requirement of 2.1 GW plus the extreme peak demand, or the amount of power that a region would need to produce to avoid a shortfall.

NPCC-NE's probabilistic assessment shows that established operating procedures should be adequate to maintain supply-demand balance under expected normal conditions during summer 2026. However, under the highest peak load and reduced resources scenario, the area faces elevated risk.[63] The extreme scenario produces an anticipated reserve margin of 11%, below the reference margin level of 13%, and short by approximately 559 MW, with numerous modeled loss-of-load events in June, July, and August.

NPCC-NE's forecasted normal net internal demand peak of 24,882 MW is up 0.3% from last summer.[64] The forecast incorporates expected demand reductions from energy efficiency, load management, behind-the-meter solar, and other distributed generation resources. While the assessment area assumes a net interchange of about 409 MW as firm transmission, actual summer imports often approach 3,000 MW during summer peak conditions, including non-firm resources.[65] In January 2026, NPCC-NE added the New England Clean Energy Connect,[66] a 1,200 MW, 320 kV HVDC, import-only tie line, connecting Hydro-Québec to ISO-New England at an interconnection in Maine.[67] However, the higher-than-normal temperatures and drier conditions in the Québec assessment area may limit transfers into NPCC-NE, a problem exacerbated by the relatively small amount of firm transmission capacity (409 MW) projected as available for net interchange into NPCC-NE this summer.

ERCOT. ERCOT's preliminary summer 2026 outlook indicates a strong chance of warmer and drier-than-normal conditions, with drought potentially driving high statewide electricity demand. While ERCOT expects sufficient operating reserves for the August peak load hour under normal summer conditions, rapid load growth and intermittent renewable resources increase the risk of emergency conditions during evening hours when solar generation ramps down and demand remains elevated.[68]

62 A 50/50 peak load forecast is based on a 50% chance that the actual system peak load will exceed the forecasted value. A 90/10 peak load forecast is based on a 10% chance that the actual system peak load will exceed the forecasted value.

63 The study evaluated a base case reflecting 50/50 normal demand and a highest peak load scenario with a 7% probability.

64 NERC, *2026 Summer Reliability Assessment* at 46, (May 19, 2026), www.nerc.com/our-work/assessments.

65 *Id* at 21.

66 Iberdrola, *NECEC: Connecting Canada and the United States to supply renewable energy to New England*, (Accessed Apr. 23, 2026), www.iberdrola.com/about-us/what-we-do/smart-grids/necec-project-canada-united-states-and-new-england.

67 EIA, *New Transmission line connecting Hydro-Quebec to ISO-NE begins commercial operations,* (Jan. 30, 2026), www.eia.gov/todayinenergy/detail.php?id=67105.

68 NERC, *2026 Summer Reliability Assessment* at 30, (May 19, 2026), www.nerc.com/our-work/assessments.

Rapid load growth in far West Texas has created new reliability challenges.[69] High demand combined with low solar and wind output may overload transmission lines, risking thermal cascading. Additionally, significant and concentrated growth of large, energy-intensive loads such as data centers and industrial facilities pose risks[70] of sudden load loss, which can trigger frequency disturbances, voltage instability, and cascading outages.[71] ERCOT has implemented new Interconnection Reliability Operating Limits in the far west as mitigation efforts. Until longer-term upgrades are in place, ERCOT relies on price-responsive demand to maintain reliability during tight supply periods.[72]

ERCOT is implementing its operational preparedness activities, including its Real-Time Co-optimization Plus Batteries (RTC+B) program to enable improved decision making for energy dispatch, unit commitment, and reserves procurements during periods of tight supply. Also, ERCOT has improved real-time visibility into energy storage resource state of charge, enabling earlier actions when reserves appear insufficient for summer.[73] ERCOT anticipates no major impacts on summer grid reliability from neighboring assessment areas. However, some Switchable Generation Resources[74] totaling about 1,941 MW will be operated to serve SPP's load during the summer to meet contractual obligations. While this reduces capacity available to ERCOT under normal conditions, some of these resources could be temporarily returned to ERCOT if an EEA condition is declared.[75]

WECC-NW. The WECC-NW assessment area faces reliability risks from weather, resource variability, and infrastructure constraints, with wildfire remaining a major concern.[76] As described earlier, below-average snowpack and shifting precipitation patterns reduce hydropower output, increasing reliance on flexible thermal resources and real-time monitoring to manage variability.

