Table of Exhibits

Exhibit No.	Exhibit Name
1.	U.S. Dep't of Energy, DOE 202(c) Order Rehearing Procedures, https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures (last visited June 18, 2025)
2.	Email from Lot Cooke, U.S. Dep't of Energy to Linda Alle-Murphy Re: Rehearing procedures for DOE Order No. 202-05-3 (Dec. 28, 2005)
3.	Email from Lawrence Starfield (EPA) to Patricia Hoffman (DOE) Re: Confirmation that the Department of Energy consulted with the Environmental Protection Agency (Sept. 11, 2017)
4.	Department of Energy Order No. 202-17-4 Summary of Findings (Sept. 15, 2017)
5.	Department of Energy Order No. 202-20-2 (Sept. 6, 2020)
6.	Department of Energy Order No. 202-22-1 Amendment No. 2 (Sept. 2, 2022)
7.	Department of Energy Order No. 202-22-2 Amendment No. 1 (Sept. 4, 2022)
8.	Department of Energy Order No. 202-22-4 (Dec. 24, 2022)
9.	Department of Energy Order No. 202-24-1 (Oct. 9, 2024)
10.	Lisa Friedman and Brad Plumer, Five Takeaways From Trump's Plan to Rescue Coal, New York Times (Apr. 9, 2025)

Exhibit No.	Exhibit Name
11.	Eddystone Title V Permit (issued Apr. 17, 2025)
12.	Department of Energy Order No. 202-25-3 (May 23, 2025)
13.	Department of Energy Order No. 202-25-4 (May 30, 2025) ("Initial Order")
14.	Motion to Intervene and Request for Rehearing of Natural Resources Defense Council, Citizens for Pennsylvania's Future, Environmental Defense Fund, Sierra Club and Public Citizen (July 1, 2025) ("Initial RFR")
15.	DOE, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid (July 2025) ("RAR")
16.	GridLab Analysis: Department of Energy Resource Adequacy Report (July 11, 2025)
17.	Institute for Policy Integrity Report: Enough Energy A Review of DOE's Resource Adequacy Methodology ("IPI Report") (July 2025)
18.	Motion to Intervene and Request for Rehearing of the "Resource Adequacy Report, Evaluating the Reliability and Security of the United States Electric Grid," Natural Resources Defense Council, Ecology Center, Environmental Defense Fund, Environmental Law & Policy Center, Public Citizen Inc., Sierra Club and Vote Solar (Aug. 6, 2025)
19.	Department of Energy Order No. 202-25-7 (Aug. 20, 2025)
20.	Department of Energy Order No. 202-25-8 (Aug. 27, 2025) ("First Renewed Order")

Exhibit No.	Exhibit Name
21.	DOE Response to RFR on RAR (Sept. 5, 2025)
22.	Department of Energy Order No. 202-25-3B (Sept. 8, 2025)
23.	Department of Energy Order No. 202-25-10 (Nov. 25, 2025) ("Second Renewed Order")
24.	North American Electric Reliability Corporation ("NERC"), 2025-2026 Winter Reliability Assessment (Nov. 2025)
25.	PJM Inside Lines, PJM Winter Outlook: Adequate Power Supplies Available to Serve Growing Demand Under Expected Conditions (Nov. 3, 2025)
26.	PJM, Winter Storm Elliott: Event Analysis and Recommendation Report (July 17, 2023)
27.	U.S. EPA, Clean Air Markets Program Data (CAMPD): Eddystone Generating Station Hourly Emissions and Generation Data (Nov. 25 - Dec. 23, 2022), https://campd.epa.gov/
28.	Department of Energy Order No. 202-26-17 (Feb. 23, 2026) ("Third Renewed Order")
29	Grid Strategies LLC, Review of NERC's 2025 Long-Term Reliability Assessment (Mar. 5, 2026)
30	Department of Energy Order No. 202-26-24 (May 21, 2026) ("Current Renewal Order")
31	NERC, 2026 Summer Reliability Assessment (May 2026)

Exhibit No.	Exhibit Name
32	PJM, 2025/2026 Base Residual Auction Report (July 30, 2024)
33	PJM, 2026/2027 Base Residual Auction Report (July 22, 2025)
34	PJM, 2026/2027 RPM Third Incremental Auction Results (Mar. 9, 2026)
35	Order Granting Waiver Request, 195 FERC ¶ 61,162 (June 1, 2026) ("Waiver Order")
36	Constellation Energy Generation, LLC's Request for Prospective, Limited Waiver, Dkt. No. ER26-2028 (FERC Mar. 31, 2026)

Exhibit 1

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U.S. DEPARTMENT of ENERGY

DOE 202(c) Order Rehearing Procedures

DOE may revise these procedures through advance written notification to the parties and posting here.

Intervention. Any person seeking to intervene to become a party must file a written motion to intervene by emailing AskCR@hq.doe.gov. A motion to intervene must state the movant's interest in sufficient factual detail to demonstrate that the movant has or represents an interest which may be directly and substantially affected by the outcome of the proceeding. A motion to intervene must be filed within 30 days after the

issuance of a section 202(c) order, which includes an original order or a renewal order. No grant of late intervention is permitted unless DOE finds good cause. The grant of party status will be expressly stated by DOE order within thirty days of filing. A motion to intervene may be combined with a motion for rehearing, answer, or other motion.

Rehearing. Pursuant to 16 U.S. Code § 825*l*, any party applying for rehearing must file a written motion for rehearing by emailing AskCR@hq.doe.gov within 30 days after the issuance of a section 202(c) order. The motion for rehearing must set forth specifically the ground or grounds upon which such motion is based and must contain a clear and concise statement of the facts and law which support the motion and the specific relief or ruling requested. Any grounds not specifically identified in such motion shall be waived. All motions for rehearing will be addressed in a consolidated proceeding and order on rehearing. Unless DOE acts upon the motion for rehearing within 30 days of filing, such motion may be deemed to have been denied.

Answers. Any party may file an answer to another party's motion by emailing AskCR@hq.doe.gov within 7 days after the motion is filed. An answer must contain a clear and concise statement of any disputed factual allegations and any law upon which the answer relies. An answer to an answer is not permitted.

Timing and Service. DOE will use best efforts to post filings here within 24 hours of receipt. Such posting constitutes service to all parties. Filing or posting due dates that fall on a federal holiday or weekend shall be extended to the next business day. Documents received after 4:30 p.m. Eastern Time are deemed filed on the next business day.

Confidentiality. DOE strongly encourages that all filings be limited to information suitable for public release. If procedures to maintain confidentiality are requested, DOE will provide them as needed at the discretion of DOE.

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Exhibit 2

-----Original Message-----
From: Alle-Murphy, Linda
Sent: Wednesday, December 28, 2005 9:05 AM
To: Mansueti, Lawrence
Subject: Re: Order No. 202-05-3

Dear Mr. Mansueti,

I am an associate at Schnader Harrison Segal and Lewis, working together with John Britton, who represents the City of Alexandria in the Mirant Power Plant matter. I have a few procedural questions regarding the application for rehearing.

According to Section VI.H. of Order No. 202-05-3, applications for rehearing in this matter should be addressed to you. Section VI.H. cites to 16 U.S.C. Section 825(l), which refers to the "Commission" (FERC). I am just seeking to confirm that Section 825(l) also applies to this DOE proceeding.

Also, are 10 CFR Section 1003.1 et seq., Office of Hearings and Appeals Procedural Regulations applicable to this proceeding (e.g. re service requirements, etc.) If not, are there other procedural rules that apply to this proceeding?

Thank you very much for your assistance! You may respond by return e-mail or, if that is not convenient for you, by telephone or fax.

Linda Alle-Murphy
Linda B. Alle-Murphy
Schnader Harrison Segal & Lewis LLP
1600 Market Street, Suite 3600
Philadelphia, PA 19103-7286

From: Cooke, Lot
Sent: Friday, December 30, 2005 8:51 AM
To: 'LAlle-Murphy@Schnader.com'
Subject: Rehearing procedures for DOE Order No. 202-05-3

Dear Ms. Alle-Murphy:

In response to your emailed question to Mr. Mansueti--

The DOE Organization Act transferred the authority of the Federal Power Commission to the Secretary, except for authority over rates and charges for the transmission and sale of electric energy, which was transferred to FERC. Federal Power Act (FPA) Section 202(c) emergency authority was generally and specifically given to the Secretary.

An order issued under the FPA is only reviewable pursuant to the rehearing provisions contained in section 313 of the FPA, so that is the applicable provision under which to seek rehearing of the December 20,
2005 order.

The DOE regulations on emergency orders, 10 CFR section 205.370, et seq., do not a have specific rehearing section, but a party seeking rehearing can look for procedural guidance to FERC's Rules of Practice and Procedure, 18 CFR Part 385. In particular the rehearing regulations contained at 18 CFR section 385.713 and the service requirement contained at 18 CFR section 385.2010. The Office of Hearings and Appeals procedures are not applicable as the Secretary will make the rehearing decision pursuant to FPA section 313.

Exhibit 3

From: Starfield, Lawrence <Starfield.Lawrence@epa.gov>
Date: Monday, Sep 11, 2017, 11:27 AM
To: Hoffman, Patricia <Pat.Hoffman@hq.doe.gov>
Cc: Lucas, John T. <John.T.Lucas@hq.doe.gov>, Minoli, Kevin <Minoli.Kevin@epa.gov>, Kelley, Rosemarie <Kelley.Rosemarie@epa.gov>, Chapman, Apple <Chapman.Apple@epa.gov>
Subject: DOE section 202(c) order

To: Pat Hoffman, DOE Acting Under Secretary for Science and Energy

On August 24, 2017, PJM submitted a renewal application requesting a 90-day renewal of the Order issued on June 16, 2017, by the Secretary of Energy. This email confirms that the Department of Energy (DOE) consulted with the Environmental Protection Agency (EPA), the primary Federal agency with expertise in the Mercury and Air Toxics Standard and section 316(b) of the Clean Water Act, with respect to a renewal order under Section 202(c) of the Federal Power Act related to Virginia Electric and Power Company's Units 1 and 2 at its Yorktown Power Station, near Yorktown, Virginia. See 16 U.S.C. § 824a(c)(4)(B) (Federal Power Act, Section 202(c)(4)(B)). DOE's proposed operational conditions for the order are generally consistent with EPA's Administrative Compliance Order, AED-CAA-113(a)-2016-002, as amended.

Thank you for your coordination on this matter.

Larry Starfield
Acting Assistant Administrator
Office of Enforcement and Compliance Assurance
U.S. EPA
Washington, DC

(202) 564-2440 (office)
(202) 564-8179 (direct)

Exhibit 4

Summary of Findings
Department of Energy Order No. 202-17-4

September 14, 2017

Section 202(c) of the Federal Power Act (FPA) (codified at 16 U.S.C. § 824a(c)), through section 301(b) of the Department of Energy Organization Act (codified at 42 U.S.C. § 7151(b)), authorizes the Secretary of Energy, upon finding "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," to issue an order "requir[ing] . . . such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in [the Secretary's] judgment will best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(1). If the order "may result in a conflict with [an] environmental law or regulation," then the Secretary must "ensure that such order requires generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, is consistent with any applicable . . . environmental law or regulation and minimizes any adverse environmental impacts." *Id.* § 824a(c)(2). Orders issued under FPA section 202(c) "that may result in a conflict with [an] environmental law or regulation" expire 90 days after they are issued, but the Secretary "may renew or reissue such order[s] . . . for subsequent periods, not to exceed 90 days for each period, as [the Secretary] determines necessary to meet the emergency and serve the public interest." *Id.* § 824a(c)(4)(A).

The Department's regulations implementing FPA section 202(c) define the term "emergency" to mean, among other situations, "a specific inadequate power supply situation." 10 C.F.R. § 205.371. The regulations do not exhaustively list what qualifies as an emergency, but they note specifically that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations." *Id.*

On June 13, 2017, PJM filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Order Application) (included in the docket[1] of this Order) with the Department "to preserve the reliability of [the] bulk power transmission system in the North Hampton Roads area." Virginia Electric and Power Company[2] (Dominion), the electric utility serving the area, owns the coal-fired, power generating Units 1 and 2 at the Yorktown Power Station in Yorktown, Virginia. In November 2011 and October 2012, Dominion notified PJM of its plan to deactivate Units 1 and 2, respectively, effective December 31, 2014, because the units were not equipped to

[1] The docket of this Order is available at https://www.energy.gov/oe/downloads/federal-power-act-section-202c-dominion-energy-virginia-june-2017.
[2] *See* Dominion Energy, Inc., Form 10-Q filing, at 1 (Aug. 3, 2017), included in the docket of this Order.

comply with the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS), 40 C.F.R. part 63 subpart UUUUU. On June 24, 2014, pursuant to 40 C.F.R. § 63.6(i)(4)(i)(A), the Virginia Department of Environmental Quality granted Dominion a one-year MATS compliance extension for Yorktown Units 1 and 2.

On April 16, 2016, pursuant to section 113(a) of the Clean Air Act, 42 U.S.C. § 7413(a)(3) and (4), the EPA issued an Administrative Compliance Order (ACO) through April 15, 2017. The ACO implemented a 2011 MATS Enforcement Policy regarding issuance of section 113(a) administrative orders to sources that are unable to comply with the MATS but that may need to operate for up to a year to address a specific and documented reliability concern. The 2011 MATS Enforcement Policy was limited in application to units critical for reliability purposes. The EPA found that operation of Yorktown Units 1 and 2 met the policy criteria, as verified by the Federal Energy Regulatory Commission (FERC). Dominion has not achieved full compliance with the MATS for Yorktown Units 1 or 2 since the ACO expired, and section 113(a) of the Clean Air Act bars further compliance extensions.

Since Dominion's decision to retire the coal-fired Yorktown units, PJM has planned for their permanent deactivation by including required transmission upgrades in its own Regional Transmission Expansion Planning Process. PJM is subject to federal reliability standards enforced by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization designated by FERC. PJM holds the highest-level reliability responsibilities for the system it manages as a certified Reliability Coordinator, Balancing Authority, and Transmission Operator. PJM is also registered with NERC as a Planning Coordinator and Transmission Planner, among other functions. NERC Compliance Registry Active Entities List (updated Sept. 7, 2017), included in the docket of this Order. PJM applies reliability criteria to evaluate transmission system conditions and then develops the transmission solutions needed to ensure compliance with the reliability standards. The PJM Board of Managers approves those solutions in a Regional Transmission Expansion Plan (RTEP). Through its Transmission Expansion Advisory Committee (TEAC) and Sub-Regional RTEP Committees, PJM works with stakeholders throughout the RTEP's development. PJM Manual 14B, "Regional Planning Process," included in the docket of this Order. The PJM Board of Managers approved the transmission upgrades necessitated by the retirement of Yorktown Units 1 and 2 on May 17, 2012. TEAC Recommendations to the PJM Board (PJM Staff Whitepaper), May 2012, at 12, included in the docket of this Order.

PJM's approved solution was the Skiffes Creek Transmission Project, which consists of three components: a 500kV line, a 230kV line rebuild, and a new switching station. United States Army Corps of Engineers (Army Corps), Memorandum for the Record re: Department of the Army Environmental Assessment and Statement of Findings for the Above-Referenced Standard Individual Permit Application, CENAO-WR-RS (NAO-2012-00080 / 13-V0408), at 1, included in the docket of this Order. A

number of issues in the North Hampton Roads area, many of which are interrelated, needed to be addressed to avoid overloading transmission lines with too much power, as detailed in PJM's Deactivation Study. Yorktown Units 1 and 2 Generator Deactivation Notification: Deactivation Study Results – updated June 26, 2017 (PJM Deactivation Study), included in the docket of this Order. *See also Va. Elec. & Power Co.*, Commission Comments on Requests for EPA Administrative Orders, Docket No. AD16-11-000, 153 FERC ¶ 61,265 at PP 14-16 (2015).

PJM completed a series of analyses consistent with RTEP procedures, finding that only the Skiffes Creek Transmission Project—and none of the stakeholder-proposed alternatives—addressed the full range of potential reliability violations. Order Application, app. I, at 16. For example, reliance on operation of the oil-fired Yorktown Unit 3 generator would not address thermal overload and voltage violations on the 230kV and 115kV bulk electric system that PJM identified because of significant environmental operating restrictions and other plant operation constraints associated with that unit, including an 8 percent capacity factor limitation. *See id.*, app. II, at 18. As a result, PJM did not recommend reliance on Yorktown Unit 3 as a sustainable alternative solution to the identified reliability criteria violations. *Id.*

As part of PJM's analyses, Dominion transmission staff provided PJM with an analysis of system needs as well as potential solutions to the retirement of generating units at Yorktown and elsewhere. Dominion Update to Retirement Study Results (Mar. 10, 2012), included in the docket of this Order. Dominion's analysis, which was based on PJM's initial determination of reliability criteria violations that needed to be addressed, was independently validated by PJM and publicly vetted through the PJM stakeholder process before PJM staff recommended that the Board of Managers approve the Skiffes Creek Transmission Project. PJM Staff Whitepaper at 12, included in the docket of this Order.

PJM, as the Regional Transmission Organization (RTO) responsible for transmission system operation across multiple states, including Virginia, maintains its expert determination that the Skiffes Creek Transmission Project is the most effective and efficient solution to address the identified reliability criteria violations. Order Application, app. I, at 16. As recently as March 1, 2017, PJM provided the Army Corps with an analysis of proposed alternatives and found that none of them sufficiently resolved the identified violations. Letter to Col. Jason E. Kelly, U.S. Army Corps of Engineers (Mar. 1, 2017), included in the docket of this Order. PJM's subsequent RTEP materials reaffirm the need for the Skiffes Creek Transmission Project, even considering the updated, steadily rising load forecasts in the recently released 2017 PJM Load Forecast Report (included in the docket of this Order). *See* PJM Interconnection, L.L.C., 2017 RTEP Process Scope & Input Assumptions, rev. 1, at 25-27 (Aug. 3, 2017), included in the docket of this Order.

Construction of the Skiffes Creek Transmission Project began in July 2017 and is expected to take approximately 18-20 months. *Order No. 202-17-2 Renewal Application Filing* (Renewal Application) at 3. Until the Project is completed, a plan known as the North Hampton Remedial Action Scheme (RAS) remains in effect. According to NERC's Glossary of Terms, a RAS is "[a] scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation ([megawatts] and [megavolt amperes (reactive)]), tripping load, or reconfiguring a System(s)." Glossary of Terms Used in NERC Reliability Standards (updated Aug. 1, 2017), at 24, included in the docket of this Order.

To preserve the grid's reliability, the North Hampton RAS would allow PJM, the grid operator, to drop load—that is, shut off power to certain customers—to prevent voltage collapse. Dominion presented this RAS to PJM in January 2017, and the SERC Reliability Corporation, the NERC-delegated regional reliability enforcement entity, approved it that same month. *See* Dave Rees, *Dominion Virginia Power Sets Plan for Emergency Blackouts*, Daily Press, Jan. 13, 2017, included in the docket of this Order. If Yorktown Units 1 and 2 were unavailable, many N-1-1 contingencies could result in voltage collapse and thermal overloads. New Remedial Action Scheme, North Hampton RAS (Presentation to PJM), at 4, included in the docket of this Order; PJM Deactivation Study, included in the docket of this Order. According to FERC, "An N-1-1 contingency is a sequence of events consisting of an initial loss of a single generator or transmission element, followed by system adjustment, followed by another loss of a single generator or transmission element." *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD14-14-000, 153 FERC ¶ 61,221 at P 30 n.61 (2015).

The North Hampton RAS is on standby for use at PJM's discretion. If PJM detects the loss of certain facilities, it could trip the remaining feeds to the Yorktown area and drop service to approximately 150,000 customers, preventing voltage collapse. Rotating outages would follow until the system returns to normal operating parameters. New Remedial Action Scheme, North Hampton RAS (Presentation to PJM), at 6, included in the docket of this Order. According to U.S. Census estimates, the region PJM identifies as the North Hampton Roads load area in its Order Application had a population of more than 660,000 as of July 2016. At a minimum, rotating outages under the RAS would therefore impact, directly or indirectly, several hundred thousand people. United States Census Bureau, QuickFacts database, available at https://www.census.gov/quickfacts/fact/table/US/PST045216.

On July 3, 2017, the Army Corps issued a permit to Dominion for the Skiffes Creek Transmission Project pursuant to section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. § 403) and section 404 of the Clean Water Act (33 U.S.C. § 1344). On July

10, 2017, Dominion commenced construction of the Skiffes Creek Transmission Project. Renewal Application at 3.

On August 24, 2017, PJM filed its Renewal Application with DOE. The filing included all reports required by Order No. 202-17-2 (included in the docket of this Order). PJM said that construction of the Project was still expected to take 18-20 months, and that periodic transmission outages would be necessary to proceed apace with the Project. The same day, Dominion wrote to the Department that it "agrees with the Renewal Application and will operate in accordance with its provisions." Further, Dominion acknowledged that a 202(c) order "is not a long term solution to the reliability issues in the North Hampton Roads area on the Virginia Peninsula." The Skiffes Creek Transmission Project, underway as of July 2017, is the long-term solution.

On September 7, 2017, the Department received comments from Sierra Club opposing PJM's renewal request. On September 13, 2017, the Department received an answer to Sierra Club's comments from PJM. Both documents are included in the docket of this Order.

Discussion

Order No. 202-17-2 directs operation of Yorktown Units 1 and 2 as needed to address reliability issues, subject to a dispatch methodology submitted to the Department for review. The reliability issues noted in Order No. 202-17-2 were described as Scenario One, increased load due to weather-related temperature extremes, and Scenario Two, decreased transmission capacity required by the RTEP upgrade. Scenario Two was contemplated but not yet applicable when Order No. 202-17-2 was issued because the Army Corps permit application for the Skiffes Creek Transmission Project was still pending. On July 3, the Army Corps issued Permit No. NAO-2012-00080, resulting in the potential need to operate Yorktown Units 1 and 2 to address both Scenario One and Two reliability issues. To date, in accordance with Order No. 202-17-2, PJM has directed operation of Yorktown Units 1 and/or 2 for all or part of 13 days. PJM Interconnection, L.L.C., Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2, Attachment 1, included in the docket of this Order; Telephone call to Steven Pincus, Associate General Counsel, PJM, Sept. 11, 2017.

Scenario One applies when load conditions exceed a certain threshold due to local transmission issues that would cause PJM to operate the system outside its normal operating parameters.[3] Weather-related temperature extremes are one example of such a local transmission issue. Scenario Two is also triggered when load conditions exceed a certain threshold, but the threshold is lowered depending on the particular construction-related transmission outages in effect as the Skiffes Creek Transmission Project is built.

[3] Exact load thresholds were submitted as critical electric infrastructure information and are thus not described here so as not to provide vulnerability information on critical infrastructure.

Because the Project minimizes environmental impacts by utilizing existing transmission line rights-of-way to the extent possible, portions of existing transmission lines must be taken offline for upgrades. Under either scenario, when the relevant thresholds are exceeded, to prevent system overload and uncontrolled power disruptions, PJM must implement the North Hampton RAS. The only sufficient alternative to the RAS and its resulting outages for up to approximately 150,000 customers is the emergency operation of Yorktown Units 1 and 2. The demand response available to PJM is a small fraction of the load threshold and is "not sufficient to ensure reliable service." Order Application, app. II, at 18. Likewise, Dominion has limited demand-side management and curtailment capabilities, insufficient for reliability purposes even when fully deployed. *See id.*, app. III, at 21.

Activating the RAS would immediately interrupt service to load in the North Hampton Roads area. PJM asserts that, according to the RAS, during certain high load conditions, this "load shedding" could result in the loss of roughly 950 MW of electric power—that is, the loss of service to over 150,000 North Hampton Roads area customers. Order Application at 9. This service interruption could last hours or even days. *See* North Hampton RAS Presentation to PJM, at 8, included in the docket of this Order. Activating the RAS is not a gradual approach that presents a wide range of likely impacts; it is an extreme measure with immediate consequences to 150,000 customers. While the RAS is designed to prevent more catastrophic, uncontrolled grid impacts from occurring, load shedding of this magnitude is significant, and would trigger mandatory reporting both to DOE and FERC. DOE Form OE-417 requires reporting within one hour for "[l]oad shedding of 100 Megawatts or more implemented under emergency operational policy," and within six hours for "[l]oss of electric service to more than 50,000 customers for 1 hour or more." This is the same level of reporting triggered by a cyber or other hostile attack on grid resources. Form OE-417, Electric Emergency Incident and Disturbance Report, https://www.oe.netl.doe.gov/docs/OE417_Form_03312018.pdf. Similarly, FERC and NERC mandate notification for a variety of serious events including when a bulk electric system emergency triggers automatic load shedding of 100 MW or more, as in the RAS. *See* North American Electric Reliability Corporation, Reliability Standard EOP-004-3 (Event Reporting), http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-004-3&title=Event%20Reporting.

To underscore the potential impact of RAS activation, the estimated 150,000 impacted customers are counted by meter, not individual. One or more meters could translate to large household or commercial or industrial facilities, including those critical to health and safety systems. Whether counted as 150,000 or that amount multiplied several times over, the anticipated impact of this emergency situation is on par with or exceeds the impacts described in prior 202(c) orders. *Crisp Cnty. Power Comm'n v. Ga. Power Co.*, 35 FPC 629, 630-31 (1966) (ordering interconnection to prevent, in part,

outages lasting more than an hour and affecting 500 to 2,000 customers on Crisp County, Georgia's system). *City of Cleveland, Ohio v. Cleveland Elec. Illuminating Co.*, 47 FPC 747, 749 (1972) (ensuring reliable service was provided to the approximately 20% of the city's consumers). Cleveland's 1970 Census-reported population was 750,903, suggesting that just over 150,000 individuals were affected by the 1972 202(c) order. *See* https://www.census.gov/population/www/documentation/twps0027/tab20.txt. As described earlier, the U.S. Census estimated the population of the North Hampton Roads load area at nearly 661,000 people just over a year ago.

A benefit of the planning efforts mandated by federal reliability standards is that entities such as PJM can accurately forecast the impacts to the bulk power system in steady-state and various contingency event situations. Thus, as reliability planning continues to mature, there should be fewer electric energy shortages that take bulk power system owners, operators, and regulators by surprise. That planners can identify conditions under which shortages may occur, however, does not rule out electric energy shortages constituting emergencies under FPA section 202(c) and the Department's implementing regulations. It is impossible to plan for every contingency, and challenges may arise even when implementing the most prudent plans. FPA section 202(c) affords the Secretary of Energy discretion in finding when an emergency exists and how best to meet the emergency and serve the public interest.

Here, an emergency exists due to the imminent possibility of implementing the North Hampton RAS under a range of both steady-state and contingency events, including potential transmission congestion preventing the delivery of available generation to the North Hampton Roads area. PJM Deactivation Study at 1-2, included in the docket of this Order. The RAS would leave approximately 150,000 customers without power, including residential, industrial, commercial, health and safety facilities, major national defense, and educational institutions. *See* Order Application, app. IV, at 30-31. That creates serious health and safety issues. Issuance of today's Order meets the emergency and serves the public interest.

In these circumstances, transmission outages, like those contemplated for or otherwise in connection with the construction of the Skiffes Creek Transmission Project, constitute an emergency for purposes of a section 202(c) order. As stated earlier, the Department's implementing regulations, in their current form since 1981, contemplate that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities [may create] an emergency." 10 C.F.R. § 205.371. The regulations add that "[i]n such cases, the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed." *Id.* PJM, the impacted entity in this case, requested today's Order. Through the RTEP, PJM made firm arrangements to resolve the problem through the Skiffes Creek Transmission Project, which is now permitted and under construction. That construction was delayed due to events beyond

PJM's control has no bearing on the likelihood of power outages for 150,000 customers. Such a power loss event would also constitute an emergency as contemplated by FERC in its Public Utility Regulatory Policies Act of 1978 regulations, which define "system emergency" as "a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property." 18 C.F.R. § 292.101(b)(4). The risk faced by 150,000 customers will continue, assuming the Skiffes Creek Transmission Project construction schedule is met, for approximately another 18 months. Today's Order is limited in time and specifically tailored to address an emergency contemplated both in the authorizing statute and the Department's implementing regulations.

Between 2005 and 2007, DOE issued orders under similar circumstances, directing the Mirant Potomac River Generation Station to operate until two new 230kV transmission lines could be built to ensure reliability to a portion of the District of Columbia. *See* Order No. 202-5-3 (relying on DOE regulatory definition of emergency as including extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities). In a series of orders under FPA section 202(c), the Secretary ordered operation of the generation units while the two existing 230kV lines that supplied the central District of Columbia area were temporarily and sequentially removed from service to connect the new lines. Neither the problems leading up to the closure of the generating units nor the need for a particular transmission solution were unexpected. Nevertheless, the Department found that imminent power shortages, faced if contingency events occurred, constituted an emergency under the Federal Power Act. Order Nos. 202-5-3, 202-6-1, 202-6-2, 202-7-1, and 202-7-2.

In this matter, the likelihood of RAS activation is not theoretical. While Order No. 202-17-2 was in effect, PJM had to call upon Yorktown Units 1 and/or 2 on 13 days over three months. Absent Order No. 202-17-2, the RAS would have been activated instead. The alternatives available to PJM and Dominion are not sufficient to ensure reliability without available capacity from Yorktown Units 1 and 2. As described, PJM and Dominion cannot mobilize adequate alternatives to counter the loss of transmission during construction of the Skiffes Creek Transmission Project. For example, demand response resources, while potentially helpful at the margin, are insufficient to address either Scenario One or Scenario Two. *See* Order Application, app. II, at 18. Further, PJM's recent RTEP Input Assumptions and Scope Whitepaper indicates that Dominion theoretically has up to 130 MW of distributed solar generation available during the summer. 2017 RTEP Process Scope and Input Assumptions, rev. 1, tbl.3.2, at 18 (Aug. 3, 2017), included in the docket of this Order. Outside of ramp-up and ramp-down times, each Yorktown Unit typically ran at 100 MW output or higher, day or night, when operational while Order No. 202-17-2 was in effect. PJM Interconnection, L.L.C., Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2, Attachment 1. Distributed generation is an intermittent resource; even under ideal conditions, with full-capacity, daytime generation and load reduction at the height of the

summer, distributed generation generally would still not have offset the baseload generating capacity needed to ensure reliability on the North Hampton Roads area grid. And any flexibility for scheduling the Skiffes Creek Transmission Project's construction during historically low-load periods ended when the EPA ACO expired, as expeditious completion of the Project is now the priority. Therefore, even if PJM and Dominion made full use of available alternatives, capacity from Yorktown Unit 1, 2, or both would still be necessary to meet the emergency and serve the public interest.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law or regulation be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, [be] consistent with any applicable . . . environmental law or regulation and minimize[] any adverse environmental impacts." Certain load conditions may necessitate operation of Yorktown Units 1 and 2.

To minimize the hours of operation and adverse environmental impacts, the Order contains certain limitations. First, DOE maintains consistency with EPA's approach in the 2016 ACO by authorizing operation of Yorktown Units 1 and 2 only when called upon by PJM for reliability purposes. The Department consulted with EPA and has reviewed data provided by PJM and Dominion on operations, air emissions, and water usage. This Order will continue the operational limitations described in EPA's above-referenced ACO, AED-CAA-113(a)-2016-0005. Second, DOE requires that PJM and Dominion, consistent with good utility practice, first exhaust all reasonably and practically available resources, including demand response and behind-the-meter generation resources, before operating Yorktown Units 1 and 2. Third, DOE requires continued compliance with the June 27 dispatch methodology, which was reviewed by the Department, and which remains subject to continuing oversight by the Department. In particular, the dispatch methodology establishes Yorktown Units 1 and 2 commitment procedures, describes the utilization and trip conditions of the North Hampton RAS for mitigating congestion on the Virginia Peninsula or North Hampton Roads area, and describes Dominion's mitigation options for the existing James River tower contingency. The dispatch methodology is an operating protocol that limits the ability of PJM to dispatch Yorktown Units 1 and 2 only when needed to mitigate reliability issues associated with scheduled and emergency transmission outages directly related to the Skiffes Creek Transmission Project and other local transmission issues. The EPA ACO recognized that such a dispatch methodology, under which PJM determines when the Yorktown units are needed for reliability issues, serves the objective of minimizing emissions. ACO at 8-9, included in the docket of this Order. Fourth, to track when Yorktown Units 1 and 2 are operated to maintain grid reliability and to monitor associated air emissions and water usage, reports will be required every two weeks going forward. If the Department becomes concerned with PJM or Dominion's compliance with this Order, enforcement actions are available, up to and including termination of the underlying order.

While DOE has constrained PJM's operations with regard to Yorktown Units 1 and 2, it is necessary to preserve reasonable discretion for PJM, as a Transmission Operator, to address the second-to-second operational challenges of grid management. This follows DOE's practice in earlier orders issued under FPA section 202(c), which prioritized reliability concerns as identified and assessed by the operator. For example, Order No. 202-02-1 (Aug. 16, 2002) ordered Cross-Sound Cable Company, LLC to operate a cable across Long Island Sound, limiting "transmission and delivery of . . . electric capacity and/or energy [to that] necessary in the judgment of the New York Independent System Operator [ISO] to meet the supply and essential reserve margin needs of the Long Island Power Authority [LIPA]," but only "in order for LIPA to serve its firm retail customers after it has implemented all available load reduction measures consistent with good utility practice." Order No. 202-03-1 (Aug. 14, 2003) directed operation of the same cable, but specifically ordered the New York ISO and ISO New England to require Cross-Sound Cable Company to operate the cable. That order also required both RTOs to "consult with each other and with appropriate reliability organizations." Today's Order similarly requires PJM to identify and mitigate reliability issues in accordance with DOE's specified operational limitations.

In considering renewal or reissuance of an order under FPA section 202(c) that may conflict with an environmental law or regulation, DOE is required to "consult with the primary Federal agency with expertise in the environmental interest protected by such law or regulation" and to include "conditions as such Federal agency determines necessary . . . to the extent practicable." 16 U.S.C. § 824a(c)(4). The EPA is the primary federal agency in this case with expertise in the protected environmental interest, specifically MATS and section 316(b) of the Clean Water Act, and the Department consulted with EPA after receiving the Renewal Application. Email from Acting Assistant Administrator Starfield, Office of Enforcement and Compliance Assurance, to Acting Under Secretary for Science and Energy Hoffman (Sept. 11, 2017), included in the docket of this Order. After consulting with EPA, and consistent with that consultation, the Department found that the only appropriate short-term emissions limitation on Yorktown Units 1 and 2 would be to curtail operating hours to the maximum extent practical for reliability purposes.

Pursuant to the National Environmental Policy Act of 1969, the Department has determined that issuance of this Order fits within the category of actions included in Categorical Exclusion (CX) B4.4 and otherwise meets the requirements for application of a CX. The Order fits within the category of actions because it authorizes "[p]ower marketing services and power management activities (including, but not limited to, storage, load shaping and balancing, seasonal exchanges, and other similar activities), provided that the operations of generating projects would remain within normal operating limits." Records of Categorical Exclusion Determination, Order No. 202-17-4, Sept. 11, 2017, included in the docket of this Order.

For the reasons stated above, the Secretary of Energy finds that an emergency exists threatening imminent electric energy shortages, and that this Order is necessary to address the emergency and serve the public interest in the North Hampton Roads area. The limitations on operation set forth in Order No. 202-17-4 and outlined above are, to the maximum extent practicable, consistent with applicable environmental laws or regulation and minimize any adverse environmental impacts, and the reporting requirements for operations and estimated emissions ensure transparency of implementation.

Exhibit 5

Department of Energy
Washington, DC 20585

Order No. 202-20-2

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated to the Deputy Secretary of Energy by paragraph 1.11(A) of Delegation Order No. 00-001.00G (Apr. 10, 2018), and re-delegated to the Assistant Secretary for Electricity on September 6, 2020, and for the reasons set forth below, I hereby determine that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

On September 6, 2020, the California Independent System Operator (CAISO), the Regional Transmission Organization whose service territory includes California and a portion of Nevada, filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of bulk electric power system."

Since August, California has experienced several periods of extreme heat, some of which have resulted in rolling blackouts. On September 2, 2020, California Governor Gavin Newsom issued an emergency proclamation to help alleviate the stress on the state's power grid due to an "Extreme Heat Event." In declaring a statutory emergency, the proclamation cited a number of factors and observations, including the following:

- "[B]eginning on September 2, 2020, a significant heat wave struck California, bringing widespread temperatures well in excess of 100 degrees throughout the State;"
- "[T]he National Weather Service [has] issued multiple Excessive Heat Warnings within [California];"
- "[T]he Extreme Heat Event has and will continue to put significant demand and strain on California's energy grid; and"
- "[T]he Extreme Heat Event is expected to last through at least September 7, 2020."

The proclamation authorizes emergency use of stationary generators, portable generators, and "auxiliary engines by ocean-going vessels berthed in California ports," and directs the state's Air Resources Board to "exercise maximum discretion to permit the use of stationary and portable generators or auxiliary ship engines to reduce the strain on the energy infrastructure and increase energy capacity." The proclamation also

suspends "[a]ny permit, regulation or law prohibiting, restricting or penalizing the use of stationary or portable generators or auxiliary ship engines" as allowed by the proclamation order.

On September 3, the CAISO issued a statewide flex alert for September 5-7, encouraging voluntary load reduction between 3:00 p.m. and 9:00 p.m. local time each day. The alert warns that consumers should "be prepared for potential power outages, both planned and unplanned during heat waves, especially in extremely high temperatures that last multiple days," noting that "[h]ot weather can also impact generation and transmission equipment, as it runs harder and longer with less time to cool, which can cause machinery failure." The alert explains that there is little energy available to import due to high heat predicted throughout the West, and that the wildfires in the state may take out transmission lines or cause lines to be shut down for the safety of firefighters in the area.

The CAISO notes that "[e]lectric demand forecasts have continued to increase since the issuance of the California Governor's emergency proclamation and the CAISO balancing authority area has lost additional generation supply because of wildfires." Application at 3. To address the situation, the "CAISO has started to direct all generators in its balancing authority area to produce to their maximum capability during certain times of the day," and has gone so far as to allow, when reliable and safe based on currently operating conditions, "certain generators to generate more than their interconnection capacity to provide additional power to the grid." *Id.* at 3. The impetus for the Application, however, arose on September 5, 2020, when the operator of the natural gas-fired resources identified in Exhibit A of the Application informed the CAISO that it could not produce to its maximum generation capability without exceeding its federal air quality or other permit limitations. *Id.* "The CAISO is informed and believes these limitations involve both permit limitations under federal law for nitrogen oxide emissions and ammonia releases as well as a limitations regarding fuel and ammonia throughput." *Id*.

The CAISO requests "that the Secretary issue an order immediately, effective September 6, 2020, authorizing specific electric generating units located within the CAISO balancing authority area to operate at their maximum generation output levels when directed to do so by the CAISO, notwithstanding air quality or other permit limitations." *Id.* at 1. The generating units specified are units 1 - 5 at the Walnut Creek Energy Park in the City of Industry, California; units 5/6 and 7/8 at the El Segundo Energy Center in El Segundo, California; and units 1 - 4 at the Long Beach Generating Station located in Long Beach, California. *Id.* For purposes of this Order, these units are referred to as the "Specified Resources." Collectively, they represent up to as much as 100 MW. The CAISO requests "such order be entered today, September 6, 2020, and remain effective for a period of seven (7) days, without prejudice to the possible issuance of further orders as necessary to address the emergency…[to] ensure additional supply is

available during a period in which California may continue to experience extreme weather and wildfires that have forced generation out of service." *Id*. at 2.

Given the emergency nature of the expected load stress, the responsibility of the CAISO to ensure maximum reliability on its system, and the ability of the CAISO to identify and dispatch generation necessary to meet the additional load, I have determined that additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. The CAISO anticipates that this Order may result in exceedance of National Ambient Air Quality Standards under the Clean Air Act and notes that the Specified Resources are located in different communities within California and should not result in any disproportionate impact on a single community. *Id.* at 4. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by the CAISO for reliability purposes.

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

A. From September 6, 2020, to September 13, 2020, in the event that the CAISO determines that generation from the Specified Resources is necessary to meet the exceptional levels of electricity demand that the CAISO anticipates in California, I direct the CAISO to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in California between the hours of 14:00 Pacific Daylight Time and 22:00 Pacific Daylight Time on days when the demand on the CAISO system exceeds expected energy and reserve requirements.

B. The CAISO shall select the combination of units that meets the reliability emergency and minimizes environmental impact. Consistent with good utility practice, the CAISO shall exhaust all reasonably and practically available resources, including demand response and identified behind-the-meter generation resources to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources.

C. By September 21, 2020, the CAISO shall report all dates between September 6, 2020, and September 13, 2020, on which the Specified Resources were

operated, the hours of operation, and the estimated air emissions (including nitrogen oxides and ammonia releases) and fuel and ammonia throughput associated with operating each unit. The CAISO shall submit a final report by October 13, 2020, with any revisions to the information reported on September 21.

D. This Order shall be effective upon its issuance, and shall expire at 23:59 Pacific Daylight Time on September 13, 2020, with the exception of the reporting requirements in paragraph C. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. this 6th day of September, 2020.

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Bruce Walker
Assistant Secretary for Electricity

Exhibit 6

Department of Energy
Washington, DC 20585

Amendment Number 2 to Order No. 202-22-1

On September 2, 2022, because of a shortage of currently operational electric generating facilities, high demand for electricity, and other adverse conditions resulting from the extreme heat event in California, I issued Order No. 202-22-1. Order No. 202-22-1 authorizes the California Independent System Operator Corporation (CAISO), to direct the operation of the Covered Resources identified in Order No. 202-22-1 and on the terms set forth therein. On September 7, 2022, because of the continuing shortage of electric energy and the need for continued operation of the two units at Calpine's Greenleaf Unit 1 site in Yuba City, California (Greenleaf Units), I issued Amendment No. 1 to Order No. 202-22-1. Amendment No. 1 to Order No. 202-22-1 added the Greenleaf Units as Covered Resources subject to the terms of Order No. 202-22-1, except that the Greenleaf Units may be operated through September 9, 2022. By its terms, Order No. 202-22-1 as amended by Amendment No. 1 expires at the end of the day on September 8, 2022 with respect to the Covered Resources other than the Greenleaf Units, and at the end of the day on September 9, 2022 with respect to the Greenleaf Units. Order No. 202-22-1 as amended by Amendment No. 1 is sometimes referred to herein as Amended Order No. 202-22-1.

On September 7, 2022, CAISO submitted a *Request for Extension of Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Renewal Application) to the Department. In its Renewal Application, CAISO requests an extension of the expiration date of Order No. 202-22-1 through September 12, 2022.

Emergency Situation

In its Renewal Application, CAISO states that California is experiencing extreme heat, which the CAISO forecasts to continue through at least September 9, 2022. Further, CAISO explains that unpredictable conditions could exacerbate grid reliability issues at any time. The threat of wildfire to the reliable operation of the bulk power system remains significant, and drought conditions are affecting the availability of hydroelectric power. Ambient conditions facing generating facilities are causing de-rates at some units and forcing other units offline. Wildfire threats arising from the extreme heat event are unpredictable and could force transmission and resources out of service. Consequently, the CAISO believes it prudent to ask that the expiration date of Order No. 202-22-1 be extended through September 12, 2022.

Consultation

In considering renewal or reissuance of an order under FPA section 202(c) that may conflict with an environmental law or regulation, DOE is required to "consult with the primary Federal agency with expertise in the environmental interest protected by such law or regulation" and to include "conditions as such Federal agency determines necessary . . . to the extent practicable." 16 U.S.C. § 824a(c)(4). The Environmental

Protection Agency (EPA) is the primary federal agency in this case with expertise in the protected environmental interest, specifically Title V of the Clean Air Act and the Department consulted with EPA after receiving the Renewal Application and EPA did not request any additional conditions be included in this Order. Email from Acting Assistant Administrator Larry Starfield, EPA Office of Enforcement and Compliance Assurance to Kathleen Hogan, Acting Under Secretary for Infrastructure for DOE, September 7, 2022.

Based on the information submitted to the Department, I have determined that an emergency continues to exist in California due to a shortage of electric energy. I find that the issuance of this Order will help to meet the emergency conditions and serve the public interest as required by FPA section 202(c).

ORDER

For the reasons set forth above, pursuant to Section 202(c) of the FPA, I hereby grant CAISO's Renewal Application and issue this Order to extend the expiration date of Amended Order No. 202-22-1 through September 12, 2022.

1. In accordance with the foregoing, (a) the date September 8, 2022 where it appears in Ordering Paragraphs A, D, and H of Order No. 202-22-1 is hereby replaced by the date September 12, 2022, and (b) the date September 9, 2022 where it appears in the Ordering Paragraph of Amendment No. 1 to Order No. 202-22-1 is hereby replaced by the date September 12, 2022.

2. All other terms of Amended Order No. 202-22-1 remain the same and in effect, including Ordering Paragraphs A-H, except as modified herein.

3. This Amendment Number 2 to Order No. 202-22-1 shall be effective upon its issuance and shall expire at 23:59 Pacific Time on September 12, 2022.

Issued in Washington, D.C. at 15:52 Eastern Time on this 8th day of September, 2022.



Kathleen Hogan
Acting Under Secretary for
Infrastructure

Exhibit 7

Amendment Number 1 to Order No. 202-22-2

On September 4, 2022, because of a shortage of currently operational electric generating facilities, high demand for electricity, and other adverse conditions resulting from the extreme heat event in California, I issued Order No. 202-22-2. Order No. 202-22-2 authorized the Balancing Authority of Northern California (BANC) to direct the identified electric generating resource (Covered Resources) to operate in BANC's Balancing Authority Area (BAA), under specified conditions, to prevent or mitigate potential power disruptions and provide relief to the bulk power system during stressed grid conditions caused by extreme heat until September 8, 2022. Order No. 202-22-2 expires at the end of the day on September 8, 2022, by its own terms.

On September 7, 2022, BANC submitted a *Request for Extension and Limited Amendment of Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Renewal Application) to the Department. In its Renewal Application, BANC requests an extension of Order 202-22-1 through September 11, 2022 and certain modifications to the run time hour limitations contained in Order No. 202-22-2. On September 8, 2022, BANC filed a Revised Request for *Request for Extension and Limited Amendment of Emergency Order Pursuant to Section 202(c) of the Federal Power Act* in response to questions from DOE.

Emergency Situation

In its Renewal Application, BANC states that "the actual heat event has been more severe and records loads have been experienced." The emergency conditions brought about by the ongoing extreme heat event in California have continued and worsened and the supply of electricity is at increased risk for meeting system demand. As stated in its Renewal Application, BANC established a new record peak of approximately 4943 MW on September 6. BANC entered into an EEA-2 as of 1330 hours that same day. During this period BANC had forced outages of significant generation but was able to return units to service in approximately 90 minutes. It is believed that BANC members Roseville and Modesto exceeded their all-time peaks. Consequently, BANC requests the expiration date of Order No. 202-22-2 be extended through September 11, 2022.

In addition to the extension of Order No. 202-22-2, BANC has requested that the Order be modified to remove the 2 PM to 10 PM run time limitation so as to allow additional operational flexibility. BANC specifically requests that the Covered Resource be allowed to run during anytime that they have received notice of an Energy Emergency Alert Level 2 (EEA2) condition or greater. The practical impact of this will be to allow the Covered Resource more notice to follow their protocols for ramping up their diesel-fired generator units. In addition, BANC has requested the ramp down of the Covered Resource could extend beyond the period in which the EEA 2 condition exists. Specifically, the ramp down would commence at the time the EEA 2 condition is declared ended and should be completed as soon as possible consistent with good utility and operational

Consultation

In considering renewal or reissuance of an order under FPA section 202(c) that may conflict with an environmental law or regulation, DOE is required to "consult with the primary Federal agency with expertise in the environmental interest protected by such law or regulation" and to include "conditions as such Federal agency determines necessary . . . to the extent practicable." 16 U.S.C. § 824a(c)(4). The Environmental Protection Agency (EPA) is the primary federal agency in this case with expertise in the protected environmental interest, specifically Title V of the Clean Air Act and the Department consulted with EPA after receiving the Renewal Application and EPA did not request any additional conditions be included in this Order. Email from Acting Assistant Administrator Larry Starfield, EPA Office of Enforcement and Compliance Assurance to Kathleen Hogan, Acting Under Secretary for Infrastructure for DOE, September 7, 2022.

