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Exhibit 30



Department of Energy
Washington, DC 20585

PJM Interconnection, L.L.C. and
Constellation Energy Corp.
Regarding Eddystone Unit 3 and Unit 4

Order No. 202-26-24

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 (DOE or the Department) Organization Act,² and for the reasons set forth below, I hereby determine that an emergency exists in the PJM Interconnection, L.L.C. (PJM) region due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The Eddystone Generating Station is a power plant owned by Constellation Energy Corporation (Constellation Energy) and located in Eddystone, Pennsylvania. Units 3 and 4 (Eddystone Units), each with 380 MW of generation capacity, are subcritical steam boiler-turbine generator units that run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order Nos. 202-25-04, 202-25-08, and 202-25-10, issued pursuant to FPA section 202(c), each required that the Eddystone Units remain available to operate for 90 days, until August 28, 2025, November 26, 2025, and February 24, 2026, respectively. Subsequently, Order No. 202-26-17, issued pursuant to FPA section 202(c), required the Eddystone Units to remain available to operate for 90 days, through May 24, 2026. Those orders were based on my determination that emergency conditions existed in the PJM region. Specifically, I explained that there was a potential shortage of electric energy and a shortage of facilities for the generation of electric energy.³ I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety.⁴ I determined that continued operation and economic dispatch of the Eddystone

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ See, e.g., *PJM Interconnection, L.L.C.*, Order No. 202-25-10, at 7 (Nov. 25, 2025).

⁴ *Id.* at 9.

Units was necessary to best meet the emergency and serve the public interest.⁵ My determination was based on a number of different facts.

First, in congressional testimony, PJM's President and CEO stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of dispatchable resources, and other factors.⁶ Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM's interconnection queue.⁷ Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."⁸ In its February 2023 assessment, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, PJM highlighted increasing reliability risks in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.⁹

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a

⁵ *Id.* at 9 & Ordering Paragraph A.

⁶ *Keeping the Lights On: Examining the State of Reg'l Reliability; Hearing Before the House Comm. on Energy & Com., SubComm. on Energy*, 119th Cong. 4–5 (2025) (testimony of Mr. Manu Asthana, President and CEO, PJM) [hereinafter Asthana Test.], <https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf>.

⁷ *Id.*; see also *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 15 (2025) ("PJM states . . . that, in 2023, it found that generator retirements, load growth, the pace of new entry, and the operating characteristics of the intermittent and limited duration resources that make up a large part of PJM's interconnection queue pose increasing reliability risks through 2030.").

⁸ *PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing Risk*, PJM INSIDE LINES (May 9, 2025), <https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/>.

⁹ PJM, *Energy Transition in PJM: Res. Rets., Replacements & Risks*, at 1 (Feb. 24, 2023) [hereinafter Four Rs Report], <https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx>.

resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry.”¹⁰

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-04, 202-25-08, 202-25-10, and 202-26-17 continue, both in the near and long term.¹¹ The production of electricity from the Eddystone Units will continue to be a critical asset for maintaining reliability in PJM. According to data from the U.S. Environmental Protection Agency (EPA), the Eddystone Units generated 26,971 MWh between June 2025 and December 2025,¹² providing vital generation capacity to the region. Over the summer of 2025, PJM took action to manage grid operations, issuing Hot Weather Alerts and/or Maximum Generation Alerts (i.e., an Energy Emergency Alert (EEA) 1) to manage grid reliability covering a total of 20 days, including days in June, July, and August.¹³

PJM’s resource adequacy concerns were recently demonstrated during Winter Storm Fern, when PJM operated under a cold weather alert and declared conservative operations from January 24 to February 2, 2026. Additionally, on January 27, 2026, PJM declared a Maximum Generation Emergency/Load Management Alert and an EEA 1.¹⁴

¹⁰ *PJM Interconnection*, 190 FERC ¶ 61,084 at P 14.

¹¹ Further, it likely would be difficult for these units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Moreover, if Constellation Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. Thus, continued operation is required in such cases so long as the Secretary determines that an emergency exists. The costs and time of decommissioning a coal plant are extensive and includes various components. Therefore, restarting such decommissioned plants could have significant costs in terms of dollars and time. See Section 4 in Lessick, Jennifer, et al. *Business Models for Coal Plant Decommissioning*. www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf.

¹² See EPA, *Custom Data Download*, EPA CAMPD (Clean Air Mkts. Program Data), <https://campd.epa.gov/data/custom-data-download> (choose “Emissions” from Data Type dropdown; choose “Monthly Emissions” from Data Subtype dropdown; choose “Unit (No Aggregation)” from Aggregation dropdown; then click “Apply”; then type “2025” into “Time Period” filter and click “June, July, August, September, October, November, December”; then click “Apply Filter”; then click “Facility” filter and type “Eddystone Generating Station (3161)”; then click “Eddystone Generating Station (3161)”; then click “Apply Filter”; then click “Preview Data”).

¹³ See PJM, *Emergency Procs.*, <https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf> (search Effective From 06/01/2025 Effective To 08/31/2025).

¹⁴ See *id.* (search Effective From 01/20/2026 Effective To 02/07/2026).

Due to concerns about resource adequacy from the high demand driven by the extreme cold, PJM also applied for an order pursuant to FPA section 202(c) “that broadly authorizes all electric generating units located within the PJM Region to operate up to their maximum generation output levels, notwithstanding air quality or other permit limitations or fuel shortages during the pendency of this emergency.”¹⁵ DOE granted PJM’s application and issued Order No. 202-26-02 on January 25, 2026.¹⁶

On January 29, 2026, PJM applied for an extension of Order No. 202-26-02, which was designated as Order No. 202-26-02A, which was granted by the Department on the same day.¹⁷ Furthermore, on March 17, 2026, in his testimony to the House Committee on Energy and Commerce, North American Electric Reliability Corporation (NERC) Chief Executive Officer Jim Robb stated that “PJM and other grid operators indicated that 202(c) facilities made material contributions” with regard to reliability during Winter Storm Fern.¹⁸

PJM’s resource adequacy concerns are well documented. In January 2025, PJM reached a new record peak for winter demand, exceeding the previous winter peak set in 2015.¹⁹ PJM notes that the “20-year annualized growth rate in the 2025 Long-Term Load Forecast for the winter peak is up to 2.4%.”²⁰ Further, PJM’s risk profile continues to shift from the summer season to the winter season. For example, in a March 2025 presentation, PJM estimated that 87.8% of the expected unserved energy for the 2025/2026 delivery year falls in the winter season.²¹

¹⁵ Letter from Michael E. Bryson, Senior Vice Pres., Operations, PJM, to Hon. Chris Wright, Sec’y, DOE, at 2 (Jan. 4, 2026) (requesting emergency order under FPA section 202(c)), <https://www.energy.gov/documents/pjm-202c-application-2026-01-24>.

¹⁶ *PJM Interconnection, L.L.C.*, Order No. 202-26-02 (Jan. 25, 2026).

¹⁷ *PJM Interconnection, L.L.C.*, Order No. 202-26-02A (Jan. 29, 2026).

¹⁸ *Winter Storm Fern Lessons: Supplying Reliable Power to Meet Peak Demand; Hearing Before the House Comm. on Energy & Com., Subcomm. On Energy*, 119th Cong. 8 (2026) (statement of James B. Robb, President and CEO, NERC), <https://www.congress.gov/119/meeting/house/119077/witnesses/HHRG-119-IF03-Wstate-RobbJ-20260317.pdf>.

¹⁹ *Jan. 22 Update: Extreme Cold Produces PJM Record for Winter Elec.y Demand*, PJM INSIDE LINES (Jan. 22, 2025), <https://insidelines.pjm.com/jan-22-update-extreme-cold-produces-pjm-record-for-winter-electricity-demand/>.

²⁰ *2025 Long-Term Load Forecast Rep. Predicts Significant Increase in Elec. Demand*, PJM INSIDE LINES (Jan. 30, 2025), <https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/>.

²¹ PJM Res. Adequacy Planning Special Planning Comm., *2026/27 BRA IRM, FPR, & ELCC Class Ratings: Shift Towards More Winter Risk*, at 8 (Mar. 13, 2025), <https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf>.

Recognizing the need for and importance of additional generation resources, on April 20, 2026, a Consent Decree between the Commonwealth of Pennsylvania and Keystone-Conemaugh Projects, LLC (KEY-CON) authorized operations to continue at two coal-fired steam electric generating plants that were slated for permanent cessation. The Consent Decree explained that “[d]ue to recent changes in the long-term electricity market outlook based on recent projections by PJM Interconnection LLC and the U.S. Department of Energy, including the need for electricity generators to cover projected increased electrical demand driven by build-out of data centers, particularly within the Mid-Atlantic Area Council, a portion of the PJM Interconnection LLC regional transmission organization that the [Conemaugh Generating Station and Keystone Generating Station] CON has recently reevaluated its 2021 decision to achieve [permanent cessation of coal combustion] at the [Conemaugh Generating Station and Keystone Generating Station] by December 31, 2028.”²²

In the fall of 2025, Pennsylvania Governor Josh Shapiro recognized the need for and importance of securing more electricity generation for the grid. Governor Shapiro stated that “[c]hange is needed to keep energy costs low, bring new energy generation onto the grid more quickly, and meet the needs of the 67 million Americans who rely on this grid for everything from running a business to keeping the lights on at home.”²³ Furthermore, PJM expressed support for Order No. 202-25-04, since it has “repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers.”²⁴

PJM has indeed voiced these concerns for years. In its February 2023 Four Rs Report, PJM cautioned that 40 GW of thermal generation are at risk of retirement

²² Commonwealth of Pennsylvania, Dep’t of Env’t Prot. v. Keystone-Conemaugh Projects, LLC, No. 2169-CD-2025-1, slip op. at 4 (Apr. 20, 2026) (Unopposed Motion to Enter Consent Decree), <https://www.pa.gov/content/dam/copapwp-pagov/en/governor/documents/motion%20to%20enter%20cd-as%20filed.pdf>.

²³ *How Josh Shapiro wants to reshape the region’s power grid operator as prices rise*, Spotlight PA (Oct. 14, 2025), <https://www.spotlightpa.org/news/2025/10/electricity-prices-shapiro-grid-operator-pjm-data-centers-environment/>.

²⁴ *PJM Statement on the U.S. Dept. of Energy 202(c) Order of May 30*, PJM INSIDE LINES (May 31, 2025), <https://insidelines.pjm.com/pjm-statement-on-the-u-s-department-of-energy-202c-order-of-may-30/>. Further, PJM concluded, “In light of these concerns, PJM supports the U.S. Department of Energy’s Order, issued May 30, pursuant to Section 202(c) of the Federal Power Act, to defer the retirements of certain generators operating in PJM’s footprint.” *Id.*

by 2030.²⁵ PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for renewable projects is approximately 5%.²⁶ PJM determined that the pace of new capacity additions “would be insufficient to keep up with expected retirements and demand growth by 2030.”²⁷ PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.²⁸

In its December 2024 Reliability Resource Initiative (RRI) filing with FERC, PJM stated that “[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report.”²⁹ PJM warned that its “resource adequacy concerns are increasing at an extraordinary pace.”³⁰ PJM went on to explain that its “resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers” and that its preliminary analysis shows “substantial increases [in load additions] since the 2024 forecast” for both the summer and winter seasons.³¹ According to PJM, “load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence.”³² Although the RRI process will help expedite the construction of needed new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.³³

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM’s Director, Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as “extraordinary” and “unprecedented,” stating that it “could not have been foreseen as recently as a year ago.”³⁴ Mr. Bielak expressed the opinion that the “rapid” retirement of thermal generation resources, “extreme”

²⁵ Four Rs Report, *supra* note 9, at 2.

²⁶ *Id.*

²⁷ *Id.* at 16 tbl. 1.

²⁸ *Id.*

²⁹ PJM, Filing, , Dkt. No. ER25-712-000, at 10 (Dec. 13, 2024).

³⁰ *Id.*

³¹ *Id.* at 10-11; *see also id.* at 13 (stating that “the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements”).

³² *Id.* at 14.

³³ *See id.* attach. C (Affidavit of Mr. Donald Bielak), at 18–19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, “could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner”).

³⁴ Bielak Aff. at 10.

forecasted load growth, and “delays in new generation resources achieving commercial operation,” would adversely affect resource adequacy throughout PJM’s electricity grid.³⁵

On February 11, 2025, FERC accepted PJM’s proposed tariff revisions in its RRI filing.³⁶ In its order on rehearing, FERC concluded that “PJM identified increasing reliability risks arising in the next few years and significant resource adequacy issues anticipated by the 2030/31 delivery year. The record supports that these resource adequacy concerns are likely to manifest.”³⁷

The NERC has raised similar concerns. In its 2025 Long-Term Reliability Assessment, released in January 2026, NERC observed that the PJM region is at high risk of energy shortfalls over the next five years³⁸ and faces significant reliability challenges as “[c]urrent projections for resource additions do not keep pace with escalating demand forecasts and expected generator retirements.”³⁹ The assessment notes that “[d]emand for electricity in PJM is growing at its fastest pace in years, driven primarily by data centers, followed by electrification and manufacturing loads;” however “[a]t the same time, PJM faces an extreme and rapid tightening of capacity resources in the near term because of generator retirements and project delays.”⁴⁰ Overall, the assessment concludes that “[b]ased 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.”⁴¹

Order Nos. 202-25-04, 202-25-08, 202-25-10, and 202-26-17 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

³⁵ *Id.* at 12.

³⁶ *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 (2025); *see also, e.g., id.* P 263.

³⁷ *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,085, at P 25 (2025).

³⁸ NERC, *2025 Long-Term Reliability Assessment*, at 7 fig. 1 (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

³⁹ *Id.* at 8.

⁴⁰ *Id.* at 16.

⁴¹ *Id.* at 91.

security, and foreign policy.”⁴² 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.”⁴³ 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.”⁴⁴

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.”⁴⁵ The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.⁴⁶ As of December 2024, Dominion Energy has 40.2 GW of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.⁴⁷ In collaboration with the national labs, the Department modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced

⁴² Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), <https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency>.

⁴³ *Id.*

⁴⁴ Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), <https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid>.

⁴⁵ DOE, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025) [hereinafter Resource Adequacy Report], <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

⁴⁶ See PPL Corporation, *PPL Corporation Q2 2025 Investor Update*, at 7 (July 31, 2025), https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINAL.pdf.

⁴⁷ See Dominion Energy Virginia, *Q4 2024 Earnings Call*, at 18 (Feb. 12, 2025), https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slides-vTCII.pdf.

coal, gas, and oil generation retirements.⁴⁸ Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a maximum unserved load of approximately 21.335 GW.⁴⁹

Grid operators, including PJM, have likewise acknowledged the Nation's current energy crisis. For instance, during a hearing before the United States House of Representatives Committee on Energy and Commerce on March 25, 2025, Manu Asthana, President and CEO, PJM, testified that there was a "growing resource adequacy concern . . . impacting a significant part of our country."⁵⁰ Mr. Asthana explained that the "rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from industrial growth."⁵¹ Mr. Asthana noted that, though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening.⁵² Therefore, Mr. Asthana stated that PJM "encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability."⁵³

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

⁴⁸ Resource Adequacy Report, *supra* note 44, at 28.

⁴⁹ *Id.* at 27.

⁵⁰ Asthana Test., *supra* note 6, at 4.

⁵¹ *Id.*

⁵² *Id.* at 9–10.

⁵³ *Id.* at 10.

interest.”⁵⁴ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

As described above, the emergency conditions resulting from the combination of increasing demand and the capacity shortfall stemming from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-04, 202-25-08, 202-25-10, and 202-26-17 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 PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Eddystone Units is necessary to best meet the increased demand for emergency and mitigate the observed shortage of generation, thus serving the public interest pursuant to FPA section 202(c).

To ensure that the Eddystone Units will be available if needed to address emergency conditions, they shall remain available to operate through August 22, 2026.⁵⁵

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

- A. From May 25, 2026, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.
- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by PJM pursuant to paragraph A. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units have operated in compliance with the allowances contained in this Order.
- C. All operations of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with

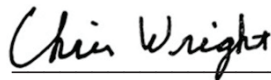
⁵⁴ Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. See 42 U.S.C. § 7151(b).

⁵⁵ 16 U.S.C. § 824a(c)(4).

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 8, 2026, PJM 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 Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time.
- E. Constellation Energy 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 Eddystone Units to comply with applicable state, local, or Federal laws or regulations following the expiration of this Order.
- G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Eddystone Units shall not be considered capacity resources.
- H. This Order shall be effective on May 25, 2026, through August 22, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 21st day of May 2026.



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

Pennsylvania Public Utility Commission
Chairman Stephen M. DeFrank
Vice Chair Kimberly M. Barrow
Commissioner Kathryn L. Zerfuss
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora

Exhibit 31

2026 Summer Reliability Assessment

May 2026

RELIABILITY | RESILIENCE | SECURITY

POWERING TODAY. PROTECTING TOMORROW.

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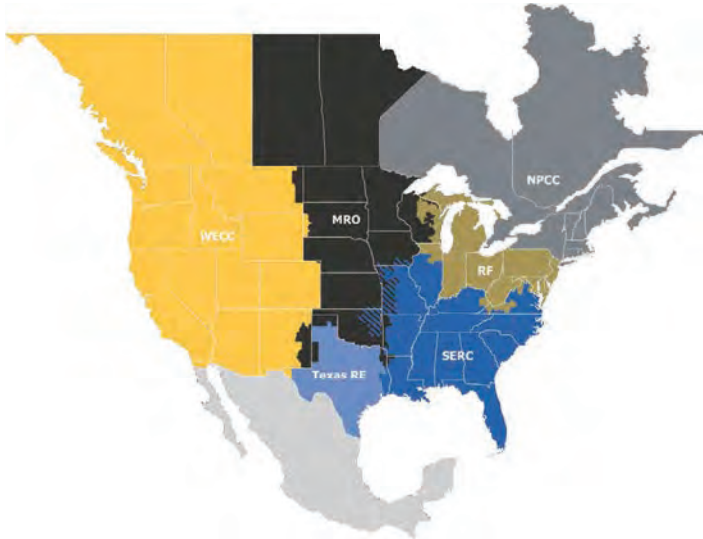
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Preface

Electricity powers our modern life and is the bedrock of our economic wellbeing. The Electric Reliability Organization (ERO) Enterprise—comprised of NERC and the six Regional Entities—is firmly committed to assuring a highly reliable, resilient, and secure bulk power system (BPS) in North America. The ERO Enterprise enables collaborative engagement with industry, regulators, and stakeholders, embracing innovation and supporting the needs of nearly 400 million people.

RELIABILITY | RESILIENCE | SECURITY
POWERING TODAY. PROTECTING TOMORROW.

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's *2026 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 risk hours 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 *2025 Long-Term Reliability Assessment* (LTRA), which covers a 10-year horizon, and other earlier reliability assessments and reports.¹

The 2026 Summer risk profile is marked by rising demand, significant generation growth in many areas, the prospect of challenging hydrological conditions, and the unpredictability of large loads, from both a forecasting and operational perspective. Multiple assessment areas have revised load forecasts downward from mid-2025 projections to account for the observed rate of completion for large load interconnections and the slower-than-expected pace at which some of those loads are coming on-line. Still, aggregated peak demand across all assessment areas has increased by over 11 GW from Summer 2025 projections that were set earlier in 2025. That level of growth exceeds the year-on-year rise of 10 GW that preceded Summer 2025. As important as the demand growth itself is the timing of the demand. The early arrival of summer heat and high demand in March has highlighted the risks associated with potential overlaps between spring maintenance outages and high demand. The importance of shoulder season supply-demand analysis continues to grow. The BPS has added slightly more than 58 GW of new resources year on year heading into the coming summer. This large resource addition has partly contributed to the improved risk outlook for some areas. The resource additions continue to include a high proportion of variable energy resources, supporting the prioritization of low-wind event preparation and probabilistic analysis of available energy at peak and risk hours.

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 2026.

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

Resource Adequacy Assessment and Energy Risk Analysis

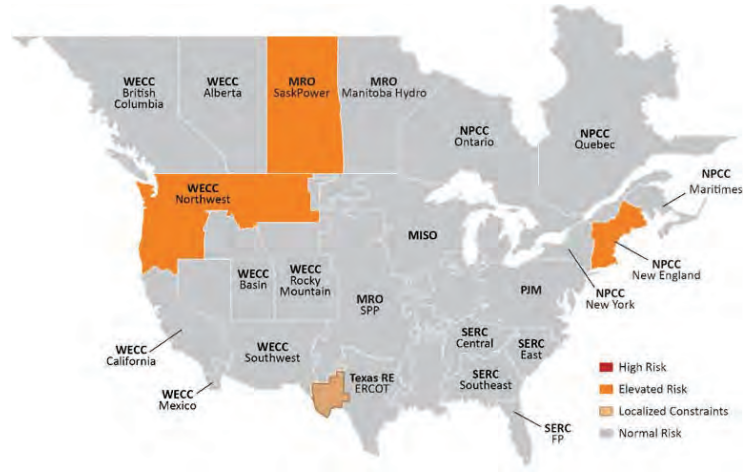
All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see [Figure 1](#)). However, the following areas face elevated risks of electricity supply shortfalls during periods of more extreme summer conditions or are subject to localized constraints that raise the risk levels of certain small areas within the broader system. 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 photovoltaic (PV) energy conditions:

- **NPCC-New England:** The New England area expects to have sufficient resources to meet the 2026 Summer peak demand forecast for normal conditions with an Anticipated Reserve Margin of 14%, just above the Reference Margin Level of 13%. New England may rely on non-firm imports to cover shortfalls even as the region has lowered its projected net firm imports by 836 MW from the previous year's projections to just 409 MW for the coming summer season. The decline in firm transfers is the main driver of the 2.6% year-on-year drop in anticipated resources. Non-firm imports, however, received a boost in January with the addition of New England Clean Energy Connect (NECEC), a symmetric monopole +/- 320 HVdc line from the Appalachies substation in Québec to a new substation in Lewiston, Maine. NECEC will be used as an "import-only" tie with Hydro Québec and can import up to 1,200 MW into New England. Total internal demand for the 50/50 peak summer demand forecast is 25,228 MW, up marginally from the demand projections in the 2025 SRA of 25,202 MW. Expected increases in electrification are the biggest driver in the region's demand forecast as well as slight weather normalization changes. Other resource types have slightly increased from last year within the region. Based on NPCC's most recent energy assessment, some use of New England's operating procedures for mitigating resource shortages is anticipated during Summer 2026 for the base case (50/50 normal demand). For the scenario with the highest peak load and reduced resources, the results were a cumulative loss of load expectation (LOLE) of <0.35 days/period, loss of load hours (LOLH) of <1.2 hours and expected unserved energy (EUE) of 628 MWh/period.
- **MRO-SaskPower:** SaskPower was at elevated risk in the 2025 SRA, and resource adequacy metrics have declined slightly year on year for the upcoming summer period. Reserves have tightened from 34% to 29% due to a ~1.9% demand growth and no substantial change in resources. While SaskPower does not anticipate capacity constraints or reliability issues under normal conditions, extreme summer conditions may cause SaskPower to require maintenance rescheduling, short-term power transfers from neighboring utilities, and/or available demand-response programs. SaskPower's probabilistic in-house model showed an LOLH for an elevated risk scenario for the 2026 Summer season to be 0.09 hours; the month with the highest LOLH is September (0.05 hours).
- **WECC-Northwest:** The coming summer brings challenging hydrological conditions for regions in which hydropower makes up half or more of the supply fleet. Almost the entire Western Interconnection is in the grips of a persistent drought or in an area where drought development has a greater likelihood through the end of July. In Washington, for example, the snow water equivalent was at 52% of normal levels as of April 1 this year,² when snowpack typically reaches its peak. While the total water year supply is forecast to be nearly average in the Columbia River Basin, snowpack peaked at low elevation and melted early in the year. This has implications for the expected resources available to the Northwest, the generation mix for which is 55% hydropower. The region is contending with a nearly 5% increase in net internal demand from the 2025 SRA and a nearly 2% drop in existing resources as well as a roughly 43% drop in expected Tier 1 resources. Though higher modeled net transfers are projected to contribute double what they were projected to last year (albeit with the increase largely attributable to a modeling change that accounts for economic transfers), this was not enough to prevent the drop in the Anticipated Reserve Margin from 32% last year to 27% this year. For this summer's assessment, WECC's study for the Northwest region resulted in small amounts of EUE, increasing from zero in the previous probabilistic assessment. The study also indicated an LOLH of >0.1 hours/period. The hour of greatest risk occurs around 6:00 p.m. in early September.
- **Texas RE:** The Texas Interconnection is widely at a normal risk level for Summer 2026 due to a 12% jump in anticipated resources for the summer period and a 4.5% decline in projected net internal demand. The lower demand forecast is the result of updated load modeling that reflects the observed behavior of load during peak periods and more demand response from large computational loads. The results of ERCOT's Probabilistic Reserve Risk Model (PRRM) simulation indicate a low risk of declaring an energy emergency alert (EEA) during the risk hour (9:00 p.m. local time). However, the PRRM does not capture the pre-contingency load shedding risk in the Far West region of ERCOT's footprint resulting from rapid growth in both load and resources in this zone. Operational

² WSOR-WA

Key Findings

challenges could arise in Far West Texas during periods of high demand combined with low wind output and absence of solar generation. Under these conditions, transmission constraints in the Far West Texas zone may become binding. Price-responsive demand is expected to help reduce transmission congestion and maintain balance with supply during tight conditions. In addition, ERCOT and transmission service providers have developed mitigation measures to address these constraints by incorporating dynamic line ratings that account for solar irradiance along with ambient temperatures. Operating procedures that include involuntary load curtailment are in place to maintain system operating limits when needed. In September 2025, two new thermal cascading Interconnection reliability operating limits (IROL) became effective in the Far West region of ERCOT's footprint.



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

Figure 1: Summer Reliability Risk Area Summary

Other Key Reliability Highlights

- **Weather services are expecting an El Niño weather pattern to influence the weather outlook for the 2026 Summer period.**³ El Niño weather patterns can suppress Atlantic hurricanes, which are a major reliability consideration for the Gulf Coast and Southeast United States. Temperature and precipitation forecasts for the coming summer show a higher likelihood of hotter-than-normal temperatures in the U.S. South and West and cooler-than-normal temperatures in the upper Midwest and parts of the Northeast (see [Figure 2](#)). Wetter-than-normal conditions could alleviate drought severity in the Gulf Coast, but the U.S. Northwest is still expected to see drier-than-normal conditions,⁴ starting with sub-average snowpack⁵ heading into spring that can impact the availability of hydropower units in a region that relies heavily on hydro-fueled electricity generation. In Canada, higher-than-normal temperatures are expected across the country, with the greatest likelihood residing in northeast and southwest Canada. Snowpack in Canada is generally in average conditions. British Columbia has experienced below-average snowpack in the southwest part of the province and above-average snowpack in the Columbia and Peace regions. The [Review of 2025 Capacity and Energy Performance](#) section describes actual demand and resource levels in comparison with NERC's 2025 SRA and summarizes 2025 resource adequacy events.
- **A large influx of BPS resources over the past year has outpaced demand and is boosting reserves.** BPS resources for the upcoming summer have jumped by over 58.5 GW with the addition of substantial amounts of solar PV and battery resources and some new natural-gas-fired generators. Sixteen of the 23 assessment areas have increased available capacity ahead of summer. Solar PV is the leading type of new resource (+30.5 GW nameplate additions, contributing an additional 16.4 GW of capacity at peak demand). The addition of solar and batteries, which perform well under more hours of the day during summer than they do in winter, is helping to meet escalating demand and increase reserves in many assessment areas.
- **Strong load growth continues in nearly all assessment areas.** Load growth from data centers and large loads continues to propel North American electricity demand forecasts higher, with an increase in peak demand since Summer 2025 exceeding the change observed from the prior summer. Aggregated peak demand across all assessment areas

has increased by over 11 GW since 2025. The level of growth exceeds the year-on-year rise of 10 GW that preceded Summer 2025. The largest increases are in parts of the U.S. West. WECC-Southwest saw the largest year-on-year increase in net internal demand at +9.5%, followed by WECC-Northwest with +4.6% and WECC-Basin with 3.8%. Overall, 19 out of 23 assessment areas saw demand increases from the 2025 SRA projections.

- **Large computational and other large loads pose operational challenges for the upcoming summer.** Recent events of unexpected disconnections underscore the need for operational readiness for the upcoming summer. For example, the Eastern and ERCOT Interconnections have observed load-reduction events with each Interconnection experiencing approximately 1,500 MW of voltage-sensitive load reduction.⁶ The event in the Eastern Interconnection was primarily attributed to data centers and other power electronic loads (PEL) transferring load to backup generation, which caused frequency overshoot and high voltages. The ERCOT Interconnection event involved many different types of loads of varying sizes 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 issued a Level 3 essential actions alert related to large loads⁷ as well as a reliability guideline regarding risk mitigation for emerging large loads.⁸
- **Battery resource additions help maintain stable frequency on the grid.** Since last summer, over 16 GW of nameplate battery storage capacity has been added to the grid. Texas and the Western Interconnection continue to have the strongest growth in these resources. The *2025 State of Reliability* report noted an upward trend in frequency response capability that can be attributed to the addition of battery storage resources.⁹ Charged battery storage resources can respond quickly to the abrupt decline in system frequency that occurs during disturbances and sudden imbalances, helping to maintain the nominal 60 Hz system frequency and prevent equipment damage and system instability. NERC's *2026 State of Reliability* report, to be published in June, will report on this continuing trend of improved grid frequency response.

³ Climate Prediction Center: ENSO Diagnostic Discussion

⁴ Climate Prediction Center: Seasonal Drought Outlook

⁵ WSOR-WA

⁶ Incident Review: Considering Simultaneous Voltage-Sensitive Load Reductions, NERC, January 2025. Available: https://www.nerc.com/pa/rm/ea/Documents/Incident_Review_Large_Load_Loss.pdf

⁷ NERC Level 3 Alert: Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control

⁸ Risk Mitigation for Emerging Large Loads

⁹ NERC State of Reliability reports

Key Findings

- **The overlap of early summer heat and spring maintenance outages can lower operating reserves in the shoulder season and early summer.** March 2026 was the warmest March in the 132 years of recordkeeping in the contiguous United States.¹⁰ The average temperature across the country was 9.4°F above the 20th-century average. Raising the average were at least 10 states in the U.S. West that had their warmest March on record. The widespread heat-dome bled across the border and infused unseasonably warm temperatures into British Columbia as well, with at least five communities in the southern part of the province recording their warmest overnight low temperatures ever observed for the month of March.¹¹ Some assessment areas in the West have reported that extended lead times for hydro unit overhauls and the limited availability of engineering, procurement, and construction contractors are contributing to longer outage durations that complicate maintenance planning. Longer-than anticipated maintenance periods, in turn, can lead to higher-than-expected calls on electricity imports from neighboring regions. In other areas, there are older sites that may require extensive overhauls, such as

generator rewinds that can keep resources out of service for extended periods of time, potentially longer than planned, as discovery work manifests into additional maintenance.

- **Impacts of wind drought (i.e., low wind periods) pose a risk to reliability.** Areas of the North American electric grid continue to experience periods of wind drought or steep wind down-ramping, and installed wind capacity across the BPS is up by 3% year on year. It is critical that areas experiencing these events continue to maintain operational awareness, including accurate forecasts and appropriate operating procedures to mitigate these periods. Additionally, the impact of wind ramp events—particularly down ramp—must be anticipated and planned for such that appropriate resources are ready to replace the energy lost during these conditions. It is not uncommon for areas to experience several thousands of megawatts of wind energy coming off-line during these events. For example, in January 2025, MISO experienced a wind reduction event of 1,600 MW per hour, which also coincided with a solar ramping down and evening load ramp up.¹²

¹⁰ [Assessing the U.S. Temperature and Precipitation Analysis in March 2026 | News | National Centers for Environmental Information \(NCEI\)](#)

¹¹ [Blazing hot: 1,000+ records fall in brutal March heat wave - The Weather Network](#)

¹² [Incident Review: Preparing the Grid for Wind Energy Droughts and Down-Ramps,
https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_low_wind_event.pdf](#)

Recommendations

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

- Reliability Coordinators (RC), Balancing Authorities (BA), and Transmission Operators (TOP) 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 above-normal 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. Past system performance reviews noted that early declaration of conservative operations in advance of extreme conditions helped reduce grid congestion and enhance transfer capability.¹³
 - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans.
- RCs, TOPs, and BAs should review outage coordination processes and policies and consider if adjustments are needed to account for potential above-normal temperatures to extend beyond the traditional summer season. Those same entities should also be prepared to adjust operating plans in early summer for delayed return-to-service of BPS generation and transmission elements.
- BAs should consider the following steps to reduce risks to system balance from conditions that could affect resources or demand for the upcoming summer:
 - **Wind energy:** In areas with ample wind resources, employ proactive operating plans for low-wind events and wind down-ramping events when weather conditions are developing or are uncertain.
 - **Hydro availability and output:** In areas with a predominance of hydro generation in the supply stack, consider in operating plans the potential for low water conditions to affect hydro generation. Coordinate a sufficient supply of alternative resource types and ready necessary demand-side management mechanisms if needed.
 - **Large computational load disconnects:** Be aware of the potential for load reductions from large computational loads in response to system conditions and include conservative practices in operating plans. Refer to NERC's incident reviews for details of recent events involving voltage-sensitive data centers and cryptocurrency mining facilities.¹⁴

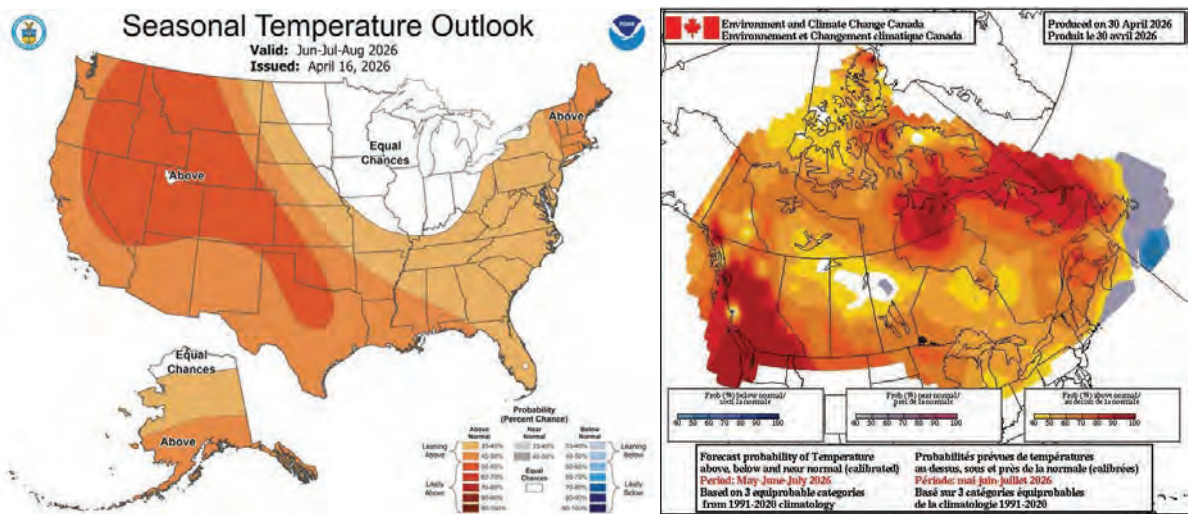
¹³ See notable operations practices in Appendix 2 of the [January 2025 Arctic Events System Performance Review | FERC, NERC, and its Regional Entities: A Joint Staff Report](#), April 2025.

¹⁴ See Incident Review section of [NERC Event Analysis](#) page.

Risk Highlights

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. March of this year brought record heat for the month and exacerbated concerns over persisting or worsening drought, concerns that gained even more traction following an underwhelming snowpack peak in the Pacific Northwest in April. 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. 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.



¹⁵ 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

Demand and Resource Trends

Strong load growth from data centers and large loads continues to propel North American electricity demand forecasts higher, with an increase in peak demand since Summer 2025 exceeding the change observed from the prior summer. Resource additions over the past year have outpaced demand growth, contributing to higher reserves.

Summer Electricity Demand Continues to Rise

Aggregated peak demand across all assessment areas has increased by over 11 GW since 2025, comparing forecasted net internal demand (NID). This measure of peak demand is inclusive of the benefits from demand response, which offset total internal demand (TID) (see [Figure 3](#)). NID continues to accelerate. The year-on-year increase in peak demand for Summer 2025 was 10 GW—more than double the increase in peak demand from 2023 to 2024.

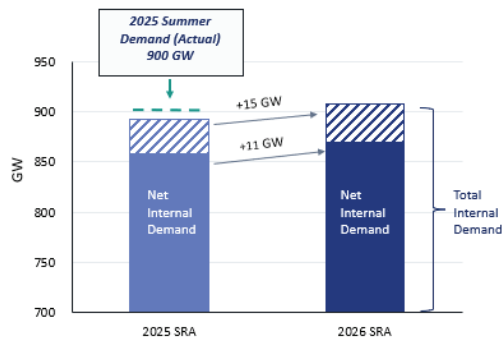


Figure 3: BPS Total and Net Internal Demand
Aggregated Peak Demand from All Assessment Areas

Nearly all assessment areas are experiencing demand growth. Peak demand forecasts have risen since 2025 in 19 of the 23 assessment areas. The largest increases are in parts of the U.S. West. In Canada, all provinces are forecasted to have increases of 2% or more except for Québec, which is

forecasting a 1% decline in peak demand. Texas RE-ERCOT is a notable exception to the growth trend this summer. TID in ERCOT declined by 1.9 GW (2.3%), largely driven by updated forecasting that accounts for observed behavior of large computational loads at peak demand. NID, which includes demand response, is 3.7 GW lower (4.6%) compared to last summer because more data centers can be curtailed by grid operators when needed to prevent grid emergencies. A summary of assessment area demand changes is provided in the [Net Internal Demand](#) section.

More Resources Available for Summer

BPS resources for the upcoming summer have jumped by over 58.5 GW with the addition of substantial amounts of solar PV and battery resources and some new natural gas-fired generators (see [Figure 4](#)). Sixteen of the 23 assessment areas have increased available capacity ahead of summer. Solar PV is the leading type of new resource (+30.5 GW nameplate additions, contributing an additional 16.4 GW of capacity at peak demand). Battery additions account for 14.7 GW in increased on-peak capacity. These resources also help balance variability in solar PV and wind resources, as well as demand fluctuations. Other capacity changes since 2025 amounting to 19 GW are attributed to resource additions of other types as well as changes to generator availability (e.g., completion of extended nuclear generator outages, changes to maintenance plans). The addition of solar and batteries, which perform well under more hours of the day during summer than they do in winter, is helping to meet escalating demand and increase reserves in many assessment areas.

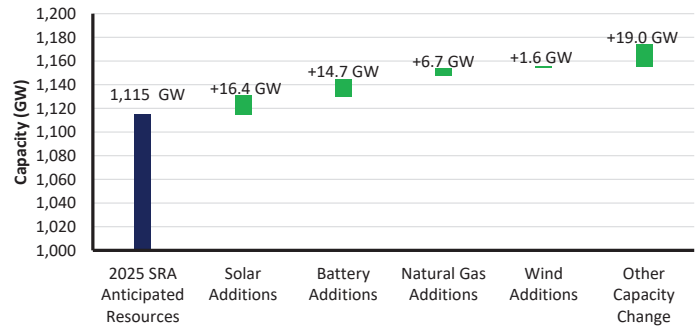


Figure 4: Summer BPS Resource Capacity Change Since 2025

Generators Extended by Federal Power Act Emergency Authority

Starting in 2025, the Department of Energy (DOE) issued emergency orders, pursuant to section 202(c) of the Federal Power Act, requiring that six different power plants maintain operational availability. Thermal generators with diverse fuel sources can be an important electricity resource, especially during winter when solar PV and battery resources are less capable compared to summer months. The DOE has since renewed those emergency orders, extending availability requirements into late May and early June (see [Table 1](#)). These plants and units were not incorporated into the anticipated resources of their corresponding assessment areas for Summer 2026 but may be called upon within the orders' time frames.

Table 1: Power Plants Impacted by Department of Energy 202(c) Orders in 2025 and 2026

Assessment Area	Plant Name	Nameplate Capacity (MW)	Summer Capacity (MW)	DOE 202(c) Order Expiration
MISO	J.H. Campbell	782	760	5/18/2026
MISO	F.B. Culley Generating Station	104	90	6/21/2026
MISO	Schahfer Generating Station	847	722	6/21/2026
PJM	Eddystone Generating Station	782	760	5/24/2026
WECC-NW	Centralia Generating Station	730	670	6/14/2026
WECC-RM	Craig Station	446	427	6/28/2026

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in [Table 2](#).

Table 2: Seasonal Risk Assessment Summary	
Category	Criteria ¹
High	- Planning Reserve Margins do not meet Reference Margin Levels - Probabilistic indices exceed benchmarks (e.g., LOLH of 2 hours or higher across the season) - Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under normal peak-day demand with normal resource scenarios²
Potential for insufficient operating reserves in normal peak conditions	
Elevated	- Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours across 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 scenarios² (i.e., typical or expected outage and derate scenarios for conditions) - Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under normal peak-day demand with reduced resource scenarios³ (i.e., extreme outage and derate scenarios)
Potential for insufficient operating reserves in above-normal conditions	
Normal	- Probabilistic indices are negligible (e.g., LOLH below 0.1 hours across the season) - Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios⁴
Sufficient operating reserves expected	

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 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 3](#).

Table 3: 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	31.1%	21.6%	3.8%
MRO-Manitoba	13.2%	9.5%	4.3%
MRO-SaskPower	29.2%	23.2%	7.3%
MRO-SPP	26.8%	21.4%	3.8%
NPCC-Maritimes	83.8%	73.4%	53.3%
NPCC-New England	14.0%	4.0%	-0.9%
NPCC-New York	34.2%	15.0%	7.5%
NPCC-Ontario	32.4%	32.4%	12.3%
NPCC-Québec	34.5%	16.4%	7.3%
PJM	26.2%	16.1%	3.8%
SERC-C	18.9%	13.9%	5.6%
SERC-E	26.3%	17.4%	10.3%
SERC-FP	25.8%	20.7%	13.6%
SERC-SE	36.9%	33.1%	24.7%
TRE-ERCOT	67.9%	60.2%	20.4%
WECC-AB	32.3%	28.2%	9.1%
WECC-Basin	37.6%	34.9%	11.5%
WECC-BC	40.5%	40.0%	9.6%
WECC-Cal	55.6%	54.3%	17.0%
WECC-Mex	32.5%	25.5%	11.0%
WECC-NW	26.9%	25.2%	8.8%
WECC-RM	51.9%	49.2%	21.5%
WECC-SW	48.1%	44.7%	25.2%

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

dashboards provide potential summer peak demand and resource condition information, as well as risk hour resource condition information for areas where the risk hour differs from the peak demand hour. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the [Data Concepts and Assumptions](#) section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In [Table 3](#), each assessment area's 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 on maintenance or forced outage during peak demand conditions. 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 summer risk 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 4](#). 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 2026. 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.

EEA 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 4: Probability-Based Risk Assessment

Assessment Area	Type of Assessment	Results and Insight from Assessment
MISO	Planning Year 2026–2027 LOLE Study Report	MISO's values for LOLH and EUE are taken from the noted assessment report, where the annual LOLE was set at 1 day in 10 years or 0.1 LOLE but equated to 0.076 LOLE for the summer. For Summer 2026, LOLH is 0.235 hrs/year and EUE is 983.8 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	2024 and 2025 NERC Probabilistic Assessment (ProbA)	Manitoba Hydro's probability-based resource adequacy risk assessments for the summer season display risk when hydro flow conditions are low and load is higher than expected. Based on the analysis that was conducted for the 2024 and 2025 ProbA, this risk was considered low as normalized EUE was less than 2 parts per million and LOLH was less than 0.2 hrs/year.
MRO-SaskPower	Probability-based capacity adequacy assessment Summer 2026	SaskPower conducted a probability-based capacity adequacy assessment for the 2026 Summer season. This assessment considered uncertainties in load forecasts, wind forecasts, and forced generation outages to calculate the expected number of hours with energy deficiencies (LOLH). LOLH equated to 0.09 hrs/season, and the month of highest risk has shifted from June to September, when the system experiences the largest uncertainties in load and generator availability forecasts. September risk makes up over 50% of summer season risk within this assessment area. SaskPower indicated that in extreme conditions, it may have to use short-term power transfers from neighboring utilities, maintenance rescheduling, and/or demand-response programs to prevent energy shortfall.
MRO-SPP	SPP East Assessment Area and 2024 NERC Probabilistic Assessment (ProbA)	Based on SPP East's probabilistic assessment and the 2024 NERC ProbA, risk observed in summer 2026 was minimal. Risk hours that materialized during simulations occurred during late afternoon and early evening periods and were driven by high demand and low wind conditions.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources 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		The preliminary results of NPCC's probabilistic assessment indicate that the Maritimes Area is not expected to require use of its established operating procedures designed to mitigate resource shortages during Summer 2026 based on a probabilistic-based assessment. The Maritimes Area did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks, and established operating procedures were sufficient to maintain a balance over the May–September summer period for all the scenarios modeled.
NPCC-New England		The preliminary results ¹⁶ of NPCC's probabilistic assessment indicate that use of New England's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages. Preliminary cumulative LOLE (days/season), LOLH (hours/season), and EUE (MWh/season) risks were reported as negligible over the summer May to September period for the expected load with expected resources scenario. Under an extreme scenario, the estimated cumulative LOLE risk is 0.343 days/period, with associated LOLH of 1.178 hours/period and EUE of 628 MWh/period with the highest risk occurring in June, with some in July and August.

¹⁶ Based on preliminary runs from March 31, 2026

Table 4: Probability-Based Risk Assessment

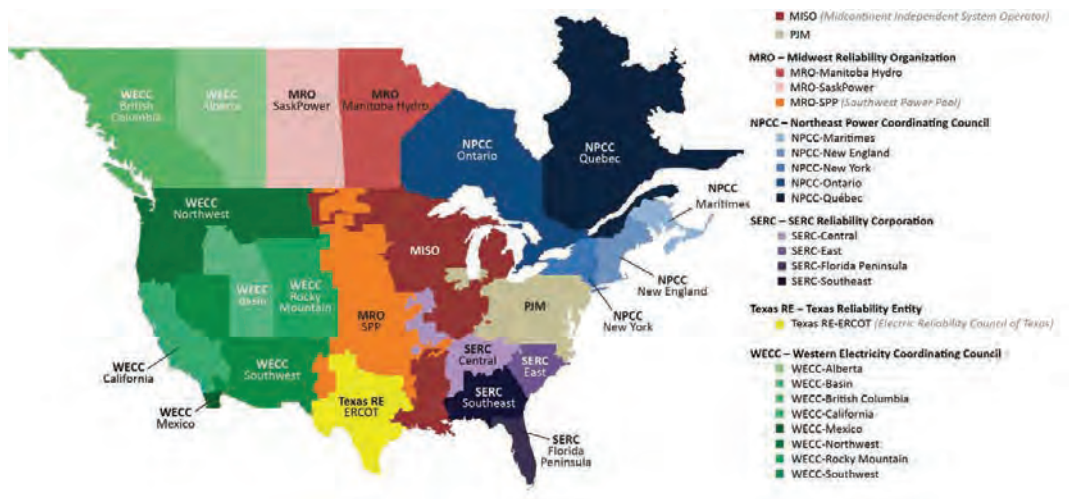
Assessment Area	Type of Assessment	Results and Insight from Assessment
NPCC-New York		The preliminary results of NPCC's probabilistic assessment indicate that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2026 with less than 0.017 days of LOLE, 0.042 hours of LOLH, and 20 MWh of EUE, which is below elevated risk criteria under the scenario of highest peak load and reduced resource conditions; the estimated cumulative risk reached 0.655 days of LOLE, 2.004 hours of LOLH, and 1,262 MWh of EUE, with the greatest risks occurring in July and August.
NPCC-Ontario		The preliminary results of NPCC's probabilistic assessment indicate that operating procedures are not needed to maintain a balance between electricity supply and demand. Even under peak load and low-resource conditions, the risk of LOLE remained negligible. This stability is supported by nearly 1,100 MW of new capacity from recent gas facility upgrades and storage projects. Consequently, no emergency operating procedures were required to maintain the balance between supply and demand.
NPCC-Québec		The preliminary results of NPCC's probabilistic assessment indicate that Québec area is not expected to require use of its operating procedures designed to mitigate resource shortages during Summer 2026 based on a probabilistic-based assessment. 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. The Québec area expects to be able to help other areas if needed.
PJM	2023 PJM Reserve Requirement Study (RRS)	The RRS 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. 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. PJM is forecasting 26% installed reserves (including expected committed demand response), which is above the reserve requirement margin of 18.6% necessary to meet the 1-day-in-10-years LOLE criterion.
SERC	Probabilistic resource adequacy assessment for the 2026 Summer season	SERC performed a probabilistic resource adequacy assessment for the summer season (June–September) using the PowerGEM SERVM model. The analysis is based on an 8,760 hourly model with 5,375 Monte Carlo simulations per hour and incorporates data across 43 historical weather years (1980–2022), load forecast uncertainty, generator forced outages, power transfer between SERC assessment areas, and variable energy resource performance.
SERC-Central		Results from the summer 2026 probabilistic risk assessment indicate that resources will be sufficient to meet projected demand and do not exhibit any EUE or LOLH.
SERC-East		Simulations performed show that small amounts of EUE materialized in a single summer evening hour under a high-stress scenario involving elevated load, reduced solar output during the evening ramp, and coincident generator outages. The magnitude and frequency of the event are low and do not indicate a broader resource adequacy concern.
SERC-Florida Peninsula		No EUE or LOLH materialized within SERC-Florida Peninsula across all simulations, which resulted in an implied LOLE of approximately zero. These results indicate that available resources are sufficient to meet projected demand under modeled conditions.
SERC-Southeast		The probabilistic assessment did not identify any loss of load events for SERC-Southeast during the Summer 2026 season. EUE and LOLH were both zero across all simulation hours.
Texas RE-ERCOT	ERCOT probabilistic assessment using the PRRM	The simulation indicates low risk of having to declare an EEA for hour 21, the highest risk hour for the peak load day in August (which is also the expected summer peak load day) with a probability of declaring an EEA of 0.43%. 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 2025 SRA, ERCOT reported EEA declaration probability for hour ending 21 of 3.1%. The large decrease in EEA probabilities is due to the addition of 8,780 MW of BESS capacity in 2025 and 2,677 MW more as of March 2026.

Table 4: Probability-Based Risk Assessment

Assessment Area	Type of Assessment	Results and Insight from Assessment
WECC	Probabilistic resource adequacy assessment for the 2026 Summer season	For the 2026 SRA, WECC, for the first time, performed a probabilistic resource adequacy assessment using the PowerGEM SERV model based on an 8,760 hourly model that incorporates data across 43 historical weather years, load forecast uncertainty, generator forced outages, power transfers, and variable energy resources shapes. With this shift, WECC opted to default to the NERC defined Reference Margin Level and change its reporting to reflect the different data construct and reporting of results.
WECC-AB		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-Basin		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-BC		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-CA		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-Mex		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-RM		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-NW		WECC's probabilistic analysis showed EUE at 2.7 MWh and LOLH of 0.1 hours weighted average under a range of weather scenarios for demand and energy availability conditions.
WECC-SW		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.

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](#) section), 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](#) section) 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

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

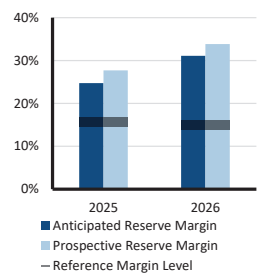
Highlights

- Although MISO's peak load has increased by 2.5 GW from the 2025 SRA, MISO is not anticipating operational or reliability issues for the 2026 Summer season. Load growth is driven by increased projections of data center load and is expected to accelerate in 2027 and beyond, which may lead to increased reliability risk in the future if resource additions cannot keep pace with rising load forecasts.
- MISO's capacity resources have improved since Summer 2025, and new additions are made up of predominantly solar resource installations, along with smaller amounts of natural gas, wind, and battery storage resources. Solar resources are helping the system serve peak load but are shifting risk hours to later in the day where intermittent resource capabilities are low and temperatures are above expected conditions.
- MISO benefits from transmission connections with neighbors to meet extreme weather conditions, and reliance may increase when extreme conditions arise.

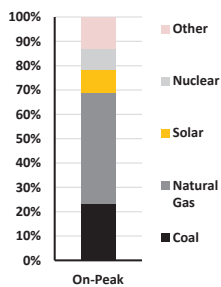
Risk Scenario Summary

Expected resources meet operating reserve requirements for assessed scenarios. Above-normal summer peak load combined with low resource conditions could result in the need to employ operating mitigations (e.g., load-modifying resources) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access demand-response resources when operating reserve shortfalls are projected.

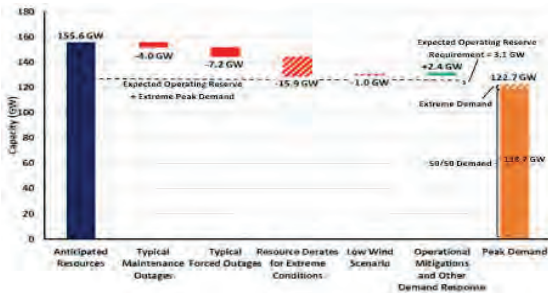
On-Peak Reserve Margin



Fuel Mix



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 forecast (50/50) plus transmission losses.

Maintenance Outages: Rolling three-year average of maintenance outages that occurred during the summer (June-September) peak hour.

Forced Outages: Rolling three-year average of forced outages that occurred during the summer (June-September) peak hour.

Extreme Derates: Rolling three-year average of maintenance and planned outages that occurred across thermal resources during the summer (June-September) peak hour, plus a reduction in solar resource performance during the risk hour.

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



MRO-Manitoba Hydro

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 Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the RC for Manitoba Hydro.