To address extreme weather, variable renewable output, and growing load additions, WECC-NW is expanding weather forecasting, wildfire monitoring, conservative hydropower management, battery storage transmission upgrades, and new gas generation. WECC-NW has enhanced its resource planning to manage these impacts.[77]

Reduced local generation, especially hydropower, increases dependence on imports, adding operational exposure during peak periods.[78] Finally, persistent supply chain constraints, including long equipment lead times, rising costs, and limited manufacturing capacity,[79] continue to delay infrastructure projects and reduce operational flexibility,

69 ERCOT, Notice Operations: M-A022326-01 Large Load Interconnection Studies update for Far West Texas region, (Feb. 23, 2026), www.ercot.com/services/comm/mkt_notices/M-A022326-01

70 NERC, *2026 Summer Reliability Assessment* at 30, (May 19, 2026), www.nerc.com/our-work/assessments.

71 ERCOT proposed an operating guide revision (NOGRR 282) establishing frequency and voltage ride-through requirements for certain Large Electronic Loads. This will not be in place for Summer 2026. ERCOT, NOGRR 282 - Large Electronic Load Ride-Through Requirements, www.ercot.com/mktrules/issues/NOGRR282#summaryERCOT, NOGRR 282 - Large Electronic Load Ride-Through Requirements (Accessed May 14, 2025), www.ercot.com/mktrules/issues/NOGRR282#keydocs .

72 NERC, *2026 Summer Reliability Assessment* at 30, (May 19, 2026), www.nerc.com/our-work/assessments.

73 ERCOT, *ERCOT Goes Live with Real-Time Co-optimization Plus Batteries,* press release, (Dec. 5, 2025), https://www.ercot.com/news/release/12052025-ercot-goes-live.

74 Switchable Generation Resources are generating units that are capable of nonsimultaneous synchronization with both the Texas Interconnection and the Eastern Interconnection.

75 NERC, *2026 Summer Reliability Assessment* at 30, (May 19, 2026), https://www.nerc.com/our-work/assessments.

76 *Id* at 36.

77 *Ibid.*

78 *Ibid*.

79 Sonal Patel, *Transformers in 2026: Shortage, Scramble, or Self-Inflicted Crisis?,* POWER, Jan. 2, 2026, www.powermag.com/transformers-in-2026-shortage-scramble-or-self-inflicted-crisis/.

making those constraints a sustained and structural risk to reliability. According to WECC, the Northwest area supply chain constraints and economic uncertainty may impact Tier 1 resources (i.e., future capacity that is typically considered more certain because it is either under construction or has received approved planning requirements) that total 477 MW.[80] When large loads go offline, the WECC-NW assessment area may experience energy imbalance and over-frequency, increasing the need for regulation reserves requiring operator intervention.[81]

80 NERC, *2026 Summer Reliability Assessment* at 36 (May 19, 2026), https://www.nerc.com/our-work/assessments.

81 *Ibid.*



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2026 Summer Energy Market and Electric Reliability Assessment

May 21, 2026

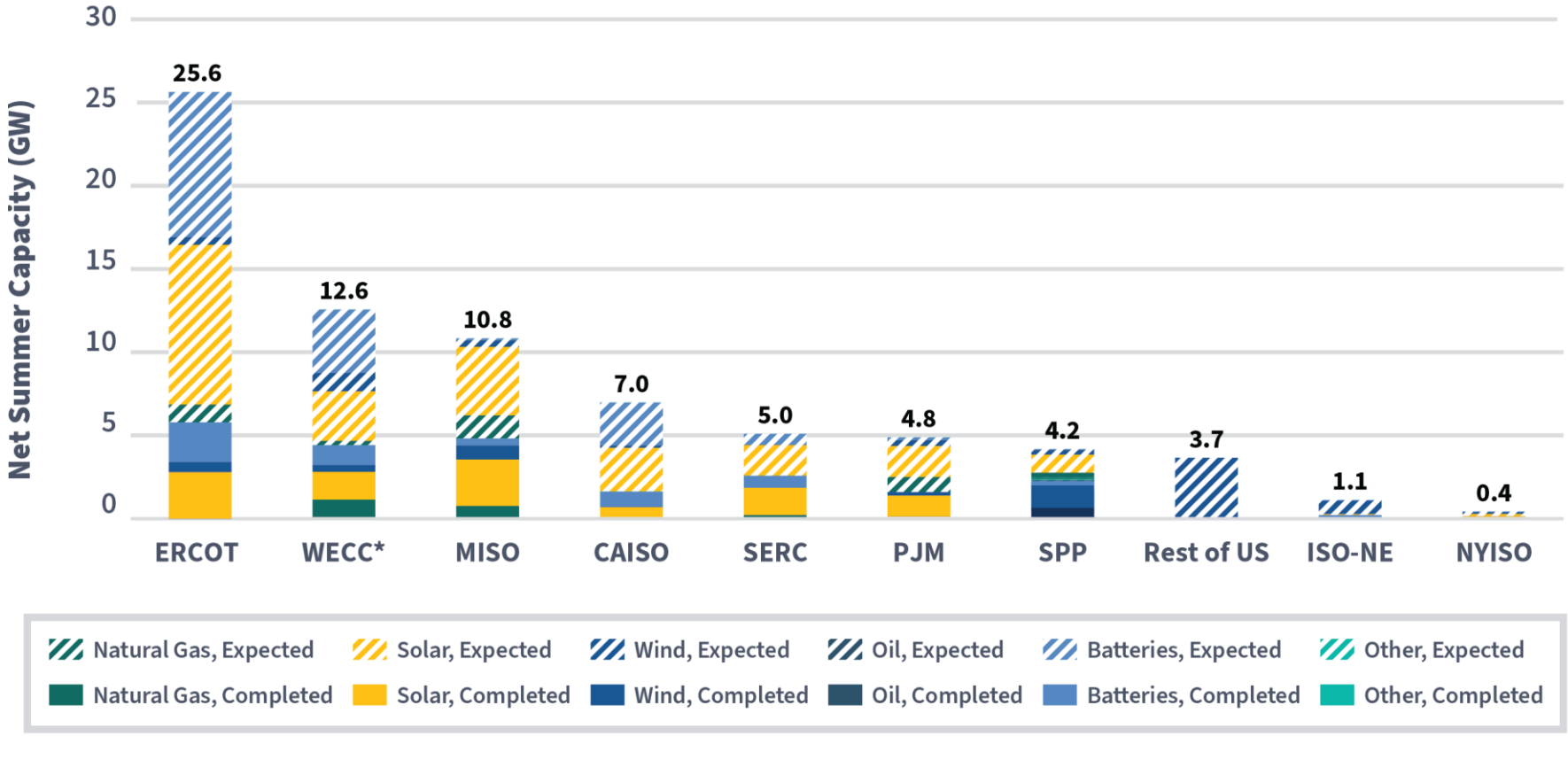
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Key Findings in Summer 2026 Assessment