Based on the information submitted to the Department, I have determined that an emergency continues to exist in California due to a shortage of electric energy. I find that the issuance of this Order will help to meet the emergency conditions and serve the public interest as required by FPA section 202(c).

ORDER

For the reasons set forth above, pursuant to Section 202(c) of the FPA, I hereby grant BANC's Renewal Application and issue this Order, with modifications as explained below, to extend the expiration date of Order No. 202-22-2 through September 11, 2022.

1. Ordering Paragraph A appearing on page 4 of Order No. 202-22-2 is hereby deleted and replaced in its entirety by the following:

   A. From September 8, 2022, to September 11, 2022, in the event that BANC determines that generation from the Covered Resource is necessary to preserve the reliability of the bulk electric power system in California, I direct BANC to dispatch such unit or units and to order their operation solely under the following conditions: the notification of an Energy Emergency Alert Level 2[1] condition or greater after exhausting all reasonably and practically available resources, together with such reasonable and limited time as is necessary for a Covered Resource to ramp down following an Energy Emergency Alert Level 2 or greater, consistent with good utility practice as directed by the BANC with the goal of limited operation outside of an Energy Emergency Alert Level 2 or greater to the greatest extent possible.

[1] For the purposes of this Order, "Energy Emergency Alert Level 2" has the meaning set forth in Section 3.6.3 of the California ISO System Emergency Operating Procedure, Procedure No. 4420, Version 14.0, Effective Date May 1, 2022 (CAISO Emergency Operating Procedure).

2. The date September 8, 2022 where it appears in Ordering Paragraphs D and H of Order No. 202-22-2 is hereby replaced by the date September 11, 2022.

3. All other terms of Order No. 202-22-2 remain the same and in effect, including Ordering Paragraphs A-H, except as modified herein.

4. This Amendment Number 1 to Order No. 202-22-2 shall be effective upon its issuance, and shall expire at 23:59 Pacific Time on September 11, 2022.

Issued in Washington, D.C. at 16:38 Eastern Time on this 8th day of September, 2022.



Kathleen Hogan
Acting Under Secretary for
Infrastructure

Exhibit 8

Department of Energy
Washington, DC 20585

Order No. 202-22-4

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated by email correspondence (Dec. 23, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in the electricity grid operated by PJM Interconnection, LLC (PJM) due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On December 24, 2022, PJM, the Regional Transmission Operator (RTO) for 65 million people in thirteen states and the District of Columbia (the PJM Region), filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system."

The PJM Region, like many regions across the country, is currently being affected by a severe winter weather system. PJM states that this weather system caused a significant drop in temperatures across the PJM Region on December 23, 2022, accompanied by high winds in excess of 40 mph. As a consequence of the impact of wind and decreasing temperatures, the demand for electricity in the PJM Region rose to an unusually high peak load on the evening of December 23, 2022, in excess of 135,000 MW. This severely cold weather is expected to last through Sunday morning.

While the vast majority of generating units in the PJM Region continue to function adequately under these stressed conditions, some units have experienced operating difficulties due to cold weather or fuel limitations, primarily gas. Specifically, approximately 45,000 MW of generating units (the majority of which are thermal) are currently outaged or derated. PJM has expressed its concern that these units will be unable to return to service over at least the next 48 hours, which coincides with the time period for which PJM is requesting this Order. Since these units may not promptly return to service, and in the event PJM experiences additional generating unit outages, PJM states that it may need to curtail some amount of firm load on December 24, December 25, or December 26, 2022 in order to maintain the security and reliability of the PJM system.

Description of Mitigation Measures

In its Application, PJM identifies the measures it is taking to ensure the supply of generation will continue to be sufficient to meet system demand and reserve requirements. On December 20, 2022, PJM issued a cold weather advisory in the PJM Region in anticipation of the forecasted weather conditions. Then on December 23, 2022, PJM issued

a PJM Region-wide cold weather alert which further highlighted PJM's expected need to call higher-than-normal generation resources in light of the anticipated weather.

On December 23, 2022, generating reserves diminished to a level that required PJM to declare an Energy Emergency Alert (EEA) Level 2 and take other emergency actions. PJM states that after having exhausted economic operation, PJM triggered a Maximum Generation Emergency Action to increase the PJM Region generation above the maximum economic level. Further, PJM triggered its load management reduction actions to provide additional load relief by using PJM-controllable load management programs. PJM called on demand response providers and curtailment service providers to reduce load. PJM also issued public appeals for consumers to reduce usage. PJM has continued to employ these emergency actions through December 24, 2022, and anticipates needing to continue them through the order end date that it has requested.

Since December 23, 2022, PJM has also taken additional measures to provide additional reserves, including:

- Reducing exports to neighboring regions and requested shared reserves for neighboring regions; consistent with joint operating agreements and other regulatory requirements, PJM has continued to communicate and collaborate with its interconnected neighboring systems when the demand on the PJM system has exceeded expected energy and reserve requirements and when emergency transfers were required to support PJM's interconnected neighboring systems;
- Issuing additional public conservation appeals;
- Running uneconomic generation during lower load periods to ensure their availability during peak conditions;
- Utilizing its Emergency Procedures to assist in maximizing the pumped storage hydro generation levels;
- Communicating and preparing transmission and distribution service providers to implement distribution voltage reduction measures; and
- Communicating and preparing transmission and distribution service providers to implement firm load shed.

In its Application, PJM committed to continue to take such actions, including utilizing other supply resources before calling upon any generators to operate in excess of permitting levels. According to PJM, it is nevertheless possible that the measures it has and will take may not be sufficient to avoid the need to curtail firm load in order to ensure system reliability.

Request for Order

PJM requests that the Secretary issue an order immediately, effective today, December 24, 2022, through 12:00 p.m. Eastern Time on Monday, December 26, 2022, authorizing the electric generating units identified in Exhibit A, as well as any other

generating units subject to emissions or other permit limitations in the PJM Region to operate up to their maximum generation output levels under the limited circumstances described in this Order, notwithstanding air quality or other permit limitations. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-22-4 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet the additional load, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current cold weather event threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the PJM Region demonstrate the need for the Specified Resources to contribute to the reliability of the PJM Region.
- PJM is responsible to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the additional load resulting from the cold weather event is enhanced.

In line with the anticipated circumstances precipitated by the cold weather event, this Order is limited to the period beginning with the issuance of this Order on December 24, 2022 through 12:00 pm Eastern Time on December 26, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. PJM anticipates that this Order may result in exceedance of emissions of sulfur dioxide, nitrogen oxide, mercury, and carbon monoxide emissions, as well as wastewater release limits. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes.

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

A. From the time this Order is issued on December 24, 2022, to 12:00 pm Eastern Time on December 26, 2022, in the event that PJM determines that generation from the Specified Resources is necessary to meet the electricity demand that PJM anticipates in the PJM Region during this event, I direct PJM to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements. Specified Resources are those generating units set forth on the Order 202-22-4 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions, to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

In furtherance of the foregoing and, in each case, subject to the exhaustion of all available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions available to support grid reliability:

(i) For any generation resource whose operator notifies PJM that the unit is unable, or expected to be unable, to produce at its maximum output due to an emissions or other limit in any federal environmental permit, and during the pendency of a PJM-triggered Maximum Generation Emergency Action, at any point before 12:00 Eastern Time on Monday, December 26, 2022, the unit will be allowed to exceed any such limit only during any period for which PJM has declared an Energy Emergency Alert (EEA) Level 2 or Level 3 (during which time PJM will have triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that the EEA Level 2 event has ended, the unit would be required to immediately return to operation within its permitted limits. And at all other times, the unit would be required to operate within its permitted limits, except for the limited exceptions provided herein for operations in anticipation of an EEA Level 2 to prevent the cycling of units or facilitate the charging or pumping of other resources necessary for the EEA Level 2.

(ii) For any generation resource whose operator notifies PJM that the unit is offline or would need to go offline at any point before 12:00 Eastern Time on Monday, December 26, 2022, due to an emissions or other limit in any

federal environmental permit, PJM may direct the unit operator to bring the unit online, or to keep the unit online, and to operate at the level consistent with its permits but subject to the exceptions set forth in this Order. In this circumstance, the operator is allowed to make all of the unit's capacity available to PJM for dispatch during any period for which PJM has declared an EEA Level 2 or 3 (during which time PJM has triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that such an EEA Level 2 event has ended and the Maximum Generation Emergency Action is discontinued, the unit would be required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

(iii) PJM is hereby granted authority to operate the Specified Units that are combined cycle generating units in certain limited circumstances in advance of declaring an EEA Level 2, Maximum Generation Emergency, or in between such events, where such operation or continued operation of the Specified Resource is reasonably necessary to avoid shutting down and restarting the Specified Unit. PJM has represented that such cycling of units can cause reliability issues regarding restarting, delays, and increased emissions during start up. PJM is further authorized to operate the Specified Units in certain limited circumstances in advance of the declaring an EEA Level 2, Maximum Generation Emergency where such operation or continued operation of the Specified Resource is reasonably necessary to facilitate charging storage resources or pumping for pumped storage facilities that will needed during an anticipated EEA Level 2. PJM is required to take measures to dispatch units for which cycling would otherwise be required in a manner reasonably intended to limit the duration and operating level of those units in such a way as to minimize exceedance of permit limitations consistent with the security and reliability of the PJM Region.

(iv) To minimize adverse environmental impacts as set forth herein, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, and notwithstanding standard merit order dispatch, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response and identified behind-the-meter generation resources selected to minimize an increase in emissions to the extent that such resources provide support to maintain grid reliability prior to dispatching the Specified Resources at levels above their permitted emissions levels. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

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

D. In the event that PJM identifies additional generation units that it deems necessary to operate in excess of federal environmental permitting limits in order to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements, PJM shall provide prompt written notice to the Department of Energy at AskCR@hq.doe.gov with the name and location of those units that PJM has identified, as well as additional notice by the same means through updating Exhibit A to its Application with such additional generation units, the fuel type of such unit, and the anticipated category of environmental impact, at 09:00 Eastern Time or 21:00 Eastern Time, whichever follows closest in time to the unit identification by PJM to the greatest extent feasible. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department updating Exhibit A, and PJM may dispatch such additional generation units, provided that if the Department of Energy notifies PJM that it does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department. The Department shall post an updated Order 202-22-4 Resource List as soon as practicable following notification from PJM under this paragraph.

E. PJM shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By January 26, 2023, PJM shall report all dates between December 24, 2022, and December 26, 2022, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. PJM shall submit a final report by February 27, 2023, with any revisions to the information reported on January 26, 2023. The environmental information submitted in the final report shall also include the following information:

(i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, VOC, and SO2;

(ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

(iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g., "Generator #1; December 25, 2022; 4 hours; 04:00-08:00 CT";

(iv) Amount, type and formulation of any fuel used by each Specified Resource;

(v) All reporting provided under the Specified Resource's operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;

(vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

(vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, PJM shall provide information to the Department quantifying the net revenue in aggregate associated with generation in excess of environmental limits in connection with orders issued by the Department pursuant to Section 202(c) of the Federal Power Act.

F. PJM shall take reasonable measures to inform affected communities where all Specified Resources operate that PJM has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows PJM to do. At a minimum, PJM shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of Specified Resources covered by this Order, as the Specified Resources may be updated pursuant to paragraph D above. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by PJM with respect to the cold weather event and will include a reference to the website posting required by the preceding sentence for further information. PJM shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph E above.

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

H. PJM shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

I. This Order shall be effective upon its issuance, and shall expire at 12:00 Eastern Time on Monday, December 26, 2022, with the exception of the reporting requirements in

paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 5:30 PM Eastern Standard Time on this 24th day of December 2022.

Undersecretary of Energy for Infrastructure

Exhibit 9



Department of Energy
Washington, DC 20585

Order No. 202-24-1

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

Emergency Situation

On October 9, 2024, Duke Energy Florida, LLC (Duke), an investor-owned utility, whose service territory includes electric customers in Florida, filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system." As of 4 PM EDT on October 9, 2024, Hurricane Milton is a Category 3 storm forecast to remain a major hurricane and expand in size as it approaches the west coast of Florida. The center is likely to make landfall along the west-central coast of Florida during the night on Wednesday, October 9, 2024, or in the early morning on Thursday, October 10, 2024, and move east-northeastward across central Florida through October 10, 2024. Hurricane Milton follows the landfall of Hurricane Helene in Florida on September 26, 2024, which resulted in over 230 deaths in the southeast United States and for which recovery and restoration efforts remain ongoing. As of 5:00 PM EDT on October 9, 2024, Florida was experiencing 118,000 outages related to the approaching Hurricane Milton, with the number increasing rapidly.

On October 7, 2024, President Biden declared that an emergency exists in the State of Florida and ordered Federal assistance to supplement State, tribal, and local response efforts due to the emergency conditions resulting from Hurricane Milton beginning on October 5, 2024, and continuing.

Duke has indicated that its service territory is being impacted by Hurricane Milton. Duke expects that Hurricane Milton will cause hurricane-force-gusts across the St. Petersburg/Tampa metropolitan region at the height of the storm overnight into early Thursday, October 10, 2024. Elsewhere, strong tropical-storm to near hurricane-force-gusts are projected to impact highly populated zones along the I-4 corridor served by Duke. The combination of damaging winds,

torrential rain and subsequent flooding, storm surge at the coast, and possible tornadoes, will result in major power outages, damaging distribution and transmission infrastructure, and threaten several generation stations along the path. Application at 1.

While many generating units in the Duke service territory continue to function adequately under these stressed conditions, several of Duke's generating units are expected to be forced to shut down due to facility limits on wind speeds and storm surge, as well as staffing issues caused by mandatory evacuations. Additionally, Crystal River Units 4 and 5 remain in forced outage from storm surge impacts from Hurricane Helene. Specifically, approximately 4,000 MW of generating units are currently offline and will remain offline during Hurricane Milton. Application at 2.

Additionally, several units at Citrus Combined Cycle, the subject of this Order, may be forced offline by conditions in its Title V operating permit. With projected outages and low demand, in order to keep the Citrus Combined Cycle units online, they would potentially need to operate at low load for an extended period of time, which could result in noncompliance with its Title V permit. If these units are brought offline due to these compliance requirements, they may not be able ramp up quickly enough to meet demand as load increases following power restoration, particularly in light of the amount of generation predicted to be offline due to hurricane impacts. For example, ramp-up times from a cold start could be eight or nine hours, and could be further delayed by pre-generation start-up checks. Additionally, shutting down also increases the risk or equipment failure, as well as the risk of water intrusion due to thermal and pressure gradient changes. If equipment fails or is damaged by Hurricane Milton, units may not be able to start without additional maintenance. In that case, Duke may have to declare an Energy Emergency Alert (EEA) Level 3 and institute rotating load shed. Such impacts would hinder post-hurricane restoration and recovery activities and overall grid reliability. Although Duke would attempt to mitigate such impacts through alternative generation as well as power purchases, it is unknown what will be available following Hurricane Milton and whether the necessary transmission infrastructure will remain for this purpose. Application at 2.

The Florida Reliability Coordinating Council, Inc. (FRCC), the Reliability Coordinator for Duke's service territory and others, filed a formal endorsement on October 9, 2024, of Duke's Application, specifically the need to continue operation of the Specified Resources in Application Exhibit A at low load operation to help reduce the likelihood of any firm load shedding during the hurricane event. FRCC Letter at 1. The endorsement explains:

> It is the FRCC's firm opinion that granting this relief request will provide an immeasurable benefit to this mission and in turn, the public served by the FRCC and its member entities. Allowing this relief will not only serve the reliability of [Duke's] service territory, but also the many local electric cooperatives served by [Duke] and other interconnected electric utilities and service providers.

FRCC Letter at 2.

Description of Mitigation Measures

Duke has indicated that it will attempt to keep the Citrus Combined Cycle units operating at a load level compliant with its Title V permit whenever possible, including attempting to sell power to keep load higher. Duke anticipates needing to continue these efforts through October 13, 2024. Subject to the exceptions included in this Order, Duke has committed to continuing to take such actions, including attempting to sell power, before operating any units in a manner that will result in a conflict with a requirement of any federal, state, or local environmental statute or regulation, including requirements in permits issued pursuant to such laws or regulations.

Request for Order

Duke requests that the Secretary issue an order immediately, effective October 9, 2024, through 00:00 EDT on October 13, 2024, authorizing "continued operation of the Specified Resources" in the Duke service territory. Application at 3. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-24-1 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of Duke to ensure maximum reliability on its system, and the ability of Duke to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current extreme weather event and its aftermath threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the State of Florida and within the region demonstrate the need for the Specified Resources to contribute to system reliability.
- Duke's responsibility to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the load resulting from the extreme weather event and its aftermath.

In line with the anticipated circumstances precipitated by Hurricane Milton, this Order is limited to the period beginning with the issuance of this Order on October 9, 2024, through 00:00 EDT on October 13, 2024. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. Duke anticipates that this Order may result in exceedance of emissions of Volatile Organic Compounds (VOC), specifically formaldehyde. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by Duke for reliability purposes.

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

A. From the time this Order is issued on October 9, 2024, to 00:00 EDT on October 13, 2024, in the event that Duke determines that generation from the Specified Resources is necessary to meet the electricity demand that Duke anticipates in Florida during and immediately following this event, I direct Duke to dispatch such unit or units and to order their operation only as needed to maintain the necessary expected generation in the Duke service territory. Specified Resources are those generating units set forth on the Order 202-24-1 Resource List, which the Department shall post on www.energy.gov. Duke is directed to provide updates, if any, to Exhibit A to its Application with the anticipated category of environmental impact(s) (i.e., formaldehyde, sulfur dioxide, nitrogen oxide, mercury, carbon monoxide emissions, wastewater release, other air pollutants) by 21:00 EDT on October 10, 2024.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by Duke for maintaining grid reliability to avoid adverse health and safety impacts to customers from shedding firm customer load. Duke shall exhaust all possible measures to run the Specified Units at a load level in compliance with permit requirements, including attempting to sell power. Duke shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

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

D. Duke shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By October 20, 2024, Duke shall report all dates between October 9, 2024, and October 13, 2024, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting

limits, including formaldehyde, sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. Duke shall submit a final report by November 20, 2024, with any revisions to the information reported on October 20, 2024. The environmental information submitted in the final report shall also include the following information:

(i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, formaldehyde, VOC, and SO2;

(ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

(iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g. "Generator #1; October 10, 2024; 4 hours; 04:00-08:00 EDT";

(iv) Amount, type and formulation of any fuel used by each Specified Resource;

(v) All reporting provided under the Specified Resource's operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;

(vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

(vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, Duke shall provide information to the Department quantifying the net revenue associated with generation in excess of environmental limits accruing to the Specified Resources in connection with any order issued by the Department pursuant to Section 202(c) of the Federal Power Act.

E. Duke shall take reasonable measures to inform affected communities where all Specified Resources operate that Duke has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows Duke to do. At a minimum, Duke shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of any Specified Resource covered by this Order. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by Duke with respect to the extreme weather event and will include a reference to the website posting required by the preceding sentence for further information. Duke shall describe the actions taken to comply with this paragraph in the

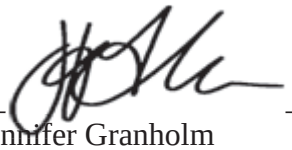
reports delivered to the Department pursuant to paragraph D above.

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

G. Duke shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on Sunday, October 13, 2024, with the exception of the reporting requirements in paragraph D. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 8:00 PM Eastern Daylight Time on this 9th day of October 2024.



Jennifer Granholm
Secretary of Energy

Exhibit 10

Five Takeaways From Trump's Plan to Rescue Coal

To help the struggling coal industry, President Trump used his executive authority to try to keep aging plants alive and burn more coal for electricity.



By Lisa Friedman and Brad Plumer

April 9, 2025

Hard hats are back. So is "beautiful, clean" coal.

President Trump signed four executive orders on Tuesday to try to bolster the country's declining coal industry, including the lifting of restrictions on mining and burning of the dirtiest fossil fuel.

In addition to waiving air pollution limits and other regulations on coal imposed by the Biden administration, Mr. Trump directed the Justice Department to go after states like California that have sought to tackle climate change by reducing the use of fossil fuels.

"I call it beautiful, clean coal — I tell my people to never use the word 'coal' unless you put 'beautiful, clean' before it," Mr. Trump said in the East Room of the White House surrounded by dozens of mostly men in hard hats. "We're ending Joe Biden's war on beautiful, clean coal once and for all."

Here are five takeaways from Mr. Trump's directives.

Miners as backdrops

Mr. Trump has always loved the coal miner as a masculine symbol.

At the White House ceremony on Tuesday, he repeatedly referred to the burly men who surrounded him, joking about whether the stage could handle their collective weight and about arm wrestling several of them. He recalled how during his 2016 campaign against Hillary Clinton, she was talking about job retraining for miners. "She was going to put them in a high-tech industry where you make little cellphones and things," he said as he gestured daintily and laughed.

Coal itself is a strong fossil fuel, he said. "Pound for pound, coal is the single most reliable, durable, secure and powerful form of energy," Mr. Trump said.

"It's almost indestructible," he said. "You could drop a bomb on it and it's going to be there for you to use the next day."

What climate change?

Coal emits more carbon dioxide when burned than any other fossil fuel — making it a major contributor to climate change. More mining and burning of coal will add to the pollution that is dangerously heating the planet, leading to more frequent and deadly heat waves, drought, floods and rising sea levels as well as faster melting of the ice sheet in Greenland, the island Mr. Trump has said he wants the United States to acquire.

Scientists say major economies like the United States must sharply reduce their emissions — not increase them — to avoid the most catastrophic effects of climate change.

Coal combustion also releases other pollutants, including mercury and sulfur dioxide, that are linked to heart disease, respiratory problems and premature deaths. And the activity of mining and the resulting coal ash from power plants pose environmental hazards.

There was no mention of any of those consequences of coal on Tuesday.

He ignored the biggest threat to coal: natural gas

Regulations that limit the amount of pollution from coal-burning power plants have made those plants more expensive to operate and have cut into the industry's profitability. But the biggest reason for the decline in coal power over the past two decades hasn't been "radical green" policies, as Mr. Trump said. It's been cheap natural gas from fracking.

In the mid-2000s, American drillers perfected methods to unlock vast reserves of low-cost natural gas from shale rock. Electric utilities quickly realized they could replace coal with cheaper gas, which emits less carbon dioxide than coal when burned.

According to a 2019 study in The Rand Journal of Economics, energy markets and low natural gas prices accounted for nearly all the declines in coal plant profitability between 2005 and 2015, as well as the resulting retirement of hundreds of coal-fired power plants. "Environmental regulations had little effect on these outcomes," the study found.

Mr. Trump, for his part, has said he wants to "drill, baby, drill" and continue cutting gas prices, which could put even more economic pressure on coal.

Boasting of law firm shakedowns

"Have you noticed that lots of law firms have been signing up with Trump?" the president asked the crowd at the coal event on Tuesday.

He was referring to the millions of dollars in pro bono legal services that some major law firms have offered the Trump administration after the president targeted or threatened to target them in executive orders.

One firm that was subject to an executive order — Paul, Weiss — cut a deal with the White House and promised concessions, including $40 million in pro bono work for Trump-friendly causes. Three other firms — Milbank; Skadden, Arps; and Willkie Farr & Gallagher — proactively agreed to their own deals with the White House.

On Tuesday Mr. Trump gave an indication where some those free legal services would be directed: fighting climate policies and helping the coal industry.

"We're going to use some of those firms to work with you on your leasing and your other things," Mr. Trump told coal leaders.

Coal stocks rose — but will the revival last?

Tuesday was a good day for the coal industry. The stock price of Peabody Energy, a mining company, rose 9 percent. Alliance Resource Partners, led by Joseph W. Craft III, a billionaire coal magnate who helped lead Mr. Trump's fund-raising during the presidential campaign, was up nearly 5 percent.

But many experts are skeptical that Mr. Trump can do much to turn around the outlook for coal. "We believe Trump's coal executive orders are unlikely to have a material impact on power or carbon markets, given the constraints on the use of emergency authorities and the orders' symbolic nature," wrote analysts at Capstone, a research firm. They called Tuesday's bump in coal stocks "an overreaction."

The average coal plant in the United States is more than 50 years old, and it is still often cheaper for utilities to use a mix of gas, wind, solar power and batteries to generate electricity. Those fundamentals, analysts say, will be hard to alter.

Lisa Friedman is a Times reporter who writes about how governments are addressing climate change and the effects of those policies on communities.

Brad Plumer is a Times reporter who covers technology and policy efforts to address global warming.

A version of this article appears in print on , Section A, Page 17 of the New York edition with the headline: President Signs Orders To Help Revive Industry Of 'Beautiful, Clean Coal'

Exhibit 11

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
AIR QUALITY PROGRAM

TITLE V/STATE OPERATING PERMIT

Issue Date: April 17, 2025 Effective Date: April 17, 2025

Expiration Date: April 16, 2030

In accordance with the provisions of the Air Pollution Control Act, the Act of January 8, 1960, P.L. 2119, as amended, and 25 Pa. Code Chapter 127, the Owner, [and Operator if noted] (hereinafter referred to as permittee) identified below is authorized by the Department of Environmental Protection (Department) to operate the air emission source(s) more fully described in this permit. This Facility is subject to all terms and conditions specified in this permit. Nothing in this permit relieves the permittee from its obligations to comply with all applicable Federal, State and Local laws and regulations.

The regulatory or statutory authority for each permit condition is set forth in brackets. All terms and conditions in this permit are federally enforceable applicable requirements unless otherwise designated as "State-Only" or "non-applicable" requirements.

TITLE V Permit No: 23-00017

Federal Tax Id - Plant Code: 23-3064219-1

Owner Information

Name: CONSTELLATION ENERGY GENERATION LLC
Mailing Address: 1 INDUSTRIAL HWY
EDDYSTONE, PA 19022-1524

Plant Information

Plant: CONSTELLATION ENERGY GENERATION LLC/EDDYSTONE
Location: 23 Delaware County 23821 Eddystone Borough
SIC Code: 4911 Trans. & Utilities - Electric Services

Responsible Official

Name: PAUL WEEKS
Title: VP REGIONAL OPERATIONS
Phone (610) 909 - 6626 Email: paul.weeks@constellation.com

Permit Contact Person

Name: JOSEPH M KUKLINSKI
Title: ENVIRONMENTAL SPECIALIST
Phone: (610) 595 - 8113 Email: joseph.kuklinski@constellation.com

[Signature] _____
JILLIAN A. GALLAGHER, SOUTHEAST REGION AIR PROGRAM MANAGER

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Note: These same sub-sections are repeated for each source!

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F-III: Monitoring Requirements
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Section G. Emission Restriction Summary

Section H. Miscellaneous

SECTION A. Site Inventory List

Source ID	Source Name	Capacity/Throughput		Fuel/Material
033	BOILER 3	4,116.000	MMBTU/HR	
		33,352.000	Gal/HR	#2 Oil
		4.480	MMCF/HR	Natural Gas
034	AUXILIARY BOILER A	124.000	MMBTU/HR	
		925.900	Gal/HR	#2 Oil
		122.300	MCF/HR	Natural Gas
035	AUXILIARY BOILER B	124.000	MMBTU/HR	
		925.900	Gal/HR	#2 Oil
		122.300	MCF/HR	Natural Gas
036	AUXILIARY BOILER C	124.000	MMBTU/HR	
		925.900	Gal/HR	#2 Oil
		122.300	MCF/HR	Natural Gas
041	BOILER 4	4,116.000	MMBTU/HR	
		33,352.000	Gal/HR	#2 Oil
		4.480	MMCF/HR	Natural Gas
037	NO. 10 COMBUSTION TURBINE	1,726.000	Gal/HR	Kerosene
		1,726.000	Gal/HR	#2 Oil
038	NO. 20 COMBUSTION TURBINE	1,726.000	Gal/HR	Kerosene
		1,726.000	Gal/HR	#2 Oil
039	NO. 30 COMBUSTION TURBINE	2,104.000	Gal/HR	Kerosene
		2,104.000	Gal/HR	#2 Oil
040	NO. 40 COMBUSTION TURBINE	2,104.000	Gal/HR	Kerosene
		2,104.000	Gal/HR	#2 Oil
122	#2 OIL STORAGE TANK (1.05 MMGAL)			
123	FUEL OIL STORAGE TANKS(2)			
F04	OIL DELIVERY FUGITIVES			
FML01	NATURAL GAS LINE			
FML02	#2 FUEL OIL			
S03	BOILER 3/4 STACK			
S04	TURBINE 10 STACK			
S05	TURBINE 20 STACK			
S06	TURBINE 30 STACK			
S07	TURBINE 40 STACK			
S08	AUX BOILER A STACK			
S09	AUX BOILER B STACK			
S10	AUX BOILER C STACK			
Z04	OIL HANDLING FUGITIVES			
Z122	OIL TANK FUGITIVES			
Z123	FUEL OIL STORAGE TANK(S) FUGITIVES			

PERMIT MAPS

PERMIT MAPS


CU 033
STAC S03
FML FML01
FML FML02
CU 034
STAC S08
FML FML01
FML FML02
CU 035
STAC S09
FML FML02
FML FML01
CU 036
STAC S10
FML FML02
FML FML01
CU 041
STAC S03
FML FML01
FML FML02
PROC 037
STAC S04
FML FML02
PROC 038
STAC S05
FML FML02

PERMIT MAPS


PROC 039
STAC S06
FML FML02
PROC 040
STAC S07
FML FML02
PROC 122
STAC Z122
PROC 123
STAC Z123
PROC F04
STAC Z04

SECTION B. General Title V Requirements

#001 [25 Pa. Code § 121.1]

Definitions

Words and terms that are not otherwise defined in this permit shall have the meanings set forth in Section 3 of the Air Pollution Control Act (35 P.S. § 4003) and 25 Pa. Code § 121.1.

#002 [25 Pa. Code § 121.7]

Prohibition of Air Pollution

No person may permit air pollution as that term is defined in the Air Pollution Control Act (35 P.S. §§ 4001-4015).

#003 [25 Pa. Code § 127.512(c)(4)]

Property Rights

This permit does not convey property rights of any sort, or any exclusive privileges.

#004 [25 Pa. Code § 127.446(a) and (c)]

Permit Expiration

This operating permit is issued for a fixed term of five (5) years and shall expire on the date specified on Page 1 of this permit. The terms and conditions of the expired permit shall automatically continue pending issuance of a new Title V permit, provided the permittee has submitted a timely and complete application and paid applicable fees required under 25 Pa. Code Chapter 127, Subchapter I and the Department is unable, through no fault of the permittee, to issue or deny a new permit before the expiration of the previous permit. An application is complete if it contains sufficient information to begin processing the application, has the applicable sections completed and has been signed by a responsible official.

#005 [25 Pa. Code §§ 127.412, 127.413, 127.414, 127.446(e), 127.503 & 127.704(b)]

Permit Renewal

(a) An application for the renewal of the Title V permit shall be submitted to the Department at least six (6) months, and not more than 18 months, before the expiration date of this permit. The renewal application is timely if a complete application is submitted to the Department's Regional Air Manager within the timeframe specified in this permit condition.

(b) The application for permit renewal shall include the current permit number, the appropriate permit renewal fee, a description of any permit revisions and off-permit changes that occurred during the permit term, and any applicable requirements that were promulgated and not incorporated into the permit during the permit term. The fees shall be made payable to "The Commonwealth of Pennsylvania Clean Air Fund" and submitted with the fee form to the respective regional office.

(c) The renewal application shall also include submission of proof that the local municipality and county, in which the facility is located, have been notified in accordance with 25 Pa. Code § 127.413. The application for renewal of the Title V permit shall also include submission of compliance review forms which have been used by the permittee to update information submitted in accordance with either 25 Pa. Code § 127.412(b) or § 127.412(j).

(d) The permittee, upon becoming aware that any relevant facts were omitted or incorrect information was submitted in the permit application, shall promptly submit such supplementary facts or corrected information during the permit renewal process. The permittee shall also promptly provide additional information as necessary to address any requirements that become applicable to the source after the date a complete renewal application was submitted but prior to release of a draft permit.

#006 [25 Pa. Code §§ 127.450(a)(4) & 127.464(a)]

Transfer of Ownership or Operational Control

(a) In accordance with 25 Pa. Code § 127.450(a)(4), a change in ownership or operational control of the source shall be treated as an administrative amendment if:

(1) The Department determines that no other change in the permit is necessary;

(2) A written agreement has been submitted to the Department identifying the specific date of the transfer of permit responsibility, coverage and liability between the current and the new permittee; and,

(3) A compliance review form has been submitted to the Department and the permit transfer has been approved by

SECTION B. General Title V Requirements

the Department.

(b) In accordance with 25 Pa. Code § 127.464(a), this permit may not be transferred to another person except in cases of transfer-of-ownership which are documented and approved to the satisfaction of the Department.

#007 [25 Pa. Code § 127.513, 35 P.S. § 4008 and § 114 of the CAA]

Inspection and Entry

(a) Upon presentation of credentials and other documents as may be required by law for inspection and entry purposes, the permittee shall allow the Department of Environmental Protection or authorized representatives of the Department to perform the following:

(1) Enter at reasonable times upon the permittee's premises where a Title V source is located or emissions related activity is conducted, or where records are kept under the conditions of this permit;

(2) Have access to and copy or remove, at reasonable times, records that are kept under the conditions of this permit;

(3) Inspect at reasonable times, facilities, equipment including monitoring and air pollution control equipment, practices, or operations regulated or required under this permit;

(4) Sample or monitor, at reasonable times, substances or parameters, for the purpose of assuring compliance with the permit or applicable requirements as authorized by the Clean Air Act, the Air Pollution Control Act, or the regulations promulgated under the Acts.

(b) Pursuant to 35 P.S. § 4008, no person shall hinder, obstruct, prevent or interfere with the Department or its personnel in the performance of any duty authorized under the Air Pollution Control Act.

(c) Nothing in this permit condition shall limit the ability of the EPA to inspect or enter the premises of the permittee in accordance with Section 114 or other applicable provisions of the Clean Air Act.

#008 [25 Pa. Code §§ 127.25, 127.444, & 127.512(c)(1)]

Compliance Requirements

(a) The permittee shall comply with the conditions of this permit. Noncompliance with this permit constitutes a violation of the Clean Air Act and the Air Pollution Control Act and is grounds for one (1) or more of the following:

(1) Enforcement action

(2) Permit termination, revocation and reissuance or modification

(3) Denial of a permit renewal application

(b) A person may not cause or permit the operation of a source, which is subject to 25 Pa. Code Article III, unless the source(s) and air cleaning devices identified in the application for the plan approval and operating permit and the plan approval issued to the source are operated and maintained in accordance with specifications in the applications and the conditions in the plan approval and operating permit issued by the Department. A person may not cause or permit the operation of an air contamination source subject to 25 Pa. Code Chapter 127 in a manner inconsistent with good operating practices.

(c) For purposes of Sub-condition (b) of this permit condition, the specifications in applications for plan approvals and operating permits are the physical configurations and engineering design details which the Department determines are essential for the permittee's compliance with the applicable requirements in this Title V permit.

#009 [25 Pa. Code § 127.512(c)(2)]

Need to Halt or Reduce Activity Not a Defense

It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

SECTION B. General Title V Requirements

#010 [25 Pa. Code §§ 127.411(d) & 127.512(c)(5)]

Duty to Provide Information

(a) The permittee shall furnish to the Department, within a reasonable time, information that the Department may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit.

(b) Upon request, the permittee shall also furnish to the Department copies of records that the permittee is required to keep by this permit, or for information claimed to be confidential, the permittee may furnish such records directly to the Administrator of EPA along with a claim of confidentiality.

#011 [25 Pa. Code §§ 127.463, 127.512(c)(3) & 127.542]

Reopening and Revising the Title V Permit for Cause

(a) This Title V permit may be modified, revoked, reopened and reissued or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay a permit condition.

(b) This permit may be reopened, revised and reissued prior to expiration of the permit under one or more of the following circumstances:

(1) Additional applicable requirements under the Clean Air Act or the Air Pollution Control Act become applicable to a Title V facility with a remaining permit term of three (3) or more years prior to the expiration date of this permit. The Department will revise the permit as expeditiously as practicable but not later than 18 months after promulgation of the applicable standards or regulations. No such revision is required if the effective date of the requirement is later than the expiration date of this permit, unless the original permit or its terms and conditions has been extended.

(2) Additional requirements, including excess emissions requirements, become applicable to an affected source under the acid rain program. Upon approval by the Administrator of EPA, excess emissions offset plans for an affected source shall be incorporated into the permit.

(3) The Department or the EPA determines that this permit contains a material mistake or inaccurate statements were made in establishing the emissions standards or other terms or conditions of this permit.

(4) The Department or the Administrator of EPA determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

(c) Proceedings to revise this permit shall follow the same procedures which apply to initial permit issuance and shall affect only those parts of this permit for which cause to revise exists. The revision shall be made as expeditiously as practicable.

(d) Regardless of whether a revision is made in accordance with (b)(1) above, the permittee shall meet the applicable standards or regulations promulgated under the Clean Air Act within the time frame required by standards or regulations.

#012 [25 Pa. Code § 127.543]

Reopening a Title V Permit for Cause by EPA

As required by the Clean Air Act and regulations adopted thereunder, this permit may be modified, reopened and reissued, revoked or terminated for cause by EPA in accordance with procedures specified in 25 Pa. Code § 127.543.

#013 [25 Pa. Code § 127.522(a)]

Operating Permit Application Review by the EPA

The applicant may be required by the Department to provide a copy of the permit application, including the compliance plan, directly to the Administrator of the EPA. Copies of title V permit applications to EPA, pursuant to 25 PA Code §127.522(a), shall be submitted, if required, to the following EPA e-mail box:

R3_Air_Apps_and_Notices@epa.gov

Please place the following in the subject line: TV [permit number], [Facility Name].

SECTION B. General Title V Requirements

#014 [25 Pa. Code § 127.541]

Significant Operating Permit Modifications

When permit modifications during the term of this permit do not qualify as minor permit modifications or administrative amendments, the permittee shall submit an application for significant Title V permit modifications in accordance with 25 Pa. Code § 127.541. Notifications to EPA, pursuant to 25 PA Code §127.522(a), if required, shall be submitted, to the following EPA e-mail box:

R3_Air_Apps_and_Notices@epa.gov

Please place the following in the subject line: TV [permit number], [Facility Name].

#015 [25 Pa. Code §§ 121.1 & 127.462]

Minor Operating Permit Modifications

The permittee may make minor operating permit modifications (as defined in 25 Pa. Code §121.1), on an expedited basis, in accordance with 25 Pa. Code §127.462 (relating to minor operating permit modifications). Notifications to EPA, pursuant to 25 PA Code §127.462(c), if required, shall be submitted, to the following EPA e-mail box:

R3_Air_Apps_and_Notices@epa.gov

Please place the following in the subject line: TV [permit number], [Facility Name].

#016 [25 Pa. Code § 127.450]

Administrative Operating Permit Amendments

(a) The permittee may request administrative operating permit amendments, as defined in 25 Pa. Code §127.450(a). Copies of request for administrative permit amendment to EPA, pursuant to 25 PA Code §127.450(c)(1), if required, shall be submitted to the following EPA e-mail box:

R3_Air_Apps_and_Notices@epa.gov

Please place the following in the subject line: TV [permit number], [Facility Name].

(b) Upon final action by the Department granting a request for an administrative operating permit amendment covered under §127.450(a)(5), the permit shield provisions in 25 Pa. Code § 127.516 (relating to permit shield) shall apply to administrative permit amendments incorporated in this Title V Permit in accordance with §127.450(c), unless precluded by the Clean Air Act or the regulations thereunder.

#017 [25 Pa. Code § 127.512(b)]

Severability Clause

The provisions of this permit are severable, and if any provision of this permit is determined by the Environmental Hearing Board or a court of competent jurisdiction, or US EPA to be invalid or unenforceable, such a determination will not affect the remaining provisions of this permit.

#018 [25 Pa. Code §§ 127.704, 127.705 & 127.707]

Fee Payment

(a) The permittee shall pay fees to the Department in accordance with the applicable fee schedules in 25 Pa. Code Chapter 127, Subchapter I (relating to plan approval and operating permit fees). The applicable fees shall be made payable to "The Commonwealth of Pennsylvania Clean Air Fund" with the permit number clearly indicated and submitted to the respective regional office.

(b) Emission Fees. The permittee shall, on or before September 1st of each year, pay applicable annual Title V emission fees for emissions occurring in the previous calendar year as specified in 25 Pa. Code § 127.705. The permittee is not required to pay an emission fee for emissions of more than 4,000 tons of each regulated pollutant emitted from the facility.

(c) As used in this permit condition, the term "regulated pollutant" is defined as a VOC, each pollutant regulated under Sections 111 and 112 of the Clean Air Act and each pollutant for which a National Ambient Air Quality Standard has been promulgated, except that carbon monoxide is excluded.

SECTION B. General Title V Requirements

(d) Late Payment. Late payment of emission fees will subject the permittee to the penalties prescribed in 25 Pa. Code § 127.707 and may result in the suspension or termination of the Title V permit. The permittee shall pay a penalty of fifty percent (50%) of the fee amount, plus interest on the fee amount computed in accordance with 26 U.S.C.A. § 6621(a)(2) from the date the emission fee should have been paid in accordance with the time frame specified in 25 Pa. Code § 127.705(c).

(e) The permittee shall pay an annual operating permit maintenance fee according to the following fee schedule established in 25 Pa. Code § 127.704(d) on or before December 31 of each year for the next calendar year.

(1) Eight thousand dollars ($8,000) for calendar years 2021—2025.

(2) Ten thousand dollars ($10,000) for calendar years 2026—2030.

(3) Twelve thousand five hundred dollars ($12,500) for the calendar years beginning with 2031.

#019 [25 Pa. Code §§ 127.14(b) & 127.449]

Authorization for De Minimis Emission Increases

(a) This permit authorizes de minimis emission increases from a new or existing source in accordance with 25 Pa. Code §§ 127.14 and 127.449 without the need for a plan approval or prior issuance of a permit modification. The permittee shall provide the Department with seven (7) days prior written notice before commencing any de minimis emissions increase that would result from either: (1) a physical change of minor significance under § 127.14(c)(1); or (2) the construction, installation, modification or reactivation of an air contamination source. The written notice shall:

(1) Identify and describe the pollutants that will be emitted as a result of the de minimis emissions increase.

(2) Provide emission rates expressed in tons per year and in terms necessary to establish compliance consistent with any applicable requirement.

The Department may disapprove or condition de minimis emission increases at any time.

(b) Except as provided below in (c) and (d) of this permit condition, the permittee is authorized during the term of this permit to make de minimis emission increases (expressed in tons per year) up to the following amounts without the need for a plan approval or prior issuance of a permit modification:

(1) Four tons of carbon monoxide from a single source during the term of the permit and 20 tons of carbon monoxide at the facility during the term of the permit.

(2) One ton of NOx from a single source during the term of the permit and 5 tons of NOx at the facility during the term of the permit.

(3) One and six-tenths tons of the oxides of sulfur from a single source during the term of the permit and 8.0 tons of oxides of sulfur at the facility during the term of the permit.

(4) Six-tenths of a ton of PM10 from a single source during the term of the permit and 3.0 tons of PM10 at the facility during the term of the permit. This shall include emissions of a pollutant regulated under Section 112 of the Clean Air Act unless precluded by the Clean Air Act or 25 Pa. Code Article III.

(5) One ton of VOCs from a single source during the term of the permit and 5.0 tons of VOCs at the facility during the term of the permit. This shall include emissions of a pollutant regulated under Section 112 of the Clean Air Act unless precluded by the Clean Air Act or 25 Pa. Code Article III.

(c) In accordance with § 127.14, the permittee may install the following minor sources without the need for a plan approval:

(1) Air conditioning or ventilation systems not designed to remove pollutants generated or released from other sources.

(2) Combustion units rated at 2,500,000 or less Btu per hour of heat input.

SECTION B. General Title V Requirements

(3) Combustion units with a rated capacity of less than 10,000,000 Btu per hour heat input fueled by natural gas supplied by a public utility, liquefied petroleum gas or by commercial fuel oils which are No. 2 or lighter, viscosity less than or equal to 5.82 c St, and which meet the sulfur content requirements of 25 Pa. Code § 123.22 (relating to combustion units). For purposes of this permit, commercial fuel oil shall be virgin oil which has no reprocessed, recycled or waste material added.

(4) Space heaters which heat by direct heat transfer.

(5) Laboratory equipment used exclusively for chemical or physical analysis.

(6) Other sources and classes of sources determined to be of minor significance by the Department.

(d) This permit does not authorize de minimis emission increases if the emissions increase would cause one or more of the following:

(1) Increase the emissions of a pollutant regulated under Section 112 of the Clean Air Act except as authorized in Subparagraphs (b)(4) and (5) of this permit condition.

(2) Subject the facility to the prevention of significant deterioration requirements in 25 Pa. Code Chapter 127, Subchapter D and/or the new source review requirements in Subchapter E.

(3) Violate any applicable requirement of the Air Pollution Control Act, the Clean Air Act, or the regulations promulgated under either of the acts.

(4) Changes which are modifications under any provision of Title I of the Clean Air Act and emission increases which would exceed the allowable emissions level (expressed as a rate of emissions or in terms of total emissions) under the Title V permit.

(e) Unless precluded by the Clean Air Act or the regulations thereunder, the permit shield described in 25 Pa. Code § 127.516 (relating to permit shield) shall extend to the changes made under 25 Pa. Code § 127.449 (relating to de minimis emission increases).

(f) Emissions authorized under this permit condition shall be included in the monitoring, recordkeeping and reporting requirements of this permit.

(g) Except for de minimis emission increases allowed under this permit, 25 Pa. Code § 127.449, or sources and physical changes meeting the requirements of 25 Pa. Code § 127.14, the permittee is prohibited from making physical changes or engaging in activities that are not specifically authorized under this permit without first applying for a plan approval. In accordance with § 127.14(b), a plan approval is not required for the construction, modification, reactivation, or installation of the sources creating the de minimis emissions increase.

(h) The permittee may not meet de minimis emission threshold levels by offsetting emission increases or decreases at the same source.

#020 [25 Pa. Code §§ 127.11a & 127.215]

Reactivation of Sources

(a) The permittee may reactivate a source at the facility that has been out of operation or production for at least one year, but less than or equal to five (5) years, if the source is reactivated in accordance with the requirements of 25 Pa. Code §§ 127.11a and 127.215. The reactivated source will not be considered a new source.

(b) A source which has been out of operation or production for more than five (5) years but less than 10 years may be reactivated and will not be considered a new source if the permittee satisfies the conditions specified in 25 Pa. Code § 127.11a(b).

#021 [25 Pa. Code §§ 121.9 & 127.216]

Circumvention

(a) The owner of this Title V facility, or any other person, may not circumvent the new source review requirements of 25 Pa. Code Chapter 127, Subchapter E by causing or allowing a pattern of ownership or development, including the

SECTION B. General Title V Requirements

phasing, staging, delaying or engaging in incremental construction, over a geographic area of a facility which, except for the pattern of ownership or development, would otherwise require a permit or submission of a plan approval application.

(b) No person may permit the use of a device, stack height which exceeds good engineering practice stack height, dispersion technique or other technique which, without resulting in reduction of the total amount of air contaminants emitted, conceals or dilutes an emission of air contaminants which would otherwise be in violation of this permit, the Air Pollution Control Act or the regulations promulgated thereunder, except that with prior approval of the Department, the device or technique may be used for control of malodors.

#022 [25 Pa. Code §§ 127.402(d) & 127.513(1)]

Submissions

(a) Reports, test data, monitoring data, notifications and requests for renewal of the permit shall be submitted to the:

Regional Air Program Manager
PA Department of Environmental Protection
(At the address given on the permit transmittal letter, or otherwise notified)

(b) Any report or notification for the EPA Administrator or EPA Region III should be addressed to:

Enforcement & Compliance Assurance Division
Air, RCRA and Toxics Branch (3ED21)
Four Penn Center
1600 John F. Kennedy Boulevard
Philadelphia, PA 19103-2852

The Title V compliance certification shall be emailed to EPA at R3_APD_Permits@epa.gov.