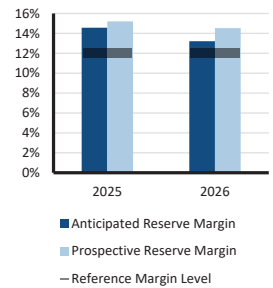
Highlights

- Manitoba Hydro is not anticipating any operational challenges or emerging reliability issues in its assessment area for Summer 2026.
- Manitoba Hydro's demand increase of 2.5% is driven primarily by population and economic growth, including electrification of a large industrial customer to reduce carbon emissions. Currently, new cryptocurrency operations cannot connect in Manitoba due to a moratorium.
- The 2024 ProbA for the 2026 load year shows an EUE of 4 MWh and an LOLH of 0.05 hours.
- Manitoba Hydro's reservoir storage conditions are below average, but winter snowfall has been above average, which should favorably impact spring runoff. The Manitoba Hydro system is designed and operated such that reliable operations can be maintained under extreme drought. Manitoba Hydro expects to reliably supply its internal demand and export obligations, even if extreme drought develops through 2026–2027.
- Manitoba Hydro continues to monitor summer resource adequacy in the MISO area but does not believe that there are significant seasonal reliability issues in MISO or in other neighboring assessment areas that have potential to impact Manitoba Hydro operations for Summer 2026.
- The Anticipated Reserve Margin for Summer 2026 exceeds the 12% Reference Margin Level.

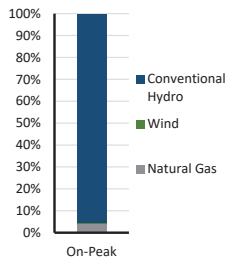
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

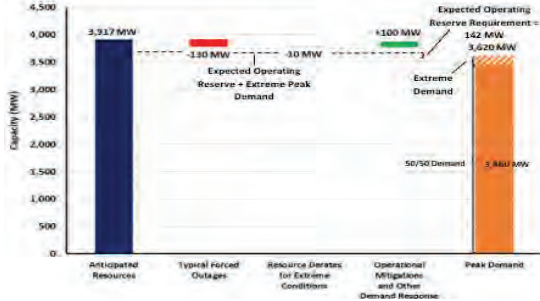
On-Peak Reserve Margin



Fuel Mix



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 a 90th percentile extreme weather scenario of 36.0 C (96.8 F).

Forced Outages: Typical forced outages.

Extreme Derates: Summer wind capacity accreditation of 18.2% of nameplate rating based on MISO seasonal analysis. No further wind output derates based on experience; wind farms constitute less than 1% of Manitoba Hydro's available capacity.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; assume 100 MW of non-firm imports available.



MRO-SaskPower

MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its interconnections. Overall, SaskPower operates nearly 14,816 circuit-km of transmission lines, 65 high-voltage switching stations, and 191 distribution substations. Peak electricity demand on the SaskPower system currently occurs during the winter season.

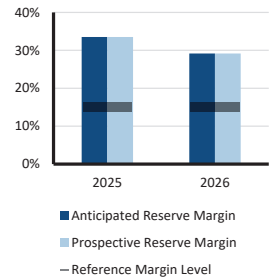
Highlights

- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- There is a 1.9% increase in TID from the 2025 SRA projection. This growth is mainly driven by population growth in the province, expansion projects, reduced self-generation in the industrial sector, and increased electrification.
- SaskPower conducted a probability-based capacity adequacy assessment for the 2026 Summer season. This assessment considered uncertainties in load forecasts, wind forecasts, and forced generation outages to calculate the expected number of hours with energy deficiencies (LOLH). According to probabilistic in-house model, the LOLH for an elevated risk scenario for the 2026 Summer season is 0.09 hours, which is nearly in line with the 0.1 LOLH risk criteria NERC sets for the elevated-risk level. The month with the highest LOLH is September (0.05 hours).
- Based on the planned maintenances, typical forced outages from historical data, and expected renewable generation under the normal and extreme demand conditions, SaskPower does not anticipate any reliability issues during Summer 2026. Under extreme conditions, however, SaskPower may have to use short-term power transfers from neighboring utilities, maintenance outage deferrals, and/or demand-response programs to maintain sufficient supplies.

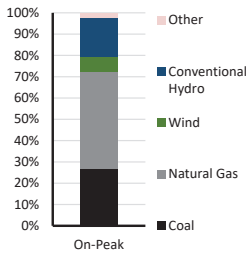
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand and outage conditions. During extreme summer conditions causing above-normal demand or generator outages, SaskPower can experience operating reserve shortfalls that it would mitigate using rescheduled planned maintenance, short-term power transfers from neighboring utilities, and/or available demand-response programs.

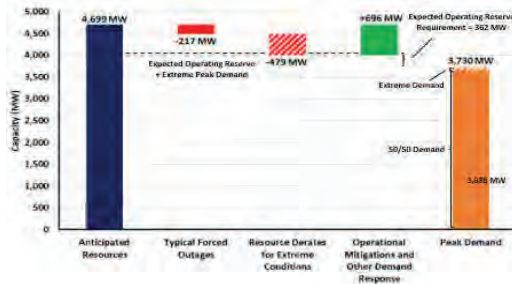
On-Peak Reserve Margin



Fuel Mix



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: Based on historic generation stats and SaskPower's forced outage rate models.

Extreme Derates: Based on the wind turbines datasheet and the percentage of the total available wind that will be cut off when the temperature is extremely high (40 degrees and higher).

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7 days' notice. In addition, 176 MWs of demand response can be called upon during operating emergencies.



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 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.

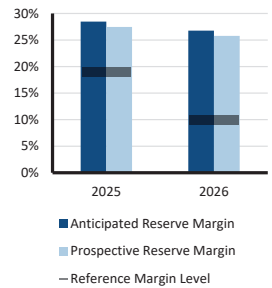
Highlights

- At this time, SPP does not anticipate any operational challenges that would result in reliability risk under normal conditions.
- SPP has operational procedures in place to manage generation outages taken over the summer to ensure appropriate generation is in place for high load. These procedures utilize probabilistic forecasts on factors such as load, generation, and outages to prepare for upcoming peak conditions.
- With heavy reliance on wind generation, SPP's greatest summer risk periods are when wind availability is low. If these low wind periods correspond to peak load conditions, then the combination presents extra risk for the area.
- SPP is projecting a 1.5% increase in forecasted 2026 Summer peak load vs. 2025 Summer peak actuals. Solar PV and energy storage continue to grow rapidly.

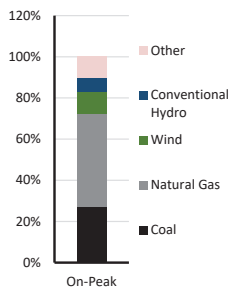
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. A combination of higher-than-average demand or lower-than-expected wind generation could result in the need for operating mitigations (e.g., demand response and transfers from neighboring systems), including resource advisories and EEAs, where appropriate.

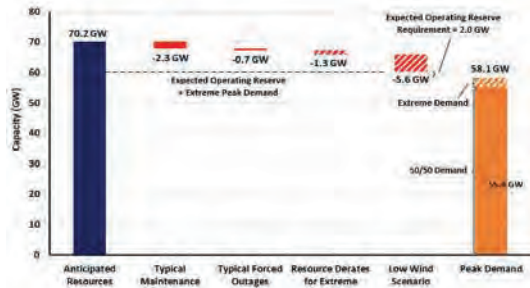
On-Peak Reserve Margin



Fuel Mix



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 4.9% 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 an average low-wind day in the summer.



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.

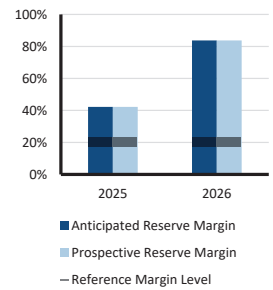
Highlights

- There are no anticipated issues for the Maritimes in the upcoming summer assessment period with sufficient firm capacity to meet the forecast peak demand.
- The Maritimes has not identified any operational issues that are expected to impact system reliability. Emergency operations and planning procedures are in place to mitigate operational events.
- Maritimes summer on-peak reserve margin is largely driven by resource maintenance outages. As a result of fewer planned outages (~1,000 MW) at peak, the 2026 on-peak reserve margin doubled from the 2025 SRA (84% compared to 42%).
- The preliminary results of NPCC's probabilistic assessment indicate that the Maritimes area is not expected use their operating procedures during the Summer of 2026 to maintain sufficient supply. The Maritimes area did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks, and established operating procedures were sufficient to maintain an energy balance over the May–September summer period for all the scenarios.
- Although margins can go negative in May under the high load (above 90:10) scenario, there are opportunities to purchase non-firm energy through the interconnections with neighboring control areas as this scenario does not coincide with either the Maritimes or the NPCC summer peaks.
- Dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to enable sustained operation in the event of natural gas supply interruptions.

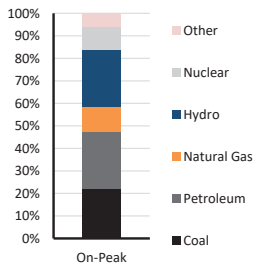
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

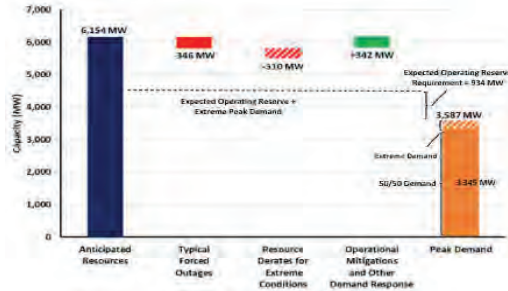
On-Peak Reserve Margin



Fuel Mix



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 historic operating experience.

Extreme Derates: A low-likelihood scenario comprising a 100% derate of solar and storage, a 50% derate of wind (calm weather), and a 50% derate to natural gas (fuel supply issue).

Operational Mitigations: Changes to system operating conditions in the Maritimes area (i.e., transmission and/or generator outages) will be managed using short-term operating procedures (STOP), which would outline any special operating conditions for the operators.



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.

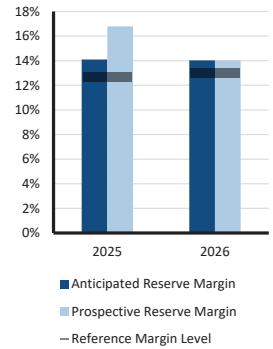
Highlights

- The New England area Anticipated Reserve Margin of 14% marginally exceeds the Reference Margin Level of 13%, avoiding a shortfall between anticipated resources and the reference level for reserves. There is, however, a 41 MW shortfall if resource additions are not included.
- ISO-NE assumes a net interchange of 409 MW, which is capacity-backed; however, ISO-NE typically imports around 3,000 MW during summer peak load conditions.
- ISO-NE does not anticipate any operational challenges or reliability issues for the upcoming 2026 Summer assessment period and forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand and operating reserves.
- Since January 2026, New England has added NECEC, a symmetric monopole +/- 320kV HVdc line from the 735 kV Appalachies substation in Québec to a new 345 kV substation, Merrill Road in Lewiston, Maine. NECEC will be used as an "import-only" tie with Hydro Québec and is capable of importing up to 1,200 MW into New England, but only on a non-firm basis for the coming summer.
- A probabilistic assessment was conducted for New England, modeling both NPCC and its neighboring regions. The analysis simulated a base case (50/50 normal demand) alongside a highest peak load scenario, which has a 7% probability of occurrence. The preliminary results of the probabilistic assessment indicate that use of New England's established operating procedures is sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2026. Under the scenario of highest peak load levels and reduced resource conditions, the estimated cumulative risk reached 0.343 days of LOLE, 1.178 hours of LOLH, and 628 MWh of EUE, with the greatest risks occurring in June and July. The final NPCC 2026 Summer Reliability Assessment will be approved in May 2026.

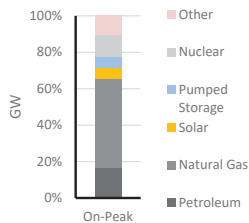
Risk Scenario Summary

The New England area expects to have sufficient resources to meet the 2026 summer peak demand forecast through the use of its established operating procedures and significant imports over its many ties to its neighbors that have historically been able to provide up to 3,000 MW during summer peak load conditions.

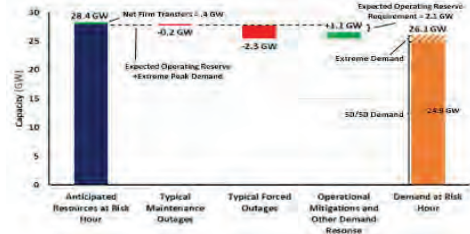
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Forecasted risk hour demand (50/50) and (90/10) extreme demand adder.

Maintenance Outages: Historical average of maintenance outages.

Typical Forced Outages: Based on historical average of forced outages for summer period.

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



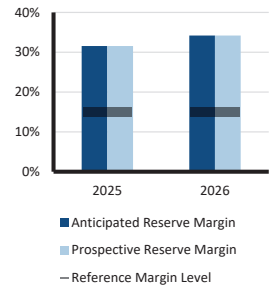
NPCC-New York

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 2026–2027 IRM at 24.5%.

Highlights

- NYISO is not anticipating any operational issues in the New York control area for the upcoming summer.
- Adequate capacity margins are projected for the summer peak, and prospective transactions with neighbors should mitigate reliability concerns. Operating procedures should be sufficient to handle any issues that may occur.
- The preliminary results of the NPCC probabilistic assessment indicate that use of New York's established operating procedures is sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2026. The expected load and resource scenario resulted in negligible risks over the May to September summer period, with less than 0.017 days of LOLE, 0.042 hours of LOLH, and 20 MWh of EUE.
- In contrast, under the scenario of highest peak load and reduced resources, the estimated cumulative risk reached 0.655 days of LOLE, 1.996 hours of LOLH, and 1,255 MWh of EUE, with the greatest risks occurring in July and August.
- to coordinate extensively with neighboring RCs and BAs to improve situational awareness and vet needs for firm or non-firm transfers to address extreme system conditions

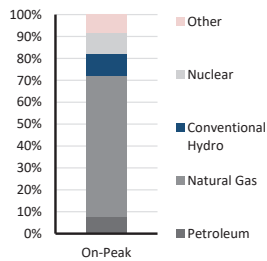
On-Peak Reserve Margin



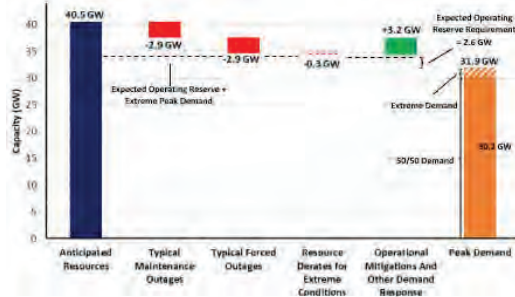
Risk Scenario Summary

The preliminary results of NPCC's probabilistic assessment indicate that New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected demand, if needed, to mitigate shortages during Summer 2026.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: The risk period is at the time of peak demand.

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 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 BA for the province of Ontario. NPCC-Ontario is electrically interconnected with NPCC-Québec, MRO-Manitoba, MISO, and NPCC-New York. Peak electricity demand in NPCC-Ontario occurs during the summer season.

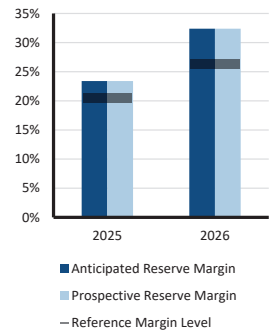
Highlights

- Ontario is well prepared for Summer 2026, and the IESO expects that the electricity system will remain reliable.
- Demand increased 2.7% over last year, driven in part by a rise in certain economic indicators, such as higher total employment, across the forecast horizon. However, uncertainty persists in the current economic environment with Ontario's largest trading partner.
- Existing-certain capacity is 8.4% higher than last year, reflecting the addition of new units. Established resource adequacy policy sets out a competitive strategy for securing new resources in the short, medium, and long terms. Also, Darlington G4 nuclear refurbishment was completed early and will be available for the summer period.
- Net firm capacity transfers increased 30.6% from Summer 2025. Although the capacity auction secured fewer imports for Summer 2026 compared to Summer 2025, IESO has chosen to utilize 300 MW of the 2015 Capacity Sharing Agreement with Hydro-Québec for the period commencing June 1, 2026, and ending September 30, 2026.
- Anticipated resources are projected 9% higher than Summer 2025 due to upgrades at existing natural gas facilities and new energy storage facilities anticipated to be coming on-line this summer.
- The preliminary results of NPCC's probabilistic assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. Even under peak load and low-resource conditions, the risk of LOLE remained negligible. This stability is supported by nearly 1,100 MW of new capacity from recent gas facility upgrades and storage projects. Consequently, no emergency operating procedures were required to maintain the balance between supply and demand.

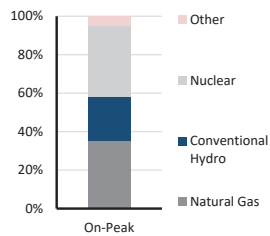
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

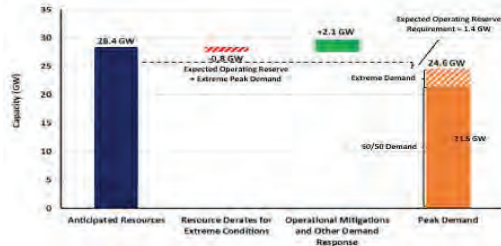
On-Peak Reserve Margin



Fuel Mix



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 modeled data.

Extreme Derates: Derived from weather-adjusted temperature ratings 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 2,100 MW for the On-Peak Risk Scenario, consisting of Imports, Public Appeals, and voltage reductions.



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.

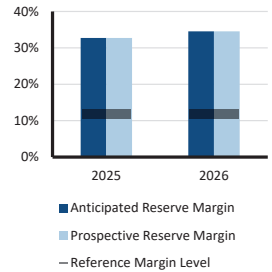
Highlights

- Québec is a winter-peaking hydroelectric system. Despite reduced generation because of reduced runoff in northern Québec since 2023, the Québec area expects no issues in meeting its operational needs this summer.
- Load (NID) is projected to decrease by 1% with respect to 2025.
- Net firm capacity exports have significantly increased (+1,018 MW) this year, as the CHPE is positioned to provide firm capacity to New York for the summer.
- There is a significant change to existing-certain capacity (3.7% or +1,192 MW). Hydro-Québec includes its planned outages in its certain capacity. This year, Hydro-Québec improved its modeling of its outages partially to account for its flexibility in managing outages; notably, the ability to recall certain outages to improve margins during peak events is highlighted.
- The preliminary results of NPCC's probabilistic assessment indicate that Québec area is not expected to require use of operating procedures designed to mitigate resource shortages during Summer 2026. 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. The Québec area expects to be able to help other areas if needed.

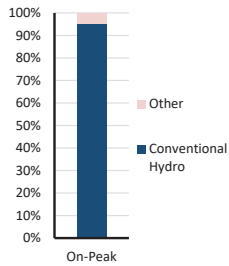
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

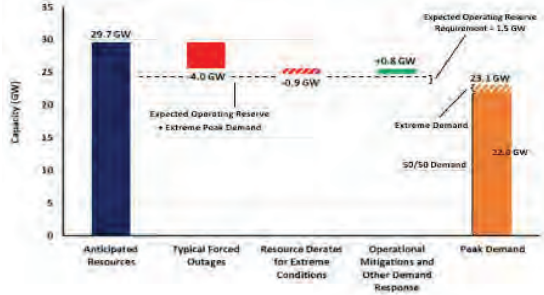
On-Peak Reserve Margin



Fuel Mix



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.

Forced Outages: Based on historical data and trending.

Extreme Derates: Estimated resources unavailable in extreme conditions.

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.



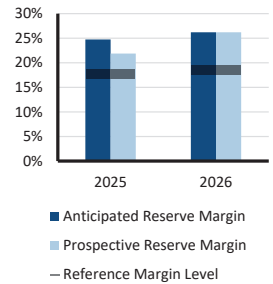
PJM

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's footprint covers approximately 369,054 square miles and serves more than 67 million people. PJM is the area's BA, Transmission and Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC. PJM is electrically interconnected with MISO, NPCC-New York, SERC-Central, and SERC-East. Peak electricity demand in PJM occurs during the summer season.

Highlights

- PJM is expecting a low risk of resources falling below the required reserve requirement during Summer 2026.
- PJM is forecasting ~26% installed reserves (including expected committed demand resources), which is above the PJM reserve requirement margin of 18.6% that is necessary to meet the 1-day-in-10-years LOLE criterion. The highest risk for unserved energy is at peak demand hour.
- If extreme high temperatures are experienced, PJM anticipates the need for demand-response resources to help reduce load.
- New and better load forecasts and advancement of planned resources have improved PJM's reserve margin looking into this summer over previous assessments.
- The LOLH and EUE values reported in the 2024 LTRA for 2026 were 0.12 hours/year and 537.52 MWh/year, respectively. These values corresponded to a 17.8% operable margin (also reported in the 2024 LTRA). Since the expected actual reserve margin for the PJM system is 26% in 2026, the LOLH and EUE values associated with a 26% reserve margin are expected to be lower than those reported in the 2024 LTRA.

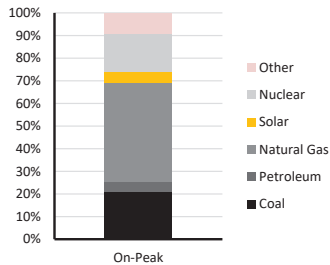
On-Peak Reserve Margin



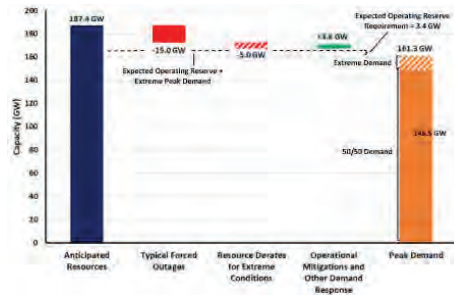
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



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 thermal capacity contributions due to performance in extreme conditions.

Operational Mitigations: A total of 3.6 GW estimated based on operational/emergency procedures. This includes 500 MWs of additional demand response that can be called upon during operating emergencies.



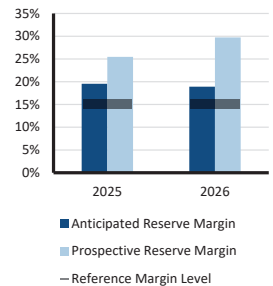
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity and includes all or portions of Alabama, Georgia, Iowa, Kentucky, Mississippi, Missouri, North Carolina, Oklahoma, Tennessee, and Virginia. SERC-Central is a dual-peaking assessment area, experiencing peak electricity demand during both the summer and winter seasons. The PCs in this subregion include Associated Electric Cooperative Inc., Louisville Gas & Electric/Kentucky Utilities, Owensboro, KY Municipal Utilities, and the Tennessee Valley Authority. Other SERC member entities in this subregion include Brookfield/Smoky Mountain, Memphis Light, Gas and Water Division, and Nashville Electric Service.

Highlights

- No significant reliability concerns were identified.
- Modest load growth (~1–3%) is driven by residential, industrial, and emerging data center demand.
- Increased demand response (DR) results from new demand-side management (DSM) programs and large industrial load enrollments.
- Adequate capacity, transfers, resource assumptions and reserve margins remain sufficient to support reliability.
- Robust operational planning and coordination, with DSM/DR programs providing additional flexibility during peak conditions.
- ProbA results show negligible risk for this summer.

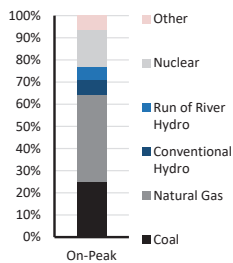
On-Peak Reserve Margin



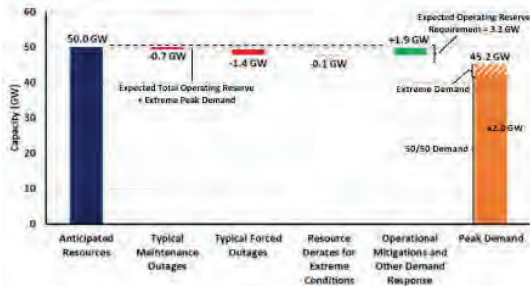
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



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: 1.9 GW based on operational/emergency procedures.



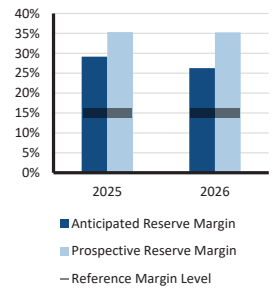
SERC-East

SERC-East is an assessment area within the SERC Regional Entity and includes North Carolina and South Carolina. SERC-East is a winter-peaking assessment area. The PCs in this subregion include Cube Hydro Carolinas LLC, Dominion Energy South Carolina Inc., Duke Energy Carolinas LLC, Duke Energy Progress LLC, and the South Carolina Public Service Authority (Santee Cooper). Other SERC member entities in this subregion include the Cube Hydro Carolinas-Yadkin Division and Southeastern Power Administration.

Highlights

- No significant operational challenges or emerging reliability issues were identified; system conditions remain adequate for Summer 2026.
- Fuel supply, generation availability, and transmission operations are expected to be adequate, with no major outages anticipated to impact reliability.
- Minimal changes are expected in demand and resource mix; reserve margins remain above planning targets despite updated solar/storage accreditation.
- Strong coordination processes and established operating procedures support reliable peak demand management.
- ProbA results show negligible risk for this summer.

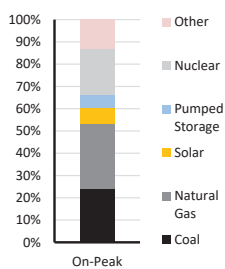
On-Peak Reserve Margin



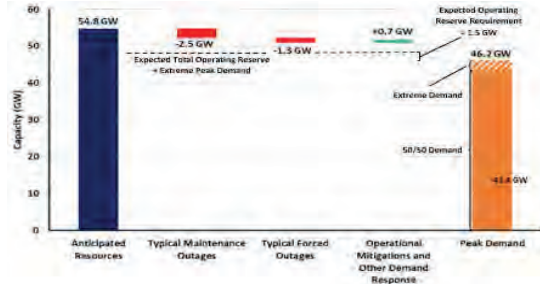
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



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 728 MW based on operational/emergency procedures.



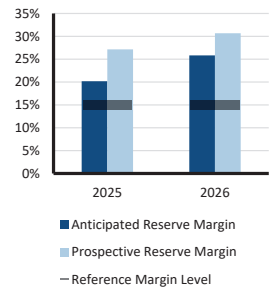
SERC-Florida Peninsula

SERC-Florida Peninsula is an assessment area within the SERC Regional Entity and includes all of Florida. SERC-Florida Peninsula is a summer-peaking assessment area. The PCs in this subregion include Duke Energy Florida LLC, the Florida Municipal Power Agency, Florida Power & Light Company, Florida Reliability Coordinating Council Inc., Gainesville Regional Utilities, the City of Homestead, JEA, Lakeland Electric, the Orlando Utilities Commission, Seminole Electric Cooperative, the City of Tallahassee, and Tampa Electric Company.

Highlights

- No significant operational challenges or emerging reliability issues were identified; system conditions remain stable for Summer 2026.
- There is an adequate demand and capacity outlook, with minimal year-over-year changes and no significant operational risks.
- There is strong resource adequacy, with projected reserve margins (~26%) well above the 15% reference margin.
- DR (~3,350 MW available) and established coordination practices support peak demand and emergency preparedness.
- ProbA results show negligible risk for this summer.

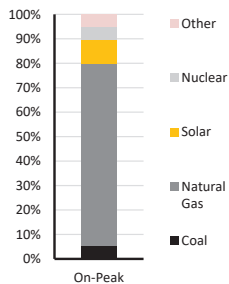
On-Peak Reserve Margin



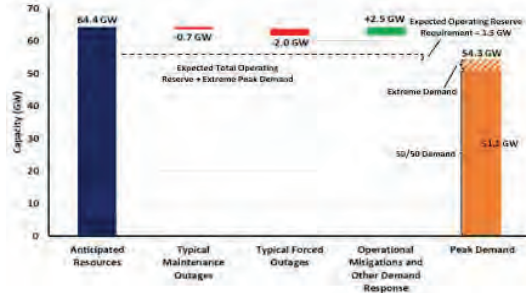
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



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 2.5 GW based on operational/emergency procedures.



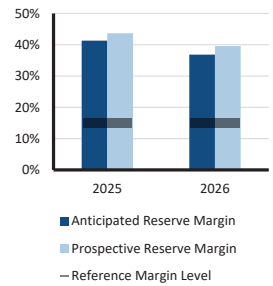
SERC-Southeast

SERC-Southeast is an assessment area within the SERC Regional Entity and includes all or portions of Alabama, Florida, Georgia, and Mississippi. SERC-Southeast is a summer-peaking assessment area. The PCs in this subregion include Georgia Transmission Corporation, the Municipal Electric Authority of Georgia, PowerSouth Energy Cooperative, and Southern Company Services, Inc. - Trans.

Highlights

- No significant reliability risks were identified; fuel supply and generation portfolios remain diverse and adequate.
- Natural gas pipeline constraints and increasing solar penetration present manageable operational considerations, not reliability threats.
- Moderate load growth (~1–3%), driven by economic conditions, residential and commercial expansion, and emerging data center load.
- Limited reliance on DR; existing operating practices and planning processes are sufficient to meet peak demand.
- ProbA results show negligible risk for this summer.

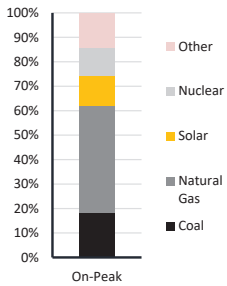
On-Peak Reserve Margin



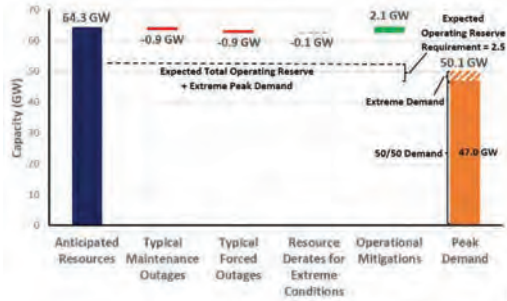
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



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 2.1 GW based on operational/emergency procedures.



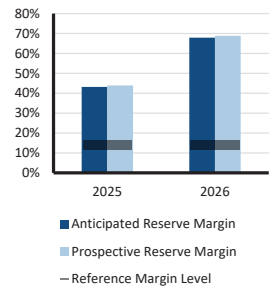
Texas RE-ERCOT

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 54,100 miles of transmission lines, has over 1,460 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

- Given an Anticipated Reserve Margin of 67.9% and Reference Reserve Margin of 13.75%, ERCOT expects to have sufficient operating reserves for the August peak load hour given expected normal system summer conditions.
- Continued growth in load and intermittent resources drives a higher risk of emergency conditions in the evening hours when solar generation ramps down and loads are high.
- The probability of an EEA during the expected August (and summer) peak load day continues to drop relative to previous SRAs due to continued robust growth in battery energy storage capacity (up 2,677 MW year-on-year as of March 2026). The EEA probability for the highest-risk hour—hour ending 9:00 p.m.—is 0.43%, down from 3.1% previously.
- The projected EEA risk does not account for regional constraints in Far West Texas, which may lead to a reliance on price-responsive demand in certain low-generation scenarios.
- An identified risk is the potential of newly interconnected large loads (mainly data centers and crypto-mining facilities) to trip and potentially cause grid stability problems. ERCOT has implemented mandatory ride-through capabilities and requires dynamic model submissions, among other solutions, to address this risk.
- The risk assessment process for this SRA will be the same as ERCOT's upcoming August 2026 Monthly Outlook of Resource Adequacy (MORA) to be released on June 5.

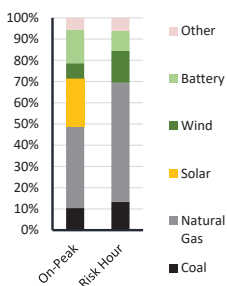
On-Peak Reserve Margin



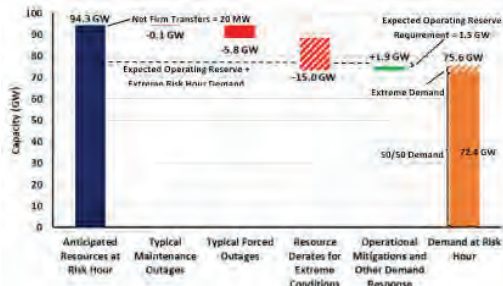
Risk Scenario Summary

The risk of having to declare an EEA for hour 21 is low (0.43%), according to ERCOT's probabilistic reserve risk model (PRRM) simulation results. The highest risk hour for the peak load day in August (which is also the expected summer peak load day).

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Hour: The highest risk hour, HE 2100 (9:00 pm CDT).

Demand Scenarios: Net internal demand, and an adjustment to extreme demand based on the 95th percentile of the PRRM's distribution of load simulation outcomes for the highest-risk hour (HE 2100).

Forced Outages: The adjustment is the 95th percentile of 10,000 daily thermal forced outage values generated by the PRRM, less the 50th percentile value.

Low-Wind Scenario: The adjustment is the 50th percentile of 10,000 wind generation values for hour ending 2100 generated by the PRRM, less the 0th percentile value.

Extreme Derates: The adjustment is the 50th percentile of 10,000 solar generation values for hour ending 2100 generated by the PRRM, less the 0th percentile value.

Operational Mitigations: Additional capacity from switchable generation and additional imports.



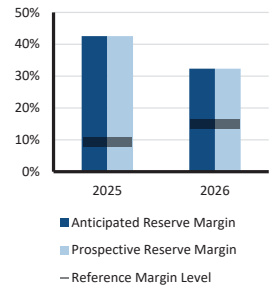
WECC-Alberta

WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province's planning entity and RC responsible for safe, reliable, and economic operation of the Alberta Interconnected Electric System. AESO is a non-profit corporation that operates a system that includes approximately 26,000 kilometers of transmission lines and connects approximately 426 qualified generating units and nearly 250 market participants through a wholesale market. Alberta's transmission system has three interties with neighboring areas—Saskatchewan (see MRO-SaskPower), British Columbia (see WECC-British Columbia), and Montana (see WECC-Northwest). Peak electricity demand on the AESO system currently occurs during the winter season.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. Additionally, WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions.
- Peak demand is projected to increase by 2.1% over last summer's forecast.
- Wide-area heat events and wildfires that affect resource and transmission availability across the Western Interconnection are a reliability concern. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability.

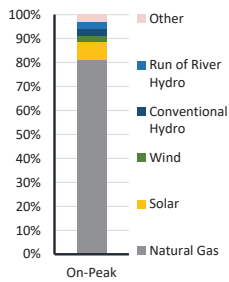
On-Peak Reserve Margin



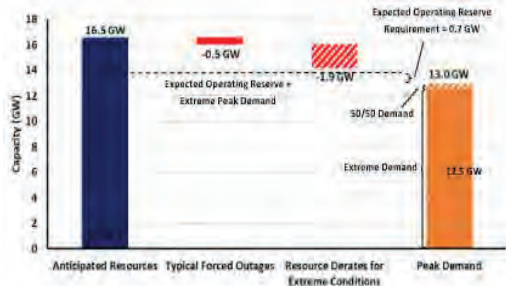
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



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: (90/10) resource performance distribution at peak hour.



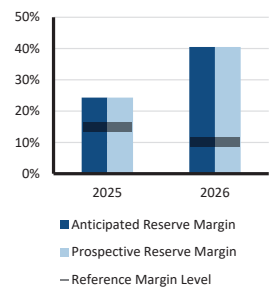
WECC-Basin

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.

Highlights

- WECC-Basin has established a 15% Reference Margin Level for the 2026 Summer assessment period.
- Wildfires remain a reliability concern for the region, particularly in areas with remote generation such as remotely located hydro. Mitigation programs such as hardening and public safety shutoff programs are in place.
- Extreme temperatures pose a risk to the area, impacting load levels and renewable variability. WECC-Basin is positioned to rely on imports during such conditions, which also poses a risk of concurrent impacts should neighbors experience similar conditions.
- Load forecasts for the area are projected to be 2.5% higher than 2025 Summer actuals.
- Wind, solar, and energy storage resources continue to grow.
- Reserve margins are not anticipated to fall below the 15% Reference Margin Level for 2026 Summer. Both Anticipated and Prospective Reserve Margins are expected to be adequate at 37.6%.

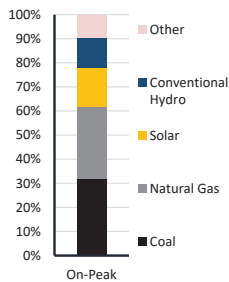
On-Peak Reserve Margin



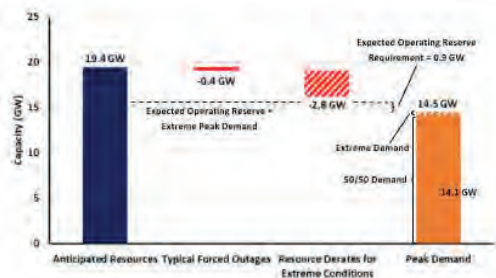
Risk Scenario Summary

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

Fuel Mix



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: (90/10) resource performance distribution at peak hour.



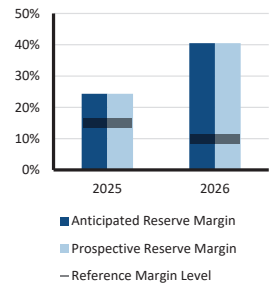
WECC-British Columbia

WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and RC for the province of British Columbia and is the principal supplier of electricity for the province. BC Hydro is a provincial Crown corporation and, under provincial legislation, is responsible for the oversight of the British Columbia BES and its interconnections. BC Hydro operates an integrated system supported by 32 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.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-recommended Reference Margin Level.
- WECC's probabilistic analysis shows no LOLH nor EUE under a range of demand and energy availability conditions.
- Peak net internal demand is projected to increase 2.4% over last summer's forecast while anticipated resources increase by 15.7%.
- Wide-area heat events or wildfires that affect resource and transmission availability across the Western Interconnection are a reliability concern. Energy imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability.
- Supply chain constraints and economic uncertainty may impact Tier 1 resources.

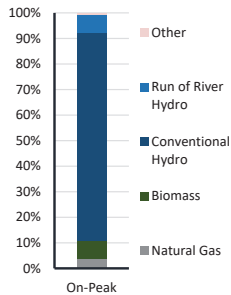
On-Peak Reserve Margin



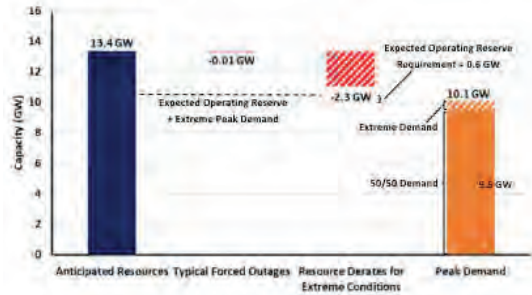
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



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: (90/10) resource performance distribution at peak hour.



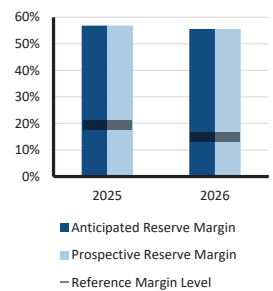
WECC-California

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, the Los Angeles Department of Water and Power, the Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions.
- Extreme heat and wildfires exacerbated by continued climate change may impact generation and transmission resources and remain a reliability concern.
- Cyber attacks pose significant reliability concerns for the area.
- Supply chain constraints and economic uncertainty may impact Tier 1 resources.
- Inverter-based resource (IBR) output variability remains a concern, such as from the evening ramp requirements from declining solar and Santa Ana winds, which can overspeed wind turbines, requiring them to curtail.

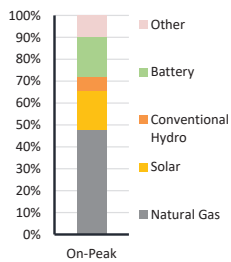
On-Peak Reserve Margin



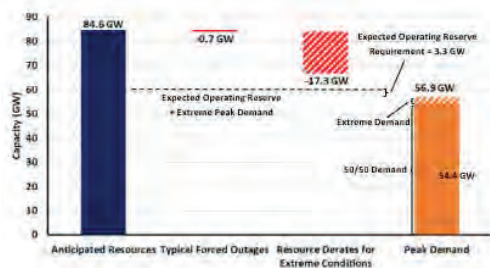
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: On-peak risk scenario.

Demand Scenarios: 50/50 and 90/10. Significant difference in delta from 2025. May be from switch to SERV and weather year adjustment taken out.

Forced Outages: Based on historical average of forced outages for a specified period/conditions (e.g., average of forced outages for June through September weekdays, over the past three years), or area-specific methodology for determining anticipated forced outages for non-intermittent resources (e.g., thermal, hydro).

Extreme Derates: Capacity derate for resources for extreme conditions. The derate accounts for reduced capacity contributions due to performance in extreme conditions for thermal, wind, PV, storage, and other.



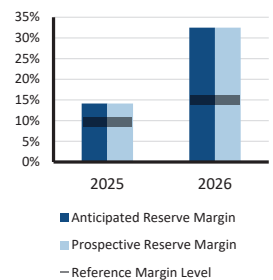
WECC-Mexico

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 Centro Nacional de Control de Energía (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.

Highlights

- WECC-Mexico has added an additional 1 GW of natural-gas-fired resources since last summer, greatly improving its outlook from the 2025 SRA.
- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions. Anticipated resources are projected to be 15.5% higher.
- 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 EEA and a request for assistance from RC West.
- Some generating units have reached advanced operational age, resulting in an observable increase in the forced outage rate. This condition increases the risk of capacity shortfalls and may compromise system reliability during peak seasonal demand.

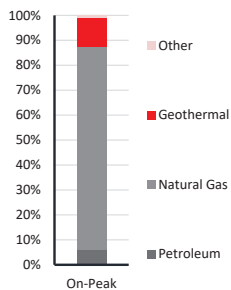
On-Peak Reserve Margin



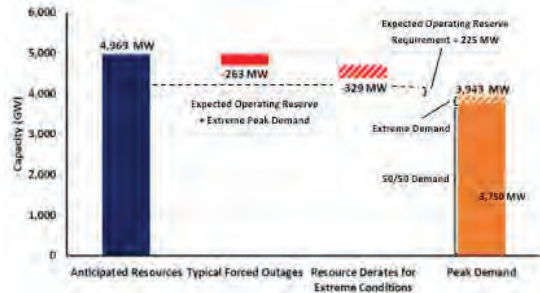
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



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-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.

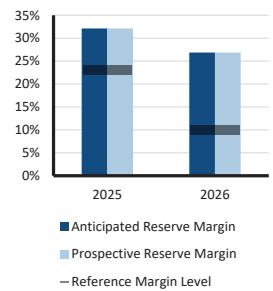
Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows EUE at 2.7 MWh and LOLH of 0.1 hours weighted average under a range of weather scenarios for demand and energy availability conditions.
- The EUE and LOLH occurs in hours 17 and 18 in August and September, with the vast majority September hour 18.
- Peak net internal demand is projected to grow 4.6% over last summer's forecasts; however, anticipated resources are showing just a 1.5% increase in energy availability, leading to tighter margins.
- Wide-area heat events, wildfires, and low snow-water equivalents due to a changing climate impact generation resource and transmission availability and remain a continued reliability concern. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads or derates, limiting energy availability.
- Supply chain constraints and economic uncertainty may impact Tier 1 resources.
- There have been instances where operators had difficulty maintaining frequency due to sudden disconnection of large loads necessitating additional regulation capability.

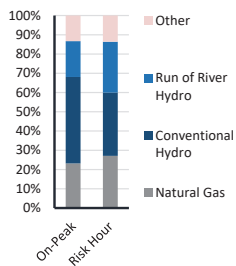
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under the assessed extreme scenarios. WECC's probabilistic analysis showed EUE at 2.7 MWh and LOLH of 0.1 hours weighted average under a range of weather scenarios for demand and energy availability conditions, placing the area at risk of shortfall during extreme conditions.

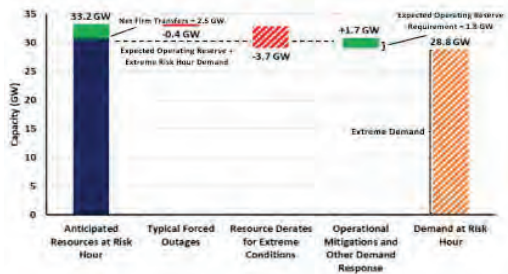
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Modeled output depicting load-loss event from the probabilistic model.

Risk Period: Off-peak highest risk hour is primarily 6 p.m. in September.

Demand Scenarios: Modeled load for the risk hour during load-loss event.

Typical Forced Outages: Based on historical average of forced outages for the period.

Extreme Derates: Modeled outage and derates to account for underperformance of resources at the risk hour.

Operational Mitigations: An operational procedure used to mitigate extreme conditions not already included in the margins is the depletion of operating reserves by 1.7 GW. WECC did not use an operational model prior to this year's report, and it the first time the model includes operating reserves of 6% withheld through unserved energy.



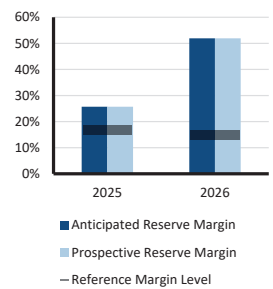
WECC-Rocky Mountain

WECC-BC (British Columbia) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

Highlights

- WECC-Rocky Mountain has established a 15% Reference Margin Level for the 2026 Summer assessment period.
- Anticipated Reserve Margins for the summer exceed the NERC-recommended Reference Margin Level.
- Wildfires in the region, along with extreme heat conditions for the summer, pose the greatest reliability risk scenario for the Rocky Mountains. These conditions can impact rural co-ops disproportionately.
- The existing certain and Anticipated Reserve Margins are projected to be at 43% and 52%, respectively, above the established 15% for the summer. Projections for summer load indicate minimal growth from 2025 and are 0.6% higher than 2025 Summer peak load conditions.

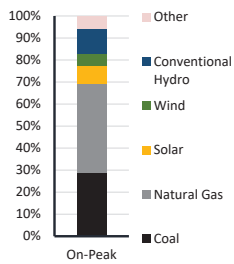
On-Peak Reserve Margin



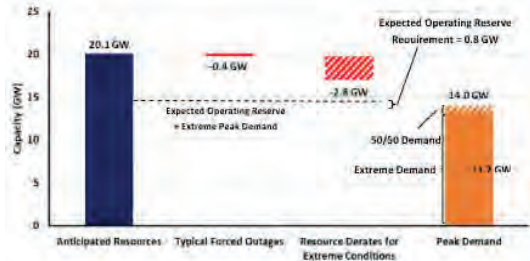
Risk Scenario Summary

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

Fuel Mix



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) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

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



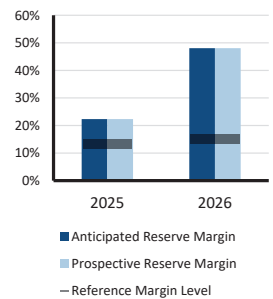
WECC-Southwest

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.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions.
- Peak net internal demand is projected to grow 9.5% over last summer's forecasts. DR availability has also increased from 199 MW to 364 MW.
- Anticipated resource capacity is expected to be 32.5% higher than last summer, mostly due to methodological changes to capacity of incoming future resources. Supply chain constraints and economic uncertainty may impact Tier 1 resources.
- Elevated forced outage rates due to the amount of aging generation capacity along with extensive overhaul requirements can keep resources out of service for extended periods of time.
- Extreme heat events can result in prolonged periods of elevated demand, derates to thermal generation, and—given the large area that heat waves cover—drastically reduced import capability from neighboring areas. The area also faces significant wildland fire potential this summer. Wildfires have the potential to interrupt large numbers of customers by damaging generation, transmission, and distribution assets.

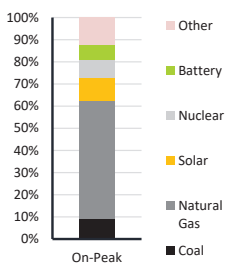
On-Peak Reserve Margin



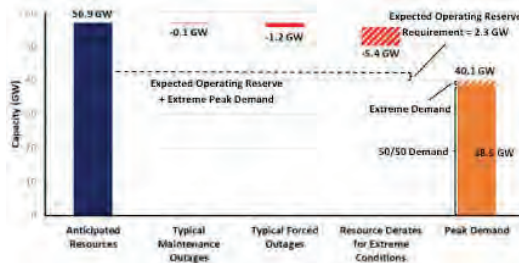
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



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 load¹⁷ or total internal demand for the summer and winter of each year.¹⁸ - Total internal demand projections are based on normal weather (50/50 distribution)¹⁹ and are provided on a coincident²⁰ 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.

¹⁷ https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

¹⁸ The summer season represents June–September and the winter season represents December–February.

¹⁹ 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.

²⁰ 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.

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.

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 Reference Margin Level 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 a Reference Margin Level 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 forecast. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Level s may be different for the summer and winter seasons. If a Reference Margin Level 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, 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.²¹ 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 Anticipated Reserve Margins to meet or exceed their Reference Margin Level for Summer 2026 as shown in **Figure 5**.

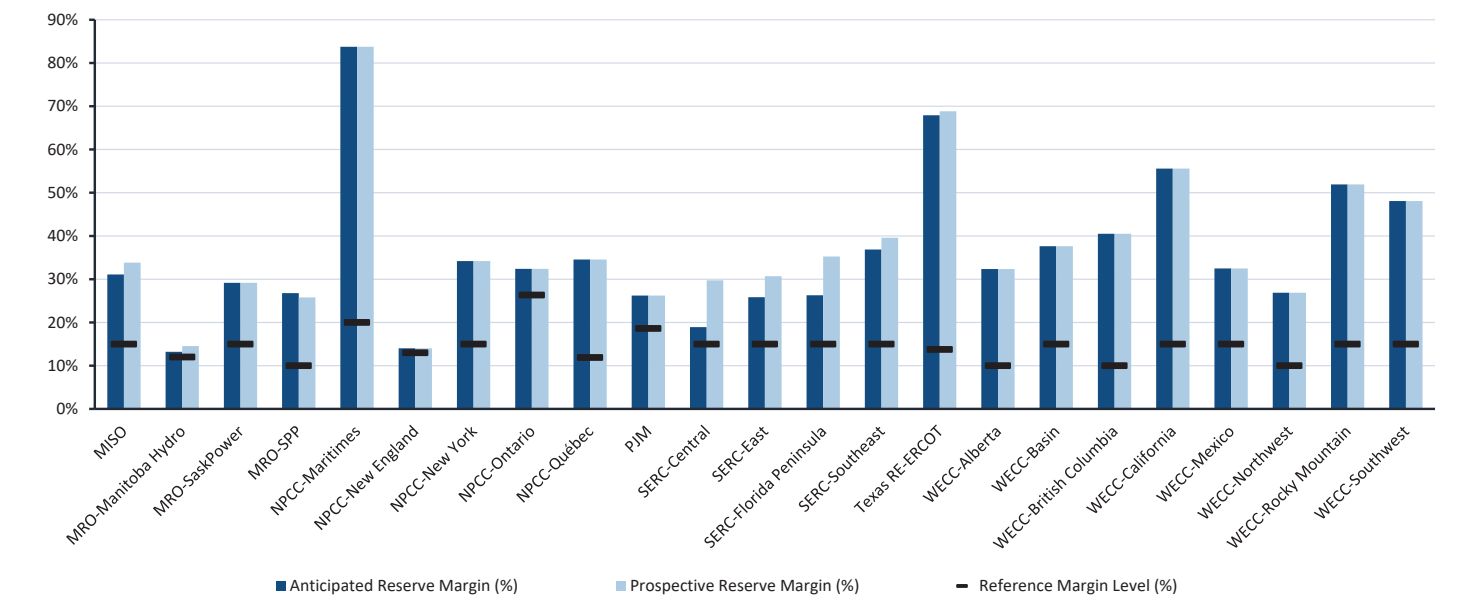


Figure 5: Summer 2026 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

²¹ 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 Reference Margin Levels.

Changes from Year to Year

Figure 6 provides the relative change in the forecast Anticipated Reserve Margins from the 2025 Summer to the 2026 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.