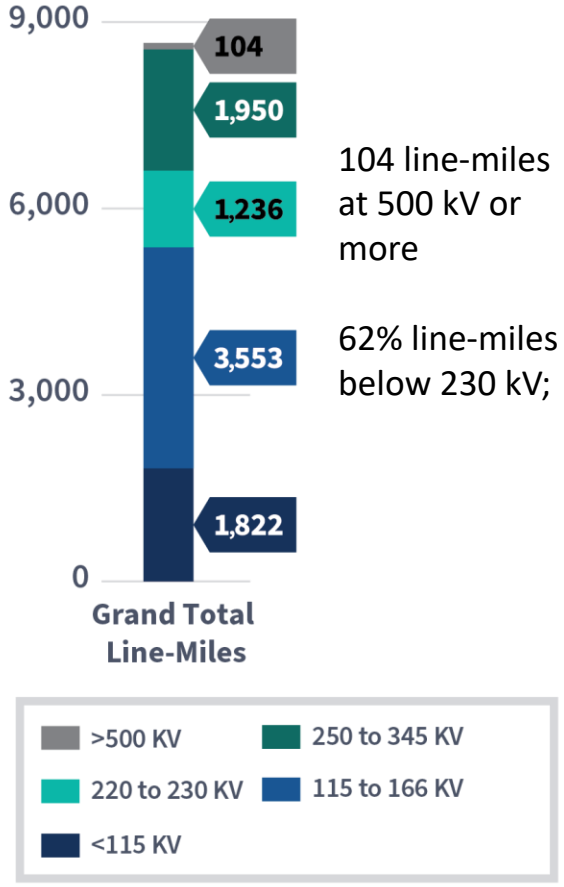
- High temperatures and extreme weather events are expected to challenge the electric grid.
  - Drought and low snowpack could curb hydropower generation.
  - Wildfires and hurricanes may affect some parts of the country.
- Projected generation and transmission additions will help address forecasted high electricity demand growth.
- Natural gas demand and production are both expected to increase.
- Resources and operating reserves are expected to be adequate in all NERC assessment areas under normal operating conditions.
  - Possible reliability challenges in NPCC-NE, western ERCOT, and WECC-NW under extreme operating conditions.

Generators Expected to Add 75 GW of Net Summer Capacity
New Transmission Capacity Mostly for Reliability and Asset Renewal