(c) An application, form, report or compliance certification submitted pursuant to this permit condition shall contain certification by a responsible official as to truth, accuracy, and completeness as required under 25 Pa. Code § 127.402(d). Unless otherwise required by the Clean Air Act or regulations adopted thereunder, this certification and any other certification required pursuant to this permit shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

#023 [25 Pa. Code §§ 127.441(c) & 127.463(e); Chapter 139; & 114(a)(3), 504(b) of the CAA]

Sampling, Testing and Monitoring Procedures

(a) The permittee shall perform the emissions monitoring and analysis procedures or test methods for applicable requirements of this Title V permit. In addition to the sampling, testing and monitoring procedures specified in this permit, the Permittee shall comply with any additional applicable requirements promulgated under the Clean Air Act after permit issuance regardless of whether the permit is revised.

(b) The sampling, testing and monitoring required under the applicable requirements of this permit, shall be conducted in accordance with the requirements of 25 Pa. Code Chapter 139 unless alternative methodology is required by the Clean Air Act (including §§ 114(a)(3) and 504(b)) and regulations adopted thereunder.

#024 [25 Pa. Code § 127.513]

Compliance Certification

(a) One year after the date of issuance of the Title V permit, and each year thereafter, unless specified elsewhere in the permit, the permittee shall submit to the Department and EPA Region III a certificate of compliance with the terms and conditions in this permit, for the previous year, including the emission limitations, standards or work practices. This certification shall include:

(1) The identification of each term or condition of the permit that is the basis of the certification.
(2) The compliance status.
(3) The methods used for determining the compliance status of the source, currently and over the reporting period.
(4) Whether compliance was continuous or intermittent.

(b) The compliance certification shall be postmarked or hand-delivered no later than thirty days after each anniversary of

SECTION B. General Title V Requirements

the date of issuance of this Title V Operating Permit, or on the submittal date specified elsewhere in the permit, to the Department in accordance with the submission requirements specified in Section B, Condition #022 of this permit. The Title V compliance certification shall be emailed to EPA at R3_APD_Permits@epa.gov.

#025 [25 Pa. Code §§ 127.511 & Chapter 135]

Recordkeeping Requirements

(a) The permittee shall maintain and make available, upon request by the Department, records of required monitoring information that include the following:

(1) The date, place (as defined in the permit) and time of sampling or measurements.

(2) The dates the analyses were performed.

(3) The company or entity that performed the analyses.

(4) The analytical techniques or methods used.

(5) The results of the analyses.

(6) The operating conditions as existing at the time of sampling or measurement.

(b) The permittee shall retain records of the required monitoring data and supporting information for at least five (5) years from the date of the monitoring sample, measurement, report or application. Supporting information includes the calibration data and maintenance records and original strip-chart recordings for continuous monitoring instrumentation, and copies of reports required by the permit.

(c) The permittee shall maintain and make available to the Department upon request, records including computerized records that may be necessary to comply with the reporting, recordkeeping and emission statement requirements in 25 Pa. Code Chapter 135 (relating to reporting of sources). In accordance with 25 Pa. Code Chapter 135, § 135.5, such records may include records of production, fuel usage, maintenance of production or pollution control equipment or other information determined by the Department to be necessary for identification and quantification of potential and actual air contaminant emissions. If direct recordkeeping is not possible or practical, sufficient records shall be kept to provide the needed information by indirect means.

#026 [25 Pa. Code §§ 127.411(d), 127.442, 127.463(e) & 127.511(c)]

Reporting Requirements

(a) The permittee shall comply with the reporting requirements for the applicable requirements specified in this Title V permit. In addition to the reporting requirements specified herein, the permittee shall comply with any additional applicable reporting requirements promulgated under the Clean Air Act after permit issuance regardless of whether the permit is revised.

(b) Pursuant to 25 Pa. Code § 127.511(c), the permittee shall submit reports of required monitoring at least every six (6) months unless otherwise specified in this permit. Instances of deviations (as defined in 25 Pa. Code § 121.1) from permit requirements shall be clearly identified in the reports. The reporting of deviations shall include the probable cause of the deviations and corrective actions or preventative measures taken, except that sources with continuous emission monitoring systems shall report according to the protocol established and approved by the Department for the source. The required reports shall be certified by a responsible official.

(c) Every report submitted to the Department under this permit condition shall comply with the submission procedures specified in Section B, Condition #022(c) of this permit.

(d) Any records, reports or information obtained by the Department or referred to in a public hearing shall be made available to the public by the Department except for such records, reports or information for which the permittee has shown cause that the documents should be considered confidential and protected from disclosure to the public under Section 4013.2 of the Air Pollution Control Act and consistent with Sections 112(d) and 114(c) of the Clean Air Act and 25 Pa. Code § 127.411(d). The permittee may not request a claim of confidentiality for any emissions data generated for the Title V facility.

SECTION B. General Title V Requirements

#027 [25 Pa. Code § 127.3]

Operational Flexibility

The permittee is authorized to make changes within the Title V facility in accordance with the following provisions in 25 Pa. Code Chapter 127 which implement the operational flexibility requirements of Section 502(b)(10) of the Clean Air Act and Section 6.1(i) of the Air Pollution Control Act:

(1) Section 127.14 (relating to exemptions)

(2) Section 127.447 (relating to alternative operating scenarios)

(3) Section 127.448 (relating to emissions trading at facilities with federally enforceable emissions caps)

(4) Section 127.449 (relating to de minimis emission increases)

(5) Section 127.450 (relating to administrative operating permit amendments)

(6) Section 127.462 (relating to minor operating permit amendments)

(7) Subchapter H (relating to general plan approvals and operating permits)

#028 [25 Pa. Code §§ 127.441(d), 127.512(i) and 40 CFR Part 68]

Risk Management

(a) If required by Section 112(r) of the Clean Air Act, the permittee shall develop and implement an accidental release program consistent with requirements of the Clean Air Act, 40 CFR Part 68 (relating to chemical accident prevention provisions) and the Federal Chemical Safety Information, Site Security and Fuels Regulatory Relief Act (P.L. 106-40).

(b) The permittee shall prepare and implement a Risk Management Plan (RMP) which meets the requirements of Section 112(r) of the Clean Air Act, 40 CFR Part 68 and the Federal Chemical Safety Information, Site Security and Fuels Regulatory Relief Act when a regulated substance listed in 40 CFR § 68.130 is present in a process in more than the listed threshold quantity at the Title V facility. The permittee shall submit the RMP to the federal Environmental Protection Agency according to the following schedule and requirements:

(1) The permittee shall submit the first RMP to a central point specified by EPA no later than the latest of the following:

(i) Three years after the date on which a regulated substance is first listed under § 68.130; or,
(ii) The date on which a regulated substance is first present above a threshold quantity in a process.

(2) The permittee shall submit any additional relevant information requested by the Department or EPA concerning the RMP and shall make subsequent submissions of RMPs in accordance with 40 CFR § 68.190.

(3) The permittee shall certify that the RMP is accurate and complete in accordance with the requirements of 40 CFR Part 68, including a checklist addressing the required elements of a complete RMP.

(c) As used in this permit condition, the term "process" shall be as defined in 40 CFR § 68.3. The term "process" means any activity involving a regulated substance including any use, storage, manufacturing, handling, or on-site movement of such substances or any combination of these activities. For purposes of this definition, any group of vessels that are interconnected, or separate vessels that are located such that a regulated substance could be involved in a potential release, shall be considered a single process.

(d) If the Title V facility is subject to 40 CFR Part 68, as part of the certification required under this permit, the permittee shall:

(1) Submit a compliance schedule for satisfying the requirements of 40 CFR Part 68 by the date specified in 40 CFR § 68.10(a); or,

(2) Certify that the Title V facility is in compliance with all requirements of 40 CFR Part 68 including the registration and submission of the RMP.

SECTION B. General Title V Requirements

(e) If the Title V facility is subject to 40 CFR Part 68, the permittee shall maintain records supporting the implementation of an accidental release program for five (5) years in accordance with 40 CFR § 68.200.

(f) When the Title V facility is subject to the accidental release program requirements of Section 112(r) of the Clean Air Act and 40 CFR Part 68, appropriate enforcement action will be taken by the Department if:

(1) The permittee fails to register and submit the RMP or a revised plan pursuant to 40 CFR Part 68.

(2) The permittee fails to submit a compliance schedule or include a statement in the compliance certification required under Section B, Condition #026 of this permit that the Title V facility is in compliance with the requirements of Section 112(r) of the Clean Air Act, 40 CFR Part 68, and 25 Pa. Code § 127.512(i).

#029 [25 Pa. Code § 127.512(e)]

Approved Economic Incentives and Emission Trading Programs

No permit revision shall be required under approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in this Title V permit.

#030 [25 Pa. Code §§ 127.516, 127.450(d), 127.449(f) & 127.462(g)]

Permit Shield

(a) The permittee's compliance with the conditions of this permit shall be deemed in compliance with applicable requirements (as defined in 25 Pa. Code § 121.1) as of the date of permit issuance if either of the following applies:

(1) The applicable requirements are included and are specifically identified in this permit.

(2) The Department specifically identifies in the permit other requirements that are not applicable to the permitted facility or source.

(b) Nothing in 25 Pa. Code § 127.516 or the Title V permit shall alter or affect the following:

(1) The provisions of Section 303 of the Clean Air Act, including the authority of the Administrator of the EPA provided thereunder.

(2) The liability of the permittee for a violation of an applicable requirement prior to the time of permit issuance.

(3) The applicable requirements of the acid rain program, consistent with Section 408(a) of the Clean Air Act.

(4) The ability of the EPA to obtain information from the permittee under Section 114 of the Clean Air Act.

(c) Unless precluded by the Clean Air Act or regulations thereunder, final action by the Department incorporating a significant permit modification in this Title V Permit shall be covered by the permit shield at the time that the permit containing the significant modification is issued.

#031 [25 Pa. Code §135.3]

Reporting

(a) The permittee shall submit by March 1 of each year an annual emissions report for the preceding calendar year. The report shall include information for all active previously reported sources, new sources which were first operated during the preceding calendar year, and sources modified during the same period which were not previously reported. All air emissions from the facility should be estimated and reported.

(b) A source owner or operator may request an extension of time from the Department for the filing of an annual emissions report, and the Department may grant the extension for reasonable cause.

#032 [25 Pa. Code §135.4]

Report Format

Emissions reports shall contain sufficient information to enable the Department to complete its emission inventory. Emissions reports shall be made by the source owner or operator in a format specified by the Department.

SECTION C. Site Level Requirements

I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.1]

Prohibition of certain fugitive emissions

(a) No person may permit the emission into the outdoor atmosphere of fugitive air contaminant from a source other than the following:

(1) Construction or demolition of buildings or structures.

(2) Grading, paving and maintenance of roads and streets.

(3) Use of roads and streets. Emissions from material in or on trucks, railroad cars and other vehicular equipment are not considered as emissions from use of roads and streets.

(4) Clearing of land.

(5) Stockpiling of materials.

(6) Open burning operations, as specified in 25 Pa. Code § 129.14.

(7) N/A

(8) N/A

(9) Sources and classes of sources other than those identified in (1)-(8) of this condition, for which the permittee has obtained a determination from the Department that fugitive emissions from the source, after appropriate control, meet the following requirements:

(i) The emissions are of minor significance with respect to causing air pollution; and

(ii) The emissions are not preventing or interfering with the attainment or maintenance of any ambient air quality standard.

 # 002 [25 Pa. Code §123.2]

Fugitive particulate matter

A person may not permit fugitive particulate matter to be emitted into the outdoor atmosphere from a source specified in 25 Pa. Code § 123.1(a) (relating to prohibition of certain fugitive emissions) if such emissions are visible at the point the emissions pass outside the person's property.

 # 003 [25 Pa. Code §123.31]

Limitations

A person may not permit the emission into the outdoor atmosphere of any malodorous air contaminants from any source in such a manner that the malodors are detectable outside the property of the person on whose land the source is being operated.

 # 004 [25 Pa. Code §123.41]

Limitations

A person may not permit the emission into the outdoor atmosphere of visible air contaminants in such a manner that the opacity of the emission is either of the following:

(a) Equal to or greater than 20% for a period or periods aggregating more than three minutes in any 1 hour.

(b) Equal to or greater than 60% at any time.

 # 005 [25 Pa. Code §123.42]

Exceptions

The opacity limitations as per 25 Pa. Code § 123.41 shall not apply to a visible emission in any of the following instances:

(a) When the presence of uncombined water is the only reason for failure of the emission to meet the limitations.

(b) When the emission results from the operation of equipment used solely to train and test persons in observing the opacity of visible emissions.

(c) When the emission results from the sources specified in 25 Pa. Code § 123.1(a) (relating to prohibition of certain fugitive emissions).

 # 006 [25 Pa. Code §129.14]

Open burning operations

No person may permit the open burning of material in the Southeast Air Basin except where the open burning operations result from:

(a) A fire set to prevent or abate a fire hazard, when approved by the Department and set by or under the supervision of a

SECTION C. Site Level Requirements

public officer.
(b) Any fire set for the purpose of instructing personnel in fire fighting, when approved by the Department.
(c) A fire set for the prevention and control of disease or pests, when approved by the Department.
(d) A fire set in conjunction with the production of agricultural commodities in their unmanufactured state on the premises of the farm operation.
(e) A fire set for the purpose of burning domestic refuse, when the fire is on the premises of a structure occupied solely as a dwelling by two families or less and when the refuse results from the normal occupancy of the structure.
(f) A fire set solely for recreational or ceremonial purposes.
(g) A fire set solely for cooking food.

Fuel Restriction(s).

 # 007 [25 Pa. Code §123.22]

Combustion units

The following applies to all fuel oil used in combustion units (boilers):

(a) A person may not offer for sale, deliver for use, exchange in trade or permit the use of commercial fuel oil in a combustion unit in the Southeast Pennsylvania air basin if the commercial fuel oil contains sulfur in excess of 15 ppm or 0.0015% by weight for No. 2 fuel oil by weight sulfur content, pursuant to 25 Pa. Code § 123.22(e)(2)(i), except as described in 25 Pa. Code § 123.22(e)(2)(ii) and (iii).

(b) Commercial No. 2 fuel oil that was stored in the Commonwealth by the ultimate consumer prior to September 1, 2020 which met the applicable maximum allowable sulfur content for commercial fuel oil through August 31, 2020 in subparagraph (a) at the time it was stored, may be used by the ultimate consumer in this Commonwealth on and after September 1, 2020.

[Compliance with this condition assures compliance with the sulfur emission rate of 1.2/1.0 lb SO2/MMBtu as found in 25 Pa. Code § 123.22(e)(1) for the outer/inner zone, while firing No. 2 fuel oil and the SOx emissions limit of 0.80 lb/MMBtu found in 40 CFR § 60.43.]

II. TESTING REQUIREMENTS.

 # 008 [25 Pa. Code §123.22]

Combustion units

The actual sulfur content of commercial fuel oil shall be determined:

(a) in accordance with the sample collection, test methods and procedures specified under 25 Pa. Code § 139.16 (relating to sulfur in fuel oil); or
(b) by other methods developed or approved by the Department or the Administrator of the EPA, or both.

 # 009 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code § 127.512.]

(a) If at any time the Department has cause to believe that air contaminant emissions from any source may be in excess of the limitations specified in this Permit, or established pursuant to, any applicable rule or regulation contained in 25 Pa. Code Article III, the permittee shall be required to conduct whatever tests are deemed necessary by the Department to determine the actual emission rate(s).

(b) Such testing shall be conducted in accordance with the provisions of 25 Pa. Code Chapter 139, the most current version of the DEP Source Testing Manual, and the EPA Clean Air Act National Stack Testing Guidance, when applicable, and in accordance with any restrictions or limitations established by the Department at such time as it notifies the permittee that testing is required.

SECTION C. Site Level Requirements

 # 010 [25 Pa. Code §139.16]

Sulfur in fuel oil.

(a) The following are applicable to tests for the analysis of commercial fuel oil:

(1) The fuel oil sample for chemical analysis shall be collected in a manner that provides a representative sample. Upon the request of a Department official, the person responsible for the operation of the source shall collect the sample employing the procedures and equipment specified in 25 Pa. Code § 139.4(10) (relating to references).

(2) Test methods and procedures for the determination of viscosity shall be that specified in 25 Pa. Code § 139.4(11) (relating to references). The viscosity shall be determined at 100°F.

(3) Tests methods and procedures for the determination of sulfur shall be those specified in 25 Pa. Code § 139.4(12)--(15) and (20).

(4) Results shall be reported in accordance with the units specified in 25 Pa. Code § 123.22 (relating to combustion units).

(b) The testing requirements in subpart (a) above shall be waived in the event that a delivery receipt from the supplier, showing the percentage sulfur in the fuel, is obtained each time a fuel oil delivery is made.

III. MONITORING REQUIREMENTS.

 # 011 [25 Pa. Code §123.43]

Measuring techniques

Visible emissions may be measured using either of the following:

(a) A device approved by the Department and maintained to provide accurate opacity measurements.
(b) Observers, trained and qualified to measure plume opacity with the naked eye or with the aid of any devices approved by the Department.

 # 012 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code § 127.511.]

(a) The permittee shall monitor the facility, once per operating day, for the following:

(1) odors which may be objectionable (as per 25 Pa. Code §123.31);
(2) visible emissions (as per 25 Pa. Code §§123.41 and 123.42); and
(3) fugitive particulate matter (as per 25 Pa. Code §§ 123.1 and 123.2).

(b) Objectionable odors, fugitive particulate emissions, and visible emissions that are caused or may be caused by operations at the site shall:

(1) be investigated;
(2) be reported to the facility management, or individual(s) designated by the permittee;
(3) have appropriate corrective action taken (for emissions that originate on-site); and
(4) be recorded in a permanent written log.

(c) After six (6) months of daily monitoring, and upon the permittee's request, the Department will determine the feasibility of decreasing the monitoring frequency to weekly.

(d) After six (6) months of weekly monitoring, and upon the permittee's request, the Department will determine the feasibility of decreasing the frequency of monitoring to monthly.

(e) The Department reserves the right to change the above monitoring requirements at any time, based on but not limited

SECTION C. Site Level Requirements

to: the review of the compliance certification (if applicable), complaints, monitoring results, and/or Department findings.

(f) The daily monitoring of visible emissions, specified in (a), above, shall be waived for those stacks monitored by a Department certified Continuous Opacity Monitoring System (COMs).

IV. RECORDKEEPING REQUIREMENTS.

 # 013 [25 Pa. Code §123.22]
Combustion units

The permittee shall receive with each No. 2 fuel oil delivery an electronic or paper record which legibly and conspicuously contains the following information:

(a) the date of the sale or transfer;
(b) the name and address of the seller;
(c) the name and address of the buyer;
(d) the delivery address;
(e) the volume of commercial fuel oil purchased; and
(f) the identification of the sulfur content of the shipment of fuel oil, determined using the sampling and testing methods specified in the testing requirement above, expressed as one of the following statement: ‘‘The sulfur content of this shipment is 15 ppm or below.’’

 # 014 [25 Pa. Code §127.441]
Operating permit terms and conditions.

The permittee shall maintain records of all the facility's increases of emissions from the following categories:

(a) emissions increase of minor significance without notification to the Department.
(b) de minimis increases with notification to the Department, via letter.
(c) increases resulting from a Request for Determination (RFD) to the Department.
(d) increases resulting from the issuance of a plan approval and subsequent operating permit.

 # 015 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code § 127.511.]

The permittee shall maintain a record of all monitoring of fugitive emissions, visible emissions and odors, including those that deviate from the conditions found in this permit. The record of deviations shall contain, at a minimum, the following items:

(a) Date, time, and location of the incident(s);
(b) The cause of the event; and
(c) The corrective action taken, if necessary, to abate the situation and prevent future occurrences.

For visible emissions monitored by a Department certified Continuous Opacity Monitoring System (COMs) for which the Department's Enforcement Policy-Continuous Emission Monitoring System established penalties for excess emissions the aforementioned recordkeeping requirement will be waived.

V. REPORTING REQUIREMENTS.

 # 016 [25 Pa. Code §123.22]
Combustion units

The permittee shall provide an electronic or written copy of the commercial fuel oil shipment record to the Department upon request, in accordance with 25 Pa. Code § 123.22(g)(4)(ii).

 # 017 [25 Pa. Code §127.441]
Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code § 127.511(c).]

SECTION C. Site Level Requirements

The permittee shall submit the following:

(a) An annual certificate of compliance, due by April 1st of each year, for the period covering January 1 through December 31 of the previous year. This certificate of compliance shall document compliance with all permit terms and conditions set forth in this Title V permit as required under condition #26 of section B of this permit. The annual certificate of compliance shall be submitted to DEP electronically, and to EPA Region III in electronic form at the following email address: R3_APD_Permits@epa.gov. The subject line shall read: "TVOP No. 23-00017, Constellation Energy Generation LLC/ Eddystone."

(b) A semi-annual deviation report to DEP, due by October 1 of each year, for the period covering January 1 through June 30 of the same year. Note: The annual certification of compliance fulfills the obligation for the second deviation reporting period (July 1 through December 31 of the previous year).

 # 018 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code § 127.511.]

(a) The permittee shall report malfunctions, emergencies or incidents of excess emissions to the Department at 484-250-5920. A malfunction is any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. An emergency is any situation arising from sudden and reasonably unforeseeable events beyond the control of the owner or operator of a facility which requires immediate corrective action to restore normal operation and which causes the emission source to exceed emissions, due to unavoidable increases in emissions attributable to the situation. An emergency shall not include situations caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error.

(b) When the malfunction, emergency or incident of excess emissions poses an imminent danger to the public health, safety, welfare, or environment, it shall be reported to the Department and the County Emergency Management Agency by telephone within one (1) hour after the discovery of the malfunction, emergency or incident of excess emissions. The owner or operator shall submit a written or emailed report of instances of such malfunctions, emergencies or incidents of excess emissions to the Department within three (3) business days of the telephone report.

(c) The report shall describe the following:

(1) Name, permit or authorization number, and location of the facility;
(2) Nature and cause of the malfunction, emergency or incident;
(3) Date and time when the malfunction, emergency or incident was first observed;
(4) Expected duration of excess emissions;
(5) Estimated rate of emissions; and
(6) Corrective actions or preventative measures taken.

(d) Any malfunction, emergency or incident of excess emissions that is not subject to the notice requirements of paragraph (b) of this condition shall be reported to the Department by telephone within 24 hours (or by 4:00 PM of the next business day, whichever is later) of discovery and in writing or by e-mail within five (5) business days of discovery. The report shall contain the same information required by paragraph (c), and any permit specific malfunction reporting requirements.

(e) During an emergency an owner or operator may continue to operate the source at their discretion provided they submit justification for continued operation of a source during the emergency and follow all the notification and reporting requirements in accordance with paragraphs (b)-(d), as applicable, including any permit specific malfunction reporting requirements.

(f) Reports regarding malfunctions, emergencies or incidents of excess emissions shall be submitted to the appropriate DEP Regional Office Air Program Manager.

(g) Any emissions resulted from malfunction or emergency are to be reported in the annual emissions inventory report, if the annual emissions inventory report is required by permit or authorization.

SECTION C. Site Level Requirements

 # 019 [25 Pa. Code §135.21]

Emission statements

The permittee shall submit by March 1, of each year, an annual emission statement showing the actual emissions of NOx and VOC emissions for the preceding calendar year. Additionally, a description of the method used to calculate the emissions shall be included. The statement shall contain a certification by a company official or plant manager that the information contained in the statement is true and accurate.

 # 020 [25 Pa. Code §139.16]

Sulfur in fuel oil.

Results of the fuel oil sulfur test shall be reported in accordance with the units specified in 25 Pa. Code § 123.22 (relating to combustion units).

VI. WORK PRACTICE REQUIREMENTS.

 # 021 [25 Pa. Code §123.1]

Prohibition of certain fugitive emissions

A person responsible for any source specified in 25 Pa. Code § 123.1 shall take all reasonable actions to prevent particulate matter from becoming airborne. These actions shall include, but not be limited to, the following:

(a) Use, where possible, of water or suitable chemicals, for control of dust in the demolition of buildings or structures, construction operations, the grading of roads, or the clearing of land.
(b) Application of asphalt, water, or other suitable chemicals, on dirt roads, material stockpiles and other surfaces which may give rise to airborne dusts.
(c) Paving and maintenance of roadways.
(d) Prompt removal of earth or other material from paved streets onto which earth or other material has been transported by trucking or earth moving equipment, erosion by water, or by other means.

 # 022 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code § 127.512.]

The permittee shall ensure that the source(s) and air pollution control device(s), listed in this permit, are operated and maintained in a manner consistent with good operating and maintenance practices, and in accordance with manufacturer's specifications.

 # 023 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code § 127.512.]

The permittee shall immediately, upon discovery, implement measures which may include the application for the installation of an air cleaning device(s), if necessary, to reduce the air contaminant emissions to within applicable limitations, if at any time the operation of the source(s) identified in this permit, is causing the emission of air contaminants in excess of the limitations specified in, or established pursuant to 25 Pa. Code Article III or any other applicable rule promulgated under the Clean Air Act.

 # 024 [25 Pa. Code §127.441]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code § 127.512.]

The permittee may not modify any air contaminant system identified in this permit, prior to obtaining Department approval, except those modifications authorized by Condition #019(g), of Section B, of this permit.

VII. ADDITIONAL REQUIREMENTS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

SECTION C. Site Level Requirements

VIII. COMPLIANCE CERTIFICATION.

No additional compliance certifications exist except as provided in other sections of this permit including Section B (relating to Title V General Requirements).

IX. COMPLIANCE SCHEDULE.

No compliance milestones exist.

***** Permit Shield In Effect *****

SECTION D. Source Level Requirements

Source ID: 033 Source Name: BOILER 3

Source Capacity/Throughput:	4,116.000	MMBTU/HR	
	33,352.000	Gal/HR	#2 Oil
	4.480	MMCF/HR	Natural Gas

Conditions for this source occur in the following groups: MAIN BOILERS



I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.512]

Operating permit terms and conditions.

This source consists of a Combustion Engineering tangential fired boiler. Installed in 1974, the boiler was orginially designed to accommodate No.6, crude, and waste oil with a 4116 MMBtu/hr input. The boiler was modified in 1994 to operate on No. 2 oil and natural gas. Originally equipped with ESP for crude oil use, the EPS were not ever used since crude oil was never used in the boiler. Currently, the boiler operates only on No. 2 oil and natural gas.

SECTION D. Source Level Requirements

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 034 Source Name: AUXILIARY BOILER A

Source Capacity/Throughput:	124.000	MMBTU/HR	
	925.900	Gal/HR	#2 Oil
	122.300	MCF/HR	Natural Gas

Conditions for this source occur in the following groups: AUX BOILERS



I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.512]

Operating permit terms and conditions.

This source consists of a Combustion Engineering 124 MMBtu/hr package type boiler capable of burning natural gas and No. 2 fuel oil and is used for steam only. Unit was installed in 1973 but the burner was upgraded in 1994 to a low NOx burner.

SECTION D. Source Level Requirements

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 035 Source Name: AUXILIARY BOILER B

Source Capacity/Throughput:	124.000	MMBTU/HR	
	925.900	Gal/HR	#2 Oil
	122.300	MCF/HR	Natural Gas

Conditions for this source occur in the following groups: AUX BOILERS



I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.512]

Operating permit terms and conditions.

This source consists of a Combustion Engineering 124 MMBtu/hr package type boiler capable of burning natural gas and No. 2 fuel oil and is used for steam only. Unit was installed in 1973 but the burner was upgraded in 1994 to a low NOx burner.

SECTION D. Source Level Requirements

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 036 Source Name: AUXILIARY BOILER C

Source Capacity/Throughput:	124.000	MMBTU/HR	
	925.900	Gal/HR	#2 Oil
	122.300	MCF/HR	Natural Gas

Conditions for this source occur in the following groups: AUX BOILERS



I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.512]

Operating permit terms and conditions.

This source consists of a Combustion Engineering 124 MMBtu/hr package type boiler capable of burning natural gas and No. 2 fuel oil and is used for steam only. Unit was installed in 1973 but the burner was upgraded in 1994 to a low NOx burner.

SECTION D. Source Level Requirements

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 041 Source Name: BOILER 4

Source Capacity/Throughput:	4,116.000	MMBTU/HR	
	33,352.000	Gal/HR	#2 Oil
	4.480	MMCF/HR	Natural Gas

Conditions for this source occur in the following groups: MAIN BOILERS



I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.512]

Operating permit terms and conditions.

This source consists of a Combustion Engineering tangential fired boiler. Installed in 1974, the boiler was orginially designed to accommodate No.6, crude, and waste oil with a 4116 MMBtu/hr input. The boiler was modified in 1994 to operate on No. 2 oil and natural gas. Originally equipped with ESP for crude oil use, the EPS were not ever used since crude oil was never used in the boiler. Currently, the boiler operates only on No. 2 oil and natural gas.

SECTION D. Source Level Requirements

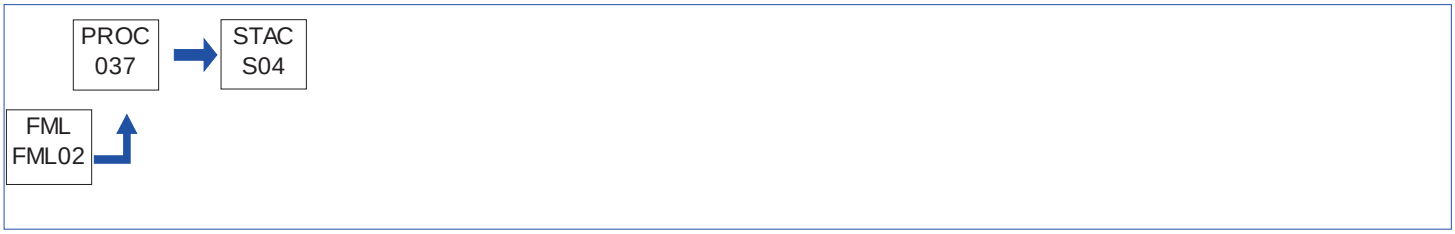
***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 037 Source Name: NO. 10 COMBUSTION TURBINE

Source Capacity/Throughput:	1,726.000	Gal/HR	Kerosene
	1,726.000	Gal/HR	#2 Oil

Conditions for this source occur in the following groups: TURBINES



I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The source consists of a 233 MMBtu/hr Pratt and Whitney FT4-8 diesel /kerosene fueled turbine installed in 1967 that powers a 18 MW generator.

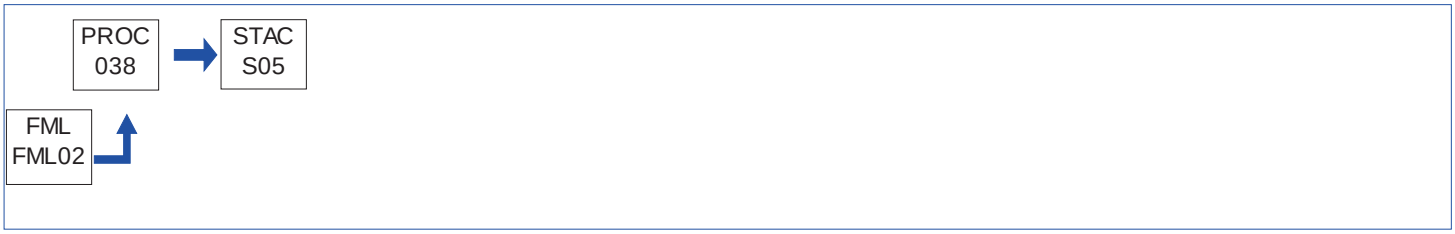
***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 038 Source Name: NO. 20 COMBUSTION TURBINE

Source Capacity/Throughput:	1,726.000	Gal/HR	Kerosene
	1,726.000	Gal/HR	#2 Oil

Conditions for this source occur in the following groups: TURBINES



I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The source consists of a 233 MMBtu/hr Pratt and Whitney FT4-8 diesel /kerosene fueled turbine installed in 1967 that powers a 18 MW generator.

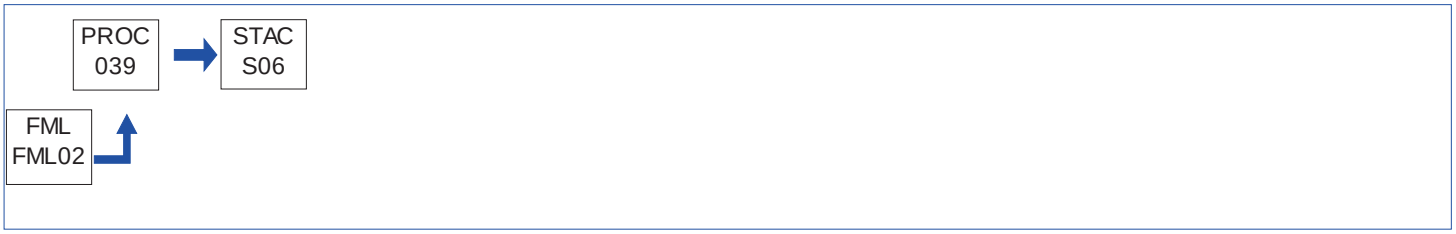
***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 039 Source Name: NO. 30 COMBUSTION TURBINE

Source Capacity/Throughput:	2,104.000	Gal/HR	Kerosene
	2,104.000	Gal/HR	#2 Oil

Conditions for this source occur in the following groups: TURBINES



I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The source consists of a 284 MMBtu/hr Pratt and Whitney FT4-9 diesel /kerosene fueled turbine installed in 1970 that powers a 20 MW generator.

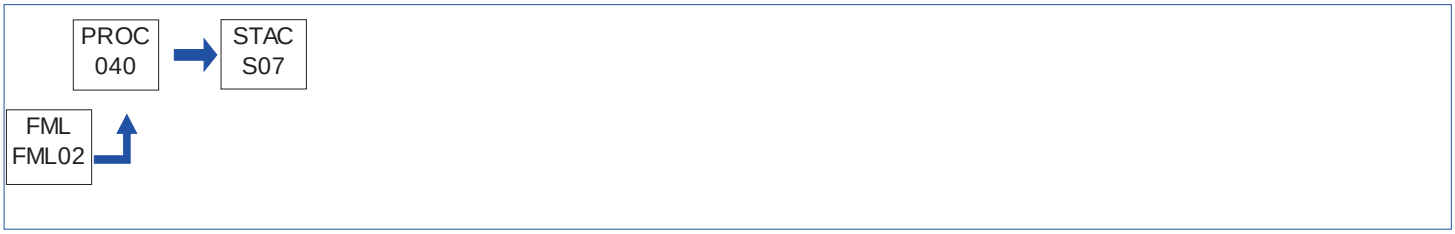
***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 040 Source Name: NO. 40 COMBUSTION TURBINE

Source Capacity/Throughput:	2,104.000	Gal/HR	Kerosene
	2,104.000	Gal/HR	#2 Oil

Conditions for this source occur in the following groups: TURBINES



I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The source consists of a 284 MMBtu/hr Pratt and Whitney FT4-9 diesel /kerosene fueled turbine installed in 1970 that powers a 20 MW generator.

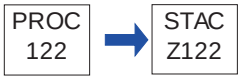
***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 122 Source Name: #2 OIL STORAGE TANK (1.05 MMGAL)

Source Capacity/Throughput:

Conditions for this source occur in the following groups: OIL STORAGE



I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

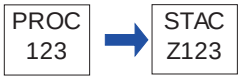
***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: 123 Source Name: FUEL OIL STORAGE TANKS(2)

Source Capacity/Throughput:

Conditions for this source occur in the following groups: OIL STORAGE



I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements) and/or Section E (Source Group Restrictions).

VII. ADDITIONAL REQUIREMENTS.

 # 001 [25 Pa. Code §127.503]

Application information.

This source consists of two (2) 8.4 million gallon fixed roof storage tanks used to store fuel oil.

***** Permit Shield in Effect. *****

SECTION D. Source Level Requirements

Source ID: F04 Source Name: OIL DELIVERY FUGITIVES

Source Capacity/Throughput:

PROC F04 → STAC Z04

I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

No additional monitoring requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

IV. RECORDKEEPING REQUIREMENTS.

No additional record keeping requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VI. WORK PRACTICE REQUIREMENTS.

 # 001 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Good operating practices shall be followed to minimize fugitive emissions.

VII. ADDITIONAL REQUIREMENTS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

***** Permit Shield in Effect. *****

SECTION E. Source Group Restrictions.

Group Name: AUX BOILERS

Group Description: Auxilary Boilers 124 MMBtu

Sources included in this group

ID	Name
034	AUXILIARY BOILER A
035	AUXILIARY BOILER B
036	AUXILIARY BOILER C

I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.11]

Combustion units

A person may not permit the emission into the outdoor atmosphere of particulate matter from this boiler in excess of 0.24 lbs/MMBtu of heat input, pursuant to 25 Pa. Code § 123.11(a)(2).

 # 002 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code §§ 129.112(g)(1)(i)-(ii).]

NOx emissions from each boiler in this group shall not exceed any of the following as a daily average:

(1) 0.10 lb NOx/MMBtu heat input when firing natural gas.
(2) 0.12 lb NOx/MMBtu heat input when firing No. 2 fuel oil

[Compliance with the above RACT III NOx emission standards assure compliance with the RACT I NOx emission standards according to 25 Pa. Code §129.91- NOx emissions from this boiler shall not exceed 0.14 lbs/MMBtu. and 129.97(i) and the RACT II NOx emission standards according to 25 Pa. Code §§ 129.97(g)(1)(i) - (ii).]

(b) The permittee shall conduct monitoring and testing in accordance with a Department-approved emissions source test that meets the requirements of Chapter 139, Subchapter A (relating to sampling and testing methods and procedures). The source test shall be conducted one time in each 5-year calendar period.

 # 003 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code §§ 129.91 and 129.112.]

NOx emissions from each boiler in this group shall not exceed 36.0 tons in any 12 consecutive month period.

 # 004 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.7500]

Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters.

What emission limits, work practice standards, and operating limits must I meet?

[Additional authority for this permit conditions is also derived from Table 2 of this subpart, 40 CFR § 63.7510(e), and 25 Pa. Code § 127.441.]

When burning fuel oil, emissions to the atmosphere shall not exceed the following, except for start-up and shut-down:
(a) HCl - 1.1E-03 lbs/MMBtu of heat input or 1.4E-03 lb per MMBtu of steam output;
(b) Hg - 7.3E-07 lb per MMBtu of heat input or 8.8E-07 lb per MMBtu of steam output;
(c) CO - 130 ppm by volume on a dry basis corrected to 3 percent oxygen or 0.13 lb per MMBtu of steam output; and
(d) PM emissions:
(1) filterable PM - 7.9E-03 lb per MMBtu of heat input or 9.6E-03 lb per MMBtu of steam output; or
(2) the permittee may choose to limit the emissions Total Select Metals (TSM) to 6.2E-05 lb per MMBtu of heat input or

SECTION E. Source Group Restrictions.

7.5E-05 lb per MMBtu of steam output.

Fuel Restriction(s).

 # 005 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Only No. 2 fuel oil and/or natural gas shall be burned in these auxiliary boilers.

Throughput Restriction(s).

 # 006 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The heat throughput for each auxiliary boiler shall not exceed 657,000 MMBtu, or an annual capacity factor of 60%, in any 12 consecutive month period. Heat input shall be determined by a Department approved method.

II. TESTING REQUIREMENTS.

 # 007 [25 Pa. Code §127.512]

Operating permit terms and conditions.

(a) The permittee shall perform stack tests on boilers in this group according to the following:

(i) For compliance with NOx limits under 25 Pa Code § 129.115(b)(6):

(1) One boiler shall be tested every five (5) years, where five (5) calendar years is defined as beginning with the calendar year the latest stack test was performed and ending on December 31, five (5) years later.

(2) No one boiler shall be tested repeatedly for each consecutive five (5) year period. The permittee must alternate between boilers for stack tests.

(3) Each boiler must be tested at least once in the 15-year period (three 5-year periods).

(4) If the permittee fails to comply with requirements of the above schedule; modifies the boilers or changes their operation in a manner that would increase emissions; or does not comply with the maintenance requirements in Condition #021 of this Group and Section, all boilers will need to be tested in the same 5- year period. The permittee may request a return to the alternating schedule above once any deficiencies listed in this paragraph have been addressed, all boilers have been tested during one five(5) year interval and the tests have been found acceptable.

(ii) For compliance with Hg, HCl, CO and filterable PM or total suspended metals (TSM) testing shall be performed as follows:

(1) Perform annual stack test for each contaminant. Tests must be completed no more than 13 months after the previous test unless the boiler is eligible for the reduced testing listed in Paragraph (a)(ii)(2) of this Condition. In lieu of testing for Hg, HCl and TSM only, the permittee may use fuel analysis for liquid fuel only to comply with limits as allowed under 40 CFR § 63.7505(a). For gaseous fuels, fuel testing for Hg is permitted in lieu of stack testing. Fuel testing must be performed according to requirements of 40 CFR §§ 63.7515, 63.7521, 63.7530, and Table 6 of 40 CFR Part 63 Subpart DDDDD.

(2) If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit for the pollutant, and if there are no changes in the operation of the individual boiler that could increase emissions, the permittee may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test.

(3) If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit for a pollutant, the permittee must conduct annual performance tests for that pollutant until all performance tests over a

SECTION E. Source Group Restrictions.

consecutive 2-year period meet the required level (at or below 75 percent of the emission limit).

(4) Under 40 CFR § 63.7515(h), if the boilers are designed to burn light distillate oil (diesel, No. fuel oil, biodiesel), the fuel used by the boilers is ultra-low sulfur (15 ppm sulfur or lower), and the pollutants measured during the initial compliance performance tests meet the emission limits in Table 2 of 40 CFR Part 63 Subpart DDDDD, the facility does not need to conduct further performance tests (stack tests). The facility must demonstrate ongoing compliance with the emissions limits by monitoring and recording the type of fuel and amount combusted on a monthly basis. The facility shall keep a copy of the initial compliance test results at the facility for review and verification. If the facility intends to use a fuel other than ultra-low sulfur liquid fuel, natural gas, refinery gas, or other gas 1 fuel, the facility must conduct new performance tests within 60 days of burning the new fuel type.

(5) If fuel testing is being used in lieu of stack testing and the boilers share a common fuel supply, sampling from the common supply is acceptable for compliance for all boilers sharing the supply.

(b) In accordance with 25 Pa. Code § 139.11(1), performance tests shall be conducted while the source is operating at maximum routine operating conditions or under such other conditions, within the capacity of the equipment, as may be requested by the Department. When testing of a source is required on a recurring basis, a single procedural protocol may be submitted for approval; thereafter, a letter referencing the previously approved procedural protocol is sufficient. However, if modifications are made to the process(es), if a different stack testing company is used, or if an applicable section of the stack testing manual has been revised since approval, a new protocol must be submitted for approval. Refer to PADEP Source Testing Program website online for further information related to source testing including Source Testing FAQ and the PADEP Source Testing Manual.

(c) The stack test shall, at a minimum, test for the following according to listed regulations:

(i) NOx – testing shall be conducted according to the requirements in 25 Pa Code § 129.115(b)(6)
(ii) Hg, HCl, CO and filterable PM or TSM – testing shall be performed according to requirements of 40 CFR § 63.7505 and 40 CFR Part 63 Subpart DDDDD Table 5.

(d) Tests shall also be conducted in accordance with the provisions of the current version of the DEP Source Testing Manual, the methods found in the 40 CFR Part 60 Appendices and the EPA Clean Air Act National Stack Testing Guidance.

(e) At least ninety (90) days prior to the test, the permittee shall submit to the Department for approval the procedures for the test and a sketch with dimensions indicating the location of sampling ports and other data to ensure the collection of representative samples.

(f) At least thirty (30) days prior to the test, the Regional Air Quality Manager, shall be informed of the date and time of the test.

(g) Within sixty (60) days after the source test(s), an electronic copy of the complete test report, including all operating conditions, shall be submitted to the Regional Air Quality Manager for approval.

(h) In the event that any of the above deadlines cannot be met, the permittee may request an extension for the due date(s) in writing and include a justification for the extension. The Department may grant an extension for a reasonable cause.

 # 008 [25 Pa. Code §127.512]

Operating permit terms and conditions.

(a) The permittee shall email all source test submissions (notifications, protocols, reports, supplemental information, etc.) to both the AQ Program Manager for the Southeast Regional Office and the PSIMS Administrator in Central Office (email addresses are provided below). Any questions or concerns about source testing submissions can be sent to RA-EPstacktesting@pa.gov and the PSIMS Administrator will address them.

Southeast Region
RA-EPSEstacktesting@pa.gov

SECTION E. Source Group Restrictions.

Central Office
RA-EPstacktesting@pa.gov

(b) The following pertinent information shall be listed on the title page.

1. Test Date(s)

a. For protocols, provide the proposed date on which testing will commence or “TBD”
b. For reports, provide the first and last day of testing

2. Facility Identification Number (Facility - ID): For test programs that were conducted under a multi-site protocol, also include the PF ID under which the protocol was stored in PSIMS, as indicated in the protocol response letter.

3. Source ID(s) for the applicable source(s) and air pollution control device(s): The term Source ID is used in the permit but “Other Id” is used in DEP electronic systems. They are the same number and must also be listed for control equipment

4. Testing Requirements:

(i). Operating permit number 23-00017
(ii) 40 CFR Part 63 Subpart DDDDD (when testing for Hg, HCl, CO or filterable PM/TSM)
(iii) RACT III Compliance under 25 Pa Code § 129.112(g)(1)(i)-(ii)

(c) If confidential information must be submitted, submit both a public copy, which has been redacted, and a confidential copy. The cover page of each submittal should state whether it is a “Public Copy” or “Confidential Copy” and each page of the latter must be marked “CONFIDENTIAL”.

 # 009 [25 Pa. Code §127.512]

Operating permit terms and conditions.

For fuel testing used in lieu of stack testing, the facility may use fuel analysis provided by the supplier if the following are met:

(a) The testing is done in accordance with the requirements for each pollutant in Table 6 of 40 CFR Part 63 Subpart DDDDD, 40 CFR §§ 63.7510 and 63.7521.
(b) The permittee shall maintain records of the result of testing performed provided by the supplier. The records shall list the supplier, fuel tested, the date of testing, test method used for each pollutant, and results in units prescribed for limits from Subcategories 14 and 16 of Table 2 of 40 CFR Part 63 Subpart DDDDD.

(c) Fuel analysis must be performed monthly for each type of fuel burned. The permittee may comply with this monthly requirement by having the supplier comply with the sampling interval found in 40 CFR § 63.7515(e). If each of 12 consecutive monthly fuel analyses demonstrates 75 percent or less of the compliance level, the permittee may decrease the fuel analysis frequency for the supplier to quarterly for that fuel. If any quarterly sample exceeds 75 percent of the compliance level or the boiler begins burning a new type of fuel, the permittee must return to monthly monitoring for that fuel, until 12 months of fuel analyses are again less than 75 percent of the compliance level.

 # 010 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.7515]

Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters.

When must I conduct subsequent performance tests or fuel analyses, or tune-ups?

[Additional authority for this permit condition is derived from 25 Pa. Code § 127.441.]

For units that burn light liquid fuel as described in 40 CFR 63, Subpart DDDDD, the permittee shall demonstrate compliance status for the following:
(1) Hg and HCl emissions: by conducting a performance test or fuel analysis
(2) PM (TSM) emissions: by conducting a performance test
(3) CO emissions: by conducting a performance test

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If your performance tests for a given pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit for the pollutant, and if there are no changes in the operation of the individual boiler that could increase emissions, the permittee may choose to conduct performance tests for the pollutant every third year. Each such performance test must be conducted no more than 37 months after the previous performance test.

If a performance test shows emissions exceeded the emission limit or 75 percent of the emission limit for a pollutant, the permittee must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period meet the required level (at or below 75 percent of the emission limit).

Results of the performance test shall be submitted to the Department within sixty (60) days after completion of the test.

III. MONITORING REQUIREMENTS.

 # 011 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The following shall be monitored on a daily basis for each boiler when operating:

(a) fuel consumed, by type and amount;
(b) steam output; and
(c) hours of operation.

IV. RECORDKEEPING REQUIREMENTS.

 # 012 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Records, and sufficient calculations, shall be maintained to document compliance with each limit for these sources. The data shall be recorded and maintained in a time frame consistent with the averaging period.