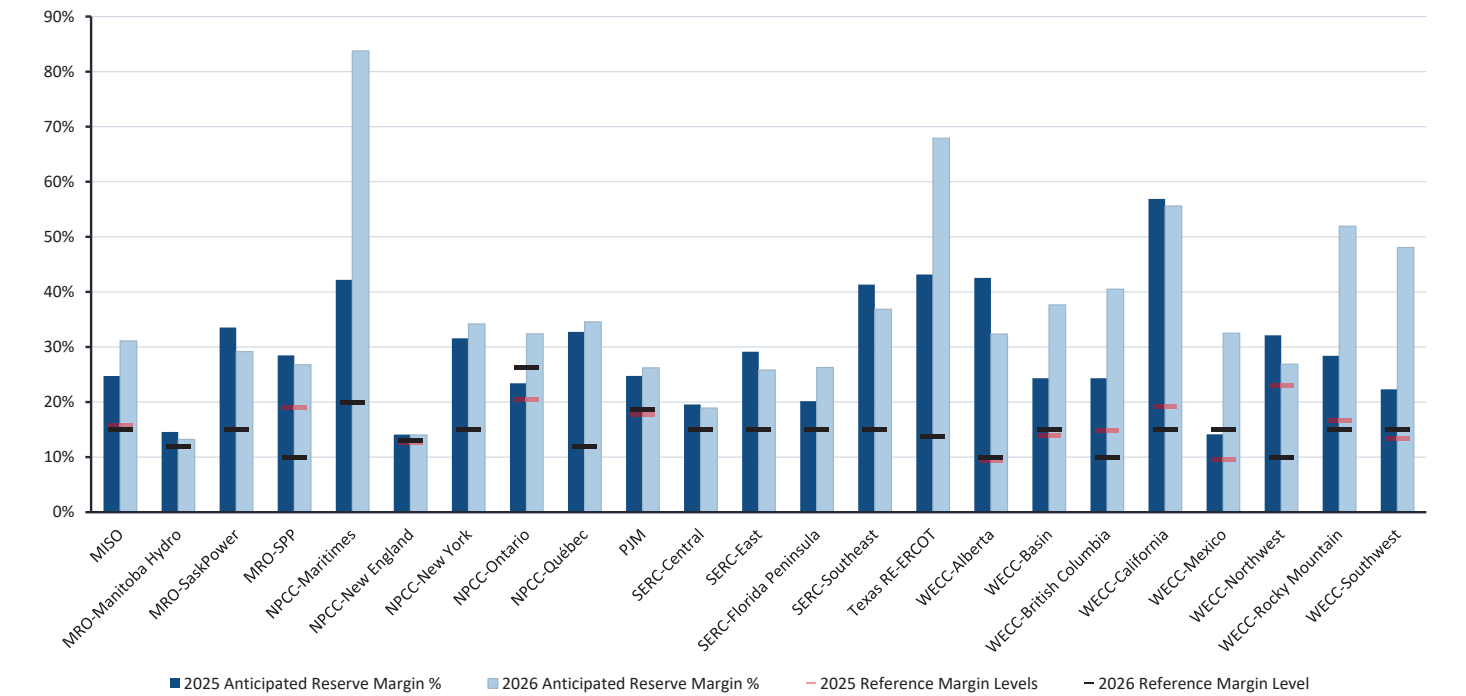


Figure 6: Summer 2025 and Summer 2026 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in **Figure 7**.²² Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

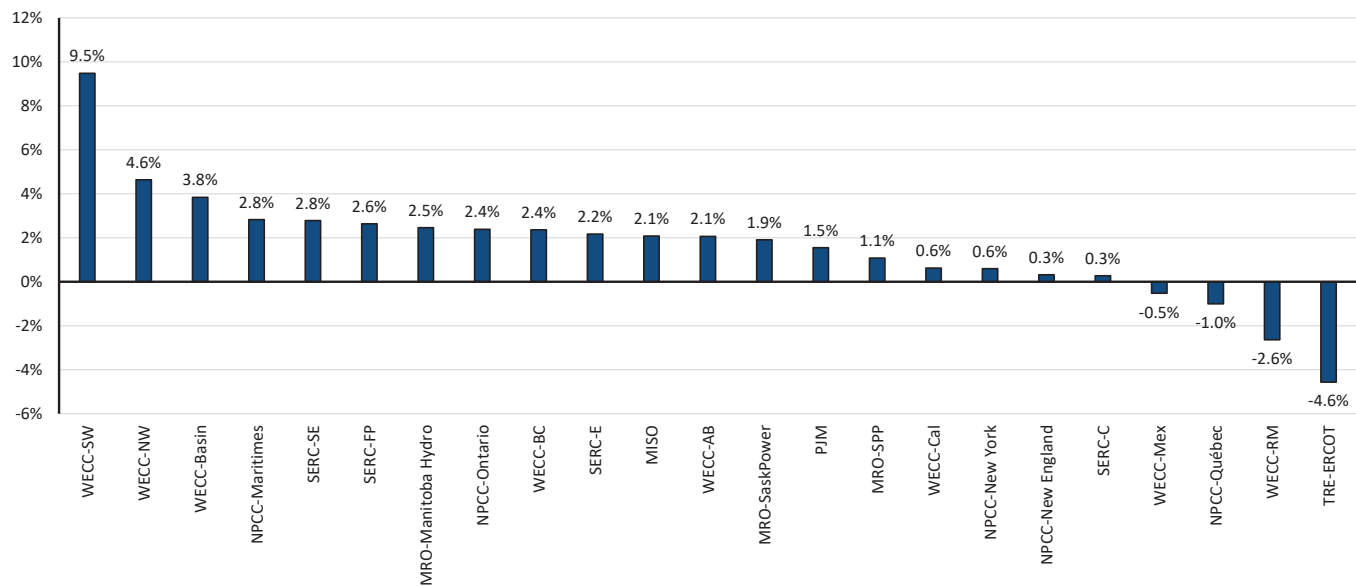


Figure 7: Changes in Net Internal Demand—Summer 2025 Forecast Compared to Summer 2026 Forecast

²² The lower demand forecast in Texas RE-ERCOT is the result of updated load modeling that reflects the observed behavior of load during peak periods and more demand response from large computational loads.

Demand and Resource Tables

The tables in this section contain peak demand and supply capacity data (i.e., resource adequacy data) for each assessment area.

MISO			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	125,313	127,824	2.0%
Demand Response: Available	9,004	9,100	1.1%
Net Internal Demand	116,309	118,725	2.1%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	142,793	152,382	6.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,280	3,259	42.9%
Anticipated Resources	145,073	155,641	7.3%
Existing-Other Capacity	1,190	0	-100.0%
Prospective Resources	148,543	158,900	7.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	24.7%	31.1%	6.4
Prospective Reserve Margin	27.7%	33.8%	6.1
Reference Margin Level	15.7%	15.0%	-0.7

MRO-SaskPower			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	3,620	3,688	1.9%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,570	3,638	1.9%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	4,477	4,409	-1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,767	4,699	-1.4%
Existing-Other Capacity	0	0	-
Prospective Resources	4,767	4,699	-1.4%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	33.5%	29.2%	-4.4
Prospective Reserve Margin	33.5%	29.2%	-4.4
Reference Margin Level	15.0%	15.0%	0.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	3,377	3,611	6.9%
Demand Response: Available	0	151	-
Net Internal Demand	3,377	3,460	2.5%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	5,583	5,631	0.9%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,714	-1,714	0.0%
Anticipated Resources	3,869	3,917	1.2%
Existing-Other Capacity	21	46	114.6%
Prospective Resources	3,890	3,963	1.9%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	14.6%	13.2%	-1.4
Prospective Reserve Margin	15.2%	14.5%	-0.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	56,168	57,122	1.7%
Demand Response: Available	1,408	1,772	25.8%
Net Internal Demand	54,760	55,350	1.1%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	70,549	69,317	-1.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-201	851	-524.0%
Anticipated Resources	70,348	70,168	-0.3%
Existing-Other Capacity	0	0	-
Prospective Resources	69,801	69,621	-0.3%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	28.5%	26.8%	-1.7
Prospective Reserve Margin	27.5%	25.8%	-1.7
Reference Margin Level	19.0%	10.0%	-9.0

Demand and Resource Tables

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	3,584	3,691	3.0%
Demand Response: Available	327	342	4.6%
Net Internal Demand	3,257	3,349	2.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	4,348	5,721	31.6%
Tier 1 Planned Capacity	220	280	27.3%
Net Firm Capacity Transfers	63	153	142.9%
Anticipated Resources	4,631	6,154	32.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,631	6,154	32.9%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	42.2%	83.8%	41.6
Prospective Reserve Margin	42.2%	83.8%	41.6
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	31,471	31,578	0.3%
Demand Response: Available	1,487	1,415	-4.8%
Net Internal Demand	29,984	30,163	0.6%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	37,682	37,324	-1.0%
Tier 1 Planned Capacity	0	210	-
Net Firm Capacity Transfers	1,769	2,941	66.3%
Anticipated Resources	39,451	40,475	2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	39,451	40,475	2.6%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	31.6%	34.2%	2.6
Prospective Reserve Margin	31.6%	34.2%	2.6
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	25,202	25,228	0.1%
Demand Response: Available	399	346	-13.3%
Net Internal Demand	24,803	24,882	0.3%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	27,054	27,667	2.3%
Tier 1 Planned Capacity	0	295	-
Net Firm Capacity Transfers	1,245	409	-67.1%
Anticipated Resources	28,299	28,371	0.3%
Existing-Other Capacity	668	0	-100.0%
Prospective Resources	28,967	28,371	-2.1%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	14.1%	14.0%	-0.1
Prospective Reserve Margin	16.8%	14.0%	-2.8
Reference Margin Level	12.7%	13.0%	0.3

NPCC-Ontario			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	21,955	22,545	2.7%
Demand Response: Available	998	1,088	9.1%
Net Internal Demand	20,957	21,457	2.4%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	24,760	26,837	8.4%
Tier 1 Planned Capacity	413	670	62.2%
Net Firm Capacity Transfers	689	900	30.6%
Anticipated Resources	25,862	28,407	9.8%
Existing-Other Capacity	0	0	-
Prospective Resources	25,862	28,407	9.8%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	23.4%	32.4%	9.0
Prospective Reserve Margin	23.4%	32.4%	9.0
Reference Margin Level	20.5%	26.3%	5.9

Demand and Resource Tables

NPCC-Québec			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	23,283	22,490	-3.4%
Demand Response: Available	1,020	450	-55.9%
Net Internal Demand	22,263	22,040	-1.0%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	32,132	33,324	3.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,582	-3,670	42.1%
Anticipated Resources	29,550	29,655	0.4%
Existing-Other Capacity	0	0	-
Prospective Resources	29,550	29,655	0.4%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	32.7%	34.5%	1.8
Prospective Reserve Margin	32.7%	34.5%	1.8
Reference Margin Level	11.9%	11.9%	0.0

SERC-Central			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	42,765	44,369	3.8%
Demand Response: Available	864	2,354	172.3%
Net Internal Demand	41,900	42,016	0.3%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	46,949	47,603	1.4%
Tier 1 Planned Capacity	592	202	-66.0%
Net Firm Capacity Transfers	2,554	2,158	-15.5%
Anticipated Resources	50,095	49,962	-0.3%
Existing-Other Capacity	2,475	4,546	83.7%
Prospective Resources	52,570	54,508	3.7%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	19.6%	18.9%	-0.6
Prospective Reserve Margin	25.5%	29.7%	4.3
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	154,144	156,373	1.4%
Demand Response: Available	7,898	7,864	-0.4%
Net Internal Demand	146,246	148,509	1.5%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	186,638	188,854	1.2%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-4,200	-1,427	-66.0%
Anticipated Resources	182,438	187,427	2.7%
Existing-Other Capacity	0	0	-
Prospective Resources	178,238	187,427	5.2%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	24.7%	26.2%	1.5
Prospective Reserve Margin	21.9%	26.2%	4.3
Reference Margin Level	17.7%	18.6%	0.9

SERC-East			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	44,015	44,765	1.7%
Demand Response: Available	1,558	1,387	-11.0%
Net Internal Demand	42,457	43,378	2.2%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	54,665	54,637	0.0%
Tier 1 Planned Capacity	17	23	36.9%
Net Firm Capacity Transfers	150	119	-20.7%
Anticipated Resources	54,832	54,780	-0.1%
Existing-Other Capacity	2,628	3,890	48.1%
Prospective Resources	57,459	58,670	2.1%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	29.1%	26.3%	-2.8
Prospective Reserve Margin	35.3%	35.3%	0.0
Reference Margin Level	15.0%	15.0%	0.0

Demand and Resource Tables

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	52,987	54,477	2.8%
Demand Response: Available	3,158	3,335	5.6%
Net Internal Demand	49,829	51,142	2.6%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	59,395	64,163	8.0%
Tier 1 Planned Capacity	102	58	-43.4%
Net Firm Capacity Transfers	381	131	-65.6%
Anticipated Resources	59,878	64,352	7.5%
Existing-Other Capacity	3,482	2,481	-28.7%
Prospective Resources	63,360	66,833	5.5%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	20.2%	25.8%	5.7
Prospective Reserve Margin	27.2%	30.7%	3.5
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	85,151	83,224	-2.3%
Demand Response: Available	3,292	5,100	54.9%
Net Internal Demand	81,859	78,124	-4.6%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	112,321	125,975	12.2%
Tier 1 Planned Capacity	4,854	5,189	6.9%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	117,195	131,184	11.9%
Existing-Other Capacity	0	0	-
Prospective Resources	117,770	131,903	12.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	43.2%	67.9%	24.8
Prospective Reserve Margin	43.9%	68.8%	25.0
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	47,049	48,625	3.3%
Demand Response: Available	1,338	1,642	22.7%
Net Internal Demand	45,711	46,983	2.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	64,111	64,391	0.4%
Tier 1 Planned Capacity	0	375	-
Net Firm Capacity Transfers	489	-467	-195.5%
Anticipated Resources	64,600	64,299	-0.5%
Existing-Other Capacity	1,077	1,277	18.7%
Prospective Resources	65,676	65,576	-0.2%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	41.3%	36.9%	-4.5
Prospective Reserve Margin	43.7%	39.6%	-4.1
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	12,246	12,499	2.1%
Demand Response: Available	0	0	-
Net Internal Demand	12,246	12,499	2.1%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	17,176	16,179	-5.8%
Tier 1 Planned Capacity	281	323	15.1%
Net Firm Capacity Transfers	0	40	-
Anticipated Resources	17,457	16,542	-5.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,457	16,542	-5.2%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	42.6%	32.3%	-10.2
Prospective Reserve Margin	42.6%	32.3%	-10.2
Reference Margin Level	9.4%	15.0%	5.6

Demand and Resource Tables

WECC-BC			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	9,309	9,529	2.4%
Demand Response: Available	0	0	-
Net Internal Demand	9,309	9,529	2.4%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	11,313	12,307	8.8%
Tier 1 Planned Capacity	260	469	80.3%
Net Firm Capacity Transfers	0	612	-
Anticipated Resources	11,573	13,388	15.7%
Existing-Other Capacity	0	0	-
Prospective Resources	11,573	13,388	15.7%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	24.3%	40.5%	16.2
Prospective Reserve Margin	24.3%	40.5%	16.2
Reference Margin Level	14.9%	10.0%	-4.9

WECC-California			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	54,797	55,073	0.5%
Demand Response: Available	746	685	-8.2%
Net Internal Demand	54,051	54,388	0.6%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	75,726	78,788	4.0%
Tier 1 Planned Capacity	8,470	2,085	-75.4%
Net Firm Capacity Transfers	598	3,751	527.2%
Anticipated Resources	84,794	84,623	-0.2%
Existing-Other Capacity	0	0	-
Prospective Resources	84,794	84,623	-0.2%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	56.9%	55.6%	-1.3
Prospective Reserve Margin	56.9%	55.6%	-1.3
Reference Margin Level	19.2%	15.0%	-4.2

WECC-Southwest			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	35,321	38,814	9.9%
Demand Response: Available	199	364	82.9%
Net Internal Demand	35,122	38,451	9.5%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	40,300	46,476	15.3%
Tier 1 Planned Capacity	1,966	6,667	239.1%
Net Firm Capacity Transfers	695	3,791	445.4%
Anticipated Resources	42,961	56,934	32.5%
Existing-Other Capacity	0	0	-
Prospective Resources	42,961	56,934	32.5%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	22.3%	48.1%	25.8
Prospective Reserve Margin	22.3%	48.1%	25.8
Reference Margin Level	13.3%	15.0%	1.7

WECC-Northwest			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	29,157	30,479	4.5%
Demand Response: Available	30	2	-93.3%
Net Internal Demand	29,127	30,477	4.6%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	36,388	35,708	-1.9%
Tier 1 Planned Capacity	844	477	-43.5%
Net Firm Capacity Transfers	1,249	2,483	98.8%
Anticipated Resources	38,481	38,668	0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	38,481	38,668	0.5%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	32.1%	26.9%	-5.2
Prospective Reserve Margin	32.1%	26.9%	-5.2
Reference Margin Level	23.1%	10.0%	-13.1

Demand and Resource Tables

WECC-Basin			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	14,214	14,564	2.5%
Demand Response: Available	620	448	-27.7%
Net Internal Demand	13,594	14,116	3.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	14,923	16,759	12.3%
Tier 1 Planned Capacity	704	1,382	96.3%
Net Firm Capacity Transfers	1,274	1,288	1.1%
Anticipated Resources	16,901	19,429	15.0%
Existing-Other Capacity	0	0	-
Prospective Resources	16,901	19,429	15.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	24.3%	37.6%	13.3
Prospective Reserve Margin	24.3%	37.6%	13.3
Reference Margin Level	14.0%	15.0%	1.0

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	13,848	13,516	-2.4%
Demand Response: Available	284	310	9.1%
Net Internal Demand	13,564	13,206	-2.6%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	17,312	18,363	6.1%
Tier 1 Planned Capacity	104	1,206	1059.6%
Net Firm Capacity Transfers	0	495	-
Anticipated Resources	17,416	20,063	15.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,415	20,063	15.2%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	28.4%	51.9%	23.5
Prospective Reserve Margin	28.4%	51.9%	23.5
Reference Margin Level	16.7%	15.0%	-1.7

WECC-Mexico			
Demand, Resource, and Reserve Margins	2025 SRA	2026 SRA	2025 vs. 2026 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	3,770	3,750	-0.5%
Demand Response: Available	0	0	-
Net Internal Demand	3,770	3,750	-0.5%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	4,303	4,761	10.6%
Tier 1 Planned Capacity	0	765	-
Net Firm Capacity Transfers	0	-557	-
Anticipated Resources	4,303	4,969	15.5%
Existing-Other Capacity	0	0	-
Prospective Resources	4,303	4,969	15.5%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	14.1%	32.5%	18.4
Prospective Reserve Margin	14.1%	32.5%	18.4
Reference Margin Level	9.6%	15.0%	5.4

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (VER) (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 (MW) 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												
Assessment Area / Interconnection	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Run-of- River Hydro	Expected Run-of- River Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	32,066	5,611	17%	20,419	12,322	60%	1,294	770	60%	3,560	3,457	97%
MRO-Manitoba Hydro*	259	47	18%	-	-	0%	202	-	0%	-	-	0%
MRO-SaskPower	816	319	39%	30	9	28%	121	74	61%	-	-	0%
MRO-SPP	35,760	8,114	23%	3,926	2,139	54%	113	66	59%	1,318	1,113	84%
NPCC-Maritimes	1,341	423	32%	148	80	54%	1,316	1,316	100%	162	106	65%
NPCC-New England	2,431	424	17%	3,609	1,728	48%	584	287	49%	723	686	95%
NPCC-New York	2,598	417	16%	661	283	43%	914	354	39%	23	-	0%
NPCC-Ontario*	4,943	735	15%	478	66	14%	-	-	0%	451	226	50%
NPCC-Québec*	4,024	885	22%	10	1	12%	444	444	100%	-	-	0%
PJM	13,855	4,570	33%	16,852	9,951	59%	2,505	2,505	100%	256	238	93%
SERC-Central	1,324	370	28%	2,303	1,446	63%	4,979	3,213	65%	100	100	100%
SERC-East	-	-	0%	7,843	4,205	54%	3,096	3,033	98%	323	235	73%
SERC-Florida Peninsula	-	-	0%	13,502	6,276	46%	-	-	0%	1,177	1,145	97%
SERC-Southeast	-	-	0%	9,412	8,087	86%	3,326	3,374	101%	164	141	86%
Texas RE-ERCOT	40,586	9,450	23%	40,279	29,682	74%	579	447	77%	21,979	20,688	94%
WECC-AB	5,684	455	8%	1,870	1,271	68%	896	481	54%	261	222	85%
WECC-Basin	5,959	360	6%	3,773	2,605	69%	884	386	44%	655	557	85%
WECC-BC*	753	60	8%	17	12	71%	1,871	888	47%	-	-	0%
WECC-Cal	7,985	907	11%	27,495	14,278	52%	1,120	628	56%	16,711	14,204	85%
WECC-Mexico	296	3	1%	350	35	10%	-	-	0%	-	-	0%
WECC-NW*	9,941	1,016	10%	1,729	1,051	61%	14,086	8,303	59%	547	461	84%
WECC-RM	5,684	1,034	18%	2,920	1,551	53%	117	61	52%	342	291	85%
WECC-SW	4,848	1,473	30%	11,112	4,868	44%	376	270	72%	3,691	3,137	85%
EASTERN INTERCONNECTION	94,474	21,180	22%	78,714	46,528	59%	18,892	15,435	82%	7,805	7,220	92%
QUÉBEC INTERCONNECTION	4,024	885	22%	10	1	12%	444	444	100%	-	-	0%
TEXAS INTERCONNECTION	40,586	9,450	23%	40,279	29,682	74%	579	447	77%	21,979	20,688	94%
WECC INTERCONNECTION ²³	41,150	5,308	13%	49,266	25,670	52%	19,350	11,017	57%	22,207	18,872	85%
All INTERCONNECTIONS	181,153	36,673	20%	168,736	101,946	60%	38,822	26,899	69%	52,442	47,005	90%

*On peak contributions from conventional hydro are not represented in this table, and in certain areas those contributions are significant.

²³ Some areas in the Western Interconnection re-categorized their hydro resources for the 2026 SRA from run-of-river hydro to conventional hydro

Review of 2025 Capacity and Energy Performance

The summer of 2025 was the 12th hottest on record for the contiguous United States²⁴ during the meteorological summer period (June–August) and the 11th warmest summer in Canada.²⁵ Cooler-than-normal temperatures were observed in the eastern U.S., whereas most of Canada experienced slightly above-normal temperatures. Despite the comparatively temperate 2025 Summer (summer of 2024 was the fourth-hottest on record in both the United States²⁶ and Canada²⁷), U.S. electricity generation reached a record high for the assessment summer period (June – September) at 1,628 TWh²⁸, topping the prior year’s summer electricity generation total of 1,603 TWh. The month of July in the U.S. set a new monthly generation record at 446 TWh. In Canada, the comparatively cooler summer appears to have brought electricity generation down from the 2024 summer high of 192 TWh to the 2025 total of 188 TWh²⁹. Actual peak demand exceeded normal demand forecasts across 19 assessment areas and exceeded extreme demand projections from the 2025 SRA in three assessment areas. Despite a lower average summer temperature in 2025, a widespread heatwave³⁰ in early summer impacted much of the central and eastern U.S., bringing record-setting temperatures across several hundred counties.

Canada experienced its second-worst wildfire year on record³¹ (2023 being the worst) with fires burning an area larger than New Brunswick and Prince Edward Island combined. Saskatchewan and Manitoba comprised nearly half of the total area impacted by the fires. Drought that began in 2021 has also deepened across Canada, resulting in reduced hydroelectric power generation for a third straight year in British Columbia.

Eastern Interconnection–Canada and Québec Interconnection

In Ontario, grid operators utilized demand response resources on 10 different occasions during the summer period,³² culminating in demand reductions of 316 MW during the time of peak demand (24,862 MW) on June 24, 2025, the single highest peak in 12 years. Other demand-side management programs further reduced peak demand by 1,800 MW, contributing to 7% total reduction in demand stemming from consumer programs.

Québec saw electricity generation of roughly 52 TWh during the summer period,³³ down from 56 TWh for Summer 2024 amid relatively cooler temperatures and a year beset by low runoff levels that have persisted since 2023.³⁴ The Maritimes saw a slight increase in electricity generation to 5.8 TWh for Summer 2025, up from 5.3 TWh the prior summer. Nova Scotia Power realized nearly a 20% reduction in annual 2025 power outages from the year before but still fell short of targets set by the Nova Scotia Energy Board relating to power-outage duration and frequency.

Saskatchewan saw severe storms and large hail in late August that damaged infrastructure, triggering emergency operating conditions and power outages.³⁵

²⁴ [Assessing the U.S. Temperature and Precipitation Analysis in August 2025 | News | National Centers for Environmental Information \(NCEI\)](#)

²⁵ [Climate Trends and Variations Bulletin - summer 2025 - Canada.ca](#)

²⁶ [U.S. sweltered through its 4th-hottest summer on record | National Oceanic and Atmospheric Administration](#)

²⁷ [Climate Trends and Variations Bulletin - Summer 2024 - Canada.ca](#)

²⁸ [U.S. Energy Information Administration - EIA - Independent Statistics and Analysis](#)

²⁹ [Electric power generation, monthly generation by type of electricity](#)

³⁰ [Assessing the U.S. Climate in June 2025 | News | National Centers for Environmental Information \(NCEI\)](#)

³¹ [Canada’s top 10 weather stories of 2025 - Canada.ca](#)

³² [2025 Year in Review](#)

³³ [Electric power generation, monthly generation by type of electricity](#)

³⁴ [Hydro-Québec - Quarterly Bulletin - Third Quarter 2025](#)

³⁵ [SaskPower crews still working to restore power after weekend outages - WestCentralOnline: West Central Saskatchewan's latest news, sports, weather, community events.](#)

Eastern Interconnection–United States

New York and New England saw region-wide heat waves in June and July. ISO-NE saw peak-hour demand in June exceed its extreme demand projections from the 2024 SRA, a significant step up from the prior year’s summer peak (+7%). Heat and humidity, high demand, and some unexpected generation reductions and outages left the region short of the resources needed to maintain required operating reserves for more than three hours around the evening peak on June 24,³⁶ though electricity supply was not interrupted. NYISO declared an EEA Level 1 on June 24, June 25, and July 29 due to limited capacity availability,³⁷ resulting in the deployment of emergency DR programs and other special-case resources. Both the New York and New England ISOs saw peak loads that exceeded their demand projections.

PJM saw their third-highest all-time summer peak³⁸ of more than 160 GW. This exceeded extreme demand projections for the summer (159 GW). The system operator was able to manage load by calling on customers who were enrolled in financially incentivized DR programs.

MISO declared an EEA Level 1³⁹ on June 23 to access emergency capacity. At the time of the event, more than 4 GW of generation was trapped in the south due to transmission constraints. MISO was able to dispatch 565 MW of emergency capacity in the Midwest, but only 45% performed. MISO has been engaged in efforts to highlight the need for non-performance penalties. On June 24, when neighboring areas were experiencing peak demand, MISO had to curtail non-firm exports to avoid going into EEA. In late July, MISO experienced a shortage of operating reserves due to errors in forecasting load and renewables. This was one of 24 total instances of operating reserve shortage, double the amount from the previous year.

In SERC, an EEA Level 2 was declared in the Carolinas amid high load conditions and generation resources that were unavailable⁴⁰ during the peak of the June heat wave affecting the broader Eastern Interconnection – a precautionary reliability measure to support system operations during peak demand and generation outages. During this event, the affected service territory recorded a new all-time peak demand of 21,931 MW on June 25.

Texas Interconnection–ERCOT

Texas saw a relatively mild summer and above-average rainfall in 2025 with the June–July period ranking as the 43rd hottest out of 131 historical years. But even so, Summer 2025 load levels were comparable to the 2023 Summer load levels when the summer was far hotter.⁴¹ Forced outages of thermal resources outstripped such forced outages from the summer of 2024, prompting a larger discharge of energy storage resources (ESR) some evenings. Texas set a new solar generation record in July at 29.3 GW, and solar contributed just under 17 GW at the hour of peak demand on August 18 (hour ending at 6:00 pm). Wind generation was relatively high at the peak demand hour and also set records in the spring. Energy storage also reached a new discharge record at 7.2 GW on August 20.

Western Interconnection

The Western Interconnection saw summer peak demand decrease slightly from the previous year’s summer peak, reaching 163,140 MW in 2025, down from 168,206 MW the prior summer. Operators and RCs were able to maintain the flow of electricity through the summer months.

³⁶ Summer 2025 recap: Reliability maintained as grid sees highest peak in over a decade - ISO Newswire

³⁷ NYISO Summer 2025

³⁸ 2025 in Review: Operations Improvements See PJM Through Record Peaks, Growing Demand | PJM Inside Lines

³⁹ Microsoft PowerPoint - IMM Quarterly Report, Summer 2025

⁴⁰ DOE grants Duke Energy authority to exceed power plant permit limits during extreme heat | Utility Dive

⁴¹ 12 Summer 2025 Operational and Market Review.pptx

Western Interconnection–Canada

Western Canada experienced a heat wave from late August and through early September, breaking daily records in British Columbia and the Yukon and exacerbating the ongoing drought in western Canada. Wildfire activity also increased due to heat and dry conditions. The same period brought generation outages that triggered emergency operations in parts of western Canada.

Western Interconnection–United States

The western United States overall navigated last summer with the BPS experiencing relatively few emergency events, and demand in western assessment areas never reached or exceeded the projections for extreme demand from the 2025 SRA. Variable resources performed as expected with the exception of California seeing much less solar generation than anticipated, 65% less solar than was projected ahead of the prior year's assessment. California's lower-than-expected solar did not result in energy shortfalls.

In Mexico, generation losses in late August triggered Level 3 EEAs, but the overall number of Level 3 EEAs was down year-on-year and on par with the number of Level 3 EEAs triggered in 2023 for the same seasonal period.

Despite the moderation in summer heat when compared to 2024, certain Rocky Mountain states saw record temperatures with Utah and Nevada recording their warmest years on record. The Rocky Mountain region saw peak demand surpass the projected normal demand conditions but remained under extreme demand projections.

2025 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	121.6	116.3 121.6	1,105	6,039	12,323	9,123	8,856
MRO-Manitoba Hydro	3.5	3.4 3.6	0	48	0	0	252
MRO-SaskPower	3.6	3.6 3.8	232	310	26	9	0
MRO-SPP	54.5	54.8 57.5	8,130	5,556	810	492	4,370
NPCC-Maritimes	3.6	3.3 3.5	151	314	69	0	33
NPCC-New England	26.6	24.7 26.4	566	142	180	1,412	1,963
NPCC-New York	32	30.0 31.7	1,256	446	164	243	1,372
NPCC-Ontario	24.9	21.0 24.5	607	742	39	66	1,532
NPCC-Québec	23.0	22.3 23.3	790	885	0	0	5,029
PJM	160.7	146.2 158.7	4,515	1,855	7,730	6,244	15,945
SERC-C	43.2	41.9 45.7	84	370	714	1,053	701
SERC-E	44.8	42.5 45.7	0	0	3,200	5,022	2,407
SERC-FP	54.6	49.8 50.8	0	0	8,035	5,749	1,599
SERC-SE	46.4	45.7 55.9	0	0	3,366	7,728	1,380
TRE-ERCOT	83.7	85.2 ⁵ 91.3 ⁵	14,509	9,396	16,961	22,962	11,095
WECC-AB	12.5	12.2 12.7	2,870	796	32	1,480	**
WECC-BC	9.8	9.3 10.0	293	149	4.8	0	**
WECC-CA	54	54.1 64.3	1,744	1,207	5,064	14,756	1,063

2025 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-MX	3.5	3.8	2.5	50	296	227	**
		4.1					
WECC-NW	29.8	29.1	1,054	3,107	1,398	666	1,825
		32.7					
WECC-RM	13.4	13.8	2,313	1,359	1,571	1,669	1,954
		15.0					
WECC-Basin	13.8	13.6	931	911	2,660	2,231	0
		15.0					
WECC-SW	36.9	35.1	1,230	1,091	4,472	4,293	2,323
		39.0					
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 the assessment areas.

² See NERC 2025 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 2025 SRA.

⁴ Values from NERC Generator Availability Data System for the 2025 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 2025 SRA.

⁵ Texas RE-ERCOT peak demand scenarios are obtained by adding expected demand response (3.2 GW) to the demand scenarios found on p. 30 of the 2025 SRA.

**Data unavailable - 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.

Exhibit 32



2025/2026 Base Residual Auction Report

July 30, 2024

For Public Use

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Introduction

This document provides information for PJM stakeholders regarding the results of the 2025/2026 Reliability Pricing Model (RPM) Base Residual Auction (BRA).

In each BRA, PJM seeks to procure a target capacity reserve level for the RTO in a least-cost manner while recognizing the following reliability-based constraints on the location and type of capacity that can be committed:

- Internal PJM locational constraints are established by setting up Locational Deliverability Areas (LDAs) with each LDA having a separate target capacity reserve level and a maximum limit on the amount of capacity that it can import from resources located outside of the LDA.
- Across the RTO, seasonal sell offers must account for annual CP commitments by matching summer-period and winter-period sell offers.

The clearing solution may be required to commit capacity resources out-of-merit order but again in a least-cost manner to ensure that all of these constraints are respected. In those cases where one or more of the constraints results in out-of-merit commitment in the auction solution, resource clearing prices will be reflective of the price of resources selected out of merit order to meet the necessary requirements.

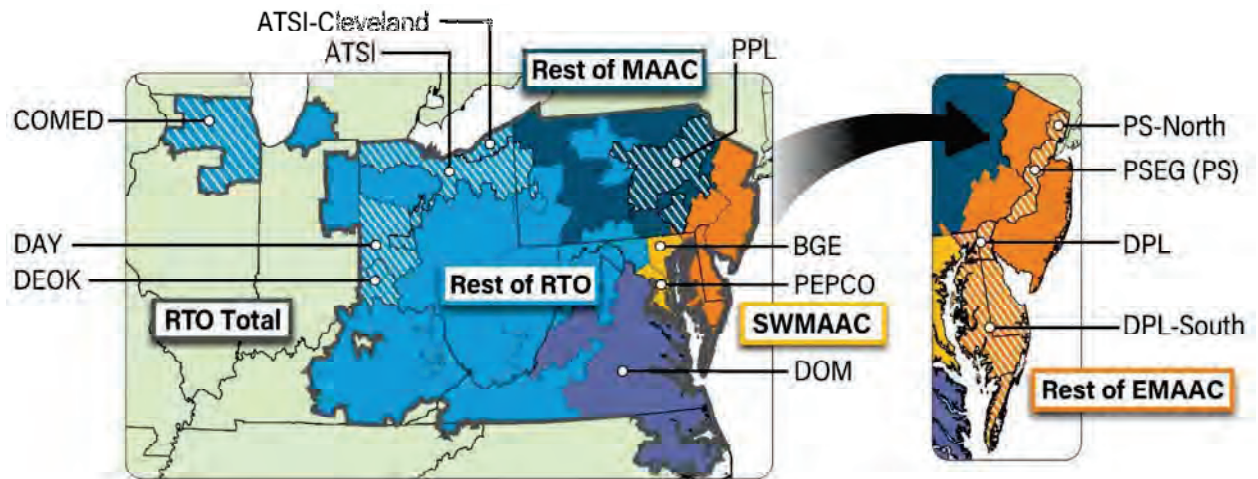
An LDA was modeled in the BRA and had a separate VRR Curve if (1) the LDA has a CETO/CETL margin that is less than 115%; or (2) the LDA had a locational price adder in any of the three immediately preceding BRAs; or (3) the LDA is EMAAC, SWMAAC and MAAC. An LDA not otherwise qualifying under the above three tests may also be modeled if PJM finds that the LDA is determined to be likely to have a Locational Price Adder based on historic offer price levels or if such LDA is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards.

As a result of the above criteria, MAAC, EMAAC, SWMAAC, PSEG, PS-NORTH, DPL-SOUTH, PEPCO, ATSI, ATSI-Cleveland, COMED, BGE, PL, DAY, DOM and DEOK were modeled as LDAs in the 2025/2026 RPM Base Residual Auction. A Locational Price Adder represents the difference in Resource Clearing Prices for the Capacity Performance product between a resource in a constrained LDA and the immediate higher level LDA.

Locational Deliverability Area Definition

Locational Deliverability Areas (LDAs) defined as “(rest of)” do not include figures from modeled child LDAs contained within the parent LDA. For example, the PS (rest of) LDA does not include PS-NORTH within its totals.	• EMAAC total includes DPL-SOUTH, PS-NORTH, PS (rest of), EMAAC (rest of). • SWMAAC total includes PEPCO, BGE, SWMAAC (rest of). • MAAC total includes EMAAC total, SWMAAC total, PPL, MAAC (rest of).	RTO total includes MAAC total, ATSI (rest of), ATSI-Cleveland, COMED, DAY, DEOK, DOM, RTO (rest of). See Map 1.
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Map 1. PJM LDAs



Executive Summary

The 2025/2026 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 135,684 MW of unforced capacity in the RTO from non-energy efficiency annual, summer-period, and winter-period resources representing a 18.6% reserve margin. Energy Efficiency (EE) resources are excluded from this calculation because their impact is reflected in a lower load forecast and therefore not used to meet the Reliability Requirement. The total cost to load for the 2025/2026 BRA was \$14.7 billion, which includes the cost of EE. The reserve margin for the entire RTO, which includes Fixed Resource Requirement (FRR) is 18.5% or 0.7 percentage points higher than the target reserve margin of 17.8%. This is a significant reduction in the overall reserve margin, which includes FRR, from the 2024/2025 BRA. The 2024/2025 overall reserve margin for the entire RTO was 20.4%, or 5.7 percentage points higher than the target reserve margin of 14.7%. The 2025/26 to 2024/25 Delivery Year supply and demand changes are not straightforward comparisons because of the implementation of marginal Effective Load Carrying Capability accreditation for all resources and the associated reduction of the reliability requirement through the Forecast Pool Requirement (FPR) as well as the transition of load from FRR into RPM. The Delivery Year over Delivery Year unforced capacity or reliability requirement comparisons in the report have not been adjusted for these changes.

Supply offered into the RPM capacity market, excluding EE resources, declined 13,252.1 MW from 148,945.7 MW in the 2024/2025 BRA to 135,692.3 MW in the 2025/2026 BRA. This is the fourth BRA in a row where the total capacity offered from non-EE resources has declined. The number of constrained LDAs dropped from five to two in the 2025/2026 BRA. The total amount of capacity, excluding EE Resources, in RPM that cleared decreased by 5,743.6 MW from 140,415.8 MW in the 2024/2025 BRA to 134,672.2 MW in the 2025/2026 BRA.

The RTO as a whole failed the Market Structure Test (i.e., the Three-Pivotal Supplier Test), resulting in the application of market power mitigation to all Existing Generation Capacity Resources. Mitigation was applied to a supplier's existing generation resources resulting in utilizing the lesser of the supplier's approved Market Seller Offer Cap for such resource or the supplier's submitted offer price for such resource in the RPM Auction clearing.

Table 1. Comparison of BRA Clearing Prices by Delivery Year by LDA

Capacity Type	BRA	BRA Resource Clearing Prices (\$/MW-day)		
		Rest of RTO	BGE	DOM
Capacity	2025/26	\$269.92	\$466.35	\$444.26
Performance	2024/25	\$28.92	\$73.00	-

Note: Clearing prices in bold indicate constrained LDA

The following is a list of new market rules or planning parameter changes that may have impacted the auction results:

- Planning Parameters (please see the [Planning Parameters Report](#)) changes which include:
 - 3,243 MW increase in forecasted load
 - IRM increase from 14.7% to 17.8%
- Significant decrease in overall supply from retirements (actual retirements plus must offer exceptions for future retirements), change in status from capacity resource to energy only and must offer exceptions for exports (see change of status and must offer exception [report](#))

- Critical Issue Fast Path (CIFP) changes were approved by FERC (ER24-99-000). These changes included marginal resource accreditation (ELCC), Forecast Pool Requirement (FPR) and a binding notice of intent for planned resources among other changes.
- Dominion FRR has changed to RPM and therefore the entire Dominion zone is now in RPM.
- Net CONE values used to determine the VRR Curve changed significantly in some LDAs. In most cases, LDAs received lower Net CONE values, and the range was between +4.1% in the PE zone to -80.6% in the BGE zone.

Note: This BRA was conducted under a compressed auction schedule where the auction occurred ~10 months prior to the start of the delivery year. A typical BRA is held more than three years before the start of the delivery year. The prior BRA was conducted under the same compressed auction schedule.

Detailed Report

Table 2 contains a summary of the RTO clearing prices, cleared unforced capacity and implied cleared reserve margins for the 2015/2016 through 2025/2026 RPM BRAs. The Reserve Margin presented in **Table 2** represents the percentage of installed capacity cleared in RPM and committed by FRR entities in excess of the RTO load (including load served under the FRR alternative). The reserve margin for the entire RTO, which includes FRR and RPM load, is 18.5%, or 0.7 percentage points higher than the target reserve margin of 17.8%.

Table 2. RPM Base Residual Auction Resource Clearing Price Results in the RTO

Delivery Year	Auction Results				
	Resource Clearing Price	Cleared UCAP (MW)	RPM Reserve Margin	Total Reserve Margin ¹	Total Cost to Load (\$ billion)
2015/16 ²	\$136.00	164,561.2	19.7%	19.3%	\$9.7
2016/17 ³	\$59.37	169,159.7	20.7%	20.3%	\$5.5
2017/18	\$120.00	167,003.7	20.1%	19.7%	\$7.5
2018/19	\$164.77	166,836.9	20.2%	19.8%	\$10.9
2019/20	\$100.00	167,305.9	22.9%	22.4%	\$7.0
2020/21 ⁴	\$76.53	165,109.2	23.9%	23.3%	\$7.0
2021/22	\$140.00	163,627.3	22.0%	21.5%	\$9.3
2022/23	\$50.00	144,477.3	21.1%	19.9%	\$3.9
2023/24	\$34.13	144,870.6	21.6%	20.3%	\$2.2
2024/25	\$28.92	147,478.9	21.7%	20.4%	\$2.2
2025/26 ⁵	\$269.92	135,684.0	18.6%	18.5%	\$14.7

¹ Reserve Margin includes FRR+RPM (Total ICAP/Total Peak-1; ² 2015/2016 BRA includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative; ³ 2016/2017 BRA includes EKPC zone;

⁴ Beginning 2020/2021 Cleared UCAP (MW) includes Annual and matched Seasonal Capacity Performance sell offers; ⁵ DOM zone included in RPM

Figure 1 represents the trend in BRA capacity price by delivery year for RTO, EMAAC, SWMAAC and MAAC. For 2025/2026, all four LDAs cleared at \$269.97. This clearing price was an increase from \$28.92 in RTO, \$49.49 in MAAC and SWMAAC and \$54.95 in EMAAC in the 2024/2025 BRA. The number of constrained LDAs decreased from five LDAs (MAAC, BGE, DPL-S, EMAAC and DEOK) to two LDAs (BGE and DOM).

Figure 1. BRA Clearing Prices by Delivery Year for Major LDAs

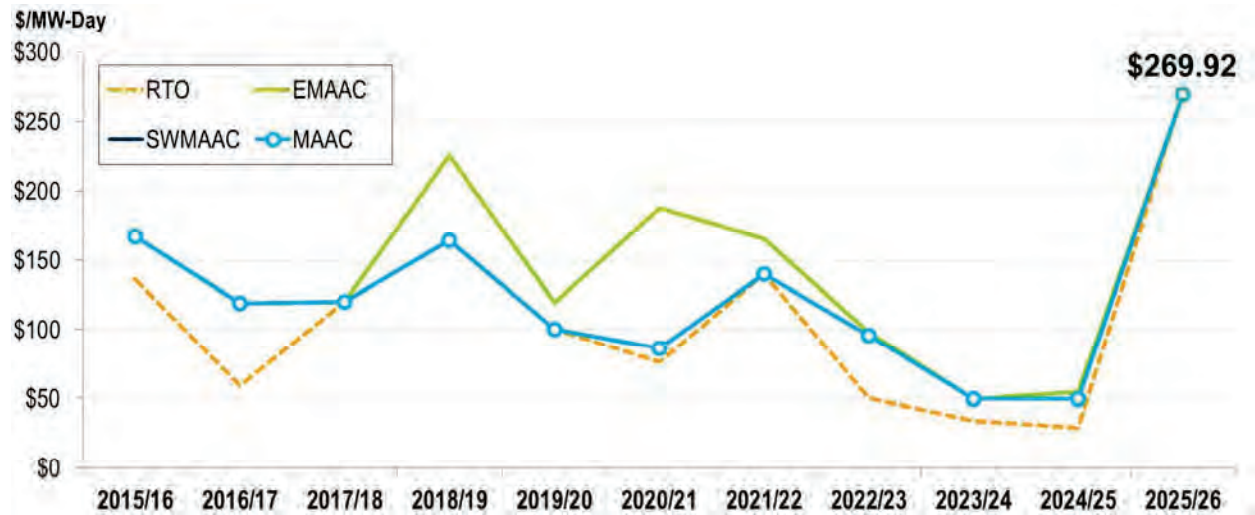


Table 3 provides the total offered and cleared MWs and associated prices by LDA. This table provides an indication of how much supply did not clear for each LDA. Since BGE and DOM were constrained LDAs, they cleared at a higher price than the rest of RTO or \$466.35 and \$444.26, respectively.

Since BGE and DOM were constrained LDAs, Capacity Transfer Rights (CTRs) will be allocated to loads in these constrained LDAs for the 2025/2026 Delivery Year. CTRs are allocated by load ratio share to all Load Serving Entities (LSEs) in a constrained LDA that has a higher clearing price than the unconstrained region. CTRs serve as a credit back to the LSEs in the constrained LDA for use of the transmission system to import less expensive capacity into that constrained LDA and are valued at the difference in the clearing prices of the constrained and unconstrained regions.

For 2025/2026, only 20.7 MW UCAP of annual generation and DR resources did not clear in the auction. Any remaining amount that did not clear was winter only where there were no summer-only resources that did not clear.

Table 3. Offered and Cleared MWs and Associated Prices by LDA

LDA	MW (UCAP)		System Marginal Price	Locational Price Adder***	RCP for Capacity Performance Resources
	Offered MW*	Cleared MW**			
ATSI	7,791.9	7,764.9	\$269.92	\$0.00	\$269.92
ATSI-CLEVELAND	1,615.5	1,614.0	\$269.92	\$0.00	\$269.92
COMED	22,524.4	21,813.9	\$269.92	\$0.00	\$269.92
DAY	493.1	488.6	\$269.92	\$0.00	\$269.92
DEOK	1,639.5	1,633.8	\$269.92	\$0.00	\$269.92
DOM	20,100.2	20,049.6	\$269.92	\$174.34	\$444.26
MAAC	51,529.4	51,303.2	\$269.92	\$0.00	\$269.92
PPL	8,785.1	8,757.6	\$269.92	\$0.00	\$269.92
EMAAC	24,478.2	24,373.3	\$269.92	\$0.00	\$269.92
DPL-SOUTH	960.4	956.9	\$269.92	\$0.00	\$269.92
PSEG	4,446.5	4,390.3	\$269.92	\$0.00	\$269.92
PS-NORTH	2,536.4	2,507.4	\$269.92	\$0.00	\$269.92
SWMAAC	5,089.1	5,060.8	\$269.92	\$0.00	\$269.92
BGE	612.9	606.9	\$269.92	\$196.43	\$466.35
PEPCO	2,285.5	2,263.2	\$269.92	\$0.00	\$269.92
RTO	137,152.1	135,684.0	\$269.92	\$0.00	\$269.92

* Offered MW values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers.

** Cleared MW values include Annual and matched Seasonal Capacity Performance sell offers within the LDA.

*** Locational Price Adder is with respect to the immediate parent LDA

As seen in **Figure 2**, the 2025/2026 BRA procured 110.3 MW of capacity from new generation and 753.8 MW from uprates to existing or planned generation. The quantity of new generation is down from the previous BRA where there was 328.5 MW of new generation. The quantity of capacity procured from external Generation Capacity Resources in the 2025/2026 BRA is 1,268.5 MW. All external generation capacity that cleared in the 2025/2026 BRA are Prior Capacity Import Limit (CIL) Exception External Resources¹ that qualify for an exception for the 2025/2026 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138. The total quantity of DR procured in the 2025/2026 BRA is 6,064.7 MW, and the total quantity of EE procured in the 2025/2026 BRA is 1,459.8 MW.

Figure 2. Cleared MWs (UCAP) by New Generation/Uprates/Imports by Delivery Year

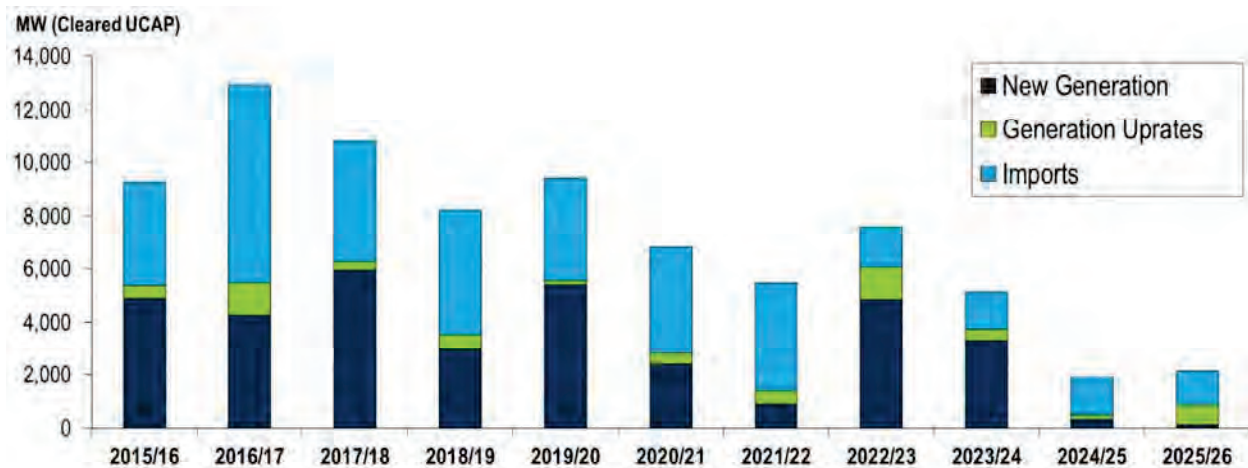


Table 4 contains a summary of the RTO resources for each cleared BRA from 2015/2016 through the 2025/2026 Delivery Years in terms of ICAP. The summary includes all resources located in the RTO (including FRR Capacity Plans).

A total of 195,853.1 MW of ICAP was eligible to be offered into the 2025/2026 Base Residual Auction or used in an FRR Capacity Plan. The total amount of supply in PJM decreased from 202,376.6 MW ICAP to only 195,853.1 MW ICAP, or a decline in the total amount of supply by 6,523.5 MW ICAP. Since this comparison is in ICAP and includes total eligible capacity for both FRR and RPM, it is not impacted by the CILP capacity accreditation changes or the addition of Dominion load into RPM.

¹ A Prior CIL Exception Resource is an external Generation Capacity Resource for which (1) a capacity market seller had, prior to May 9, 2017, cleared a Sell Offer in an RPM Auction under the exception provided to the definition of CIL as set forth in Article 1 of the Reliability Assurance Agreement or (2) an FRR Entity committed, prior to May 9, 2017, in an FRR Capacity Plan under the exception provided to the definition of CIL.

A total of 171,324.3 MW (ICAP) of generation and Demand Response capacity was offered into the Base Residual Auction. This is an increase of 17,262 MW from that which was offered into the 2024/2025 BRA and was driven by the return of Dominion to RPM from FRR. The total DR offered into the auction significantly declined from 9321.1 MW ICAP to 8009.7 MW ICAP. EE resources are considered to be included in the forecast and therefore do not contribute to meeting the reliability requirement. A total of 24,528.8 MW (ICAP) was eligible, but not offered due to (1) inclusion in an FRR Capacity Plan; (2) export of the resource; (3) excused from offering into the auction; (4) Deactivated; or (5) not required to offer into the auction and elected to not offer into the auction. Resources were excused from the must offer requirement for the following reasons: approved retirement requests or external sale of capacity. Resources with approved removal of capacity status requests also did not have a capacity must offer requirement.

Table 4. Total RTO Resources (RPM + FRR) Offered vs Unoffered by Resource Type Used To Meet the Reliability Requirement

Auction Supply	Delivery Year (All values in ICAP)										
	2015/16*	2016/17**	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26***
Internal PJM Gen Capacity	187,407.7	193,052.5	190,333.2	191,322.3	195,203.0	197,804.7	198,726.6	193,412.2	189,704.7	191,133.4	186,134.2
Internal PJM DR+PRD Capacity	19,243.6	13,932.9	10,855.2	10,772.8	10,859.2	8,245.5	10,694.8	9,501.2	9,517.2	9,626.1	8,233.7
Imports Offered Eligible	4,649.7	8,412.2	6,300.9	5,724.6	4,821.4	5,440.5	4,725.0	1,649.1	1,601.2	1,617.1	1,485.2
RPM Capacity	211,301.0	215,397.6	207,489.3	207,819.7	210,883.6	211,490.7	214,146.4	204,562.5	200,823.1	202,376.6	195,853.1
Exports/ Delistings	1,218.8	1,218.8	1,223.2	1,313.4	1,318.2	1,319.8	1,319.8	1,525.3	1,518.9	1,522.7	1,525.3
FRR Commitments	15,997.9	15,576.6	15,776.1	15,793.0	15,385.3	13,931.6	13,657.4	33,297.1	33,500.7	34,584.2	13,184.5
Excused	8,712.9	8,524.0	4,305.3	2,348.4	1,454.5	8,384.4	9,433.8	2,190.0	9,949.6	12,207.4	9,819.0
Total Eligible RPM Capacity: Excused	25,929.6	25,319.4	21,304.6	19,454.8	18,158.0	23,635.8	24,411.0	37,012.4	44,969.2	48,314.3	24,528.8
Remaining Eligible RPM Capacity	185,371.4	190,078.2	186,184.7	188,364.9	192,725.6	187,854.9	189,735.4	167,550.1	155,853.9	154,062.3	171,324.3
Generation Offered	166,127.8	176,145.3	175,329.5	177,592.1	181,866.4	178,807.1	178,823.5	157,872.2	146,571.7	144,741.2	163,314.6
DR Offered	19,243.6	13,932.9	10,855.2	10,772.8	10,859.2	9,047.8	10,911.9	9,677.9	9,282.2	9,321.1	8,009.7
Total Eligible RPM Capacity: Offered	185,371.4	190,078.2	186,184.7	188,364.9	192,725.6	187,854.9	189,735.4	167,550.1	155,853.9	154,062.3	171,324.3

Note: *includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative; **includes EKPC zone; ***includes DOM zone load previously under the FRR Alternative.

Table 5 shows the Generation, DR, and EE Resources Offered and Cleared in the RTO translated into Unforced Capacity (UCAP) MW amounts. Until the 2025/2026 Delivery Year, participants' sell offers for thermal resource EFORd values were used to convert a resource's installed capacity (ICAP) values into unforced capacity (UCAP) values. Effective for 2025/2026, the appropriate Accredited UCAP Factor will be used to convert installed capacity (ICAP) values into unforced capacity (UCAP) values. Prior to the 2025/2026 Delivery Year, DR sell offers and EE sell offers were converted into UCAP using the appropriate Forecast Pool Requirement (FPR). Beginning in 2025/2026, DR sell offers are converted into UCAP using the appropriate DR Accredited UCAP Factor while EE sell offers remain as in prior years, by multiplying the EE nominated value by the Forecast Pool Requirement.

Total offered Gen and DR (UCAP) used to meet the reliability requirement declined from 148,945.7 MW to 135,692.3 MW. Please note that UCAP for Delivery Years prior to 2025/2026 were not calculated using the marginal ELCC methodology, and these changes are in part responsible for the year-over-year decrease in offered and cleared UCAP.

Table 5. Capacity Resource Offered and Cleared by Type by Delivery Year (UCAP)

		Delivery Year											
Auction Results		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21*	2021/22	2022/23	2023/24	2024/25	2025/26	
Offered	Generation	157,691.1	168,716.0	166,204.8	166,909.6	172,071.2	171,262.3	171,663.2	152,128.6	141,026.7	138,799.3	129,607.5	
	DR	19,956.3	14,507.2	11,293.7	11,675.5	11,818.0	9,846.7	11,886.8	10,513.0	10,116.7	10,146.4	6,084.8	
	Total GEN/DR Offered	177,647.4	183,223.2	177,498.5	178,585.1	183,889.2	181,109.0	183,550.0	162,641.6	151,143.4	148,945.7	135,692.3	
	EE	940.3	1,156.8	1,340.0	1,306.1	1,650.3	2,242.5	2,954.8	5,056.8	5,471.1	8,417.0	1,459.8	
Cleared	Generation	148,805.9	155,634.3	154,690.0	154,506.0	155,442.8	155,976.5	150,385.0	131,541.6	131,777.4	132,423.1	128,607.5	
	DR	14,832.8	12,408.1	10,974.8	11,084.4	10,348.0	7,820.4	11,125.8	8,811.9	8,096.2	7,992.7	6,064.7	
	Total GEN/DR Cleared	163,638.7	168,042.4	165,664.8	165,590.4	165,790.8	163,796.9	161,510.8	140,353.5	139,873.6	140,415.8	134,672.2	
	EE	922.5	1,117.3	1,338.9	1,246.5	1,515.1	1,710.2	2,832.0	4,810.6	5,471.1	7,668.7	1,459.8	
Uncleared GEN/DR		14,008.7	15,180.8	11,833.7	12,994.7	18,098.4	17,312.1	22,039.2	22,288.1	11,269.8	8,529.9	1,020.1	

Note: RTO numbers include all LDAs. UCAP calculated using ELCC values for Generation Resources. DR and EE UCAP values include appropriate DR AUCAP Factor and FPR.