Electricity Capacity Additions



Transmission New Line-Miles



104 line-miles at 500 kV or more

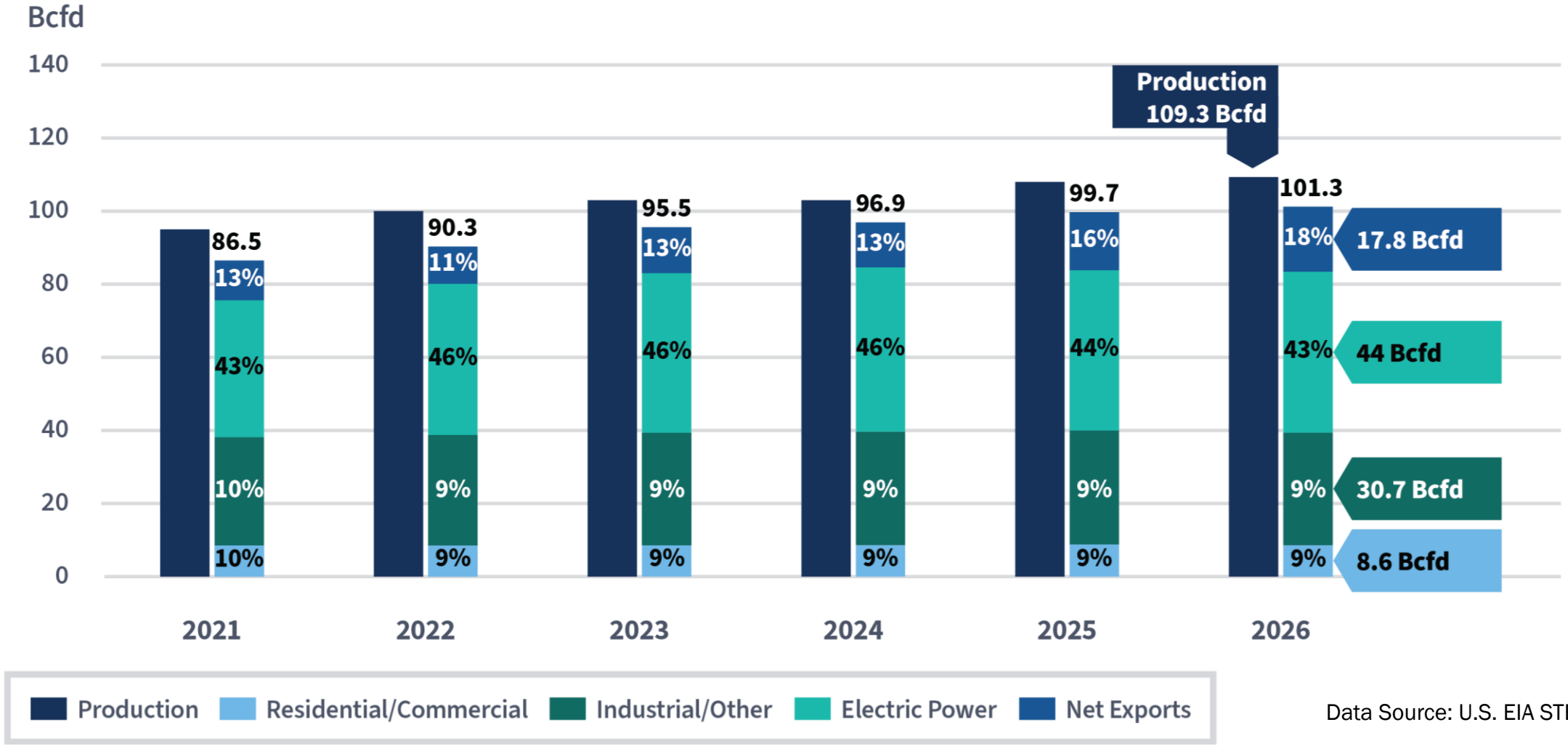
62% line-miles below 230 kV;

Data Source: U.S. EIA Form 860M and *North American Electric Transmission and Distribution Project Database, The C Three Group L.L.C*