 # 013 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The following fuel oil characteristics shall be verified and recorded on a monthly, and an as-delivered, basis:

(a) sulfur content percent, by weight; and
(b) heat content, in MMBtu/gal.

 # 014 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The following daily records for these boilers shall be kept:

(a) fuel consumed, by type and amount;
(b) steam output; and
(c) hours of operation.

Calculations shall be performed monthly, to demonstrate compliance with the 12 consecutive month heat throughput limit, or capacity factor for these auxiliary boilers.

 # 015 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority form 40 CFR § 63.7540(a)(10)(vi).]

(a)The permittee shall keep maintenace reports for maintenance required under Condition #022 of this Group and Section containing the following information on site and available:

(1) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler;

(2) A description of any corrective actions taken as a part of the tune-up; and

SECTION E. Source Group Restrictions.

(3) The type and amount of fuel used over the 12 months prior to the tune-up. Units sharing a fuel meter may estimate the fuel used by each unit.

(b) Records shall be maintained for at least 5 years.

 # 016 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.7555]

Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters.

What records must I keep?

[Additional authority for this permit condition is also derived from 25 Pa. Code 127.441.]

The permittee shall retain the following records:
(a) a copy of each notification and report submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report submitted, according to the requirements in 40 CFR § 63.10(b)(2)(xiv); and
(b) records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in 40 CFR § 63.10(b)(2)(viii).

 # 017 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.7555]

Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters.

What records must I keep?

[Additional authority for this permit condition is also derived from 25 Pa. Code § 127.441.]

For each boiler, you must also keep the following records:
(a) monthly records of fuel use and type for each boiler;
(b) for units in the limited use subcategory, you must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler was operating;
(c) a copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of 40 CFR § 63.7530, that were done to demonstrate continuous compliance with the HCl emission limit, for sources that demonstrate compliance through performance testing;
(d) a copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 of 40 CFR § 63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing;
(e) if, consistent with 40 CFR § 63.7515(b), you choose to stack test less frequently than annually, you must keep a record that documents that your emissions in the previous stack test(s) were less than seventy-five (75) percent of the applicable emission limit, and document that there was no change in source operations including fuel composition that would cause emissions of the relevant pollutant to increase within the past year;
(f) records of the occurrence and duration of each malfunction of the boiler;
(g) records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in 40 CFR § 63.7500(a)(3), including corrective actions to restore the malfunctioning boiler to its normal or usual manner of operation;
(h) records of the calendar date, time, occurrence and duration of each startup and shutdown; and
(i) records of the type(s) and amount(s) of fuels used during each startup and shutdown.

V. REPORTING REQUIREMENTS.

 # 018 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.7550]

Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters.

What reports must I submit and when?

[Additional authority for this permit condition is also derived from 25 Pa.Code § 127.441.]

The permittee shall submit compliance reports according to the following schedule:

Initial report covering the period between January 31, 2016 and June 30, 2016.

Subsequent reports shall cover the periods from July 1 through December 30 and from January 1 through June 30.

SECTION E. Source Group Restrictions.

All reports shall be post marked (or electronically delivered) to the Department and the EPA no later than July 31 (for the period ending June 30) and January 31 (for the period ending December 31).

The compliance report shall contain the following information:
(a) If the facility is subject to a the requirements of a tune up they must submit a compliance report with the following information:
(1) company and Facility name and address;
(2) process unit information, emissions limitations, and operating parameter limitations;
(3) date of report and beginning and ending dates of the reporting period;
(4) the total operating time during the reporting period; and
(5) include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up according to 40 CFR § 63.7540(a)(10), (11), or (12) respectively. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown.
(b) If a facility is complying with the applicable emissions limit with performance testing they must submit a compliance report with the following information:
(1) company and Facility name and address;
(2) process unit information, emissions limitations, and operating parameter limitations;
(3) date of report and beginning and ending dates of the reporting period;
(4) the total operating time during the reporting period;
(5) the total fuel use by each individual boiler or process heater subject to an emission limit within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by the EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure;
(6) if you are conducting performance tests once every three (3) years consistent with 40 CFR § 63.7515(b) or (c), the date of the last two (2) performance tests and a statement as to whether there have been any operational changes since the last performance test that could increase emissions;
(7) if there are no deviations from any emission limits or operating limits, a statement that there were no deviations from the emission limits or operating limits during the reporting period;
(8) if a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken during a malfunction of the boiler to minimize emissions in accordance with 40 CFR § 63.7500(a)(3), including actions taken to correct the malfunction;
(9) if you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent than the level or control technology contained in the notification of compliance status in 40 CFR § 63.7545(e)(5)(i); and
(10) for each deviation from an emission limit or operating limit in this subpart that occurs at an individual boiler or process heater where you are not using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in (i) through (iii), below.
(i) a description of the deviation and which emission limit or operating limit from which you deviated;
(ii) information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken; and
(iii) if the deviation occurred during an annual performance test, provide the date the annual performance test was completed.

VI. WORK PRACTICE REQUIREMENTS.

 # 019 [25 Pa. Code §127.512]
Operating permit terms and conditions.

Fuel oil analysis, or fuel samples shall be provided to the Department, upon request.

 # 020 [25 Pa. Code §127.512]
Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code §§ 129.91, 129.97 and 129.112 .]

NOx emissions from these boilers shall be controlled with Low-NOx burners.

SECTION E. Source Group Restrictions.

 # 021 [25 Pa. Code §127.512]

Operating permit terms and conditions.

These boilers shall be maintained in accordance with requirements of 40 CFR § 63.7540(a)(10). Each boiler shall have an annual tune-up including the following items:

(a) Inspect the burner, and clean or replace any components of the burner as necessary (you may perform the burner inspection any time prior to the tune-up or delay the burner inspection until the next scheduled unit shutdown but not to exceed 36 months from previous inspection) At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment;

(b) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(c) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown but not to exceed 36 months from previous inspection);

(d) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (you may delay the inspection until the next scheduled unit shutdown but not to exceed 36 months from previous inspection);

(e) Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NOX requirement to which the unit is subject; and

(f) Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer.

 # 022 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.7525]

Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters.

What are my monitoring, installation, operation, and maintenance requirements?

[Additional authority for this permit condition is also derived from 25 Pa. Code § 127.441.]

The permittee shall install, operate, calibrate, and maintain the oxygen analyzer systems in accordance with the manufacturer's specifications.

 # 023 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.7530]

Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters.

How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

[Additional authority for this permit condition is derived from 40 CFR 63, Subpart DDDDD, Table 4, and 25 Pa. Code § 127.441.]

The permittee shall maintain the operating load of each unit such that it does not exceed 110 percent of the highest hourly average operating load recorded during the most recent performance test.

The permittee shall maintain the 30-day rolling average oxygen content at or above the lowest hourly average oxygen concentration measured during the most recent CO performance test.

VII. ADDITIONAL REQUIREMENTS.

 # 024 [40 CFR Part 63 NESHAPS for Source Categories §40 CFR 63.7500]

Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial

SECTION E. Source Group Restrictions.

and Institutional Boilers and Process Heaters.

What emission limits, work practice standards, and operating limits must I meet?

The one time energey assessment for these boilers was completed on Septmember 18, 2015 to satisfy the requirements of 40 CFR § 63.7510(e).

***** Permit Shield in Effect. *****

SECTION E. Source Group Restrictions.

Group Name: MAIN BOILERS

Group Description: Large EGU Boilers 4116 MMBtu

Sources included in this group

ID	Name
033	BOILER 3
041	BOILER 4

I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.11]

Combustion units

A person may not permit the emission into the outdoor atmosphere of particulate matter from the stack associated with this boiler in excess of 0.1 lbs/MMBtu of heat input, pursuant to 25 Pa. Code § 123.11(a)(3).

 # 002 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code §§ 129.112(g)(1)(i)-(ii).]

NOx emissions from each boiler in this group shall not exceed any of the following as a daily average:

(1) 0.10 lb NOx/MMBtu heat input when firing natural gas.
(2) 0.12 lb NOx/MMBtu heat input when firing No. 2 fuel oil

When co-firing fuels, the emissions shall be prorated, as described in 40 CFR § 60.44(b), from the above emission limits and the percent heat input for each fuel fired in lb/MMBtu.

[Compliance with the above RACT III NOx emission standards assure compliance with the RACT I NOx emission standards (Condition #002(a) under this source), according to 25 Pa. Code §§ 129.97(a)(1) and 129.97(i); the RACT II NOx emission standards according to 25 Pa. Code §§ 129.97(g)(1)(i) - (ii); and the NOx emissions standards of 40 CFR § 60.44(a)(1)-(2). Additionally, these RACT III limits supersede the limits and requirements under 25 Pa Code §§ 129.201-205.]

 # 003 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code § 129.91.]

NOx emissions from the combined stack, which includes Boilers 3 and 4, shall not exceed any of the following, whichever is more stringent:

(a) 0.29 lbs/MMBtu of heat input as a 30-operating day average;

(1) an operating day is a 24-hour period between midnight and the following midnight during which any fuel is combusted in the steam-generating unit for at least one operating hour;
(2) an operating hour is a clock hour in which any fuel is combusted in the steam-generating unit for at least 45 minutes; and
(3) compliance shall be determined each operating day by calculating the arithmetic average of all hourly emission rates for 30 consecutive operating days, inclusive of the current operating day.

(b) 5568 tons in any 12 consecutive month period.

[Compliance with Section E, Condition #002 which contains RACT III requirements under 25 Pa Code § 129.112 for this source group ensures compliance with this condition.]

SECTION E. Source Group Restrictions.

 # 004 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code §§ 129.91 and 129.114]

The aggregated VOC emissions from the boilers in this group shall not exceed 0.002 lbs/MMBtu, and 35.9 tons in any 12 consecutive month period, whichever is more stringent.

Fuel Restriction(s).

 # 005 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Only #2 fuel oil and/or natural gas shall be burned in these boilers.

Throughput Restriction(s).

 # 006 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The annual heat input for each boiler in the group shall not exceed 17,186,207 MMBtu of heat input as a 12-month rolling aggregate calculated monthly.

 # 007 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority from 40 CFR § 63 Subpart UUUUU]

These boilers meet the definition of limited-use liquid oil-fired units from 40 CFR § 63.10042 by remaining below an annual capacity factor of less than 8% of the nameplate heat input capacity (36,056,160 MMBtu/yr total capacity) when burning when burning No. 2 oil. If the annual heat input to a boiler from No.2 fuel oil exceed 2,884,493 MMBtu annually, that boiler will be subject to the full requirements of 40 CFR Part 63 Subpart UUUUU for continental liquid oil-fired units.

II. TESTING REQUIREMENTS.

 # 008 [25 Pa. Code §127.512]

Operating permit terms and conditions.

A Relative Accuracy Test Audit (RATA) shall be conducted on each CEMs to demonstrate compliance with the performance specifications of the Department's "Continuous Source Monitoring Manual".

III. MONITORING REQUIREMENTS.

 # 009 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Fuel throughput and type, and hours of operation, shall be monitored on a daily basis for each boiler.

 # 010 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Fuel oil sulfur percent content (by weight) and heat content (MMBtu/gal) shall be verified and recorded, in the time-frames prescribed by this permit, for this source.

IV. RECORDKEEPING REQUIREMENTS.

 # 011 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Records, and sufficient calculations, shall be maintained to document compliance with each emission limit for these sources. The data shall be recorded and maintained in a time frame consistent with the averaging period.

 # 012 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Fuel throughput and type, and hours of operation, shall be recorded on a daily basis for each boiler.

SECTION E. Source Group Restrictions.

 # 013 [25 Pa. Code §127.512]
Operating permit terms and conditions.

The NOx emission tracking system shall record, at a minimum, the following information:

(a) heat input (MMBtu/hr) on an hourly basis for each boiler;
(b) hours of operation for each boiler; and
(c) flue flow and flue gas contaminants concentration.

 # 014 [25 Pa. Code §127.512]
Operating permit terms and conditions.

Records of tune-ups perform on each boiler for compliance with 40 CFR Part 63 Subpart UUUUU must be keep onsite documenting the work performed during tune-ups, the pre- and post- CO and NOX concentrations in the exhaust stream, any correction actions taken due to tune-ups, and the types and amounts of fuel use in the 12 months preceding each tune-up.

 # 015 [25 Pa. Code §127.512]
Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code §§ 129.100 and 129.115(b)(4).]

The owner or operator shall demonstrate compliance with the emission limitations under Conditions #001 and 002, for these sources, by operating a CEMS for NOx, in accordance with the following procedures:

(1) Compliance shall be demonstrated using a daily average for RACT III in Condition #001:

(i) The daily average shall be calculated by summing the total pounds of pollutant emitted for the calendar day and dividing that value by the total heat input to the source for the same calendar day for each boiler.

(ii) The daily average for the source shall include all emissions that occur during the entire day, including startup, shutdown and malfunction.

[Compliance with the RACT III requirements ensure compiance with RACT II under 25 Pa Code § 129.100]

 # 016 [25 Pa. Code §127.512]
Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code §§ 129.97,129.100, 129.112 and 129.115]

(a) The permittee shall record data and perform sufficient calculations to demonstrate compliance with each of the emission limits for these sources.

(b) The records shall be retained for 5 years and made available to the Department or appropriate approved local air pollution control agency upon receipt of a written request from the Department or appropriate approved local air pollution control agency.

V. REPORTING REQUIREMENTS.

 # 017 [25 Pa. Code §127.512]
Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR 63, Subpart UUUUU.]

Recordkeeping and reporting requirements shall follow those set forth in the general requirements found in 40 CFR §§ 63.9 and 10 as well as those found in 40 CFR § 63.10031.

 # 018 [25 Pa. Code §127.512]
Operating permit terms and conditions.

[Additional authority from 40 CFR § 63.10031.]

SECTION E. Source Group Restrictions.

Tune-ups must be reported in the quarterly compliance report of the quarter in which it took place. Tune-up date is the date on which the requirements of the tune-up under 63.10021(e) have been completed.

VI. WORK PRACTICE REQUIREMENTS.

 # 019 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The permittee shall use the methods provided in 40 CFR 75.31-33 for NOx emissions and 40 CFR 75 Appendix D for fuel flow to supplement any data not captured by the continuous monitors required for these source. The CEMS, along with any missing data determined under this condition, shall be used to determine compliance with the NOx emission limits for this source.

 # 020 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Continuous Monitors shall be operated and maintained in accordance with the latest applicable version of the Department's "Continuous Source Monitoring Manual", for CO2, NOx, Opacity and fuel flow.

 # 021 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The continuous monitoring system for CO2, opacity, and NOx shall be operated and maintained to achieve the following data availability requirements:

(1) At least 95% valid hours/calendar quarter, or at least 90% valid hours/calendar month, where a valid hour is as defined in the current revision of the Continuous Source Monitoring Manual.

(2) The permittee shall use the method provided in 40 CFR Section 75.31-33 for NOx emissions and 40 CFR 75 Appendix D for fuel flow to supplement any data not captured by the CEMS required for these sources. The CEMS, along with any missing data determined under this condition will be used to determine compliance with the NOx emission limits for these sources.

 # 022 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The NOx analyzer, and Department approved Data Acquisition System, shall quantify emissions in lbs NOx/MMBtu heat input to demonstrate compliance with the NOx emission limit for these sources.

 # 023 [25 Pa. Code §127.512]

Operating permit terms and conditions.

NOx emissions from these boilers shall be controlled by a separate over-fire air (SOFA) system to reduce NOx emissions.

 # 024 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The NOx and fuel flow continuous monitors shall be certified by the Department. The resulting total output of the common stack shall be reported in pounds of NOx per hour. The methods to quantify NOx emissions from the common stack and each individual unit shall be approved by the Department, with the resulting output in lbs/MMBtu.

 # 025 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this permit condition is derived from 40 CFR 63, Subpart UUUUU, Table 3.]

The permittee shall conduct a tune-up on each boiler's EGU burners and combustion controls no more than thirty-six (36) calendar months after the previous tune-up. Tune-up shall include the following as applicable:

(1) Inspection needs to include inspection of the flame pattern and adjustment according to manufacturer specs or best combustion engineering practices.

(2) Inspect the windbox pressures and air proportions and adjust as needed. Repair any dampers, actuators, controls and sensors as needed.

SECTION E. Source Group Restrictions.

(3) Optimize combustion to minimize generation of NOx and CO according to manufacturer's spec or best combustion engineering practices.

(4) Measure the concentration of NOx and CO under full load or predominant operating load before and after the tune-up. If using a neural network optimization system only one pre- and post-tune up measurement is required rather than continuous monitoring.

(5) For repairs: If special parts are needed that impact control of NOx and CO, they must be installed within 3 calendar months after the inspection. Parts not impacting NOx and CO may be installed according to operator's schedule.

 # 026 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this condition from 40 CFR § 72.9(b)]

(a) The permittee shall operate and maintain a CEM system for SO2 in compliance with 40 CFR Part 75 standards.

(b) The permittee may calculate SO2 emissions in accordance with Appendix D to 40 CFR Part 75 when natural gas or No. 2 fuel oil is used as fuel.

 # 027 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code §§ 129.97,129.100 and 129.115]

(a) The permittee shall record data and perform sufficient calculations to demonstrate compliance with each of the emission limits for these sources.

(b) The records shall be retained for 5 years and made available to the Department or appropriate approved local air pollution control agency upon receipt of a written request from the Department or appropriate approved local air pollution control agency.

VII. ADDITIONAL REQUIREMENTS.

 # 028 [25 Pa. Code §127.11a]

Reactivation of sources.

(a) If any of these sources are out of operation for one (1) year or more and less than five (5) years without submission to the Department of a maintenance plan as described in 25 PA Code § 127.11a(a)(1), a plan approval will be required to reactivate the source. Sources out of operation for one (1) year or more and less than five (5) years with an implemented maintenance plan will require a reactivation plan submitted to the Department at least 60 days prior to reactivation date.

(b) If any of these sources are out of operation for at least five (5) years but less than 10 years without the submissions to the Department of a maintenance plan as described in 25 PA Code § 127.11a(a)(1), the source will be considered a new source and subject the requirements applicable to new sources. Sources out of operation for at least five (5) years but less than 10 years with an implemented maintenance plan will not be considered new sources. A plan approval is required to reactivate a source that is out of operation for more than 5 years.

 # 029 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Compliance with the initial tune-up, as required under 40 CFR § 63.10005(f) and due no later October 13, 2015, was demonstrated 6/23/2015 for Boiler 3 (Source ID 033) and 6/24/2015 for Boiler 4 (Source ID 041).

 # 030 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[40 C.F.R. § 52.2040 and 40 C.F.R. §52.2041 (relating to interstate pollutant transport provisions)]

(a) The owner and operator of each NOx or SO2 source located within the State of Pennsylvania and for which requirements are set forth under the Federal CSAPR in 40 C.F.R. Part 97 must comply with such applicable requirements. The obligation to comply with these requirements in Part 97 will be eliminated by the promulgation of an approval by the EPA's Administrator of a revision to the Pennsylvania State Implementation Plan (SIP) as meeting the requirements of CSAPR,

SECTION E. Source Group Restrictions.

except to the extent the EPA Administrator's approval is partial or conditional or unless such approval is under 40 C.F.R. § 51.123 or under 40 C.F.R. § 51.124. Upon the approval of Pennsylvania's State Implementation Plan, the owner and operator shall comply with 25 Pa. Code §§ 145.8 through 145.223.

(b) Notwithstanding any provisions 40 C.F.R. § 52.2040, if, at the time of such approval of the State's SIP, the EPA's Administrator has already allocated CSAPR NOx Ozone Season allowances to sources in the State for any years, the provisions of 40 C.F.R. Part 97 authorizing the Administrator to complete the allocation of CSAPR NOx Ozone Season allowances for those years shall continue to apply, unless the Administrator approves a SIP provision that provides for the allocation of the remaining CSAPR NOx Ozone Season allowances for those years.

 # 031 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Transport Rule (TR) SO2 Group 1 Trading Program requirements (40 CFR § 97.606)]

(a) Designated representative requirements.

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§ 97.613 through 97.618.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each TR SO2 Group 1 source and each TR SO2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§ 97.630 through 97.635.

(2) The emissions data determined in accordance with §§ 97.630 through 97.635 shall be used to calculate allocations of
TR SO2 Group 1 allowances under §§ 97.611(a)(2) and (b) and 97.612 and to determine compliance with the TR SO2 Group 1 emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§ 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) SO2 emissions requirements.

(1) TR SO2 Group 1 emissions limitation.

(i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each TR SO2 Group 1 source and each TR SO2 Group 1 unit at the source shall hold, in the source's compliance account, TR SO2 Group 1 allowances available for deduction for such control period under § 97.624(a) in an amount not less than the tons of total SO2 emissions for such control period from all TR SO2 Group 1 units at the source.

(ii) If total SO2 emissions during a control period in a given year from the TR SO2 Group 1 units at a TR SO2 Group 1 source are in excess of the TR SO2 Group 1 emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each TR SO2 Group 1 unit at the source shall hold the TR SO2 Group
1 allowances required for deduction under § 97.624(d); and

(B) The owners and operators of the source and each TR SO2 Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) TR SO2 Group 1 assurance provisions.

(i) If total SO2 emissions during a control period in a given year from all TR SO2 Group 1 units at TR SO2 Group 1

SECTION E. Source Group Restrictions.

sources in a State (and Indian country within the borders of such State) exceed the State assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO2 emissions during such control period exceeds the common designated representative's assurance level for the State and such control period, shall hold (in the assurance account established for the owners and operators of such group) TR SO2 Group 1 allowances available for deduction for such control period under § 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with § 97.625(b), of multiplying—

(A) The quotient of the amount by which the common designated representative's share of such SO2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the State (and Indian country within the borders of such State) for such control period, by which each common designated representative's share of such SO2 emissions exceeds the respective common designated representative's assurance level; and

(B) The amount by which total SO2 emissions from all TR SO2 Group 1 units at TR SO2 Group 1 sources in the State (and Indian country within the borders of such State) for such control period exceed the State assurance level.

(ii) The owners and operators shall hold the TR SO2 Group 1 allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii) Total SO2 emissions from all TR SO2 Group 1 units at TR SO2 Group 1 sources in a State (and Indian country within
the borders of such State) during a control period in a given year exceed the State assurance level if such total SO2 emissions exceed the sum, for such control period, of the State SO2 Group 1 trading budget under § 97.610(a) and the State's variability limit under § 97.610(b).

(iv) It shall not be a violation of this subpart or of the Clean Air Act if total SO2 emissions from all TR SO2 Group 1 units at TR SO2 Group 1 sources in a State (and Indian country within the borders of such State) during a control period exceed the State assurance level or if a common designated representative's share of total SO2 emissions from the TR SO2 Group 1 units at TR SO2 Group 1 sources in a State (and Indian country within the borders of such State) during a control period exceeds the common designated representative's assurance level.

(v) To the extent the owners and operators fail to hold TR SO2 Group 1 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) of this section,

(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each TR SO2 Group 1 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) Compliance periods.

(i) A TR SO2 Group 1 unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under § 97.630(b) and for each control period thereafter.

(ii) A TR SO2 Group 1 unit shall be subject to the requirements under paragraph (c)(2) of this section for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under § 97.630(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i) A TR SO2 Group 1 allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a

control period in a given year must be a TR SO2 Group 1 allowance that was allocated for such control period or a control period in a prior year.

(ii) A TR SO2 Group 1 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) of this section for a control period in a given year must be a TR SO2 Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each TR SO2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) Limited authorization. A TR SO2 Group 1 allowance is a limited authorization to emit one ton of SO2 during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the TR SO2 Group 1 Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A TR SO2 Group 1 allowance does not constitute a property right.

(d) Title V permit requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of TR SO2 Group 1 allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report SO2 emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under § 75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§ 97.630 through 97.635 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§ 70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§ 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each TR SO2 Group 1 source and each TR SO2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under § 97.616 for the designated representative for the source and each TR SO2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation;
provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under § 97.616 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the TR SO2 Group 1 Trading Program.

(2) The designated representative of a TR SO2 Group 1 source and each TR SO2 Group 1 unit at the source shall make all submissions required under the TR SO2 Group 1 Trading Program, except as provided in § 97.618. This requirement

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does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) Liability.

(1) Any provision of the TR SO2 Group 1 Trading Program that applies to a TR SO2 Group 1 source or the designated representative of a TR SO2 Group 1 source shall also apply to the owners and operators of such source and of the TR SO2 Group 1 units at the source.

(2) Any provision of the TR SO2 Group 1 Trading Program that applies to a TR SO2 Group 1 unit or the designated representative of a TR SO2 Group 1 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the TR SO2 Group 1 Trading Program or exemption under § 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a TR SO2 Group 1 source or TR SO2 Group 1 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

 # 032 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Transport Rule (TR) NOX Ozone Season Trading Program Requirements (40 CFR § 97.806)]

(a) Designated representative requirements.
The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with §§97.813 through 97.818.

(b) Emissions monitoring, reporting, and recordkeeping requirements.

(1) The owners and operators, and the designated representative, of each CSAPR NOX Ozone Season Group 2 source and each CSAPR NOX Ozone Season Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of §§97.830 through 97.835.

(2) The emissions data determined in accordance with §§97.830 through 97.835 shall be used to calculate allocations of CSAPR NOX Ozone Season Group 2 allowances under §§97.811(a)(2) and (b) and 97.812 and to determine compliance with the CSAPR NOX Ozone Season Group 2 emissions limitation and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§97.830 through 97.835 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NOX emissions requirements
(1) CSAPR NOX Ozone Season Group 2 emissions limitation.
(i) As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NOX Ozone Season Group 2 source and each CSAPR NOX Ozone Season Group 2 unit at the source shall hold, in the source's compliance account, CSAPR NOX Ozone Season Group 2 allowances available for deduction for such control period under §97.824(a) in an amount not less than the tons of total NOX emissions for such control period from all CSAPR NOX Ozone Season Group 2 units at the source.

(ii) If total NOX emissions during a control period in a given year from the CSAPR NOX Ozone Season Group 2 units at a CSAPR NOX Ozone Season Group 2 source are in excess of the CSAPR NOX Ozone Season Group 2 emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

(A) The owners and operators of the source and each CSAPR NOX Ozone Season Group 2 unit at the source shall hold the CSAPR NOX Ozone Season Group 2 allowances required for deduction under §97.824(d); and

(B) The owners and operators of the source and each CSAPR NOX Ozone Season Group 2 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

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(2) CSAPR NOX Ozone Season Group 2 assurance provisions.

(i) If total NOX emissions during a control period in a given year from all base CSAPR NOX Ozone Season Group 2 units at base CSAPR NOX Ozone Season Group 2 sources in a State (and Indian country within the borders of such State) exceed the State assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NOX emissions during such control period exceeds the common designated representative's assurance level for the State and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NOX Ozone Season Group 2 allowances available for deduction for such control period under §97.825(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with §97.825(b), of multiplying—

(A) The quotient of the amount by which the common designated representative's share of such NOX emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the State (and Indian country within the borders of such State) for such control period, by which each common designated representative's share of such NOX emissions exceeds the respective common designated representative's assurance level; and

(B) The amount by which total NOX emissions from all base CSAPR NOX Ozone Season Group 2 units at base CSAPR NOX Ozone Season Group 2 sources in the State (and Indian country within the borders of such State) for such control period exceed the State assurance level.

(ii) The owners and operators shall hold the CSAPR NOX Ozone Season Group 2 allowances required under paragraph (c)(2)(i) of this section, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after the year of such control period.

(iii) Total NOX emissions from all base CSAPR NOX Ozone Season Group 2 units at base CSAPR NOX Ozone Season Group 2 sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total NOX emissions exceed the sum, for such control period, of the State NOX Ozone Season Group 2 trading budget under §97.810(a) and the State's variability limit under §97.810(b).

(iv) It shall not be a violation of this subpart or of the Clean Air Act if total NOX emissions from all base CSAPR NOX Ozone Season Group 2 units at base CSAPR NOX Ozone Season Group 2 sources in a State (and Indian country within the borders of such State) during a control period exceed the State assurance level or if a common designated representative's share of total NOX emissions from the base CSAPR NOX Ozone Season Group 2 units at base CSAPR NOX Ozone Season Group 2 sources in a State (and Indian country within the borders of such State) during a control period exceeds the common designated representative's assurance level.

(v) To the extent the owners and operators fail to hold CSAPR NOX Ozone Season Group 2 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) of this section,

(A) The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B) Each CSAPR NOX Ozone Season Group 2 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) of this section and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(3) Compliance periods.

(i) A CSAPR NOX Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(1) of this section for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under §97.830(b) and for each control period thereafter.

(ii) A base CSAPR NOX Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(2) of this section for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under §97.830(b) and for each control period thereafter.

SECTION E. Source Group Restrictions.

(4) Vintage of CSAPR NOX Ozone Season Group 2 allowances held for compliance.

(i) A CSAPR NOX Ozone Season Group 2 allowance held for compliance with the requirements under paragraph (c)(1)(i) of this section for a control period in a given year must be a CSAPR NOX Ozone Season Group 2 allowance that was allocated or auctioned for such control period or a control period in a prior year.

(ii) A CSAPR NOX Ozone Season Group 2 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (c)(2)(i) through (iii) of this section for a control period in a given year must be a CSAPR NOX Ozone Season Group 2 allowance that was allocated or auctioned for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR NOX Ozone Season Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with this subpart.

(6) Limited authorization. A CSAPR NOX Ozone Season Group 2 allowance is a limited authorization to emit one ton of NOX during the control period in one year. Such authorization is limited in its use and duration as follows:

(i) Such authorization shall only be used in accordance with the CSAPR NOX Ozone Season Group 2 Trading Program; and

(ii) Notwithstanding any other provision of this subpart, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR NOX Ozone Season Group 2 allowance does not constitute a property right.

(d) Title V permit requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NOX Ozone Season Group 2 allowances in accordance with this subpart.

(2) A description of whether a unit is required to monitor and report NOX emissions using a continuous emission monitoring system (under subpart H of part 75 of this chapter), an excepted monitoring system (under appendices D and E to part 75 of this chapter), a low mass emissions excepted monitoring methodology (under §75.19 of this chapter), or an alternative monitoring system (under subpart E of part 75 of this chapter) in accordance with §§97.830 through 97.835 may be added to, or changed in, a title V permit using minor permit modification procedures in accordance with §§70.7(e)(2) and 71.7(e)(1) of this chapter, provided that the requirements applicable to the described monitoring and reporting (as added or changed, respectively) are already incorporated in such permit. This paragraph explicitly provides that the addition of, or change to, a unit's description as described in the prior sentence is eligible for minor permit modification procedures in accordance with §§70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B) of this chapter.

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR NOX Ozone Season Group 2 source and each CSAPR NOX Ozone Season Group 2 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i) The certificate of representation under §97.816 for the designated representative for the source and each CSAPR NOX Ozone Season Group 2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under §97.816 changing the designated representative.

(ii) All emissions monitoring information, in accordance with this subpart.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NOX Ozone Season Group 2 Trading Program.

SECTION E. Source Group Restrictions.

(2) The designated representative of a CSAPR NOX Ozone Season Group 2 source and each CSAPR NOX Ozone Season Group 2 unit at the source shall make all submissions required under the CSAPR NOX Ozone Season Group 2 Trading Program, except as provided in §97.818. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in parts 70 and 71 of this chapter.

(f) Liability.

(1) Any provision of the CSAPR NOX Ozone Season Group 2 Trading Program that applies to a CSAPR NOX Ozone Season Group 2 source or the designated representative of a CSAPR NOX Ozone Season Group 2 source shall also apply to the owners and operators of such source and of the CSAPR NOX Ozone Season Group 2 units at the source.

(2) Any provision of the CSAPR NOX Ozone Season Group 2 Trading Program that applies to a CSAPR NOX Ozone Season Group 2 unit or the designated representative of a CSAPR NOX Ozone Season Group 2 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities. No provision of the CSAPR NOX Ozone Season Group 2 Trading Program or exemption under §97.805 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NOX Ozone Season Group 2 source or CSAPR NOX Ozone Season Group 2 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

[Note: On July 6, 2011, EPA promulgated the Cross-State Air Pollution Rule (CSAPR) to replace CAIR. The CSAPR provisions of 40 CFR Part 97, Subpart AAAAA (relating to CSAPR NOx Annual Trading Program), replaced the provisions of 40 CFR Part 96, Subpart AA (relating to CAIR NOx Annual Trading Program General Provisions), and remain in effect. On October 26, 2016, EPA promulgated the CSAPR Update to establish the provisions of 40 CFR Part 97, Subpart EEEEE (relating to CSAPR NOx Ozone Season Group 2 Trading Program), to replace the previously-established CAIR NOx Ozone Season Trading Program and CSAPR NOx Ozone Season Group 1 Trading Program for certain states, including Pennsylvania, beginning with the 2017 ozone season. On April 30, 2021, EPA promulgated the Revised CSAPR Update to establish the provisions of 40 CFR Part 97, Subpart GGGGG (relating to CSAPR NOx Ozone Season Group 3 Trading Program), to replace the provisions of 40 CFR Part 97, Subpart EEEEE, for certain states, including Pennsylvania, beginning with the 2021 ozone season (though DEP will accept CSAPR NOx Ozone Season Group 2 allowances of current year vintage from other states, if available). Accordingly, the permittee shall surrender CSAPR NOx Annual allowances and CSAPR NOx Ozone Season Group 2 allowances, CSAPR NOx Ozone Season Group 3 allowances or CSAPR NOx Ozone Season Expanded Group 2 allowances, as defined in 40 CFR §§ 97.402, 97.802, and 97.1002, respectively, instead of the CAIR NOx allowances and CAIR NOx Ozone Season allowances indicated in 25 Pa. Code § 129.204(c), as the latter are no longer available.]

***** Permit Shield in Effect. *****

SECTION E. Source Group Restrictions.

Group Name: OIL STORAGE

Group Description: No.2 and fuel Oil Storage Tanks

Sources included in this group

ID	Name
122	#2 OIL STORAGE TANK (1.05 MMGAL)
123	FUEL OIL STORAGE TANKS(2)

I. RESTRICTIONS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

 # 001 [25 Pa. Code §127.511]

Monitoring and related recordkeeping and reporting requirements.

Fuel throughput shall be monitored on a weekly basis.

IV. RECORDKEEPING REQUIREMENTS.

 # 002 [25 Pa. Code §127.511]

Monitoring and related recordkeeping and reporting requirements.

Fuel throughput shall be recorded on a weekly basis.

V. REPORTING REQUIREMENTS.

No additional reporting requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VI. WORK PRACTICE REQUIREMENTS.

No additional work practice requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

VII. ADDITIONAL REQUIREMENTS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

***** Permit Shield in Effect. *****

SECTION E. Source Group Restrictions.

Group Name: TURBINES

Group Description: Diesel / Kerosene Peaking Turbines

Sources included in this group

ID	Name
037	NO. 10 COMBUSTION TURBINE
038	NO. 20 COMBUSTION TURBINE
039	NO. 30 COMBUSTION TURBINE
040	NO. 40 COMBUSTION TURBINE

I. RESTRICTIONS.

Emission Restriction(s).

 # 001 [25 Pa. Code §123.13]

Processes

No person may permit the emission into the outdoor atmosphere of particulate matter from these turbines at any time, in excess of 0.027 gr/dscf, pursuant to 25 Pa. Code § 123.13 (c)(1)(ii).

 # 002 [25 Pa. Code §123.21]

General

No person may permit the emission into the outdoor atmosphere of sulfur oxides from these turbines in a manner that the concentration of the sulfur oxides, expressed as SO2, in the effluent gas exceeds 500 parts per million, by volume, dry basis.

Fuel Restriction(s).

 # 003 [25 Pa. Code §127.512]

Operating permit terms and conditions.

Only No. 2 fuel oil, kerosene, or a mixture of kerosene and No.2 fuel oil shall be burned in these turbines.

Throughput Restriction(s).

 # 004 [25 Pa. Code §127.512]

Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code §129.112(c)(9)]

(a) The annual capacity factor for each turbine shall not exceed 5%.

(b) The annual capacity factor is the ratio of the unit's actual electric output (expressed in MWe/hr) to the unit's nameplate capacity [or maximum observed hourly gross load (in MWe/hr) if greater than the nameplate capacity] multiplied by 8,760 hours during a period of 12 consecutive calendar months.

[Compliance with this condition assures compliance with RACT II requirements under 25 Pa. Code §129.97(g)(2).]

II. TESTING REQUIREMENTS.

No additional testing requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

III. MONITORING REQUIREMENTS.

 # 005 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The net electrical power generated (MWH) by each turbine shall be monitored monthly.

 # 006 [25 Pa. Code §127.512]

Operating permit terms and conditions.

The permittee shall monitor the fuel usage and hours of operation for each of these turbines on a monthly basis.

SECTION E. Source Group Restrictions.

IV. RECORDKEEPING REQUIREMENTS.

 # 007 [25 Pa. Code §127.512]
Operating permit terms and conditions.

The following information shall be recorded for each turbine:

(a) certification from the fuel supplier of the type of fuel; and
(b) monthly electrical power (MWe/hr) generated for this turbine.

 # 008 [25 Pa. Code §127.512]
Operating permit terms and conditions.

Sufficient records and calculations shall be performed to demonstrate compliance with each emission limit for each turbine.

 # 009 [25 Pa. Code §127.512]
Operating permit terms and conditions.

For each turbine, the follwoing shallbe recorded:

(a) The net electrical power generated (MWH) shall be recorded monthly.

(b) The annual capacity factor shall be calculated and recorded monthly.

 # 010 [25 Pa. Code §127.512]
Operating permit terms and conditions.

The permittee shall record the fuel usage and hours of operation for each turbine on a monthly basis.

V. REPORTING REQUIREMENTS.

 # 011 [25 Pa. Code §127.512]
Operating permit terms and conditions.

Annual reports of fuel consumption, hours of operation, and megawatts generated by these turbines and generators shall be made available to the Department upon request.

VI. WORK PRACTICE REQUIREMENTS.

 # 012 [25 Pa. Code §127.512]
Operating permit terms and conditions.

[Additional authority for this permit condition is also derived from 25 Pa. Code §§ 129.97(c). and 129.112(c)]

These turbines shall be operated and maintained in accordance with manufacturers specifications and with good operating practices.

 # 013 [25 Pa. Code §129.202]
Stationary combustion turbines.

(a) By October 31 of each year, the permittee shall calculate the difference between the actual emissions from each stationary combustion turbine for the period from May 1 through September 30 and the allowable emissions for that period.

(b) The permittee shall calculate allowable emissions by multiplying the unit's cumulative heat input for the period by the applicable emission rate set forth below

(1) The emission rate for a stationary simple cycle combustion turbine with a nameplate rated capacity of greater than 100 million Btu/hour but less than or equal to 250 million Btu/hour heat input shall be as follows:

(A) When firing natural gas or a noncommercial gaseous fuel, 0.20 lbs NOx/MMBtu or 2.2 lbs NOx/MWH.
(B) When firing oil, 0.30 lbs NOx/MMBtu or 3.0 lbs NOx/MWH.

(2) The emission rate for a stationary combustion turbine with a nameplate rated capacity of greater than 250 million Btu/hour heat input that is not subject to § 145.8(c) or (d) is 0.17 lbs NOx per million Btu heat input.

 # 014 [25 Pa. Code §129.204]
Emission accountability.

SECTION E. Source Group Restrictions.

(a) If the affected source(s) has NOx CEMS, the permittee shall determine actual emissions in accordance with the CEMS data reported to the Department. Any data invalidated under Chapter 139 (relating to sampling and testing) shall be substituted with data calculated using the potential emission rate for the unit or, if approved by the Department in writing, an alternative amount of emissions that is more representative of actual emissions that occurred during the period of invalid data.

(b) If the permittee is not required to monitor NOx emissions with a CEMS, one of the following shall be used to determine actual emissions of NOx:

(1) The 1-year average emission rate calculated from the most recent permit emission limit compliance demonstration test data for NOx.

(2) The maximum hourly allowable NOx emission rate contained in the permit or the higher of the following:

(i) The highest rate determined by use of the emission factor for the unit class contained in the most up-to-date version of the EPA publication, ''AP-42 Compilation of Air Pollution Emission Factors.''

(ii) The highest rate determined by use of the emission factor for the unit class contained in the most up-to-date version of EPA's ''Factor Information Retrieval (FIRE)'' data system.

(3) CEMS data, if the permittee elects to monitor NOx emissions with a CEMS. The permittee shall monitor emissions and report the data from the CEMS in accordance with Chapter 139 or Chapter 145 (relating to interstate pollution transport reduction). Any data invalidated under Chapter 139 shall be substituted with data calculated using the potential emission rate for the unit or, if approved by the Department in writing, an alternative amount of emissions that is more representative of actual emissions that occurred during the period of invalid data.

(4) An alternate calculation and recordkeeping procedure based upon emissions testing and correlations with operating parameters. The permittee shall demonstrate that the alternate procedure does not underestimate actual emissions throughout the allowable range of operating conditions. In regard to obtaining the Department's approval for an alternate calculation method and recordkeeping procedure for actual emissions, the permittee may request an adjustment to the allowable emissions calculations set forth in § § 129.201—129.203. An allowable emission adjustment may not overestimate a unit's allowable emissions and must be based upon the parameters and procedures proposed in the alternate calculation method for actual emissions. The alternate calculation and recordkeeping procedures must be approved by the Department, in writing, prior to implementation.

 # 015 [25 Pa. Code §129.204]

Emission accountability.

(a) The permittee shall surrender to the Department one CAIR NOx allowance and one CAIR NOx Ozone Season allowance, as defined in 40 CFR 96.102 and 96.302 (relating to definitions), for each ton of NOx by which the combined actual emissions exceed the allowable emissions of the units subject to this section at a facility from May 1 through September 30. The surrendered allowances shall be of current year vintage. For the purpose of determining the amount of allowances to surrender, any remaining fraction of a ton equal to or greater than 0.50 ton is deemed to equal 1 ton and any fraction of a ton less than 0.50 ton is deemed to equal zero tons.

(b) If the combined allowable emissions from units subject to this section at a facility from May 1 through September 30 exceed the combined actual emissions from units subject to this section at the facility during the same period, the permittee may deduct the difference or any portion of the difference from the amount of actual emissions from units subject to this section at the permittee's other facilities.

(c) By November 1 of each year, the permittee shall surrender the required NOx allowances to the Department's designated NOx allowance tracking system account and provide to the Department, in writing, the following:

(1) The serial number of each NOx allowance surrendered.
(2) The calculations used to determine the quantity of NOx allowances required to be surrendered.

SECTION E. Source Group Restrictions.

(d) If the permittee fails to comply with subsection (c), the permittee shall by December 31 surrender three NOx allowances of the current or later year vintage for each NOx allowance that was required to be surrendered by November 1 of that year.

(e) The surrender of NOx allowances under subsection (d) does not affect the liability of the permittee for any fine, penalty or assessment, or an obligation to comply with any other remedy for the same violation, under the CAA or the act.

(1) For purposes of determining the number of days of violation, if a facility has excess emissions for the period May 1 through September 30, each day in that period (153 days) constitutes a day in violation unless the permittee demonstrates that a lesser number of days should be considered.
(2) Each ton of excess emissions is a separate violation.

[Note: On July 6, 2011, EPA promulgated the Cross-State Air Pollution Rule (CSAPR) to replace CAIR. The CSAPR provisions of 40 CFR Part 97, Subpart AAAAA (relating to CSAPR NOx Annual Trading Program), replaced the provisions of 40 CFR Part 96, Subpart AA (relating to CAIR NOx Annual Trading Program General Provisions), and remain in effect. On October 26, 2016, EPA promulgated the CSAPR Update to establish the provisions of 40 CFR Part 97, Subpart EEEEE (relating to CSAPR NOx Ozone Season Group 2 Trading Program), to replace the previously-established CAIR NOx Ozone Season Trading Program and CSAPR NOx Ozone Season Group 1 Trading Program for certain states, including Pennsylvania, beginning with the 2017 ozone season. On April 30, 2021, EPA promulgated the Revised CSAPR Update to establish the provisions of 40 CFR Part 97, Subpart GGGGG (relating to CSAPR NOx Ozone Season Group 3 Trading Program), to replace the provisions of 40 CFR Part 97, Subpart EEEEE, for certain states, including Pennsylvania, beginning with the 2021 ozone season (though DEP will accept CSAPR NOx Ozone Season Group 2 allowances of current year vintage from other states, if available). Accordingly, the permittee shall surrender CSAPR NOx Annual allowances and CSAPR NOx Ozone Season Group 2 allowances, CSAPR NOx Ozone Season Group 3 allowances or CSAPR NOx Ozone Season Expanded Group 2 allowances, as defined in 40 CFR §§ 97.402, 97.802, and 97.1002, respectively, instead of the CAIR NOx allowances and CAIR NOx Ozone Season allowances indicated in 25 Pa. Code § 129.204(c), as the latter are no longer available.]

VII. ADDITIONAL REQUIREMENTS.

No additional requirements exist except as provided in other sections of this permit including Section B (Title V General Requirements).

***** Permit Shield in Effect. *****

SECTION F. Alternative Operation Requirements.

No Alternative Operations exist for this Title V facility.

SECTION G. Emission Restriction Summary.

Source Id	Source Description
033	BOILER 3

Emission Limit			Pollutant
0.100	Lbs/MMBTU	firing natural gas, RACT II and III	NOX
0.120	Lbs/MMBTU	firing No. 2 oil, RACT II and III	NOX
0.290	Lbs/MMBTU	Boilers 3 & 4 combined, RACT I	NOX
5,568.000	Tons/Yr	Boilers 3 & 4 combined, RACT I	NOX
0.100	Lbs/MMBTU	Particulate matter per stack	TSP
0.100	Lbs/MMBTU	Particulate matter per stack, combined Boilers 3 & 4	TSP
0.002	Lbs/MMBTU	Boilers 3 & 4 combined emissions	VOC
35.900	Tons/Yr	Boilers 3 & 4 combined emissions	VOC

Source Id	Source Description
034	AUXILIARY BOILER A

Emission Limit			Pollutant
130.000	PPMV	drybasis, corr to 3% O2, or 0.13 lb per MMBtu of steam output. (fuel oil)	CO
130.000	PPMV	drybasis, correct to 3% O2, or 0.13 lb/MMBtu of steam output firing fuel oil	CO
0.001	Lbs/MMBTU	or 1.4E-03 lb per MMBtu of steam output. (fuel oil)	Hydrochloric Acid
0.001	Lbs/MMBTU	or 1.4E-03 lb/MMBtu of steam output firing fuel oil	Hydrochloric Acid
0.005	gr/MMBTU	or 8.8E-07 lb/MMBtu of steam output firing fuel oil	Mercury
0.014	gr/MMBTU	or 2.5E-06 lb per MMBtu of steam output. (fuel oil)	Mercury
0.100	Lbs/MMBTU	Firing natural gas, RACT III	NOX
0.120	Lbs/MMBTU	Firing No. 2 oil, RACT III	NOX
36.000	Tons/Yr		NOX
0.053	gr/MMBTU	1.4E-05 lb per MMBtu of steam output. (natural gas)	SO2
0.008	Lbs/MMBTU	or 9.6E-03 lb/MMBtu of steam output firing fuel oil (filterable PM only)	TSP
0.079	Lbs/MMBTU	or 9.6E-03 lb per MMBtu of steam output (filterable PM only). (fuel oil)	TSP
0.240	Lbs/MMBTU	Particulate Matter	TSP

Source Id	Source Description
035	AUXILIARY BOILER B

Emission Limit			Pollutant
130.000	PPMV	drybasis, corr to 3% O2, or 0.13 lb per MMBtu of steam output. (fuel oil)	CO
130.000	PPMV	drybasis, correct to 3% O2, or 0.13 lb/MMBtu of steam output firing fuel oil	CO
0.001	Lbs/MMBTU	or 1.4E-03 lb per MMBtu of steam output. (fuel oil)	Hydrochloric Acid
0.001	Lbs/MMBTU	or 1.4E-03 lb/MMBtu of steam output firing fuel oil	Hydrochloric Acid
0.005	gr/MMBTU	or 8.8E-07 lb/MMBtu of steam output firing fuel oil	Mercury
0.014	gr/MMBTU	or 2.5E-06 lb per MMBtu of steam output. (fuel oil)	Mercury
0.100	Lbs/MMBTU	Firing natural gas, RACT III	NOX

SECTION G. Emission Restriction Summary.