*Starting 2020/2021: Generation, DR, and EE offered and cleared values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers.

The 2025/2026 numbers in **Tables 6** and **7** have been significantly impacted by the marginal ELCC accreditation changes so it is difficult to simply compare delivery year over delivery year results. **Table 6** shows the offered and cleared megawatts by Resource type for RPM plus FRR commitments over the last four delivery years. Since Energy Efficiency is already included in the load forecast, it is not used to meet the Reliability Requirement and therefore separated from the Grand Totals in the tables to provide a more accurate picture of the Resources that will be used to meet the Reliability Requirement.

Table 6. Offered and Cleared MWs by Type for RPM and Committed FRR for Previous BRAs

Type	Offered and Cleared UCAP							
	2022/23		2023/24		2024/25		2025/26 (Reflects ELCC Accreditation)	
	Offered	Cleared	Offered	Cleared	Offered	Cleared	Offered	Cleared
Coal	45,754	39,230	37,164	31,811	35,114	31,532	30,081	30,081
Distillate Oil (No.2)	3,178	2,897	2,894	2,855	2,776	2,674	2,408	2,408
Gas	85,562	79,329	85,217	81,643	85,469	83,258	66,354	66,354
Nuclear	31,944	26,140	31,960	31,960	31,835	31,629	30,549	30,549
Oil	2,674	2,527	2,350	2,269	2,493	2,220	578	578
Solar	2,633	2,096	2,945	2,935	4,234	4,232	1,337	1,337
Water	6,917	6,749	6,375	6,375	6,137	6,137	5,365	5,361
Wind	2,595	1,839	1,608	1,416	1,396	1,396	2,618	1,676
Battery/Hybrid	-	-	16	16	36	36	14	14
Other	1,205	1,168	1,185	1,185	1,153	1,153	911	911
Demand Response	10,604	8,903	10,652	8,631	10,334	8,180	6,363	6,342
Aggregate Resource	484	386	511	511	503	503	327	273
Total (without EE)	193,551	171,263	182,875	171,605	181,481	172,951	146,905	145,883
Energy Efficiency	5,057	4,811	5,471	5,471	8,417	7,669	1,460	1,460
Total (with EE)	198,608	176,073	188,346	177,076	189,898	180,620	148,364	147,343

The table shows the UCAP MW quantities that offered and cleared in the BRA of each DY plus the UCAP MW committed to FRR Capacity Plans. Notes: Offered and Cleared MW quantities include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers. Other consist of: Kerosene, Other Gas, Other Liquid, Other Solid, Wood. *Starting in 2020/2021, Generation, DR, and EE offered and cleared values include Annual, Summer-Period, and Winter-Period Capacity Performance

Capacity Import Participation

Table 7 shows the quantity of capacity imports cleared in the 2025/2026 BRA at 1,268.5 MW (UCAP). The majority of the imports are from resources located in regions west of the PJM RTO. All external generation capacity that has cleared are Prior CIL Exception External Resources that qualify for an exception for the 2025/2026 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138.

Table 7. Capacity Imports (UCAP) Offered and Cleared by Region

	External Source Zones					Total
	NORTH	WEST 1	WEST 2	SOUTH 1	SOUTH 2	
Offered MW (UCAP)*	233.7	0.0	570.3	227.2	237.3	1,268.5
Cleared MW (UCAP)*	233.7	0.0	570.3	227.2	237.3	1,268.5
Resource Clearing Price (\$/MW-day)	\$269.97	\$269.97	\$269.97	\$269.97	\$269.97	

*Offered and Cleared MW quantities include resources that received CIL Exception and those associated with pre-OATT grandfathered transmission. Attachment G of Manual 14B provides a mapping of outside Balancing Authorities to the External Source Zones.

Resource Type Participation

Table 8 provides a breakdown of the offered and cleared megawatts by season by Resource Type. There were 448 MW of Summer capability and 1,447.4 MW of Winter capability offered in the auction. All 448 MW of Summer resources were matched with Winter resources to meet the annual Capacity Performance capability requirement.

Table 8. Offered and Cleared (UCAP) by Resource Type by Season

Resource Type	Capacity Performance					
	Offered MW (UCAP)			Cleared MW (UCAP)		
	Annual	Summer	Winter	Annual	Summer	Winter
GEN	128,115.1	45.0	1,447.4	128,114.5	45.0	448.0
DR	5,962.5	122.3	-	5,942.4	122.3	-
EE	1,179.1	280.7	-	1,179.1	280.7	-
PRD	210.2	-	-	210.2	-	-
Grand Total	135,466.9	448.0	1,447.4	135,446.2	448.0	448.0

Figure 3 displays the trend in offered and cleared DR and PRD and cleared EE by Delivery Year. Both DR and EE offered and cleared amounts declined significantly for 2025/2026, particularly for EE, which declined by 6,209 MW from the previous year. The amount of PRD remains small and declined slightly in the 2025/2026 Delivery Year.

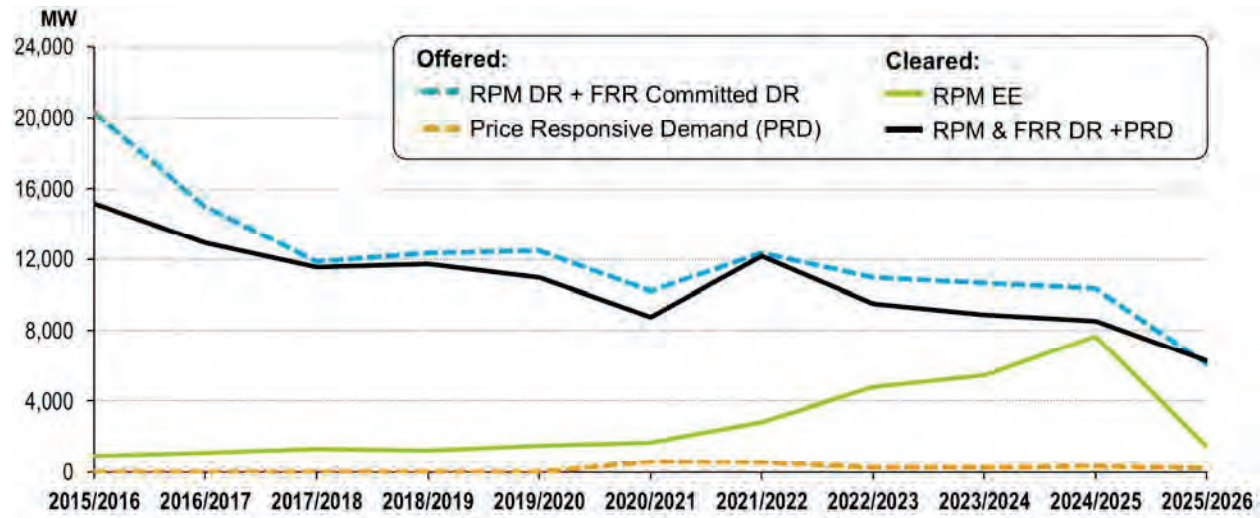
Figure 3. DR and PRD Offered and Cleared and EE Cleared MW(UCAP) by Delivery Year


Table 9 provides a breakdown of offered and cleared DR and EE by LDA. COMED cleared the most DR and EE (1,424.5 MW), followed by AEP (1,055.7 MW) and then DOM (827.7 MW).

Table 9. DR and EE Offered and Cleared by LDA

LDA	Zone	Offered MW (UCAP)*			Cleared MW (UCAP)*		
		DR	EE	Total	DR	EE	Total
EMAAC	AECO	44.7	17.5	62.2	40.9	17.5	58.4
EMAAC/DPL-S	DPL	117.3	32.7	150.0	117.3	32.7	150.0
EMAAC	JCPL	104.8	52.7	157.5	100.7	52.7	153.4
EMAAC	PECO	296.4	137.8	434.2	292.6	137.8	430.4
PSEG/PS-N	PSEG	237.3	167.2	404.5	228.9	167.2	396.1
EMAAC	RECO	2.3	2.2	4.5	2.3	2.2	4.5
EMAAC Sub Total		802.8	410.1	1,212.9	782.7	410.1	1,192.8
PEPCO	PEPCO	132.5	80.0	212.5	132.5	80.0	212.5
BGE	BGE	163.0	71.8	234.8	163.0	71.8	234.8
MAAC	METED	136.0	21.8	157.8	136.0	21.8	157.8
MAAC	PENELEC	208.2	17.7	225.9	208.2	17.7	225.9
PPL	PPL	422.5	45.7	468.2	422.5	45.7	468.2
MAAC** Sub Total		1,865.0	647.1	2,512.1	1,844.9	647.1	2,492.0
RTO	AEP	926.2	129.5	1,055.7	926.2	129.5	1,055.7
RTO	APS	478.9	60.8	539.7	478.9	60.8	539.7
ATSI/ATSI-C	ATSI	546.1	68.5	614.6	546.1	68.5	614.6
COMED	COMED	1,086.9	337.6	1,424.5	1,086.9	337.6	1,424.5
DAY	DAY	140.1	18.5	158.6	140.1	18.5	158.6
DEOK	DEOK	159.6	24.9	184.5	159.6	24.9	184.5
RTO	DOM	673.5	154.2	827.7	673.5	154.2	827.7
RTO	DUQ	86.9	18.7	105.6	86.9	18.7	105.6
RTO	EKPC	121.6	-	121.6	121.6	-	121.6
Grand Total		6,084.8	1,459.8	7,544.6	6,064.7	1,459.8	7,524.5

* MW values include both Annual and Summer-Period Capacity Performance DR and EE

** MAAC sub-total includes all MAAC Zones

Price Responsive Demand Participation

210.2 MW (UCAP) of PRD was elected and committed in the 2025/2026 BRA. PRD is provided by a PJM Member that represents retail customers having the ability to predictably reduce consumption in response to energy wholesale prices. In the PJM capacity market, a PRD Provider may voluntarily make a firm commitment of the quantity of PRD that will reduce its consumption in response to real time energy price during a Delivery Year. A PRD Provider that is committing PRD in a BRA must also submit a PRD election in the Capacity Exchange system that indicates the Nominal PRD Value in megawatts that the PRD Provider is willing to commit at different reservation prices (\$/MW-day). The VRR Curve of the RTO and each affected LDA is shifted leftward along the horizontal axis by the UCAP MW quantity of elected PRD where the leftward shift occurs only for the portion of the VRR Curve at or above the PRD Reservation price. The Planning Parameters includes a breakdown of elected PRD in ICAP, which can be converted to UCAP by taking ICAP * FPR. The breakdown of PRD UCAP that elected and committed is: 126.7 MW in the BGE LDA, 70.4 MW in the PEPCO LDA, and 13.1 MW in the rest of EMAAC LDA. The VRR Curve of the RTO and each affected LDA is shifted leftward along the horizontal axis by the UCAP MW value of these quantities at the PRD Reservation Price. Once committed in a BRA, a PRD commitment cannot be replaced; the commitment can only be satisfied through the registration of price response load in the DR Hub system prior to or during the delivery year.

Table 10. PRD UCAP Committed

PRD UCAP Committed (MW)			
Zone/LDA Location			
BGE	PEPCO	EMAAC	Total
126.7	70.4	13.1	210.2

Exhibit 33



2026/2027 Base Residual Auction Report

July 22, 2025

For Public Use

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Introduction

This document provides information for PJM stakeholders regarding the results of the 2026/2027 Reliability Pricing Model (RPM) Base Residual Auction (BRA).

In each BRA, PJM seeks to procure a target capacity reserve level for the RTO in a least-cost manner while recognizing the following reliability-based constraints on the location and type of capacity that can be committed:

- Internal PJM locational constraints are established by setting up Locational Deliverability Areas (LDAs) with each LDA having a separate target capacity reserve level and a maximum limit on the amount of capacity that it can import from resources located outside of the LDA.
- Across the RTO, seasonal sell offers must account for annual CP commitments by matching summer-period and winter-period sell offers.

The clearing solution may be required to commit capacity resources out-of-merit order but again in a least-cost manner to ensure that all of these constraints are respected. In those cases where one or more of the constraints results in out-of-merit commitment in the auction solution, resource clearing prices will be reflective of the price of resources selected out-of-merit order to meet the necessary requirements.

An LDA was modeled in the BRA and had a separate VRR Curve if (1) the LDA has a CETO/CETL margin that is less than 115%; or (2) the LDA had a locational price adder in any of the three immediately preceding BRAs; or (3) the LDA is EMAAC, SWMAAC and MAAC. An LDA not otherwise qualifying under the above three tests may also be modeled if PJM finds that the LDA is determined to be likely to have a Locational Price Adder based on historic offer price levels or if such LDA is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards.

As a result of the above criteria, MAAC, EMAAC, SWMAAC, PSEG, PS-NORTH, DPL-SOUTH, PEPCO, ATSI, ATSI-Cleveland, COMED, BGE, PL, DAY, DOM, DEOK and JCPL were modeled as LDAs in the 2026/2027 RPM Base Residual Auction. A Locational Price Adder represents the difference in Resource Clearing Prices for the Capacity Performance product between a resource in a constrained LDA and the immediate higher level LDA.

Locational Deliverability Area Definition

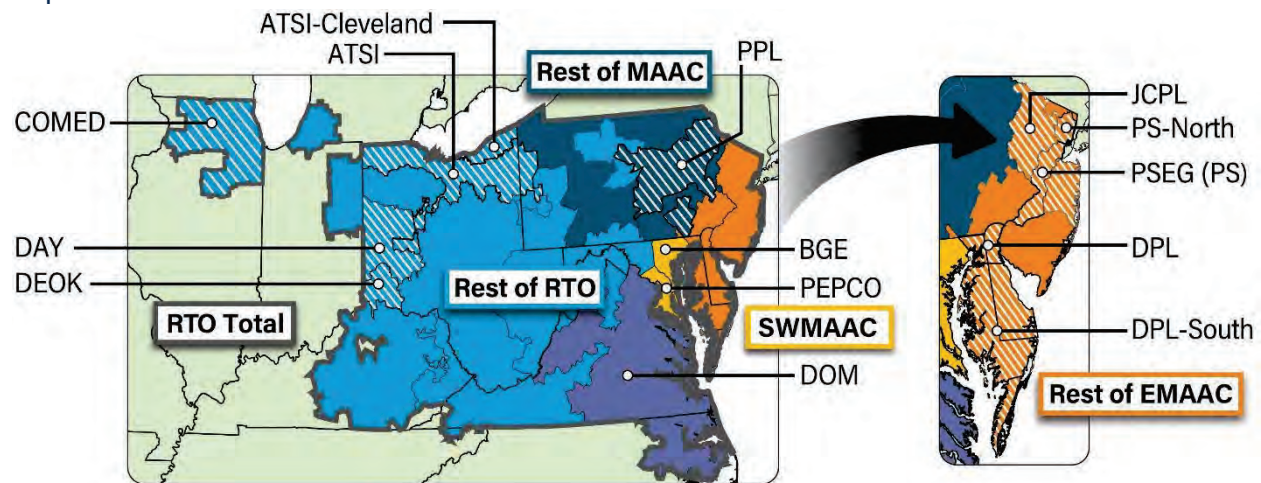
Locational Deliverability Areas (LDAs) defined as “(rest of)” do not include figures from modeled child LDAs contained within the parent LDA. For example, the PS (rest of) LDA does not include PS-NORTH within its totals.

- EMAAC total includes DPL-SOUTH, PS-NORTH, PS (rest of), JCPL, EMAAC (rest of).
- SWMAAC total includes PEPCO, BGE, SWMAAC (rest of).
- MAAC total includes EMAAC total, SWMAAC total, PPL, MAAC (rest of).

RTO total includes MAAC total, ATSI (rest of), ATSI-Cleveland, COMED, DAY, DEOK, DOM, RTO (rest of).

See Map 1.

Map 1. PJM LDAs



Executive Summary

The 2026/2027 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 134,310.8 MW of Unforced Capacity (UCAP) in the RTO from annual, Summer-Period and Winter-Period matched resources and Price Responsive Demand (“PRD”). Fixed Resource Requirement (“FRR”) committed 11,933 MW UCAP which resulted in total procured capacity in the RTO of 146,243.8 MW UCAP or 139 MW UCAP above the RTO Reliability Requirement.

Supply offered into the RPM capacity market declined 500.5 MW (UCAP) from 135,692.3 MW in the 2025/2026 BRA to 135,191.8 MW in the 2026/2027 BRA. The total amount of new generation and generation uprates was 2,669 MW UCAP. This represents an increase, which reversed a three-BRA downward trend in the amount of new generation and generation uprates. The number of constrained LDAs dropped from two to zero in the 2026/2027 BRA since the total amount cleared was less than the RTO Reliability Requirement. The total amount of capacity in RPM that cleared decreased by 296.1 MW from 134,672.2 MW in the 2025/2026 BRA to 134,376.1 MW in the 2026/2027 BRA.

The RTO as a whole failed the Market Structure Test (i.e., the Three-Pivotal Supplier Test), resulting in the application of market power mitigation to all Existing Generation Capacity Resources. Mitigation was applied to a supplier’s existing generation resources, resulting in utilizing the lesser of the supplier’s approved Market Seller Offer Cap for such resource or the supplier’s submitted offer price for such resource in the RPM Auction clearing.

Table 1 summarizes the prices (\$/MW-day UCAP) from last BRA and this BRA. For the 2026/2027 BRA, all prices cleared at the cap (\$329.17). BGE and DOM LDA prices decreased from \$466.35 and \$444.26, respectively, to \$329.17. The rest of RTO prices increased from \$269.92 to \$329.17.

The product of the total cleared supply and the associated clearing price in the 2026/2027 BRA was \$16.1 billion, which increased 9.5% from the \$14.7 billion value in the 2025/2026 BRA. Note that this value does not equate to a total cost to load because load that is hedged via self-supply and bilateral transactions is not exposed to the clearing prices in the auction.

Table 1. Comparison of BRA Clearing Prices by Delivery Year by LDA

Capacity Type	BRA	BRA Resource Clearing Prices (\$/MW-day)*		
		Rest of RTO	BGE	DOM
Capacity	2026/27**	\$329.17	\$329.17	\$329.17
Performance	2025/26	\$269.92	\$466.35	\$444.26

*Clearing prices in bold indicate constrained LDA; **Cap of \$329.17 \$/UCAP-MW

The following is a list of significant planning parameter and market rules changes that impacted the auction results:

- Key planning parameters changes (please see the [Planning Parameters Report](#) for additional details), which include:
 - RTO Reliability Requirement increase from 144,450 to 146,105 MW (UCAP)
 - 5,446.1 MW increase in forecasted load

- IRM increase from 17.8% to 19.1%
- FPR decrease from .9387 to .917
- First year for new Quadrennial Review, which resulted in changes to the VRR Curve points
- JCPL zone modeled as an LDA
- Implemented a cap of \$256.75 \$/MW-ICAP (\$329.17 \$/MW-UCAP) and a floor of \$138.25 \$/MW-ICAP (\$177.24 \$/MW-UCAP) to the VRR Curve.¹ This will be in effect for the 2026/2027 and 2027/2028 BRAs. All offers below the floor were cleared, and all offers above the cap were not cleared.
- Expanded the capacity must-offer requirement to all Generation Capacity Resources (solar, wind, batteries, etc.)
- PJM submitted \$0 offers for specific Reliability Must-Run units and will allocate the revenue as a credit to the associated load.
- MSOC changes, which allowed a CPQR-only price and segmented prices
- The Energy Efficiency product was sunset and not eligible to participate in this auction.

Note: This BRA was conducted under a compressed auction schedule where the auction occurred ~10 months prior to the start of the delivery year. A typical BRA is held more than three years before the start of the delivery year. The prior BRA was conducted under the same compressed auction schedule.

Detailed Report

Table 2 contains a summary of the RTO clearing prices, cleared Unforced Capacity (UCAP) and estimated procured installed reserve margins for the 2016/2017 through 2026/2027 RPM BRAs. The estimated reserve margin presented in Table 2 represents the percentage of installed capacity (ICAP) cleared in RPM and committed by FRR entities in excess of the RTO load (including load served under the FRR alternative). The estimated reserve margin used a pool wide accredited UCAP factor to convert from cleared UCAP to estimate cleared ICAP which may result in a difference from the actual reserve margin. The reserve margin procured for the entire RTO, which includes FRR and RPM load, is 18.9%, or 0.2 percentage points lower (or 309 MW ICAP lower) than the target reserve margin of 19.1% included in the Reliability Requirement to meet one loss-of-load day in 10 years criteria (or 0.1 loss of load days per year).

¹ Approximate cap/floor price of \$325/\$175 \$/MW-UCAP filed in ER25-1357 was based on preliminary Reference Resource AUCAP Factor. Actual Reference Resource AUCAP Factor resulted in stated \$/MW-UCAP values.

Table 2. RPM Base Residual Auction Resource Clearing Price Results in the RTO

Delivery Year	Auction Results				
	Resource Clearing Price	Cleared UCAP (MW)	RPM Reserve Margin ¹	Total Reserve Margin ^{1,2,7}	Cleared MW Times Clearing Price (\$ billion)
2016/17 ³	\$59.37	169,159.7	20.7%	20.3%	\$5.5
2017/18	\$120.00	167,003.7	20.1%	19.7%	\$7.5
2018/19	\$164.77	166,836.9	20.2%	19.8%	\$10.9
2019/20	\$100.00	167,305.9	22.9%	22.4%	\$7.0
2020/21 ⁴	\$76.53	165,109.2	23.9%	23.3%	\$7.0
2021/22	\$140.00	163,627.3	22.0%	21.5%	\$9.3
2022/23	\$50.00	144,477.3	21.1%	19.9%	\$3.9
2023/24	\$34.13	144,870.6	21.6%	20.3%	\$2.2
2024/25	\$28.92	147,478.9	21.7%	20.4%	\$2.2
2025/26 ⁵	\$269.92	135,684.0	18.6%	18.5%	\$14.7
2026/27 ⁶	\$329.17	134,205.3	18.9%	18.9%	\$16.1

¹ Reserve Margins converted to ICAP using Pool-Wide AUCAP Factor; ² Total Reserve Margin includes FRR+RPM (Total ICAP/Total Peak-1); ³ 2016/2017 BRA includes EKPC zone;

⁴ Beginning 2020/2021 Cleared UCAP (MW) includes Annual and matched Seasonal Capacity Performance sell offers; ⁵ DOM zone included in RPM; ⁶ EE removed from Market; ⁷ Total Reserve margin does not include FRR commitments to meet the threshold to allow sales into RPM.

Figure 1 represents the trend in BRA capacity price by delivery year for RTO, EMAAC, SWMAAC and MAAC. For 2026/2027, all four LDAs cleared at \$329.17. This clearing price was an increase from \$269.92 in RTO, MAAC, SWMAAC and EMAAC in the 2025/2026 BRA. The number of constrained LDAs decreased from two LDAs (BGE and DOM) to zero LDAs.

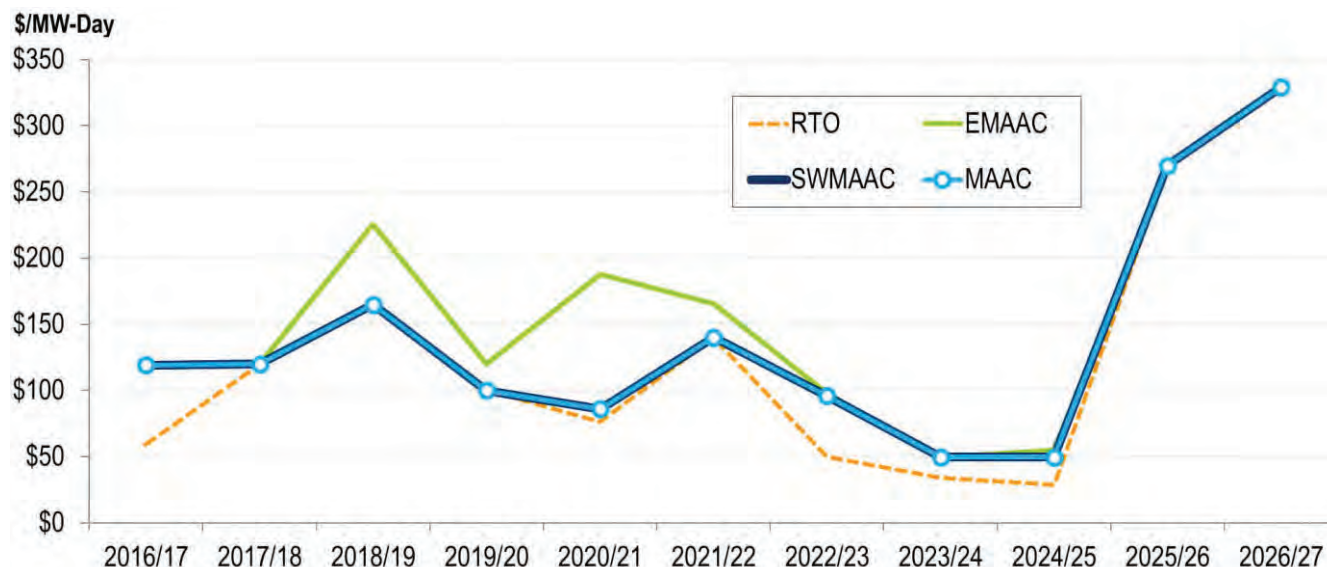
Figure 1. BRA Clearing Prices by Delivery Year for Major LDAs


Table 3 provides the total offered and cleared megawatts and associated prices by LDA. This table provides an indication of how much supply did not clear for each LDA.

Since there were no constrained LDAs in the 2026/2027 BRA, Capacity Transfer Rights (CTRs) have no value for the 2026/2027 Delivery Year. CTRs are allocated by load ratio share to all Load Serving Entities (LSEs) in a constrained LDA that has a higher clearing price than the unconstrained region. CTRs serve as a credit back to the LSEs in the constrained LDA for use of the transmission system to import less expensive capacity into that constrained LDA and are valued at the difference in the clearing prices of the constrained and unconstrained regions.

For 2026/2027, only 17.2 MW UCAP of annual generation did not clear. These megawatts did not clear because the offer was subject to a MOPR price that was above the cap. Any remaining amount that did not clear was winter-only where there were no matching summer-only resources that did not clear.

Table 3. Offered and Cleared MW and Associated Prices by LDA

LDA	MW (UCAP)		System Marginal Price	Locational Price Adder***	RCP for Capacity Performance Resources
	Offered MW*	Cleared MW**			
ATSI	7,433.9	7,433.9	\$329.17	\$0.00	\$329.17
ATSI-CLEVELAND	1,609.7	1,609.7	\$329.17	\$0.00	\$329.17
COMED	20,698.2	20,271.9	\$329.17	\$0.00	\$329.17
DAY	933.1	933.1	\$329.17	\$0.00	\$329.17
DEOK	1,560.1	1,560.1	\$329.17	\$0.00	\$329.17
DOM	20,079.9	19,975.8	\$329.17	\$0.00	\$329.17
MAAC	51,765.7	51,551.8	\$329.17	\$0.00	\$329.17
PPL	8,424.6	8,377.4	\$329.17	\$0.00	\$329.17
EMAAC	23,951.8	23,939.8	\$329.17	\$0.00	\$329.17
DPL-SOUTH	998.0	998.0	\$329.17	\$0.00	\$329.17
PSEG	4,086.9	4,086.7	\$329.17	\$0.00	\$329.17
PS-NORTH	2,361.6	2,361.5	\$329.17	\$0.00	\$329.17
JCPL	2,542.9	2,542.9	\$329.17	\$0.00	\$329.17
SWMAAC	6,531.8	6,446.0	\$329.17	\$0.00	\$329.17
BGE	2,202.0	2,201.8	\$329.17	\$0.00	\$329.17
PEPCO	2,212.6	2,127.0	\$329.17	\$0.00	\$329.17
RTO	135,191.8	134,205.3	\$329.17	\$0.00	\$329.17

* Offered MW values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers.

** Cleared MW values include Annual and matched Seasonal Capacity Performance sell offers within the LDA.

*** Locational Price Adder is with respect to the immediate parent LDA.

As seen in Figure 2, the 2026/2027 BRA procured 1,474.6 MW UCAP of capacity from new generation and 1,194 MW UCAP from uprates to existing or planned generation. The quantity of capacity procured from external Generation Capacity Resources in the 2026/2027 BRA remained comparable as that in the 2025/2026 BRA at 1,281.7 MW. The total quantity of new, uprated, reactivated and imported generation increased from 2,132.6 MW in 2025/2026 to 4,268.6 MW in 2026/2027. Certain external generation capacity that cleared in the 2026/2027 BRA are Prior Capacity Import Limit (CIL) Exception External Resources² that qualify for an exception for the 2026/2027 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138.

Figure 2. Cleared Megawatts (UCAP) by New Generation/Uprates/Imports by Delivery Year

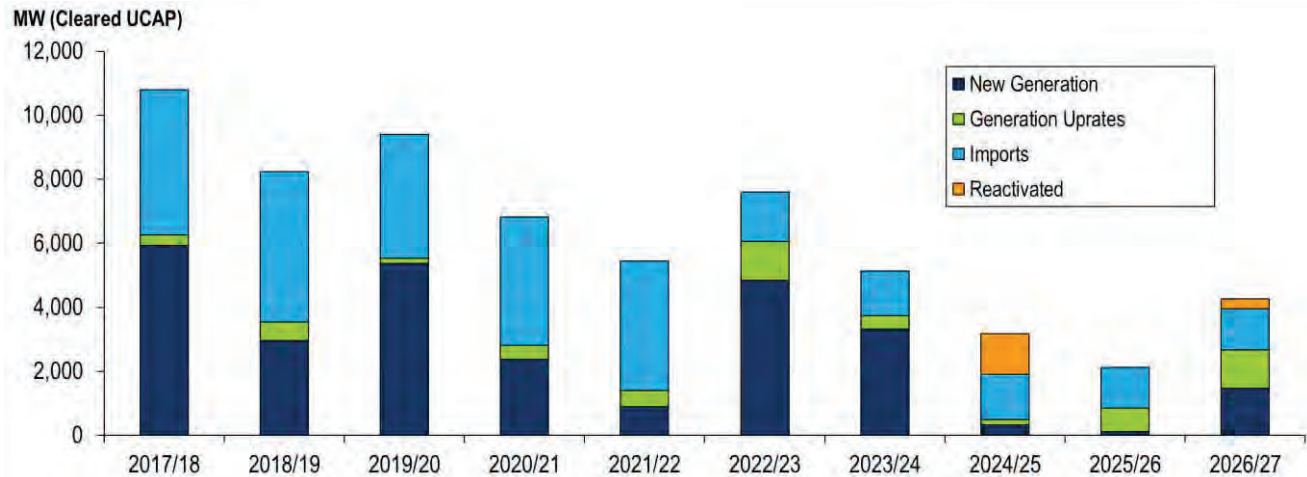


Table 4 contains a summary of the RTO resources for each cleared BRA from 2016/2017 through the 2026/2027 Delivery Years in terms of ICAP. The summary includes all resources located in the RTO (including FRR Capacity Plans).

A total of 196,649.5 MW of ICAP was eligible to be offered into the 2026/2027 Base Residual Auction or used in an FRR Capacity Plan. The total amount of supply in PJM increased from 195,853.1 MW ICAP to 196,649.5 MW ICAP, or an increase in the total amount of supply by 796.4 MW ICAP.

A total of 178,401.3 MW (ICAP) of Generation Capacity Resources and Demand Response Resources were offered into the Base Residual Auction. This is an increase of 7,077 MW offered when compared to the 2025/2026 BRA. This increase was driven by the new expanded capacity must-offer requirement for all Generation Capacity Resources. The total Demand Response (DR) offered into the auction remained almost constant from 8,009.7 MW ICAP to 8,020.1 MW ICAP.

A total of 18,248.2 MW (ICAP) was eligible but not offered, because those resources (1) were included in an FRR Capacity Plan; (2) received a must-offer exception; (3) were approved for a removal of capacity status; (4) are planned resources, which were not required to offer into the auction, did not submit a Notice of Intent (NOI), and therefore were not eligible to offer in the auction; (5) are resources with a must-offer requirement that did not offer

² A Prior CIL Exception Resource is an external Generation Capacity Resource for which (1) a Capacity Market Seller had, prior to May 9, 2017, cleared a Sell Offer in an RPM Auction under the exception provided to the definition of CIL as set forth in Article 1 of the Reliability Assurance Agreement or (2) an FRR Entity committed, prior to May 9, 2017, in an FRR Capacity Plan under the exception provided to the definition of CIL.

into the auction (“unoffered”) and did not receive a must offer exception; or (6) are planned generation resources that submitted an NOI but did not offer in the auction.

Resources received a must-offer exception for the following reasons: approved retirement requests, external sale of capacity and significant physical operational restrictions. Resources with approved removal of capacity status requests also did not have a capacity must offer requirement.

591 MW ICAP (328 MW UCAP) were not offered but were required to offer and are included in the 18,248.2 MW ICAP described above. This was primarily from units with a must-offer requirement that did not offer and from planned generation resources that submitted an NOI but then did not offer. Based on discussions with sellers, the units with a must-offer requirement that did not offer indicated they did not offer because they: (1) had an external contract to export capacity to load outside PJM, (2) did not realize they needed to go through the must-offer exception process, (3) were not aware of the removal of capacity status process, or (4) were concerned about PAI risk. A small amount was associated with resources that were: (a) subject to both MOPR and MSOC where the MOPR price was greater than the MSOC price and the resource did not request and receive a unit-specific price or (b) subject to MOPR but did not have a default MOPR price and did not request a unit-specific MOPR price.

All megawatts that are considered “unoffered” may not be used as capacity for the delivery year. This means they may not be used to participate in an incremental auction or bilateral transaction or be included in an FRR plan. All reasons stated above will result in “unoffered” megawatts except for the planned generation. Any Seller with unoffered megawatts or that submitted an NOI and then did not offer is subject to further review by PJM and the IMM. Such review may result in a referral to FERC Office of Investigation for a comprehensive investigation to ensure Seller did not withhold in order to exercise market power.


Table 4. Total RTO Resources (RPM + FRR) Offered vs. Unoffered by Resource Type Used To Meet the Reliability Requirement

Auction Supply	Delivery Year (All values in ICAP)										
	2016/17*	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26**	2026/27
Internal PJM Gen Capacity	193,052.5	190,333.2	191,322.3	195,203.0	197,804.7	198,726.6	193,412.2	189,704.7	191,133.4	186,134.2	187,022.1
Internal PJM DR+PRD Capacity	13,932.9	10,855.2	10,772.8	10,859.2	8,245.5	10,694.8	9,501.2	9,517.2	9,626.1	8,233.7	8,135.1
Imports Offered	8,412.2	6,300.9	5,724.6	4,821.4	5,440.5	4,725.0	1,649.1	1,601.2	1,617.1	1,485.2	1,492.3
Eligible RPM Capacity	215,397.6	207,489.3	207,819.7	210,883.6	211,490.7	214,146.4	204,562.5	200,823.1	202,376.6	195,853.1	196,649.5
Exports/Delistings	1,218.8	1,223.2	1,313.4	1,318.2	1,319.8	1,319.8	1,525.3	1,518.9	1,522.7	1,525.3	1,426.3
FRR Commitments	15,576.6	15,776.1	15,793.0	15,385.3	13,931.6	13,657.4	33,297.1	33,500.7	34,584.2	13,184.5	14,454.8
Excused/Unoffered	8,524.0	4,305.3	2,348.4	1,454.5	8,384.4	9,433.8	2,190.0	9,949.6	12,207.4	9,819.0	2,367.1
Total Eligible RPM Capacity: Excused	25,319.4	21,304.6	21,304.6	19,454.8	18,158.0	24,411.0	37,012.4	44,969.2	48,314.3	24,528.8	18,248.2
Remaining Eligible RPM Capacity	190,078.2	186,184.7	186,515.1	191,428.8	193,332.7	189,735.4	167,550.1	155,853.9	154,062.3	171,324.3	178,401.3
Generation Offered	176,145.3	175,329.5	177,592.1	181,866.4	178,807.1	178,823.5	157,872.2	146,571.7	144,741.2	163,314.6	170,381.2
DR Offered	13,932.9	10,855.2	10,772.8	10,859.2	9,047.8	10,911.9	9,677.9	9,282.2	9,321.1	8,009.7	8,020.1
Total Eligible RPM Capacity: Offered	190,078.2	186,184.7	188,364.9	192,725.6	187,854.9	189,735.4	167,550.1	155,853.9	154,062.3	171,324.3	178,401.3

Note: *Includes EKPC zone; **includes DOM zone load previously under the FRR Alternative.

Internal PJM Gen Capacity includes ICAP MW effective as of June 1 of the DY.



Table 5 shows the Generation, DR and EE Resources offered and cleared in the RTO translated into UCAP megawatt amounts. Until the 2025/2026 Delivery Year, participants' sell offers for thermal resource EFORD values were used to convert a resource's ICAP values into UCAP values. Effective for 2025/2026, the appropriate Accredited UCAP Factor is used to convert ICAP values into UCAP values. Prior to the 2025/2026 Delivery Year, DR sell offers and EE sell offers were converted into UCAP using the appropriate Forecast Pool Requirement (FPR). Beginning in 2025/2026, DR sell offers are converted into UCAP using the appropriate DR Accredited UCAP Factor, while EE sell offers continued to be calculated by multiplying the EE nominated value by the Forecast Pool Requirement. Beginning in 2026/2027, EE resources are not eligible to participate as a capacity resource in PJM.

Total offered Generation and DR (UCAP) used to meet the Reliability Requirement declined from 135,692.3 MW to 135,191.8 MW. Please note that UCAP for delivery years prior to 2025/2026 were not calculated using the marginal ELCC methodology, and changes going forward from 2025/2026 are in part responsible for the subsequent decreases in offered and cleared UCAP.

Table 5: Capacity Resource Offered and Cleared by Type by Delivery Year (UCAP)

Auction Results (UCAP)	Delivery Year										
	2016/17	2017/18	2018/19	2019/20	2020/21*	2021/22	2022/23	2023/24	2024/25	2025/26**	2026/27***
Generation	168,716.0	166,204.8	166,909.6	172,071.2	171,262.3	171,663.2	152,128.6	141,026.7	138,799.3	129,607.5	129,661.2
DR	14,507.2	11,293.7	11,675.5	11,818.0	9,846.7	11,886.8	10,513.0	10,116.7	10,146.4	6,084.8	5,530.6
Total GEN/DR Offered	183,223.2	177,498.5	178,585.1	183,889.2	181,109.0	183,550.0	162,641.6	151,143.4	148,945.7	135,692.3	135,191.8
EE	1,156.8	1,340.0	1,306.1	1,650.3	2,242.5	2,954.8	5,056.8	5,471.1	8,417.0	1,459.8	0.0
Generation	155,634.3	154,690.0	154,506.0	155,442.8	155,976.5	150,385.0	131,541.6	131,777.4	132,423.1	128,607.5	128,845.5
DR	12,408.1	10,974.8	11,084.4	10,348.0	7,820.4	11,125.8	8,811.9	8,096.2	7,992.7	6,064.7	5,530.6
Total GEN/DR Cleared	168,042.4	165,664.8	165,590.4	165,790.8	163,796.9	161,510.8	140,353.5	139,873.6	140,415.8	134,672.2	134,376.1
EE	1,117.3	1,338.9	1,246.5	1,515.1	1,710.2	2,832.0	4,810.6	5,471.1	7,668.7	1,459.8	0.0
Uncleared GEN/DR	15,180.8	11,833.7	12,994.7	18,098.4	17,312.1	22,039.2	22,288.1	11,269.8	8,529.9	1,020.1	815.7

Note: RTO numbers include all LDAs. UCAP calculated using ELCC values for Generation Resources. DR and EE UCAP values include appropriate DR AUCAP Factor and FPR.

*Starting 2020/2021: Generation, DR and EE offered and cleared values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers. **Marginal ELCC accreditation implemented for all Generation Capacity Resources and Demand Resources. ***EE Eliminated.

The 2025/2026 and 2026/2027 numbers in Table 6 and Table 7 were significantly impacted by the marginal ELCC accreditation changes (see [ELCC class rating](#)), so it is difficult to simply compare delivery year over delivery year results for 2024/2025 and earlier to 2025/2026 and future delivery years. Table 6 shows the offered and cleared megawatts by resource type for RPM plus FRR commitments over the last four delivery years. Intermittent and Capacity Storage Resources (solar, wind, water, battery/hybrid) increased by 2,388 MW UCAP primarily because of the expanded must-offer requirement and additional resources in the market. Coal offered increased by 867 MW UCAP mostly from the inclusion of RMR resources in the auction. Oil offered increased by 578 MW UCAP because of reactivations and postponed retirements. Natural gas declined by 2,977 MW UCAP primarily from retirements and a decline in accredited UCAP factors. Demand Response declined by 568 MW UCAP primarily due to a decline in the accredited UCAP factor. Since Energy Efficiency is already included in the load forecast where applicable, it was not used to meet the Reliability Requirement and therefore separated from the grand totals in the tables to provide a more accurate picture of the resources that were used to meet the Reliability Requirement.

Table 6. Offered and Cleared MWs by Type for RPM and Committed FRR for Previous BRAs

Type	Offered and Cleared UCAP									
	2023/24		2024/25		2025/26 (Reflects ELCC Accreditation)		2026/27 (Reflects ELCC Accreditation)		2026/27 - 2025/26 Change	
	Offered	Cleared	Offered	Cleared	Offered	Cleared	Offered	Cleared	Offered	Cleared
Coal	37,164	31,811	35,114	31,532	30,081	30,081	30,948	30,948	867	867
Distillate Oil (No.2)	2,894	2,855	2,776	2,674	2,408	2,408	2,608	2,608	201	201
Gas	85,217	81,643	85,469	83,258	66,354	66,354	63,377	63,377	(2,977)	(2,977)
Nuclear	31,960	31,960	31,835	31,629	30,549	30,549	30,562	30,562	13	13
Oil	2,350	2,269	2,493	2,220	578	578	1,155	1,155	578	578
Solar	2,945	2,935	4,234	4,232	1,337	1,337	1,584	1,567	247	230
Water	6,375	6,375	6,137	6,137	5,365	5,361	5,597	5,597	233	236
Wind	1,608	1,416	1,396	1,396	2,618	1,676	4,507	3,717	1,888	2,041
Battery/Hybrid	16	16	36	36	14	14	35	35	20	20
Other	1,185	1,185	1,153	1,153	911	911	899	899	(11)	(11)
Demand Response	10,652	8,631	10,334	8,180	6,363	6,342	5,795	5,795	(568)	(547)
Aggregate Resource	511	511	503	503	327	273	58	49	(269)	(224)
Total (without EE)	182,875	171,605	181,481	172,951	146,905	145,883	147,125	146,309	220	426
Energy Efficiency	5,471	5,471	8,417	7,669	1,460	1,460	-	-	NA	NA

The table shows the UCAP MW quantities that offered and cleared in the BRA of each DY plus the UCAP MW committed to FRR Capacity Plans. Notes: Offered and Cleared MW quantities include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers. Other consists of: Kerosene, Other Gas, Other Liquid, Other Solid, Wood.

Capacity Import Participation

Table 7 shows the quantity of capacity imports cleared in the 2026/2027 BRA at 1,281.7 MW (UCAP). The majority of the imports are from resources located in regions north and west of the PJM RTO. Certain external generation capacity that has cleared are Prior CIL Exception External Resources that qualify for an exception for the 2026/2027 Delivery Year to satisfy the enhanced pseudo-tie requirements established by FERC Order ER17-1138.

Table 7. Capacity Imports (UCAP) Offered and Cleared by Region

	External Source Zones					Total
	NORTH	WEST 1	WEST 2	SOUTH 1	SOUTH 2	
Offered MW (UCAP)*	250.8	0.0	568.0	226.2	236.7	1,281.7
Cleared MW (UCAP)*	250.8	0.0	568.0	226.2	236.7	1,281.7
Resource Clearing Price (\$/MW-day)	\$329.17	\$329.17	\$329.17	\$329.17	\$329.17	

*Offered and cleared MW quantities include resources that received CIL Exception and those associated with pre-OATT grandfathered transmission. Attachment G of Manual 14B provides a mapping of outside Balancing Authorities to the External Source Zones.

Resource Type by Season Participation

Table 8 provides a breakdown of the offered and cleared megawatts by season by resource type. There were 170.8 MW of Summer Capability and 969.3 MW of Winter Capability offered in the auction. All 170.8 MW of Summer Resources were matched with Winter Resources to meet the annual Capacity Performance capability requirement.

Table 8. Offered and Cleared (UCAP) by Resource Type by Season

Resource Type	Capacity Performance					
	Offered MW (UCAP)			Cleared MW (UCAP)		
	Annual	Summer	Winter	Annual	Summer	Winter
GEN	128,691.9	-	969.3	128,674.7	-	170.8
DR	5,359.8	170.8	-	5,359.8	170.8	-
PRD	105.5	-	-	105.5	-	-
Grand Total	134,157.2	170.8	969.3	134,140.0	170.8	170.8

Figure 3 displays the trend in offered and cleared DR and Price Responsive Demand (PRD) and cleared EE by delivery year. DR offered and cleared amounts declined significantly for 2026/2027, while EE resources no longer participate in RPM Auctions. The amount of PRD remains small and declined by approximately 50% in the 2026/2027 Delivery Year.

Figure 3. DR and PRD Offered and Cleared and EE Cleared MW(UCAP) by Delivery Year

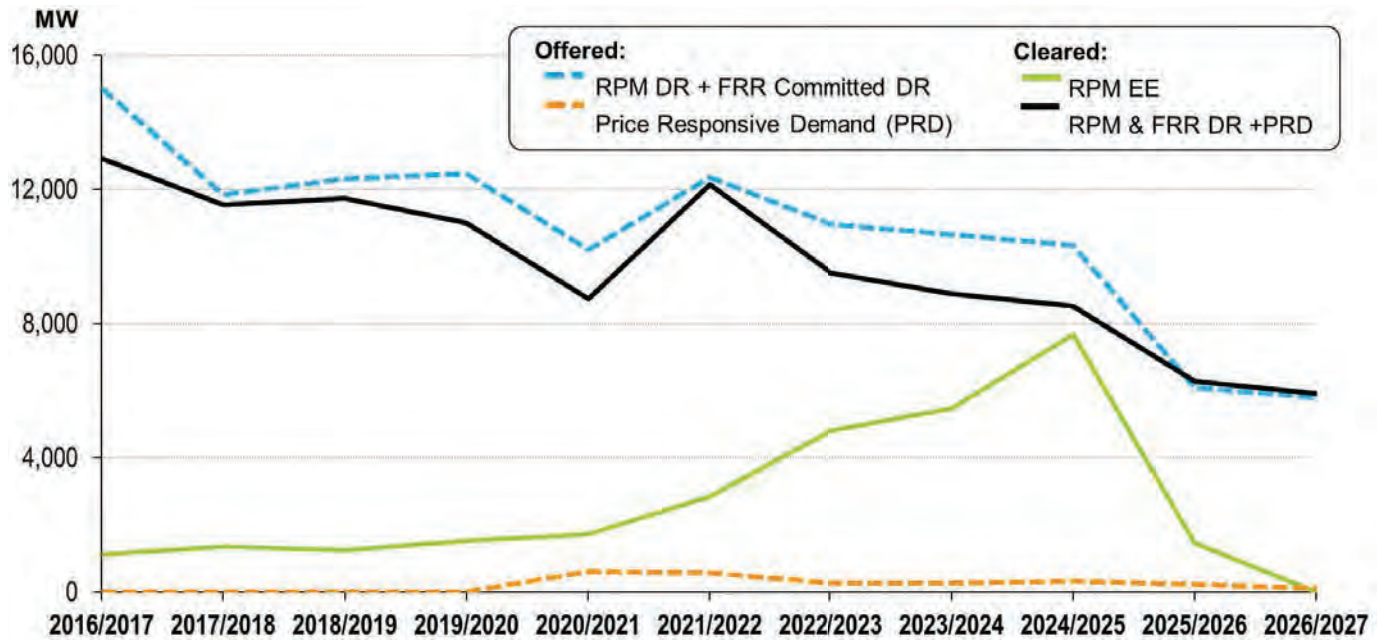


Table 9 provides a breakdown of offered and cleared DR by LDA. COMED cleared the most DR (969.9 MW), followed by AEP (941.1MW) and then DOM (555.1 MW).

Table 9. DR Offered and Cleared by LDA

LDA	Zone	Offered MW (UCAP)*	Cleared MW (UCAP)*	% Cleared
EMAAC	AECO	34.3	34.3	100.0%
EMAAC/DPL-S	DPL	114.3	114.3	100.0%
JCPL	JCPL	59.2	59.2	100.0%
EMAAC	PECO	226.0	226.0	100.0%
PSEG/PS-N	PSEG	179.1	179.1	100.0%
EMAAC	RECO	1.2	1.2	100.0%
EMAAC Sub Total		614.1	614.1	100.0%
PEPCO	PEPCO	189.8	189.8	100.0%
BGE	BGE	149.9	149.9	100.0%
MAAC	METED	122.5	122.5	100.0%
MAAC	PENELEC	157.7	157.7	100.0%
PPL	PPL	319.8	319.8	100.0%
MAAC** Sub Total		1,553.8	1,553.8	100.0%
RTO	AEP	941.1	941.1	100.0%
RTO	APS	502.3	502.3	100.0%
ATSI/ATSI-C	ATSI	510.0	510.0	100.0%
COMED	COMED	969.6	969.6	100.0%
DAY	DAY	149.8	149.8	100.0%
DEOK	DEOK	114.9	114.9	100.0%
DOM	DOM	555.1	555.1	100.0%
RTO	DUQ	78.1	78.1	100.0%
RTO	EKPC	155.9	155.9	100.0%
Grand Total		5,530.6	5,530.6	100.0%

* MW values include both Annual and Summer-Period Capacity Performance DR

** MAAC sub-total includes all MAAC Zones

Price Responsive Demand Participation

105.5 MW (UCAP) of PRD was elected and committed in the 2026/2027 BRA. PRD is provided by a PJM Member that represents retail customers having the ability to predictably reduce consumption in response to energy wholesale prices. In the PJM capacity market, a PRD Provider may voluntarily make a firm commitment of the quantity of PRD that will reduce its consumption in response to real-time energy price during a delivery year. A PRD Provider that is committing PRD in a BRA must also submit a PRD election in the Capacity Exchange system that indicates the Nominal PRD Value in megawatts that the PRD Provider is willing to commit at different reservation prices (\$/MW-day). The VRR Curve of the RTO and each affected LDA is shifted leftward along the horizontal axis by the UCAP megawatt quantity of elected PRD where the leftward shift occurs only for the portion of the VRR Curve at or above the PRD Reservation price. The planning parameters includes a breakdown of elected PRD in ICAP, which can be converted to UCAP by taking $ICAP * FPR$. The VRR Curve of the RTO and each affected LDA is shifted leftward along the horizontal axis by the UCAP megawatt value of these quantities at the PRD Reservation Price. Once committed in a BRA, a PRD commitment cannot be replaced; the commitment can only be satisfied through the registration of price response load in the DR Hub system prior to or during the delivery year.

Appendix

BRA Clearing Simulation without Cap and Floor

Table 1 contains a summary of the estimated RTO clearing prices,³ cleared UCAP and estimated procured reserve margins for the 2026/2027 RPM BRA without the cap and floor applied. Cleared UCAP and estimated reserve margins are identical to the results with the cap and floor applied, but the resource clearing price increased, resulting in the cleared megawatt times clearing price increase of \$2.9 billion.

Table 1. RPM Auction Resource Clearing Prices Results in the RTO With No Cap or Floor Simulation

	Auction Simulation – Estimated Impact of No Cap or Floor				
Delivery Year	Resource Clearing Price	Cleared UCAP (MW)	Estimated RPM Reserve Margin	Estimated Total Reserve Margin ¹	Cleared MW Times Clearing Price (\$ billion)
2026/27	\$388.57	134,205.3	18.9%	18.9%	\$19.0

Table 2 provides the total offered and cleared megawatts and associated prices by LDA when no cap or floor is applied. The cleared capacity is identical to the cap and floor case, but the system marginal price increased to \$388.57.

³ The PJM simulation included existing offers provided by Capacity Market Sellers. PJM does not know how offers may have changed if the temporary cap and floor was not implemented.

Table 2. Offered and Cleared MW and Associated Prices by LDA – No Cap or Floor Simulation

LDA	MW (UCAP)		System Marginal Price	Locational Price Adder***	RCP for Capacity Performance Resources
	Offered MW*	Cleared MW**			
ATSI	7,433.9	7,433.9	\$388.57	\$0.00	\$388.57
ATSI-CLEVELAND	1,609.7	1,609.7	\$388.57	\$0.00	\$388.57
COMED	20,698.2	20,271.9	\$388.57	\$0.00	\$388.57
DAY	933.1	933.1	\$388.57	\$0.00	\$388.57
DEOK	1,560.1	1,560.1	\$388.57	\$0.00	\$388.57
DOM	20,079.9	19,975.8	\$388.57	\$0.00	\$388.57
MAAC	51,765.7	51,624.6	\$388.57	\$0.00	\$388.57
PPL	8,424.6	8,377.4	\$388.57	\$0.00	\$388.57
EMAAC	23,951.8	23,939.8	\$388.57	\$0.00	\$388.57
DPL-SOUTH	998.0	998.0	\$388.57	\$0.00	\$388.57
PSEG	4,086.9	4,086.7	\$388.57	\$0.00	\$388.57
PS-NORTH	2,361.6	2,361.5	\$388.57	\$0.00	\$388.57
JCPL	2,542.9	2,542.9	\$388.57	\$0.00	\$388.57
SWMAAC	6,531.8	6,446.0	\$388.57	\$0.00	\$388.57
BGE	2,202.0	2,201.8	\$388.57	\$0.00	\$388.57
PEPCO	2,212.6	2,127.0	\$388.57	\$0.00	\$388.57
RTO	135,191.8	134,205.3	\$388.57	\$0.00	\$388.57

* Offered MW values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers.