**WECC refers to WECC without CAISO.*

Natural Gas Production and Demand Continue Growth

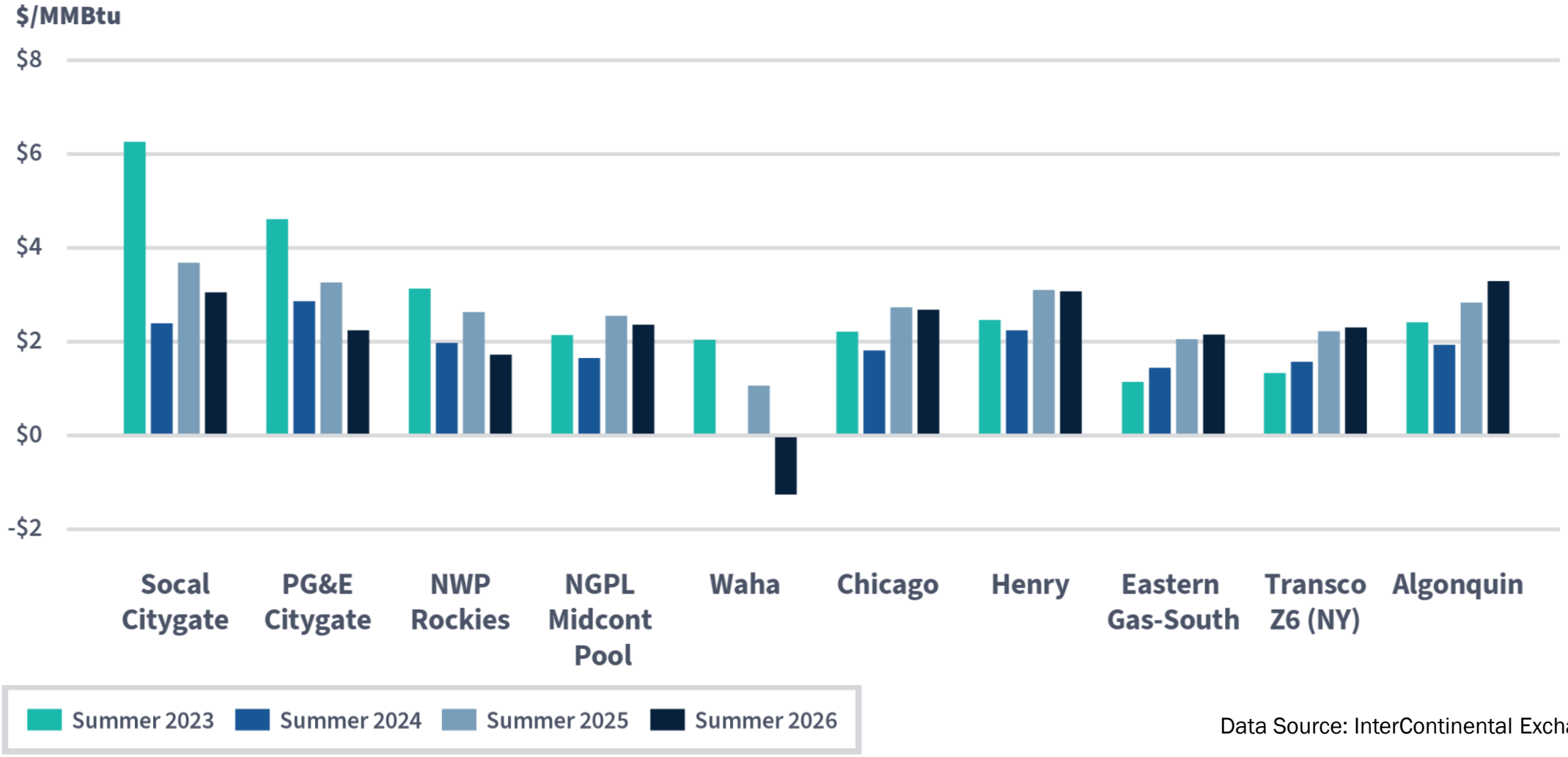
U.S. Summer Natural Gas Production and Demand by Sector



Data Source: U.S. EIA STEO Table 5a

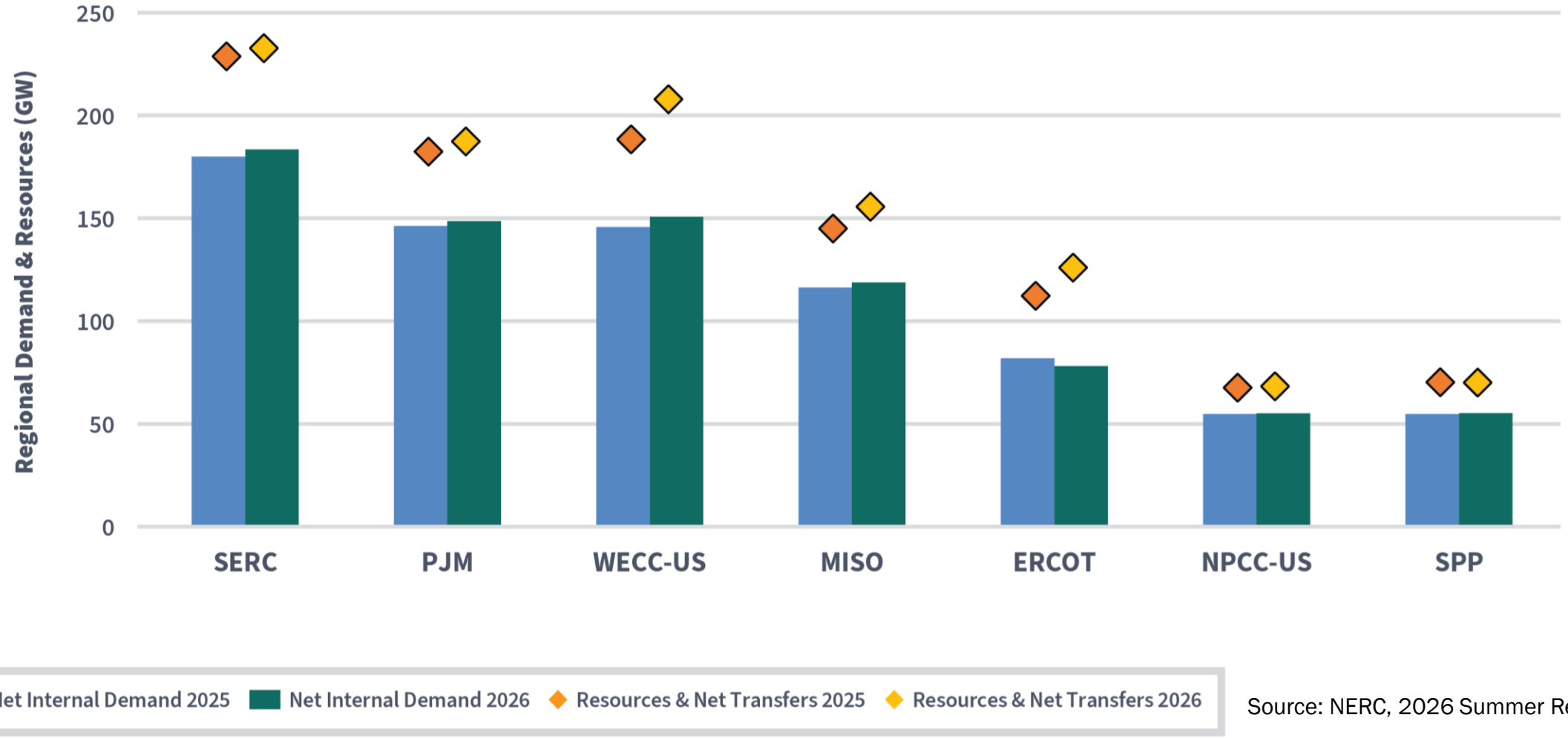
Natural Gas Prices Decrease at Western Hubs and Increase at Eastern Hubs