Source Id	Source Description

0.120	Lbs/MMBTU	Firing No. 2 oil, RACT III	NOX
36.000	Tons/Yr		NOX
0.053	gr/MMBTU	1.4E-05 lb per MMBtu of steam output. (natural gas)	SO2
0.008	Lbs/MMBTU	or 9.6E-03 lb/MMBtu of steam output firing fuel oil (filterable PM only)	TSP
0.079	Lbs/MMBTU	or 9.6E-03 lb per MMBtu of steam output (filterable PM only). (fuel oil)	TSP
0.240	Lbs/MMBTU	Particulate Matter	TSP

036 AUXILIARY BOILER C

Emission Limit			Pollutant
130.000	PPMV	drybasis, corr to 3% O2, or 0.13 lb per MMBtu of steam output. (fuel oil)	CO
130.000	PPMV	drybasis, correct to 3% O2, or 0.13 lb/MMBtu of steam output firing fuel oil	CO
0.001	Lbs/MMBTU	or 1.4E-03 lb per MMBtu of steam output. (fuel oil)	Hydrochloric Acid
0.001	Lbs/MMBTU	or 1.4E-03 lb/MMBtu of steam output firing fuel oil	Hydrochloric Acid
0.005	gr/MMBTU	or 8.8E-07 lb/MMBtu of steam output firing fuel oil	Mercury
0.014	gr/MMBTU	or 2.5E-06 lb per MMBtu of steam output. (fuel oil)	Mercury
0.100	Lbs/MMBTU	Firing natural gas, RACT III	NOX
0.120	Lbs/MMBTU	Firing No. 2 oil, RACT III	NOX
36.000	Tons/Yr		NOX
0.053	gr/MMBTU	1.4E-05 lb per MMBtu of steam output. (natural gas)	SO2
0.008	Lbs/MMBTU	or 9.6E-03 lb/MMBtu of steam output firing fuel oil (filterable PM only)	TSP
0.079	Lbs/MMBTU	or 9.6E-03 lb per MMBtu of steam output (filterable PM only). (fuel oil)	TSP
0.240	Lbs/MMBTU	Particulate Matter	TSP

041 BOILER 4

Emission Limit			Pollutant
0.100	Lbs/MMBTU	firing natural gas, RACT II and III	NOX
0.120	Lbs/MMBTU	firing No. 2 oil, RACT II and III	NOX
0.290	Lbs/MMBTU	Boilers 3 & 4 combined, RACT I	NOX
5,568.000	Tons/Yr	Boilers 3 & 4 combined, RACT I	NOX
0.100	Lbs/MMBTU	Particulate matter per stack	TSP
0.100	Lbs/MMBTU	Particulate matter per stack, combined Boilers 3 & 4	TSP
0.002	Lbs/MMBTU	Boilers 3 & 4 combined emissions	VOC
35.900	Tons/Yr	Boilers 3 & 4 combined emissions	VOC

SECTION G. Emission Restriction Summary.

Source Id	Source Description
037	NO. 10 COMBUSTION TURBINE

Emission Limit		Pollutant
500.000	PPMV	SO2
0.027	gr/DRY FT3	TSP

Source Id	Source Description
038	NO. 20 COMBUSTION TURBINE

Emission Limit		Pollutant
500.000	PPMV	SO2
0.027	gr/DRY FT3	TSP

Source Id	Source Description
039	NO. 30 COMBUSTION TURBINE

Emission Limit		Pollutant
500.000	PPMV	SO2
0.027	gr/DRY FT3	TSP

Source Id	Source Description
040	NO. 40 COMBUSTION TURBINE

Emission Limit		Pollutant
500.000	PPMV	SO2
0.027	gr/DRY FT3	TSP

Site Emission Restriction Summary

Emission Limit	Pollutant

SECTION H. Miscellaneous.

The Department has determined that the emissions from the following activities, excluding those indicated as site level requirements, in Section C, of this permit, do not require additional limitations, monitoring, or recordkeeping:

- Lube oil reservoirs and vents.
- Chemical storage tanks.
- Handling of wet solids.
- Oil-water seperator.
- Chemistry lab vents.
- Miscellaneous delivery truck traffic.

The following previously issued Operating Permits serve as the basis for certain terms and conditions set forth in this Title V Permit:

OP-23-00017A, as amended.

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On October 31, 2000, PECO Energy Co. requested that the Department change their name to Exelon Generation Company, LLC. On March 6, 2001, the Department accepted the name and address change, and the Title V permit has been revised to reflect these changes.

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September 2004. APS No. 346561; Authorization No. 562528: This Title V Permit has been administratively amended to incorporate the requirements of a plan approval (PA-23-0017A) in accordance with 25 Pa. Code § 127.450(a)(5). The plan approval (PA-23-0017A) was for the installation of Selective Non-Catalytic Reduction (SNCR) Systems on Boiler Nos. 1 and 2 (Source ID Nos. 031 and 032). Added requirements include a limit on the amount of ammonia emitted from the stack of 10 ppmdv and monitoring and recordkeeping of the amount of reagent being injected whenever the SNCR Systems are in operation.

Other Administrative Changes Made to This Permit Under This Revision

(a). The Responsible Official Contact information was changed to reflect the current responsible official at this facility.
(b). Section C Condition #021 - The tiered monitoring approach for facility-wide monitoring for odors, visible emissions, and fugitive particulate matter replaces an older version requiring the facility to monitor once per day for odors, visible emissions, and fugitive particulate matter through the effective dates of the permit.
(c). Section C Condition #021 - a reference to another condition number in this permit was removed and replaced by a direct reference to 25 Pa. Code § 123.43.
(d). The phone number for Air Quality was corrected in Section C Condition #029 to reflect the Department's move to the new office building in Norristown, PA.
(e). The response time for the facility to call the Department in case of a malfunction (Section C, Condition #029(a)) was changed from "one hour" to "two hours."
(f). NOx Budget Account Representatives at this facility have changed since the initial issuance of this permit. The permit has been changed to reflect this change in personnel.
(g). For Condition #038 under Source ID No. 031, all scrubber trains are utilized in controlling particulate matter and sulfur dioxide. There is no back-up scrubber. This was incorrectly described in the Title V Permit, and the condition was changed to correctly describe the operation of this source at this facility.
(h). For Source ID Nos. 033 and 041, CEM Systems measure sulfur dioxide emissions for the acid rain program only. References to 25 Pa. Code Chapter 139 were removed since the facility is not required by the Department to monitor and record sulfur dioxide emissions from these sources by using CEMS. CEMS are only used in these sources in the Acid Rain Program.

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December, 2004, APS No.: 570416, AUTH ID: 570461. The Department amended this permit for cause to incorporate the Acid Rain (Title IV) renewal permit into the Title V permit.

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September, 2008. APS: 346561, AUTH: 643648. The Department renewed this permit. No new sources have been added since the last amendment.
- Several new regulations have become applicable, these are: Small NOx regulations for the four (4) turbines, the state's Mercury Rule, and 40 CFR, Subpart 64 (CAM). Sources 031 and 032 are subject to each of these and they have been incorporated into this renewal permit.
- Coal Car Thaw Pit (Source 124) has been removed from the permit at the request of Exelon.
- At the request of DEP Central Office, the Acid Rain (Title IV) permit has been removed from the TVOP and is its own stand-alone operating permit.
- Submittal dates for the annual compliance certification and semi-annual deviation reports have been changed to April 1 and October 1, respectively.

SECTION H. Miscellaneous.

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May, 2008. APS: 346561, AUTH: 711670. Major modification to incorporate the federal CAIR regulations. The Department removed the permit conditions pertaining to mercury as these regulations have been withdrawn.

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November 2013. APS: 346561,AUTH: 971592. Permit renewal.
- The following sources have been shut down and the the ERCs generated: Boiler 1 (source 031) in February 2011, Boiler 2, (Source 032), Centrifuge Dryers (Sources 113 & 114), and the Coal Handling Fugitives (Source F01) all in April 2011. The above shutdowns include the respective control devices for these sources.
- New applicable regulations for this facility include NESHAP DDDDD, UUUUU for the boilers.
- RFDs incorporated are: 699, 1019, 1593, 2091, and 2332.
- Incorporated the Acid Rain Permit (Title IV) ORIS number 3161 into the TVOP.

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February 2015. APS: 346561, Auth: 1059904. Permit amendment to address a change in the federal regulation regarding tuneup date requirements for Sources 031, 032, 033, and 041. This is to match the changes made in 40 CFR § 63.10005(f) for existing EGUs without a neural network..

April 2015. APS: 346561, Auth: 1067454. Administrative amendment to address a change in the responsible official from Paul Weeks to Bryan Bennett.

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December 2015. APS: 346561, AUTH: 1100105. Administrative amendment to address a change in the federal regulations (40 CFR § 63.7510(e), which allows for an additional 180 days to demonstrate initial compliance with the emission limits for Sources 034, 035, and 036, all subject to Subpart DDDDD).

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August 2017. APS: 346561, Auth 1188054. Administrative amendment to address the emission limits and testing for Total Select Metals (TSM) as allowed by 40 CFR 63, Subpart DDDDD.

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March 2019. APS: 346561,AUTH: 1231260. Permit renewal.
- RFD No. 4386 and applicable RACT II requirements are incorporated into the permit.
- Acid Rain Permit (Title IV, ORIS number 3161) is a stand-alone permit issued by DEP effective January 1, 2018 through December 31, 2022. All permit conditions associated with Acid Rain Permit are removed.
- CSAPR conditions are added and CAIR conditions are removed.
- Applicable requirements of 40 CFR Part 63 Subpart DDDDD are added for Sourced ID 042.

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April 2025: AUTH 1450624: APS 346561. Renewal of TVOP. Update of RACT III requirements for all boilers; update of requirements for main boilers under 40 CFR Part 63 Subpart UUUUU; update of requirements for auxiliary boilers under 40 CFR Part 63 Subpart DDDDD.

****** End of Report ******

Exhibit 12

Order No. 202-25-3

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

Emergency Situation

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

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

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

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

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

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

ORDER

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

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

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

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

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

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

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

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

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

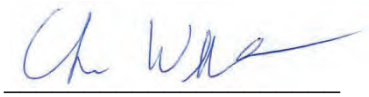
E. The extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.

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

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

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

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



Chris Wright
Secretary of Energy

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

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

Exhibit 13

Order No. 202-25-4

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

Emergency Situation

PJM has recently stated its system faces "growing resource adequacy concern" due to load growth, the retirement of dispatchable resources, and other factors.[1] Upcoming retirements, including the planned retirement of Unit 3 and Unit 4 of the Eddystone Generating Station in Eddystone, Pennsylvania, will exacerbate these resource adequacy issues.

PJM indicates that resource constraints could exist within the service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."[2] In its February 2023 assessment "*Energy Transition in PJM: Resource Retirements, Replacements & Risks*," PJM highlights the increasing risk of reliability risk in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.[3]

In December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."[4] In March 2025 congressional testimony, PJM found "a growing resource adequacy concern" due to a combination of load growth, the retirement of dispatchable resources, and other factors.[5] Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM's interconnection queue.[6]

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[1] https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf
[2] https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/
[3] https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx
[4] https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250211-3120
[5] https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf
[6] Ibid.

Constellation Energy owns the Eddystone Generating Station, which includes Unit 3 and Unit 4, each of which has a nameplate capacity of 380 MW. Units 3 and 4 have a planned retirement date of May 31, 2025. The retirement of these units would further decrease available dispatchable generation within PJM's service territory.

Pursuant to Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid* (EO 14262), DOE is developing a methodology to identify current and anticipated reserve margins for all regions of the bulk-power system regulated by the Federal Energy Regulatory Commission. EO 14262 requires this methodology to be published by July 7, 2025, and be used to establish a protocol to identify which generation resources within a region are critical to system reliability and prevent identified generation resources from leaving the bulk-power system. DOE plans to use this methodology to further evaluate Eddystone Units 3 and 4.

ORDER

Given the emergency nature of resource adequacy concerns, the declared state of national energy emergency, the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, operational availability and economic dispatch of the aforementioned Eddystone Units 3 and 4 (Eddystone Units) is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the potential load stress due to aforementioned resource adequacy concerns, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The potential shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the region support the need for the Eddystone Units to contribute to system reliability.
- PJM's responsibility to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Eddystone Units, necessary to meet the load demands.

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

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse

environmental impacts. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes.

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

A. From the time this Order is issued on May 30, 2025, PJM and Constellation Energy shall take all measures necessary to ensure that Eddystone Units are available to operate. For the duration of this order, PJM is directed to take every step to employ economic dispatch of the units to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.

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

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

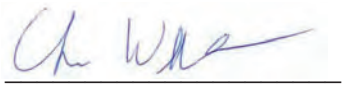
D. By June 15, 2025, PJM is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with the public interest. PJM shall also provide such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

E. In addition, PJM and Constellation Energy are directed to file with the Federal Energy Regulatory Commission any tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

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

G. This Order shall be effective upon its issuance, and shall expire at 5:03 PM EDT on August 28, 2025, with the exception of the reporting requirements in paragraph D.

H. Issued in Simi Valley, California, at 5:03 PM Eastern Daylight Time on this 30th day of May 2025.



Chris Wright
Secretary of Energy

Exhibit 14

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: PJM Interconnection And Constellation Energy	)))))	Order No. 202-25-4

Motion to Intervene and Request for Rehearing of
Natural Resources Defense Council, Citizens for Pennsylvania's Future,
Environmental Defense Fund, Sierra Club and Public Citizen

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I. INTRODUCTION

Pursuant to section 313 of the Federal Power Act ("the Act"), 16 U.S.C. § 825*l*, Natural Resources Defense Council, Citizens for Pennsylvania's Future, Environmental Defense Fund, Sierra Club, and Public Citizen (together "Public Interest Organizations") request that the Department of Energy ("Department" or "DOE") grant rehearing of Order No. 202-25-4 (May 30, 2025) (the "Order").[1] Acting on its own motion and without providing notice, the Department issued the Order on May 30, 2025, pursuant to its emergency authority under section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c) ("Section 202(c)"), to instruct PJM Interconnection, LLC ("PJM") and Constellation Energy Corporation ("Constellation") to "take all measures necessary to ensure that" Units 3 and 4 of the Eddystone Generating Station, in Eddystone, Pennsylvania, ("Eddystone" or the "Eddystone Units"), remain "available to operate" until August 28, 2025, and further directed PJM to "take every step to employ economic dispatch" during that time period. Ex. 1 at 3. Prior to the Department's eleventh-hour intrusion, Constellation was preparing to retire these two oil- and gas-burning units on May 31, 2025, with PJM's approval.

The Department should grant rehearing and rescind this costly, harmful, unnecessary, and unlawful order. There is no energy emergency in the PJM region as defined by Section 202(c). The Eddystone Units were scheduled to deactivate only following analysis showing that this would not cause any transmission

[1] A copy of the Order is attached as Exhibit 1.

instability and that replacement economic capacity resources were available. The result of the Department's overreach will be unnecessary costs imposed on already-overburdened ratepayers, needless pollution emitted into Pennsylvania and neighboring states, and unprecedented interference with regulation of grid resource adequacy, an area Congress reserved for other authorities. 16 U.S.C. § 824(b)(1).

The Order's emergency declaration cannot withstand even the mildest scrutiny. On its face, the Order fails to identify conditions necessary to invoke Section 202(c)'s extraordinary powers, which are reserved for sudden, imminent, and unexpected energy shortages.[2] The Order offers only selective quotes from PJM documents about potential future risks of shortages well outside the 90-day period covered by the Order. In fact, the cited documents refute the Department's conclusory assertions. Nor does the Order's reference to the "declared state of national energy emergency" cure the defect. Ex. 1 at 2. The vague, unsupported assertions in Executive Order ("EO") 14,156 *Declaring a National Energy Emergency* ("Energy Emergency EO")—belied by the U.S. Energy Information Administration's current data[3]—do not override Section 202(c), nor do they supply

[2] As the Department's own regulations emphasize, an "emergency," arises when there is an "unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities," due to weather, acts of God, "sudden" increases in demand, inability to obtain fuel, or a regulatory action prohibiting the use of certain facilities. 10 C.F.R. § 205.371. The Department makes no pretense of identifying these conditions as the bases for the Order.

[3] Indeed, U.S. energy production and exports are currently at an all-time high: Energy Info. Admin., U.S. primary energy production, consumption, and exports increased in 2024 (June 20, 2025), https://www.eia.gov/todayinenergy/detail.php?id=65524.

the specific information needed to support issuance of this Order or any other Section 202(c) order. The Order also refers to EO 14,262 (*Strengthening the Reliability and Security of the United States Electric Grid*) ("Grid EO"), but that order merely directs the Department to develop an as-yet unpublished methodology to analyze grid reliability to support future 202(c) orders, and can't be bootstrapped to supply a *post hoc* basis for this Order.

Even assuming there is an emergency under Section 202(c), the Order also fails to demonstrate that continued operation of the Eddystone Units is the action that "best meet[s] the emergency and serve[s] the public interest." 16 U.S.C. § 824a(c). The Order completely fails to address alternatives to continued operation of the Eddystone Units, including PJM's contracted demand reserve programs,[4] which ensure grid reliability at a lower cost even in the event of historically high demand peaks. Nor does the Order provide sufficiently clear instructions for Constellation and PJM, both as to plant operations and economic dispatch. And compounding these failures, the Order makes no effort to limit the environmental and public health harms that Eddystone imposes on the surrounding communities, despite explicit instruction from Congress to do so.

In short, the Order is an unlawful abuse of the Department's emergency authority and should be rescinded. The statutory bases for issuing an order under

[4] *See* PJM Interconnection, PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing Risk, Inside Lines (May 9, 2025), https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/ (hereinafter "Summer Outlook 2025").

Section 202(c) are not present; and even if they were, the Order would still be unlawful because it fails to comply with the substantive requirements of Section 202(c), resulting in a twofold blow to PJM ratepayers: higher rates and more pollution with no net benefit received. The Department is authorized only to use Section 202(c) for real emergencies, not to usurp authority for grid reliability planning and to prop up fossil fuel businesses.

II. STATEMENT OF ISSUES AND SPECIFICATION OF ERROR

The undersigned Public Interest Organizations move to intervene and request rehearing and a stay pursuant to section 313(a) of the Federal Power Act, 16 U.S.C. § 825*l*(a), and the applicable rules of practice and procedure,[5] based upon the following errors and issues:

- The order exceeds the Department's authority because it has not, and cannot, demonstrate an unexpected emergency under Section 202(c) necessitating continued operation of Eddystone. 16 U.S.C. § 824a(c).

- Section 202(c) only authorizes the Department to respond to specific, imminent, unexpected, and temporary events, not to mandate generation based on longer-term reliability concerns. 16 U.S.C. § 824a(c); H.R. Rep. No. 114-357 § 61002 (2015); *Jarecki v. G.D. Searle & Co.*, 367 U.S. 303 (1961); *Richmond Power & Light of City of Richmond, Ind. v. FERC*, 574 F.2d 610

[5] U.S. Dep't of Energy, DOE 202(c) Order Rehearing Procedures, https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures (last visited June 18, 2025) (attached as Ex. 2) (hereinafter "DOE Rehearing Procedures"). This website was altered after June 18, 2025, and the procedures were removed. *Compare* https://web.archive.org/web/20250604093213/https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures with the current website. *See also* Ex. 3 (Email from Lot Cooke, U.S. Dep't of Energy to Linda Alle-Murphy Re: Rehearing procedures for DOE Order No. 202-05-3 (December 28, 2005)) (recommending that "a party seeking rehearing can look for procedural guidance to [Federal Energy Regulatory Commission's ("FERC")] Rules of Practice and Procedure, 18 CFR Part 385.").

(D.C. Cir. 1978); S. Rep. No. 74-621 (1935); 16 U.S.C. § 824a(a) & (b); *Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232 (8th Cir. 1970); 16 U.S.C. § 824o; 70 Fed. Reg. 53,117; S. Rep. No. 109-78 (2005); *Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009); 16 U.S.C. § 824o(c)-(d); 16 U.S.C. § 824o(a)(3); 16 U.S.C. § 824o(d)(2)-(4); 16 U.S.C. § 824o(e); 16 U.S.C. § 824o(i)-(j); *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120 (2000); *Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395 (D.C. Cir. 2004); 10 C.F.R. § 205.371; 10 C.F.R. § 205.375; 46 Fed. Reg. 39,984; *FTC v. Bunte Brothers, Inc.*, 312 U.S. 349 (1941).

- There is no factual basis supporting the Department's Order. 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371; *Biden v. Nebraska*, 600 U.S. 477 (2023); S. Rep. No. 94-1168 (1976); 1976 U.S.C.C.A.N. 2288; 16 U.S.C. § 824o-1; 16 U.S.C. § 809; 16 U.S.C. § 824a; 50 U.S.C. § 1631; Executive Order 14,156, Declaring a National Energy Emergency, 90 Fed. Reg. 8,433 (Jan, 20, 2025); 42 U.S.C. § 7172; 5 U.S.C. § 706(2)(A); 10 C.F.R. 205.375; *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260 (2016); *Dep't of Homeland Sec. v. Regents of the Univ. of California,* 140 S. Ct. 1891 (2020); Order Accepting Tariff Revisions Subject to Condition, 190 FERC ¶ 61,088 (2025); *Youngstown Sheet & Tube Co. v. Sawyer*, 343 U.S. 579 (1952); *Dept. of Com. v. New York*, 588 U.S. 752 (2019); *Motor Vehicle Mfrs. Ass'n of the U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983); *Amerijet Int'l, Inc. v. Pistole*, 753 F.3d 1343 (D.C. Cir. 2014); *D.C. Fed'n of Civic Ass'ns v. Volpe*, 459 F.2d 1231 (1971).

- The Order will undermine competitive markets to the detriment of consumers and reliability. Executive Order 14,156, Declaring a National Energy Emergency, 90 Fed. Reg. 8,433 (Jan, 20, 2025); 16 U.S.C. § 824a(c); 16 U.S.C. § 824d; Order Terminating Rulemaking Proceeding, Initiating New Proceeding, And Establishing Additional Procedures, 162 FERC ¶ 61,012 (2018); Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996); Order No. 888-A, FERC Stats. & Regs. ¶ 31,048; Order No. 888-B, 81 FERC ¶ 61,248 (1997); Order No. 888-C, 82 FERC ¶ 61,046 (1998); *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000); *New York v. FERC*, 535 U.S. 1 (2002); Order No. 890, FERC Stats. & Regs. ¶ 31,241 (1997); Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999); Order 787, 145 FERC ¶ 61,134 (2013); Order 809, 151 FERC ¶ 61,049 (2015); Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, 149 FERC ¶ 61,145 (2014); Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and EOP-012-1 and Directing Modification of Reliability Standard EOP-012-1, 182 FERC ¶ 61094 (2023); Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification, 187 FERC ¶ 61,204 (2024); Order Accepting Tariff Revisions Subject to Condition, 186 FERC ¶ 61,080 (2024).

- Even if there were a short-term need—there is not—the Order does not comply with the statutory command to set terms that best meet the emergency and serve the public interest. 16 U.S.C. § 824a(c)(1); *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208 (2009); *Sierra Club v. Env't. Prot. Agency*, 353 F.3d 976 (D.C. Cir. 2004); *Dep't of Homeland Sec. v. Regents of the Univ. of Calif.*, 591 U.S. 1 (2020); *Motor Vehicle Mfrs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983); *Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200 (D.C. Cir. 2013); *Chamber of Com. of the U.S. v. Secs. & Exch. Comm'n*, 412 F.3d 133 (D.C. Cir. 2005); 10 C.F.R. § 205.370; 16 U.S.C. § 824a(c); 10 C.F.R. § 205.373; *Wabash Valley Power Ass'n*, 268 F.3d 1105 (D.C. Cir. 2001); *Gulf States Utils. Co. v. Fed. Power Comm'n*, 411 U.S. 747 (1973); *California v. Fed. Power Comm'n*, 369 U.S. 482, 484–86 (1962); *NAACP v. Fed. Power Comm'n*, 425 U.S. 662 (1976); *Otter Tail Power Co. v. United States*, 410 U.S. 366 (1973); *Pa. Water & Power Co. v. Fed. Power Comm'n*, 343 U.S. 414 (1952); 46 Fed. Reg. 39,985.

- Because the order is ambiguous, it fails to provide fair notice to the public and regulated entities and conflicts with limitations on the Department's authority. *Fed. Commc'ns Comm'n v. Fox Telev. Stations, Inc.*, 567 U.S. 239 (2012); *Grayned v. City of Rockford*, 408 U.S. 104 (1972); 16 U.S.C. § 824a(c); *Allentown Mack Sales & Serv., Inc. v. N.L.R.B.*, 522 U.S. 359 (1998).

- The Order fails to provide the conditions necessary to override environmental standards under Section 202(c)(2). 16 U.S.C § 824a(c)(2); *City of New Orleans v. FERC*, 67 F.3d 947 (D.C. Cir. 1995); *Fla. Power & Light Co. v. FERC*, 88 F.3d 1239 (D.C. Cir. 1996); 68 Fed. Reg. 1660.

- The Order and the Department's continued conduct are inconsistent with departmental procedure, depriving the public and the Public Interest Organizations of fair Notice and an adequate record. *Morton v. Ruiz*, 415 U.S. 199 (1974); *Mine Reclamation Corp. v. FERC*, 30 F.3d 1519 (D.C. Cir. 1994); *United States v. Nova Scotia Food Prods. Corp.*, 568 F.2d 240 (2d Cir. 1977).

III. INTERVENORS' INTERESTS

As further discussed below, each of the Public Interest Organizations has interests that may be directly and substantially affected by the outcome of this proceeding. Each party may therefore intervene in this proceeding. DOE Rehearing Procedures; *see also* 18 C.F.R. § 385.214.

Each of the Public Interest Organizations also demonstrate a concrete injury arising from the Order that is redressable by a favorable outcome. Each organization is therefore aggrieved by the Order and may properly apply for rehearing. *See* 16 U.S.C. § 825*l*(a); *Wabash Valley Power Ass'n, Inc. v. FERC*, 268 F.3d 1105, 1112-13 (D.C. Cir. 2001); *NextEra Energy Res. v. ISO New Eng., Inc.*, 157 FERC ¶ 61,059, at P 5 (2016).

A. Natural Resources Defense Council

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

NRDC and its members are aggrieved by the Order. Over 19,800 NRDC members reside in Pennsylvania, over 1,500 NRDC members reside in Delaware, over 9,600 NRDC members reside in Maryland, and 12,600 NRDC members reside in New Jersey. Of these, approximately 1,300 members reside within ten miles of the Eddystone Units. These NRDC members are harmed by the order to operate Eddystone beyond its planned retirement date because continued operation will subject NRDC members to air and water pollution in the areas where they live, work, and recreate. NRDC members are also exposed to the noise and visual

impacts of the plant's operation. The impact of the Order on the health, aesthetic, and recreational interests of NRDC members is compounded by the Order's failure to address the Federal Power Act's requirements for environmental protection that apply even in true emergencies (discussed in section V.G. below). In addition, NRDC members are ratepayers in the PJM region who will be subject to higher electric bills as a result of the Order. NRDC also operates an office in Washington D.C., which is in the PJM region. NRDC pays for the electricity used by its Washington D.C. office and will be subject to higher electric bills as a result of the Order. Moreover, NRDC has a sustainable operations plan with a goal of reducing net creation of greenhouse gas emissions derived from building operational activity to zero. NRDC and its members therefore have a strong interest in promoting actions that displace less cost-effective fossil generation with more cost-effective clean energy.

B. Citizens for Pennsylvania's Future

Citizens for Pennsylvania's Future ("PennFuture") is a Pennsylvania-based statewide environmental organization dedicated to leading the transition to a clean energy economy in Pennsylvania and beyond. PennFuture has approximately 1,000 members across the state. PennFuture's mission is to protect our air, water, and land, and to empower citizens to build sustainable communities for future generations. One focus of PennFuture's work is to address the climate-warming pollution from Pennsylvania's power fleet. PennFuture also works to advance understanding and recognition of Pennsylvania's Environmental Rights Amendment, contained in Article 1, Section 27 of Pennsylvania's Constitution and

to ensure that Commonwealth entities meet their obligations under the Amendment as trustees of Pennsylvania's public natural resources. To promote affordable and clean energy, PennFuture advocates before government entities, including local, state, and federal agencies such as FERC, on issues related to electricity markets, policies affecting the clean energy transition, and just and reasonable rates. This proceeding raises issues which are important to the environmental, public health, and affordability interests that PennFuture seeks to advance.

C. Environmental Defense Fund

The Environmental Defense Fund ("EDF") is a nonprofit membership organization with hundreds of thousands of members nationwide, including more than thirteen thousand members in Pennsylvania, whose mission is to build a vital Earth for everyone by preserving the natural systems on which all life depends. Guided by expertise in science, economics, law, and business partnerships, EDF seeks practical and lasting solutions to address environmental problems and protect human health, including in particular by addressing pollution from the power sector. On behalf of its members, EDF works with partners across the private and public sectors to engage in utility regulatory forums at the federal level and throughout the United States to advocate for policies that will create an affordable, reliable, and low pollution energy system. The Order harms EDF members because it will result in increased pollution that will impact the health of people and nature and because it will increase energy costs for EDF members throughout the PJM region.

D. Sierra Club

Sierra Club and its members are aggrieved by the Order. Over 55,000 Sierra Club members reside in Pennsylvania and New Jersey; and over 4,000 of those members reside in one of the four counties most likely to be impacted by pollution from Eddystone. Sierra Club members are harmed by pollution produced by operating the Eddystone Units. The Order to operate the plant beyond its planned retirement date will subject Sierra Club members to additional air pollution in the areas where they live and recreate. The Order's impact on the health, aesthetic, and recreational interests of Sierra Club members is heightened by the Order's failure to address the Federal Power Act's requirements for environmental protection that apply even in true emergencies. In addition, Sierra Club operates multiple offices in the PJM region, and has well over 100,000 members living in the PJM region, all of whom will be subject to higher electric bills as a result of the Department's Order.

E. Public Citizen

Established in 1971, Public Citizen is a national, not-for-profit, non-partisan, research and advocacy organization representing the interests of household consumers. Public Citizen has over 500,000 members and supporters across the United States, including in PJM and Pennsylvania. Public Citizen is active before FERC promoting just and reasonable rates, and supporting efforts for utilities to be accountable to the public interest. Public Citizen's interests in this proceeding are unique, and cannot be represented by any other party.

IV. BACKGROUND

A. Constellation Energy Group and the Eddystone Plant

The Eddystone Generating Station is owned and operated by Constellation. It is a six-unit, 820 megawatt ("MW") power plant located along the banks of the Delaware River in Eddystone, Pennsylvania, just south of Philadelphia and in the PJM regional transmission organization ("RTO").[6] Units 3 and 4 are both 380 MW capacity steam boiler-turbine generator units that can run on either natural gas or distillate fuel oil. These units were installed between 1967 and 1970 and are "peakers," i.e., units that run only during periods of high demand. The plant also includes two smaller pairs of oil fueled peaking units—Units 10, 20, 30, and 40—which have a total combined capacity of 60 MW that were also installed between 1967 and 1970. Eddystone Units 1 and 2, which operated on coal, were both closed over ten years ago. As shown in Table 1 below, Eddystone Units 3 and 4 have each operated less than 1% of the time during the last four years. In Pennsylvania's restructured utility market, generation units like Eddystone are not committed to serve customers of a particular utility; rather, Constellation submitted offers into regional markets for services that Eddystone was eligible to provide and generated energy or provided other services when those offers were selected by the market mechanism.

[6] Constellation, Eddystone Generating Station, https://www.constellationenergy.com/our-company/locations/location-sites/eddystone-generating-station.html (last visited June 20, 2025).

Table 1						
Capacity Factor	**2020**	**2021**	**2022**	**2023**	**2024**	**Average**
Capacity Factor	0.18%	0.25%	0.27%	0.40%	0.92%	**0.40%**

Sources: EIA, *Form EIA-923: Power Plant Operations Report, Net Generation Data for Eddystone Generating Station*, 2020–2023, https://www.eia.gov/electricity/data/eia923/ (accessed June 20, 2025); EPA, *CEMS Gross Load Data for Eddystone Generating Station*, 2020–2023, CAMPD, https://campd.epa.gov/ (accessed June 20, 2025) (2024 capacity factor estimated using average gross-to-net ratio from 2020–2023).

The Eddystone Units are located just outside of Chester, Pennsylvania, a community that faces one of the nation's worst cases of environmental racism.[7] Whenever it is operating, Eddystone contributes to the pollution impacting this community. On a yearly basis, Eddystone emits thousands of tons of criteria air pollutants, *see* Table 2, and large amounts of water pollutants.[8] And when Eddystone operates on oil rather than natural gas, it emits higher levels of both criteria pollutants and hazardous air pollutants.[9] These air pollutants are linked to

[7] *See* Chester Residents Concerned for Quality Living, https://chesterpaej.org/ (last visited June 26, 2025); University of Pennsylvania, Perelman School of Medicine, Center of Excellence in Environmental Toxicology, *Chester*, http://ceet.upenn.edu/community/target-communities/chester/ (last visited June 26, 2025).

[8] EPA, Pollutant Loading Report, https://echo.epa.gov/trends/loading-tool/reports/dmr-pollutant-loading?permit_id=PA0013714&year=2024 (last visited June 26, 2025) (including over 2 million pounds of total suspended solids, and over 25,000 pounds of ammonia, as well as 1,617 pounds of copper and 564 pounds of lead, in 2024 alone).

[9] Ex. 4 (Eddystone Title V Permit) at 28, 50 (noting sulfur content of oil and higher NOx emissions from oil-fired generation); 68 Fed. Reg. 1660,1678 (Jan. 13, 2003) (noting that switching from oil to natural gas "would reduce mercury, metallic [toxics], and inorganic" hazardous air pollutant emissions).

respiratory symptoms like asthma,[10] cancer, reproductive difficulties, and other health problems.[11]

Table 2						
Annual Emissions	**2020**	**2021**	**2022**	**2023**	**2024**	**Cumulative Emissions**
CO2 (tons)	11,167	14,943	18,636	28,332	58,566	**131,644**
NOx (lbs)	11,918	15,488	20,506	29,606	59,232	**136,750**
SO2 (lbs)	128	176	234	322	704	**1,564**
Source: EPA, *Annual Emissions Data for Eddystone Generating Station*, 2020–2024, available at CAMPD, https://campd.epa.gov/ (accessed June 20, 2025).						

On December 1, 2023, Constellation notified PJM of its intent to deactivate Eddystone Units 3 and 4 effective May 31, 2025.[12] 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."[13] Such a notice triggers PJM's process under Section 113.2 of its Open Access Transmission Tariff to study whether the deactivation will cause any reliability violations. In February 2024, PJM sent a letter to Constellation indicating that it had completed its study and no

[10] EPA, Effects of NO2, Health Effects, https://www.epa.gov/no2-pollution/basic-information-about-no2#:~:text=Health%20effects,more%20about%20Visibility%20and%20Haze; https://www.epa.gov/so2-pollution/sulfur-dioxide-basics (last visited June 26, 2025).

[11] EPA, Health and Environmental Effects of Hazardous Air Pollutants, https://www.epa.gov/haps/health-and-environmental-effects-hazardous-air-pollutants (last visited June 26, 2025).

[12] Letter from Bryan Hanson, Constellation, to Michael Bryson, PJM (Dec. 1, 2023), https://www.pjm.com/-/media/DotCom/planning/gen-retire/deactivation-notices/eddystone-deactivation-letter.pdf.

[13] *Id.*

reliability violations had been identified; PJM granted permission to deactivate "on May 31, 2025, or sooner if desired."[14]

B. How PJM Ensures Resource Adequacy and Reliability

PJM serves as the grid operator for a region that spans all or part of 13 states and the District of Columbia.[15] PJM has established rules and processes for maintaining grid reliability that meet both industry standards and the requirements of the FERC certified Electric Reliability Organization—the North American Electric Reliability Corporation ("NERC")—including through ensuring resource adequacy. Electric utilities and other load-serving entities that have joined PJM comply with those rules and participate in those processes to maintain regional reliability. Many of the utilities in PJM own few or no generation assets and therefore rely substantially on PJM-run markets to procure both energy and other services that support the reliable operation of the grid.

PJM's primary tool to maintain resource adequacy throughout the region, including the state of Pennsylvania, is its Reliability Pricing Model ("RPM"), commonly known as its capacity market, which is designed to ensure there is enough energy supply on the system to meet demand, especially during high-risk

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[14] Letter from Paul McGlynn, PJM, to Bryan Hanson, Constellation (Feb. 27, 2024), https://www.pjm.com/-/media/DotCom/planning/gen-retire/deactivation-notices/pjm-response-letter-eddystone.pdf.

[15] PJM, About PJM, https://www.pjm.com/about-pjm (last visited June 20, 2025).

periods.[16] The capacity market does not pay for energy itself but pays resources for the promise to make a given quantity of energy available for sale at any time over the course of one year (the contracted "delivery year") upon demand of the grid operator.[17] For each "delivery year," which begins June 1, PJM determines the region's "Reliability Requirement" and sub-regional reliability requirements for any "locational deliverability areas" that are transmission-constrained.[18] PJM determines the Reliability Requirement based on a granular risk model of the system that reflects variability in consumer demand as well as the performance of all the supply resources on its system. The determination of the Reliability Requirement includes a forecast of the peak load and the addition of a reserve margin to account for uncertainties, in order to meet the reliability standard set out in PJM's Reliability Assurance Agreement—i.e., a loss of load expectation ("LOLE")

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[16] High risk periods are generally winter storms and hot summer days. *See Advanced Energy Mgmt. All. v. FERC*, 860 F.3d 656, 659-61 (D.C. Cir. 2017); *see also* PJM, PJM Capacity Market: Promoting Future Reliability, https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/pjm-capacity-market-promoting-future-reliability-fact-sheet.pdf (Jan. 25, 2025).

[17] *See* PJM, Capacity Market (RPM) https://learn.pjm.com/three-priorities/buying-and-selling-energy/capacity-markets.aspx (last visited June 26, 2025); FERC, An Introductory Guide to Electricity Markets Regulated by the Federal Energy Regulatory Commission, https://www.ferc.gov/introductory-guide-electricity-markets-regulated-federal-energy-regulatory-commission#_ednref2 (last visited June 26, 2025).

[18] PJM, Manual 18: PJM Capacity Market, Revision 57, at 26 (July 26, 2023), https://www.pjm.com/-/media/DotCom/documents/manuals/archive/m18/m18v57-capacity-market-07-26-2023.pdf.

no greater than one occurrence in ten years.[19] The systemwide Reliability Requirement is the number of megawatts of capacity needed to ensure adequate reserve margins during high-risk periods; Local Reliability Requirements for constrained locational deliverability areas reflect the local capacity needed to ensure adequate reserve margins during high risk periods, when accounting for transmission constraints applicable to that area. Using the same granular risk model, PJM determines the capacity accreditation values for each supply resource on its system—these values represent the amount of capacity, in "unforced capacity" or "UCAP" terms that a resource may offer into the capacity market. Since 2024, PJM has determined these accreditation values using a marginal effective load carrying capability ("ELCC") methodology, that assesses how much adding one additional megawatt of a particular generation type to the system increases the system's ability to serve consumer demand.[20] A generator or demand response resource's marginal ELCC value is expressed as a percentage—the unit can sell capacity equivalent to its nameplate capacity times that percentage. When PJM applied ELCC to oil and gas resources, the capacity accreditation values for these sources decreased from prior values, due to their historically poor performance

[19] *See* PJM Interconnection LLC, 186 FERC ¶ 61,080, at P 2 (2024) (citing PJM Resource Adequacy Planning, 2022 PJM Reserve Requirement Study (Oct. 4, 2022).

[20] *PJM Interconnection, L.L.C.*, 186 FERC ¶ 61,080 (2024) (approving PJM's proposal to adopt use of ELCC methodology for capacity accreditation).

during extreme winter weather.[21] In other words, PJM concluded that oil and gas resources such as Eddystone should be deemed to contribute less to capacity requirements than it previously had assumed.

For each delivery year, PJM conducts a series of auctions to procure commitments from supply resources to provide capacity—to be available to generate power (or curtail power in the case of demand response) when needed by PJM as the system operator. The primary event is the Base Residual Auction, typically held three years in advance of the delivery year. In this auction, supply resources submit offers for the price at which they are willing to sell the quantity of capacity that reflects their ELCC. Demand in the auction is represented by the Variable Resource Requirement Curve, which reflects the administratively determined price that, in PJM's judgment, consumers should be willing to pay to attract sufficient supply to the auction. PJM constructs a supply curve from the sellers' offers. Where this supply curve crosses the demand curve determines the quantity of capacity that will be obligated for the delivery year, as well as the clearing price that will be paid to all sellers that submitted offers at or below that price level. Between the Base Residual Auction and the delivery year, PJM will conduct one or

[21] Ex. 5, Affidavit of Adam Keech on Behalf of PJM Interconnection LLC in *PJM Interconnection, L.L.C.*, FERC Accession No. 20231013-5157 (Oct. 13, 2023) (PJM's filing in the above docket) ¶ 9: "Winter Storm Elliott represents the fifth event where, 'cold weather-related generation outages jeopardized bulk power system reliability,'" (citing FERC, NERC, and Regional Entity Joint Staff Inquiry, December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations, Federal Energy Regulatory Commission, 3 (Sept. 21, 2023), https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott.)

more incremental auctions that allow additional capacity to be procured, or released if the load forecast declines relative to the three-year ahead forecast, and for suppliers to be relieved of their obligations or take on new ones.

In addition to these market mechanisms, RPM also includes a reliability backstop mechanism.[22] As PJM's Senior VP of Markets recently described it, this mechanism exists in part "to resolve reliability criteria violations caused by . . . lack of sufficient capacity committed through the Reliability Pricing Model auctions" and is "intended to guarantee that sufficient generation, transmission and demand response solutions will be available to preserve system reliability."[23]

Load-serving entities in PJM are utilities or competitive retail suppliers that have obligations to serve retail electricity consumers. PJM requires these load-serving entities to purchase an amount of capacity for each delivery year that corresponds to their peak-load contribution—the amount of electricity they serve consumers (the load) during specific times when demand is highest on PJM's system.[24] Load-serving entities have two options for demonstrating compliance—they can either have capacity purchased on their behalf through the auction, or opt out of participation in the auction by meeting 100% of their obligations through a

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[22] *See* PJM Open Access Transmission Tariff, Att. DD, section 16 (Reliability Backstop), https://agreements.pjm.com/oatt/5130.

[23] Prefiled Statement of Adam Keech on Behalf of PJM Interconnection, L.L.C., FERC Docket No. AD25-7, at p. 6 n.7 (June 4, 2025), https://www.ferc.gov/media/adam-keech-pjm-vice-president-market-design-and-economics.

[24] PJM Reliability Assurance Agreement, Rate Schedule FERC No. 44, https://www.pjm.com/pjmfiles/directory/merged-tariffs/raa.pdf.

"Fixed Resource Requirement" plan. Most load-serving entities in PJM, including those that serve load in Pennsylvania, choose the prior option.

PJM is responsible for aspects of reliability beyond resource adequacy. For example, PJM maintains operational reliability of the system on a minute-to-minute basis through its use of security-constrained economic dispatch of generators and energy storage resources on its system.[25] In addition to paying generators for their actual production of electricity in response to PJM's dispatch instructions, PJM also pays generators and storage providers for ancillary services. These services include operating reserves that remain available on short notice to respond to disturbances on the system, such as other generators unexpectedly dropping offline. Market participants utilize PJM's Markets Gateway software system to submit information and otherwise participate in PJM's energy and ancillary service markets.[26]

Another tool that PJM has to maintain reliability and reduce energy costs for consumers is interregional transmission with its neighboring grid regions. As PJM's President recently explained, PJM's "strong interconnected ties with our neighbors have allowed us to facilitate exports to our neighbors in MISO

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[25] PJM, Manual 11: Energy & Ancillary Services Market Operations, Revision 120, at 54 (2022), https://www.pjm.com/-/media/DotCom/documents/manuals/archive/m11/m11v120-energy-and-ancillary-services-market-operations-05-25-2022.pdf. *See* PJM, Understanding the Differences Among PJM's Markets (2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/understanding-the-difference-among-pjms-markets.pdf.

[26] *See* PJM, Markets Gateway, https://www.pjm.com/markets-and-operations/etools/markets-gateway.aspx (last visited June 26, 2025).

[Midcontinent Independent System Operator], TVA [Tennessee Valley Authority], Duke Energy-Carolinas and the Southwest Power Pool (SPP) during tight conditions" and "also enables us to import energy from our neighbors when our system is stressed."[27] PJM incorporates some benefits from these interregional ties into its resource adequacy planning, which reduces the amount of capacity it must procure internally and thus lowers costs for consumers.[28]

Moreover, to ensure the stability of the transmission system when generators deactivate, PJM requires generators to provide advance notice of such deactivations so that PJM can study the impacts and determine whether any system upgrades are needed to maintain the stability of the system upon deactivation. In some cases, these upgrades won't be operational until after the generator's planned deactivation date, in which case PJM will seek to retain the generator to operate under specific conditions through a Part V agreement, commonly known as a reliability-must-run agreement ("RMR"). The Eddystone units were studied under those provisions, and in February 2024, PJM reported that it "did not identify any reliability violations resulting from the proposed deactivation of the Eddystone Generating Units #3&4" and stated that "[b]ecause there are no reliability

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[27] Testimony of Manu Asthana, President and CEO, PJM Interconnection, Before the Subcomm. on Energy of the H. Comm. on Energy & Com. 3 (Mar. 25, 2025), https://docs.house.gov/meetings/IF/IF03/20250325/118040/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf.

[28] Adria Brooks, et al., Resource Adequacy Value of Interregional Transmission at 49-50 (June 2025), https://cleanenergygrid.org/wp-content/uploads/2025/06/250610_RAValueInterregionalTx_Corrections.pdf.

violations associated with the deactivation of this generator…the generating unit may deactivate on May 31, 2025, or sooner if desired."[29]

PJM states retain authority that strongly influences resource adequacy, including authority to approve and site new generation and energy storage projects, and to incentivize the development and utilization of particular types of resources.[30] While some PJM states have retained traditional vertically integrated utilities, others—such as Pennsylvania—have restructured their utilities so that they no longer own generation facilities, and have introduced retail choice to permit end use consumers to purchase power from a load-serving entity other than their utility.[31] Pennsylvania state utility regulators expressly rely on PJM's markets to ensure resource adequacy,[32] while also actively shaping those markets to prioritize

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[29] Letter from PJM to Bryan C. Hanson, Constellation Re: Deactivation Notice for Eddystone Generation Units #3&4 at 1 (Feb. 27, 2024), https://www.pjm.com/-/media/DotCom/planning/gen-retire/deactivation-notices/pjm-response-letter-eddystone.pdf.

[30] *See* 16 U.S.C. § 824(b)(1) (reserving authority over generation facilities to the states); *see also Devon Power LLC et al.,* 109 FERC ¶ 61,154, P 47 (2004) ("Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.").

[31] Electricity Generation Customer Choice and Competition Act, Pa. Code Ch. 28. *See also*, Electric Choice, The Ultimate Guide to Pennsylvania Electricity Deregulation, https://www.electricchoice.com/blog/guide-deregulation-pennsylvania/#:~:text=Pennsylvania%20decided%20in%20favor%20of,save%20$2.5%20billion%20every%20year (last visited June 27, 2025).

[32] *See, e.g.,* Letter from Pennsylvania PUC to PJM Board of Managers 1, (July 7, 2021), https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/20210706-pa-puc-letter-regarding-minimum-offer-price-rule.pdf ("Pennsylvania was one of the first restructured states in PJM that embraced the

affordability.[33] Through a combination of market signals and state policies, Pennsylvania has added nearly 3.5 gigawatt ("GW") UCAP of capacity, net of retirements, since 2015—the most of any state in PJM.[34]

C. The Department's May 30, 2025 202(c) Order and PJM's June 13 Letter

On May 30, 2025, the Department issued the Order based on its "determin[ation] that an emergency exists in portions of the electricity grid operated by PJM due to a shortage of facilities for the generation of electric energy, resource adequacy concerns, and other causes." Ex. 1 at 1. The Order provides a brief, general description of the "Emergency Situation" based primarily on PJM public statements and regulatory filings referring to a "growing resource adequacy concern" that PJM asserts will arise by the end of the decade due to exceptional load growth and a rate of new entry that is inadequate to replace resource

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promise of competition in the wholesale generation market and then spent considerable time and effort developing a burgeoning retail electricity market built on the expectations and benefits of a properly functioning wholesale market."); *see also* Comments of the Pennsylvania Public Utility Commission, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, AD13-7-000 (Jan. 8, 2014), https://www.puc.pa.gov/General/pdf/FERC/DN_AD13-7-000.pdf.