** Cleared MW values include Annual and matched Seasonal Capacity Performance sell offers within the LDA.

*** Locational Price Adder is with respect to the immediate parent LDA

Exhibit 34



2026/2027 RPM Third Incremental Auction Results

March 9, 2026

For Public Use

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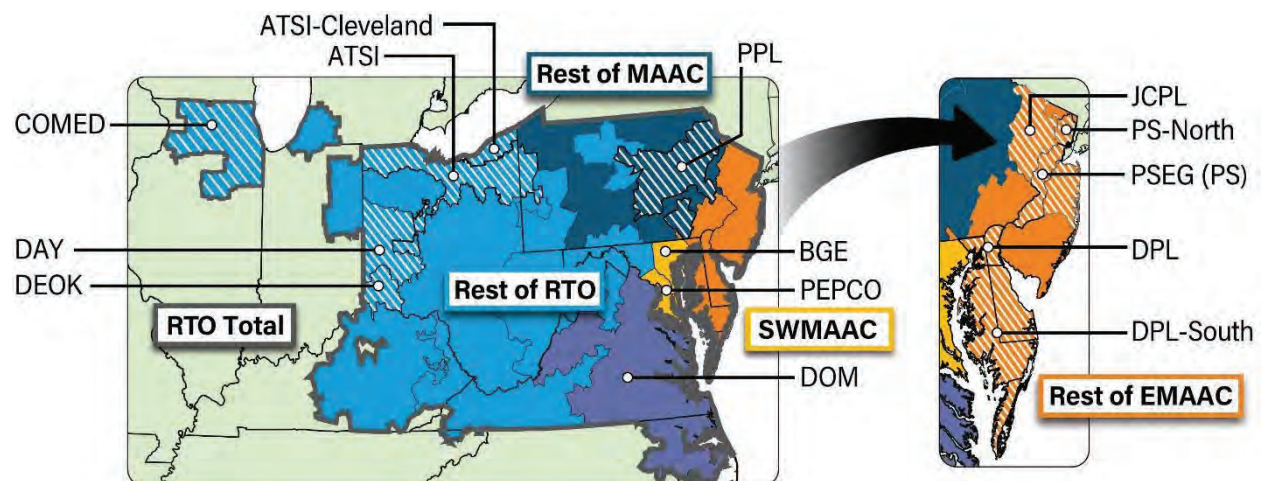
Introduction

The 2026/2027 Third Incremental Auction opened on February 24, 2026, and the results were posted on March 9, 2026. This document provides a summary of the 2026/2027 Third Incremental Auction results. Incremental Auctions provide a mechanism for capacity suppliers to sell and purchase capacity and a means for PJM to adjust previously committed capacity levels due to Reliability Requirement increases or decreases.

Locational Deliverability Area Definition

Locational Deliverability Areas (LDAs) defined as (rest of) do not include figures from modeled child LDAs contained within the parent LDA. For example, the PS (rest of) LDA does not include PS-NORTH within its totals.	• EMAAC total includes DPL-SOUTH, PS-NORTH, PS (rest of), JCPL, EMAAC (rest of). • SWMAAC total includes PEPCO, BGE, SWMAAC (rest of). • MAAC total includes EMAAC total, SWMAAC total, PPL, MAAC (rest of).	RTO total includes MAAC total, ATSI (rest of), ATSI-Cleveland, COMED, DAY, DEOK, RTO (rest of). See Map 1.
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Map 1. PJM LDAs



Summary of the 2026/2027 RPM Third Incremental Auction Results

Table 1 summarizes the clearing prices and cleared participant activity of the 2026/2027 Third Incremental Auction. The resource clearing price for Capacity Performance (CP) resources located in the entire PJM RTO region is \$164.70/MW-day. Please see Table 7 for a comparison of the Third Incremental Auction prices and the associated BRA prices.

Participant Sell Offers and Buy Bids are combined with the PJM Sell Offers and Buy Bids shown in Table 6 to form the supply and demand curves. The solution algorithm clears all Buy Bids and Sell Offers in a least-cost manner while respecting the capacity import limits into each LDA. Total cleared summer-period Sell Offers must exactly equal total cleared winter-period Sell Offers across the entire RTO to ensure that seasonal CP Sell Offers clear to form annual CP commitments.

Across the entire RTO, total cleared annual participant Sell Offers of 3,597.8 MW were more than the total cleared participant Buy Bids (3,312.4 MW) due to the purchase of 285.4 MW of Buy Bids by PJM. Across PJM, there was 1,528.8 MW of offered capacity, including seasonal offers, which was not cleared. PJM bought a total net capacity amount of 285.4 MW, comprised of 0 MW of cleared PJM Sell Offers and 285.4 MW of cleared PJM Buy Bids. The cleared PJM Buy Bids were the result of an increase in the reliability requirement of the applicable LDA(s) and the only buy bids that impacted the final cost to load.

Table 1. Summary of 2026/2027 Third Incremental Auction Results

Region	Clearing Price (\$/MW-Day)	Cleared Participant Sell Offers ¹ (UCAP MW)	Cleared Participant Buy Bids (UCAP MW)	Net Cleared PJM Buy Bids ² (UCAP MW)
RTO	\$164.70	3,597.8	3,312.4	285.4
RTO Total	--	3,597.8	3,312.4	285.4

¹ Cleared Participant Sell Offers include Annual and matched Seasonal Capacity Performance cleared sell offers

² A PJM Sell Offer is indicated by a negative PJM Buy Bid

Participant Sell Offers and Buy Bids

RPM Incremental Auctions provide capacity suppliers with an opportunity to sell or purchase capacity for the Delivery Year through a PJM-administered auction process. Resource-specific Sell Offers are submitted into this auction by suppliers with available, uncommitted capacity. All Sell Offers into an Incremental Auction from Existing Generation Capacity Resources are subject to market power mitigation through the application of the Market Structure Test.

Any party that desires to purchase replacement capacity for the Delivery Year may do so by submitting a Buy Bid into the Incremental Auction. Participants submitting a Buy Bid must specify a megawatt quantity, price and LDA-specific location. All Buy Bids in Incremental Auctions for Delivery Year 2023/2024 and forward are of the annual CP product type. Cleared Buy Bids purchased in an Incremental Auction may be used as replacement capacity to cover a Delivery Year commitment provided the cleared Buy Bid has the same locational characteristics as the resource that it replaces.

Table 2 shows the offered and cleared quantities for participant Sell Offers. A total of 5,172.0 MW of supply was offered into the Third Incremental Auction composed of uncleared capacity from prior 2026/2027 auctions and new capacity in the form of uprates, accreditation increases, and/or new resources that were not previously capacity resources in PJM.¹ Across the entire RTO, 3,643.2 MW of participant Sell Offers cleared, of which 3,552.4 MW were annual CP and 90.8 MW were matched seasonal CP (45.4 MW of summer resources matched with 45.4 MW of winter resources).

Table 2. Participant Sell Offers (Offered and Cleared Quantities)

LDA	Sell Offers (UCAP MW)*	Cleared Sell Offers (UCAP MW)*
DPL-SOUTH	33.7	31.9
PS-NORTH	75.0	75.0
PSEG (rest of)	72.1	62.4
JCPL	108.2	102.7
EMAAC (rest of)	276.4	147.1
EMAAC Total	565.4	419.1
PEPCO	134.9	117.7
BGE	72.9	59.1
SWMAAC (rest of)	31.0	31.0
SWMAAC Total	238.8	207.8
PPL	446.8	279.2
MAAC (rest of)	383.9	252.3
MAAC Total	1,634.9	1,158.4
AT SI (rest of)	296.4	266.2
AT SI-Cleveland	32.1	32.1
COMED	961.1	558.0
DAY	41.8	40.0
DEOK	101.9	85.6
DOM	771.4	645.1
RTO (rest of)	1,332.4	857.8
RTO Total	5,172.0	3,643.2

*Values include annual, summer and winter offered and cleared by LDA where the resource is modeled

There were 45.4 MW of seasonal capacity resources cleared in an aggregated manner to form a year-round commitment. 45.4 MW of summer CP resources comprising 45.4 MW of DR summer resources along with 45.4 MW of winter resources (from wind units). Total cleared summer-period and winter-period Sell Offers must exactly match across the entire RTO to ensure that seasonal CP Sell Offers clear to form annual CP commitments. Table 3 shows a breakdown of the seasonal resources offered and cleared in the 2026/2027 Third Incremental Auction.

¹ The total offered supply quantity was determined using the annual , summer and winter Capacity Sell Offers.

Table 3. Breakdown of Seasonal Capacity Performance Resources by Resource Type and Season That Offered and Cleared in the 2026/2027 Third Incremental Auction

Resource Type	Offered MW (UCAP)			Cleared MW (UCAP)		
	Annual	Summer	Winter	Annual	Summer	Winter
GEN	3,807.2	0.0	785.4	3,418.1	0.0	45.4
DR	534.0	45.4	0.0	134.3	45.4	0
Grand Total	4,341.2	45.4	785.4	3,552.4	45.4	45.4

Participant demand in an Incremental Auction is composed of Buy Bids submitted by participants seeking replacement capacity for a previously committed capacity resource. The Buy Bids are specified in UCAP terms and, if cleared, are binding commitments to purchase capacity for the entire Delivery Year. Across the RTO, participants submitted a total of 7,712.6 MW of Buy Bids, of which 3,312.4MW cleared. The Participant buy bids are further illustrated by location in Table 4.

Table 4. Participant Buy Bids (Bid and Cleared Quantities)

LDA	Buy Bids (UCAP MW)	Cleared Buy Bids (UCAP MW)
DPL-SOUTH	134.9	18.4
PS-NORTH	13.0	11.8
PSEG (rest of)	8.7	7.6
JCPL	766.4	71.5
EMAAC (rest of)	721.1	146.2
EMAAC Total	1,644.1	255.5
PEPCO	143.4	14.7
BGE	34.8	31.3
SWMAAC (rest of)	0.0	0.0
SWMAAC Total	178.2	46.0
PPL	99.5	93.1
MAAC (rest of)	1,936.2	1,025.8
MAAC Total	3,858.0	1,420.4
ATSI (rest of)	114.4	100.5
ATSI-Cleveland	26.6	23.8
COMED	1,977.4	448.9
DAY	37.3	33.5
DEOK	11.7	11.0
DOM	831.3	581.7
RTO (rest of)	855.9	692.6
RTO Total	7,712.6	3,312.4

PJM Sell Offers and Buy Bids

[Sections 5.4](#) and [5.12](#) of Attachment DD of the [Tariff](#) (PDF) define the Incremental Auction requirements regarding the procurement or sale of capacity by PJM. Section 5.4 describes the triggering tests used by PJM prior to an Incremental Auction to determine the need for the procurement and/or sale of capacity by PJM in relation to updates of the Reliability Requirement and capacity already procured. Section 5.12 describes the determination of the megawatt quantities and prices of Buy Bids and/or Sell Offers that PJM will submit when the various tests in Section 5.4 are triggered.

Prior to each Incremental Auction, PJM recalculates the Reliability Requirement based on an updated peak load forecast, updated Installed Reserve Margin and other updated planning information. For the RTO and each LDA, PJM sums the following component quantities to determine the total quantity that it will seek to procure or release in each Incremental Auction:

- The updated Reliability Requirement minus the Reliability Requirement utilized in the most recent prior auction conducted for that Delivery Year
 - Note that this quantity is negative if the updated Reliability Requirement is less than the Reliability Requirement utilized in the most recent prior auction. For a First or Second Incremental Auction, this difference is only considered if the change in Reliability Requirement is greater than the lesser of 500 MW or 1% of the prior auction's Reliability Requirement.
- Plus/minus the amount of committed capacity that PJM sought to procure/release that did not clear in previous Incremental Auctions for the same Delivery Year
- Minus any capacity PJM seeks to release in a parent LDA as a result of any Conditional Incremental Auction commitments for the same Delivery Year

If the result of such summation is a positive quantity, PJM will seek to procure such quantity by employing a PJM Buy Bid. The price of the PJM Buy Bid is based on the Updated VRR Curve Increment, which is the portion of the Updated VRR Curve located to the right of the point representing all capacity already procured for the Delivery Year. If the result of such summation is a negative quantity, PJM will seek to release such quantity by employing a PJM Sell Offer. The price of the PJM Sell Offer is based on the Updated VRR Curve Decrement, which is the portion of the Updated VRR Curve to the left of the point representing all capacity already procured for the Delivery Year.

PJM submitted the Buy Bids at the pricing points shown in Table 5 into the Third Incremental Auction for the 2026/2027 Delivery Year.² Note that a PJM Sell Offer is indicated by a negative PJM Buy Bid. PJM submitted a net Buy Bid for the Third Incremental Auction for the 2026/2027 Delivery Year totaling 285.4 MW across the RTO. All PJM Buy Bids were for the annual CP product type.

² The determination of the PJM Buy Bid and Sell Offer quantities is detailed in the [2026/2027 Third Incremental Auction Planning Parameters](#) (XLS).

Table 5. PJM Buy Bids and Sell Offers for the 2026/2027 Third Incremental Auction

Price Points for PJM Buy Bids and PJM Sell Offers									
LDA	PJM Buy Bid ¹ (MW)	Point 1		Point 2		Point 3		Point 4	
		x-axis (MW)	y-axis (\$/MW-Day)	x-axis (MW)	y-axis (\$/MW- Day)	x-axis (MW)	y-axis (\$/MW-Day)	x-axis (MW)	y-axis (\$/MW-Day)
RT O (Rest of)	0.0	--	--	--	--	--	--	--	--
MAAC (Rest of)	0.0	--	--	--	--	--	--	--	--
EMAAC (Rest of)	42.9	0.0	\$325.00	42.9	\$325.00	--	--	--	--
SWMAAC (Rest of)	0.0	--	--	--	--	--	--	--	--
PS (Rest of)	0.0	--	--	--	--	--	--	--	--
PS NORTH	0.0	--	--	--	--	--	--	--	--
DPL SOUTH	13.4	0.0	\$325.00	13.4	\$325.00	--	--	--	--
PEPCO	0.0	--	--	--	--	--	--	--	--
ATSI (Rest of)	25.9	0.0	\$325.00	25.9	\$325.00	--	--	--	--
ATSI-CLEVELAND	0.0	--	--	--	--	--	--	--	--
COMED	45.0	0.0	\$325.00	45.0	\$325.00	--	--	--	--
BGE	0.0	--	--	--	--	--	--	--	--
PL	0.0	--	--	--	--	--	--	--	--
DAYTON	3.6	0.0	\$325.00	3.6	\$325.00	--	--	--	--
DEOK	5.5	0.0	\$325.00	5.5	\$325.00	--	--	--	--
DOM	140.8	0.0	\$325.00	140.8	\$325.00	--	--	--	--
JCPL	8.3	0.0	\$325.00	8.3	\$325.00	--	--	--	--
TOTAL	285.4								

¹ A PJM Sell Offer is indicated by a negative PJM Buy Bid.

The total net amount of capacity procured or released by PJM is a function of the clearing of the PJM Sell Offers and Buy Bids. Table 6 shows the offered and cleared quantities of PJM Sell Offers and Buy Bids for reliability employed in the 2026/2027 Third Incremental Auction. Across the entire RTO region, PJM cleared Sell Offers totaled 0 MW while the PJM cleared Buy Bid quantity was 285.4 MW; therefore, PJM procured a total net capacity of 285.4 MW.

Table 6. Net Procurement of PJM Buy Bids/Sell Offers

LDA	PJM Bids/Offers (UCAP MW)		PJM Cleared Bids/Offers (UCAP MW)		
	Buy Bids	Sell Offers	Buy Bids	Sell Offers	Net Bids/Offers for Reliability
DPL-SOUTH	13.4	0.0	13.4	0.0	13.4
PS-NORTH	0.0	0.0	0.0	0.0	0.0
PSEG (rest of)	0.0	0.0	0.0	0.0	0.0
JCPL	8.3	0.0	8.3	0.0	8.3
EMAAC (rest of)	42.9	0.0	42.9	0.0	42.9
EMAAC Total	64.6	0.0	64.6	0.0	64.6
PEPCO	0.0	0.0	0.0	0.0	0.0
BGE	0.0	0.0	0.0	0.0	0.0
SWMAAC (rest of)	0.0	0.0	0.0	0.0	0.0
SWMAAC Total	0.0	0.0	0.0	0.0	0.0
PPL	0.0	0.0	0.0	0.0	0.0
MAAC (rest of)	0.0	0.0	0.0	0.0	0.0
MAAC Total	64.6	0.0	64.6	0.0	64.6
AT SI (rest of)	25.9	0.0	25.9	0.0	25.9
AT SI-Cleveland	0.0	0.0	0.0	0.0	0.0
COMED	45.0	0.0	45.0	0.0	45.0
DAY	3.6	0.0	3.6	0.0	3.6
DEOK	5.5	0.0	5.5	0.0	5.5
DOM	140.8	0.0	140.8	0.0	140.8
RTO (rest of)	0.0	0.0	0.0	0.0	0.0
RTO Total	285.4	0.0	285.4	0.0	285.4

Mitigation in the 2026/2027 Third Incremental Auction

All parent companies failed the Three Pivotal Supplier (TPS) test in the 2026/2027 Third Incremental Auction. Offers submitted for resources that fail as pivotal suppliers will have those offers mitigated to their Market Seller Offer Cap (MSOC). Demand Resources are not subject to market power mitigation.

APPENDIX: Comparison of auction results and final zonal net load prices

Table 7. Comparison of Base Residual Auction and Third Incremental Auction Prices

	BRA SMP	3IA SMP
RTO/System Marginal Price (SMP)	\$329.43	\$164.70
	Resource Clearing Price	
LDA	BRA	3IA
RTO	\$329.43	\$164.70
MAAC	\$329.43	\$164.70
EMAAC	\$329.43	\$164.70
SWMAAC	\$329.43	\$164.70
PS	\$329.43	\$164.70
PSNORTH	\$329.43	\$164.70
DPLSOUTH	\$329.43	\$164.70
PEPCO	\$329.43	\$164.70
ATSI	\$329.43	\$164.70
ATSI-CLEVELAND	\$329.43	\$164.70
COMED	\$329.43	\$164.70
BGE	\$329.43	\$164.70
PL	\$329.43	\$164.70
DAYTON	\$329.43	\$164.70
DEOK	\$329.43	\$164.70
DOM	\$329.43	\$164.70
JCPL	\$329.43	\$164.70

Table 8. Preliminary and Final UCAP Obligations and Net Load Prices

Zone	Base Zonal UCAP Obligation	Preliminary Zonal Net Load Price	Final Zonal UCAP Obligation	Final Zonal Net Load Price
AE	2,160.0	\$329.43	2,176.4	\$329.08
AEP	12,278.4	\$329.43	12,291.5	\$329.08
APS	8,007.8	\$329.43	8,030.0	\$329.08
ATSI	11,437.6	\$329.43	11,380.0	\$329.08
BGE	5,784.6	\$329.43	5,767.4	\$329.08
COMED	17,602.8	\$329.43	17,799.0	\$329.08
DAYTON	2,888.2	\$329.43	2,927.3	\$329.08
DEOK	3,918.1	\$329.43	3,919.3	\$329.08
DLCO	2,399.7	\$329.43	2,404.5	\$329.08
DOM	22,133.2	\$329.43	22,773.9	\$329.08
DPL	3,437.1	\$329.43	3,508.4	\$329.08
EKPC	2,178.6	\$329.43	2,210.1	\$329.08
JCPL	5,257.7	\$329.43	5,303.9	\$329.08
METED	2,752.8	\$329.43	2,687.2	\$329.08
OVEC	54.9	\$329.43	55.6	\$329.08
PECO	7,482.6	\$329.43	7,495.2	\$329.08
PENLC	2,557.9	\$329.43	2,485.1	\$329.08
PEPCO	5,369.3	\$329.43	5,355.8	\$329.08
PL	7,004.2	\$329.43	6,732.3	\$329.08
PS	9,142.2	\$329.43	8,831.8	\$329.08
RECO	357.7	\$329.43	355.9	\$329.08
* - The Base Zonal UCAP Obligation and Preliminary Zonal Net Load Price includes all previous RPM auctions for the delivery year. The Final Zonal UCAP Obligation and Final Zonal Net Load Price represents the impact of all RPM Auctions for the delivery year.				

Exhibit 35

195 FERC ¶ 61,162
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Laura V. Swett, Chairman;
David Rosner, Lindsay S. See,
Judy W. Chang, and David LaCerte.

Constellation Energy Generation, LLC

Docket No. ER26-2028-000

ORDER GRANTING WAIVER REQUEST

(Issued June 1, 2026)

1. On March 31, 2026, Constellation Energy Generation, LLC (Constellation) submitted a request for waiver of: (1) section 6.6(g) of Attachment DD of PJM Interconnection, L.L.C.'s (PJM) Open Access Transmission Tariff (Tariff) to enable Constellation to remove Eddystone Units 3 and 4 (Eddystone Units) from Capacity Resource status;¹ and (2) Part VII, Subpart C, section 306(E)(5) and Part VII, Subpart D, section 311(B)(4) of the Tariff to allow for the transfer of Capacity Interconnection Rights (CIR) from the Eddystone Units to Crane Clean Energy Center (Crane). As discussed below, we grant Constellation's waiver request.

I. Background

A. Interconnection Process, Resource Types, and Deliverability

2. In 2022, the Commission accepted PJM's proposal to move from a serial first-come, first-served interconnection queue process to a first-ready, first-served clustered cycle approach that groups projects in cluster cycles for purposes of studying and allocating costs.² The current process includes rules for two transition cycles, in Part VII of the Tariff, and rules that apply to cycles after the transition cycles, in Part VIII of the Tariff. All these rules describe an interconnection process using a single

¹ Capitalized terms that are not defined in this order have the meaning specified in the Tariff.

² *PJM Interconnection, L.L.C.*, 181 FERC ¶ 61,162 (2022) (accepting PJM's Tariff revisions to reform its interconnection process), *reh'g denied*, 184 FERC ¶ 61,006 (2023), *Hecate Energy LLC v. FERC*, *pet. for review dismissed*, No. 23-1089, 2025 WL 249062, at *2 (D.C. Cir. 2025).

application and study process that includes three phases (each with a System Impact Study) and three decision points to evaluate New Service Requests on a clustered basis.³ The process ends with a negotiation to execute a generation interconnection agreement.

3. Each New Service Request must elect a status type for the resource: Capacity Resource or Energy Resource.⁴ A Capacity Resource designation permits the generator to be used by PJM load-serving entities to meet their capacity obligations through PJM's capacity market, which includes annual Base Residual Auctions for future delivery years.⁵ PJM grants Capacity Resource status based on the availability of sufficient transmission capability to ensure the deliverability of generator output to network load.⁶ To this end, each System Impact Study analyzes the effect of adding to the transmission system the new facilities and services proposed by New Service Requests.⁷ Pursuant to the Tariff, each System Impact Study identifies any Contingent Facilities, which are unbuilt facilities upon which the New Service Request's cost, timing, and study findings are dependent and, if delayed or not built, could cause a need for interconnection restudies.⁸ PJM includes the list of the Contingent Facilities in both the System Impact Studies and the generation interconnection agreement.

4. PJM also conducts interim deliverability studies for projects that request to come into service prior to the construction of Contingent Facilities.⁹ PJM conducts these

³ PJM, Intra-PJM Tariffs, OATT, pt. VII (Tariff pt. VII), subpt. D, § 307 (1.0.0). Similar rules are found in Part VIII of the Tariff, but because the focus here is on Transition Cycle #2, citations are to the Tariff Part VII rules.

⁴ PJM, *Manual 14H: New Service Requests Cycle Process* § 9.4 (Sep. 25, 2025), <https://www.pjm.com/-/media/DotCom/documents/manuals/m14h.pdf> (Manual 14H).

⁵ Load-serving entities may also meet their capacity requirements through the election of the Fixed Resource Requirement Alternative, i.e., through a self-supply arrangement. PJM, Intra-PJM Tariffs, RAA, RAA Schedule 8.1 (3.00).

⁶ Because the planning studies for generating units seeking to be an Energy Resource do not include these deliverability analyses, Energy Resources cannot participate in PJM's capacity market. Manual 14H, § 9.4.2.

⁷ Tariff pt. VII, subpt. D, § 307(A)(2).

⁸ Tariff pt. VII, subpt. D, § 307(A)(3).

⁹ PJM Manual 14H, § 4.10.1; PJM, Intra-PJM Tariffs, OATT, pt. IX, subpt. B, GIA Specs (2.0.0), § 2.1.

studies to determine whether a project is deliverable for all or a portion of its output during the delivery year.

B. CIRs and CIR Transfers

5. The Tariff provides that CIRs are “the rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection.”¹⁰ Generation resources accredited as deliverable under the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region are awarded CIRs commensurate with the size in megawatts (MW) of the generation as identified in the generation interconnection agreement.¹¹

6. PJM’s CIR rules state that in the event of Deactivation of a Generation Capacity Resource, or removal of Capacity Resource status, any CIRs associated with such Generating Facility terminate one year from the Deactivation Date, or the effective date of the status change, unless the holder of such rights (including any holder that acquired the rights after Deactivation or removal of Capacity Resource status) has submitted a completed Generation Interconnection Request which claims the same CIRs.¹² Regarding changes in Capacity Resource status, the Tariff authorizes PJM to remove a unit’s Capacity Resource status if, in relevant part, (1) the Independent Market Monitor for PJM (Market Monitor) determines that the change in Capacity Resource status will not create market power issues, or (2) the Commission issues an order terminating the Capacity Resource status.¹³ The Tariff provides that if the interconnection request to which the CIRs are transferred is later terminated and/or withdrawn, the CIRs terminate one year after either the Deactivation or the Capacity Resource status change of the original generator.¹⁴ The Tariff provides that CIRs may be sold or otherwise transferred to a third party under transfer and notice procedures set by PJM.¹⁵ The Tariff specifies that PJM may perform thermal, short circuit, and/or stability studies, as necessary and in

¹⁰ Tariff pt. VII, subpt. A, § 300(C) (2.0.0) (defining Capacity Interconnection Rights).

¹¹ Tariff pt. VII, subpt. E, § 328 (Capacity Interconnection Rights) (0.0.0), § 328(B).

¹² Tariff pt. VII, subpt. E, § 328(C)(3).

¹³ PJM, Intra-PJM Tariffs, Tariff, attach. DD, § 6.6 (Offer Requirement for Capacity Resources) (3.0.0), § 6.6(g).

¹⁴ Tariff pt. VII, subpt. E, § 328(C)(3).

¹⁵ Tariff pt. VII, subpt. E, § 328(C)(4).

accordance with the PJM Manuals, due to any changes in the electrical characteristics of any newly proposed equipment, or where there is a change in Point of Interconnection, which may result in the loss of a portion of all the CIRs as determined by such studies.¹⁶

7. Part VII, Subpart D, section 311(B)(4) of the Tariff provides that a project developer “may not request a modification that is not expressly allowed” at Decision Point II.¹⁷ To request a CIR transfer at Decision Point II, the project developer would be required to “withdraw its New Service Request and resubmit the New Service Request with the proposed modification in a subsequent Cycle” to effectuate the transfer.¹⁸ Furthermore, Part VII, Subpart C, section 306(E)(5) of the Tariff states that “no changes to an RRI Project’s Maximum Facility Output or [CIRs] shall be allowed at any point prior to the time the Project Developer enters into a Generation Interconnection Agreement or Wholesale Market Participation Agreement.”¹⁹

C. Reliability Resource Initiative (RRI) Projects

8. On December 13, 2024, PJM filed its RRI proposal to address near-term resource adequacy concerns.²⁰ PJM explained that based on its analysis, its planning reserve margin may suffer erosion as soon as 2026, resource adequacy issues were expected to occur as soon as the 2029/2030 delivery year, and by the 2030/2031 delivery year PJM anticipated a 10-gigawatt (GW) gap in capacity that could swell to more than 20 GW based on forecasted load growth.²¹ To address these concerns, PJM proposed to introduce a limited application window for additional projects to be studied in Transition Cycle #2.²² PJM proposed to allow a maximum of 50 additional projects, with a 10 MW

¹⁶ Tariff pt. VII, subpt. E, § 328(C)(3).

¹⁷ Tariff pt. VII, subpt. D, § 311 (Decision Point II) (2.1.0), § 311(B)(4)(a).

¹⁸ *Id.*

¹⁹ Tariff pt. VII, subpt. C, § 306 (Application Rules) (1.1.0), § 306(E)(5).

²⁰ *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at PP 1, 3-4 (2025) (RRI Order).

²¹ RRI Order, 190 FERC ¶ 61,084 at PP 4, 15; *PJM Interconnection, L.L.C.*, Filing, Docket No. ER25-712-000, at 9 (filed Dec. 13, 2024) (discussing drivers of these concerns, including retirement of thermal generation resources, replacement of such resources with intermittent renewable resources with low completion rates, and greatly increased load growth).

²² RRI Order, 190 FERC ¶ 61,084 at PP 2, 4.

unforced capacity (UCAP)²³ minimum for project size and a requirement to participate in Base Residual Auctions for 10 consecutive delivery years.²⁴ PJM explained that adding the RRI projects to Transition Cycle #2 would accelerate their development by at least 18 months as compared to their expected completion dates if they could not be studied and interconnected until Cycle #1, the first regular cycle following the transition period.²⁵ By accelerating these projects' completion dates through the RRI proposal, PJM sought to bring significant amounts of UCAP to the PJM markets before 2028, when PJM anticipates the resource adequacy issues will become more severe, and in advance of the 2030/2031 delivery year, when PJM anticipates demand could begin outstripping supply.²⁶

9. On February 11, 2025, the Commission accepted PJM's proposal, finding that PJM's RRI proposal represented a just and reasonable and not unduly discriminatory approach to addressing PJM's near-term resource adequacy concerns.²⁷

D. Relevant Constellation Facilities

1. Crane

10. Constellation states that Crane is a nuclear resource in Pennsylvania that will be available to generate over 800 MW in the second half of 2027.²⁸ According to Constellation, in May 2025, PJM notified Constellation that it had included Crane in RRI, allowing the project to join Transition Cycle #2.²⁹ Constellation states that during Crane's Phase 1 System Impact Study, PJM identified numerous transmission projects as Contingent Facilities.³⁰ Constellation states that these Contingent Facilities were all

²³ UCAP is the product in PJM's capacity market.

²⁴ RRI Order, 190 FERC ¶ 61,084 at PP 4, 19.

²⁵ *Id.* P 19.

²⁶ *Id.* P 20.

²⁷ *Id.* P 53.

²⁸ *Id.* at 1, 4-5, 17.

²⁹ *Id.* at 2, 5 (citing *id.*, Ex. 1 (Affidavit of Yonas K. Habtemichael) ¶ 7 (Habtemichael Aff.); Constellation Energy Corp., *Constellation Reports Second Quarter 2025 Results* (Aug. 7, 2025), <https://investors.constellationenergy.com/node/9361/pdf>).

³⁰ *Id.* at 5 (citing Habtemichael Aff. ¶ 14).

regionally planned and approved by PJM before Constellation submitted Crane's RRI interconnection request, and include hundreds of miles of new 765-kilovolt (kV) and 500 kV transmission lines with projected in-service dates as late as December 2030.³¹ Constellation contends that many of these projects have already incurred years of delays and could be delayed further. Constellation explains that unlike typical Network Upgrades, these Contingent Facilities are not developed for or funded by interconnecting resources and are fully cost-allocated to load.³² Constellation states that if the Contingent Facilities are included in Crane's final interconnection agreement, Crane will not be considered fully deliverable until every Contingent Facility is completed.³³ Constellation states that in the meantime, Crane will be subject to annual interim deliverability studies that will determine whether and to what extent Crane can provide capacity and energy to the grid.³⁴ Hence, Constellation argues, even if these transmission projects finish on time, Crane's full deliverability could be in limbo until December 2030, three years or more after Constellation expects it will be ready to generate.³⁵

2. Eddystone Units

11. Constellation states that the Eddystone Units are dual-fuel units, each with a generating capacity of 380 MW, located in Pennsylvania.³⁶ Constellation explains that on December 1, 2023, it announced its plans to retire the Eddystone Units and submitted deactivation requests to PJM and the Market Monitor. Constellation states that in early 2024, both PJM and the Market Monitor notified Constellation that it could proceed with deactivation. Constellation states that on May 30, 2025, the day prior to the scheduled deactivation, the United States Department of Energy (DOE) issued an order, pursuant to Federal Power Act (FPA) section 202(c),³⁷ declaring that the operational availability and economic dispatch of the Eddystone Units is necessary to meet an emergency and serve the public interest.³⁸ Constellation notes that DOE directed PJM and Constellation to

³¹ *Id.* at 5-6 (citing Habtemichael Aff. ¶ 16).

³² *Id.* at 6 (citing Habtemichael Aff. ¶ 14).

³³ *Id.* (citing Habtemichael Aff. ¶¶ 16-17; Manual 14H, § 4.10.1.3).

³⁴ *Id.* (citing Habtemichael Aff. ¶ 15).

³⁵ *Id.* (citing Habtemichael Aff. ¶ 16).

³⁶ *Id.* (citing Habtemichael Aff. ¶ 20).

³⁷ 16 U.S.C. § 824a(c).

³⁸ Waiver Request at 7 (citing U.S. Dept. of Energy, May 30, 2025 Emergency

“take all measures necessary to ensure that [the] Eddystone Units are available to operate” through August 28, 2025.³⁹ Constellation notes further that DOE has extended the Eddystone order three times, most recently on February 23, 2026.⁴⁰ Constellation argues that although the February 2026 Eddystone Order will expire on May 24, 2026, DOE may continue to renew the orders as the “emergency conditions . . . continue [] both in the near and long term.”⁴¹ Constellation states that DOE has ordered that “the Eddystone Units shall not be considered capacity resources.”⁴²

II. Waiver Request

12. Constellation states that, based on its analysis of Crane’s Phase I System Impact Study Report (Crane Phase I Report), it has determined that transferring the Eddystone Units’ CIRs to Crane would enable Constellation to expedite Crane’s full deliverability and improve its position for interim deliverability in the meantime.⁴³ To this end, Constellation requests that the Commission issue a one-time, limited, prospective waiver of (1) section 6.6(g) of Attachment DD of the Tariff to enable Constellation to remove the Eddystone Units from Capacity Resource status, thereby making the Eddystone Units’ CIRs available for transfer; and (2) Part VII, Subpart C, section 306(E)(5), and Part VII, Subpart D, section 311(B)(4), of the Tariff to allow Constellation to transfer the

Order No. 202-25-4, at 2 (May 2025 Eddystone Order)).

³⁹ *Id.* (citing May 2025 Eddystone Order at 3, ordering paras. (A), (G)).

⁴⁰ *Id.* at 2 (citing U.S. Dept. of Energy, February 23, 2026 Emergency Order No. 202-26-17 (February 2026 Eddystone Order); U.S. Dept. of Energy, November 25, 2025 Emergency Order No. 202-25-10; U.S. Dept. of Energy, August 28, 2025 Emergency Order No. 202-25-8; May 2025 Eddystone Order).

⁴¹ *Id.* at 7 (citing February 2026 Eddystone Order at 3). On May 21, 2026, DOE issued an order directing PJM to ensure that the Eddystone Units remain available to operate through August 22, 2026. U.S. Dept. of Energy, May 21, 2026 Emergency Order No. 202-26-24, <https://www.energy.gov/ceser/federal-power-act-section-202c-pjm-interconnection-llc-pjm-order-no-202-26-24>.

⁴² Waiver Request at 7 (citing February 2026 Eddystone Order at 10, ordering para. (G)).

⁴³ *Id.* at 2, 7.

Eddystone CIRs to Crane—modifying the source (but not the level) of the CIRs in Crane’s interconnection request—at Decision Point II, slated to open on June 2, 2026.⁴⁴

13. Constellation explains that transferring CIRs from an existing resource can provide electric interconnection benefits to a new entrant—even if it is interconnected at a different point—because the two resources may have similar effects on downstream transmission lines.⁴⁵ Constellation asserts that in such a case, the CIR transfer may not be one-to-one, but to the extent the new entrant obtains transferred CIRs, PJM may not attribute certain reliability violations to the new entrant, nor condition its interconnection on the resolution of those violations. Constellation states that with the transferred CIRs, the new resource may not be responsible for certain mitigations—such as waiting for the construction of Contingent Facilities to be completed—that PJM would otherwise require.

14. Constellation states that, although Crane will interconnect to the grid about 100 miles northwest of the Eddystone Units, Constellation’s analysis of the Crane Phase I Report and subsequent modeling posted by PJM confirm that Crane and the Eddystone Units contribute similarly to a number of the identified reliability violations.⁴⁶ Thus, Constellation contends that transferring the Eddystone Units’ CIRs to Crane will address a significant number of the reliability violations identified in the Crane Phase I Report, both enabling Constellation to expedite Crane’s full deliverability and improving its position for providing interim deliverability.

15. Constellation states that transferring the Eddystone Units’ CIRs to Crane requires the aforementioned two steps and waiver.⁴⁷ First, Constellation explains that it must make the Eddystone Units’ CIRs available for transfer by removing the Eddystone Units’ status as a Capacity Resource.⁴⁸ Constellation states that section 6.6(g) of Attachment DD of the Tariff authorizes PJM, as relevant here, to remove a unit’s Capacity Resource status if (1) the Market Monitor determines that the change in Capacity Resource status will not create market power issues, or (2) the Commission issues an order terminating the Capacity Resource status.⁴⁹ Constellation argues that waiver of the Market Monitor’s

⁴⁴ *Id.* at 3, 11.

⁴⁵ *Id.* at 7-8 (citing Habtemichael Aff. ¶ 21).

⁴⁶ *Id.* at 8 (citing Habtemichael Aff. ¶ 24).

⁴⁷ *Id.*

⁴⁸ *Id.* at 9 (citing Tariff pt. VII, subpt. E, § 328(C)(3)).

⁴⁹ *Id.* (citing Tariff, attach. DD, § 6.6(g)).

review would be appropriate because the Market Monitor already completed the same analysis in connection with the Eddystone Units' proposed deactivation, there is no possibility of withholding given the Eddystone Units' unique status as non-Capacity Resources under DOE's directive, and the CIR transfer requires additional waivers to effectuate it.

16. Constellation notes that following removal of Capacity Resource status, the "holder" can transfer CIRs to a new resource under development, provided it "has submitted a completed Generation Interconnection Request . . . up to one year from the date the Capacity Resource status changes take effect."⁵⁰ Constellation states that it will comply with this requirement because it submitted its Crane interconnection request prior to the Eddystone Units' CIRs becoming available. Constellation states, however, that it will need to amend its interconnection request for Crane at the next opportunity in the interconnection process, which is Decision Point II.⁵¹ Constellation states that doing so will require waiver of two Tariff provisions. First, Constellation requests a waiver of Part VII, Subpart D, section 311(B)(4) of the Tariff, which provides that a project developer "may not request a modification that is not expressly allowed" at Decision Point II.⁵² Constellation explains that unless the Commission waives this provision, Crane would be required to "withdraw its New Service Request and resubmit the New Service Request with the proposed modification in a subsequent Cycle" to effectuate the transfer.⁵³ According to Constellation, given PJM's anticipated schedule for Cycle # 1, submitting a new interconnection request would likely delay Crane receiving an interconnection agreement at least to 2028, after Constellation hopes for Crane to begin generating.⁵⁴

17. Constellation states that, out of an abundance of caution, Constellation also requests a waiver of Part VII, Subpart C, section 306(E)(5) of the Tariff, under which "no changes to an RRI Project's Maximum Facility Output or [CIRs] shall be allowed at any point prior to the time the Project Developer enters into a Generation Interconnection Agreement or Wholesale Market Participation Agreement."⁵⁵ Constellation states that it is not seeking to change the number of CIRs for Crane, which appears to be the target of

⁵⁰ *Id.* at 10 (citing Tariff pt. VII, subpt. E, § 328(C)(3)).

⁵¹ *Id.* (citing Habtemichael Aff. ¶ 8).

⁵² *Id.* (citing Tariff pt. VII, subpt. D, § 311(B)(4)(a)).

⁵³ *Id.* at 10-11 (citing Tariff pt. VII, subpt. D, § 311(B)(4)(a)).

⁵⁴ *Id.* at 11 (citing Habtemichael Aff. ¶ 28).

⁵⁵ *Id.* (quoting Tariff pt. VII, subpt. C, § 306(E)(5)).

the Tariff's restriction. Constellation states that it will only request to reflect the transfer of the Eddystone Units' CIRs to Crane. But to the extent the Commission considers the transfer a "change" to Crane's CIRs, Constellation requests a waiver.

18. Constellation argues that the waiver request satisfies the Commission's criteria for granting waiver.⁵⁶ First, Constellation contends that the waiver request is submitted in good faith because, supported by a DOE loan, Constellation has invested about \$1.6 billion to bring Crane online as quickly as possible.⁵⁷ Constellation states that it is also taking responsibility for expediting Crane's full deliverability by, for example, entering into an Upgrade Construction Service Agreement to expedite the construction of a Network Upgrade at a cost to Constellation of roughly \$100 million.⁵⁸ In addition, Constellation argues that it could not have anticipated the need to transfer the Eddystone Units' CIRs sooner.⁵⁹ Constellation explains that in early 2025, before submitting its interconnection request for Crane, Constellation conducted modeling to assess what steps it could take to mitigate potential delays in Crane's interconnection process.⁶⁰ Constellation states that based on the composition of Crane's cluster at the time, it did not appear that the transfer of the Eddystone Units' CIRs would accelerate Crane's deliverability. According to Constellation, it first learned of the Contingent Facilities for Crane on October 31, 2025, when it received PJM's Phase I System Impact Study results.⁶¹ Constellation states that it then immediately began analyzing PJM's results and conducting its own modeling, through which Constellation determined that transferring the Eddystone Units' CIRs to Crane would address a number of the reliability violations

⁵⁶ *Id.* at 3, 12.

⁵⁷ *Id.* at 3, 13 (citing Constellation Energy Corp., Annual Report (Form 10-K) at 39 (Feb. 18, 2025)). Constellation argues that other factors confirming that the waiver request is made in good faith include that the waiver request is prospective and that the Market Monitor has already conducted the market power analysis for changing the Eddystone Units' Capacity Resource status envisioned under section 6.6 of Attachment DD of the Tariff. *Id.* at 14-15.

⁵⁸ *Id.* at 13 (citing *Upgrade Construction Service Agreement by and Among PJM Interconnection, L.L.C., Constellation Energy Generation, LLC, and Mid-Atlantic Interstate Transmission, LLC* appen. I ¶ C (Mar. 18, 2026), <https://www.pjm.com/-/media/DotCom/temporary-files/ur25-0005-ucsa.pdf>).

⁵⁹ *Id.* at 3.

⁶⁰ *Id.* at 13 (citing Habtemichael Aff. ¶ 22).

⁶¹ *Id.* at 14 (citing Habtemichael Aff. ¶ 14).

identified in the Crane Phase I Report.⁶² Constellation notes that the waiver request followed soon after.

19. Second, Constellation argues that the waiver request is of limited scope because it “leverages the confluence of unique circumstances highly unlikely to recur.”⁶³ Constellation notes that the Eddystone Units were scheduled to deactivate, were subsequently required to remain available under the DOE orders, and were prohibited from participating as Capacity Resources.⁶⁴ Constellation argues that under these unusual factors, (1) PJM and the Market Monitor previously approved the Eddystone Units to deactivate, including following the Market Monitor’s market power review; (2) Eddystone has remained online well past its planned retirement date, but the CIRs cannot be used to provide value to PJM customers; and (3) PJM has been modeling the Eddystone Units in its interconnection studies such that transferring the Eddystone Units’ CIRs can only help other projects.⁶⁵ Constellation argues that the benefits that Crane will provide to the region only add to the factors making the waiver request unique and unlikely to recur.⁶⁶

20. Third, Constellation argues that the waiver request addresses a concrete problem.⁶⁷ Constellation states that the Contingent Facilities may prevent Crane’s full deliverability, potentially depriving PJM of significant reliability and affordability benefits for years. Constellation states that, absent the waiver, if the Contingent Facilities identified in the Crane Phase I Report are included in Crane’s interconnection agreement, Crane’s ability to provide its full capabilities will be at risk at least through December 31, 2030—long after Crane will be available to generate.⁶⁸ Constellation states that by enabling

⁶² *Id.* (citing Habtemichael Aff. ¶¶ 18, 23-28).

⁶³ *Id.* at 3.

⁶⁴ *Id.* at 16 (citing February 2026 Eddystone Order at 10, ordering para. (G)).

⁶⁵ *Id.* (citing Habtemichael Aff. ¶ 31).

⁶⁶ Constellation states that those benefits include that PJM selected Crane in the RRI process because it was a “shovel-ready resource” that “can most effectively contribute to reliability.” *Id.* (citing PJM, *PJM Chooses 51 Generation Resource Projects to Address Near-Term Electricity Demand Growth* (May 2, 2025), <https://insidelines.pjm.com/pjm-chooses-51-generation-resource-projects-to-address-near-term-electricity-demand-growth/>).

⁶⁷ *Id.* at 3, 17.

⁶⁸ *Id.* at 17-18.

Constellation to transfer the Eddystone Units' CIRs to Crane and incorporate them into Crane's interconnection request at Decision Point II, the waiver will (1) expedite Crane's full deliverability, and (2) improve Crane's position for interim deliverability in the meantime.⁶⁹ Constellation states that in the Crane Phase I Report, for example, PJM identified steady-state thermal reliability violations relating to Crane on 10 unique facilities—violations on seven 500 kV facilities and three 230 kV facilities.⁷⁰ Constellation states that its modeling indicates that the combination of transferring the Eddystone Units' CIRs to Crane and updates in PJM's posted Phase II case would address all of the violations affecting 500 kV facilities. Constellation explains that this result, in turn, would eliminate many of the most significant Contingent Facilities from Crane's violations, including hundreds of miles of new 765 kV and 500 kV lines, and a number of facilities with December 2030 in-service dates.⁷¹

21. Fourth, Constellation argues that its requested waiver will not harm third parties because the proposed CIR transfer would not shift any interconnection costs or otherwise disadvantage other projects under development.⁷² Constellation maintains that its requested waiver will not delay PJM's interconnection study process because PJM has already designed its study process to accommodate developers modifying interconnection requests at Decision Point II, and Constellation has no reason to believe that the proposed transfer would disrupt PJM's Phase III study. Constellation reiterates that the Contingent Facilities being resolved are regionally planned projects that PJM included in the Regional Transmission Expansion Plan prior to Crane's interconnection request whose costs are allocated entirely to load.⁷³ Therefore, Constellation states, the CIR transfer will have no financial impact on other projects in the queue. Constellation adds that its

⁶⁹ Constellation argues that reaching full deliverability is especially important for Crane because, as a nuclear unit, it faces challenges related to the uncertainty caused by interim deliverability status. *Id.* at 19. According to Constellation, those challenges include procuring nuclear fuel and long-lead-time nuclear materials, planning outages for refueling and maintenance, and maintaining a large on-site staff. Constellation adds that, unlike other technologies, nuclear units face potential equipment reliability challenges—like elevated vibration and wear—when operating for extended periods below rated power output.

⁷⁰ *Id.* at 18 (citing Habtemichael Aff. ¶ 12).

⁷¹ *Id.* at 18 (citing Habtemichael Aff. ¶ 25).

⁷² *Id.* at 4, 22. Constellation states that it agrees to reimburse PJM for any additional study or processing costs caused by this request. Waiver Request at 22 n.92.

⁷³ *Id.* at 22-23. Constellation notes that the CIR transfer will also have no effect on the development of the Contingent Facilities themselves. *Id.* at 4, 23.

review of PJM’s modeling in the Phase I System Impact Study results confirms that the proposed CIR transfer is not expected to affect any other project in the cluster.⁷⁴ Constellation also reiterates that because the Market Monitor has already determined that there are no market power concerns with deactivating the Eddystone Units, there also cannot be market power concerns regarding removing the units’ Capacity Resource status—especially given that DOE has directed that the Eddystone Units “shall not be considered capacity resources.”⁷⁵

22. Finally, Constellation argues that the requested waiver will enable Crane to provide reliability and affordability benefits as quickly as possible to address PJM’s rapid need for new Capacity Resources, while the Eddystone Units remain available as energy-only resources, as they are today.⁷⁶ Constellation argues that this approach uses the Eddystone Units’ CIRs most efficiently, since they are not currently being used.

III. Notice and Responsive Pleadings

23. Notice of Constellation’s filing was published in the *Federal Register*, 91 Fed. Reg. 17800 (Apr. 8, 2026), with interventions and protests due on or before April 21, 2026. Timely motions to intervene were filed by: Dominion Energy Services, Inc.; Exelon Corporation; Grid Reform; Monitoring Analytics, LLC, acting in its capacity as

⁷⁴ *Id.* at 23 (citing Habtemichael Aff. ¶ 31).

⁷⁵ *Id.* at 23 (citing February 2026 Eddystone Order at 10, ordering para. (G)). Constellation adds that the requested CIR transfer will enhance competition in PJM by enabling Crane to add supply to the PJM market as soon as possible.

⁷⁶ *Id.* at 4. Constellation notes that in the 2027/2028 Base Residual Auction, PJM failed to procure sufficient supply to meet its reliability standard. *Id.* at 21 (citing PJM, *2027/2028 Base Residual Auction Report* (Dec. 17, 2025), <https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-bra-report.pdf>). Constellation further notes that DOE has declared “that an emergency exists in [PJM] due to . . . a shortage of facilities for the generation of electric energy,” and that emergency will “continue[] both in the near and long term.” *Id.* at 21 (citing February 2026 Eddystone Order at 1, 3). Constellation states that North American Electric Reliability Corporation (NERC) also has declared that PJM is at a “high risk” of energy shortages as of 2029 due to “an extreme and rapid tightening of supply and demand for capacity resources,” necessitating “resources to rapidly address [the] near-term reliability challenges.” *Id.* (citing NERC, *2025 Long-Term Reliability Assessment* 92 (2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf (NERC Assessment)). Constellation notes that NERC has found that “an adequate supply of thermal resources will be needed to maintain grid stability.” *Id.* (citing NERC Assessment at 93).

the Market Monitor; New Jersey Division of Rate Counsel; PJM; Public Citizen, Inc.; and Union of Concerned Scientists. On April 22, 2026, Old Dominion Electric Cooperative (ODEC) filed a motion to intervene out-of-time.

24. PJM filed comments, and the Market Monitor filed a protest. On April 24, 2026, Constellation filed a motion for leave to answer and answer to the Market Monitor's protest. On May 11, 2026, the Market Monitor filed a motion for leave to answer and answer to Constellation's answer.

A. PJM's Comments

25. PJM states that it does not oppose Constellation's waiver request.⁷⁷ PJM suggests, however, that if the Commission grants the waiver request, the Commission should make clear that such action is limited to the unique facts set forth in the record of this proceeding.⁷⁸ PJM argues further that the Commission should note that the action, if not limited to the specific circumstances, could have the potential of further complicating timely resolution of the interconnection process.⁷⁹ According to PJM, the Tariff and its interconnection process have operated as intended and the waiver request is limited to the fact that this request relates solely to the CIR transfer stemming from a series of unique circumstances: (1) the Eddystone Units maintain the unique status as non-Capacity Resources under DOE's directive, despite maintaining 760 MW of CIRs; (2) but for the initial DOE order, the Eddystone Units' CIRs would have terminated by May 31, 2026, one year after the units' proposed deactivation date, freeing up the 760 MW of CIRs; and (3) the proposed Crane project is on target to become fully operational by 2027.

26. PJM also explains how Constellation's waiver request relates to PJM's broader efforts to address resource adequacy concerns. PJM notes that on May 2, 2025, PJM selected 51 RRI Projects, including Crane, based off a set of criteria approved by the Commission.⁸⁰ PJM explains that part of the criteria included "Commercial Operation Date Viability," to ensure that RRI priority is given to projects that can be in commercial

⁷⁷ PJM Comments at 6.

⁷⁸ *Id.* at 6; *see id.* at 2 (encouraging the Commission to use "limiting language to avoid a ruling on this [w]aiver [r]equest being extended beyond the narrow facts of this case").

⁷⁹ *Id.* at 11.

⁸⁰ *Id.* at 8 (citing PJM Inside Lines, *PJM Chooses 51 Generation Resource Projects to Address Near-Term Electricity Demand Growth* (May 2, 2025), <https://insidelines.pjm.com/pjm-chooses-51-generation-resource-projects-to-address-near-term-electricity-demand-growth/>).

operation in advance of the 2028/2029 delivery year, when PJM's projected capacity supply begins to tighten.⁸¹ Thus, PJM argues, the intended outcome of Constellation's waiver request would work toward these means.

27. PJM states that it has not reviewed and cannot opine on Constellation's studies and analysis regarding the CIR transfer.⁸² PJM states that transferring CIRs to facilities at different Points of Interconnection, as Constellation is seeking here, requires studies performed by PJM, to evaluate the benefits of the transfer.⁸³ PJM explains that these studies will determine the final impact attributed to Crane, any associated cost allocations and Contingent Facilities, as well as the total CIRs available at the new location. Ultimately, PJM continues, its planning studies control, and granting of the waiver request should not presuppose the outcome of any studies that PJM must perform as to the CIR transfer or the remainder of Transition Cycle #2.

B. Market Monitor's Protest

28. The Market Monitor argues that Constellation's waiver request fails to satisfy all four of the Commission's criteria for granting waiver requests.⁸⁴ First, the Market Monitor asserts that Constellation has not demonstrated good faith because Constellation's desire to revise CIR sourcing arises from decisions that allegedly could, and should, have been made prior to Decision Point II.⁸⁵ The Market Monitor contends that the waiver request is a knowing deviation from the Tariff's sequencing and study requirements, not an inadvertent failure to comply.⁸⁶ According to the Market Monitor, the Commission rejects such attempts to use waiver as a vehicle for process changes, recognizing that waiver is not a substitute for an FPA section 205⁸⁷ filing to revise tariff terms. The Market Monitor further argues that Constellation has not demonstrated good faith in attempting to rely on the Market Monitor's previous market power review of the

⁸¹ *Id.* at 8 (citing RRI Filing at 32-33).

⁸² *Id.* at 10.

⁸³ *Id.* at 10-11.

⁸⁴ Market Monitor Protest at 1.

⁸⁵ *Id.* at 2.

⁸⁶ *Id.* at 4.

⁸⁷ 16 U.S.C. § 824d.

Eddystone Units.⁸⁸ The Market Monitor asserts that such reviews are transaction-specific, and that when the facts change, the analysis must also change. According to the Market Monitor, allowing reliance on a prior evaluation would render section 6.6(g) of Attachment DD of the Tariff meaningless and invite strategic behavior designed to evade regulatory oversight.