U.S. Summer Natural Gas Prices



Data Source: InterContinental Exchange

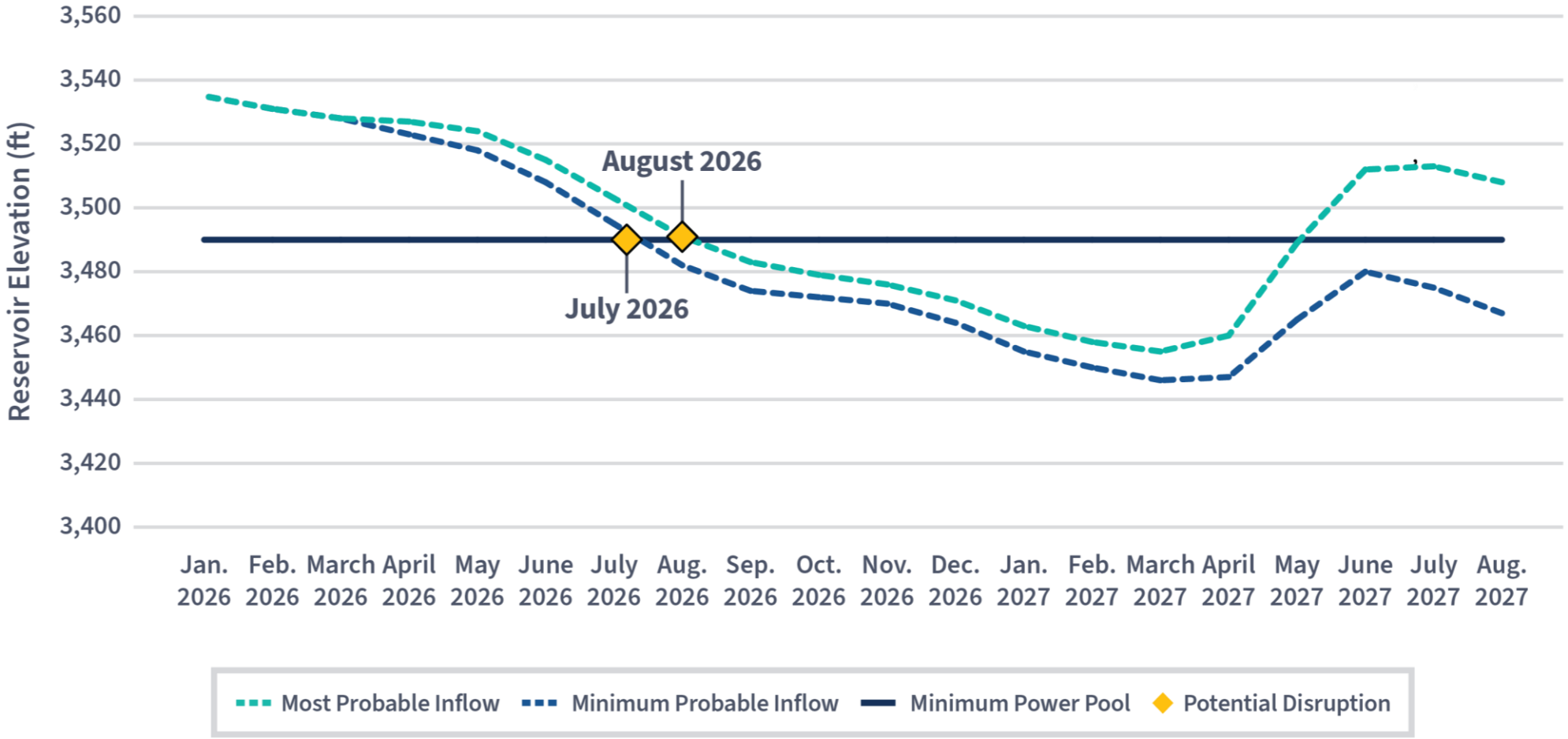
NERC Forecasted Electricity Demand and Resources Summers 2025 and 2026