[33] *See, e.g.*, Pa. PUC Dkt. No. M-2024-3051988 (hosting a technical conference and collecting extensive public comments regarding steps the PUC can take to ensure resource adequacy for retail customers), https://www.puc.pa.gov/filing-resources/issues-laws-regulations/technical-conference-on-resource-adequacy/; Pa. PUC, Technical Conference on Resource Adequacy, https://www.puc.pa.gov/filing-resources/issues-laws-regulations/technical-conference-on-resource-adequacy/ (last visited June 26, 2025).

[34] Prefiled Statement of Manu Asthana on Behalf of PJM Interconnection, L.L.C., at 9, Table 2, Meeting the Resource Adequacy Challenge in RTOs/ISOs, FERC Dkt. No. AD25-7 (May 20, 2025) (Acc. No. 20250520-5173).

retirements. *Id.* The "declared state of national energy emergency" is also cited as a basis for the Department's determination of an emergency. The Department asserts that the retirement of the Eddystone Units would "further decrease available dispatchable generation within PJM's service territory" and therefore exacerbate these general issues. *Id.* at 2. The Order was effective immediately, expiring at 5:03 pm ET on August 28, 2025. *Id.* at 3.

Based on this determination, the Department orders Constellation to take all measures necessary to ensure that the Eddystone Units are available to operate and orders PJM to take steps to employ economic dispatch for the Units. *Id.* The Order includes various reporting requirements and instructs PJM and Constellation to file tariff revisions or waivers necessary to effectuate the order. *Id.*

The Order also requires PJM, by June 15, 2025, to provide the Department "with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with the public interest." *Id.* PJM published the letter it provided to the Department on June 13, 2025.[35] That letter indicates that PJM has worked with Constellation to develop an Operations Memorandum setting out the circumstances in which Eddystone can be committed to run. In a summary of that Memorandum, PJM states that Constellation "will maintain active cost offers in Markets Gateway that

[35] Letter from Michael Bryson, PJM, to Secretary of Energy Christopher Wright, PJM Report in Compliance with Ordering Paragraph D of the Department of Energy's May 30, 2025 Order No. 202-25-4 (June 13, 2025), https://www.pjm.com/-/media/DotCom/documents/other-fed-state/20250613-doe-pjm-report-on-compliance-with-Eddystone-order-202-25-4.pdf.

reflects the prevailing costs . . . to operate on gas or oil for both Eddystone 3 and 4, unless either fuel is unavailable or if the units are on a Planned, Maintenance or Forced outage," but that "[t]he units will be shown as 'unavailable' until PJM operators direct the units" to operate "for reliability purposes."[36] Those purposes include: (1) supporting the PJM system operation within established thermal, voltage, and stability limits, when these needs "cannot otherwise be met with available economically dispatched generating resources;" (2) system restoration needs; and (3) a Capacity Emergency, during which "PJM determines that the resources scheduled for an operating day are not sufficient to maintain the appropriate reserve levels for PJM."[37]

PJM's June 13 letter to the Department expresses PJM's "understanding that the Eddystone Units have been available to operate, consistent with the DOE Order, since the order's issuance on May 30, 2025."[38] It also states that "PJM and [Constellation] have coordinated, pursuant to existing generation outage coordination practices and procedures, outages needed by the Eddystone Units to ensure their operational availability consistent with the public interest."[39] A Constellation's spokesperson has publicly stated that, "we are working quickly to

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[36] PJM, Eddystone 3 and 4 Unit Reporting and Commitment Process (June 12, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/postings/20250612-eddystone-3-and-4-unit-reporting-and-commitment-process.pdf.

[37] *Id.*

[38] *Id.*

[39] *Id.* at 3.

retain necessary staff and perform necessary maintenance to allow for safe and reliable operations this summer and beyond."[40]

V. REQUEST FOR REHEARING

A. The Order Exceeds the Department's Authority Because It Has Not, and Cannot, Demonstrate an Unexpected Emergency Under Section 202(c) Necessitating Continued Operation of Eddystone.

Section 202(c) confers an extraordinary power; it permits the Department to command action from market participants and to do so freed from core procedural safeguards, jurisdictional boundaries, and substantive limitations that undergird the rest of the Federal Power Act. *See* 16 U.S.C. § 824a(c). It comes as no surprise, then, that when Congress granted this power, Congress narrowly tailored its use to extraordinary circumstances. Simply, the Order here exceeds the Department's authority because this is not one of those extraordinary circumstances. There is no emergency within the meaning of Section 202(c).

The Order fails to meet the standards of Section 202(c) both because the Department does not demonstrate that any emergency currently exists and because the resource adequacy concerns it does describe are long-term concerns, that no one has even alleged, much less provided a credible projection, will ripen into actual supply shortages within the ninety-day term of the Order. As detailed *infra*, Section V.B, Section 202(c) provides the Department with a limited authority to

[40] Jon Hurdle, Aging Pennsylvania Power Plant to Keep Running after Trump Order on Eve of Shutdown, Pennsylvania Capital-Star (June 9, 2025), https://penncapital-star.com/energy-environment/aging-pennsylvania-power-plant-to-keep-running-after-trump-order-on-eve-of-shutdown/.

address immediate electric supply shortages to meet emergency conditions; it does not authorize the Department to address long-term energy system shifts by appointing itself the central planner and supplanting the decisions of participants in an organized electric market. Yet here, even though the Department claims that the "Order is limited in duration to align with the anticipated emergency circumstances," Ex. 1 at 2, the Department offers no evidence of an emergency in the specified period. The Order speaks only of "growing resource adequacy *concern*," resource adequacy constraints that "*could* exist," and the "increasing risk of reliability risk in *the coming years*." Ex. 1 at 1 (emphasis added).

In fact, the results of the 2025-2026 Base Residual Auction demonstrate that the PJM grid has more than enough committed capacity to offer reliable service throughout Summer 2025 without the need for the Eddystone Units, and even if there were to be supply shortages, PJM has mechanisms to handle them.[41] Furthermore, PJM has rules and processes in place to ensure long-term reliability even as shifts occur in electric demand and resource availability, and has access to a number of both short-term and long-term tools that are better suited to address long-term resource adequacy concerns than an unlawful Section 202(c) Order.[42]

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[41] Summer Outlook 2025, *supra* n. 4.

[42] PJM Interconnection, LLC, PJM Capacity Market: Promoting Future Reliability (2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/pjm-capacity-market-promoting-future-reliability-fact-sheet.pdf.

B. Section 202(c) Only Authorizes the Department to Respond to Specific, Imminent, Unexpected, and Temporary Events, Not to Mandate Generation Based on Longer-Term Reliability Concerns.

The plain language and structure of Section 202(c), the legislative history for the provision, the Federal Power Act overall, as well as case law interpreting Section 202(c), the Department's regulations, and its historic use of Section 202(c) all establish that an "emergency" under Section 202(c) must be sudden, unexpected, imminent, and specific.

1. Section 202's Text and Structure Establish that Emergency Authority Can Only Be Invoked to Address Imminent, Certain Supply Shortfalls Requiring Immediate Response.

Section 202(c)'s text and context confirm that it provides only authority to address imminent, near-term, and exigent electricity supply shortfalls requiring immediate response; it does not permit the Department to act based merely on concerns over long-term reliability. Had Congress intended to vest regulatory authority over long-term reliability in Section 202(c), it would have stated so clearly. But it did not.[43]

The statute's text empowers the Department to act only upon "emergency." 16 U.S.C. § 824a(c). The statute itself does not define "emergency." At the time Congress enacted Section 202(c), Webster's New International Dictionary of the English Language (1930) defined "emergency" as a "*sudden* or *unexpected*

[43] Congress amended Section 202(c) in 2015, but it did not alter the description of conditions that trigger the Department's grant of authority to issue emergency orders; it only addressed occasions on which a Department order might produce a conflict with other laws. *See* H.R. Rep. No. 114-357 § 61002 (2015).

appearance or occurrence… An *unforeseen* occurrence or combination of circumstances which calls for *immediate* action or remedy; *pressing* necessity; exigency." (emphasis added).[44] Contemporary dictionaries similarly define "emergency" as demanding imminence: an emergency is "an *unforeseen* combination of circumstances or the resulting state that calls for *immediate* action."[45]

The remainder of Section 202(c) underscores the exigency inherent in the governing term "emergency": the authority granted by Section 202(c) is, in the first instance, a wartime power. 16 U.S.C. § 824a(c) (beginning with "[d]uring the continuance of any war in which the United States is engaged"); *see Jarecki v. G.D. Searle & Co.*, 367 U.S. 303, 307 (1961) (noting that statutory terms should be interpreted in the context of nearby parallel terms "in order to avoid the giving of unintended breadth to the Acts of Congress"). An "emergency" under the statute is limited to circumstances of similar urgency: "a *sudden* increase in the demand for electric energy," for example. 16 U.S.C. § 824a(c) (emphasis added); *see Richmond Power & Light of City of Richmond, Ind. v. FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978) (holding that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances"); S. Rep. No. 74-621, at 49 (1935) (explaining that Section

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[44] *See also* 3 Oxford English Dictionary 119 (1st ed. 1913) (defining emergency similarly as "a state of things unexpectedly arising, and urgently demanding immediate action" (emphasis added).

[45] *Emergency*, Merriam-Webster Dictionary, https://www.merriam-webster.com/dictionary/emergency (last visited June 27, 2025) (emphasis added)); *See also* Benjamin Rolsma, The New Reliability Override, 57 Conn. L. Rev. 789, 812 n.147 (2025) (noting that dictionaries have given the term "emergency" the "same meaning for many years").

202(c) provides "temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose").

The text's use of the present tense also underscores that focus on imminent and certain shortfalls: it empowers the Department to act only where "an emergency *exists*." 16 U.S.C. § 824a(c) (emphasis added). That near-term focus, along with the statute's strictly "temporary" authority, 16 U.S.C. § 824a(c), precludes use of Section 202(c) to pursue long-term policy goals, such as a preference for a particular fuel source. *Richmond Power & Light*, 574 at 615 (Section 202(c) "is aimed at situations in which demand for electricity exceeds supply and not those in which supply is adequate but a means of fueling its production is in disfavor.").

Section 202's overall structure further highlights Section 202(c)'s emphasis on imminent, near-term concerns. The preceding subsections 202(a) and (b) together define and limit the tools by which the federal government may pursue "abundant" energy supplies in the normal course. 16 U.S.C. § 824a(a) (seeking "abundant supply of electric energy" by directing the federal government to "divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy") & § 824a(b) (allowing the federal government to order "physical connection . . . to sell energy or to exchange energy" upon application, and after an opportunity for hearing). The resulting statutory "machinery for the promotion of the coordination of electric facilities" comprises the following: in subsection (a), an

instruction to establish a general framework meant to facilitate "coordination by voluntary action;" in subsection (b), "limited authority to compel interstate utilities to connect their lines and sell or exchange energy," subject to defined procedural and substantive requirements, when "interconnection cannot be secured by voluntary action;" and in subsection (c), "much broader" but "temporary" authority "to compel the connection of facilities and the generation, delivery, or interchange of energy during times of war or other emergency." S. Rep. No. 74-621 at 49 (1935).

That tiered structure—relying on voluntary action for quotidian energy planning, specifying limited authority where that voluntary system fails, and allowing for "temporary" central command-and-control only in case of "emergency"—requires that Section 202(c) remain narrowly bounded to instances of an immediate and unavoidable "break-down in electric supply," *id.*, rather than mere want of more abundant supply in the future, *cf.* Ex. 1 at 2 (imposing responsibility on PJM "to ensure maximum reliability on its system"). Interpreting Section 202(c)'s "emergency" powers to encompass longer-term concerns—e.g., potential shortfalls years into the future—would unwind the careful balance of voluntary, market-driven action and federal power set out in subsections 202(a) and 202(b). *See infra*, Section V.D. Such an interpretation cannot be squared with the statutory text and structure. *See Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232, 233-34 (8th Cir. 1970) (holding that Section 202(c) "enables the Commission to react to a war or national disaster," while Section 202(b) "applies to a crisis which is likely to develop in the foreseeable future").

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

That Section 202(c) cannot be used to enforce the Department's view of long-term reliability needs is confirmed by Section 215 of the Federal Power Act—which specifically and directly delineates the scope of federal power to enforce mandatory long-term reliability requirements. 16 U.S.C. § 824o ("Section 215"). Congress added Section 215 to the Federal Power Act in 2005 precisely because the Act as it then existed—including Section 202(c)—did not provide the federal government with the power to enforce measures designed to ensure broad, long-term reliability. *See* 70 Fed. Reg. 53,117, 53,118 ("In 2001, President Bush proposed making electric Reliability Standards mandatory and enforceable," leading to enactment of Section 215 in 2005); Report of the National Energy Policy Development Group (May 2001) at p. 7-6[46] (noting that "[r]egional shortages of generating capacity and transmission constraints combine to reduce the overall reliability of electric supply in the country" and that "[o]ne factor limiting reliability is the lack of enforceable reliability standards" because "the reliability of the U.S. transmission grid has depended entirely on *voluntary* compliance," and then recommending "legislation providing for enforcement" of reliability standards) (emphasis added); S. Rep. No. 109-78 at 48 (2005) (Section 215 "changes our current voluntary rules system to a mandatory rules system" for long-term reliability). *See Alcoa, Inc. v. FERC*, 564 F.3d 1342, 1344 (D.C. Cir. 2009) (noting that prior to the Energy Policy Act of 2005,

[46] https://www.nrc.gov/docs/ml0428/ml042800056.pdf.

"the reliability of the nation's bulk-power system depended on participants' voluntary compliance with industry standards").

By enacting Section 215, Congress provided a comprehensive and carefully circumscribed scheme to empower the federal government to enforce long-term reliability requirements. That statutory scheme strikes a careful balance between state and federal authority, and between private, market-driven decisions and top-down control. Reliability standards are devised by NERC independent "of the users and owners and operators of the bulk-power system" but with "fair stakeholder representation." 16 U.S.C. § 824o(c)-(d). *See also id.* 824o(a)(3) (defining reliability standards as "a requirement … to provide for reliable operation of the bulk-power system"). FERC may approve or remand those standards (but not replace them with its own) and is required to "give due weight" to NERC's "technical expertise" while independently assessing effects on "competition." *Id.* § 824o(d)(2)-(4). Section 215 provides specified enforcement mechanisms and procedures for reliability standards. *Id.* § 824o(e). And it carefully preserves state authority over "the construction of additional generation" and in-state resource adequacy, establishing regional advisory boards to ensure appropriate state input on the administration of reliability standards. *Id.* § 824o(i)-(j).

Interpreting Section 202(c) to permit the Department to mandate generation based on its declaration that non-imminent reliability concerns create an "emergency" would effectively allow the Department to bypass Section 215's procedural safeguards, constraints on federal authority, and protection of state

power. Such a bypass would impermissibly "contradict Congress' clear intent as expressed in its more recent," reliability-specific "legislation," enacted "with the clear understanding" that the Department had "no authority" to address long-term reliability through Section 202(c). *See FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 142 & 149 (2000); s*ee also Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 401–02 (D.C. Cir. 2004) ("Congress's specific and limited enumeration of [agency] power" over a particular matter in one section of the Federal Power Act "is strong evidence that [a separate section] confers no such authority on [agency]."). Congress has, in Section 215, directly established the mechanisms (and limitations) by which the federal government may compel action to ensure long-term electric-system reliability. In so doing, it has confirmed that the word "emergency," in Section 202(c), does not extend to long-term reliability concerns.

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

The Department's regulations demonstrate its own long-standing understanding that Section 202(c)'s authority is confined to imminent and unavoidable resource shortages, rather than long-term reliability concerns. The regulations define an emergency as "an *unexpected* inadequate supply of electric energy which may result from the *unexpected* outage or breakdown" of generating or transmission facilities—not a means of planning against distant expectations or risks. 10 C.F.R. § 205.371 (emphasis added). Emergencies "may result" from a number of events. *Id.* ("may result from the unexpected outage," "may be the result of weather conditions," "can result from a sudden increase in customer demand").

The use of the verb "result," defined as "arise as a consequence, effect, or conclusion,[47] suggests that the event triggering the emergency has already happened rather than that there is a speculation that it could occur. Moreover, the events are characterized by those produced by "weather conditions, acts of God, or *unforeseen* occurrences not reasonably within the power of the affected 'entity' to prevent," *id.* (emphasis added), not an event that can be planned for because there is a forecasted risk. Where the culprit is increased demand, it must be "a *sudden* increase in customer demand" producing a "*specific* inadequate power supply situation," *id.* (emphasis added), rather than long-term demand projections producing general reliability concerns. The need for both specificity and certainty is repeated in the Department's regulations defining an inadequate energy supply: "A system may be considered to have" inadequate supply when "the projected energy deficiency... *will* cause the applicant [for a 202(c) Order] to be unable to meet its normal peak load requirements based upon use of all of its otherwise available resources so that it *is* unable to supply adequate electric service to its customers." 10 C.F.R. § 205.375 (emphasis added).

And while the regulations suggest that "inadequate planning or the failure to construct necessary facilities *can result* in an emergency," they recognize that the Department may not utilize a "continuing emergency order" to mandate long-term system planning. 10 C.F.R. § 205.371 (also recognizing that "where a shortage of

[47] *Result*, Merriam-Webster Dictionary, https://www.merriam-webster.com/dictionary/result (last visited June 27, 2025).

electricity is projected due solely to the failure of parties to agree to terms, conditions, or other economic factors" there is no emergency "unless the inability to supply electric service is *imminent*") (emphasis added). An emergency may exist where past planning failures produce an immediate, present-tense shortfall (that is where, a shortfall *results* from insufficient planning); the Department has no authority to commandeer long-term planning merely because it deems current plans inadequate to meet far-distant needs. *See* 10 C.F.R. § 205.375 (requiring present inability to meet demand to demonstrate inadequate energy supply). As the Department stated when it promulgated those regulations, the statute allows the Department to provide "assistance [to a utility] during a period of unexpected inadequate supply of electricity," but does not empower it to "solve long-term problems." 46 Fed. Reg. 39,984, 39,985–86 (Aug. 6, 1981).

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

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

Richmond Power and Light of City of Richmond, Indiana v. FERC, 574 F.2d 610 (D.C. Cir. 1978) arose out of the 1973 oil embargo. The Federal Power Commission ("Commission") needed to decide how to respond to oil shortages, and decided to call for the voluntary transfer of electricity from non-oil power plants to areas of the country that relied heavily on oil, such as New England. *Id.* at 613. The New England Power Pool was not convinced that the voluntary program would

work and petitioned the Commission for a 202(c) order. *Id.* The Commission instead facilitated an agreement between state commissions and supplying utilities, which satisfied the New England Power Pool and it withdrew its petition. *Id.* A dissatisfied utility sought judicial review of the Commission's decision to allow the withdrawal of the Section 202(c) petition. *Id.* at 614.

The court easily upheld the Commission's decision not to invoke Section 202(c). *Id.* Though the oil embargo had ended, the utility argued that the "high cost and uncertain supply of imported oil" justified an emergency order. *Id.* The Commission countered that the voluntary program had worked, the New England Power Pool never interrupted service, and there was no need for a Section 202(c) order. *Id.* at 615. The court agreed with the Commission. *Id.*

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

The Eighth Circuit has similarly held that Section 202(c) can only be used to respond to immediate crises. In *Otter Tail Power Co. v. Federal Power Commission*, 429 F.2d 232 (8th Cir. 1970), a utility insisted that the only way for the Commission

to properly order the utility to connect to a municipal power provider was to issue a Section 202(c) order. Demand for electricity in the city had increased, and the peak load of the municipal power provider was getting to be so high that both of its two generators would likely need to be used simultaneously in the near future, "causing a possible loss of service should one malfunction during a peak period." *Id.* at 233-34. To avoid this possible loss of service, the Commission issued a Section 202(b) order, requiring the utility to connect the municipal power provider. *Id.* at 234. The utility argued that the Commission used the wrong section and should have used Section 202(c) instead. *Id.*

The court explained that Section 202(c) "enables the Commission to react to a war or national disaster" by ordering "immediate" interconnection during an "emergency." *Id.* (citing 16 U.S.C. § 824a(c)). For non-emergency situations, "[o]n the other hand, § 202(b) applies," including when there is a "crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission." *Id.* The court upheld the Commission's use of Section 202(b) instead of Section 202(c) because there was no immediate emergency.

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

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

The Department's consistent application of Section 202(c) further corroborates the urgency of the conditions necessary to invoke the provision. *See FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941) ("[J]ust as established

practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred."). The Department has only ever used Section 202(c) to address specific, imminent, and unexpected shortages—never to address longer-term reliability concerns or demand forecasts. *See, e.g.,* Ex. 6, Department of Energy Order No. 202-22-4 (Dec. 24, 2022) (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between December 23 and December 26); Ex. 7, Department of Energy Order 202-20-2 (Sept. 6, 2020) at 10-2 (responding to shortages produced by ongoing extreme heat and wildfires); *see also* Rolsma, 57 Conn. L. Rev. at 803-4 (describing "sparing[]" use of Section 202(c) outside of wartime shortages during the twentieth century). The Department has also narrowly tailored the remedies in Section 202(c) orders to ensure that the orders only address the stated emergency, to limit the order to the minimum period necessary, and to mitigate violations of environmental requirements and impacts to the environment. *See, e.g.*, Ex. 6, Department of Energy Order No. 202-22-4 (Dec. 24, 2022) at 4-7 (limiting order to the 3 days of peak load, directing PJM to exhaust all available resources beforehand, requiring detailed environmental reporting, notice to affected communities, and calculation of net revenue associated with actions violating environmental laws); Ex. 7, Department of Energy Order 202-20-2 (Sept. 6, 2020) at 3-4 (limiting order to the 7 days of peak load, directing CAISO to

exhaust all available resources beforehand, requiring detailed environmental reporting).

Public Interest Organizations are not aware of any instance in which the Department has utilized Section 202(c) to mandate generation the Department views as necessary to ensure long-term resource sufficiency, or to retain fuel sources that the Department believes beneficial, *Richmond Power and Light,* 574 F.2d at 616—and for good reason.

C. There Is No Factual Basis Supporting the Department's Order.

The Department asserts that the Order is justified by "the declared state of national energy emergency" and "resource adequacy concerns." Ex. 1 at 2. However, the Department fails to demonstrate that either of these factors constitutes an emergency under Section 202(c). 16 U.S.C. § 824a(c). No agency can lean exclusively on a Presidential declaration of an emergency; emergency authority is circumscribed by the authority granted by Congress. Further, a broad, generic declaration of a national emergency is not sufficient on its own to justify the use of emergency powers under a statute with specific requirements. And the Department fails to provide evidence that there are such imminent resource adequacy shortfalls that an emergency exists pursuant to Section 202(c). The Department's suggestion that there is an emergency due to resource inadequacy is also belied by the robust portfolio of capacity resources available this summer.

1. The Energy Emergency Executive Order does not provide a valid basis under Section 202(c).

The Order generally states that the availability of Eddystone is necessary considering "the declared state of national energy emergency," but fails to explain what state of emergency it refers to or cite any evidence supporting this claim. Without more, this statement of a national emergency is not specific enough to provide evidence of an emergency for purposes of Section 202(c). *See* 10 C.F.R. § 205.371 (defining emergency as a "*specific* inadequate power supply situation") (emphasis added). Even assuming the Order refers to the Energy Emergency EO, that Executive Order also does not provide a valid basis for an emergency under Section 202(c). To the extent that the Order is a stopgap to maintain Eddystone until the Department can produce its national methodology meant to address the alleged national energy emergency, that too is beyond the authority of Section 202(c). *See infra,* Section V.C.2.

If the Department's reference to a national energy emergency is meant to serve as evidence of an emergency as defined under Section 202(c), it is insufficient. An emergency under Section 202(c) must be "a *specific* inadequate power supply situation," 10 C.F.R. 205.371 (emphasis added), but the Energy Emergency EO only generically claims "[t]he energy … generation capacity of the United States [is] far too inadequate to meet our Nation's needs." The EO provides no evidence of inadequate generation nationwide, let alone in Pennsylvania specifically.[48] An

[48] Indeed, U.S. energy production and exports are currently at an all-time high. U.S. Energy Information Administration, U.S. primary energy production,

emergency under Section 202(c) also must be imminent. *See supra*, Section V.B. But the EO only generically claims that "this situation will dramatically deteriorate in *the near future*." As we demonstrate *infra*, Section V.C.3, there is sufficient generation for the claimed "emergency" period in Pennsylvania.

Indeed, unlike in previous 202(c) orders, the Department does not even claim there is an emergency specifically in Pennsylvania. Rather, in addition to citing the "national" emergency, the Order appears to describe resource concerns throughout PJM. But nowhere does the Department explain why a power plant retirement in a single state—Pennsylvania—supports the existence of an emergency in the whole region, let alone the whole country. We further demonstrate *infra*, Section V.C.3, that there is no 202(c) "emergency," and, in fact, sufficient generation in PJM.

Even if the declared national energy emergency were legitimate, a presidential declaration of an emergency does not unlock unlimited powers. *See Biden v. Nebraska*, 600 U.S. 477, 500-01 (2023) (presidential declaration of national emergency does not change the limitations on agency's emergency authority as written into statute). President Trump issued the Energy Emergency EO pursuant to authority from the National Emergencies Act.[49] Congress explained that the

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consumption, and exports increased in 2024 (Jun. 20, 2025), https://www.eia.gov/todayinenergy/detail.php?id=65524.

[49] Under the National Emergencies Act, no emergency powers unlocked by a Presidential declaration of a national emergency "shall be exercised unless and until the President *specifies the provisions of law* under which he proposes that he, or other officers will act." 50 U.S.C. § 1631 (emphasis added). The Energy Emergency EO does not adhere to this requirement. EO 14,156 (Jan. 20, 2025) (generically directing agencies to "identify and exercise any lawful emergency

National Emergencies Act "is not intended to enlarge or add to Executive power. Rather, the statute is an effort by Congress to establish clear procedures and safeguards for the exercise by the President of emergency powers *conferred on him by other statutes*." S. Rep. No. 94-1168, 3 (1976), (emphasis added). Congress sometimes ties emergency authority to a president's declaration of a national emergency and sometimes to a determination by the head of an agency. The Federal Power Act contains both types of emergency authority: two provisions of the Federal Power Act provide the President with emergency authority (section 215A, 16 U.S.C. § 824o-1, and 16 U.S.C. § 809), but Section 202(c) requires that "the *Commission* determine[] that an emergency exists." 16 U.S.C. § 824a (emphasis added).[50] Thus, the burden is on the Department to demonstrate that there is an emergency pursuant to the narrow language of Section 202(c); simply pointing to the Energy Emergency EO without determining for itself that an emergency exists results in an arbitrary and capricious order.

2. The Department Failed to Produce Evidence of an Emergency.

None of the sources that the Department relies on in the Order provides evidence that a 202(c) emergency exists. The Order relies on four sources of evidence for its emergency declaration: (1) a March 2025 testimony of the President and CEO of PJM, (2) the FERC order accepting PJM's Reliability Resource

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authorities available to them, as well as all other lawful authorities they may possess, to facilitate the … generation of domestic energy resources.").

[50] The Department has exercised certain powers under Section 202(c) since the DOE Organization Act of 1977. 42 U.S.C. § 7172.

Initiative, (3) PJM's 2023 report *Energy Transition in PJM,* and (4) PJM's 2025 Summer Outlook. Ex. 1 at 1. The Department misconstrues these sources and consequently its reliance on them is not reasoned decision-making. *See* 5 U.S.C. § 706(2)(A) (agency actions that are "arbitrary" or "capricious" are to be "set aside"). Even if there were longer-term risks of an energy supply shortage some number of years in the future, that would not constitute a legal basis for invoking Section 202(c).

First, the Department notes that "PJM has recently stated its system faces 'growing resource adequacy concern' due to load growth, the retirement of dispatchable resources, and other factors," citing testimony from PJM's current President, Manu Asthana, to the U.S. House of Representatives Committee on Energy and Commerce, and contends that retirement of the Eddystone Units will "exacerbate" these issues.[51] While President Asthana's testimony indeed describes an emerging—but not present—resource adequacy concern, the primary focus of his testimony was on how PJM is preparing to meet resource adequacy challenges that PJM forecasts may emerge later in the decade as a result of potential data center growth in the region.[52] According to President Asthana, PJM has instituted reforms to PJM's interconnection process that will permit new resources to come

[51] Ex. 1 at 1 (citing Testimony of Manu Asthana, President and CEO, PJM Interconnection, to the U.S. House of Representatives, Committee on Energy and Commerce, Subcommittee on Energy (Mar. 25, 2025), https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf.).

[52] Testimony of Manu Asthana, at 1, 4.

online in the PJM region much more quickly than they have in recent years (though not as quickly as FERC Order 2023 would require), thus responding to capacity market price signals that incentivize that new entry.[53] As President Asthana notes, these reforms include not only changes to PJM's interconnection tools and processes it employs, but also the introduction of an interconnection fast track for resources that PJM concludes will substantially contribute to resource adequacy (the Reliability Resource Initiative), and two pathways for new generation to be added at existing points of interconnection (capacity interconnection rights transfer and surplus interconnection service).[54] He also describes changes that PJM has made to its capacity market to ensure that market prices accurately reflect available supply, concluding that "[c]ollectively, the various proposals and reforms that PJM have pursued are making a difference as they are rolled out and implemented."[55] Specifically, he notes that "since the beginning of last year, 1,100 MW of existing generation chose to remain as supply resources in PJM after previously submitting a notice to retire," and expresses optimism that this process will continue given market reforms.[56]

A full review of President Asthana's testimony demonstrates the inappropriateness of 202(c) emergency action based on resource adequacy shortfalls that may arise in future years. PJM has already identified actions it is taking

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[53] *Id.* at 8.

[54] *Id.*

[55] *Id.* at 8-9.

[56] *Id.* at 11.

through its rates and practices overseen by FERC to address the same long-term resource adequacy concerns relied upon in the Order, and the Department neither suggests nor demonstrates that PJM's long-term market mechanisms will not be successful in addressing resource adequacy needs.

Indeed, Constellation itself takes a bullish view on the state of reliability in Pennsylvania as a result of PJM's markets:[57]

> Notably, investment in new generation resources is currently being proposed in Pennsylvania. Constellation has announced the relaunch of the renamed Crane Clean Energy Center ("CCEC") in Dauphin County, which will add approximately 835 MWs of carbon-free baseload generation to the grid. Likewise, just last month, Homer City Generation Station, the largest coal-burning facility in Pennsylvania before it was closed in 2023, announced plans to restart and increase its generating capacity through burning natural gas. In addition, 31,608 MW of new generation is proposed to be built in Pennsylvania, according to the PJM generation interconnection queue. In short, the PJM markets are working to ensure resource adequacy in Pennsylvania.

Second, the Order cites FERC's approval of the Reliability Resource Initiative filed by PJM to alleviate "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry"[58]—a possibility that would only come to pass well after the 90-day period relevant to the Order. Curiously, the Order fails to discuss the results of the Reliability Resource Initiative published in May, which PJM intends will expedite interconnection for 9.3 GW of capacity, most of it thermal resources, by 2031—the vast majority of it by

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[57] Comments of Constellation at 2, Pennsylvania Public Utility Commission Docket No. Docket No. M-2024-3051988, https://www.puc.pa.gov/pcdocs/1861961.pdf.

[58] Ex. 1 at 1 (citing PJM Interconnection LLC, 190 FERC ¶ 61,084 (Feb. 11, 2025)).

2030.[59] On the time scale relevant to PJM's expressed concerns about a growing resource adequacy problem, the existence of the Reliability Resource Initiative demonstrates the effectiveness of existing tools to avoid an emergency arising. Suffice it to say, the Department's citation of an approved solution to a problem that would otherwise arise in several years does not constitute evidence of an emergency in the next 90 days as required for a Section 202(c) order.

Third, the Order cites PJM's February 2023 assessment, "Energy Transition in PJM: Resource Retirements, Replacements & Risks," commonly known as the "R4" report, in which "PJM highlights the increasing risk of reliability risk in the coming years due to the 'potential timing mismatch between resource retirements, load growth and the pace of new generation entry' under 'low new entry' scenarios for renewable generation." Ex. 1 at 1.[60] The problems with the Order's reliance on this 2023 assessment are manifold.

As the Department's statement makes plain, the February 2023 R4 Report describes only "increasing risk of reliability risk," *id.*, over a period of seven years, which falls far short of an emergency within the meaning of Section 202(c), which must be imminent and certain. *See supra*, Section V.B., 10 C.F.R. 205.375, 205.371.

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

[60] Citing PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks (Feb. 24, 2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

The potential risk of a risk of inadequacy does not meet these standards. Furthermore, the February 2023 R4 Report's assessment of increasing risk is flawed on its own terms. The most fundamental problem is that PJM failed to account for the operation of its own capacity market in ensuring resource adequacy, by assuming that capacity prices would remain at their then-recent low levels even as reserve margins shrunk. As economist James F. Wilson explained in a critique published in May 2023, this ignores that the sloped demand curve utilized in the capacity auction prevents this very result—as supply becomes more scarce, prices increase dramatically, thus incentivizing more new entry and retention of existing generators.[61] Additional flaws with PJM's R4 Report that undermine its validity as a basis for the Order include:

- Ignoring reliability safety valve mechanisms in state policies to which PJM attributes anticipated retirements, which allow for delays in retirements in the case of reliability issues.[62]

- Overstating retirements that would result from certain U.S. Environmental Protection Agency rules affecting the power sector, by assuming that all facilities subject to these rules would retire rather than retrofit.[63]

- Presenting a low new entry scenario based on historic rates of new entry that occurred during a time period when the PJM capacity market was oversupplied and prices were low.[64]

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[61] Ex. 8 James F. Wilson, Maintaining the PJM Region's Robust Reserve Margins A Critique of the PJM Report: Energy Transition in PJM: Resource Retirements, Replacements and Risks, 8 (May 2023)

[62] *Id.* at 10 fn. 36.

[63] *Id.*

[64] *Id.* at 12.

- Assuming without explanation that only one-third of the natural gas generation with a signed interconnection agreement would enter service, even while assuming that large numbers of existing thermal units would retire.[65]

- Assuming no increase in demand response resources, despite the increased capacity prices that would accompany declining reserve margins.[66]

- Overstating retirements that will result from state policies.[67]

The February 2023 R4 Report is also stale. As the PJM region now sees a level of supply that balances current demand, PJM capacity prices have skyrocketed substantially compared to the prices assumed in the R4 Report, which reflected the market's then-state of oversupply.[68] Specific unit retirements that PJM accounted for in the R4 analysis, such as those of Talen Energy's Brandon Shores and Wagner facilities in Maryland, have not occurred. These particular facilities, representing

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[65] *Id.* at 12. *See also* PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks (Feb. 24, 2023) at 3, 10, https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

[66] *Id.*

[67] *See* Statement of President Christine Guhl-Sadovy of the New Jersey Board of Public Utilities, at 8-9, FERC Docket No. AD 25-7, (describing how PJM's R4 report overstated retirements in 2027 associated with New Jersey's greenhouse gas regulations and failed to correct this once it was pointed out by the New Jersey Board of Public Utilities).

[68] *Compare* PJM, 2023/2024 RPM Base Residual Auction Results, https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2023-2024/2023-2024-base-residual-auction-report.pdf *with* PJM 2025/2026 Base Residual Auction Results (Aug. 21, 2024), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2024/20240821/20240821-item-08---2025-2026-base-residual-auction---presentation.pdf. *See also*, PJM, 2025/2026 Base Residual Auction Report (July 30, 2024), https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.pdf.

about 1.5 GW of capacity, will continue operating under RMR agreements through the end of the decade.[69] And as noted above, PJM has taken steps intended to improve its processes to enable new resources to come online, which in combination with the higher prices, are already bearing fruit. None of these changes are reflected in the low new entry scenario described in the R4 Report and upon which the Order relies.

In addition to relying on stale evidence of low new entry, all of PJM's assessments of possible resource adequacy shortfalls later this decade depend on whether forecasted data center load growth materializes at the scale, and in the locations, that PJM currently anticipates.[70] As PJM's Vice President of Market Design and Economics recently explained, "any technology that is early in its development cycle is uncertain. Data centers are still relatively new, and there's uncertainty on how big their demand might be, and there's added uncertainty as to where they might ultimately be developed."[71] PJM is evaluating ways to facilitate developers of data centers bringing their own supply to the market, incentivizing

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[69] Talen Energy, FERC Approves Reliability Must Run Settlement Agreement for Units at Talen Energy's Brandon Shores and H.A. Wagner Power Plants (May 1, 2025), https://ir.talenenergy.com/news-releases/news-release-details/ferc-approves-reliability-must-run-settlement-agreement-units. *See generally* FERC Docket No. ER24-1790 (Brandon Shores LLC submits tariff filing: RMR Arrangement).

[70] *See, e.g.,* Joe Bowring, Pre-Technical Conference Comments of the Independent Market Monitor for PJM at 3, FERC Docket No. AD25-7 (May 27 2025), https://www.ferc.gov/media/joe-bowring-monitoring-analytics-president-and-independent-market-monitor.

[71] Adam Keech, Prefiled Statement on Behalf of PJM Interconnection, L.L.C. at 7, FERC Docket No. AD25-7.

higher degrees of data center participation as a demand response resource, or allowing for lower-cost, faster interconnection by data centers that are willing to have their usage curtailed.[72] A recent study showed that even a very small degree of data center load flexibility enables large amounts of data centers—18 GW in PJM—to be added to the system without increasing the system peak that is a major input to the resource adequacy analysis.[73] Meanwhile, utilities and states are taking significant steps to require deposits and other commitments from large loads, such as data centers, to ensure that the load forecasts driving pessimism about PJM's long-term resource adequacy don't include speculative or duplicative projects.[74]

Fourth, the Department offers a single piece of evidence relating to near-term conditions—a PJM newsletter summarizing its outlook for the summer. But it too does not demonstrate an emergency. According to the Department, "PJM indicates that resource constraints could exist within the service territory under peak load conditions, stating that 'available generation capacity may fall short of required

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[72] Tim Horger, Senior Director, Forward Market Operations & Performance Compliance, "Large Load Additions Workshop," PJM (May 9, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/workshops/llaw/2025/20250509/20250509-item-02---large-load-additions-workshop---presentation.pdf.

[73] Tyler H. Norris et al., Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems 20, 22 (Duke Univ. Nicholas Inst. for Energy, Env't & Sustainability ed. 2025), https://nicholasinstitute.duke.edu/publications/rethinking-load-growth.

[74] Adam Keech, Prefiled Statement on Behalf of PJM Interconnection, L.L.C. at 7-8, FERC Docket No. AD25-7.

reserves in an extreme planning scenario.'"[75] As PJM further explains: "Demand response programs pay customers who have opted in to reduce their electricity use in times of system emergencies."[76] The Department's brief quotation of this summer outlook article omits a key point that is prominent in PJM's article—that "[u]nder such circumstances, PJM would call on contracted demand response programs to meet its required reserve needs."[77] PJM's plan to call on demand response is also noted in the article's subheading and first paragraph—it is not a subtle point.

The possibility that PJM might ask demand response resources to activate is not an "emergency" within the meaning of Section 202(c). That is exactly the point of such resources— they offer to curtail their use of power on demand in exchange for hefty payments.[78] Instead of an emergency, it is indicative of routine analysis and planning to rely upon the most cost-effective resources available to the grid operator. *See infra*, Section V.C.3. As PJM's Vice President of Markets, Adam Keech, explains, demand response is important to "maintaining resource adequacy

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[75] Order at 1 (quoting Summer Outlook 2025, *supra* n. 4).

[76] Summer Outlook 2025, *supra* n. 4.

[77] *Id.*

[78] *See, e.g.*, *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 269 (2016), *as revised* (Jan. 28, 2016) (explaining that market operators like PJM devised wholesale demand response programs, which "induce consumers to refrain from using … electricity during peak periods" for situations whenever "doing that costs less than adding more power" in order to "bring electricity supply and demand into balance at a lower price … [and] ease pressure on the grid, thus protecting against system failures").

both currently and in the future."[79] He notes that "demand response accounted for approximately 4.5% of capacity that cleared" in the 2025/26 Base Residual Auction, and that "[i]f generation resources are unable to be developed economically to meet anticipated load growth in PJM, it will be critical to have flexible demand that is willing to curtail in order to maintain reliability."[80] The Department's own regulations explicitly acknowledge that inadequate energy is an emergency only if the grid operator is unable to meet "normal peak load requirements based upon use of all of its otherwise available resources." 10 C.F.R. 205.375. Thus, the Order arbitrarily ignores PJM's plan to rely upon demand response in the event that its generation resources are inadequate to maintain the required operating reserves during extreme load conditions this summer.

Finally, the Order mentions in the description of the emergency situation the Department's intent to consider Eddystone in the as-yet unpublished resource adequacy methodology the Department is developing pursuant to the Grid EO. Ex. 1 at 2. This context cannot be evidence of an emergency under Section 202(c) for the simple reason that the methodology does not yet exist. And any reliance on the methodology, once it is published, as evidence to support the issuance of the Order will be impermissible *post hoc* rationale. *Dep't of Homeland Sec. v. Regents of the Univ. of California,* 140 S. Ct. 1891, 1907 (2020) ("'foundational principle of administrative law' that judicial review of agency action is limited to 'the grounds

[79] Adam Keech, Prefiled Statement on Behalf of PJM Interconnection, L.L.C. at 5, FERC Docket No. AD25-7.

[80] *Id.* at 5-6.

that the agency invoked when it took the action.'"). Further, this context suggests that the Order in reality is merely a preliminary step in the long-term strategy to preserve fossil fuel generation under the guise of grid reliability concerns. As discussed *infra*, Section V.C.4., regardless of this Administration's policy goals, the Department's actions must adhere to the Administrative Procedure Act's requirement of reasoned decision making as well as remain within the statutory limits Congress wrote into the Federal Power Act.

The Department's claims represent a blinkered and incorrect review of the evidence: while there is the possibility for energy demand growth over the coming years, and there has been an increase in generator retirements, PJM is equipped with the tools to address those system changes in a way that maintains resource adequacy and reliability, and indeed is already doing so. Rather than recognizing this broader picture, the Department points to cherry-picked statements by PJM that if certain conditions arise—such as particular levels of load growth and low new entry of capacity resources—then, in several years' time, the PJM region would have reserve margins below its target if appropriate action were not taken to address those conditions. The Department takes PJM's warnings of future risk that might arise out of context and ignores other mechanisms at work to address the longer-term risk and thereby prevent any energy shortfall from arising.

3. PJM Has Sufficient Capacity Resources for Summer 2025 Without Eddystone.

The Base Residual Auction for the delivery year encompassing the period of emergency that the Department identifies in the Order—Delivery Year 2025-2026—

cleared more capacity than the Reliability Requirement.[81] Specifically, the auction cleared 135,684 MW of unforced capacity, representing a 18.6% reserve margin—0.8 percentage points higher than the target reserve margin of 17.8%.[82] Constellation did not offer the Eddystone Units into the auction, considering its June 1, 2025 deactivation date was accepted by PJM, and Constellation's 2023 notice that it would seek removal of its capacity resource status.[83] Thus, the auction cleared more than sufficient resources for the 2025-2026 delivery year without Eddystone's capacity being included or otherwise counted on. Clearing an amount of capacity close to, and indeed above, the Reliability Requirement is consistent with the capacity market's design objectives.[84]

Indeed, the auction-clearing results *understate* the quantity of resources available in the PJM region for at least two reasons. The supply curve did not

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[81] PJM, 2025/2026 Base Residual Auction Report 3 (July 30, 2024), https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.pdf.

[82] *Id.* Two transmission-constrained areas that must import capacity cleared at the price cap for those areas, indicating that they had insufficient internal capacity to meet their internal demand for the delivery year. These two areas–Baltimore Gas & Electric and Dominion–are in Maryland and Virginia, respectively, and would not be able to import any additional capacity even if it were available elsewhere in the region, due to the transmission constraints.

[83] *See supra*, Section IV.A. Constellation is contemporaneously submitting a written request to PJM and the IMM for removal of capacity resource status beginning with the 2025/26 delivery year.

[84] *See* Kathleen Spees et al., Sixth Review of PJM's Variable Resource Requirement Curve for Planning Years 2028/29 through 2031/32, at 19 (Apr. 9, 2025), https://www.brattle.com/wp-content/uploads/2025/04/Sixth-Review-of-PJMs-Variable-Resource-Requirement-Curve.pdf ("By design, RPM aims to support long-term reliability by targeting a cleared volume of capacity resources consistent with the reliability requirement, the 1-in-10 reliability standard.").

include nearly 1.5 GW of capacity available in the Baltimore Gas & Electric zone that are committed to operate under RMR agreements during the 2025-2026 delivery year.[85] FERC has since approved tariff revisions filed by PJM that will, in future auctions, account for the capacity value of RMR units with obligations to perform during capacity emergencies, like the units in the Baltimore Gas & Electric zone.[86] In addition, approximately 1.6 GW of accredited wind, solar, and storage capacity did not offer into the auction for the 2025-2026 delivery year; these resources have capacity interconnection rights and will be available to provide energy, including during many of PJM's riskiest hours of this delivery year.[87]

NERC's 2025 Summer Reliability Assessment, published in May 2025, indicates that PJM has adequate anticipated resources for both normal and extreme summer load conditions, and that PJM anticipates calling upon demand response resources during any extreme high temperatures.[88] It further notes that "PJM is forecasting 27% installed reserves (including expected committed demand

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[85] *See* Maryland Office of People's Counsel, Bill and Rate Impacts of PJM's 2025/2026 Capacity Market Results & Reliability Must-Run Units in Maryland 6 (Aug. 2024), https://opc.maryland.gov/Portals/0/Files/Publications/RMR%20Bill%20and%20Rates%20Impact%20Report_2024-08-13%20Final%20corrected%208-29-24.pdf?ver=fHKa18_idtwi4Rm4OeK-7A%3d%3d.

[86] *See Order Accepting Tariff Revisions Subject to Condition*, *PJM Interconnection, L.L.C.*,190 FERC ¶ 61,088, at P 1 (2025).

[87] *See Extending the Capacity Must-Offer Requirement to All Generation Capacity Resources, PJM Interconnection, L.L.C.*, FERC Docket No. ER25-785-000 (2024), at P 7.

[88] NERC, 2025 Summer Reliability Assessment 5, 25 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.

response), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion."[89]

The heat wave that occurred June 23-26, 2025, and PJM's response thereto, demonstrate that the PJM system is working as it should to maintain grid reliability—and it would have worked as planned even without the Eddystone Units running. On June 22, 2025, PJM projected that its forecasted load across PJM from June 23 through 26 would range from 148,500 to 161,000 MW.[90] While these load forecasts are higher than PJM's summer forecast peak, they are lower than PJM's extreme planning scenario of more than 166,000 MW and lower than the 187,100 MW of total generation capacity and demand response that PJM has available this summer.[91] Thus, PJM called on ordinary economic resources to respond to this event, but also had additional typical resources it could call on to address the peak forecasts, and still would have even without Eddystone operating. PJM reached the last step before an emergency[92]—Pre-emergency Load Management Reduction, in other words, demand response.[93] Ultimately, PJM hit a peak load of approximately

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[89] *Id.* at 25.

[90] *June 23 Update: Maximum Generation Alert Issued for June 24*, PJM Inside Lines (June 19, 2025), https://insidelines.pjm.com/pjm-issues-hot-weather-alert-for-expected-heat-wave-june-22-25/.

[91] Summer Outlook 2025, *supra* n. 4.

[92] PJM, PJM Manual 13: Emergency Operations 20-21 (Feb. 20, 2025), https://www.pjm.com/-/media/DotCom/documents/manuals/m13.pdf.