29. Second, the Market Monitor argues that the waiver request is not limited in scope because allowing Constellation to alter the source of CIRs at Decision Point II would not constitute a case-specific deviation, but rather would effectively rewrite a core Tariff requirement and invite similarly situated interconnection customers to seek comparable relief.⁸⁹ The Market Monitor argues that the waiver request would effectively create a new mechanism for CIR reallocation, and such relief would not be confined to a discrete procedural misstep.⁹⁰ The Market Monitor also argues that the waiver request is not limited in scope because “granting the waiver would invite copycat requests from other developers seeking to reassign CIRs or bypass queue procedures, thereby transforming a purportedly case-specific waiver into a de facto policy change.”⁹¹ The Market Monitor similarly argues that Constellation’s request for waiver of the Market Monitor’s market power review is not limited in scope because the “waiver would effectively nullify an explicit Tariff requirement designed to protect market integrity.”⁹²

30. Third, the Market Monitor argues that the waiver request does not solve a concrete problem because Constellation’s desire to change the source of CIRs at Decision Point II reflects a change in commercial strategy, not an unforeseen or unavoidable circumstance, given that the Tariff provides earlier opportunities for interconnection customers to select CIR options.⁹³ The Market Monitor contends that circumventing the Tariff’s framework is not solving a tariff deficiency, but seeking preferential treatment and a timing advantage outside established rules.⁹⁴ Regarding Constellation’s request for waiver of the Market Monitor’s market power review, the Market Monitor argues that Constellation

⁸⁸ Market Monitor Protest at 7.

⁸⁹ *Id.* at 3.

⁹⁰ *Id.* at 4.

⁹¹ *Id.* at 5.

⁹² *Id.* at 6.

⁹³ *Id.* at 3-4.

⁹⁴ *Id.* at 5.

created its own problem by deciding to transfer the CIRs.⁹⁵ According to the Market Monitor, self-inflicted circumstances do not justify waiver.

31. Fourth, the Market Monitor argues that granting the waiver would harm third parties.⁹⁶ The Market Monitor contends that because the PJM queue operates on a cluster study basis, where each project's technical assumptions, including CIR sourcing, affect system impact analyses, Network Upgrade identification, and cost allocation, a modification after Decision Point II could invalidate prior studies (requiring re-studies and delays), shift upgrade costs to other interconnection customers, and generally introduce uncertainty in the queue.⁹⁷ In addition, the Market Monitor asserts that allowing a project to reconfigure CIRs outside the normal study process could effectively permit it to "leapfrog" other queued projects, violating the principle of queue priority. Finally, the Market Monitor argues that allowing Constellation to rely on a prior market power evaluation, one that did not consider CIR transfers, removes a critical review tailored to the actual transaction.⁹⁸ The Market Monitor contends that this creates a significant risk that anticompetitive behavior could go undetected or unmitigated.

C. Constellation's Answer

32. Constellation argues that the Market Monitor offers no valid reason for the Commission to deny the waiver request.⁹⁹ In response to the Market Monitor's argument that it must conduct a new market power analysis, Constellation argues that although some time has passed since the Market Monitor cleared the Eddystone Units to retire, there can be no new market power concerns where (1) those resources remain in service in compliance with emergency orders issued by DOE, and (2) DOE has prohibited them from participating as Capacity Resources anyway.¹⁰⁰

33. In response to the Market Monitor's argument that Constellation's waiver request could invalidate prior studies and shift upgrade costs, Constellation argues that if PJM thought that the waiver request posed such problems, it presumably would have said so as

⁹⁵ *Id.* at 6-7.

⁹⁶ *Id.* at 3.

⁹⁷ *Id.* at 3, 5.

⁹⁸ *Id.* at 7.

⁹⁹ Constellation Answer at 1.

¹⁰⁰ *Id.* at 2 (citing February 2026 Eddystone Order at 10, ordering para. (G)).

the entity responsible for overseeing the queue.¹⁰¹ In response to the Market Monitor's arguments regarding queue priority, Constellation notes that neither PJM nor other project developers raise this concern.

34. Lastly, Constellation argues that the Market Monitor is wrong to claim that the waiver request amounts to a change in commercial strategy because Constellation should have requested the CIR transfer prior to Decision Point II.¹⁰² Constellation reiterates that it considered the CIR transfer when it applied for Crane to participate in RRI, but based on the available information, there was no basis then for the request.¹⁰³ Rather, Constellation argues, it was the sequence of unexpected, unique, and exigent circumstances culminating in Crane's Phase I Study Report that brought the problem to light and spurred Constellation to develop creative solutions. Constellation argues that its good faith is also confirmed by additional factors, including Constellation's investments to make Crane fully deliverable.

D. Market Monitor's Answer

35. The Market Monitor asserts that Constellation's answer and waiver request continue to be premised on unsupported assumptions about what PJM's CIR transfer studies will show.¹⁰⁴ The Market Monitor claims that Constellation is requesting that the Commission accept Constellation's internal modeling and conclusions as a substitute for PJM's analysis, circumventing the Tariff framework. In response to Constellation's arguments that the Market Monitor's concerns are speculative and that PJM would have identified any issues, the Market Monitor asserts that the burden is on Constellation to justify its waiver request, not on other parties to disprove Constellation's assumptions and assertions.¹⁰⁵ The Market Monitor states that assertions that a proposal will not affect system modeling or other projects must be validated through PJM's studies, not presumed. The Market Monitor argues that because the Eddystone Units and Crane are located at different points of interconnection, the CIR transfer raises questions regarding transfer capability, residual constraints, and required upgrades.¹⁰⁶ The Market Monitor asserts that such questions directly affect cost allocation, including whether Crane

¹⁰¹ *Id.* at 2-3.

¹⁰² *Id.* at 3.

¹⁰³ *Id.* at 3-4 (citing Habtemichael Aff. ¶ 22).

¹⁰⁴ *Id.* at 3.

¹⁰⁵ Market Monitor Answer at 4.

¹⁰⁶ *Id.* at 5.

remains responsible for Network Upgrades identified in the interconnection process, and that such issues cannot be resolved absent PJM studies.

36. Additionally, the Market Monitor asserts that Constellation fails to demonstrate that the waiver is necessary to address a concrete problem.¹⁰⁷ The Market Monitor argues that Constellation provides no explanation as to why the available pathways established by the Tariff are insufficient, such as interim deliverability determinations by PJM or operating as an Energy Resource until full deliverability is achieved. According to the Market Monitor, Constellation does not claim that Crane is unable to interconnect, operate, or participate in the market absent waiver and, instead, seeks to accelerate or predetermine the outcome of the study process.

IV. Discussion

A. Procedural Matters

37. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2025), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

38. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d), we grant ODEC's late-filed motion to intervene given its interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

39. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2025), prohibits an answer to a protest or answer unless otherwise ordered by the decisional authority. We accept Constellation's and the Market Monitor's answers because they have provided information that assisted us in our decision-making process.

B. Substantive Matters

40. We grant Constellation's request for waiver of (1) section 6.6(g) of Attachment DD of the Tariff to enable Constellation to remove the Eddystone Units from Capacity Resource status, thereby making the Eddystone Units' CIRs available for transfer; and (2) Part VII, Subpart C, section 306(E)(5) and Part VII, Subpart D, section 311(B)(4) of the Tariff to allow Constellation to transfer the Eddystone Units' CIRs to Crane at Decision Point II of Transition Cycle #2. The Commission has granted waiver of tariff provisions where: (1) the applicant acted in good faith; (2) the waiver is of limited scope; (3) the waiver addresses a concrete problem; and (4) the waiver does not have

¹⁰⁷ *Id.* at 6.

undesirable consequences, such as harming third parties.¹⁰⁸ As discussed below, we find that the circumstances of Constellation's waiver request satisfy these criteria.

41. To begin with, as the record illustrates, we note that the instant filing presents unique circumstances involving two Constellation facilities that are separately, and respectively, seeking to interconnect and deactivate. PJM's purpose in selecting RRI projects (like Crane) was to address urgent resource adequacy concerns by expediting the interconnections of RRI projects by 18 months and requiring them to participate in 10 consecutive Base Residual Auctions.¹⁰⁹ In the case of Crane, however, PJM found that numerous Contingent Facilities would have to be built before Crane can reach commercial operation. Furthermore, Constellation explains that the Eddystone Units would have deactivated but for the DOE orders requiring them to operate as energy-only resources. Thus, as Constellation argues, the proposed CIR transfer could allow PJM to meet the purpose of RRI while making efficient use of the Eddystone Units' CIRs as the Eddystone Units operate as energy-only resources.

42. We agree with Constellation that it has demonstrated good faith by making significant investments to bring Crane online quickly. We disagree with the Market Monitor that Constellation should have requested the CIR transfer sooner. Instead, we accept Constellation's explanation that at the time of Crane's RRI application, Constellation's studies indicated that the CIR transfer would not accelerate Crane's deliverability.¹¹⁰

43. We find that Constellation's waiver request is limited in scope because it is a one-time request to remove the Capacity Resource status of one generator and transfer its CIRs from that generator to another based on the unique facts and circumstances here, discussed above. We disagree with the Market Monitor that the waiver is not of limited scope because it effectively creates a new process for transferring CIRs. The waiver applies only to the CIR transfer between the Eddystone Units and Crane, under the unique circumstances outlined above.

44. We find that granting the waiver addresses a concrete problem. As Constellation explains, absent the waiver, Crane, an RRI project with 859 MW of generation capacity, may not be able to obtain full deliverability until at least December 31, 2030, long after Crane may be available to generate in 2027. Additionally, absent the waiver, Eddystone Units' 760 MW of CIRs cannot be used by any interconnection customers in Transition

¹⁰⁸ See, e.g., *Citizens Sunrise Transmission LLC*, 171 FERC ¶ 61,106, at P 10 (2020); *Midcontinent Indep. Sys. Operator, Inc.*, 154 FERC ¶ 61,059, at P 13 (2016).

¹⁰⁹ RRI Order, 190 FERC ¶ 61,084 at PP 4, 19.

¹¹⁰ Waiver Request at 13; Constellation Answer at 3-4.

Cycle #2. We find that the requested waiver will allow for the transfer of CIRs between the Eddystone Units and Crane, which may reduce or eliminate the number of Contingent Facilities for Crane and thereby potentially increase Crane's interim deliverability and enable Crane to be fully operational before December 31, 2030.¹¹¹ We therefore disagree with the Market Monitor's assertions that this waiver does not address a concrete problem.

45. We find that granting the waiver will not have undesirable consequences, such as harming third parties. Rather, the requested waiver will provide a more efficient use of CIRs due to the Eddystone Units' current inability to use their CIRs as a result of DOE orders requiring them to operate as energy-only resources. We also note that, as Constellation explains, neither PJM nor any project developer has protested the waiver request.¹¹²

46. Regarding the Market Monitor's arguments pertaining to queue priority, we note that granting Constellation's waiver request does not change Crane's queue position. We also are not persuaded that, because of the CIR transfer, the Commission should not waive the Market Monitor's review of the Eddystone Units' changed Capacity Resource status for market power issues. We agree with Constellation that the Eddystone Units are already not participating in the capacity market, consistent with the Secretary of Energy's directive that the units "shall not be considered capacity resources."¹¹³

¹¹¹ We agree with PJM that its planning studies control, and that our granting of the waiver request should not presuppose the outcome of any studies that PJM conducts for the CIR transfer. PJM Comments at 11.

¹¹² Constellation Answer at 3.

¹¹³ Waiver Request at 23 (citing February 2026 Eddystone Order at 10, ordering para. (G)). We note that Constellation and PJM have collaborated on an operating memo that governs the operating protocol of the Eddystone Units during the term of the DOE orders. *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,159, at P 6 (2025) (citing PJM Interconnection, L.L.C., *Eddystone 3 & 4 Unit Reporting & Commitment Process*, <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/postings/20250612-eddystone-3-and-4-unit-reporting-and-commitment-process.pdf>).

The Commission orders:

Constellation's waiver request is hereby granted, as discussed in the body of this order.

By the Commission.

(S E A L)

Carlos D. Clay,
Deputy Secretary.

Exhibit 36

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Constellation Energy Generation, LLC	)))	Docket No. ER26-_____
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**CONSTELLATION ENERGY GENERATION, LLC’S
REQUEST FOR PROSPECTIVE, LIMITED WAIVER**

The Crane Clean Energy Center (“Crane”) will be ready to generate over 800 MW of critical baseload, dispatchable nuclear generation in Southern Pennsylvania as soon as next year. As NERC put it in declaring PJM at a “high risk” of energy shortfalls by 2029, the region “faces an extreme and rapid tightening of supply and demand for capacity resources,” and “an adequate supply of thermal resources will be needed to maintain grid stability.”¹ Indeed, for the first time ever, in its 2027/2028 Base Residual Auction, PJM failed to clear enough supply to meet the one-day-in-ten-years planning standard.² For those reasons, the U.S. Secretary of Energy (“Secretary”) has called Crane the “poster child” for achieving reliability and affordability goals.³

But Crane’s ability to provide its full benefits to customers could be delayed because of an unexpected interconnection issue. That risk can be mitigated by straightforward waivers of discrete provisions of PJM’s Open Access Transmission Tariff (“Tariff”). Such waivers will benefit customers by supporting new supply in a strained market, enhancing reliability and

¹ North American Electric Reliability Corp., 2025 Long-Term Reliability Assessment 92, 93 (Jan. 2026) (“NERC Assessment”), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

² PJM Interconnection, L.L.C., 2027/2028 Base Residual Auction Report (Dec. 17, 2025), <https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-bra-report.pdf>.

³ White, *Three Mile Island is ‘Poster Child’ of Trump Energy, AI Agenda: US Energy Secretary*, Lancaster Online (Dec. 18, 2025), https://lancasteronline.com/news/politics/three-mile-island-is-poster-child-of-trump-energy-ai-agenda-us-energy-secretary/article_a15599f5-554c-4bd9-9658-5e3066e445ba.html.

affordability without harming others. Granting the waivers is likely to accelerate Crane’s full deliverability by several years.

During Crane’s Phase I System Impact Study (“Study”), PJM identified numerous regionally planned transmission projects as “Contingent Facilities” that must be completed for Crane to be fully deliverable.⁴ These Contingent Facilities were planned and approved before Crane submitted its RRI interconnection request and are fully cost-allocated to load. Not only do the Contingent Facilities include hundreds of miles of new 765 kV and 500 kV transmission lines as far away as West Virginia, but their current projected in-service dates extend as late as December 2030. If those projects remain Contingent Facilities in Crane’s final interconnection agreement, Crane will not be considered fully deliverable—and its ability to provide capacity and energy will be at risk—at least until the end of 2030.

Constellation Energy Generation, LLC (“Constellation”) has determined, by carefully analyzing Crane’s Phase I Study Report (the “Crane Phase I Report”), that it can expedite Crane’s full deliverability, and improve its position for interim deliverability in the meantime, by transferring the Capacity Interconnection Rights (“CIRs”) of its Eddystone Units 3 and 4 (the “Eddystone CIRs”) to Crane. Constellation planned to deactivate Eddystone Units 3 and 4 on May 31, 2025, and obtained all required reviews from PJM and the Independent Market Monitor for PJM (“Market Monitor”) to do so. Constellation has kept those units online, however, to comply with orders issued by the Secretary under section 202(c) of the Federal Power Act (“FPA”).⁵

⁴ “Full deliverability,” as used herein, refers to meeting all requirements in the interconnection agreement to obtain Capacity Interconnection Rights and energy injection rights. As explained below, PJM can allow a unit to provide capacity and energy through annual Interim Deliverability Studies before it is fully deliverable.

⁵ Dep’t of Energy, Order No. 202-26-17 (Feb. 23, 2026) (“Feb. 2026 Eddystone Order”); Dep’t of Energy, Order No. 202-25-10 (Nov. 25, 2025); Dep’t of Energy, Order No. 202-25-8 (Aug. 28, 2025); Dep’t of Energy, Order No. 202-25-4 (May 30, 2025) (“May 2025 Eddystone Order”).

Notably, the orders direct that Eddystone Units 3 and 4 “*shall not be considered capacity resources*.”⁶ Transferring the Eddystone CIRs to Crane will not affect PJM’s ability to operate and dispatch those resources for reliability in compliance with the Secretary’s orders.

To facilitate Crane achieving full deliverability as soon as possible, ensuring Crane can provide over 800 MWs of additional supply, with its full complement of reliability and affordability benefits, Constellation respectfully requests that the Commission issue one-time, prospective waivers of:

- (i) Tariff Attachment DD § 6.6(g): This waiver enables Constellation to remove Eddystone Units 3 and 4 from Capacity Resource status, thereby making the Eddystone CIRs available for transfer to Crane; and
- (ii) Tariff §§ 306.E.5 and 311.B.4: This waiver allows Constellation to transfer the Eddystone CIRs to Crane—modifying the source (but not the level) of the CIRs in Crane’s interconnection request—at Decision Point II, slated to span from June 2, 2026 until July 1, 2026.⁷

This request meets each of the Commission’s four factors for waivers:

First, Constellation makes this prospective waiver request in good faith. Supported by a DOE Loan, Constellation is investing \$1.6 billion to restart Crane, and has already committed to spend roughly \$100 million, to expedite its full deliverability. Constellation could not have anticipated the need to transfer the Eddystone CIRs sooner.

Second, the waiver request is limited; it leverages the confluence of unique circumstances highly unlikely to recur.

Third, the waivers solve a concrete problem by enabling Constellation to expedite Crane’s full deliverability and its position in the interim. As detailed in the accompanying affidavit of

⁶ Feb. 2026 Eddystone Order at 10, Ordering Para. G (emphasis added).

⁷ Constellation also requests the Commission waive any other provision it deems necessary.

Constellation Transmission Analytics Manager Yonas Habtemichael, who previously spent eight years in transmission planning at PJM, the waivers will enable Crane and its resilient, clean, baseload megawatts to provide reliability and affordability benefits as quickly as possible to address PJM’s “rapid” need for new Capacity Resources, while Eddystone Units 3 and 4 remain available as energy-only resources, as they are today. This approach utilizes the Eddystone CIRs most efficiently, since they are not currently being used, creating a win-win for customers.

Finally, granting these waivers will not harm any third parties. The proposed CIR transfer would not shift *any* interconnection costs or otherwise disadvantage the other projects under development. Nor will it in *any way* affect the completion of the Contingent Facilities, which were planned and are being constructed outside the generator interconnection process.

To enable Constellation to transfer the Eddystone CIRs to Crane and modify Crane’s interconnection request accordingly at Decision Point II, positioning Crane to provide the benefits of over 800 MW of new supply as soon as possible, Constellation respectfully requests that the Commission grant the requested waivers no later than June 1, 2026. If necessary, and for the same reasons, the Commission can grant the same relief exercising its discretion under FPA section 309 to “issue . . . such orders . . . as it may find necessary or appropriate to carry out the [Act].”⁸

I. BACKGROUND

A. Crane Clean Energy Center

In September 2024, Constellation announced its plan to develop the Crane Clean Energy Center—the restart of Three Mile Island Unit 1—to provide over 800 MW of dispatchable, baseload capacity to the PJM grid by 2028.⁹ After the Commission approved PJM’s Reliability

⁸ 16 U.S.C. § 825h.

⁹ See Exhibit 1, Affidavit of Yonas Habtemichael in Support of Constellation Energy Generation LLC’s Request for Limited Waiver (“Habtemichael Aff.”) ¶ 6.

Resource Initiative (“RRI”) to expedite review of “shovel-ready resources” that “can most effectively contribute to reliability,”¹⁰ Constellation submitted an interconnection request for Crane to participate in RRI. On May 2, 2025, PJM notified Constellation that it had included Crane and 50 other shovel-ready projects in RRI, paving the way for those projects to join Transition Cycle #2 in the study process rather than waiting for the next available study cycle.¹¹ Based on that selection and the exceptional work of the project team, Constellation has endeavored to advance the date for Crane to begin generating critically needed megawatts from 2028 to 2027.¹² Constellation has entered into a 20-year front-of-the-meter offtake agreement under which the plant will deliver its full output to the grid.

During the Phase I Study, however, PJM identified numerous regionally planned and allocated transmission projects and subparts as Contingent Facilities for Crane’s interconnection.¹³ Contingent Facilities are “unbuilt . . . Network Upgrades upon which the Interconnection Request’s costs, timing, and study findings are dependent and, if delayed or not built, could cause a need for restudies of the Interconnection Request”¹⁴ These Contingent Facilities were all regionally planned and approved by PJM before Constellation submitted Crane’s RRI interconnection request, and include hundreds of miles of new 765 kV and 500 kV transmission

¹⁰ PJM Interconnection, L.L.C., *PJM Chooses 51 Generation Resource Projects To Address Near-Term Electricity Demand Growth* (May 2, 2025), <https://insidelines.pjm.com/pjm-chooses-51-generation-resource-projects-to-address-near-term-electricity-demand-growth/>.

¹¹ See Habtemichael Aff. ¶ 7; Constellation Energy Corp., *Constellation Reports Second Quarter 2025 Results* (Aug. 7, 2025), <https://investors.constellationenergy.com/node/9361/pdf>.

¹² Habtemichael Aff. ¶ 9.

¹³ *Id.* ¶ 14.

¹⁴ Tariff § 300.C; see also Habtemichael Aff. ¶¶ 14-15 (describing the same). When PJM identifies a Contingent Facility for a project in the queue, the project’s ability to come online prior to the completion of the Contingent Facility will depend on the outcome of “interim deliverability” studies that PJM performs separately for each Delivery Year. PJM Interconnection, L.L.C., PJM Manual 14H: New Service Requests Cycle Process § 4.10.1.3 (Rev. 3, Eff. Sept. 25, 2025) (“Manual 14H”), <https://www.pjm.com/-/media/DotCom/documents/manuals/m14h.pdf>.

lines with projected in-service dates as late as December 2030.¹⁵ Many of these projects have already incurred years of delays and could be delayed further.¹⁶ Unlike typical Network Upgrades, these Contingent Facilities are not developed for or funded by interconnecting resources.¹⁷

If the Contingent Facilities are included in Crane’s final interconnection agreement, Crane will not be considered “fully deliverable” until *each and every* Contingent Facility is completed—even if they are delayed.¹⁸ In the meantime, Crane will be subject to annual Interim Deliverability Studies that will determine whether and to what extent Crane can provide capacity and energy to the grid, leaving its full reliability and affordability benefits uncertain and at risk.¹⁹ Hence, even if these transmission projects finish on time, Crane’s full deliverability could be in limbo until December 2030, three years or more after Constellation expects it will be ready to generate.²⁰

B. Eddystone Generating Station

Eddystone Generating Station Units 3 and 4 are roughly 50-year-old oil and gas units in Pennsylvania, each with a generating capacity of 380 MW.²¹ These units lack the operational flexibility of modern combustion turbine and combined cycle facilities; among other things they take a significantly longer time to start up and synchronize to the grid, which introduces significant penalty exposure under PJM’s Capacity Performance construct. Constellation announced its plans to retire Eddystone Units 3 and 4 on December 1, 2023, and submitted deactivation requests to

¹⁵ Habtemichael Aff. ¶ 16.

¹⁶ *Id.*

¹⁷ *Id.* ¶ 14.

¹⁸ *Id.* ¶¶ 16-17; *see also* Manual 14H § 4.10.1.3 (describing Interim Deliverability Studies).

¹⁹ Habtemichael Aff. ¶ 15.

²⁰ *Id.* ¶ 16.

²¹ *Id.* ¶ 20.

PJM and the Market Monitor at the same time.²² In early 2024, both PJM and the Market Monitor notified Constellation that, in their view, it could proceed with deactivation.²³

On May 30, 2025, the day prior to the scheduled deactivation, the Secretary issued an order declaring that the “operational availability and economic dispatch of . . . Eddystone Units 3 and 4 (Eddystone Units) is necessary to best meet [an] emergency and serve the public interest for purposes of FPA section 202(c).”²⁴ The Secretary therefore directed PJM and Constellation to “take all measures necessary to ensure that Eddystone Units [3 and 4] are available to operate” through August 28, 2025.²⁵ The Secretary has extended the Eddystone orders three times, most recently on February 23, 2026. Although the February Eddystone Order will expire on May 24, 2026, the Secretary may continue to renew the orders as the “emergency conditions . . . continue [] both in the near and long term.”²⁶ Notably, the Secretary has ordered that “the Eddystone Units shall not be considered capacity resources.”²⁷

C. Transferring Capacity Interconnection Rights

For many years, the PJM Tariff has allowed for the transfer of capacity interconnection rights held by one entity at one location to another. Based on its review and analysis of the Crane Phase I Report, Constellation has determined that transferring the Eddystone CIRs to Crane will enable Constellation to expedite Crane’s full deliverability and improve its position for interim deliverability in the meantime. CIRs are the rights “to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection.”²⁸ Transferring CIRs

²² *Id.*

²³ *Id.*

²⁴ May 2025 Eddystone Order at 2.

²⁵ *Id.* at 3, Ordering Paras. A, G.

²⁶ Feb. 2026 Eddystone Order at 3.

²⁷ *See, e.g., id.* at 10, Ordering Para. G.

²⁸ Tariff § 300.C (Capacity Interconnection Rights).

from an existing resource can provide electric interconnection benefits to a new entrant—even if it is interconnected at a different point—because the two resources may have similar effects on downstream transmission lines.²⁹ In such a case, the CIR transfer may not be 1:1, but to the extent the new entrant obtains transferred CIRs, PJM may not attribute certain reliability violations to the new entrant, nor condition its interconnection on the resolution of those violations.³⁰ The upshot is that with the transferred CIRs, the new resource may not be responsible for certain mitigations—such as waiting for the construction of Contingent Facilities to be completed—that PJM would otherwise require.³¹

That is just the case for Crane and Eddystone. Although Crane will interconnect to the grid about 100 miles northwest of Eddystone, Constellation’s analysis of the Crane Phase I Report and subsequent modeling posted by PJM confirm that Crane and Eddystone contribute similarly to a number of the identified reliability violations.³² Thus, as described below and in the attached affidavit, transferring the Eddystone CIRs to Crane will address a significant number of the reliability violations identified in the Crane Phase I Report, both enabling Constellation to expedite Crane’s full deliverability and improving its position for providing interim deliverability. And because Eddystone Units 3 and 4 are precluded by the Secretary’s orders from participating in the market as Capacity Resources, the transfer would have no effect on their operations; those resources would remain available as energy resources to PJM for reliability dispatch as required by the Secretary’s FPA section 202(c) orders, just as they are today.

Transferring the Eddystone CIRs to Crane requires two steps and associated waivers:

²⁹ Habtemichael Aff. ¶ 21.

³⁰ *Id.*

³¹ *Id.*

³² *See id.* ¶ 24.

Step One: Removing Capacity Resource Status. Constellation must first make the Eddystone CIRs available for transfer. A Capacity Resource owner can transfer CIRs following a change in Capacity Resource status.³³ The Tariff authorizes PJM, as relevant here, to remove a unit's Capacity Resource status if (i) the Market Monitor determines that the change in Capacity Resource status will not create market power issues; or (ii) the Commission issues an order terminating the Capacity Resource status.³⁴

Constellation respectfully requests a waiver of the Market Monitor's review because it would be redundant, there is no possibility of withholding given Eddystone's unique status as a non-capacity resource under DOE's directive, and the transfer requires additional waivers to effectuate it. As discussed in greater detail below, the Market Monitor already completed the same analysis in connection with Eddystone Units 3 and 4's proposed deactivation. Indeed, Constellation was within 24 hours of deactivating Eddystone Units 3 and 4 when the Secretary issued the May 2025 Eddystone Order. At the same time, the Secretary has ordered that Eddystone Units 3 and 4 "shall not be considered capacity resources," and directed Constellation "to file with FERC tariff revisions or waivers to effectuate this Order, as needed."³⁵ Granting this waiver would effectuate the Secretary's direction and eliminate the need for Constellation to seek future accommodations to implement it, including must-offer exceptions.

The waiver also avoids subjecting Constellation to a catch-22. If Constellation were to request a Capacity Resource status change and PJM approved it, that change may be irreversible,

³³ Tariff § 328.C.3. A Capacity Resource owner can also transfer CIRs after a deactivation (*id.*), which follows a different process with distinct requirements. *Cf.* Tariff § 328.C.3 (imposing additional requirements for "any claim for Capacity Interconnection Rights from deactivating units"). Relying on deactivation here is impractical given that Eddystone Units 3 and 4 may be subject to additional orders from the Secretary.

³⁴ Tariff Attach. DD § 6.6(g).

³⁵ See Feb. 2026 Eddystone Order at 10, Ordering Paras. E, G.

immediately starting the one-year clock for transferring the Eddystone CIRs (described just below).³⁶ But Constellation requires the other requested waivers herein to transfer the Eddystone CIRs to Crane. Constellation, in that scenario, would be in a “use it or lose it” situation for the Eddystone CIRs without any assurance that its sacrifice of the CIRs would benefit Crane’s timeline in any way.³⁷ Considering the waivers together avoids that risk and ensures the Eddystone CIRs can be used most beneficially for PJM customers.

Step Two: Transferring CIRs to Crane. Following removal of Capacity Resource status, the “holder” can transfer CIRs to a new resource under development, provided it “has submitted a completed Generation Interconnection Request . . . up to one year from the date the Capacity Resource status changes take effect”³⁸ Constellation will comply with this requirement because it submitted its Crane interconnection request prior to the Eddystone CIRs becoming available. However, for the same reason, Constellation will need to amend its interconnection request for Crane at the next opportunity in the interconnection process, Decision Point II, which PJM anticipates will begin in June 2026.³⁹ Doing so will require waiving two Tariff provisions.⁴⁰

First, Constellation requests a waiver of Tariff § 311.B.4, which provides that a Project Developer “may not request a modification that is not expressly allowed” at Decision Point II.⁴¹ Unless the Commission waives this provision, Crane would be required to “withdraw its New

³⁶ See Tariff § 328.C.3.

³⁷ Constellation’s transmission planning team studied a scenario of simply relinquishing the rights to the system, which is, in effect, what might happen if the second part of the waivers were not granted. In sum, because of the way Eddystone is currently modeled by PJM, the benefit from relinquishing the rights is too diffuse to provide the benefit needed at Crane to clear the contingencies. Habtemichael Aff. ¶ 24.

³⁸ Tariff § 328.C.3.

³⁹ See Habtemichael Aff. ¶ 8.

⁴⁰ The requested waivers would only enable Constellation to transfer the Eddystone CIRs to Crane. It would not authorize Constellation to make a further transfer.

⁴¹ Tariff § 311.B.4.a.

Service Request and resubmit the New Service Request with the proposed modification in a subsequent Cycle” to effectuate the transfer.⁴² But given PJM’s anticipated schedule for Cycle #1, submitting a new interconnection request would likely delay Crane receiving an interconnection agreement at least to 2028, after Constellation hopes to begin generating.⁴³ And although the Tariff does not expressly allow a developer to modify the source of CIRs at Decision Point II, as explained, this waiver is necessitated by a confluence of unique and exigent circumstances and would not delay the Transition Cycle #2 study process or harm other projects.

Second, out of an abundance of caution, Constellation also requests a waiver of Tariff § 306.E.5. Under that provision, “no changes to an RRI Project’s Maximum Facility Output or Capacity Interconnection Rights shall be allowed at any point prior to the time the Project Developer enters into a Generation Interconnection Agreement or Wholesale Market Participation Agreement.”⁴⁴ Constellation is not seeking to change the number of CIRs for Crane, which appears to be the target of the Tariff’s restriction. It will only request to reflect the transfer of the Eddystone CIRs to Crane. But to the extent the Commission considers the transfer a “change[] to . . . [Crane’s] Capacity Interconnection Rights,” Constellation respectfully requests a waiver.

II. REQUEST FOR WAIVER

To enable Constellation to transfer the Eddystone CIRs to Crane and to modify Crane’s interconnection request accordingly at Decision Point II, expected to span from June 2, 2026 to July 1, 2026, Constellation respectfully requests that the Commission grant one-time, limited, prospective waivers of (i) Tariff Attachment DD § 6.6(g) and (ii) Tariff §§ 306.E.5 and 311.B.4. Doing so is critical to ensure that Crane can provide its full reliability and affordability benefits to

⁴² *Id.*; see also Habtemichael Aff. ¶ 28 (explaining the same).

⁴³ Habtemichael Aff. ¶ 28.

⁴⁴ Tariff § 306.E.5.

PJM customers as quickly as possible. The Commission grants waiver of tariff provisions where: “(1) the applicant acted in good faith; (2) the waiver is of limited scope; (3) the waiver addresses a concrete problem; and (4) the waiver does not have undesirable consequences, such as harming third parties.”⁴⁵ Constellation meets each requirement.

This request is consistent with three similar waivers recently granted by the Commission. In *NextEra Energy Duane Arnold, LLC*, for example, the Commission granted waivers to enable the recommissioning of the Duane Arnold nuclear power facility to benefit from the Midcontinent Independent System Operator, Inc.’s (“MISO”) Generator Facility Replacement Process, potentially bypassing MISO’s interconnection process.⁴⁶ Duane Arnold required waivers of MISO’s tariff because several factors made it otherwise ineligible for the expedited process.⁴⁷ Likewise, in granting PJM’s requested waiver to allow Susquehanna Nuclear, LLC to restore 148 MW of CIRs it had planned to use to serve co-located load, the Commission highlighted that the CIRs would address “the tightening system conditions” and “the resource adequacy concerns in PJM.”⁴⁸ And in *Idaho Power Company*, the Commission granted waivers of interconnection procedures to allow a developer to change the point of interconnection for three projects without submitting a new interconnection request to “ensur[e] that the Projects can be energized and serve load on schedule.”⁴⁹ The Commission should reach the same outcome as in those proceedings and grant the waivers here.

⁴⁵ E.g., *Talen Energy Mktg., LLC*, 183 FERC ¶ 61,167 at P 17 (2023) (“*Talen*”); *Parkway Generation Essex, LLC*, 179 FERC ¶ 61,132 at P 14 (2022) (“*Parkway*”).

⁴⁶ *NextEra Energy Duane Arnold, LLC*, 192 FERC ¶ 61,175 at PP 1-3 (2025).

⁴⁷ *Id.* at P 13.

⁴⁸ *PJM Interconnection, L.L.C.*, 193 FERC ¶ 61,180 at PP 27-31 (2025) (citation omitted).

⁴⁹ *Idaho Power Co.*, 189 FERC ¶ 61,219 at PP 1, 6, 14 (2024).

A. Good Faith

Constellation's request is made in good faith, as confirmed by four key factors:

First, Constellation has committed significant resources to bringing Crane online as quickly as safely possible.⁵⁰ Overall, Constellation is investing approximately \$1.6 billion to complete the restart project.⁵¹ Based on the magnitude of this investment and importance of the project to millions of PJM customers, the U.S. Department of Energy is backing Crane with a \$1 billion loan.⁵² Constellation is also directly taking responsibility for expediting Crane's full deliverability where it can. For example, Constellation entered into an Upgrade Construction Service Agreement ("UCSA") to expedite the construction of the Network Upgrade PJM required for the Jackson-TMI 230 kV line.⁵³ Constellation is fully funding this work at a cost of roughly \$100 million,⁵⁴ despite the fact that further studies could reveal that a project with reduced scope would suffice. Constellation has further agreed to fund another network upgrade fully, even though it ultimately may have shared the costs with other projects.⁵⁵ These facts confirm Constellation's commitment to Crane and to expediting its full deliverability for PJM customers.

Second, in early 2025, before submitting its interconnection request for Crane, Constellation conducted extensive internal modeling to assess what steps, if any, it could take to

⁵⁰ *E.g.*, *NextEra Energy Duane Arnold*, 192 FERC ¶ 61,175 at P 29 (spending \$50 to \$100 million to expedite commercial operation demonstrates good faith).

⁵¹ *See* Constellation Energy Corp., Annual Report (Form 10-K) at 39 (Feb. 18, 2025).

⁵² U.S. Dep't of Energy, Energy Department Closes Loan to Restart Nuclear Power Plant in Pennsylvania (Nov. 18, 2025), <https://www.energy.gov/articles/energy-department-closes-loan-restart-nuclear-power-plant-pennsylvania>.

⁵³ *See* Upgrade Construction Service Agreement by and Among PJM Interconnection, L.L.C., Constellation Energy Generation, LLC, and Mid-Atlantic Interstate Transmission, LLC, Appendix I ¶ C (Mar. 18, 2026), <https://www.pjm.com/-/media/DotCom/temporary-files/ur25-0005-ucsa.pdf>.

⁵⁴ *See id.*

⁵⁵ *Habtemichael Aff.* ¶ 13 n.1.

mitigate potential delays in Crane’s interconnection process.⁵⁶ It did not appear then that the transfer of the Eddystone CIRs would accelerate Crane’s deliverability.⁵⁷ Although that analysis was necessarily based on imperfect assumptions—most notably, including the composition of the cluster in which Crane was to be studied—there was no basis then to attempt to complete the transfer.⁵⁸ Such a transfer may not have been possible anyway, as neither trigger for transferring CIRs had been met; Eddystone Units 3 and 4 had not deactivated and PJM had not changed their Capacity Resource status.⁵⁹

Constellation first learned of the Contingent Facilities for Crane on October 31, 2025, when it received PJM’s Phase I Study results.⁶⁰ Constellation then immediately began analyzing PJM’s results and conducting its own modeling, which required a detailed, iterative review that remains ongoing.⁶¹ Through that effort, as detailed in Mr. Habtemichael’s accompanying affidavit, Constellation determined that transferring the Eddystone CIRs to Crane would address a number of the reliability violations identified in the Crane Phase I Report, both enabling Constellation to accelerate Crane’s full deliverability and improving its position for interim deliverability in the meantime.⁶² This waiver request followed soon after.

Third, this waiver request is prospective. Constellation is requesting this waiver to have the opportunity to transfer the Eddystone CIRs to Crane and then modify its interconnection request for Crane at Decision Point II, scheduled to begin in June 2026. PJM would then review

⁵⁶ *Id.* ¶ 22.

⁵⁷ *Id.*

⁵⁸ *Id.*

⁵⁹ *See* Tariff § 328.C.3.

⁶⁰ Habtemichael Aff. ¶ 14.

⁶¹ *Id.* ¶¶ 18, 24.

⁶² *Id.* ¶¶ 18, 23-28.

Crane’s modified interconnection request in its Phase III study thereafter. Both steps would be enabled by, and occur after, Commission approval of this waiver request.

Fourth, the Market Monitor has already conducted the market power analysis for changing a generator’s Capacity Resource status envisioned under Tariff Attachment DD § 6.6. When a generator owner submits a deactivation notice, the Market Monitor will “analyze the effects of the proposed deactivation with regard to potential market power issues.”⁶³ That is *exactly the same* review the Tariff contemplates for removing a unit’s Capacity Resource status: The Market Monitor will “analyze the effects of the proposed removal of a Generation Capacity Resource from Capacity Resource status with regard to potential market power issues”⁶⁴ There is no daylight between these analyses—the capacity market effect of deactivating a resource and removing its status as a Capacity Resource is exactly the same. And there is no risk of Constellation engaging in withholding the Eddystone Units from the capacity market when the Secretary, in mandating that Eddystone Units 3 and 4 remain available, specified that “the Eddystone Units shall not be considered capacity resources.”⁶⁵ To the contrary, Constellation is seeking to bring additional supply online. The Market Monitor’s confirmation that deactivating Eddystone Units 3 and 4 would result in no market power concerns applies equally to removing Eddystone’s Capacity Resource status now—if not more so. And in any case, as noted above, the Tariff *specifically contemplates* the Commission’s ability to direct a change in Capacity Resource status separate from the Market Monitor’s review.⁶⁶

⁶³ PJM Interconnection, L.L.C., PJM Manual 14D: Generator Operational Requirements § 9.1.2 (Rev. 70, Eff. Dec. 17, 2025), <https://www.pjm.com/-/media/DotCom/documents/manuals/m14d.pdf>; Tariff § 113.1. PJM has not revised the Market Monitor’s review since Constellation submitted its deactivation notice for Eddystone Units 3 and 4.

⁶⁴ Tariff Attach. DD § 6.6(g).

⁶⁵ *E.g.*, Feb. 2026 Eddystone Order at 10, Ordering Para. G.

⁶⁶ *See* Tariff Attach. DD § 6.6(g).

B. Limited Scope

Constellation's request is of limited scope. The same unique circumstances that make transferring the Eddystone CIRs to Crane enormously beneficial to PJM customers also make it virtually unrepeatable. That is true because of features of both Eddystone and Crane.

Beginning with Eddystone, as noted, Units 3 and 4 were scheduled to deactivate, were subsequently required to remain available under orders pursuant to FPA section 202(c), and specifically were prohibited from participating as capacity resources.⁶⁷ These facts are significant. Putting aside the rarity of orders issued under FPA section 202(c), it is because of the confluence of these unusual factors that:

- (1) PJM and the Market Monitor previously approved Eddystone Units 3 and 4 to deactivate, including following the Market Monitor's market power review;
- (2) Eddystone has remained online well past its planned retirement date, but the CIRs cannot be used to provide value to PJM customers; and
- (3) PJM has been modeling Eddystone in its interconnection studies in a manner where transferring the Eddystone CIRs can only help (and not harm) other projects.⁶⁸

The benefits that Crane will provide to the region only add to the factors making this waiver request unique and highly unlikely to recur:

- (1) PJM selected Crane to participate in the RRI process for expedited interconnection review because it was a "shovel-ready resource" that "can most effectively contribute to reliability;"⁶⁹

⁶⁷ See, e.g., Feb. 2026 Eddystone Order at 10, Ordering Para. G.

⁶⁸ Habtemichael Aff. ¶ 31.

⁶⁹ PJM Interconnection, L.L.C., *PJM Chooses 51 Generation Resource Projects to Address Near-Term Electricity Demand Growth* (May 2, 2025), <https://insidelines.pjm.com/pjm-chooses-51-generation-resource-projects-to-address-near-term-electricity-demand-growth/>.

- (2) As a restart of a previously operating nuclear resource, Constellation expects Crane to be physically able to generate in the second half of 2027, and to receive relevant Nuclear Regulatory Commission approvals to do so in early 2027;⁷⁰
- (3) In its Phase I Study reviewing Crane, PJM identified Contingent Facilities that could delay Crane's full deliverability for more than three years after Crane is available to generate;⁷¹
- (4) Using the Phase I Study results and additional modeling, Constellation determined that transferring CIRs from Eddystone Units 3 and 4 (which were scheduled to deactivate but are available under emergency FPA section 202(c) orders) will remove meaningful barriers to Crane serving customers, advance its full deliverability, and improve its position for interim deliverability—a resource adequacy benefit to PJM and all stakeholders;⁷² and
- (5) Constellation will not modify any other aspect of Crane's interconnection request, including Crane's point of interconnection or the amount of CIRs requested.

Simply put, this is a goldilocks opportunity. These circumstances present a one-time opportunity for the Commission to ensure that more than 800 MW of baseload, dispatchable capacity can support customers and the grid as quickly as possible.

C. Concrete Problem

The proposed waivers here directly address a significant, concrete problem: Numerous Contingent Facilities may prevent Crane's full deliverability, potentially depriving PJM of significant reliability and affordability benefits *for years*. Without waivers, if the dozens of

⁷⁰ Habtemichael Aff. ¶ 26.

⁷¹ *Id.* ¶¶ 14-17.

⁷² *Id.* ¶¶ 22-28.

Contingent Facilities identified in the Crane Phase I Report are included in Crane’s interconnection agreement, Crane’s ability to provide its full capabilities will be at risk *at least* through December 31, 2030—long after Crane will be available to generate.⁷³ But as Mr. Habtemichael explains, by enabling Constellation to transfer the Eddystone CIRs to Crane and incorporate them into Crane’s interconnection request at Decision Point II, the waivers will (1) expedite Crane’s full deliverability, and (2) improve Crane’s position for interim deliverability in the meantime, both of which directly benefit PJM customers.

Full Deliverability. In the Crane Phase I Report, PJM identified steady-state thermal reliability violations relating to Crane on ten unique facilities—violations on seven 500 kV facilities and three 230 kV facilities.⁷⁴ Constellation’s modeling indicates that the combination of transferring the Eddystone CIRs to Crane and updates in PJM’s posted Phase II case would address ***all of the violations affecting 500 kV facilities.*** This result, in turn, would eliminate many of the most significant Contingent Facilities from Crane’s violations, including hundreds of miles of new 765 kV and 500 kV lines, and a number of facilities with December 2030 in-service dates.⁷⁵

Constellation, meanwhile, is actively working to resolve the violations affecting the remaining three 230 kV facilities and believes it will be successful in doing so. Violations on one 230 kV facility will be addressed by the UCSA Constellation entered to expedite Network Upgrades at Constellation’s sole expense.⁷⁶ Constellation believes violations on a second 230 kV

⁷³ *Id.* ¶ 17; *see also Idaho Power Co.*, 189 FERC ¶ 61,219 at P 18 (finding a “concrete problem” where interconnection challenges could “result in construction delays”).

⁷⁴ Habtemichael Aff. ¶ 12.

⁷⁵ *Id.* ¶ 25. While there are no guarantees, the modeling conducted by Constellation’s transmission planners indicates with enough certainty that the transfer is expected to significantly advance Crane’s timeline that Constellation is taking the calculated risk of seeking a permanent transfer of the CIRs to Crane.

⁷⁶ *Id.* ¶¶ 13, 26.

facility will be resolved with the completion of certain transmission projects in June 2027.⁷⁷ Constellation is actively analyzing solutions for the violations affecting the final 230 kV facility, and is “very optimistic [it] will be successful, facilitating Crane reaching full deliverability well in advance—and likely years before—December 31, 2030.”⁷⁸

Beyond ensuring Crane can provide its reliability and affordability benefits to PJM customers, achieving full deliverability and eliminating the year-to-year risks associated with Interim Deliverability Studies are especially important for Crane as a nuclear unit. *First*, the uncertainty caused by interim deliverability status could create challenges for Constellation both in terms of procuring nuclear fuel and long-lead-time nuclear materials needed to operate the plant, as well as planning outages for refueling and maintenance. *Second*, unlike other technologies, nuclear units face potential equipment reliability challenges—like elevated vibration and wear—when operating for extended periods below rated power output, as could be required following Interim Deliverability Studies. And *third*, Crane’s operations will be supported by hundreds of highly skilled employees *on site*. Constellation cannot simply toggle the plant on and off year-to-year following PJM’s Interim Deliverability Studies. For these reasons, it is even more important for Crane to achieve full deliverability rather than be subject to annual interim deliverability studies.

In sum, if Constellation can transfer the Eddystone CIRs to Crane, it will only need to address a single remaining violation to advance Crane’s full deliverability, and believes it is likely it will be able to do so.⁷⁹ Without the CIR transfer, multiple violations affecting 500 kV facilities would remain, making it far less likely Constellation will be able to advance Crane’s full

⁷⁷ *Id.* ¶ 26.

⁷⁸ *Id.*

⁷⁹ *Id.*

deliverability from the current December 2030 projection.⁸⁰ Additionally, Crane would be exposed to potential delays from Contingent Facilities, many of which have already been delayed by years, further impairing Crane’s ability to provide its full reliability and affordability benefits.⁸¹

Interim Deliverability. Expediting Crane’s full deliverability will provide the greatest benefits to the PJM region, but transferring the Eddystone CIRs to Crane will also improve resource adequacy and affordability even before all of the remaining violations are addressed. PJM’s interim review process is not “all or nothing.”⁸² Anything that mitigates the identified reliability violations can also improve a unit’s deliverability—and therefore its ability to provide capacity and energy year-to-year—until any lingering Contingent Facilities are completed. Here, addressing the violations affecting 500 kV facilities will naturally reduce the obstacles to Crane serving the PJM system, “both increasing the likelihood that PJM awards CIRs and energy injection rights following an Interim Deliverability Study and the quantity of each that PJM allows.”⁸³ At bottom, transferring the Eddystone CIRs to Crane will best position Crane to serve the grid and its customers’ load to the maximum extent practicable as soon as possible.

There are no viable alternatives to the proposed CIR transfer. For example, withdrawing and resubmitting Crane’s interconnection request would only make matters worse. Crane would lose its spot in Transition Cycle #2 and the soonest Constellation would be able to execute a Generator Interconnection Agreement would be well into 2028.⁸⁴ The next cycle also will likely

⁸⁰ *Id.*

⁸¹ *Id.* ¶ 16.

⁸² *See id.* ¶ 15.

⁸³ *Id.* ¶ 27.

⁸⁴ *Id.* ¶ 28.

have a base case study year of 2029/2030—a year later than the base case study year for the RRI projects—before which Crane would also be subject to Interim Deliverability Studies.⁸⁵

Finally, it bears underscoring that eliminating potential barriers to Crane’s ability to operate and provide all of its benefits as soon as possible is paramount. The Secretary has declared “that an emergency exists in [PJM] due to . . . a shortage of facilities for the generation of electric energy,” and that emergency will “continue[] both in the near and long term.”⁸⁶ NERC similarly declared PJM is at a “high risk” of energy shortages as of 2029 as a result of “an extreme and rapid tightening of supply and demand for capacity resources,” necessitating “resources to rapidly address [the] near-term reliability challenges.”⁸⁷ And in the 2027/2028 Base Residual Auction, PJM for the first time ever failed to procure sufficient supply to meet the one-day-in-ten-years reliability standard.⁸⁸ PJM not only needs new entry as soon as possible, but the *right kind* of entry. As NERC has emphasized, given the amount of renewable penetration and intermittent resources in the queue, “an adequate supply of thermal resources *will be needed* to maintain grid stability.”⁸⁹

There is virtually no better remedy to PJM’s resource adequacy challenges than adding more than 800 MW of dispatchable baseload nuclear generation in Southern Pennsylvania. Bipartisan state and federal leaders agree. Secretary Wright has called Crane the “poster child” for achieving national reliability and affordability goals.⁹⁰ Governor Shapiro, likewise, has touted

⁸⁵ See Manual 14H § 4.10.1.3.

⁸⁶ Feb. 2026 Eddystone Order at 1, 3.

⁸⁷ NERC Assessment at 92.

⁸⁸ PJM Interconnection, L.L.C., *2027/2028 Base Residual Auction Report* (Dec. 17, 2025), <https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-bra-report.pdf>.

⁸⁹ NERC Assessment at 93.

⁹⁰ See White, *Three Mile Island is ‘Poster Child’ of Trump Energy, AI Agenda: US Energy Secretary*, Lancaster Online (Dec. 18, 2025), <https://lancasteronline.com/news/politics/three-mile-island-is-poster->

that “Crane Clean Energy Center will help us achieve” Pennsylvania’s goals of “cut[ting] energy costs and ensur[ing] the reliability of our energy grid”⁹¹ These waivers are required to realize those broad benefits as soon as possible.

In short, granting this waiver request will facilitate Crane achieving full deliverability as soon as possible—and maximize its ability to provide capacity and energy in the interim. Both are critical to enable Crane to provide the essential reliability and affordability benefits associated with over 800 MWs of new supply.

D. Harm to Third Parties

Constellation’s requested waiver will, as indicated above, provide significant reliability and affordability contributions to PJM at a time both are critically needed. The waiver will do so without any known harms to third parties.

No Delay to Transition Cycle #2. Constellation’s requested waiver will not delay PJM’s interconnection study process. PJM has already designed its study process to accommodate developers modifying interconnection requests at Decision Point II, and Constellation has no reason to believe that the proposed transfer would disrupt PJM’s Phase III study.

No Effects on Other Projects. Constellation is not aware of any potential cost shifts or other potential harms to third-party developers that would result from the proposed CIR transfer.⁹²

Crane does not share network upgrade responsibility with any other project.⁹³ And the Contingent

child-of-trump-energy-ai-agenda-us-energy-secretary/article_a15599f5-554c-4bd9-9658-5e3066e445ba.html; U.S. Dep’t of Energy, *Energy Department Closes Loan to Restart Nuclear Power Plant in Pennsylvania* (Nov. 18, 2025), <https://www.energy.gov/articles/energy-department-closes-loan-restart-nuclear-power-plant-pennsylvania>.

⁹¹ Constellation Energy Corp., *Constellation to Launch Crane Clean Energy Center, Restoring Jobs and Carbon-Free Power to The Grid* (Sept. 20, 2024) (quoting Governor Josh Shapiro), <https://www.constellationenergy.com/newsroom/2024/Constellation-to-Launch-Crane-Clean-Energy-Center-Restoring-Jobs-and-Carbon-Free-Power-to-The-Grid.html>.

⁹² Constellation agrees to reimburse PJM for any additional study or processing costs caused by this request.

⁹³ Habtemichael Aff. ¶ 30.

Facilities that Constellation seeks to resolve with this waiver request are regionally planned projects that PJM included in the RTEP prior to Crane’s interconnection request whose costs are allocated to load—they are not assigned to any developer. Therefore, the CIR transfer will have no financial impact on other projects in the queue whatsoever.⁹⁴ Constellation’s review of PJM’s modeling in the Phase I Study results (including PJM’s treatment of Eddystone), moreover, confirms that the proposed CIR transfer is not expected to affect any other project in the cluster.⁹⁵

No Effects on Transmission Development. Although Constellation anticipates that transferring the Eddystone CIRs to Crane will eliminate many Contingent Facilities from Crane’s Generator Interconnection Agreement, that will have no effect whatsoever on the development of the Contingent Facilities themselves. Again, Crane has no cost responsibility for those RTEP projects, and they were planned and are being developed outside of the generator interconnection process. Their inclusion as Contingent Facilities in no way affects their development. If anything, as noted above, Constellation’s request here would *benefit* customers region-wide by enabling Crane to come online and provide supply in a tight market as soon as possible.

No Market Power Concerns. There are no market power concerns. As discussed above, the Market Monitor has already determined there are no market power concerns with deactivating Eddystone Units 3 and 4—removing Eddystone Units 3 and 4’s Capacity Resource status is no different. That is especially true where the Secretary has directed that Eddystone “shall not be considered capacity resources.”⁹⁶ Indeed, transferring the Eddystone CIRs to Crane will enhance competition in PJM by enabling Crane to add supply to the PJM market as soon as possible.

⁹⁴ *Id.*

⁹⁵ *Id.* ¶ 31.

⁹⁶ Feb. 2026 Eddystone Order at 10, Ordering Para. G.

III. REQUEST FOR REMEDIAL RELIEF

None of the waivers requested herein are retroactive, but if required, the Commission can grant the same relief using its authority under FPA section 309 to “issue . . . such orders . . . as it may find necessary or appropriate to carry out the [Act].”⁹⁷ “Section 309 [] permits FERC to advance remedies not expressly provided by the FPA, as long as they are consistent with the Act.”⁹⁸ The relief requested here—to support the unencumbered entry of more than 800 MW of new baseload, dispatchable supply—plainly supports a primary purpose of the Federal Power Act: “[T]he orderly development of plentiful supplies of electricity . . . at reasonable prices.”⁹⁹ Thus if necessary, and for the same reasons described above, the Commission can grant the requested relief under FPA section 309.