Source: NERC, 2026 Summer Reliability Assessment

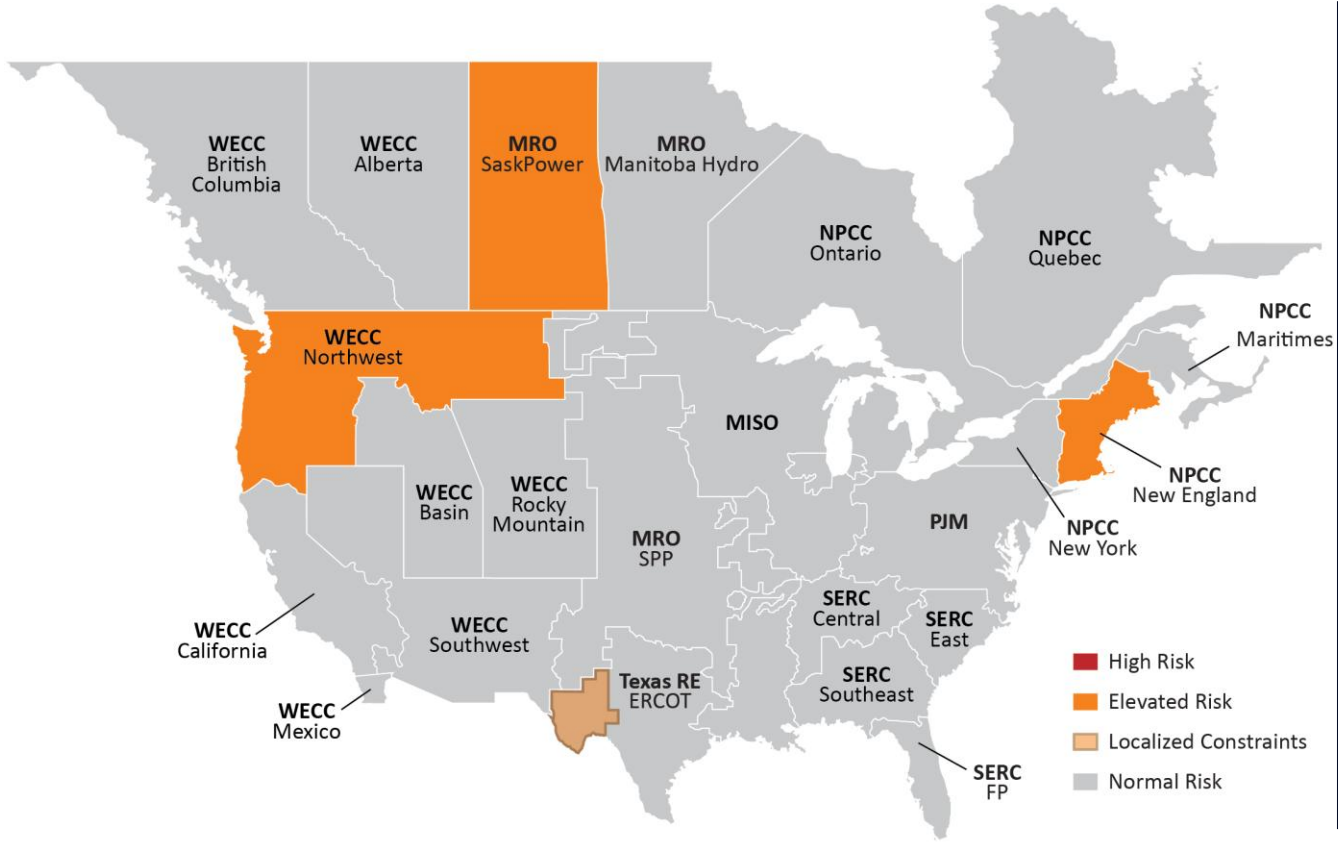
Notable Reliability Risk: Colorado River at Critical Level in 2026