[93] While this is an action under PJM's Capacity Emergency, *id.*, PJM's Operating Agreement explains that "[a] pre-emergency event is implemented when economic resources are not adequate to serve load and maintain reserves or maintain system reliability, and *prior to proceeding into emergency procedures*."

160,000 MW on June 23 and 158,000 on June 24[94] and still had additional demand response available (at least 3,640 MW) that it could have relied on rather than running Eddystone's 820 maximum MW.[95]

This event was not an emergency as defined by Section 202(c) because it did not produce a "specific inadequate power supply situation," 10 C.F.R. § 205.371. And Department regulations define an inadequate energy supply as when "the projected energy deficiency... will cause the [utility] to be unable to meet its *normal peak load* requirements based upon *use of all of its otherwise available resources*." 10 C.F.R. § 205.375 (emphasis added). For this event, PJM kept net load below its summer seasonal peak load through relying on only some of its otherwise available resources. The June 23-26 event demonstrates that PJM has sufficient capacity resources for summer 2025.

PJM, 8.5 Pre-Emergency Operations, Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. 516, https://www.pjm.com/library/governing-documents (emphasis added). In fact, the purpose of pre-emergency Load Management Reduction is to "potentially avoid, or at least reduce the duration and breadth of, a system emergency." PJM tariff filing, Revisions to the PJM OATT, OA & RAA, FERC Accession # 20131224-5000, at 8 (Dec. 24, 2013).

[94] https://www.gridstatus.io/live/pjm?date=2025-06-23to2025-06-25.

[95] PJM only issued a Pre-Emergency Load Management Reduction Action calling on only some of the available short and long capacity performance demand response (https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf#). But PJM also has 3640 MW of quick demand response. James McAnany, PJM, 2025 Demand Response Operations Markets Activity Report (June 10, 2025), https://www.pjm.com/-/media/DotCom/markets-ops/dsr/2025-demand-response-activity-report.pdf (45.5% of total 25/26 demand response is quick).

4. The Order Is Based on a False Premise and Violates the Department's Duties Under the Administrative Procedure Act.

On its face, the Department's decision to require Eddystone to recommence and continue operations over the next 90 days is completely untethered from the statutory and regulatory requirements of Section 202(c). Given the incongruity of the record and the result, the Department's decision to require Eddystone to return to service shows itself to be nothing more than a brazen effort to prop up fossil fuel generation– to the detriment of PJM ratepayers and the surrounding community– by manufacturing an "emergency" and illegally abusing an important statutory safeguard. *See, e.g. Youngstown Sheet & Tube Co. v. Sawyer*, 343 U.S. 579, 649-54, (1952) (Jackson, J., concurring) ("[Our founding fathers] knew what emergencies were, knew the pressures they engender for authoritative action, knew, too, how they afford a ready pretext for usurpation. We may also suspect that they suspected that emergency powers would tend to kindle emergencies.")[96]

[96] Administrative review does not require "exhibit[ing] a naiveté from which ordinary citizens are free," *Dep't of Com. v. New York*, 588 U.S. 752, 785 (2019). That the Department's action is intended to support the White House's stated goals of keeping fossil fuel plants from retiring is evidenced by a wealth of publicly available information surrounding the Administration's policies and stated intent. *See, e.g., Agenda47: America Must Have the #1 Lowest Cost Energy and Electricity on Earth*, Trump-Vance 2025 (Sept. 7, 2023), https://www.donaldjtrump.com/agenda47/agenda47-america-must-have-the-1-lowest-cost-energy-and-electricity-on-earth; Jill Colvin & Bill Barrow, *Trump's Vow to Only be a Dictator on 'Day One' Follows Growing Worry over his Authoritarian Rhetoric*, Associated Press (Dec. 7, 2023, 4:58 PM), https://apnews.com/article/trump-hannity-dictator-authoritarian-presidential-election-f27e7e9d7c13fabbe3ae7dd7f1235c72 (President Trump indicated he was not concerned about statutory compliance when he stated repeatedly that he would "be a dictator" on Day One in order to "drill, drill, drill.").

Whatever the political aspirations of the Executive may be or its demands of its agency leaders, actions by the Department are still governed by the Administrative Procedure Act, which requires that a court "hold unlawful and set aside agency action, findings, and conclusions found to be arbitrary, capricious, [or] an abuse of discretion." 5 U.S.C. § 706(2)(A). The Administrative Procedure Act requires agencies to make a reasoned explanation for their actions by examining the relevant data and providing a rational connection between the facts found and the choice made. *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983). And because an agency's authority rests squarely within the four corners of Congress' delegation, agencies are not permitted to make decisions based on factors which Congress has not intended it to consider. *Id.*; *see also Amerijet Int', Inc. v. Pistole*, 753 F.3d 1343, 1350 (D.C. Cir. 2014).

The Department's use of Section 202(c) is thus arbitrary and capricious because it is not tied to the requirements of the statute and is instead a product of impermissible political influence beyond those requirements. *D.C. Fed'n of Civic Ass'ns v. Volpe*, 459 F.2d 1231, 1248 (1971). As explained by the Supreme Court:

> The reasoned explanation requirement of administrative law, after all, is meant to ensure that agencies offer genuine justifications for important decisions, reasons that can be scrutinized by courts and the interested public. Accepting contrived reasons would defeat the purpose of the enterprise. If judicial review is to be more than an empty ritual, it must demand something better … [and] agencies must pursue their goals reasonably.

Dep't of Com., 588 U.S. at 785.

D. The Order Will Undermine Competitive Markets to the Detriment of Consumers and Reliability.

When viewed together with the Energy Emergency EO,[97] Grid EO, and the Department's nearly identical 202(c) order regarding the Campbell coal plant,[98] the Department advances an illegal command-and-control energy policy that effectively overrides the capacity and energy markets to force a private entity to continue operating an uneconomic unit they wished to decommission and for ratepayers to pick up the tab. Congress delegated to FERC the authority to regulate wholesale energy markets and interstate transmission and granted the Department only a narrow, backstop authority through Section 202(c). 16 U.S.C. § 824a(c). If left to stand, the Department's overbroad Order will forebode a fundamental undermining of competitive markets for energy, leading to a system that will deliver less reliability to consumers at greater cost.

1. Competitive Markets Have a Long History of Success.

For nearly a century, FERC's core responsibility under the Federal Power Act has been to ensure that rates, terms, and conditions employed by utilities for wholesale energy sales and transmission are just, reasonable, and not unduly discriminatory. 16 U.S.C. § 824d ("Section 205"). While the initial utility structure was vertically integrated such that generation, transmission, and distribution resources were all held by the same entity, advances in technology and statutory

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[97] Exec. Order No. 14,156 Declaring a National Energy Emergency, 90 Fed. Reg. 8,433 (Jan, 20, 2025).

[98] Ex. 9 at 1-2, DOE Order No. 202-25-3 (May 23, 2025) (directing dispatch of the Campbell plant, which was scheduled to cease operations the following week).

changes led to the development of energy markets and merchant generation.[99] Further regulation by FERC in the 1990s with Order Nos. 888, 890, and 2000 fostered the establishment of several independently operated RTOs, which set up competitive markets that determine the prices for energy, capacity, and ancillary services based on procurement and dispatch of least-cost resources.[100] As RTO markets expanded, many states deregulated their utility monopolies and required them to join RTOs. Generating resources in competitive RTOs are built and retired by private investors in response to market price signals designed to encourage new investment when supply is tight and to encourage the retirement of facilities that are no longer competitive when capacity is plentiful. RTOs now account for approximately 2/3 of all electricity sales in the U.S. and have saved consumers billions of dollars, increased reliability, and reduced environmental harm.[101]

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

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

[101] *See, e.g.*, Judy Chang et al., The Brattle Group, Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers, 1, 3-7 (April 2019), https://www.brattle.com/wp-

As explained by FERC, its "support of competitive wholesale electricity markets has been grounded in the substantial and well-documented economic benefits that these markets provide to consumers."[102] In addition to billions of dollars of consumer savings, FERC found that competitive markets protect consumers by "providing more supply options, encouraging new entry and innovation, spurring deployment of new technologies, promoting demand response and energy efficiency, improving operating performance, exerting downward pressure on costs, and shifting risk away from consumers."[103]

As part of its role in regulating markets, FERC has implemented Congressional mandates to ensure system reliability, including working with NERC to set industry standards for grid reliability;[104] coordination requirements for the

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content/uploads/2021/05/16092_nc_wholesale_power_market_whitepaper_april_2019_final.pdf (discussing billions of dollars in estimated cost saving); Jennifer Chen & Devin Hartman, *Why wholesale market benefits are not always apparent in customer bills*, R Street (Nov. 10, 2021), https://www.rstreet.org/commentary/why-wholesale-market-benefits-are-not-always-apparent-in-customer-bills/ (same); Jeff St. John, *A Western US energy market would boost clean energy. Will it happen?*, Canary Media (Jun. 10, 2024), https://www.canarymedia.com/articles/utilities/a-western-us-energy-market-would-boost-clean-energy.-will-it-happen; John Tsoukalis et al., Assessment of Potential Market Reforms for South Carolina's Electricity Sector, at 6, 46, 77-78 (Apr. 27, 2019), https://www.scstatehouse.gov/CommitteeInfo/ElectricityMarketReformMeasuresStudyCommittee/2022-04-27%20-%20SC%20Electricity%20Market%20Reform_Brattle%20Report.pdf (discussing cost savings across regional wholesale markets).

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

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

[104] PJM, NERC and Reliability (Jan. 5, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/nerc-and-reliability-fact-sheet.pdf.

natural gas and electricity market scheduling;[105] investigation and improvements required in light of the grid's response to extreme weather events;[106] and reviewing capacity accreditation processes to ensure that capacity markets generate reliable results.[107]

2. Command and Control Orders Run Counter to Federal Power Act Requirements and Fundamental Market Principles.

Despite the decades of evidence that competitive energy markets deliver reliable energy at least cost to consumers, as well as the extensive and constant oversight of these markets by FERC, the Order operates under the implicit

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See also PJM, PJM Ensures a Reliable Grid (Jan. 29, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/reliability-fact-sheet.pdf.

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

[106] *See, e.g., Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators*, 149 FERC ¶ 61,145 (2014) (order addressing technical conferences on, among other things, the 2014 Polar Vortex); *Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and EOP-012-1 and Directing Modification of Reliability Standard EOP-012-1*, 182 FERC ¶ 61094 (2023);*Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification*, 187 FERC ¶ 61,204 (2024). *See also,* FERC, NERC and Regional Staff, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott (Oct. 2023), https://www.ferc.gov/sites/default/files/2023-11/24_Winter-Storm_Elliot_1107_1300.pdf; FERC, NERC and Regional Staff, The February 2021 Cold Weather Outages in Texas and the South Central United States (Nov. 2021), https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/FERC%20Presentation-Phase%202.pdf; PJM, Winter Storm Elliott Event Analysis and Recommendation Report (2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf?ref=blog.gridstatus.io.

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

assumption that capacity market results are not reliable, and that market-driven generator retirement is cause for alarm. This is not the first time this President has sought to require preferential treatment for retiring resources he preferred for grid reliability.[108] When the Department proposed to have a rule that would require tariff provisions designed to prevent the retirement of preferred resources, FERC rejected the proposal unanimously.[109] FERC found that the allegations that potential retirements of particular resources would lead to grid reliability problems did not demonstrate that existing rules were unjust and unreasonable.[110] Nor was there evidence from the RTOs that any particular generator retirement would be a threat to grid resilience.[111] Moreover, FERC found that the proposal to pay cost-of-service rates for only certain types of resources "regardless of need or cost to the system" would not be just, reasonable, or unduly discriminatory.[112]

Similar to this prior effort, the Order proposes to force the Eddystone Units to run regardless of need or cost to the system. The Order demands that PJM "take every step to employ economic dispatch," which it fails to define. Ex. 1 at 3. As discussed above in section IV., PJM dispatches generators based on the lowest

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[108] *See, e.g.*, Casey Roberts, *FERC Rejects DOE's Dangerous Proposal to Shield Coal and Nuclear From Clean Energy Competition*, Sierra Club (Jan. 9, 2018), https://www.sierraclub.org/compass/2018/01/ferc-doe-coal-nukes-perry-subsidies

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

[110] *Id.* at PP 15-16.

[111] *Id.*

[112] *Id.* at P 16.

marginal price. The low historic utilization of Eddystone reflects that its costs to operate are so much higher than alternative resources that it isn't being dispatched enough of the time—even during times of peak load—to warrant keeping the unit online. *See supra*, Section IV.B. Constellation was well aware of PJM's load forecasts and the related high capacity prices when it opted to retire the Eddystone Units. This indicates that Constellation either didn't see Eddystone becoming economic even in future scenarios and/or that it felt it could make more money by retiring the Eddystone Units and investing in other options that offered the ability to dispatch more frequently and earn a greater return on investment. By forcing Eddystone to stay on the system despite this, the Department will raise prices for consumers by forcing them to pay for a resource that is unnecessary to meet PJM's Reliability Requirement for the current delivery year. Keeping Eddystone online also forces Constellation to continue to invest its money in an aging and expensive unit instead of investing in newer, more profitable units.

Should the Order be extended, as the Department suggests it will be, the consequences will become further reaching. Mandating that Eddystone remain online over a longer timeline forces PJM and Constellation to tie up the transmission capacity rights owned by the Eddystone Units that could otherwise be repurposed by Constellation for a new unit at the Eddystone site or put back into the system for allotment to new, more efficient resources waiting in PJM's

infamously years-delayed interconnection queue.[113] In other words, the Order forces Constellation to tie up an incredibly valuable transmission resource by maintaining that transmission headroom for a resource that is no longer useful and is unlikely to actually need to be used. As such, this decision is the very opposite of the bedrock principle of utility law that asset expenditures must be used and useful.[114] Moreover, it defeats the Administration's alleged concern that there are more retirements than new resources coming on the system. Ex. 1 at 1. As mentioned above, PJM has instituted new procedures for allowing resources needed for reliability to advance to the front of the interconnection queue. By tying up unused transmission capacity at the Eddystone Units, it also prevents new, more affordable and reliable resources already waiting to replace it from doing so. While extensions of the Order beyond the initial 90-days would almost certainly be unlawful and unreasonable, the Department appears to be contemplating

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[113] Joseph Rand et. al., Queued Up: 2024 Edition, *Lawrence Berkeley National Laboratory* (April 2024) at 35,https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf (showing that PJM has the longest queue processing timelines in the U.S.); Synapse Energy Economics, Inc., Sabine Chavin et al., Tackling the PJM Electricity Cost Crisis (Apr. 2025), https://www.synapse-energy.com/sites/default/files/Evergreen%20PJM%20Queue%20Report%204.10.25_%20final%2024-145.pdf; Grid Strategies, Generator Interconnection Scorecard (Feb. 2024) https://gridstrategiesllc.com/wp-content/uploads/2024/03/AEI-2024-Generation-Interconnection-Scorecard.pdf (scoring PJM's overall interconnection a D-).

[114] *See* FERC, Energy Primer, at 55 (2024), https://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf; Jim Lazar, Electricity Regulation in the US: A Guide, Second Edition, at 91 (2016), https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-electricity-regulation-US-june-2016.pd.

extensions given the statement that "DOE plans to use [the Grid EO] methodology to further evaluate Eddystone Units 3 and 4." Ex. 1 at 2.

Finally, the longer-term impacts of the Department's strategy send signals that will disrupt market stability. Markets ultimately still depend on private investors, who will be less likely to invest billions of dollars in an energy system run according to personal whim rather than on market forces. The need for market stability across administrations and department heads is why Congress deliberately placed the authority for utility regulation—a matter so fundamentally central to the entire economy and well-being of the nation—in the hands of independent regulators with specialized expertise and only allowed the Department to intervene in true emergencies.[115] In usurping the role of FERC and RTO markets to regulate the energy markets so that the Department can prioritize resources it favors and thwart the development of those it dislikes, the ultimate message is for private investors not to invest. As noted by former FERC Commissioner Brownell, to do otherwise "will have a chilling effect on markets because investors will be unlikely to risk hundreds of billions of dollars on investments regulated by politically influenced non-transparent decisions."[116]

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[115] *See generally*, Patrick M. Corrigan & Richard L. Revesz, *The Genesis of Independent Agencies*, 92 N.Y.U. L. Rev. 637 (2017).

[116] Herman K. Trabish, *Trump executive order threatens transmission, interconnection initiatives: former FERC commissioners*, Utility Dive (Mar. 26, 2025), https://www.utilitydive.com/news/trump-executive-order-agency-independence-ferc-transmission-interconnection-initiatives/742356/. *See also* Oskar Dye-Furstenberg, *The Hollow Energy Agenda of Trump's First Four Months*, Roosevelt Institute (May 29, 2025), https://rooseveltinstitute.org/blog/the-hollow-energy-agenda-of-trump/.

E. Even If There Were a Short-Term Need—There Is Not—the Order Does Not Comply with the Statutory Command to Set Terms That Best Meet the Emergency and Serve the Public Interest.

1. Section 202(c)(1) Only Authorizes the Department to Require Generation that Best Meets the Emergency and Serves the Public Interest.

Even if there were a Section 202(c) emergency, which as shown above there is not, Section 202(c)(1) requires the Department only impose requirements that (i) "best" (ii) "meet the emergency and" (iii) "serve the public interest." 16 U.S.C. § 824a(c)(1). The Department therefore must consider alternatives and choose the alternative that is most advantageous to meeting the emergency and serving the public interest as defined by the Federal Power Act.

The term "best" demands a comparative judgment that there are no better alternatives. The word "best" is inherently a comparative term and means "that which is 'most advantageous.'" *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208, 218 (2009) (quoting Webster's New International Dictionary 258 (2d ed.1953)); *cf. Sierra Club v. Env't. Prot. Agency*, 353 F.3d 976, 980, 983–84 (D.C. Cir. 2004) (explaining that statutory "best available control technology" requirement demands sources in a category clean up emissions to the level that peers have shown can be achieved). Consequently, the Department must, at minimum, consider alternatives and evaluate whether and to what extent a given alternative addresses the alleged emergency and serves the public interest, including deficiencies associated with each option.

Moreover, the Department must consider alternatives as part of exercising reasoned decision-making. It need not consider every conceivable alternative, but it

must consider alternatives within the ambit of the existing policy as well as alternatives which are significant and viable or obvious. *See Dep't of Homeland Sec. v. Regents of the Univ. of Calif.*, 591 U.S. 1, 30 (2020) (failure to consider alternative was arbitrary and capricious); *Motor Vehicle Mfrs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 51 (1983) (must consider alternatives "within the ambit of the existing standard"); *Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200, 215 (D.C. Cir. 2013) ("agency must consider and explain its rejection of reasonably obvious alternatives" (cleaned up)). Intervenors and the public may also introduce information that requires the Department to evaluate alternatives and reconsider its decision to impose or maintain a requirement. *See, e.g.*, *Chamber of Com. of the U.S. v. Secs. & Exch. Comm'n*, 412 F.3d 133, 144 (D.C. Cir. 2005) (holding that agency's failure to consider the disclosure alternative raised by dissenting Commissioners and introduced by commenters violated the Administrative Procedure Act); *cf.* 10 C.F.R. § 205.370 (stating the Department's right "to cancel, modify, or otherwise change" an order). To be sure, the nature and extent to which the Department must consider alternatives depends on the emergency. An emergency that truly requires the Department to act within hours, for instance, would permit a more abbreviated consideration than an emergency for which the Department has days to decide. 16 U.S.C. § 824a(c) (directing the Department to exercise its judgment).

The Department's regulations and practice suggest relevant alternatives for its consideration. The regulations specify information the Department shall

consider in deciding to issue an order under Section 202(c), and require an applicant for a 202(c) order to provide the information. 10 C.F.R. § 205.373. The specified information includes "conservation or load reduction actions," "efforts . . . to obtain additional power through voluntary means," 10 C.F.R. § 205.373(g)–(h), and "available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions." Ex. 6 at 4-5 (DOE Order No. 202-22-4).

The statutory command to take only measures that serve the public interest further constrains the Department's authority. The public interest element demands that the Department advance, or at least consider, the various policies of the Federal Power Act. *Cf. Wabash Valley Power Ass'n*, 268 F.3d at 1115 (interpreting the "consistent with the public interest" standard in Section 203 of the Federal Power Act); *see Gulf States Utils. Co. v. Fed. Power Comm'n*, 411 U.S. 747, 759 (1973) (discussing "public interest" standard in other provisions); *California v. Fed. Power Comm'n*, 369 U.S. 482, 484–86, 488 (1962). Primary policies of the Federal Power Act include protecting consumers against excessive prices; maintaining competition to the maximum extent possible consistent with the public interest; and encouraging the orderly development of plentiful supplies of electricity at reasonable prices. *NAACP v. Fed. Power Comm'n*, 425 U.S. 662, 670 (1976) (orderly development); *Otter Tail Power Co. v. United States*, 410 U.S. 366, 374 (1973) (maintaining competition); *Pa. Water & Power Co. v. Fed. Power Comm'n*, 343 U.S. 414, 418 (1952) (excessive prices). And because Section 202(c) expressly

protects environmental considerations, these are part of the public interest element too. *See NAACP*, 425 U.S. at 669 ("[T]he words 'public interest' . . . . take meaning from the purposes of the regulatory legislation.").

2. The Order Does Not Contain a Reasoned Basis that Eddystone Best Meets the Claimed Emergency and Serves the Public Interest.

Even if the scenario the Order lays out were an emergency pursuant to Section 202(c), the Department has not explained why ordering Eddystone to be available to operate is the best means to meet that scenario. Ex. 1 at 1 & n.2

The operational status of Eddystone suggests that it may be unable to meet purported emergencies. Although a spokesperson for Constellation indicated recently that the units were in "ready" status, that statement also indicated a need to take steps to "retain necessary staff and perform necessary maintenance to allow for safe and reliable operations."[117] And while the Eddystone Units did run during the June 23-26 heatwave, Unit 4 "went offline."[118] These old, ready-to-retire Units are themselves likely to be unreliable.

Moreover, the Order also does not address readily available and obvious alternatives which, in point of fact, would better compensate for the supposed "resource adequacy issues" asserted (inaccurately) by the Order. Ex. 1 at 1. PJM's

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[117] Jon Hurdle, *Aging Pennsylvania power plant to keep running after Trump order on eve of shutdown*, Pennsylvania Capital-Star (June 9, 2025), https://penncapital-star.com/energy-environment/aging-pennsylvania-power-plant-to-keep-running-after-trump-order-on-eve-of-shutdown/.

[118] PJM Interconnection, LLC, Compliance Report (June 24, 2025), https://www.pjm.com/-/media/DotCom/documents/other-fed-state/20250624-doe-compliance-report-for-eddystone-units-3-and-4.pdf.

own summer outlook predicts that even in the case of an all-time peak load, PJM would be able to meet its required reserve needs through its existing programs.[119] PJM has already contracted demand response programs—a lower cost means to address grid reliability concerns—that can meet even a record-high summer demand peak this year and will continue to be available, and even expanded, in the coming years.[120] Additionally, Public Interest Organizations have highlighted above the robust transmission connectivity between PJM and neighboring regions, which PJM has accessed on a regular basis to support the stability of its grid. *See supra*, Section IV.B. This is consistent with the Department's long-standing recognition that power pools and utility coordination "are a basic element in resolving electric energy shortages." 46 Fed. Reg. at 39,985–86. The Department offers no reasonable basis to question the availability of resources from neighboring regions. But even if there were some barrier to transmission from those regions, the Department has not (and likely could not) explain why the Order provides a better means of ensuring resource sufficiency than addressing those barriers directly through its power to require "interchange" and "transmission" of electric energy from those neighboring regions. 16 U.S.C. § 824a(c)(1). Finally, even if

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[119] *See* Summer Outlook 2025, *supra* n. 4.

[120] *Id.* Commissioner Chang commended PJM's use of demand response in the June 23-26 heatwave. ("In particular, I do want to highlight the PJM's use of nearly 4,000 MW of demand response to reduce the peak load, their peak load, on Tuesday from what would have been the third highest peak load experienced on the PJM system. I see load flexibility as a key tool for grid operators to meet the challenges that we face and I commend PJM for the successful use of demand response during the system strain.") FERC Commission Meeting, June 2025 Open Meeting, https://youtu.be/eAHyYMKI_Yg.

preventing the retirement of existing facilities was the best means of addressing the alleged emergency, the Order does not address why maintaining the Eddystone Units over other retiring units is the best means. Buchannan Units 1 and 2 are set to retire by July 1, 2025.[121] These more modern combustion turbines, with a combined name plate generation of 88 MW, were constructed in 2002. Not only are these units newer than Eddystone, but their recent annual generation has been at least six times as much GWh and the plant has run almost twice as efficiently.[122]

The Orders failure to include any consideration of these other alternatives. And the Order contains no reasoning demonstrating why Eddystone is the best alternative, or a better alternative than other options. As such, the Order is unlawful.

F. Because the Order Is Ambiguous, It Fails to Provide Fair Notice to the Public and Regulated Entities and Conflicts with Limitations on the Department's Authority.

The Order requires PJM and Constellation to "take all measures necessary to ensure that Eddystone Units are available to operate." Ex. 1 at 3. The Order further requires PJM to "take every step to employ economic dispatch of the units to minimize cost to ratepayers." *Id.* Those directions are so vague that neither the public nor the regulated entities have fair notice of the Department's actions, and so

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[121] Letter from Jason P. Connel, VP Planning, PJM to Nathan Dixon, VP Buchanan Generation, LLC, *Deactivation Notice for Buchanan Unit 1 & Unit 2* (May 30, 2025) https://www.pjm.com/-/media/DotCom/planning/gen-retire/deactivation-notices/buchanan-unit-1-unit-2-pjm-response.pdf.

[122] *See* U.S. Energy Information Administration., Form EIA-923: Power Plant Operations Report (2023), https://www.eia.gov/electricity/data/eia923/.

imprecise as to conflict with the limitations on the Department's authority under Section 202(c).

The Department's direction to "ensure that Eddystone Units are available to operate" is impermissibly ambiguous and vague. Ex. 1 at 3. The Order does not explain, for instance, whether it requires (a) only that PJM and Constellation take measures so they are ready to send, receive, and respond to dispatch instructions to the extent capable with no other actions, or (b) that PJM and Constellation take additional measures that enlarge their capabilities to operate (like capital investments). It is also unclear whether PJM and Constellation are required to take measures to ensure that each of the units is equally "available to operate." *Id.* at 3.

Additionally, the Order's reference to "ratepayers" is impermissibly ambiguous and vague. *Id.* For instance, does the Order refer to ratepayers in the PJM wholesale energy markets, the PJM capacity market and ancillary services markets, bilateral markets, retail ratepayers, some combination of these ratepayers, or some other set of ratepayers? The Order also contains no geographic limit on the referenced ratepayers, such that it is not clear whether PJM is directed to minimize costs to ratepayers in Pennsylvania, across PJM, or some other area. It further contains no temporal limit, such that it is unclear whether PJM is directed to minimize cost to current ratepayers, future ratepayers, or both. Moreover, the Order contains no standards or guidance on how PJM is to reconcile or balance countervailing tensions, like minimization of costs to current and future ratepayers.

The ambiguities also make unclear the scope of activities and omissions coming within the effect of Section 202(c)(3), leaving the public and Public Interest Organizations in the dark as to what pollution is and is not allowed.

The above defects are fatal to the Order's validity. The Order does not give PJM and Constellation reasonably clear direction. And a reasonably prudent person—regardless of whether such person is familiar with the electric industry—cannot ascertain the Order's meaning. As such, the Order does not give fair notice of conduct that is forbidden or required, and it is therefore unlawful. *Fed. Commc'ns Comm'n v. Fox Telev. Stations, Inc.*, 567 U.S. 239, 253 (2012) ("A fundamental principle in our legal system is that laws which regulate persons or entities must give fair notice of conduct that is forbidden or required"); *Grayned v. City of Rockford*, 408 U.S. 104, 108–09 (1972) ("an enactment is void for vagueness if its prohibitions are not clearly defined").

In addition, the ambiguities of the Order permit such a wide variety of actions and interpretations by PJM and Constellation that the Department has not met the statutory requirement to select only the activity that "*best* meet[s] the emergency and serves the public interest." 16 U.S.C. § 824a(c) (emphasis added). There can only be one "best" in the Department's judgment. Given the vagaries of the Order, many potential activities could be allowed, and the Department has not specified which activity is "best," much less explained why. As such, the Department fails to comply with Section 202(c)(1) and the Order is consequently arbitrary and capricious, an abuse of discretion, not in accordance with law, and

beyond the Department's statutory authority. *Cf. Allentown Mack Sales & Serv., Inc. v. NLRB,* 522 U.S. 359, 375 (1998).

G. The Department's Order Fails to Provide the Conditions Necessary to Override Environmental Standards Under Section 202(c)(2).

The Order purports to authorize operations that may "conflict with environmental standards and requirements." Ex. 1 at 2. Where an order may produce such a conflict, Section 202(c)(2) requires the Department to "ensure:" (1) that it compels "generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet the emergency and serve the public interest;" (2) that operations are "to the maximum extent practicable . . . consistent with any applicable Federal, State or local environmental law[s];" and (3) that it minimizes any adverse environmental impact, regardless of the facility's compliance (or non-compliance) with environmental standards. 16 U.S.C § 824a(c)(2). The Order here violates all three of those statutory obligations—a failure with especially severe consequences given the pollution produced by the Eddystone Units.

First, the Order directly contradicts the Department's obligation to require generation "only during hours necessary to meet the emergency." *Id.* The Order instead states: "For the duration of this order, PJM is directed to take every step to employ *economic dispatch* of the units to *minimize cost* to ratepayers." Ex. 1 at 3 (emphasis added). *See also* Ex. 10[123] (PJM stating that "Constellation will maintain active cost offers" on Markets Gateway to "operate on gas or oil for both

[123] Ex. 10 (PJM Reporting and Commitment Process).

Eddystone 3 and 4, unless either fuel is unavailable or if the units are on a Planned, Maintenance or Forced outage"). The "emergency" nominally described by the Order is "the potential loss of power to homes and local businesses in the areas that may be affected by curtailments," during the Order's 90-day span. Ex. 1 at 2. Even if the Department had substantiated that emergency (which it has not) the Federal Power Act would allow the Department to compel generation only when such losses would occur absent operation of the Eddystone Units. 16 U.S.C. 824a(c)(2); *see, e.g.*, Ex. 11 at 9 (DOE Order No. 202-17-4 Summary of Findings) ("authorizing operation of" units subject to emergency order "only when called upon . . . for reliability purposes," according to "dispatch methodology" approved by Department). "Economic dispatch," in sharp contrast, requires "the lowest-cost resources [to] run first," in pursuit of "the lowest-cost energy available." *City of New Orleans v. FERC,* 67 F.3d 947, 948-49 (D.C. Cir. 1995)*; see also Fla. Power & Light Co. v. FERC,* 88 F.3d 1239, 1241 (D.C. Cir. 1996) (noting distinction between economic dispatch and reserve capacity rules). PJM has, for the time being, accepted that it may only dispatch the units to address immediate reliability and capacity needs.[124] But even that has proven not precise enough; on June 23 and 24, 2025, PJM allowed Eddystone to run[125] before relying on all of its demand response

[124] *Id.*

[125] *See* Compliance Report, *supra* n. 118; PJM Interconnection, LLC, Compliance Report (June 25, 2025), https://www.pjm.com/-/media/DotCom/documents/other-fed-state/20250625-pjm-report-in-compliance-w-ordering-paragraph-b-of-the-doe-20250530-order-no-202-25-4.pdf. In fact, on June 24 Eddystone Unit 3 ran for 24 hours and Eddystone 4 ran for 20. This appears to be beyond even the vague requirements of the Order.

resources.[126] The fact that PJM had additional demand response resources available to more than cover the day-ahead load forecast and in reality did have excess demand response resources means that the emergency claimed by the Order—"the potential loss of power to homes and local businesses"—was not in play and therefore Eddystone should not have been run. Moreover, any assurance by PJM does not alter the Order's unlawful terms. By directing PJM to dispatch the plant along cost-based principles, rather than "only during hours necessary to meet the emergency," the Department has violated Section 202(c)(2). 16 U.S.C. § 824a(c)(2).

Second, the Order fails to ensure that Eddystone operates, "to the maximum extent practicable," in conformity with applicable environmental rules. *Id.* The Order paraphrases the statutory text—that "operation of the Eddystone Units must comply with applicable environmental requirements . . . to the maximum extent feasible," but fails to specify *who* bears that responsibility or *what* such operation entails. Ex. 1 at 3. It imposes no further conditions beyond requiring Constellation to "pay fees or purchase offsets or allowances for emissions." *Id.* The direction to "comply . . . to the maximum extent feasible" is, as a result, potentially unenforceable; the Order provides no basis for the Department, or anyone else, to determine whether the plant is in fact complying or who might face the consequences of any failure to do so. *See* Ex. 6 at 5–7 (DOE Order No. 202-22-4)

[126] *See* PJM Emergency Procedures, Postings, Effective from 06/23/2025 to 06/26/2025, https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf (calling on some but not all demand response).

(requiring, *inter alia,* reporting of "number and actual hours each day" of operation "in excess of permit limits or conditions," and information describing how generators met their requirement to comply with environmental requirements to the maximum extent feasible). As such, the Order does not meet the Department's statutory obligation to "*ensure*" the maximum feasible compliance with applicable environmental standards. 16 U.S.C. § 824a(c)(2) (emphasis added).

Third, the Order fails to provide any conditions at all to "minimize[] any adverse environmental impacts." 16 U.S.C. § 824a(c)(2). That mandate is textually and substantively distinct from the Department's (also unfulfilled) obligation to ensure maximum practicable compliance with environmental standards. *Id.* The Order fails, most importantly, to include measures, such as utilization of demand response resources, that would mitigate impacts when compliance with environmental standards proves impracticable. Past orders have routinely included such measures. *See, e.g.*, Ex. 11 at 2 (DOE Order No. 202-17-4 Summary of Findings) (permitting non-compliant operation only during specified hours, and requiring exhaustion of "all reasonably and practicably available resources," including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions); Ex. 6 at 7 (DOE Order No. 202-22-4) (requiring "reasonable measures to inform affected communities" of non-compliant operations). At a minimum the statute requires the Department to include sufficiently detailed reporting obligations to ascertain what impacts result from emergency operations; without such reporting, the Department

has no ability to "ensure" that adverse impacts are minimized. *See, e.g.*, Ex. 12 Department of Energy, Order No. 202-24-1, at 5 (Oct. 9, 2024) (requiring detailed data on emissions of pollutants). The Order here instead gestures towards "such additional information" as the Department may (or may not) "request[] . . . from time to time." Order at 3. That possibility of future, unspecified inquiry cannot satisfy the statute's demand that the Department "ensure" that its Order minimizes environmental impacts. 16 U.S.C. § 824a(c)(2).

Failure to meet those conditions is especially critical because the Eddystone Units can be operated on either gas or oil. PJM and Constellation have both indicated that the units intend to use fuel oil, rather than gas, when economically favorable. Ex. 10 (PJM Reporting and Commitment Process). Allowing the units to utilize oil based solely on cost—especially absent a requirement to exhaust demand-response and other available resources prior to dispatching the units at all—does not minimize environmental impacts "to the maximum extent practicable." 16 U.S.C. 824a(c)(2). *See* Ex. 13 (stating that Eddystone Units may alter fuels based on "pricing changes).[127] Oil-fired generation results in higher emissions of both criteria pollutants and hazardous air pollutants. Ex. 4 (Eddystone Title V Permit) at 28, 50 (noting sulfur content of oil and higher NOx emissions from oil-fired generation); 68 Fed. Reg. 1660, 1678 (Jan. 13, 2003) (noting that switching from oil to natural gas "would reduce mercury, metallic [toxics], and inorganic" hazardous

[127] Constellation Energy, *Eddystone Generating Station*, https://www.constellationenergy.com/our-company/locations/location-sites/eddystone-generating-station.html (last visited June 27, 2025).

air pollutant emissions). The months during which the Order operates do not pose a risk that natural gas will be unavailable, so even if an emergency requiring generation from the Eddystone Units existed—which it does not—gas-fired generation would be entirely practicable. Ex. 14 (Natural gas may not be available to Eddystone Units "[w]hen there's a cold snap" or during "a polar vortex").[128] The Order's failure to at least ensure that the Eddystone Units operate only on the least-polluting fuel available to them, even as it authorizes violation of governing environmental standards, violates the law. 16 USC § 824a(c)(2). At a minimum, the Department should impose tighter limits on the dispatch of Eddystone.

H. The Order and the Department's Continued Conduct Are Inconsistent with Departmental Procedure, Depriving the Public and the Public Interest Organizations of Fair Notice and an Adequate Record.

According to the Department's procedures, the agency will use "best efforts" to post filings on a specified website within 24 hours of receipt.[129] The Department has received, and is supposed to receive, materials related to this proceeding that it has not posted. On June 13, 2025, the Department received a letter from PJM reporting on its compliance with the 202(c) Order.[130] The Public Interest

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[128] Constellation Energy, *Natural Gas and Oil,* https://www.constellationenergy.com/our-work/what-we-do/generation/natural-gas-and-oil.html (last visited June 27, 2025).

[129] Ex. 2 DOE Rehearing Procedures, *supra* n. 5.

[130] Letter from Michael Bryson, PJM, to Secretary of Energy Christopher Wright, *PJM Report in Compliance with Ordering Paragraph D of the Department of Energy's May 30, 2025 Order No. 202-25-4* (June 13, 2025), https://www.pjm.com/-/media/DotCom/documents/other-fed-state/20250613-doe-pjm-report-on-compliance-with-Eddystone-order-202-25-4.pdf.

Organizations have been able to access this letter because PJM published the letter to its website. The Department still has not met its obligation to publish this letter to its website. The Department may have received additional materials. The Order requires daily notifications on operations, p. 3 ¶ B, and such additional information regarding environmental impacts as the Department requests, p. 3 ¶ D. None of those materials are posted on the Department's 202(c) website.[131]

The Department must follow its own procedures. *See Morton v. Ruiz*, 415 U.S. 199, 235 (1974); *Mine Reclamation Corp. v. FERC*, 30 F.3d 1519, 1524 (D.C. Cir. 1994). The Department's failure to follow its procedures deprives the public and Public Interest Organizations of fair notice and an adequate record. *See United States v. Nova Scotia Food Prods. Corp.*, 568 F.2d 240, 249 (2d Cir. 1977).

VI. REQUEST FOR STAY

Public Interest Organizations further move the Department for a stay of the Order until the conclusion of judicial review. 18 C.F.R. § 385.212.[132] The Department has the authority to issue such a stay under the Administrative Procedure Act and should do so where "justice so requires." 5 U.S.C. § 705. In

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[131] The Department still has not posted filings for other recent 202(c) orders, either. *See e.g.*, U.S. Dep't of Energy, *Federal Power Act Section 202(c) Midcontinent Independent System Operator (MISO)*, https://www.energy.gov/ceser/federal-power-act-section-202c-midcontinent-independent-system-operator-miso (last visited June 27, 2025) (the Department received at least two requests for rehearing of the Campbell 202(c) order that it has not posted).

[132] Pursuant to FPA Section 313 and Rule 713(e) of the applicable rules, the filing of a request for rehearing does not automatically stay a Department Order. 16 U.S.C. § 825*l*(c), 18 C.F.R. § 385.713(e).

deciding whether to grant a request for stay, agencies consider: (1) whether the party requesting the stay will suffer irreparable injury without a stay; (2) whether issuing a stay may substantially harm other parties; and (3) whether a stay is in the public interest. *See Nken v. Holder*, 556 U.S. 418, 434, 436 (2009); *Ohio v. EPA*, 603 U.S. 279, 291 (2024); *see, e.g., Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,020, at P 41 (2023); *ISO New Eng. Inc.*, 178 FERC ¶ 61,063, at P 13 (2022), *rev'd on other grounds sub nom. In re NTE Conn., LLC*, 26 F.4th 980, 987-88 (D.C. Cir. 2022).

Injuries under this standard must be actual, certain, imminent, and beyond remediation. *Mexichem Specialty Resins, Inc. v. EPA*, 787 F.3d 544, 555 (D.C. Cir. 2015); *Wis. Gas Co. v. FERC*, 758 F.2d 669, 674 (D.C. Cir. 1985); *ANR Pipeline Co.*, 91 FERC ¶ 61,252, at p. 61,887 (2000); *City of Tacoma*, 89 FERC ¶ 61,273, at p. 61,795 (1999) (recognizing that, absent a stay, options for "meaningful judicial review would be effectively foreclosed"). Financial injury is only irreparable where no "adequate compensatory or other corrective relief will be available at a later date, in the ordinary course of litigation." *Wis. Gas Co.*, 758 F.2d at 674 (quoting *Va. Petroleum Jobbers Ass'n v. Fed. Power Comm'n*, 259 F.2d 921, 925 (D.C. Cir. 1958)); *see also In re NTE Conn., LLC*, 26 F.4th at 990-91. Environmental injury, however, "can seldom be adequately remedied by money damages and is often permanent or at least of long duration, *i.e.*, irreparable. If such injury is sufficiently likely, therefore, the balance of harms will usually favor the issuance of an

injunction to protect the environment." *Amoco Prod. Co. v. Vill. of Gambell*, 480 U.S. 531, 545 (1987).

A. Intervenors Are Irreparably Harmed by the Order.

Here, a stay is necessary to ensure that Eddystone does not continue with activities that are already causing irreparable harm to Public Interest Organizations, their members, and the public as a result of the Order.[133]

Operating the Eddystone Units, which burn oil and natural gas, results in emissions of dangerous air pollutants, including sulfur dioxide ("SO2"), nitrogen oxides ("NOX"), particulate matter ("PM"), and carbon dioxide ("CO2") that would not otherwise have occurred but for the Order blocking the deactivation of the Eddystone Units.[134] These pollutants cause and exacerbate respiratory problems, cardiovascular issues, and other health conditions. These impacts are accentuated by Eddystone's location in an area already disproportionately overburdened by heavily polluting industrial sources and toxic waste sites.[135]

The Order also causes irreparable harm by imposing costs on PJM ratepayers that would not otherwise be borne and will not be recoverable through litigation. Constellation is complying with the Order and is seeking cost recovery through

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[133] The Eddystone Units have in fact operated as a result of the Order. *See, e.g.,* Compliance Report, *supra* n. 118.

[134] *Id.*

[135] *See supra*, Section IV.A.

FERC.[136] If that request is granted, costs will be borne by PJM ratepayers, and the Department does not identify any clear recourse for a refund in the event the Order is declared unlawful. In forcing ratepayers to reopen and operate an uneconomic, unreliable, and obsolete resource that was already approved for closure, the Order also jeopardizes the diversification of generating resources the Department itself has said increases grid reliability and will inherently and unjustifiably add to ratepayer costs.[137] As there is no clear recourse to recovering these costs from the Department should Public Interest Organizations prevail in their challenge, a stay pending judicial review is necessary to protect ratepayers from unwarranted energy cost increases-especially at a time when energy prices are already on the rise.[138]

B. A Stay Would Not Result in Harm to Any Other Interested Parties.

No other interested parties would be harmed by a stay. The issuance of a stay would not harm end-use electricity consumers because the lack of an actual emergency means that a stay would not disrupt the provision of electricity. *See supra*, Section V.C.3. Furthermore, because Constellation and PJM had both already planned for the closure of the Eddystone Units, a stay would only have the

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[136] *See* Letter from David E. Mills, Chair, PJM Board, to PJM Members and Stakeholders (June 26, 2025), 20250626-pjm-board-letter-re-results-of-the-cifp-process-for-doe-202-c-order-for-eddystone-units-3-and-4.pdf.

[137] *See* U.S. Dep't of Energy, Energy Reliability and Resilience, https://www.energy.gov/eere/energy-reliability-and-resilience (last visited June 26, 2025).

[138] *See* Mitchell Terpstra, *2024 News Release: PJM Capacity Auction Prices Skyrocket*, Energy Choice Blog (Oct. 2, 2024), https://electricityrates.com/resources/pjm-capacity-auction-spike/.

effect of relieving them of the administrative, compliance, and planning burdens imposed by the Order. *See, e.g.,* Ex. 1 at 2-3. On the balancing of equities, there is therefore no meaningful countervailing harm that would follow from a stay.

C. A Stay is in the Public Interest.

There is no public interest served by the Order, and a stay will only benefit the public. First, the Order exceeds the Department's authority; it has provided no reasonable grounds to substantiate any near-term or imminent shortfall in electricity supply that would justify the Eddystone Units' continued operation. *See League of Women Voters v. Newby*, 838 F.3d 1, 12 (D.C. Cir. 2016) (noting that "there is a substantial public interest 'in having governmental agencies abide by the federal laws that govern their existence and operations'") (quoting *Washington v. Reno*, 35 F.3d 1093, 1103 (6th Cir. 1994)). Second, a stay would protect the broader public—beyond Public Interest Organizations and their members—from the costs and additional pollution produced by unnecessary operation of the Eddystone Units.

VII. CONCLUSION

For the reasons set forth above, the undersigned Public Interest Organizations respectfully request that the Department grant intervention; grant rehearing and rescind the Order (and any renewals of the Order); and stay the Order.

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Exhibit 15

U.S. DEPARTMENT of ENERGY



Resource Adequacy Report

Evaluating the Reliability and Security of the United States Electric Grid

July 2025

Acknowledgments

This report and associated analysis were prepared for DOE purposes to evaluate both the current state of resource adequacy as well as future pressures resulting from the combination of announced retirements and large load growth.

It was developed in collaboration with and with assistance from the Pacific Northwest National Laboratory (PNNL) and National Renewable Energy Laboratory (NREL). We thank the North American Electric Reliability Corporation (NERC) for providing data used in this study, the Telos Corporation for their assistance in interpreting this data, and the U.S Energy Information Administration (EIA) for their dissemination of historical datasets. In addition, thank you to NREL for providing synthetic weather data created by Evolved Energy Research for the Regional Energy Deployment System (ReEDS) model.

DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level. The DOE study team built the methodology and analysis upon the best data that was available. However, entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience.

Historically, the nation’s power system planners would have shared electric reliability information with DOE through mechanisms such as EIA-411, which has been discontinued. Thus, one of the key takeaways from this study process is the underscored “call to action” for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our collective economic and national security.

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List of Acronyms

AI	Artificial Intelligence
CAISO	California Independent System Operator
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EO	Executive Order
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ITCS	Interregional Transfer Capability Study
LBNL	Lawrence Berkeley National Laboratory
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LTRA	Long-Term Reliability Assessment
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PJM	PJM Interconnection, LLC
PNNL	Pacific Northwest National Laboratory
ReEDS	Regional Energy Deployment System
RTO	Regional Transmission Organization
SERC	SERC Reliability Corporation
TPR	Transmission Planning Region
USE	Unserved Energy

Background to this Report

On April 8, 2025, President Trump issued Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid." EO 14262 builds on EO 14156, "Declaring a National Emergency (Jan. 20, 2025)," which declared that the previous administration had driven the Nation into a national energy emergency where a precariously inadequate and intermittent energy supply and increasingly unreliable grid require swift action. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy and the integrity of our Nation's electrical grid.

EO 14262 mandates the development of a uniform methodology for analyzing current and anticipated reserve margins across regions of the bulk power system regulated by the Federal Energy Regulatory Commission (FERC). Among other things, EO 14262 requires that such methodology accredit generation resources based on the historical performance of each generation resource type. This report serves as DOE's response to Section 3(b) of EO 14262 by delivering the required uniform methodology to identify at-risk region(s) and guide reliability interventions. The methodology described herein and any analysis it produces will be assessed on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States.

Executive Summary

Our Nation possesses abundant energy resources and capabilities such as oil and gas, coal, and nuclear. The current administration has made great strides—such as deregulation, permitting reform, and other measures—to enable addition of more energy infrastructure crucial to the utilization of these resources. However, even with these foundational strengths, the accelerated retirement of existing generation capacity and the insufficient pace of firm, dispatchable generation additions (partly due to a recent focus on intermittent rather than dispatchable sources of energy) undermine this energy outlook.

Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation. A failure to power the data centers needed to win the AI arms race or to build the grid infrastructure that ensures our energy independence could result in adversary nations shaping digital norms and controlling digital infrastructure, thereby jeopardizing U.S. economic and national security.