⁹⁷ 16 U.S.C. § 825h; *see also* *Waiver of Tariff Requirements*, 193 FERC ¶ 61,135 at P 3 (2025) (describing requests for remedial relief).

⁹⁸ *Verso Corp. v. FERC*, 898 F.3d 1, 10 (D.C. Cir. 2018); *see also* *Niagara Mohawk Power Corp. v. FPC*, 379 F.2d 153, 158 (D.C. Cir. 1967) (Section 309 authorized FERC “to use means of regulation not spelled out in” the Federal Power Act, “provided the agency’s action conforms with the purposes and policies of Congress and does not contravene any terms of the Act.”).

⁹⁹ *NAACP v. FPC*, 425 U.S. 662, 669-70 (1976) (citations omitted).

IV. COMMUNICATIONS

Correspondence and communications with respect to this proceeding should be addressed to the following:¹⁰⁰

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V. CONCLUSION

In light of the exigent circumstances described above, Constellation respectfully requests limited, one-time waivers of the indicated Tariff provisions to provide Constellation the opportunity to transfer the Eddystone CIRs to Crane and modify Crane's interconnection request at Decision Point II, which is expected to begin on June 2, 2026. Doing so will facilitate Crane providing its full benefits to PJM customers as soon as possible, contributing to key reliability and affordability goals. Constellation respectfully requests the Commission grant the waivers no later than June 1, 2026.

¹⁰⁰ Constellation respectfully requests waiver of 18 C.F.R. § 385.203(b)(3) to permit the designation of more than two persons upon whom service is to be made in this proceeding.

Dated: March 31, 2026

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CERTIFICATE OF SERVICE

I hereby certify that I have this day caused to be served the foregoing document and Exhibit 1 on counsel for PJM Interconnection, L.L.C. and counsel for the Independent Market Monitor for PJM.

Dated: March 31, 2026

/s/ Zachary B. Cohen
Zachary B. Cohen

EXHIBIT 1

**AFFIDAVIT OF YONAS K.
HABTEMICHAEL**

MARCH 31, 2026

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Constellation Energy Generation, LLC	)))	Docket No. ER26-_____
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**AFFIDAVIT OF YONAS K. HABTEMICHAEL IN SUPPORT OF
CONSTELLATION ENERGY GENERATION, LLC’S
REQUEST FOR PROSPECTIVE, LIMITED WAIVER**

I. Qualifications, Assignment, and Summary of Conclusions.

1. My name is Yonas K. Habtemichael. I am a Manager in the Transmission Analytics Organization at Constellation Energy Generation, LLC (“Constellation” or the “Company”). My business address is 1310 Point St., Baltimore, Maryland 21231.

2. I hold a Master of Engineering in Power Systems from Worcester Polytechnic Institute, a Master of Business Administration from Pennsylvania State University, and a Bachelor of Science in Electrical Engineering from Drexel University.

3. I have more than 18 years of experience in transmission planning and wholesale markets, including conducting reliability analyses, power flow modeling, and congestion analyses and modeling. In my current role, I support Constellation’s commercial activities in PJM. I contribute to long-term planning, hedging, and investment decisions by overseeing transmission modeling and congestion analysis. I also manage key analytical projects and align system-level modeling with operational and strategic needs, including directing and conducting power-flow studies to assess transmission reliability constraints. Prior to assuming my current role, from 2016 to 2024, I served as a Principal Transmission Specialist at Constellation, where I led technical studies examining congestion patterns, system limitations, and the congestion impacts of market conditions. I performed production-cost simulation analyses to evaluate outages, fuel and load trends, and policy developments. I also supported the development of hedging approaches informed by transmission system conditions.

4. I previously worked at PJM Interconnection, L.L.C. (PJM) from 2008 to 2016, both in the Transmission Planning and Interregional Planning departments. My work at PJM included performing baseline power-flow studies for the Regional Transmission Expansion Plan (RTEP), evaluating the effectiveness of proposed transmission reinforcements, building and validating

system models with Transmission Owners, and contributing to planning-related reports. I also collaborated with bordering independent system operators and regional transmission organizations on interregional studies and performed reliability analyses to assess reliability and system performance under a range of future scenarios.

5. In this Affidavit, I explain how transferring the Capacity Interconnection Rights (“CIRs”) for Eddystone Generating Station (“Eddystone”) Units 3 and 4 (the “Eddystone CIRs”) to the Crane Clean Energy Center (“Crane”) will expedite Constellation’s efforts to make Crane fully deliverable, likely by years, and meaningfully improve Crane’s position to provide capacity and energy in the meantime. I begin by describing Crane and explaining why Contingent Facilities identified in the Phase I Study Report for Crane (“Crane Phase I Report”) could delay Crane’s full deliverability—and thus its ability to provide all of its capacity and energy benefits to PJM—to the end of 2030. I then describe how Constellation identified transferring the Eddystone CIRs to Crane as a key solution for addressing reliability violations identified in the Crane Phase I Report. Finally, I explain that transferring the Eddystone CIRs to Crane will not adversely affect any third parties, including through cost shifts.

II. Overview of the Crane Clean Energy Center and its Interconnection Process.

6. Constellation is developing the Crane Clean Energy Center—the restart of Three Mile Island Unit 1—to provide a maximum facility output of 859 MW of dispatchable, baseload, carbon-free generation to the PJM grid in Southern Pennsylvania.

7. In 2025, FERC approved PJM’s Reliability Resource Initiative to accelerate the interconnection of shovel-ready reliability projects by allowing them to join Transition Cycle #2, rather than waiting for Cycle #1. Doing so would reduce the time for selected projects to complete the interconnection study process and execute a Generator Interconnection Agreement by an estimated 14 months. On May 2, 2025, PJM notified Constellation that it had selected Crane as one of the 51 Reliability Resource Initiative (“RRI”) projects, thus allowing Crane to join Transition Cycle #2 in 2025 rather than waiting for Cycle #1 to begin in mid-2026.

8. Transition Cycle #2 includes three study phases, after which developers negotiate and execute Generator Interconnection Agreements with PJM and the applicable Transmission Owner. PJM provides the below schedule for Transition Cycle #2 (future dates subject to change):

- **RRI Application Window:** Feb. 28, 2025 – Mar. 14, 2025
- **RRI Project Selection:** May 2, 2025
- **Phase I:** July 7, 2025 – Oct. 31, 2025
- **Decision Point I:** Nov. 3, 2025 – Dec. 2, 2025
- **Phase II:** Dec. 3, 2025 – June 1, 2026
- **Decision Point II (estimated):** June 2, 2026 – July 1, 2026
- **Phase III (estimated):** July 2, 2026 – Dec. 28, 2026
- **Decision Point III (estimated):** Dec. 29, 2026 – Jan. 27, 2027
- **Final Agreement Negotiation (estimated):** Dec. 29, 2026 – Feb. 26, 2027

At each decision point, developers must meet certain development criteria and submit a deposit to proceed, or they may elect to withdraw from the process.

9. Based on the rapid progress made to date on the restart of the nuclear facility itself, Crane could be ready to generate power as early as 2027.

III. Contingent Facilities May Delay Crane’s Deliverability, and Thus its Full Reliability and Affordability Benefits.

10. PJM released the Crane Phase I Report on October 31, 2025.

11. During the Phase I Study, PJM used its standardized summer peak, winter peak, and light-load RTEP base cases to identify reliability violations caused by the Transition Cycle #2 cluster of projects, including Crane. At a high level, by modeling load flows during summer and winter peak conditions, as well as under light load conditions, PJM assessed deliverability and the steady-state thermal and voltage impacts of the cluster. Where PJM identified new or worsened thermal or voltage violations after modeling the Transition Cycle #2 projects, PJM identified the transmission solution(s) needed to ensure reliability and assigned cost responsibility based on each project’s contribution to the violation, as provided in the Tariff.

12. The Crane Phase I Report determined that Crane contributed to steady-state thermal reliability violations on ten unique facilities—seven 500 kV facilities and three 230 kV facilities.

13. In the Crane Phase I Report, PJM identified network upgrades required to mitigate some, but not all, of the Crane reliability violations. The most significant required network upgrade is rebuilding and/or reconductoring the Jackson – Three Mile Island 230 kV line, for which Constellation was assigned 100% cost responsibility. Constellation has separately executed an

Upgrade Construction Service Agreement (“UCSA”) with the Transmission Owner, Mid-Atlantic Interstate Transmission, LLC (“MAIT”), and PJM, to begin this work as soon as possible.¹

14. In addition to the required network upgrades, the Crane Phase I Report identified certain “Contingent Facilities” for Crane—transmission enhancements that were already planned to be constructed, and that therefore will not be cost-allocated to Crane. Constellation did not know that Crane would be subject to the completion of Contingent Facilities prior to receiving the Crane Phase I Report. All of these Contingent Facilities included in the Crane Phase I Report are regional or backbone reinforcements that are not directly cost-allocated to Crane or any other proposed generation project.² Rather, these projects included in the Regional Transmission Expansion Plan (“RTEP”) will be cost-allocated to load. In short, while certain reliability violations that Crane contributed to will be resolved through network upgrades funded by Crane, other reliability violations will be resolved once already-planned transmission projects enter service.

15. Completion of Contingent Facilities, however, is a necessary condition precedent before generation projects are considered fully deliverable, and thus can affect when a new generation project can come online. When PJM includes Contingent Facilities in a Generator Interconnection Agreement, the Interconnection Customer’s ability to sell capacity and energy will be subject to annual Interim Deliverability Studies until those Contingent Facilities are completed. Interim Deliverability Studies assess the extent to which a project is deliverable despite the unfinished upgrades and award corresponding Capacity Interconnection Rights and energy injection rights. Interim Deliverability Studies are conducted annually and are only valid for the Delivery Year studied.

16. The Contingent Facilities identified in the Crane Phase I Report are wide ranging, including hundreds of miles of new 765 kV and 500 kV transmission lines across the mid-Atlantic, as far away as southern Virginia and West Virginia. Critically, the current projected in-service dates for many of these projects are well after Crane will be available to generate and after all other network upgrades will be completed, and extend as late as December 31, 2030. More than half of the

¹ With one exception, Crane is the sole project allocated costs for the identified network upgrades. Specifically, PJM assigned Crane \$137,130 of \$364,562 associated with replacing a wave trap on the Keystone-Cabot 500 kV line. Based on my review of PJM data, I believe the reliability violations from Crane that triggered the Keystone Wave Trap replacement will likely be eliminated. Regardless, I understand that Constellation has agreed to fully fund the Wave Trap replacement.

² See PJM Open Access Transmission Tariff, § 300.C (Contingent Facilities).

Contingent Facilities have already experienced delays, including 21 that have been delayed three or more years.

17. Based on the Crane Phase I Report, assuming the projected in-service dates hold, the soonest Crane will be “fully deliverable”—that is, not subject to annual Interim Deliverability Studies for capacity interconnection and energy injection rights—is December 31, 2030—more than three years after Constellation hopes Crane will be physically available to supply the grid. That full deliverability date could easily slip if the Contingent Facilities are delayed.

18. After receiving the Crane Phase I Report, Constellation began carefully reviewing the results to understand the causes of the reliability violations and to identify other solutions to mitigate them, with the goal of achieving Crane’s full deliverability as soon as possible. As described below, one of the most important actions Constellation has identified for addressing the identified reliability violations, expediting Crane’s full deliverability, and best positioning Crane for interim deliverability in the meantime, is transferring the Eddystone CIRs to Crane.

IV. Transferring the Eddystone CIRs to Crane Will Expedite Crane’s Deliverability.

A. Constellation Can Transfer the Eddystone CIRs to Crane.

19. PJM defines CIRs as “a resource’s right to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System.”³ At a high level, CIRs represent the quantity of a generator’s output that PJM has determined can be delivered to load under peak conditions without causing reliability violations. CIRs are awarded through PJM’s interconnection process and Interim Deliverability Studies, and are required for a resource to qualify for participation in PJM’s capacity market.

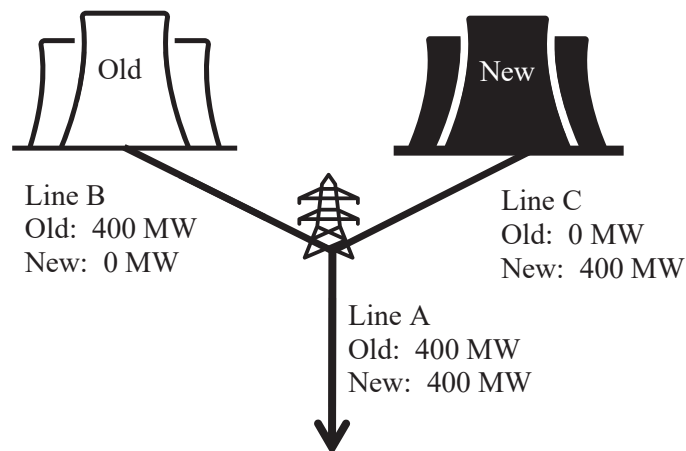
20. Eddystone Generating Station Units 3 and 4 are roughly 50-year-old oil and gas units in Pennsylvania, each with a generating capacity of 380 MW. On December 1, 2023, Constellation announced it would retire Eddystone Units 3 and 4, and submitted deactivation requests to PJM and the Market Monitor at the same time. In early 2024, both PJM and the Market Monitor approved the deactivation. Hours before the planned deactivation, on May 30, 2025, the U.S. Secretary of Energy issued an order pursuant to section 202(c) of the Federal Power Act directing PJM and Constellation to keep Eddystone Units 3 and 4 available to operate. The Department of

³ Tariff § 300.C (Capacity Interconnection Rights).

Energy has repeatedly extended its orders. The Department of Energy’s directives prevent PJM from treating Eddystone as a Capacity Resource. Accordingly, the Eddystone CIRs are not currently providing any value to the system or to customers.

21. PJM allows resource owners to transfer CIRs under conditions provided in the Tariff, including to resources that interconnect to the transmission system at a different point of interconnection. That is because a generator’s output is distributed across the transmission system in accordance with power flow principles. PJM assesses CIR transferability by comparing system effects of the transferring and receiving resources on the system. The impacts, known as “MW Contribution,” are derived from the distribution factors of the generators to the violations. Although a CIR transfer to a new point of interconnection does not necessarily have a 1:1 MW Contribution, when the receiving resource’s MW Contribution on a given line is equal to or less than the transferring resource’s MW Contribution, the receiving resource is deemed not responsible for the violations and required mitigations—including Contingent Facilities.

Consider the following simplified example of the retiring “Old Generator” and the entering “New Generator,” which we will assume have the same output. Without the CIR transfer, New Generator causes a violation on Line A. But because Old Generator and New Generator have the same MW Contribution to Line A, transferring the CIRs from Old Generator will eliminate the assignment of the violation and required mitigations on Line A to New Generator.



22. Prior to submitting the Interconnection Service Request for Crane, Constellation conducted extensive internal modeling and considered various options for accelerating Crane’s full deliverability, including transferring the Eddystone CIRs to Crane. Based on the information

available to Constellation at that time, which did not even include the composition of the cluster Crane would be studied with, it did not appear that doing so would benefit Crane. Thus, even if it were possible to complete the CIR transfer then, there was no basis then for Constellation to attempt to complete it. Now that PJM has completed the Crane Phase I Report and has posted additional data to model, Constellation has been able to determine that transferring the Eddystone CIRs is a sensible path forward to accelerate Crane's deliverability.

B. Transferring the Eddystone CIRs to Crane will Support Expediting Crane's Full Deliverability and Improve its Position for Interim Deliverability.

23. The most effective action Constellation can take both to expedite Crane's full deliverability and improve its position for interim deliverability in the meantime, is to transfer the Eddystone CIRs to Crane.

24. After receiving the Crane Phase I Report, Constellation performed a reliability assessment mirroring PJM's methodology, but transferring the Eddystone CIRs to Crane. Constellation reviewed each violation identified in the Crane Phase I Report and compared Crane's and Eddystone's MW Contributions to those constraints. Based on that modeling and Constellation's evaluation of PJM's publicly posted Phase II study case, I expect that the combination of the Eddystone CIR transfer and updates in the posted Phase II case will address the violations on *all seven* of the 500 kV violations related to Crane. Constellation separately evaluated relinquishing the Eddystone CIRs rather than transferring them to Crane. The effects, however, were too diffuse to address any of the violations that PJM identified in the Crane Phase I Report.

25. Fully addressing the violations on the 500 kV facilities—leaving only the violations on the 230 kV facilities—will expedite Constellation's efforts to make Crane fully deliverable. Doing so will eliminate at least 30 of the Contingent Facilities in the Crane Phase I Report, including some of the most significant projects. These include hundreds of miles of new transmission lines in Virginia and West Virginia, some of which have projected in-service dates as late as the end of 2030. Addressing the violations triggering these Contingent Facilities will ensure Crane (1) is not dependent on the completion of these facilities, which PJM or the developer could modify; and (2) is not subject to the in-service dates for these projects, some of which are many years beyond when Constellation hopes Crane will begin generating, and could slip even further because of permitting or construction delays.

26. At the same time, Constellation is actively working to identify solutions for the violations on the three 230 kV facilities. Constellation will resolve the violations on one 230 kV facility through the UCSA it entered with MAIT and PJM (noted above), which will expedite construction of the network upgrades cost-allocated to Crane. Constellation has accepted full cost responsibility for that work. Our analysis indicates that the violations on the second remaining 230 kV facility will be fully resolved by a transmission facility under development that is expected to enter service in June 2027. As to the violations on the final 230 kV facility, Constellation is actively exploring all options, including entering other UCSAs with applicable transmission owners, at Constellation's expense, needed to alleviate the violations. Although this work is not yet fully complete, I am very optimistic that Constellation will be successful, facilitating Crane reaching full deliverability well in advance—and likely years before—December 31, 2030. Because addressing the violations on the 500 kV facilities is a prerequisite for Crane to achieve full deliverability, Constellation's ability to advance Crane's full deliverability could be limited—and is certainly far less likely—without transferring the Eddystone CIRs to Crane.

27. Transferring the Eddystone CIRs will also meaningfully improve Crane's interim deliverability prospects prior to the plant reaching full deliverability, including if Constellation is unable to resolve the final 230 kV violation. Addressing the violations on the 500 kV facilities will naturally reduce the obstacles to Crane serving the PJM system, both increasing the likelihood that PJM awards CIRs and energy injection rights following an Interim Deliverability Study and the quantity of each that PJM allows.

28. Transferring the Eddystone CIRs to Crane at Decision Point II is the only feasible way to improve Crane's deliverability when Constellation believes it will be available for customers. Constellation's only alternative is to drop out of Transition Cycle #2 and reapply in Cycle #1, but under PJM's schedule, projects in Cycle #1 will not execute Generator Interconnection Agreements at least until February 2028. Re-applying in Cycle #1 eliminates any chance that Crane would be available to PJM and its customers in 2027.

V. Transferring the Eddystone CIRs to Crane Will Not Harm Any Third Parties.

29. Based on my review of Constellation's modeling and analysis, transferring the Eddystone CIRs to Crane will not have any adverse effects on third parties.

30. With respect to cost, all of the identified Contingent Facilities are regionally cost allocated to load as RTEP baseline upgrades, meaning that no generator projects in the queue are receiving

any cost allocations for those projects and removing assignment of those Contingent Facilities to Crane will not affect the cost allocations. Meanwhile, because Crane is the only project assigned to the remaining Network Upgrades, or has otherwise agreed to fund them fully, any changes to those projects will not affect other generators in the queue. Moreover, the proposed CIR transfer is not expected to mitigate the 230kV violations, including the remaining Network Upgrade.

31. Transferring the Eddystone CIRs to Crane also will not affect other projects' deliverability. Although CIRs provide a resource the right to use the transmission system, the CIRs do not change how PJM models the system. Put another way, PJM will model Crane the same both without the Eddystone CIRs and with them. Furthermore, Eddystone Units 3 and 4 were modeled as deactivated resources in the Transition Cycle #2 Phase I case. Accordingly, those units were dispatched in the Phase I case only to contribute to violations (i.e., harmer), but not to mitigate issues. Consequently, removing the Eddystone CIRs will not adversely impact other projects and may benefit other projects.

ATTESTATION

State of Maryland)

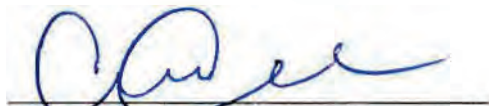
City of Baltimore)

I, Yonas K. Habtemichael, swear that the above and foregoing is true and correct to the best of my information, knowledge, and belief.


Yonas K. Habtemichael

SWORN AND SUBSCRIBED BEFORE ME

This 31 day of March 2026


Notary Public

My Commission Expires: 4/25/2027



Exhibit 37



Department of Energy
Washington, DC 20585

Constellation Energy Corp. and
PJM Interconnection, L.L.C.
Regarding Eddystone Unit 3 and Unit 4

Order No. 202-26-40

Pursuant to the authority vested in the Secretary of Energy (Secretary) by section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,² and for the reasons set forth below, I hereby determine that an emergency exists in the PJM Interconnection, L.L.C. (PJM) region of the, due to a sudden increase in demand, a shortage of electric energy, a shortage of facilities for the generation or transmission of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The Eddystone Generating Station is a power plant owned by Constellation Energy Corporation (Constellation Energy) and located in Eddystone, Pennsylvania. Units 3 and 4 (Eddystone Units), each with 380 MW of generation capacity, are subcritical steam boiler-turbine generator units that run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order Nos. 202-25-04, 202-25-08, 202-25-10, 202-26-17, and 202-26-24, issued pursuant to FPA section 202(c), each required that the Eddystone Units remain available to operate for 90 days, until August 28, 2025, November 26, 2025, February 24, 2026, May 24, 2026, and August 22, 2026, respectively. Those orders were based on my determination that emergency conditions existed in the PJM region.

Specifically, I determined that there was a potential shortage of electric energy and a shortage of facilities for the generation of electric energy.³ I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety.⁴ I determined that continued operation and economic dispatch of the Eddystone Units was necessary to best meet the emergency and serve the public interest.⁵

My determination was based on a number of different facts. First, in congressional testimony, PJM's then President and CEO stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of dispatchable

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ See, e.g., *PJM Interconnection, L.L.C.*, Order No. 202-26-24, at 10 (May 21, 2026).

⁴ *Id.* at 9.

⁵ *Id.* at 9 & Ordering Para. A.

resources, and other factors.⁶ Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM’s interconnection queue.⁷ Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that “available generation capacity may fall short of required reserves in an extreme planning scenario.”⁸ In its February 2023 assessment, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, PJM highlighted increasing reliability risks in the coming years due to the “potential timing mismatch between resource retirements, load growth and the pace of new generation entry” under “low new entry” scenarios for renewable generation.⁹

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found “the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry.”¹⁰

Fourth, PJM’s resource adequacy concerns were recently demonstrated during Winter Storm Fern, when PJM operated under a cold weather alert and declared conservative operations from January 24 to February 2, 2026. Due to concerns about resource adequacy from the high demand driven by the extreme cold, PJM also applied for an order pursuant to FPA section 202(c) “that broadly authorizes all electric

⁶ *Keeping the Lights On: Examining the State of Reg’l Reliability; Hearing Before the House Comm. on Energy & Com., Subcomm. on Energy*, 119th Cong. 4–5 (2025) (testimony of Mr. Manu Asthana, President and CEO, PJM) [hereinafter Asthana Test.], <https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf>.

⁷ *Id.*; see also *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 15 (2025) (“PJM states . . . that, in 2023, it found that generator retirements, load growth, the pace of new entry, and the operating characteristics of the intermittent and limited duration resources that make up a large part of PJM’s interconnection queue pose increasing reliability risks through 2030.”).

⁸ *PJM Summer Outlook 2025: Adequate Res. Available for Summer Amid Growing Risk*, PJM INSIDE LINES (May 9, 2025), <https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/>.

⁹ PJM, *Energy Transition in PJM: Res. Rets., Replacements & Risks*, at 1 (Feb. 24, 2023) [hereinafter *Four Rs Report*], <https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx>.

¹⁰ *PJM Interconnection*, 190 FERC ¶ 61,084 at P 14.

generating units located within the PJM Region to operate up to their maximum generation output levels, notwithstanding air quality or other permit limitations or fuel shortages during the pendency of this emergency.”¹¹ DOE granted PJM’s application and issued Order No. 202-26-02 on January 25, 2026.¹² From January 27, 2026, until early February 2026, PJM issued multiple alerts and warnings.¹³

On January 29, 2026, PJM applied for an extension of Order No. 202-26-02, which was designated as Order No. 202-26-02A, which was granted by the Department on the same day.¹⁴ Furthermore, on March 17, 2026, in his testimony to the House Committee on Energy and Commerce, North American Electric Reliability Corporation (NERC) Chief Executive Officer Jim Robb stated that “PJM and other grid operators indicated that 202(c) facilities made material contributions” with regard to reliability during Winter Storm Fern.¹⁵

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-04, 202-25-08, 202-25-10, 202-26-17, and 202-26-24 continue, both in the near and long term.¹⁶ The production of electricity from the Eddystone Units will continue to be a critical asset for maintaining reliability in PJM. According to data from the U.S.

¹¹ Letter from Michael E. Bryson, Senior Vice Pres., Operations, PJM, to Hon. Chris Wright, Sec’y, DOE, at 2 (Jan. 4, 2026) (requesting emergency order under FPA section 202(c)), <https://www.energy.gov/documents/pjm-202c-application-2026-01-24>.

¹² *PJM Interconnection, L.L.C.*, Order No. 202-26-02 (Jan. 25, 2026).

¹³ See *PJM Interconnection, L.L.C., Emergency Procedures—Postings*, <https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf>; see, e.g., Jan. 27 *PJM Cold Weather Operations Update*, PJM INSIDE LINES (Jan. 27, 2026), <https://insidelines.pjm.com/jan-26-pjm-cold-weather-operations-update/>.

¹⁴ *PJM Interconnection, L.L.C.*, Order No. 202-26-02A (Jan. 29, 2026).

¹⁵ *Winter Storm Fern Lessons: Supplying Reliable Power to Meet Peak Demand; Hearing Before the House Comm. on Energy & Com., Subcomm. On Energy*, 119th Cong. 8 (2026) (statement of James B. Robb, President and CEO, NERC), <https://www.congress.gov/119/meeting/house/119077/witnesses/HHRG-119-IF03-Wstate-RobbJ-20260317.pdf>.

¹⁶ Further, it likely would be difficult for these units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Moreover, if Constellation Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. Thus, continued operation is required in such cases so long as the Secretary determines that an emergency exists. The costs and time of decommissioning a power plant are extensive and includes various components. Therefore, restarting such decommissioned plants could have significant costs in terms of dollars and time. See, e.g., Lessick, Jennifer et al. *Bus. Models for Coal Plant Decommissioning* § 4, PAC. NW. NAT’L LAB’Y (Aug. 2021), <https://www.osti.gov/servlets/purl/1821476>.

Environmental Protection Agency (EPA), the Eddystone Units generated 27,239 MWh between August 2025 and March 2026,¹⁷ providing vital generation capacity to the region. Over the summer of 2025, PJM issued multiple alerts and warnings to manage grid operations and reliability, covering a total of 20 days, including days in June, July, and August.¹⁸ Similar actions have occurred already for summer 2026. In May, June, and July, PJM requested emergency orders for backup and non-backup generators due to high temperatures resulting in high demand forecasts, causing potential reliability issues. This resulted in the issuance of several emergency orders, namely, DOE Order Nos. 202-26-23, 202-26-24, 202-26-32, 202-26-32A, 202-26-33, 202-26-33A, and 202-26-35, with the last one ending at midnight of July 21, 2026.¹⁹ These emergency orders helped PJM manage high demand, including an instantaneous peak demand of 162.7 GW on July 2, 2026, that was higher than PJM's previously forecasted peak summer demand of 156.4 GW.²⁰

PJM's resource adequacy concerns are well documented. In January 2025, PJM reached a new record peak for winter demand, exceeding the previous winter peak set in 2015.²¹ PJM notes that the "20-year annualized growth rate in the 2025 Long-Term Load Forecast for the winter peak is up to 2.4%."²² Further, PJM's risk profile continues to shift from the summer season to the winter season. For example, in a March 2025

¹⁷ See EPA, *Custom Data Download*, EPA CAMPD (Clean Air Mkts. Program Data), <https://campd.epa.gov/data/custom-data-download> (choose "Emissions" from Data Type dropdown; choose "Monthly Emissions" from Data Subtype dropdown; choose "Unit (No Aggregation)" from Aggregation dropdown; then click "Apply"; then type "2025" into "Time Period" filter and click "August, September, October, November, December"; then click "Apply Filter"; then click "Facility" filter and type "Eddystone Generating Station (3161)"; then click "Eddystone Generating Station (3161)"; then click "Apply Filter"; then click "Preview Data"; then change the "Time Period" to "2026" and click "January, February, March"; then click "Apply Filter"; then click "Preview Data").

¹⁸ See PJM, *Emergency Procs.*, <https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf> (search Effective From 06/01/2025 Effective To 08/31/2025).

¹⁹ See 2026 DOE 202(c) Orders, Department of Energy, <https://www.energy.gov/ceser/2026-doe-202c-orders>.

²⁰ Penn. Pub. Util. Comm'n, *Summer 2026 PJM Reliability Assessment*, at 5 (May 2026), https://www.puc.pa.gov/media/3965/2026_pjm_summer_readiness_report.pdf. See also *PJM Hot Weather Operations Update: July 3*, PJM INSIDE LINES (July 3, 2026), <https://insidelines.pjm.com/pjm-hot-weather-operations-update-july-3/>.

²¹ *Jan. 22 Update: Extreme Cold Produces PJM Record for Winter Elec. Demand*, PJM INSIDE LINES (Jan. 22, 2025), <https://insidelines.pjm.com/jan-22-update-extreme-cold-produces-pjm-record-for-winter-electricity-demand/>.

²² *2025 Long-Term Load Forecast Rep. Predicts Significant Increase in Elec. Demand*, PJM INSIDE LINES (Jan. 30, 2025), <https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/>.

presentation, PJM estimated that 87.8% of the expected unserved energy for the 2025/2026 delivery year falls in the winter season.²³

Recognizing the need for and importance of additional generation resources, on April 20, 2026, a Consent Decree between the Commonwealth of Pennsylvania and Keystone-Conemaugh Projects, LLC (KEY-CON) authorized operations to continue at two coal-fired steam electric generating plants that were slated for permanent cessation. The Consent Decree explained that “[d]ue to recent changes in the long-term electricity market outlook based on recent projections by PJM Interconnection LLC and the U.S. Department of Energy, including the need for electricity generators to cover projected increased electrical demand driven by build-out of data centers, particularly within the Mid-Atlantic Area Council, a portion of the PJM Interconnection LLC regional transmission organization that KEY-CON has recently reevaluated its 2021 decision to achieve [permanent cessation of coal combustion] at the [Conemaugh Generating Station and Keystone Generating Station] by December 31, 2028.”²⁴

In the fall of 2025, Pennsylvania Governor Josh Shapiro recognized the need for and importance of securing more electricity generation for the grid. Governor Shapiro stated that “[c]hange is needed to keep energy costs low, bring new energy generation onto the grid more quickly, and meet the needs of the 67 million Americans who rely on this grid for everything from running a business to keeping the lights on at home.”²⁵ Furthermore, PJM expressed support for Order No. 202-25-04, since it has “repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers.”²⁶

²³ PJM Res. Adequacy Planning Special Planning Comm., *2026/27 BRA IRM, FPR, & ELCC Class Ratings: Shift Towards More Winter Risk*, at 8 (Mar. 13, 2025), <https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf>.

²⁴ COMMONWEALTH OF PENN., DEP’T OF ENV’T PROT. V. KEYSTONE-CONEMAUGH PROJECTS, LLC, No. 2169-CD-2025-1, slip op. at 4 (Apr. 20, 2026) (Unopposed Motion to Enter Consent Decree), <https://www.pa.gov/content/dam/copapwp-pagov/en/governor/documents/motion%20to%20enter%20cd-as%20filed.pdf>.

²⁵ Kate Huangpu, *How Josh Shapiro wants to reshape the region’s power grid operator as prices rise*, SPOTLIGHT PA (Oct. 14, 2025), <https://www.spotlightpa.org/news/2025/10/electricity-prices-shapiro-grid-operator-pjm-data-centers-environment/>.

²⁶ *PJM Statement on the U.S. Dept. of Energy 202(c) Order of May 30*, PJM INSIDE LINES (May 31, 2025), <https://insidelines.pjm.com/pjm-statement-on-the-u-s-department-of-energy-202c-order-of-may-30/>. Further, PJM concluded, “In light of these concerns, PJM supports the U.S. Department of Energy’s Order, issued May 30, pursuant to Section 202(c) of the Federal Power Act, to defer the retirements of certain generators operating in PJM’s footprint.” *Id.*

PJM has voiced these concerns for years. In its February 2023 *Four Rs Report*, PJM cautioned that 40 GW of thermal generation are at risk of retirement by 2030.²⁷ PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for renewable projects is approximately 5%.²⁸ PJM determined that the pace of new capacity additions “would be insufficient to keep up with expected retirements and demand growth by 2030.”²⁹ PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.³⁰

In its December 2024 RRI filing with FERC, PJM stated that “[c]oncerns about resource adequacy . . . have only increased since the *Four Rs Report*.”³¹ PJM warned that its “resource adequacy concerns are increasing at an extraordinary pace.”³² PJM went on to explain that its “resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers” and that its preliminary analysis shows “substantial increases [in load additions] since the 2024 forecast” for both the summer and winter seasons.³³ According to PJM, “load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence.”³⁴ Although the RRI process will help expedite the construction of needed new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.³⁵

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM’s Director of Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as “extraordinary” and “unprecedented,” stating that it “could not have been foreseen as recently as a year ago.”³⁶ Mr. Bielak expressed the opinion that the “rapid” retirement of thermal generation resources, “extreme”

²⁷ *Four Rs Report*, *supra* note 9, at 2.

²⁸ *Id.*

²⁹ *Id.* at 16 tbl. 1.

³⁰ *Id.*

³¹ PJM, Filing, Dkt. No. ER25-712-000, at 10 (filed Dec. 13, 2024).

³² *Id.*

³³ *Id.* at 10–11; *see also id.* at 13 (stating that “the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements”).

³⁴ *Id.* at 14.

³⁵ *See id.* attach. C (Affidavit of Mr. Donald Bielak), at 18–19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, “could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner”).

³⁶ Bielak Aff. at 10.

forecasted load growth, and “delays in new generation resources achieving commercial operation,” would adversely affect resource adequacy throughout PJM’s electricity grid.³⁷

On February 11, 2025, FERC accepted PJM’s proposed tariff revisions in its RRI filing.³⁸ In its order on rehearing, FERC concluded that “PJM identified increasing reliability risks arising in the next few years and significant resource adequacy issues anticipated by the 2030/31 delivery year. The record supports that these resource adequacy concerns are likely to manifest.”³⁹

NERC has raised similar concerns. In its 2025 Long-Term Reliability Assessment, released in January 2026, NERC observed that the PJM region is at high risk of energy shortfalls over the next five years⁴⁰ and faces significant reliability challenges as “[c]urrent projections for resource additions do not keep pace with escalating demand forecasts and expected generator retirements.”⁴¹ The assessment notes that “[d]emand for electricity in PJM is growing at its fastest pace in years, driven primarily by data centers, followed by electrification and manufacturing loads”; however, “[a]t the same time, PJM faces an extreme and rapid tightening of capacity resources in the near term because of generator retirements and project delays.”⁴² Overall, the assessment concludes that “[b]ased 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.”⁴³

NERC released its 2026 State of Reliability (SOR) on June 24, 2026. In the SOR, NERC identifies worsening reliability concerns tied to large-load integration and localized operating stress. In its technical discussion of major system events, NERC states “shoulder seasons have become increasingly challenging for BPS operators to manage, resulting in several recent instances of pre-contingent load shedding.”⁴⁴ The SOR also finds large load growth is increasing reliability risk and states that “data center and computational loads continued emerging as a major reliability consideration due to their scale, speed of development, and unique operational characteristics.”⁴⁵ Finally, data in the SOR shows that 2025 PJM summer peak demand of 160.7 GW met or

³⁷ *Id.* at 12.

³⁸ *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 (2025); *see also, e.g., id.* P 263.

³⁹ *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,085, at P 25 (2025).

⁴⁰ NERC, *2025 Long-Term Reliability Assessment*, at 7 fig. 1 (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

⁴¹ *Id.* at 8.

⁴² *Id.* at 16.

⁴³ *Id.* at 91.

⁴⁴ NERC, *2026 State of Reliability Technical Assessment of 2025 Bulk Power System Performance*, at 5 (June 2026), https://nerc.com/globalassets/programs/rapa/pa/nerc_sor_2026_technical_assessment.pdf.

⁴⁵ *Id.* at vii.

exceeded extreme scenario levels showing how rapid load growth and extreme weather continue to be a risk in PJM.⁴⁶

DOE Order Nos. 202-25-04, 202-25-08, 202-25-10, 202-26-17, and 202-26-24 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 No. 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.”⁴⁷ 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.”⁴⁸ In the subsequent Executive Order No. 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.”⁴⁹

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 No. 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.”⁵⁰ The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.⁵¹ As of December 2024, Dominion Energy has 40.2 GW

⁴⁶ *Id.* at 30.

⁴⁷ Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), <https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency>.

⁴⁸ *Id.*

⁴⁹ Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), <https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid>.

⁵⁰ DOE, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025) [hereinafter Resource Adequacy Report], <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

⁵¹ See PPL Corp., *PPL Corp. Q2 2025 Investor Update*, at 7 (July 31, 2025), https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINAL.pdf.

of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.⁵² In collaboration with the national labs, the Department has modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced coal, gas, and oil generation retirements.⁵³ Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a maximum unserved load of approximately 21.335 GW.⁵⁴

Grid operators, including PJM, have likewise acknowledged the Nation’s current energy crisis. As mentioned earlier in this Order, PJM’s then President Manu Asthana testified that there was a “growing resource adequacy concern . . . impacting a significant part of our country.”⁵⁵ Mr. Asthana explained that the “rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from industrial growth.”⁵⁶ Mr. Asthana noted that, though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening.⁵⁷ Therefore, Mr. Asthana stated that PJM “encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability.”⁵⁸

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 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,” 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

⁵² See Dominion Energy Virginia, *Q4 2024 Earnings Call*, at 18 (Feb. 12, 2025), https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slides-vTCII.pdf.

⁵³ Resource Adequacy Report, *supra* note 50, at 28.

⁵⁴ *Id.* at 27.

⁵⁵ Asthana Test., *supra* note 6, at 4.

⁵⁶ *Id.*

⁵⁷ *Id.* at 9–10.

⁵⁸ *Id.* at 10.

emergency and serve the public interest.”⁵⁹ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity, or a shortage of electric energy or facilities for generation or transmission of electric energy.

As described above, the emergency conditions resulting from the increasing demand and shortage of electric energy from premature retirements of Eddystone Units will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas affected by curtailments or outages, presenting a risk to public health, safety, and security.

I have determined that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), the Eddystone Units shall be made available for operation through November 20, 2026.⁶⁰

⁵⁹ 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).

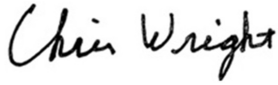
⁶⁰ 16 U.S.C. § 824a(c)(4).

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

- A. From August 23, 2026, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.
- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by PJM pursuant to paragraph A. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units have operated in compliance with the allowances contained in this Order.
- C. All operations of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees, or purchase offsets or allowances for emissions that occur during the emergency conditions, or to use other geographic or temporal flexibilities available to generators.
- D. By September 8, 2026, PJM 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 Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time.
- E. Constellation Energy 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 Eddystone Units to comply with applicable state, local, or Federal laws or regulations following the expiration of this Order.
- G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Eddystone Units shall not be considered capacity resource.

H. This Order shall be effective on August 23, 2026, through November 20, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 21st day of August 2026.



Chris Wright
Secretary of Energy

cc:

Federal Energy Regulatory Commission

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

Pennsylvania Public Utility Commission

Chairman Stephen M. DeFrank
Vice Chair Kimberly M. Barrow
Commissioner Kathryn L. Zarfuss
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora

Exhibit 38

July 27, 2026

Janine Tulloch-Reid
Facilities Permitting Chief
Pennsylvania Department of Environmental Protection

Southeast Region: Air Quality Program
2 East Main Street
Norristown, PA 19401
RA-EPSEROAQPUBCOM@pa.gov

**Re: Public Comment on Proposed Permit Amendment for Constellation Energy
Eddystone Generating Station - 23-00017 (56 Pa. Bull. 3,761 (June 27, 2026))**

Dear Ms. Reid,

We write on behalf of Citizens for Pennsylvania’s Future (“PennFuture”) and Natural Resources Defense Council (“NRDC”) opposing the proposed significant modification to the Title V operating permit for the Constellation Energy Generation station in Eddystone, Pennsylvania. The Pennsylvania Department of Environmental Protection (“PADEP” or “the Department”) should not allow the facility, which had two outdated and inefficient units slated to retire in May 2025, to instead become an area source of hazardous air pollutant emissions. The legal basis for the proposed permit modification—U.S. EPA’s “Reclassification of Major Sources as Area Sources Under Section 112 of the Clean Air Act” (“Reclassification Rule”)¹—is currently the subject of legal challenge because it conflicts with Section 112.² The Department should decline to issue a modification under a rule that is legally flawed, especially where, as here, the modification will harm the neighboring community, which already suffers from severe levels of industrial air pollution.

PennFuture is a member-supported, non-profit, environmental organization leading the fight for an equitable, job-creating state economy by advancing clean air, pure water, and climate change solutions through legal advocacy, policy engagement, and empowering all Pennsylvanians. Since 1998, PennFuture has combined legislative advocacy and legal enforcement at the local, state, and federal levels; policy development; educational outreach; and civic engagement support for just and equitable environmental outcomes. A significant focus of PennFuture’s work relates to building a sustainable energy economy in Pennsylvania.

NRDC is a national non-profit membership organization whose mission includes ensuring the rights of all people to clean air, clean water, and healthy communities. NRDC has a longstanding organizational commitment to protect the interests of its members and to reduce

¹ 85 Fed. Reg. 73,854 (Nov. 19, 2020).

² *Cal. Cmty. Against Air Toxics v. EPA*, No. 21-1024 (consol. with No. 21-1034) (D.C. Cir.).

pollution caused by fossil fuel fired power plants such as the Eddystone facility. NRDC works to achieve clean energy solutions that will lower consumer energy bills, meet greenhouse gas emission reduction goals, accelerate the use of energy efficiency and renewable energy, and ensure that clean energy is affordable and accessible to all.

We urge the Department to reject the application or, at a minimum, to defer action pending resolution of the litigation regarding the Reclassification Rule. The Department's priority should be to prevent increases in hazardous air pollutant emissions and protect the health and safety of the residents in the surrounding area.

A. PADEP should not allow the facility to increase its hazardous air pollutant emissions

First, it is reckless and inconsistent with the Department's obligations as a trustee of Pennsylvania's public natural resources to allow Constellation to increase hazardous air pollutant ("HAP") emissions. The proposed permit amendment would allow the Eddystone facility to escape compliance with federal Maximum Achievable Control Technology standards under 40 C.F.R. 63, Subpart DDDDD (covering industrial, commercial and institutional boilers and process heaters) and increase total HAP emissions up to 24.9 tons per year. *See* Significant Operating Permit Modification Application (Apr. 3, 2026) at 7–8 (proposing to delete Title V Permit No. 23-00017 Section E, Aux Boilers Condition Nos. 004, 007–010, 015–018, 021–024). The permit amendment would also allow the facility to abandon compliance with Subpart DDDDD's monitoring, record keeping and reporting requirements; no longer report monitoring semiannually through the Title V permit; no longer report deviations from compliance with Subpart DDDDD; and no longer certify compliance with Subpart DDDDD through the Title V permit. *See id.* Allowing the facility to avoid compliance and potentially emit additional HAPs into Pennsylvania's air is contrary to the Department's obligation to conserve and maintain air resources.

Second, the Eddystone community into which these HAPs are emitted is a community already overburdened with pollution. According to the PennEnviroScreen environmental justice screening tool, Eddystone is an environmental justice community. It has a pollution burden greater than the vast majority of Pennsylvania communities. It is inappropriate and unjust for this adjacent community to continue to bear the brunt of Eddystone's pollution.

Additionally, the Department should decline to approve the permit modification given the planned unit closures at the facility. The two largest units at the Eddystone plant—Units 3 and 4—are currently operating only due to a U.S. Department of Energy order that is contrary to law and is the subject of litigation. On December 1, 2023, Constellation notified regional transmission organization PJM of its intent to deactivate Eddystone Units 3 and 4 effective May 31, 2025. Units 3 and 4 are both 380 MW capacity steam boiler-turbine generator units that were installed between 1967 and 1970 and are "peakers," i.e., units that run only during periods of high demand. In that letter, Constellation explained that it was "retiring Eddystone Units 3 and 4

because continued operation of these units is expected to be uneconomic.” PJM then followed its internal processes to evaluate if closing these units would cause any reliability issues, determined that it would not, and gave permission to Constellation in February 2024 to deactivate the Eddystone units on May 31, 2025 or sooner.

However, the day before the units were scheduled to close, the U.S. Department of Energy ordered PJM and Constellation to ensure that Units 3 and 4 of the Eddystone Generating Station remain “available to operate” until August 28, 2025, and further directed PJM to “take every step to employ economic dispatch” during that time period. This order has subsequently been renewed multiple times. The Department of Energy pointed to its emergency authority under Section 202(c) of the Federal Power Act in support of its order; but as NRDC, PennFuture, and others have explained in litigation challenging that Order, there is no energy emergency in the PJM region, the Eddystone Units were scheduled to deactivate only following analysis showing that this would not cause any energy reliability issues, and the Order fails to meet the requirements for the government to invoke Section 202(c)’s extraordinary powers, which are reserved for sudden, imminent, and unexpected energy shortages. *See* Initial Joint Opening Br. of Public Interest Org. Pet’rs & Consumer Advocs., *Ill. Off. of Att’y Gen. v. Dep’t of Energy*, No. 25-1193 (consol. with Nos. 25-1194, 25-1287, 25-1288) (D.C. Cir. May 8, 2026) (attached as Ex. A).

The Department should decline to expand the operation and resultant emissions of a decrepit, polluting, uneconomic facility that was in part scheduled to close, and should have closed, over a year ago. This permit modification would do just that, and it should be rejected.

B. The proposed permit modification’s attempt to escape Subpart DDDDD is contrary to the Clean Air Act

The Clean Air Act defines a “major source” of HAPs as “any stationary source or group of stationary sources” with the potential to emit “10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination” of such pollutants, while an “area source” is “any stationary source of hazardous air pollutants that is not a major source.” 42 U.S.C. § 7412(a)(1), (2).

As noted above, Constellation seeks to take advantage of the Trump Administration’s Reclassification Rule, but that rule is unlawful and contrary to the Clean Air Act. The Reclassification Rule purports to apply an “area source” designation rather than a “major source” designation to a facility so long as it limits its “potential to emit” HAPs and adopts enforceable limits just below the two major source thresholds for HAPs (i.e. 10 tons per year of a single HAP, or 25 tons per year of all HAPs). *See* 85 Fed. Reg. at 73,878. In effect, a ‘reclassified’ source under the rule may increase HAP emissions from Maximum Achievable Control Technology (“MACT”)-controlled levels up to 9.9 tons for one HAP or 24.9 tons per year of all HAPs. *Id.*

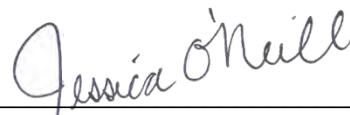
Applying the Reclassification Rule to the Eddystone facility would absolve the facility from its responsibility to comply with federal MACT standards that would otherwise apply, in this case 40 C.F.R. 63, Subpart DDDDD (covering industrial, commercial and institutional boilers and process heaters). Discarding MACT standards in favor of a limit just below the major source threshold places no meaningful constraint on emissions of pollutants like mercury and dioxins that are only emitted in pounds, grams, or even small fractions of a gram per year—orders of magnitude below the 10-ton threshold—yet are dangerous at these levels. *See* 63 Fed. Reg. 17,838, 17,847-48 (Apr. 10, 1998) (showing aggregate emissions by entire industrial categories in those small quantities).

The Reclassification Rule is unlawful because it conflicts with Clean Air Act Section 112's requirement that sources continue to comply with MACT standards after the standards' effective date. 42 U.S.C. § 7412(i)(3)(A). Litigation challenging the rule is ongoing. *Cal. Cmty. Against Air Toxics v. EPA*, No. 21-1024 (consolidated with No. 21-1034) (D.C. Cir.) (Opening and Reply Briefs attached as Ex. B). If the Reclassification Rule is struck down, sources like the Eddystone facility never should have 'reclassified' as an area source pursuant to the rule, the Eddystone facility will have been in violation of Subpart DDDDD for every day it was purporting to operate as an area source, and it will be required to resume compliance with the relevant MACT standards in Subpart DDDDD.

In short, PADEP should reject the permit modification on account of the important MACT standards—including emissions restrictions, monitoring, and recordkeeping requirements—that the modification seeks to sidestep. At the very least, PADEP should await the outcome of the D.C. Circuit litigation regarding the Reclassification Rule before processing the permit amendment. The health and safety of Pennsylvanians is at stake here, and the Department should prioritize that above the legally unsound proposed permit modification.

Thank you for your consideration of these comments.

Sincerely,

A handwritten signature in cursive script that reads "Jessica O'Neill". The signature is written in dark ink and is positioned above a horizontal line.

Jessica R. O'Neill
Managing Attorney for Litigation
Citizens for Pennsylvania's Future
1429 Walnut Street, Suite 701
Philadelphia, PA 19102
oneill@pennfuture.org

A handwritten signature in black ink, appearing to read 'K Chen', is positioned above a horizontal line.

Karen Chen

Attorney

Natural Resources Defense Council

1152 15th Street NW, Suite 300

Washington, DC 20005

kchen@nrdc.org

Exhibit 39

United States Court of Appeals
FOR THE DISTRICT OF COLUMBIA CIRCUIT

Argued May 15, 2026

Decided September 11, 2026

No. 25-1159

PEOPLE OF THE STATE OF MICHIGAN,
PETITIONER

v.

UNITED STATES DEPARTMENT OF ENERGY AND CHRISTOPHER
A. WRIGHT, SECRETARY, UNITED STATES DEPARTMENT OF
ENERGY,
RESPONDENTS

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC. AND
CONSUMERS ENERGY COMPANY,
INTERVENORS

Consolidated with 25-1160, 25-1162

On Petitions for Review of a Final Order
of the Department of Energy

Lucas Wollenzien, Assistant Attorney General, Office of
the Attorney General for the State of Michigan, argued the
cause for petitioners States of Illinois, Michigan, and
Minnesota. With him on the briefs were *Dana Nessel*, Attorney

General, *Michael E. Moody*, Assistant Attorney General, *Christopher Bzdok*, Special Assistant Attorney General, *Peter Surdo*, Special Assistant Attorney General, Office of the Attorney General for the State of Minnesota, and *Jason E. James*, Assistant Attorney General, Office of the Attorney General for the State of Illinois.

Benjamin P. Chagnon argued the cause for the Public Interest Organization petitioners. With him on the briefs were *Jennifer J. Yun*, *Michael Lenoff*, *Gregory E. Wannier*, *Sanjay Narayan*, *Elena Saxonhouse*, *Caroline Reiser*, *Gavin G. McCabe*, *Simi Bhat*, *Lauren Piette*, *Sameer H. Doshi*, *Christine A. Powell*, *Howard Learner*, *Danielle Fidler*, *Francis W. Sturges Jr.*, *Veronica Saltzman*, and *Tomas Carbonell*. *Michael C. Soules* and *Ada Statler* entered appearances.

Jennifer Danis was on the brief for amicus curiae Institute for Policy Integrity at New York University School of Law in support of petitioners.

Jonas Monast, *James P. Duffy*, *Alexandra L. St. Romain*, and *Susannah Landes Weaver* were on the brief for amici curiae Energy Law Scholars in support of petitioners.

Nicholas M. Gladd, *John B. Kenney*, and *Zachary Norris* were on the brief for amici curiae The Niskanen Center, et al., in support of petitioners.

Robert N. Stander, Deputy Assistant Attorney General, U.S. Department of Justice, argued the cause for respondents. With him on the brief were *Adam R. Gustafson*, Principal Deputy Assistant Attorney General, *Robert J. Lundman*, *Kyle Glynn*, and *Rebecca Jaffe*, Attorneys, and *Jonathan Brightbill*, General Counsel, United States Department of Energy.

Zachary C. Schauf argued the cause and filed the brief for respondent-intervenor Consumers Energy Company. With him on the brief was *Juliana Brint*. *Arjun R. Ramamurti* entered an appearance.

Adam S. Carlesco, *Daniel C.W. Narvey*, and *John Liskey* were on the brief for amici curiae Citizens Action Coalition of Indiana, et al., in support of respondent.

Before: SRINIVASAN, *Chief Judge*, PILLARD and WILKINS, *Circuit Judges*.

Opinion for the Court filed by *Circuit Judge* PILLARD.

PILLARD, *Circuit Judge*: Consumers Energy Company is a private business that owns and operates the J.H. Campbell Generating Plant, an aging coal-fired power plant in Michigan that was scheduled to shut down last year. The Company worked for several years to develop plans and secure regulatory approval to retire the old Campbell plant and replace it with a mix of expanded and new electricity-generation sources. Consumers Energy coordinated its planning with Michigan regulators and the Midwest Independent System Operator (MISO)—the 15-state regional transmission organization in which Michigan and Consumers Energy participate. The Company’s closure-and-replacement proposal received comprehensive scrutiny from the public, private industry, and expert regulators. Finding that Consumers Energy’s substitute sources would meet applicable reliability criteria, provide less polluting electricity at lower prices, and more than offset generation lost when the old plant closed, the Michigan Public Service Commission and MISO expressly approved the plan.

Shortly before Campbell’s scheduled retirement, the Department of Energy (DOE or Department) unilaterally

commanded the unit's continued operation. The Department invoked a rarely used, short-term, federal emergency authority conferred in section 202(c) of the Federal Power Act to order the Campbell coal unit to stay open. Michigan petitioned for review of DOE's order. Illinois and Minnesota also petitioned, as did a group of environmental organizations, including the Sierra Club, Natural Resources Defense Council, Michigan Environmental Council, Environmental Defense Fund, Environmental Law and Policy Center, Vote Solar, the Ecology Center, Urban Core Collective, and the Union of Concerned Scientists. Consumers Energy intervened to "protect[] the company's right to recover the costs associated with DOE's order" from ratepayers, which is at issue in separate proceedings regarding recovery and allocation of costs currently pending before FERC. Resp.-Interv. Br. iv, 7.