Forecast Reservoir Elevations at Glen Canyon Dam



Bureau of Reclamation 24-Month Study Projections, April 2026

2026 Summer Reliability Assessment
Highlights and Risk Map



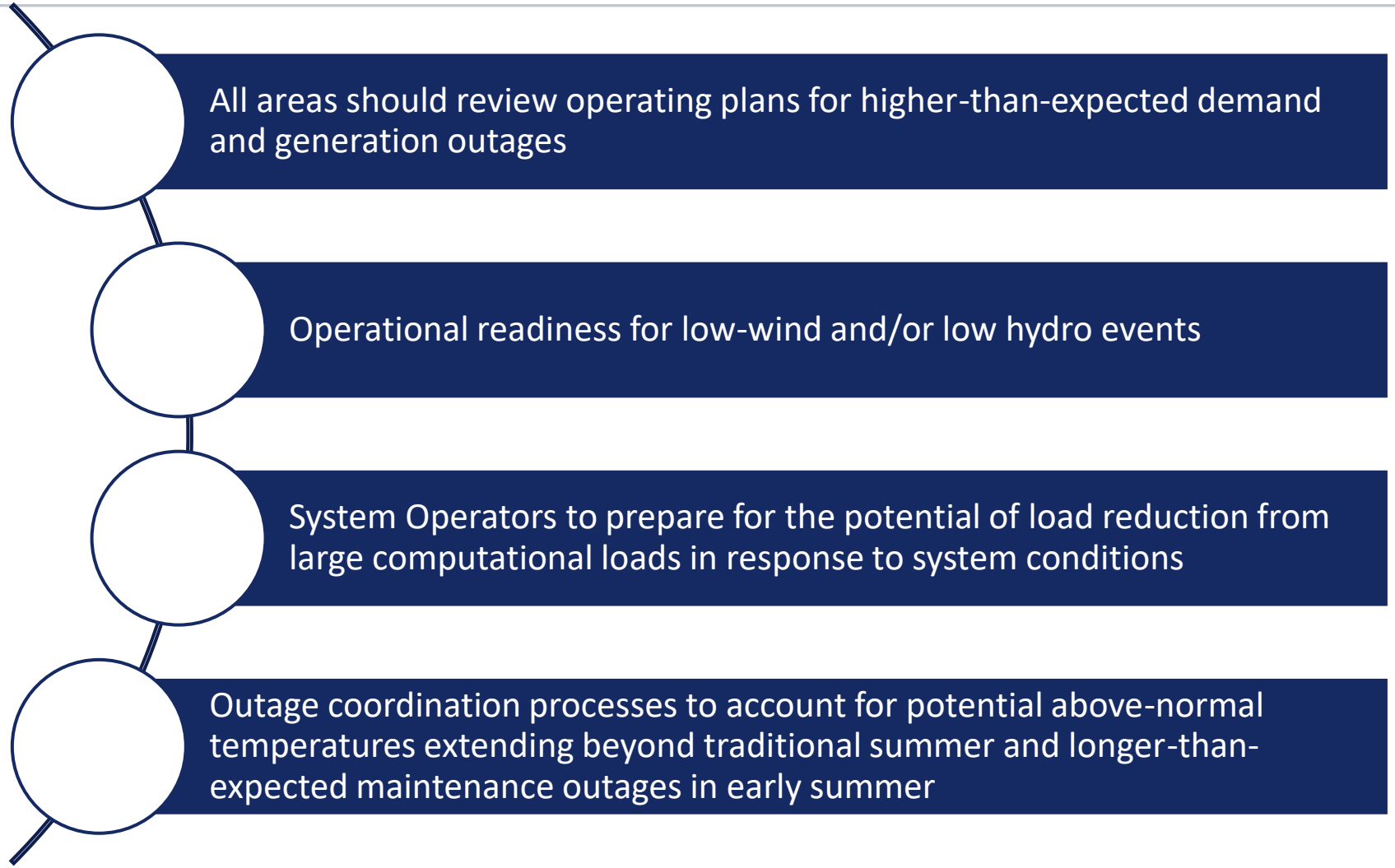
Risk Area Summary

- Elevated risk areas could experience supply shortfalls in extreme conditions
  - **NPCC New England:** Lower expected firm transfers heighten risk of supply shortages
  - **WECC Northwest:** Supply may be insufficient if low hydro conditions coincide with extreme demand
- **Texas RE-ERCOT** is at normal risk level however system constraints can limit supplying all load in the far west zone when local resource output is low

Highlights

- Increased summer capacity has improved the overall outlook
- Rapid growth in electricity demand continues
- Large computational loads pose operational challenges

2026 SRA Recommendations



While resources that support summer peak demand have increased and reduced summer season risk, risk of energy shortfalls during the spring, fall, and winter is increasing.

2026 Summer Energy Market and Electric Reliability Assessment

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