We evaluate Petitioners' challenge to DOE's interpretation of its emergency power under section 202(c) by reference to statutory text and structure. And we deploy those interpretive tools against the backdrop of states' exclusive regulatory power over the generation of electricity.

The plain meaning of the text limits section 202(c) emergency authority to address an identified risk of a substantial energy supply shortfall that calls for immediate action. Section 202(c) gives DOE limited authority to sidestep states' jurisdiction over electricity generation to briefly compel generation or interconnection in times of war or other "emergency" situations. By its terms, section 202(c) allows DOE to command certain action "[d]uring the continuance of any war in which the United States is engaged," or when the Secretary determines that "an emergency exists" due to "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. § 824a(c)(1).

The structure of the Federal Power Act and the history of the respective regulatory roles of federal and state governments show that Congress intended to further limit DOE’s section 202(c) emergency power to circumstances necessitating action by DOE in particular, as opposed to action by states.

Start with the Act’s structure: The statutory provisions immediately preceding section 202(c)—sections 202(a) and (b)—confirm the primacy of states and their utilities in planning to prevent and responding to emergency electricity shortfalls. First, section 202(a) facilitates states’ and utilities’ planning to generate and contract for adequate supplies of electrical power. It does so by enabling them to coordinate their efforts through voluntary participation in Regional Transmission Organizations (RTOs). Next, section 202(b) provides for coercive federal action to ensure adequate supply—but only at the request of states or their utilities. When “necessary or appropriate in the public interest,” a state or utility may request that the Federal Energy Regulatory Commission (FERC) order a generator to connect to and sell or exchange energy with other facilities. Lastly, section 202(c) authorizes DOE to intervene to temporarily order similar action—connection of facilities and provision of electricity—to avert an emergency. Congress’s placement of section 202(c) after subsections (a) and (b), which more broadly authorize state-level means of preventing and responding to emergency electricity shortages, strongly implies that it meant use of subsection (c) to be essentially the last alternative among the three.

Consider next the history of states’ jurisdiction over generation of electricity: The last-resort character of section

202(c) is strongly supported by the respective regulatory powers of states and the federal government under the Federal Power Act. There is no dispute that for almost a century states have exercised authority, preserved by the Federal Power Act, to regulate in-state power plants for the economic and environmental benefit of their citizens. It is the states—informed by federal, regional, and load-serving entities' assessments of available supply and reliability needs—that bear the responsibility to plan for and avert reliability risks on an ongoing basis. To that end, states decide which generation resources must be built, expanded, reduced, or shut down. The Act empowers the federal government, in contrast, to regulate wholesale marketing and interstate transmission of electricity. That demarcation of federal and state regulatory power is further reason to treat DOE intervention under section 202(c) as rare and authorized only when states, their utilities, and RTOs are unable or unwilling to respond. That is exactly how the federal government has used its section 202(c) authority until today—to address short-term crises, such as blackouts caused by war or extreme weather events, not as a substitute for the states' long-term reliability planning.

Our reading of the text, structure, and history leaves us unpersuaded by DOE's sweeping conception of its "emergency" authority under section 202(c). The Department's position would empower it to pick its preferred power sources in Michigan—or, presumably, any other state—and order them to operate without regard to the multiple procedural and substantive constraints built into state reliability planning processes. We hold that section 202(c) is best read to apply where the Department identifies a risk of substantial harm from inadequate electricity supply that calls for immediate action by DOE in particular, as opposed to by the states. Because the circumstances DOE identified in the challenged order do not warrant resort to section 202(c) as

correctly interpreted, we grant the petitions for review and vacate the Order.

I.

A.

1.

Until 1935, the federal government had no regulatory authority over the nation's electricity supply. Instead, "state and local agencies oversaw nearly all generation, transmission, and distribution of electricity." *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 265-66 (2016); see *Pacific Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205 (1983). In 1935, after the Supreme Court held that the Dormant Commerce Clause prohibited state regulation of certain interstate electricity transactions, see *Pub. Util. Comm'n of R.I. v. Attleboro Steam & Elec. Co.*, 273 U.S. 83, 89-90 (1927), Congress enacted the Federal Power Act (FPA or Act) to fill the resulting "regulatory void," *Elec. Power Supply Ass'n*, 577 U.S. at 266; see 16 U.S.C. §§ 824-824w.

The FPA affords the federal government authority to regulate "the transmission of electric energy in interstate commerce," *i.e.*, the movement of electric energy over long distances via high-voltage power lines. 16 U.S.C. § 824(b)(1). It also grants federal authority over "the sale of electric energy at wholesale in interstate commerce." *Id.* But the Act denies federal authority "over facilities used for the generation of electric energy." *Id.*

Federal regulatory authority over the nation's electrical supply is exercised by the Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), and the North American Electric Reliability Corporation (NERC), each

of which plays a distinct role. The principal and substantial federal agency acting in the electricity sector is FERC, which is responsible for rules and practices directly affecting rates for wholesale electricity sales and interstate transmission. *See generally* 16 U.S.C. §§ 824(a), 824a(f), 824d(a), 824e(a); *see also Elec. Power Supply Ass’n*, 577 U.S. at 266. NERC, which FERC designated in 2006 as an independent entity to “develop and enforce . . . reliability standards that provide for an adequate level of reliability of the bulk-power system,” conducts periodic reliability assessments of the electric grid and sets and modifies nationwide reliability standards that inform but do not control levels of energy generation within each state. 16 U.S.C. § 824o(c), (d), (g); *see also* NERC, 2025 Summer Reliability Assessment (“NERC Reliability Assessment”) (J.A. 103-56). For its part, the Department of Energy’s only direct authority over the generation of electricity is its temporary emergency power under section 202(c).

Because the Federal Power Act extends federal authority “only to those matters which are not subject to regulation by the States,” 16 U.S.C. § 824(a), it “maintains a zone of exclusive state jurisdiction,” *Elec. Power Supply Ass’n*, 577 U.S. at 266. The Act generally preserves states’ “control over in-state ‘facilities used for the generation of electric energy,’” *Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 154 (2016) (quoting 16 U.S.C. § 824(b)(1)); it contemplates incidental federal control of only those generation practices that “directly affect” FERC’s exercise of its statutory authority over wholesale rates or interstate transmission. *Elec. Power Supply Ass’n*, 577 U.S. at 278. Accordingly, we have long and repeatedly recognized that the federal government “may regulate the transmission [interstate], but not the generation, of electricity.” *NextEra Energy Res., LLC v. FERC*, 118 F.4th 361, 365 (D.C. Cir. 2024); *see La. Pub. Serv. Comm’n v. FERC*, 522 F.3d 378, 389-90 (D.C. Cir. 2008) (similar

regarding FERC authority over wholesale rates). States “retain the right to regulate the facilities responsible for the generation of electric energy,” *New England Power Generators Ass’n, Inc. v. FERC*, 757 F.3d 283, 285 (D.C. Cir. 2014), and they determine their own mix of electricity generation, *see Citizens Action Coal. of Ind. v. FERC*, 125 F.4th 229, 238 (D.C. Cir. 2025).

States, as the regulators of electricity generation, are largely responsible for meeting the core policy goal of achieving “resource adequacy.” That means it is up to the states to make sure that enough electricity is generated to safely and reliably meet users’ needs. *See Sacramento Mun. Util. Dist. v. FERC*, 616 F.3d 520, 526 (D.C. Cir. 2010) (quoting *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, P 3 (2006)) (defining resource adequacy). Indeed, FERC itself expressly recognizes that “[r]esource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there.” *Devon Power, LLC*, 109 FERC ¶ 61,154, P 47 (2004). The supply of reliable electricity to serve fluctuating demand and avoid blackouts is accordingly a key consideration of state regulators when they determine whether to permit generation sources to be added to the grid or existing sources to retire.

In making those determinations, state regulators must meet additional legal obligations and policy priorities. Those obligations and priorities may include energy affordability, the environment and climate, and diversity of generation supply. *See, e.g.*, Mich. Comp. Laws. Ann. § 460.6t(8)(a). To achieve long-term resource adequacy consistently, efficiently, and with optimal legal compliance and public support, states, load-serving entities, voluntary regional transmission organizations (RTOs), and various other stakeholders engage in extensive, coordinated planning.

Under Michigan law, the state's public utility regulator, the Michigan Public Service Commission (Michigan Commission, Commission, or simply Michigan) is responsible for monitoring the supply and demand of electricity and ensuring resource adequacy. It reviews and approves applications to construct, expand, reduce, or retire generation resources as consistent with detailed and evolving projections of state and regional energy needs. See Mich. Comp. Laws. Ann. §§ 460.6a, 460.6s. As most directly relevant here, the Michigan Commission ensures that any retirement of a generation resource in Michigan is accomplished consistently with the adequacy of electrical supply to meet demands of electricity consumers.

Because Michigan law makes load-serving utilities responsible for securing sufficient generating capacity to serve their customers, see Mich. Comp. Laws. Ann. §§ 460.6t, 460.6w, much of the Michigan Commission's power over electrical supply is exercised by regulating those utilities' investment decisions. "Load" generally refers to customers' demand for electricity—the power that users draw from the grid—at a given time. A load-serving entity is a "a utility with an obligation created under law or contract to provide electricity service to end-use customers or to a distribution utility." *S. Car. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 90 n.12 (D.C. Cir. 2014); see *NRG Power Mktg., LLC v. FERC*, 862 F.3d 108, 110 (D.C. Cir. 2017). Michigan's State Reliability Mechanism requires load-serving utilities to demonstrate annually that they have sufficient generation capacity to meet projected demand four years in the future. See *id.* § 460.6w; *State Reliability Mechanism*, Mich. Pub. Serv. Comm'n (Nov. 21, 2017), <https://perma.cc/CHH6-6NZ8>. Separately, every five years, load-serving entities must file with the Michigan Commission longer-term "integrated resource plans" (IRPs) that report five-, ten-, and fifteen-year projections of the

capacity they will generate or procure to satisfy resource adequacy and reliability requirements calibrated by MISO to meet future capacity needs. See Mich. Comp. Laws. Ann. § 460.6t(3). Each load-serving entity's integrated resource plan reports its forecasted capacity needs, the supply-side generating resources it will draw on, and available demand-side resources it will deploy (*e.g.*, energy waste reduction measures and measures to reduce consumption). *Id.* § 460.6t(5).

By exercising the state's various regulatory powers over electrical supply as contemplated by the Federal Power Act, the Michigan Commission plays the leading role in ensuring sufficient generation to serve the state's electricity needs. To approve an integrated resource plan, the state Commission must determine that the load-serving entity's plan represents "the most reasonable and prudent means of meeting" that utility's current and future commitments to supply electricity. See *id.* § 460.6t(8)(a).

Michigan has authority to protect energy supply in the face of risks of imminent shortage. The Michigan Commission regularly monitors energy supply in the state and publishes a semiannual "energy appraisal" that highlights recent events affecting supply and prices, expected conditions, and changes over the upcoming six months. See Mich. Pub. Serv. Comm'n, *Michigan Energy Supply Monitoring*, <https://perma.cc/MVF9-YGMU>. In the event of an unexpected shortage, the Commission may issue a special update of its energy appraisal. *Id.* And, as explained below, state regulators can request that FERC order an interconnection and sale of energy to address a shortfall. If needed, Michigan's governor can declare a state energy emergency and order various mitigation measures, including restrictions on energy use in non-residential buildings, restrictions on energy sales to consumers, and

directives to an energy supplier to provide energy to any facility that provides essential services to the state. Mich. Comp. Laws. Ann. §§ 10.83-10.84.

States play the primary role in assuring resource adequacy, but they do not act alone. Regional entities are instrumental to Michigan's planning for resource adequacy. Michigan and its electric utilities participate in the Midcontinent Independent System Operator (MISO), the 15-state RTO whose territory stretches from Montana to Louisiana and includes Michigan. RTOs are "independent organizations that manage the transmission of electricity over the electric grid and ensure electricity is reliably available for consumers." *Md. Off. of People's Couns. v. FERC*, 164 F.4th 920, 924 (D.C. Cir. 2026) (quotation omitted). Here, we focus on MISO's role in ensuring reliable supplies of electric energy to serve expected load in member states.

MISO—like other RTOs—works in tandem with state regulators, including the Michigan Commission, to help ensure resource adequacy. MISO recognizes that "the states have the primary responsibility to maintain resource adequacy, including overseeing the planning or securing of new resources by load-serving entities . . . to adequately meet demand." *Resource Adequacy Metrics and Criteria Roadmap*, Midcontinent Indep. Sys. Operator 9 (Dec. 2024), <https://perma.cc/8WNH-W33N>. MISO supports the states to ensure resource adequacy in several ways. *Id.*

For starters, MISO sets a regional resource-adequacy standard, *i.e.*, it develops a mathematical model to estimate how much generation capacity the system will need to run reliably. Every year, MISO updates that model with new data, such as hourly load forecasts. *Id.* Next, MISO determines whether existing capacity can meet projected peak demand—

the highest projected level of energy consumption at any given time—under various conditions. In so doing, MISO builds in several time-tested reliability safeguards.

Most importantly, MISO subjects the existing generation capacity to a process called “resource accreditation.” *Midcontinent Indep. Sys. Operator, Inc.*, 189 FERC ¶ 61,065, PP 3-4 (2024) (tariff revisions establishing accreditation methodology). Rather than simply adding up all the available generation units’ nominal maximum-capacity figures, MISO assigns a realistic capacity value to each unit’s expected contribution to system adequacy during periods of high demand. *See id.* In the case of a coal plant, the assigned capacity value discounts its total “nameplate” capacity to account for historical limits on its actual generation due to forced outages, required maintenance, and the like. *See Midcontinent Indep. Sys. Operator, Inc., Resource Accreditation White Paper Version 2.1*, at 10-11 (Mar. 2024), <https://perma.cc/KP39-DKBX>. In the case of solar- and wind-powered electrical generation units, their intermittent character is also accounted for. *Id.* at 11-12.

On the demand side, MISO does not stop with seasonal projections of system-wide peak demand. It also establishes annual “reserve margin” requirements to prevent shortages even in the face of extraordinary disruptions like extreme weather or outages that defy ordinary projection. *See Midcontinent Indep. Sys. Operator, Inc.*, 189 FERC ¶ 61,065, P 1; Energy Scholars Amicus Br. 15-16. States using MISO’s projections of peak demand thus require load-serving entities to procure enough capacity to cover the specified reserve margin increment above expected peak demand. By adding a reserve margin to projected peak demand, MISO builds a reliability buffer into the target load figures states use in planning for resource adequacy.

MISO's resource adequacy standards provide an additional benchmark, not a substitute, for state reliability requirements such as integrated resource plans. See *Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,215, P 13 (2020); see also *Midwest Indep. Sys. Operator, Inc.*, 119 FERC ¶ 61,311, P 75 (2007) ("From the beginning . . . , [FERC] has recognized the role that state resource planning plays in managing the resource adequacy of [MISO]."). MISO coordinates with states by supplying determinations of the electric capacity needed and that which is available in the system so that state regulators, generators, and load-serving entities can incorporate those figures into their resource-adequacy planning. Energy Law Scholars Amicus Br. 14.

MISO also administers its territory's electric capacity market. "In a capacity market, in contrast to a [real-time] wholesale-energy market, [a load-serving entity] purchases from a generator an option to buy a quantity of energy, rather than purchasing the energy itself." *NRG Power Mktg., LLC v. Maine Pub. Utils Comm'n*, 558 U.S. 165, 168 (2010). With those options contracts in hand, a load-serving entity "can meet high demands for electricity by calling on the generators to produce it when the need arises. Purchasing capacity, in other words, ensures that distributors can reliably meet predicted peak power demands in an upcoming month, season, or year." *Pub. Citizen, Inc. v. FERC*, 7 F.4th 1177, 1186 (D.C. Cir. 2021) (citation omitted). Load-serving entities "generally purchase more capacity, i.e., rights to acquire energy, than necessary to meet their customers' anticipated demand." *NRG Power Mktg.*, 558 U.S. at 169; see also *Maine Pub. Utils Comm'n v. FERC*, 520 F.3d 464, 467 (D.C. Cir. 2008).

Concretely, MISO runs a competitive annual planning resource auction to enable load-serving entities to procure capacity to meet projected demand and satisfy their resource

adequacy requirements. See MISO, Planning Resource Auction Results for Planning Year 2025-26 (“MISO Planning Resource Auction”) (J.A. 58-101). In the auction, generators offer capacity and load-serving entities submit bids for the amount needed to meet their “reserve margin” requirements. A crucial benefit of a competitive capacity market over command-and-control capacity requirements (including the Campbell Order at issue here) is that rising capacity prices in the market facilitate efficient resource adequacy planning by signaling to generators and regulators when they should invest in new generation resources or retain existing ones to ensure reliable supply of electricity; low or falling prices prevent over-investment in generation at ratepayers’ expense. See *Midcontinent Indep. Sys. Operator, Inc.*, 187 FERC ¶ 61,202, P 9 (2024) (MISO tariff revisions aimed at “improving investment and retirement decisions by using price signals to properly time resource entry and exit”); Niskanen Center Amicus Br. 26-27.

If, despite states’ best efforts at planning for resource adequacy, MISO identifies an imminent generation-shortage risk, it has numerous tools, like energy alerts and emergency energy procurements, to ensure adequate supply. See MISO Market Capacity Emergency 1-3 (J.A. 676-78). And, like the Michigan Commission, MISO has some power to defer a load-serving entity’s decision to retire or suspend operations of a generation resource as needed to prevent a shortage. See MISO Tariff Section 38.2.7 (J.A. 887-893); *Generator Interconnection and Retirement*, Midcontinent Indep. Sys. Operator, <https://perma.cc/WSS9-9AY7>.

2.

The federal government, too, plays an important—albeit limited—role in the resource-adequacy scheme. Even as the

Federal Power Act generally preserves states' jurisdiction over electricity generation, it vests certain powers in the federal government to help protect the coordinated resource-adequacy system. Section 202 of the Act authorizes three tiers of federal action.

In the first tier, section 202(a), Congress called on FERC to “divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy.” 16 U.S.C. § 824a(a). Acting under that provision, FERC encouraged the voluntary formation of RTOs to administer the transmission grid on a regional basis, and the formation of independent system operators (ISOs) that perform a similar function on a smaller scale. *See Amaren Servs. Co. v. FERC*, 880 F.3d 571, 574 (D.C. Cir. 2018); *see also Elec. Power Supply Ass’n*, 577 U.S. at 267-68. Regional coordination promotes efficient interstate sales of power from a state with available capacity to another state that may find itself short, for example, and prevents free-riding whereby load-serving entities in one state might “count on the capacity they expect others to buy in order to support their own reliability.” *Conn. Dep’t of Pub. Util. Control v. FERC*, 569 F.3d 477, 479 (D.C. Cir. 2009). FERC oversees ISOs and RTOs, including MISO, and reviews their electric capacity requirements, rates, and other rules under the “just and reasonable” standard. 16 U.S.C. §§ 824d, 824e; *see, e.g., Conn. Dep’t of Pub. Util. Control*, 569 F.3d at 478-79, 485 (reviewing FERC order affecting ISO capacity requirements).

The second tier, established by section 202(b), permits FERC to direct generators to connect to and sell or exchange energy with other facilities—a power afforded to FERC only upon “application of any State commission or of any person engaged in the transmission or sale of electric energy.”

16 U.S.C. § 824a(b). So, if a state energy regulator, transmission entity (*e.g.*, an RTO or ISO), or load-serving entity requests FERC to do so, FERC may—“after notice to each State commission and public utility affected and after opportunity for hearing” and a finding that action is “necessary or appropriate in the public interest”—mandate a connection or sale. *Id.*

Importantly, even as the Federal Power Act gives FERC narrow authority to respond to requests to order electricity sales or exchanges, the Act expressly denies FERC authority to regulate generation facilities directly. *See* 16 U.S.C. § 824(b)(1). It is the prerogative of states “to forbid new entrants from providing new capacity, to require retirement of existing generators, to limit new construction to more expensive, environmentally friendly units, or to take any other action in their role as regulators of generation facilities without direct interference from the Commission.” *Conn. Dep’t of Pub. Util. Control*, 569 F.3d at 481. The final tier of federal power, conferred by section 202(c), is the sole exception.

The third tier falls outside of the coordinated resource-adequacy system altogether. Section 202(c) establishes a limited backstop mechanism empowering DOE to address certain electricity supply emergencies. That section authorizes the Secretary of Energy (Secretary) to compel generation of electricity only “[d]uring the continuance of any war in which the United States is engaged” or when the Secretary “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. § 824a(c)(1).

Congress enacted section 202(c) in response to a “serious power shortage” during World War I and contemplated that its use would be limited to addressing wartime shocks and “similar crises” like “[d]rought and other natural emergencies.” S. Rep. No. 74-621, at 49 (1935). Until now, the Department has exercised its section 202(c) authority sparingly. During nearly a century of state responsibility for sufficient supply of electricity under the FPA, the federal government has rarely used section 202(c) authority outside of wartime. It “has never used its section 202(c) authority to require additional generation to address long-term resource-adequacy concerns; instead, it has always used that authority to address discrete and unexpected events that threaten immediate grid needs.” Energy Scholars Amicus Br. 21 (citing Benjamin Rolsma, *The New Reliability Override*, 57 Conn. L. Rev. 789 (2025)). The federal government has, until now, issued stopgap generation orders in response only to transitory emergencies caused by war, extreme weather events, market manipulation, or unplanned, short-term unavailability of specific generation units. See Rolsma, *supra* at 805-07, 839-46 tbls. 1 & 2. When a section 202(c) emergency arises, the Department can order generation that “in its judgment will best meet the emergency and serve the public interest.” 16 U.S.C. § 824a(c)(1).

Congress amended the Federal Power Act in 2015 to provide that section 202(c) emergency orders may override federal, state, and local environmental laws and regulations. Such an override must be cabined to circumstances in which compliance is not “practicable,” any “adverse environmental impacts” are “minimize[d],” and the facility is ordered to operate only “during hours necessary to meet the emergency and serve the public interest.” Pub. L. 114-94 § 61002, 129 Stat. 1772 (2015) (codified at 16 U.S.C. § 824a(c)(2)). Congress further specified that a section 202(c) order that “may

conflict” with environmental law “shall expire not later than 90 days after it is issued.” 16 U.S.C. § 824a(c)(4).

As described above, Michigan’s resource-adequacy regulation entails continuous, complex planning processes with intensive coordination by the state and MISO. That planning starts years in advance to prepare for future needs as well as near-term demand. FERC has peripheral—and limited—oversight of those entities, but no power to directly regulate generation facilities. And DOE has no role whatsoever in the resource-adequacy planning process. Instead, Congress in section 202(c) gave DOE narrow authority to intervene that is triggered only in the face of an electricity emergency not otherwise addressable by states or their utilities.

B.

The J.H. Campbell Generating Plant (Campbell), an aging coal-fired power plant in Michigan, is owned and operated by Consumers Energy Company, a load-serving entity that is part of MISO. Given its decades-old units, Campbell has become increasingly inefficient, polluting, and expensive to maintain. When in operation, the Campbell facility produces dangerous emissions, including SO₂, NO_x, and PM_{2.5}, that cause approximately thirty excess deaths every year. Order Approving Settlement Agreement 9 (J.A. 454); State Add. 213. In June 2021, Consumers Energy filed with the Michigan Commission an integrated resource plan that proposed to retire the Campbell plant. Once an integrated resource plan is filed, the Michigan Commission reviews the plan through a year-long “contested case” process. *See* Mich. Comp. Laws. Ann. § 460.6t(a)(7). Interested parties may intervene, take discovery, submit expert testimony, and present and cross-examine witnesses at an evidentiary hearing. *See id.* §§ 460.6t(7)(ii), 24.271-24.288.

Dozens of interested parties, including environmental groups, the Michigan Attorney General, and several power companies, intervened in the Consumers Energy proceedings. In April 2022, Consumers Energy entered a multi-party settlement agreement with the environmental groups, the Michigan Attorney General, and the Michigan Commission's enforcement staff under which it memorialized its plan to retire the Campbell plant and obtain newer, cleaner, cheaper, and more reliable resources that would increase available generation capacity. *See* Settlement Agreement (J.A. 543-63). Specifically, the agreement provided that Consumers Energy would retire the Campbell plant on or before May 31, 2025. *See id.* 4-5 (J.A. 546-47). And it directed Consumers Energy to acquire a new gas plant, extend operations of two oil- and gas-fired units at one of its other plants, and add new solar energy generation and battery storage. *See id.* 3-9 (J.A. 545-51). The parties sought approval of the settlement by the Michigan Public Service Commission, Order Approving Settlement Agreement 1 (J.A. 446), which ruled on objections and granted approval on June 23, 2022, *id.* 95-97 (J.A. 540-42); *see also id.* 45-95 (J.A. 490-540).

In reviewing the settlement agreement, the Michigan Commission assessed whether the integrated resource plan Consumers Energy filed following the settlement met statutory requirements. *See id.* 4, 95 (J.A. 449, 540). By statute, the Michigan Commission must approve an integrated resource plan if it determines that “[t]he proposed integrated resource plan represents the most reasonable and prudent means of meeting the electric utility’s energy and capacity needs.” Mich. Comp. Laws. Ann. § 460.6t(8)(a). In making that determination about the post-settlement integrated resource plan, the Michigan Commission assessed its impact on resource adequacy and on Consumers Energy’s ability to serve

anticipated peak electric load. See Order Approving Settlement Agreement 88-95 (J.A. 533-40).

Upon review of Consumers Energy's expected procurements and operating adjustments, the Commission determined that "the approval of the settlement agreement will enhance resource adequacy in [the Campbell region] in both the near-term and long term." *Id.* 93 (J.A. 538). Ultimately, the Commission concluded, Consumers Energy's retirement plan was "the most reasonable and prudent means of meeting Consumers' energy and capacity needs and otherwise meets the requirements of MCL 460.6t(8)." *Id.* 95 (J.A. 540). On appeal, the Michigan Court of Appeals affirmed the Michigan Commission's order approving the settlement agreement and determined that there was substantial evidence that the agreement would improve resource adequacy. *In re Consumers Energy*, No. 3622954, 2023 WL 2620437, at *5-6 (Mich. Ct. App. Mar. 23, 2023).

MISO, too, determined that Campbell's retirement as planned—with substitute generation provided by cheaper, cleaner, and more reliable new and expanded generation—would support reliability. See Attachment Y Notice 156 (J.A. 322). That determination followed a technical evaluation of transmission system conditions that would result from the plant's retirement. See MISO Tariff Section 38.2.7 2-3 (J.A. 888-89). MISO's analysis confirmed that Consumers Energy did not need to operate Campbell to satisfy the RTO's reliability criteria.

As Campbell's May 2025 retirement approached, Consumers Energy, the Michigan Commission, and MISO continued to prioritize resource adequacy. Consumers Energy had already begun winding down the Campbell unit, transitioning to new generation resources, and developing

additional capacity. In its annual capacity-demonstration filing with the Michigan Commission, *see* Mich. Comp. Laws. Ann. § 460.6w(8)(a), Consumers Energy documented that it had procured sufficient capacity to meet the projected demand of its customers in summer 2025 and beyond, *see* Motion to Intervene 24 (J.A. 357); Consumers Energy Capacity Demonstration 15 (J.A. 632). And MISO’s planning resource auction results for summer 2025 through spring 2026, published in April 2025, “demonstrated sufficient capacity at the regional, subregional and zonal levels.” MISO Planning Resource Auction 12 (J.A. 69); *see also id.* 5 (J.A. 62) (showing that MISO attained a reserve margin of 9.8% for summer 2025, nearly two percentage points above its target).

The Michigan Commission, utilities in the state, and MISO saw no need to invoke 202(b) to request that FERC order provision of additional electricity. Neither did the governor of Michigan see any ground to declare an energy emergency in response to Campbell’s planned closure. *See* Mich. Comp. Laws. Ann. §§ 10.83-10.84.

Just days before Campbell’s scheduled retirement, however, DOE sidestepped Michigan’s coordinated, years-long process of planning, including the detailed, judicially reviewed, multiparty settlement.

On May 23, 2025, the Secretary issued a section 202(c) Order declaring an emergency and compelling Consumers Energy to keep Campbell in operation for at least 90 days. The Order asserts 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.” DOE Order 202-25-3 1 (J.A. 1). As support, the Order identifies “potential tight reserve margins during the summer 2025” in MISO and

potential electricity supply shortfalls due to the “retirement of thermal generation capacity.” DOE Order 202-25-3 1 (J.A. 1).

DOE pointed to fragments of two documents as showing that the region faced an emergency within the meaning of section 202(c). First, it quoted a statement in a NERC report that MISO is “at elevated risk of operational reserve shortfalls during periods of high demand or low resource output.” DOE Order 202-25-3 1 (J.A. 1); *see* NERC Reliability Assessment 5 (J.A. 107). DOE characterized that statement as describing an emergency even though the very same report concluded that MISO had “adequate anticipated resources” for “peak load conditions.” NERC Reliability Assessment 5 (J.A. 107).

Second, DOE quoted a slide from a deck describing MISO’s planning resource auction results for its North/Central region, which stated that “new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources” and that the summer months reflected the “highest risk and a tighter supply-demand balance.” DOE Order 202-25-3 2 (J.A. 2); *see* MISO Planning Resource Auction 12-13 (J.A. 69-70). The first statement means that fewer capacity resources were *offered* in that region than in 2024; it does not conclude that the amount of capacity *purchased* was inadequate to serve load. *See* Michigan Attorney General Request for Rehearing 31 (J.A. 188). And, in context, the second statement is merely comparative: It explains that the supply-demand gap in summer 2025 was narrower than in fall, winter, or spring of that year. *See id.* 30-31 (J.A. 187-88). DOE acknowledges that both “MISO and Consumers ha[d] incorporated [Campbell’s] planned retirement into their supply forecasts,” and that MISO procured “sufficient capacity” for summer 2025. DOE Order 202-25-3 1-2 (J.A. 1-2). Brushing aside that vital context, DOE nonetheless concluded there was a risk of insufficient capacity

that warranted a section 202(c) emergency order. And it concluded, without explanation, that additional dispatch of Campbell in particular is “necessary to best meet the emergency and serve the public interest.” DOE Order 202-25-3 2 (J.A. 2).

In June 2025, Michigan sought administrative rehearing, as did Illinois, Minnesota, and several environmental nonprofit groups. Rehearing was denied by operation of law when DOE failed to respond within 30 days. 16 U.S.C. § 8251(a). Petitioners then sought our review of the Order. On September 8, 2025, DOE issued a Rehearing Order that “modified” the Order in some respects and otherwise sustained it. DOE Order 202-25-3B 24 (J.A. 29).

The Rehearing Order reiterates that section 202(c) “specifically applies to the potential ‘shortage of electric energy or of facilities for the generation or transmission of electric energy,’” which it describes as “exactly the situation that led to the issuance of the Emergency Order.” Order 202-25-3B 4 (J.A. 9). DOE also announced a new interpretation of section 202(c) to authorize it to countermand the state’s approval of a plant closing, even in the absence of a need for federal intercession to avert an imminent reliability risk beyond state or RTO control. Order 202-25-3B 7 (J.A. 12). It is enough, in DOE’s view, that the Order “addresses [the] risk” that, in DOE’s view, “if current retirement schedules and incremental additions remain unchanged, most regions—including the MISO region relevant to the Emergency Order—will face unacceptable reliability risks within five years,” Order 202-25-3B 14 (J.A. 19).

The Act limits to 90 days the duration of a section 202(c) order that conflicts with environmental law, *see* 16 U.S.C. § 824a(c)(4)(A)—which this one indisputably does. DOE has

nonetheless extended the Order’s 90-day period four times. Order No. 202-25-7 (DOE Aug. 20, 2025); Order No. 202-25-9 (DOE Nov. 18, 2025); Order No. 202-26-16 (DOE Feb. 17, 2026); Order No. 202-26-22 (DOE May 18, 2026). In each extension, DOE asserted that the emergency conditions “will continue in the near term and are also likely to continue in subsequent years.” *See, e.g.*, Order No. 202-25-7 7 (State Add. 88); Order No. 202-25-9 8 (State Add. 99). Thus, DOE has compelled Campbell’s continued operation for a total of 450 days, claiming that extended compulsion is appropriate “[t]o ensure that the Campbell Plant will be available if needed to address emergency conditions.” *See* Order No. 202-25-9 8 (State Add. 99). Petitioners timely sought review of the extension orders, and we held those petitions in abeyance pending the outcome here.

II.

We have jurisdiction to review the initial Order challenged in these petitions. 16 U.S.C. § 825l(b); *see* 42 U.S.C. § 7192(a). We must set aside an agency action that is “in excess of statutory jurisdiction, authority, or limitations, or short of statutory right.” *Erie Blvd. Hydropower, LP v. FERC*, 878 F.3d 258, 266 (D.C. Cir. 2017) (quoting 5 U.S.C. § 706(2)(A), (C)). When determining whether an agency has exceeded its statutory authority, we interpret the relevant statutory provisions *de novo*. *See Loper Bright Enterprises v. Raimondo*, 603 U.S. 369, 400-01 (2024).

Petitioners claim that the Order exceeds DOE’s statutory authority. Specifically, they argue that the circumstances DOE has identified—including an out-of-context quotation about an “elevated risk” of operational reserve shortfalls in summer 2025 and unspecified long-term reliability risks—do not constitute an “emergency” under section 202(c). The very

document DOE drew from established that there was in fact sufficient capacity due to Michigan's planning measures for resource adequacy and no anticipated electricity shortfall, so no "emergency." Petitioners also claim that the Order's finding that Michigan faced a section 202(c) emergency is not supported by substantial evidence and contravenes other limitations imposed by section 202(c). DOE responds that the Secretary has broad latitude to determine that a section 202(c) emergency exists and that the Order correctly identifies one here.

A.

We first address petitioners' statutory argument. And because we find that argument dispositive, we need go no further. DOE relies not on its core power to compel electricity connection or generation to meet emergency needs in wartime, but on its power to compel generation of electric energy when the Secretary "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. § 824a(c)(1). The Act gives the Secretary authority to determine whether an emergency exists. That grant of authority does not grant a boundless license to ignore the statutory text; it allows the Secretary to exercise discretion within the Act's statutory limits. The statutory limits in section 202(c) confine DOE's authority to temporary emergencies that the Secretary reasonably determines are and will be unmet by the state's resource planning.

The parties disagree about what counts as an "emergency" under section 202(c). Petitioners contend that an "emergency" for section 202(c) purposes must be sudden, unexpected,

imminent, and require an immediate response. State Pet'rs Br. 26-27. DOE contends that the term encompasses any anticipated shortage of electric power, even if neither imminent nor beyond the capability of the state to address. DOE Br. 23-25.

We hold that a section 202(c) “emergency” means a grid-reliability risk that calls for an immediate response by DOE in particular. If the Department finds the state has not and will not timely take steps that must be taken immediately to avert unacceptable risk to reliability, the need for immediate action can trigger statutory authority for DOE to step in.

In arriving at the best interpretation, “we begin with the text.” *Pacific Gas & Electric Co. v. FERC*, 113 F.4th 943, 948 (D.C. Cir. 2024) (citation omitted). The Federal Power Act does not define “emergency,” so “we look to the word’s ordinary definition.” *CSX Transp., Inc v. Ala. Dep’t of Revenue*, 562 U.S. 277, 284 (2011). Definitions of “emergency” include an “unforeseen occurrence or combination of circumstances which calls for immediate action or remedy,” a “pressing necessity,” and an “exigency.” *Webster’s New Int’l Dictionary of the English Language* 716 (2d ed. 1930); see also 3 *Oxford English Dictionary* 119 (1933) (defining emergency as “a state of things unexpectedly arising, and urgently demanding immediate action”).

The key consideration in determining whether a situation amounts to an emergency is whether it demands immediate action by DOE outside the ordinary process for assuring reliability. While the suddenness, imminence, and unexpectedness of a reliability risk will often make it more likely to warrant immediate action, it is, as we explain further below, see *infra* at 29-32, the combination of urgent need for action with circumstances showing that a federal response is

called for that epitomizes a section 202(c) emergency. And, contrary to petitioners' arguments that an emergency can stem only from an imminent and unforeseen energy shortage, *see* PI Pet'rs Br. 24; State Pet'rs Br. 25, the need for an immediate federal response might arise even when a crisis is foreseeable or will occur in the future: If, for example, a deteriorating nuclear power plant poses risks of a serious outage in three years absent immediate action to ensure repairs, and if DOE has reason to believe that the state cannot or will not act in time to reasonably respond, an emergency may exist even though the outage is foreseeable and far-off.

Based on the text, the need for immediate federal action to ensure adequate supply of electricity is the touchstone for a section 202(c) emergency. DOE's arguments to the contrary are unpersuasive.

DOE contends that the text of section 202(c) uses "emergency" broadly to include any shortages of electric energy. DOE Br. 23-25. The Department asserts that section 202(c) "spells out what constitutes a section 202(c) 'emergency' by capacious examples," including "'a shortage of electric energy'; 'a sudden increase in the demand for electric energy'; a shortage 'of facilities for the generation or transmission of electric energy'; a shortage 'of fuel or water for generating facilities'; or for 'other causes.'" DOE Br. 24 (quoting 16 U.S.C. § 824a(c)(1)). But DOE misreads the text. What it quotes in section 202(c) as statutorily identified emergencies are no such thing. They are potential *causes* of emergencies, not *examples* of emergencies. As the statute says, an emergency may "exist[] by reason of" a shortage of electric energy or of facilities for the generation or transmission of electric energy. 16 U.S.C. § 824a(c)(1). The statutory text plainly does not say those potential causes are themselves emergencies.

Next, DOE argues that the text of neighboring section 202(d) shows that the term “emergency” in section 202(c) cannot mean that immediate action is required. DOE Br. 28. Section 202(d) permits a utility that is not subject to FERC’s jurisdiction to connect temporarily to the interstate grid during “any emergency requiring immediate action,” and to do so without thereby subjecting itself to FERC’s jurisdiction. 16 U.S.C. § 824a(d). The apparent role of this provision is to encourage such voluntary connection to help meet emergency conditions. DOE argues that the word “emergency” by itself in section 202(c) cannot refer to circumstances requiring immediate action because that would treat the modifying phrase accompanying the word “emergency” in section 202(d)—“requiring immediate action”—as surplusage. That is wrong. Even if there were no section 202(c) at all, the phrase in section 202(d) would be surplusage because, as the dictionaries and common usage establish, the word “emergency” standing alone denotes an acute situation requiring an immediate response. *See supra* at 27. The fact that “emergency” conveys the same meaning more succinctly than the more emphatically worded “emergency requiring immediate action” is no reason to eschew the word’s ordinary meaning in section 202(c). After all, “the canon against surplusage is not an absolute rule,” and it “certainly does not require us to favor an unusual meaning that will avoid surplusage over a more natural one.” *Stanley v. City of Sanford*, 606 U.S. 46, 56 (2025) (quotation omitted).

For purposes of section 202(c), the ordinary meaning of “emergency” as an event that requires immediate action does not complete the analysis. “It is a fundamental canon of statutory construction that the words of a statute must be read in their context and with a view to their place in the overall statutory scheme.” *Sturgeon v. Frost*, 577 U.S. 424, 438 (2016) (quotation omitted). Given the structure and context of the

Federal Power Act, section 202(c)'s grant of emergency authority is triggered only when there is a need for immediate, essentially last-resort action *and* the circumstances require action by DOE in particular, as opposed to action by the state or states responsible for resource adequacy.

To start, Congress carefully structured the Federal Power Act, and section 202 within it, to preserve the primacy of state authority over electricity generation. At its outset, the Act clarifies that the limited federal authority it confers extends “only to those matters which are not subject to regulation by the States.” 16 U.S.C. § 824(a). And it expressly denies federal authority “over facilities used for the generation of electric energy.” *Id.* § 824(b)(1). To help ensure that generation suffices to meet long-term demand, section 215 authorizes NERC to establish nationwide reliability standards. 16 U.S.C. § 824o(d). But that section, which expressly denies NERC power to demand additional generation capacity, makes clear that NERC's standards are to guide state planning, not to authorize federal intervention to direct electricity generation. FERC, too, facilitates production of an “abundant supply of electric energy,” principally by prompting states and their utilities to engage in “voluntary interconnection and coordination” at the regional level. 16 U.S.C. § 824a(a). If those efforts prove deficient, a state, transmission organization, or load-serving entity may request, under section 202(b), that FERC direct a generator to sell or exchange energy with other facilities. *Id.* § 824a(b). But FERC only has authority to do that in response to a request. Permitting DOE to compel generation in a situation that can be resolved through the ordinary resource adequacy planning mechanisms or a request under section 202(b) would render meaningless the constraints on federal power that Congress imposed throughout the Act.

The only other court to consider Section 202(c)'s scope has come to the same conclusion. In *Otter Tail*, the court distinguished section 202(c), which enables a federal response “to react to a war or national disaster and order immediate interconnection of the facilities to maintain electrical service during such emergency,” from section 202(b), which “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 [Federal Power] Commission.” *Otter Tail Power Co. v. Fed. Power Comm’n*, 429 F.2d 232, 234 (8th Cir. 1970). So there, too, the court treated the federal government’s section 202(c) power as limited by the primacy of other, less top-down and coercive mechanisms to ensure resource adequacy.

The structure of the Federal Power Act makes clear that compelled generation under section 202(c) is generally appropriate only when DOE faces a type of reliability emergency that is unaddressed by actions contemplated by sections 202(a) and (b), so necessitates federal intervention. Section 202(c) is essentially a narrow, last-resort backstop. It provides for DOE to exercise emergency authority when coordinated state and regional resource adequacy planning, per section 202(a), and invocation of section 202(b) both fall short. When those mechanisms function as intended to address potential resource adequacy issues, there will typically be no “emergency” within the meaning of section 202(c).

The circumstances requiring use of section 202(c) are rare. If generation shortfalls or other reliability risks are anticipated, states, generators, and regional entities have every incentive and tool to make plans to procure replacement resources or prevent scheduled retirements. And even for imminent or unforeseen shortfalls, the coordinated resource-adequacy system includes alternative solutions. For instance, MISO may provide for energy imports from neighboring systems or deploy

operating mitigations like load-modifying resources—that is, demand-side measures to reduce energy consumption. See NERC Reliability Assessment 16 (J.A. 118); MISO, *Market Redefinition: Load Modifying Resource Reforms* 6 (Nov. 6, 2024), <https://perma.cc/AZ69-Q3VN>. MISO may also issue energy emergency alerts or operational alerts that require its stakeholders to take energy conservation actions. See MISO Market Capacity Emergency 21-26 (J.A. 696-701). States may declare energy emergencies pursuant to which they restrict consumption or command an energy supplier to redirect its energy to a needed facility. See, e.g., Mich. Comp. Laws. Ann. §§ 10.83-10.84. And states, transmission organizations, or load-serving entities contemplating imminent shortages can call on FERC under section 202(b) to require generators to sell or exchange energy with other facilities. See 16 U.S.C. § 824a(b). For virtually all risks of energy shortages, alternatives to DOE intercession suffice.

When DOE exercises its section 202(c) authority to compel generation other than as a last resort, including by reversing a generator's long and carefully planned retirement as it did with Consumers Energy's Campbell unit, the results are disruptive. Unjustified use of section 202(c) upends existing resource-adequacy decisions made based on years of planning with intensive expert input and broad stakeholder participation. As DOE itself acknowledges, resource adequacy planning and adding generation capacity is a "many-year" process. See DOE Br. 33. States and RTOs closely scrutinize the impact of generation retirement or reduction and engage in sophisticated planning of expansion or construction of generation units and facility interconnections. They do so with public notice and input by a broad range of stakeholders. And they seek to achieve resource adequacy in a manner that serves the public interest in affordable, environmentally sound, reliable resources going forward. See *id.* at 33-34. Contrary to

DOE's position, DOE Br. 31-36, the complexity and advance planning that go into states' assurances of resource adequacy do not imply that DOE must have vast, top-down emergency power to pick its favorite generators to run at all costs, or to abruptly order disfavored units to shut down earlier than planned. Rather, the complexity of state planning processes helps to explain why the Federal Power Act leaves resource adequacy to be managed by states, utilities, and their RTOs.

The Department's reading of "emergency" invites frequent federal interventions that are unsupported by the statute and threaten the stability of the energy market. By directing a generator approved for retirement to remain operative while effectively walling it off from planning and market frameworks, the Order challenged here interferes with ordinary methods to assess a region's true generation capacity and distorts price signals that otherwise prompt appropriate capacity investments. See Energy Law Scholars Amicus Br. 16. DOE's use of its expansive interpretation of "emergency" to prevent planned retirements of generators slated to close, for example, will likely discourage development of needed new resources by artificially lowering capacity market prices and destabilizing those markets. See *id.* 16-20. Such distortions may be justified in the face of the rare emergency requiring DOE's immediate, short-term intervention. But unless DOE's involvement is needed in response to a genuine emergency as defined by section 202(c), it must be avoided.

The text and statutory structure are alone sufficient to settle the "best" understanding of FERC's section 202(c) authority. See *Loper Bright*, 603 U.S. at 370. The correctness of our reading is powerfully confirmed by the executive branch's consistent interpretation and limited exercise of that

authority over nearly a century. *See id.* at 386 (citations omitted).

The reading of section 202(c) we provide today is a familiar one. In *Richmond Power & Light v. FERC*, 574 F.2d 610 (D.C. Cir. 1978), we held that the Federal Power Commission (predecessor to both FERC and DOE) acted within its sound discretion in eschewing reliance on Section 202(c) to address electric supply problems caused by the 1973 oil embargo. 614-15. The Commission had determined to “invoke section 202(c) only if its emergency powers could have provided the sole authorization” to alleviate the shortage. *Id.* at 614. Rejecting the position of midwestern generators seeking compelled purchases of their capacity under section 202(c), the Commission treated continued reliance on foreign oil, despite a national policy discouraging such reliance, as not among the “‘temporary’ emergencies, epitomized by wartime disturbances” to which section 202(c) applies. *Id.* at 615. Given that the anticipated need could be mitigated by a temporary regional agreement to increase energy conservation and transfers from energy-rich states to those facing shortages, the Commission saw no role for last-resort federal compulsion under section 202(c). *Id.* at 613-14.

DOE’s own rule—adopted shortly after we decided *Richmond Power & Light*—defines a section 202(c) “emergency” along similar lines 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.” 10 C.F.R. § 205.371. That rule lists as examples of events that might cause an emergent inadequacy in electricity supply “weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected ‘entity’ to prevent”; unanticipated shortfalls might also 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.” *Id.* DOE explained when it adopted the rule that section 202(c) did not empower it to issue orders to “replace prudent utility planning and system expansion.” Department of Energy, Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39,984, 39,985 (Aug. 6, 1981). As the rule specifies, a section 202(c) order is “envisioned as meeting a specific inadequate power supply situation,” not solving a long-term problem. 10 C.F.R. § 205.371.

The historical uses of section 202(c) further reinforce its limited scope. *See Loper Bright*, 603 U.S. at 386 (emphasizing that the “‘longstanding practice of the government’—like any other interpretive aid—‘can inform [a court’s] determination of what the law is’” (quoting *NLRB v. Noel Canning*, 573 U.S. 513, 525 (2014) (modification in original))). Outside of wartime, section 202(c) has been used sparingly. Between World War II and the Federal Power Commission’s dissolution and replacement by the Department of Energy in 1977, the Commission issued only seven section 202(c) orders, typically in response to local requests and based on impending outages, operating and construction difficulties, or drought. *See, e.g., City of Cleveland v. Cleveland Elec. Illuminating Co.*, 47 F.P.C. 747, 748-50 (1972) (operating difficulties); *Crisp Cnty. Power Comm’n v. Ga. Power Co.*, 35 F.P.C. 629, 630-31 (1966) (multiple system outages); *Tex. Elec. Serv. Co.*, 7 F.P.C. 574, 575 (1948) (construction delays, generator outage, and drought); *see also* Rolsma, *supra*, at 843-46 tbl. 2.

After Congress transferred section 202(c) authority from the Federal Power Commission to DOE in 1977, DOE saw no

need to use it for decades. Before 2025, DOE had issued section 202(c) orders only at the request of local entities and to alleviate discrete crises, such as those caused by severe weather events or unexpected construction delays that required an immediate response. *See, e.g.*, DOE Order 202-20-2 1-2 (Sept. 6, 2020), <https://perma.cc/7GEU-86C8> (extreme heat wave); DOE Order 202-17-1 1 (Apr. 14, 2017), <https://perma.cc/6QJC-2SEG> (unpredicted convergence of lightning strike and flooding); DOE Order 202-05-2 (Sept. 30, 2005), <https://perma.cc/WH4A-LV8A> (serial strikes of Hurricanes Rita and Katrina); *see also* Rolsma, *supra*, at 839-42 tbl 1.

In sum, an emergency under section 202(c) refers to an electricity shortage that is or will in the future be acute and is not being timely addressed by planning for resource adequacy by the state, its utilities, or an RTO. Those circumstances require immediate, essentially last-resort action by DOE outside the ordinary reliability planning process.

We next consider whether the circumstances identified by DOE are facially sufficient to meet the statutory requirement of an emergency. Because we conclude that they are not, we need not reach petitioners' substantial-evidence claims or their challenges to DOE's decision to choose Campbell as the source of additional capacity and to command it to run beyond the "hours necessary to meet the emergency." 16 U.S.C. § 824a(c)(2).

B.

The Order initially describes the emergency as "the potential for electricity supply shortfalls" in summer 2025 caused by the "retirement of thermal generation capacity." DOE Order 202-25-3 1 (J.A. 1). It warns that summer 2025 presented a risk of "potential loss of power to homes and local

businesses in the areas that may be affected by curtailments or outages.” DOE Order 202-25-3 2 (J.A. 2). DOE continues to defend the Order on that basis, arguing that “emergency conditions existed . . . due to a shortage that would cause unacceptable reliability risks in the near-term.” DOE Br. 31.

Those indeterminate assertions of summer electricity shortfalls are not what Congress meant by “emergency” in section 202(c). Had DOE pinpointed a concrete supply issue beyond the state’s competency that was likely to trigger a blackout in an identified area if temperatures peaked, immediate intervention might have been appropriate. But the mere possibility of an electricity supply shortfall—with no specifics about its potential severity, timing, location, or likelihood—does not warrant an emergency federal response. Rather, reasonable alternatives to DOE’s intervention were available, and in fact appear to have forestalled outages.

Because the circumstances DOE identified plainly did not necessitate immediate action by DOE, it did not meet the definition of an emergency under section 202(c). NERC’s Reliability Assessment—the very document on which the Department relies to support its emergency determination—describes MISO mitigation measures to prevent operating shortfalls, including accessing load-modifying resources, requesting energy transfers from neighboring systems, and issuing energy emergency alerts. See NERC Reliability Assessment 16 (J.A. 118). MISO also instructs its stakeholders to lower energy use and increase output from backup generators. See MISO Market Capacity Emergency 21-26 (J.A. 696-701). Michigan’s governor can declare an energy emergency to restrict energy consumption and direct supply to needed areas. See Mich. Comp. Laws. Ann. § 10.84. Such an intervention is modulated—in ways that DOE’s section 202(c) order is not—by the governor’s direct political accountability

to electricity users in the state and familiarity with state energy conditions. And, as already discussed, state regulators, transmission organizations, and load-serving entities have other mechanisms to address shortages, including requesting intervention from FERC under section 202(b).

DOE's Rehearing Order identifies an alternative basis for its emergency determination. The agency asserts that "most regions—including the MISO region relevant to the Emergency Order—will face unacceptable reliability risks within five years," and that requiring Campbell's continued operation "addresses that risk." DOE Order 202-25-3B 14 (J.A. 19). On appeal, DOE continues to defend the Order by pointing to longer-term reliability and resource adequacy concerns. *See* DOE Br. 79.

That added rationale falls even farther outside the meaning of "emergency" under section 202(c) than did the first. Long-term resource adequacy risks generally do not necessitate immediate action by DOE. They are routinely resolved through coordinated, forward-looking decision making within the ordinary resource adequacy system. That entire system prioritizes averting unacceptable long-term reliability risks. Again, Michigan addresses long-term reliability risks by reviewing generators' integrated resource plans and by approving or rejecting the construction and retirement of generation facilities. Regional entities like MISO facilitate states' responses to long-term reliability risks by setting resource adequacy requirements and encouraging new resource entry through effective administration of the capacity market. MISO has also adopted reliability initiatives aimed at improving its processes and transmission capabilities, such as implementing resource accreditation reforms, constructing new transmission lines, and expediting approval of new electric generation resources. *See* Testimony of Jennifer Curran 2

(J.A. 1140) (House Subcommittee testimony of MISO executive). And, if long-term resource adequacy continues to present a threat, NERC may modify its nationwide reliability standards. The federal government generally lacks statutory authority to address long-term reliability risks; much less is DOE empowered to make unauthorized use of section 202(c) emergency authority as a partial substitute for and disruption to the states' planning processes.

Because we conclude that DOE exceeded its statutory authority, we do not address petitioners' other challenges to the Order. See *MCI Telecomms Corp. v. FCC*, 765 F.2d 1186, 1188 (D.C. Cir. 1985).

III.

We vacate the Order. An order of a federal agency “that exceeds the scope of its statutory authority is, by definition, not in accordance with the law and subject to vacatur.” *All Am. Telephone Co., Inc. v. FCC*, 867 F.3d 81, 89 (D.C. Cir. 2017); see *Calif. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 396 (D.C. Cir. 2004) (vacating order that FERC had no authority to make or enforce). To determine whether vacatur is the appropriate remedy, we evaluate (1) “the likelihood that deficiencies in an order can be redressed on remand” and (2) “the disruptive consequences of vacatur.” *N.J. Conservation Found. v. FERC*, 111 F.4th 42, 64 (D.C. Cir. 2024) (quotation omitted).

The Order's deficiency cannot be redressed on remand because it depends on DOE's misconception of the nature and scope of its emergency authority under section 202(c). Because the circumstances identified by DOE do not amount to a section 202(c) emergency, the agency cannot claim any serious possibility that it will be able to “substantiate its decision on remand.” *Id.* (quoting *Allied-Signal, Inc. v.*

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Nuclear Regul. Comm'n, 988 F.2d 146, 151 (D.C. Cir. 1993)).
And vacatur will not be disruptive because the Order under review has already expired.

For the foregoing reasons, we grant the petitions and vacate the Order.

So ordered.