Despite current advancements in the U.S. energy mix, this analysis underscores the urgent necessity of robust and rapid reforms. Such reforms are crucial to powering enough data centers while safeguarding grid reliability and a low cost of living for all Americans.

Key Takeaways

- **Status Quo is Unsustainable**. The status quo of more generation retirements and less dependable replacement generation is neither consistent with winning the AI race and ensuring affordable energy for all Americans, nor with continued grid reliability (ensuring "resource adequacy"). Absent intervention, it is impossible for the nation's bulk power system to meet the AI growth requirements while maintaining a reliable power grid and keeping energy costs low for our citizens.
- **Grid Growth Must Match Pace of AI Innovation**. The magnitude and speed of projected load growth cannot be met with existing approaches to load addition and grid management. The situation necessitates a radical change to unleash the transformative potential of innovation.
- **Retirements Plus Load Growth Increase Risk of Power Outages by 100x in 2030**. The retirement of firm power capacity is exacerbating the resource adequacy problem. 104 GW of firm capacity are set for retirement by 2030. This capacity is not being replaced on a one-to-one basis and losing this generation could lead to significant outages when weather conditions do not accommodate wind and solar generation. In the "plant closures" scenario of this analysis, annual loss of load hours (LOLH) increased by a factor of a hundred.
- **Planned Supply Falls Short, Reliability is at Risk**. The 104 GW of retirements are projected to be replaced by 209 GW of new generation by 2030; however, only 22 GW would come from firm baseload generation sources. Even assuming no retirements, the model found increased risk of outages in 2030 by a factor of 34.

- **Old Tools Won't Solve New Problems.** Antiquated approaches to evaluating resource adequacy do not sufficiently account for the realities of planning and operating modern power grids. At a minimum, modern methods of evaluating resource adequacy need to incorporate frequency, magnitude, and duration of power outages; move beyond exclusively analyzing peak load time periods; and develop integrated models to enable proper analysis of increasing reliance on neighboring grids.

This report clearly demonstrates the need for rapid and robust reform to address resource adequacy issues across the Nation. Inadequate resource adequacy will hinder the development of new manufacturing in America, slow the re-industrialization of the U.S. economy, drive up the cost of living for all Americans, and eliminate the potential to sustain enough data centers to win the AI arms race.

Developing a Uniform Methodology

DOE's resource adequacy methodology assesses the U.S. electric grid's ability to meet future demand through 2030. It provides a forward-looking snapshot of resource adequacy that is tied to electricity supply and new load growth, systematically exploring a range of dimensions that can be compared across regions. As detailed in the methodology section of this report, the model is derived from the North American Electric Reliability Corporation (NERC) Interregional Transfer Capability Study (ITCS) which leverages time-correlated generation and outages based on actual historic data.[1] A deterministic approach[2] simulates system stress in all hours of the year and incorporates varied grid conditions and operating scenarios based on historical events:

- **Demand for Electricity – Assumed Load Growth:** The methodology accounts for the significant impact of data centers, particularly those supporting AI workloads, on electricity demand. Various organizations' projections for incremental data center electricity use by 2030 range widely (35 GW to 108 GW). DOE adopted a national midpoint assumption of 50 GW by 2030, aligning with central projections from Electric Power Research Institute (EPRI)[3] and Lawrence Berkeley National Laboratory (LBNL).[4] This 50 GW was allocated regionally using state-level growth ratios from S&P's forecast,[5] reflecting infrastructure characteristics, siting trends, and market activity; and, mapped to NERC Transmission Planning Regions (TPRs).

1. This model differs from traditional peak hour reliability assessments in that it explicitly simulates grid performance hour-by-hour across multiple weather years with finer geographic detail and optimized inter-regional transfers, and explores various retirement and build-out scenarios. Furthermore, the DOE approach integrates weather-synchronized outage data.
2. Deterministic approaches evaluate resource adequacy using relatively stable or fixed assumptions about the representation of the power system. Probabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty that require more computing power. Deterministic was chosen for this analysis for transparency and to model detailed historic system conditions.
3. EPRI, "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption," March 2024, https://www.epri.com/research/products/3002028905.
4. Shehabi, A., et al., "2024 United States Data Center Energy Usage Report," https://escholarship.org/uc/item/32d6m0d1.
5. S&P Global – Market Intelligence, "US Datacenters and Energy Report," 2024.

An additional 51 GW of non-data center load was modeled using NERC data, historical loads (2019-2023), and simulated weather years (2007-2013), adjusted by the Energy Information Administration's (EIA) 2022 energy forecast, with interpolation between 2024 and 2033 to estimate 2030 demand.

- **Supply of Electricity – Assumed Generation Retirements and Additions:** Between the current system and the projected 2030 system, the model considers three scenarios for generator retirements and additions. These scenarios were selected to describe the metrics of interest and how they change during certain assumptions of generation growth and retirements.

The resource adequacy standard (or criterion) is the measure that defines the desired level of adequacy needed for a given system. Conceptually, a resource adequacy criterion has two components—metrics and target levels—that determine whether a system is considered adequate. Comprehensive resource adequacy metrics[6] are incorporated in this analysis to capture the magnitude and duration of system stress events:

- **Magnitude of Outages – Normalized Unserved Energy (NUSE):** Measures the amount of unmet electrical energy demand because of insufficient generation or transmission, typically measured in megawatt hours (MWh).

  While USE describes the absolute amount of energy not delivered, it is less useful when comparing systems of different size or across different periods. Normalizing, by dividing by total load over a whole period (for example, a year) allows comparison of these metrics across different system sizes, demand levels, and periods of analysis. For example, 100 MWh of USE in a small, isolated microgrid can be more impactful than 100 MWh of USE in a larger regional grid that serves millions of people. USE is normalized by dividing by total load:

$$\frac{100\ MWh\ (of\ unserved\ energy)}{10{,}000{,}000\ MWh\ (of\ total\ energy\ delivered\ in\ a\ year)} x100 = 0.001\ percent$$

Although the use of NUSE is not standardized in the U.S. today,[7] several system operators domestically and across the world have begun using NUSE as a useful metric.

- **Duration of Outages – Loss of Load Hours (LOLH):** Measures the expected duration of power outages when a system's load exceeds its available generation capacity. At the core, LOLH helps assess how frequently and for how long the power system is likely to experience insufficient supply, providing a picture of reliability in terms of time. LOLH is calculated as both a total and average value per year, in addition to the maximum percentage of load lost in any given hour per year.

6. In the interest of technical accuracy, and separate from their contextualization in the main text, NUSE is more precisely a measure of volume that is expressed as a percentage. Similarly, 2.4 hours of LOLH represents the cumulative sum of distinct periods of load loss, not a singular, continuous duration.
7. There is no common planning criterion for this metric in North America. NERC's Long-Term Reliability Assessment employs a normalized expected unserved energy (NEUE) metric to define target risk levels for each region. Grid operators, such as ISO-NE, have also considered NUSE in energy adequacy studies. For example, see ISO-NE, "Regional Energy Shortfall Threshold (REST): ISO's Current Thinking Regarding Tail Selection," April 2025, https://www.iso-ne.com/static-assets/documents/100022/a09_rest_april_2025.pdf.

Reliability Standard

DOE's methodology recognizes that the traditional 1-in-10 loss of load expectation (LOLE) criterion is insufficient for a complete assessment of resource adequacy and risk profile. This antiquated criterion is not calculated uniformly and fails to adequately account for crucial factors such as the duration and magnitude of potential outages.[8] To provide a comprehensive understanding of system reliability and, specifically, to complement current resource adequacy standards while informing the creation of new criteria, the methodology uses the following reliability standard:

- **Duration of Outages:** No more than 2.4 hours of lost load in an individual year.[9] This translates into one day of lost load in ten years to meet the 1-in-10 criteria.

- **Magnitude of Outages:** No more than an NUSE of 0.002%.[10] This means that the total amount of energy that cannot be supplied to customers is 0.002% of the total energy demanded in a given year.

Achieving Reliability Standard

- **Perfect Capacity Surplus/Deficit:** Defined as the amount of generation capacity (in MW) a region would need to achieve specified threshold conditions. Based on these thresholds, this standard helps answer the hypothetical question of how much more (or less) power plant capacity is needed for a power system to be considered "perfectly reliable" according to pre-defined standards. This methodology employs this perfect capacity metric to identify the amount of capacity needed to remedy potential shortfalls (or excesses) in generation.

Key Results Summary

This analysis developed three separate cases for 2030. The "**Plant Closures"** case assumes all announced retirements occur plus mature generation additions based on NERC's Tier 1 resources category,[11] which encompasses completed and under-construction power generation projects, as well as those with firm-signed and approved interconnection service or power purchase agreements. The "**No Plant Closures"** case assumes no retirements plus mature additions. A "**Required Build**" case further compares the impacts of retirements on perfect capacity additions needed to return 2030 to the current system level of reliability.

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8. While 1-in-10 analyses have evolved, industry experts have raised concerns about its effectiveness to address future system risks. Concerns include energy constraints that arise from intermittent resources, increasing battery storage, limited fuel supplies, and the shifting away of peak load periods from times of supply shortfalls.

9. The "1-in-10 year" reliability standard for electricity grids means that, on average, there should be no more than one day (24 hours) of lost load over a ten-year period. This translates to a maximum of 2.4 hours of lost load per year.

10. This analysis targets NUSE below 0.002% for each region because this is the target NERC uses to represent high risk in resource adequacy analyses. Estimates used in industry and analyzed recently range from 0.0001% to 0.003%.

10. Mature generation additions are based on NERC's 2024 LTRA Tier 1 resources, which assume that only projects considered very mature in the development pipeline will be built. For example, Tier 1 additions are those with signed interconnection agreements or power purchase agreements, or included in an integrated resource plan, indicating a high degree of certainty in their addition to the grid. Full details of the retirement and addition assumptions can be found in the methodology section of this report.

DOE ran simulations using 12 different years of historical weather. Every hour was based on actual data for wind, solar, load, and thermal availability to stress test the grid under a range of realistic weather conditions. The benefit of this approach is that it allows for transparent review of how actual conditions manifest themselves in capacity shortfalls. For all scenarios, LOLH and NUSE are calculated and used to compare how they change based on generation growth, retirements, and potential weather conditions.

- **Current System:** Supply of power (generation) and demand for power (load) consistent with 2024 NERC Long-Term Reliability Assessment (LTRA), including 2023 actual generation plus Tier 1 additions for 2024.

- **Plant Closures:** This case assumes 104 GW of announced retirements based on NERC estimates including approximately 71 GW of coal and 25 GW of natural gas, which closely align with retirement numbers in EIA's 2025 Annual Energy Outlook. In addition, this case assumes 100% of 2024 NERC LTRA Tier 1 additions totaling 209 GW are constructed by 2030. This includes 20 GW of new natural gas, 31 GW of additional 4-hour batteries, 124 GW of new solar and 32 GW of incremental wind. Details of the breakdown can be found in Appendix A.

- **No Plant Closures:** This case adds all the Tier 1 NERC additions but assumes no retirements.

- **Required Build:** To understand how much capacity may need to be added to reach reliability targets, the analysis adds hypothetical perfect capacity (which is idealized capacity that has no outages or profile) until a NUSE target of 0.002% is realized in each region. This scenario includes the same assumptions about retirements as our Plant Closures scenario described above.

As shown in the figures and tables below, the model shows a significant decline in all reliability metrics between the current system scenario and the 2030 Plant Closures scenario. Most notably, there is a hundredfold increase in annual LOLH from 8.1 hours per year in the current case to 817 hours per year in the 2030 Plant Closures. In the worst weather year assessed, the total lost load hours increase from 50 hours to 1,316 hours.

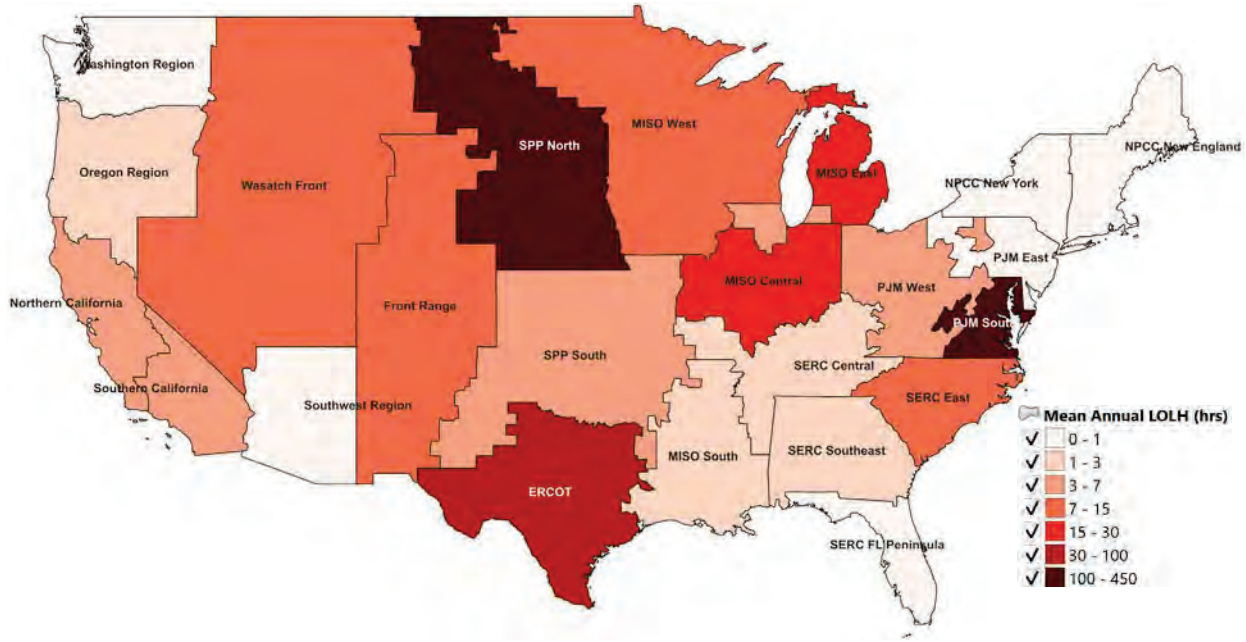


Figure 1. Mean Annual LOLH by Region (2030) – Plant Closures

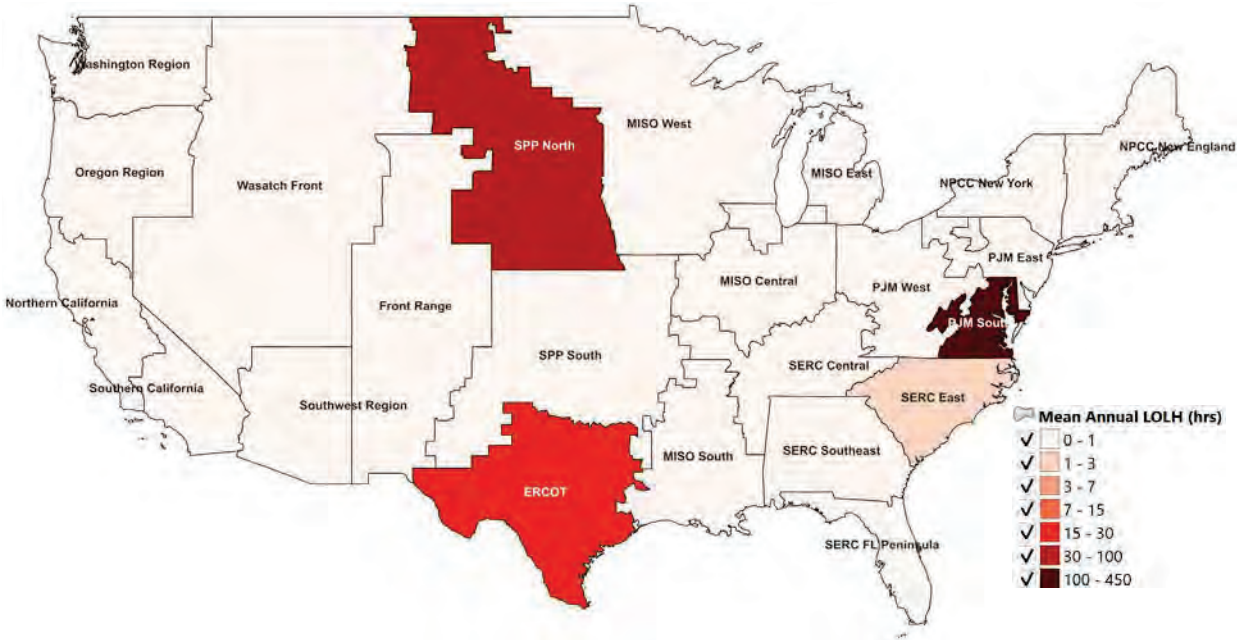


Figure 2. Mean Annual LOLH by Region (2030) – No Plant Closures

Table 1. Summary Metrics Across Cases

Reliability Metric		2030 Projection		
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	8.1	817.7	269.9	13.3
Normalized Unserved Energy (%)	0.0005	0.0465	0.0164	0.00048
WORST WEATHER YEAR				
Annual Loss of Load Hours	50	1316	658	53
Normalized Unserved Load (%)	0.0033	0.1119	0.0552	0.002

Current System Analysis

Analysis of the current system shows all regions except ERCOT have less than 2.4 hours of average loss of load per year and less than 0.002% NUSE. This indicates relative reliability for most regions based on the average indicators of risk used in this study. In the current system case, ERCOT would be expected to experience on average 3.8 LOLH annually going forward and a NUSE of 0.0032%. When looking at metrics in the worst weather years, regions meet or exceed additional criteria. All regions experienced less than 20% of lost load in any hour.

However, PJM, ERCOT,[12] and SPP experienced significant loss of load events during 2021 and 2022 winter storms Uri and Elliot which translated into more than 20 hours of lost load. This results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load. It is worth noting that in the case of PJM and SPP, the current system model shortfalls occurred within subregions rather than for the entire ISO footprint.

12. ERCOT has since winterized its generation fleet and did not suffer any outages during Winter Storm Elliot.

2030 Model Results

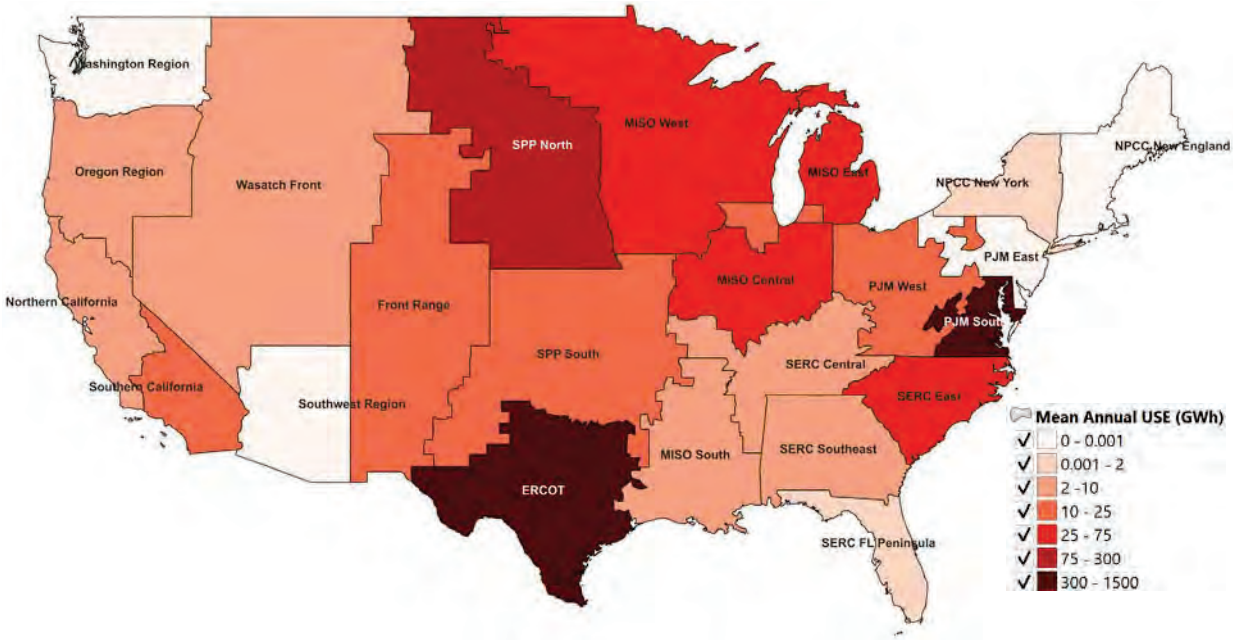


Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures

Key Findings – Plant Closures Case:

- **Systemwide Failures**: All regions except ISO-NE and NYISO failed reliability thresholds. These two regions did not have additional AI/data center (AI/DC) load growth modeled.
- **Loss of Load Hours (LOLH)**: Ranged from 7 hours/year in CAISO to 430 hours/year in PJM.
- **Load Shortfall Severity**: Max shortfall reached as high as 43% of hourly load in PJM; 31% in CAISO.
- **Normalized Unserved Energy**: Normalized values ranged from 0.0032% (non-CAISO West) to 0.1473% (PJM), far exceeding thresholds of 0.002%.
- **Extreme Events**: Most regions experienced ≥3 hours of unserved load in at least one year. PJM had 1,052 hours in its worst year.
- **Spatial Takeaways**: Subregions in PJM, MISO, and SERC met thresholds—indicating possible benefits from transmission—but SPP and CAISO failed in all subregions.

Key Findings – No Plant Closures Case:

- **Improved System Performance**: Most regions avoided loss of load events. PJM, SPP, and SERC still experienced shortfalls.
- **Regional Failures**:

- **PJM**: 214 hours/year average, 0.066% normalized unserved energy, 644 hours in worst year, max 36% of load lost.
- **SPP**: 48 hours/year average, 0.008% normalized unserved energy, max 19% load lost.
- **ERCOT**: 20 average hours, 0.028% normalized unserved energy, 101 max hours/year, peak shortfall of 27%.
- **SERC-East**: Generally adequate (avg. 1 hour/year, 0.0003% NUSE), but Elliot storm in 2022 caused 42 hours of shortfall.

The overall takeaway is that avoiding announced retirements improves grid reliability, but shortfalls persist in PJM, SPP, ERCOT, and SERC, particularly in winter.

Required Build

This required build analysis quantifies "hypothetical capacity," defined as power that is 100% reliable and available that is needed to resolve the shortfalls. Known in industry as “perfect capacity,” this metric is utilized to avoid the complex decision of selecting specific generation technologies, as that is ultimately an optimization of reliability against cost considerations. Nevertheless, it serves as a valuable indicator, illustrating either the magnitude of a resource gap or the scale of large load that will be unable to interconnect. For the Required Build case, this hypothetical capacity was calculated by adding new generating resources to each region until a target of 0.002% of NUSE is reached.

The table below shows the tuned perfect capacity results. For the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM, which experiences shortfalls due to the winter storm Elliot historical weather year. By 2030, without considering any generation retirements, an additional 12.5 GW of generating capacity is needed across PJM, SPP, and SERC to reduce shortfalls.

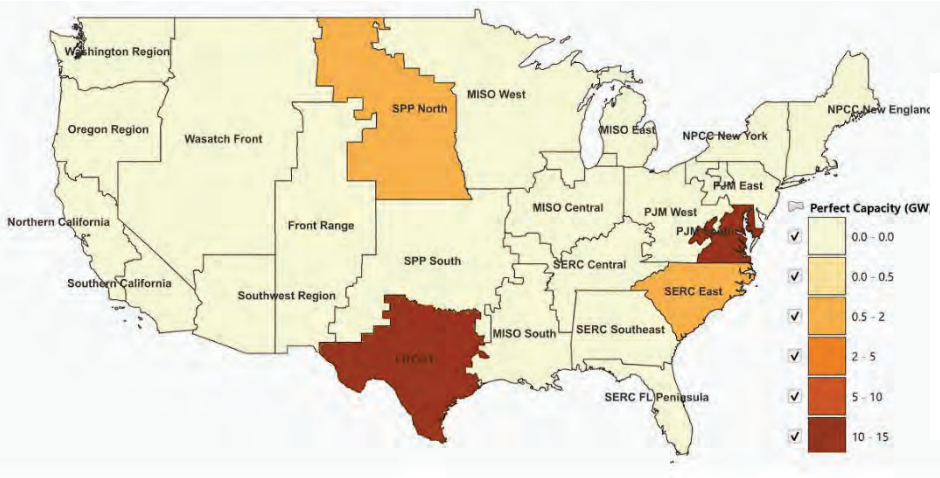


Figure 4. Tuned Perfect Capacity (MW) By Region

	2024-Current System (MW)	2030-No Plant Closures (MW)
PJM	2400	10,500
SERC-E		500
SPP-N		1,500
ERCOT	1600	10500
Total	4000	23000

Perfect Capacity/Additions

1 Modeling Methodology

The methodology uses a zonal PLEXOS[13] model with hourly time-synchronous datasets for load, generation, and interregional transfer for the 23 U.S. subregions (referred to as TPRs in this study)[14] including ERCOT (see Figure 5 below). While ERCOT operates outside of FERC's general jurisdiction,[15] it provides a valuable case for understanding broader reliability and resource adequacy challenges in the U.S. electric grid, and FPA Section 202(c) allows DOE to issue emergency orders to ERCOT.

We base this analysis on actual weather and power plant outage data from 2007 to 2023 using NERC's ITCS[16] base dataset. DOE specifically decided to start this analysis with the ITCS dataset since it is a complete representation of the interconnected electrical system for the lower 48 and it has been thoroughly reviewed by industry experts in a public and transparent process. DOE has in turn made modifications to the dataset to fit the needs of this study. The contents of this section focus on those modifications which DOE implemented for purposes of this study.

PLEXOS is an industry-trusted simulation tool used for energy optimization, resource adequacy, and production cost modeling. This study leverages PLEXOS' ability to exercise an hourly production cost model to determine the balance between loads, generation, and imports for each region. Modeling was carried out using a deterministic approach that evaluates whether a power system has sufficient resources to meet projected demand under a pre-defined set of conditions which correspond to the past few years of real-world events. The model ultimately determines the amount of unmet load if generation resources and imports are not sufficient for meeting the load in each discrete time period.

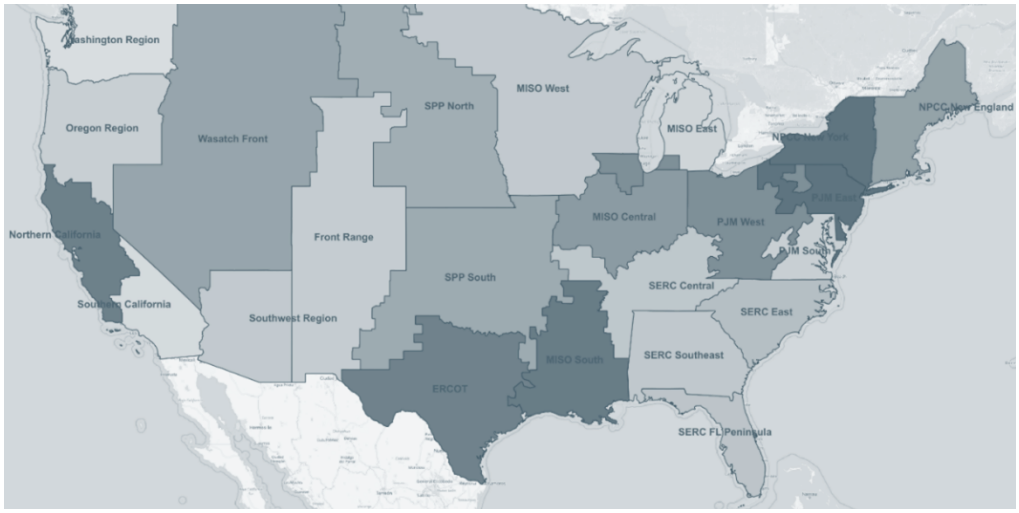


Figure 5. TPRs used in NERC ITCS

13. Energy Exemplar, "PLEXOS," https://www.energyexemplar.com/plexos.
14. The TPRs match the regional subdivisions in the NERC ITCS study, itself based on FERC's transmission planning regions.
15. Transmission within ERCOT is intrastate commerce. 16 U.S.C. § 824(b)(1) (provisions applying to "the transmission of electric energy in interstate commerce").
16. NERC "Integrated Transmission and Capacity System (ITCS)," accessed June 25, 2025, https://www.nerc.com/pa/RAPA/Pages/ITCS.aspx.

This methodology developed a current model and series of scenarios to explore how different assumptions impact resource adequacy. This sensitivity analysis includes assumptions regarding load growth, generation build-outs and retirements, and transfer capabilities. By comparing the results of the current model with the scenario results, we can assess how generation retirements and load growth affect future generation needs.

The assessment uses data from 2007–2013 (synthetic weather data) and 2019–2023 (historical data). A brief summary of the methodological assumptions is provided here, with additional details available in the relevant appendixes.

- **Solar and Wind Availability** – Created from historical output from EIA 930 data, with bias correction of any nonhistorical data to match regional capacity factors, as calibrated to EIA 930 data.[17] Synthetic years used 2018 technology characteristics from NREL based on the Variable Energy Potential (reV) model, then mapped to synthetic weather year data. See Appendix A for more details.

- **Thermal Availability** – Calculated according to NERC LTRA capacity data, adjusted for historical outages and derates, primarily with GADS data. GADS data does not capture historical outages caused by fuel supply interruptions.[18]

- **Hydroelectric Availability** – Historical outputs are processed by NERC to establish monthly power rating limits and energy budgets, but energy budgets are not enforced in alignment with how they were treated in the ITCS. The team evaluated performance under different energy budget restrictions, but did not find significant differences during peak hours, justifying NERC ITCS assumptions that hydroelectric resources could generally be dispatched to peak load conditions. Later work may benefit from exploring drought scenarios or combinations of weather and hydrological years, where energy budgets may be significantly decreased.

- **Outages and Derates** – Data for the actual data period (2019–2023) are based on historical forced outage rates and deratings. Outage and deratings data for the synthetic period (2007–2013) are based on the historical relationships observed between temperature and outages (see Appendix G of the NERC ITCS Final Report for more information).

- **Load Projections and AI Growth** – Load growth through 2030 is assumed to match NERC 2024 ITCS projections, scaling the 12 weather years to meet 2030 projections. Additional AI and data center load is then added according to reports from EPRI and S&P regarding potential futures.

- **Transfer Capabilities and Imports/Exports -** Each subregion is treated as a “copper plate,” with the transfer capacity between each subregion defined by the availability of transmission pathways. It is an approximation that assumes all resources are connected to a single point, simplifying the transmission system within the model. Subregions are generally assumed to exhaust their own capacity before utilizing capacity available from their neighbors. Once the net remaining capacity is at or below 10 percent of load, the subregion begins to use capacity from a neighbor.

17. See ITCS Final Report, Appendix F, for the method that was implemented to scale synthetic weather years 2007–2013.
18. See ITCS Final Report, Appendix G, for outage and derate methods.

  - Imports are assumed to be available up to the minimum total transfer capacity and spare generation in the neighboring subregion.

  - To the extent the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario, the model projects an energy shortfall. See "Outputs" in the appendix for more details.

  - To ensure that transfers are dispatched only after local resources are exhausted, a wheeling charge of $1,000 is applied for every megawatt-hour of energy transferred between regions through transmission pathways.

- **Storage** – In alignment with the NERC ITCS methodology, storage was split into pumped hydro and battery storage. Pumped hydro was assumed to have 12 hours duration at rated capacity with 30% round-trip losses, while battery storage was assumed to have four hours and 13% round-trip losses. Storage is dispatched as an optimization to minimize USE and demand response usage under various constraints and is recharged during periods of surplus energy.
- **Demand Response –** Demand Response (DR) is treated as a supply-side resource and dynamically scheduled after all other regional resources and imports are exhausted. It is modeled with both capacity (MW) and energy (MWh) limitations and assumed to have three hours of availability at capacity but could be spread across more than three hours up to the energy limit. DR capacity was based on LTRA Form A data submissions for "Controllable and Dispatchable Demand Response – Available", or firm, controllable DR capacity.
- **Retirements** – Retirements as per the NERC LTRA 2024 model. To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant level data are used to tabulate generation retirement or addition capacity for each ITCS region and NERC assessment area. Disaggregation fractions are then calculated by technology based on planned retirements through 2030. See Appendix B for further information. Retirements are categorized into two categories:

  1. *Announced Retirements*: Includes both confirmed retirements and announced retirements. Confirmed retirements are generators formally recognized by system operators as having started the official retirement process and are assumed to retire on their expected date. To go from LTRA regions to ITCS regions, weighting factors are derived in the same way as in the generation set, based on EIA retirement data. In addition to confirmed retirements, announced retirements are generators that have publicly stated retirement plans that have not formally notified system operators and initiated the retirement process. This disaggregation method for announced retirements mirrors used for confirmed retirements.[19]

  2. *None*: Removes all retirements (after 2024) for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirement contributes to some of the adequacy challenges in some regions.

- **Additions** – Assumes only projects that are very mature in the pipeline (such as those with a signed interconnection agreement) will be built. This data is based on projects

19. If announced retirements were less than or equal to confirmed retirements, the model adjusted the announced retirement to equal confirmed.

designated as Tier 1 in the NERC 2024 LTRA and are mapped to ITCS regions with EIA 860-derived weighting factors similar to those described for the retirements above. See Appendix A for further information.

- **Perfect Capacity Required** - Estimates perfect capacity (which is idealized capacity that has no outages or profile and is described in Section 2) until we reach a pre-defined reliability target. We used a metric of NUSE given the deterministic nature of the model, to be consistent with evolving metrics, and to be consistent with NERC's recent LTRAs. We targeted NUSE of below 0.002% for each region.

1.1 Modeling Resource Adequacy

This model calculates several reliability metrics to assess resource adequacy. These metrics were calculated using PLEXOS simulation outputs, which report the USE (in MWh) for all 8,760 hourly periods in each of the 12 weather years:

- **USE** refers to the amount of electricity demand that could not be met due to insufficient generation and/or transmission capacity. Several USE-derived indicators were considered:
    - *Normalized USE (percentage %):* The total amount of unserved load over 12 years of weather data, normalized by dividing by total load, and reported as a percentage.[20]
    - *Mean Annual USE (GWh)*: The 12-year average of each region's total USE in each weather year. This mean value represents the average annual USE across weather variability.
    - *Mean Max Unserved Power (GW)*: The 12-year average of each region's maximum USE value in each weather year. This mean value characterizes the typical non-coincident peak stress on system reliability.
    - *% Max Unserved Power*: The Mean Max Unserved Power expressed as a percentage of the average native load during those peak unserved hours for each region. This percentage value provides a normalized measure of the severity of peak unserved events relative to demand.
    - *Total number of customers without power*. The Mean Max Unserved Power expressed as the equivalent number of typical U.S. persons assuming a ratio of 17,625 persons/MW lost. This estimation contextualizes the effects of the outage on average Americans.
- **Loss of Load Hours (LOLH)** refers to the number of hours during which the system experiences USE (i.e., any hour with non-zero USE). Two LOLH-based indicators were considered:

20. NUSE can be reported as parts per million or as a percentage (or parts per hundred); though for power system reliability, this would include several zeros after the decimal point.

- *Mean Annual LOLH*: for each weather year and *TPR*, we count the total number of hours with USE across all 8,760 hours, and we then take the average of those 12 totals. *Annual LOLH Distribution* is represented in box and whisker plots for 12 samples, each sample corresponding to a unique weather year.

- *Max Consecutive LOLH (hours)*[21]: The longest continuous period with reported USE in each weather year.

It should be noted that USE is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system. Rather, it represents the unrealizable AI and data center load growth under the given assumptions for generator build outs by 2030, generator retirements by 2030, reserve requirements, and potential load growth. These numbers are used as indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need.

This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.

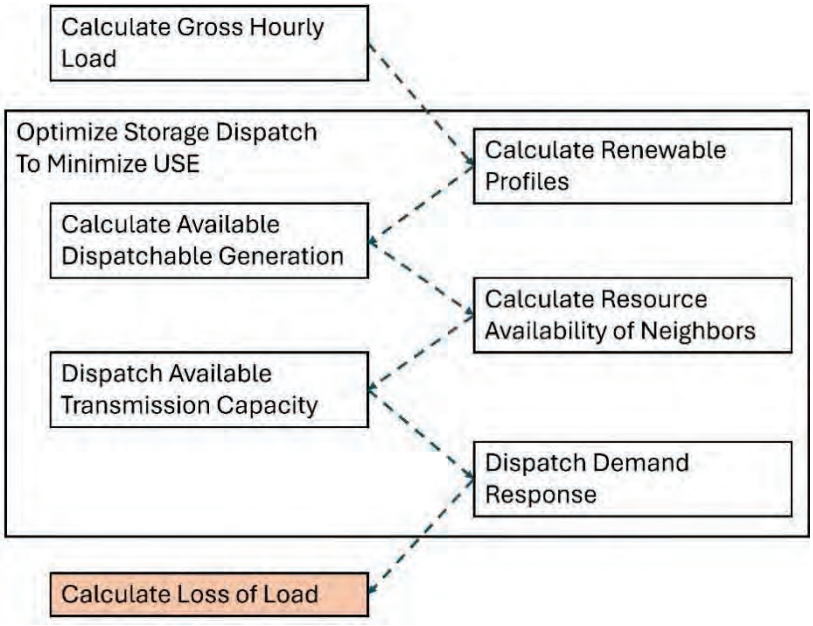


Figure 6. Simplified Overview of Model

21. One caveat on the maximum consecutive LOLH and max USE values is in how storage is dispatched in the model. Storage is dispatched to minimize the overall USE and is indifferent to the peak depth or the duration of the event. This may construe some of the max USE and max consecutive LOLH values to be higher than if storage was dispatched to minimize these values.

1.2 Planning Years and Weather Years

For the planning year (2030), historical weather year data are applied based on conditions between 2007 and 2024 to calculate load, wind and solar generation, and hydro generation. Dispatchable capacity (including dispatchable hydro capacity) is calculated through adjustment of the 2024 LTRA capacity data for historical outages from GADS data. Storage assets are scheduled to arbitrage hourly energy margins or else charge during periods of high energy margins (surplus resources) and discharge during periods of lower energy margins.

1.3 Load Modeling

Data Center Growth

Several utilities and financial and industry analysts identify data centers, particularly those supporting AI workloads, as a key driver of electricity demand growth. Multiple organizations have developed a wide range of projections for U.S. data center electricity use through 2030 and beyond, each using distinct methodologies tailored to their institutional expertise.

These datasets were used to explore reasonable boundaries for what different parts of the economy envision for the future state of AI and data center (AI/DC) load growth. For the purposes of this study, rather than focusing on any specific analysis, a more generic sweep was performed across AI/DC load growth and the various sensitivities that fit within those assumptions, as summarized below:

- McKinsey & Company projects ~10% annual growth in U.S. data center electricity demand, reaching 2,445 TWh by 2050. Their model blends internal scenarios with public signals, including announced projects, capital investment, server shipments, and chip-level power trends, supported by third-party market data.

- Lawrence Berkeley National Laboratory (LBNL) uses a bottom-up approach based on historical and projected IT equipment shipments, paired with assumptions on power draw, utilization, and infrastructure efficiency (PUE, WUE). Their projections through 2028 account for AI hardware adoption, operational shifts, and evolving cooling technologies.

- EPRI combines public data, expert input, and historical trends to define four national growth scenarios, low to higher, for 2023–2030, reflecting data processing demand, efficiency improvements, and AI-driven load impacts.

- S&P Global merges technology and power-sector models, evaluating grid readiness and facility growth under varying demand scenarios. Their forecasts consider AI adoption, efficiency trends, grid and permitting constraints, on-site generation, and offshoring risk, resulting in a wide range of outcomes.

These projections show wide variation, with 2030 electricity demand ranging from approximately 35 GW to 108 GW of average load. Given this uncertainty, including differences in hardware intensity, thermal management, siting assumptions, and behind-the-meter generation, the modeling team adopted a national midpoint assumption of approximately 50 GW by 2030.

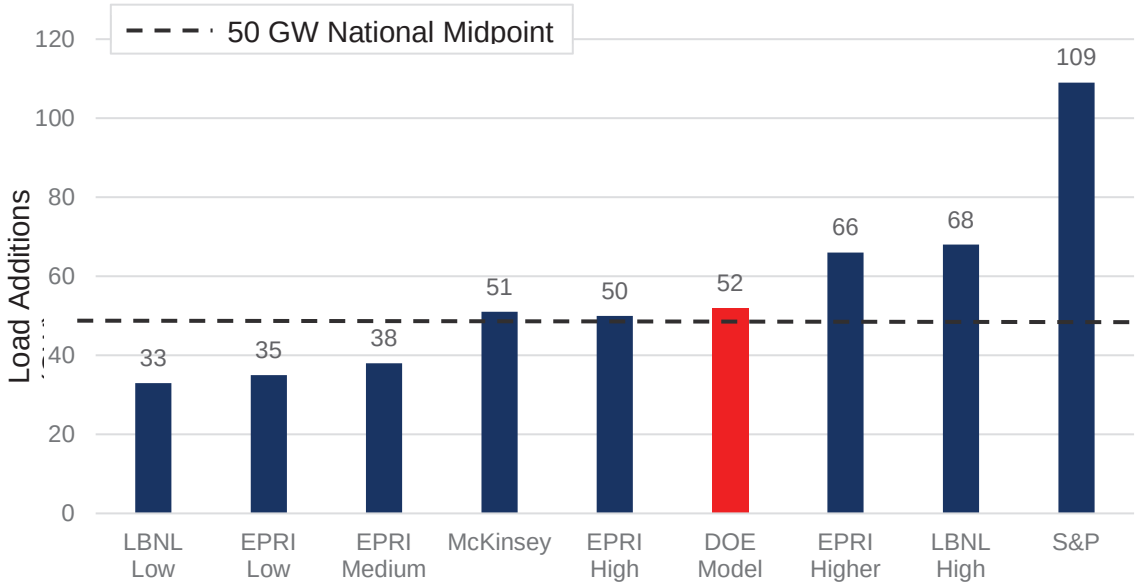


Figure 7. 2024 to 2030 Projected Data Center Load Additions

Figure 2 above displays a benchmark reflecting the median across major studies and aligns with central projections from EPRI and LBNL. Using a single planning midpoint avoids double counting and enables consistent load allocation across national transmission and resource adequacy models.

Data Center Allocation Method

To allocate the 50 GW midpoint regionally, the team used state-level growth ratios from S&P's forecast. These ratios reflect factors such as infrastructure, siting trends, and projected market activity. The modeling team mapped the state-level projections to NERC TPRs, ensuring transparent and repeatable regional allocation. While other methods exist, this approach ensured consistency with the broader modeling framework.

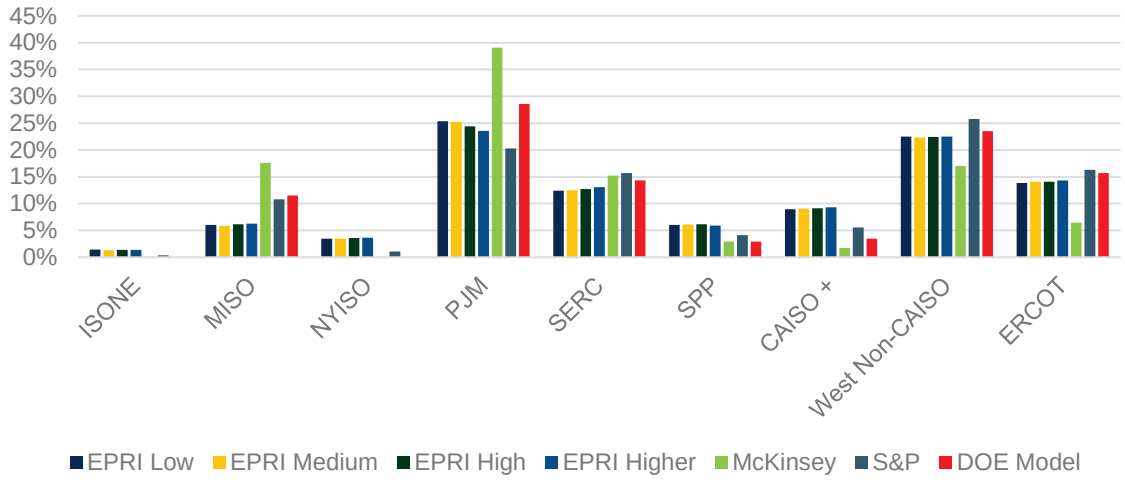


Figure 8. New Data Center Build (% Split by ISO/RTO) (2030 Estimated)

Non-Data Center Load Modeling

The current electricity demand projections were built from NERC data, using historical load (2019–2023) and simulated weather years (2007–2013). These were adjusted based on the EIA's 2022 energy forecast. To estimate 2030 demand, the team interpolated between 2024 and 2033, scaling loads to reflect energy use and seasonal peaks. NERC provided datasets to address anomalies and include behind-the-meter and USE.

Given the rapid emergence of AI/DC loads, additional steps were taken to account for this category of demand. It is difficult to determine how much AI/DC load is already embedded in NERC LTRA forecast, for example, the 2024 LTRA saw more than 50GW increase from 2023, signaling a major shift in utility expectations. To benchmark existing AI/DC contribution, DOE assumed base 2023 AI/DC load equaled the EPRI low-growth case of 166 TWh.

Overall Impact on Projected Peak Load

As a result of the methods applied above, the average year co-incident peak load is projected to grow from a current average peak of 774 GW to 889 GW in 2030. This represents a 15% increase or 2.3% growth rate per year. Excluding the impact of data centers, this would amount to a 51GW increase from 774 GW to 826 GW which represents a 1.1% annual growth rate.

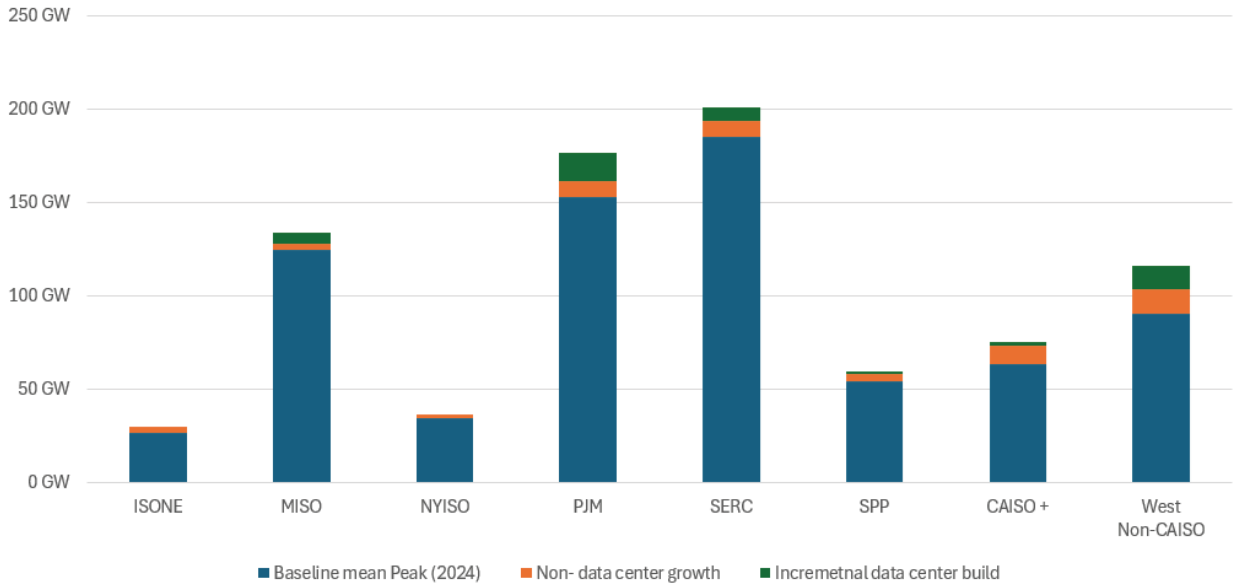


Figure 9. Mean Peak Load by RTO (Current Case vs 2030 Case)

1.4 Transfer Capabilities and Import Export Modeling

The methodology assumes electricity moves between subregions, when conditions start to tighten. Each region has a certain amount of capacity available, and the methodology determines if there is enough to meet the demand. When regions reach a “Tight Margin Level” of 10% of capacity, i.e., if a region’s available capacity is less than 110% of load, it will start transferring from other regions if capacity is available. A scarcity factor is used to determine which regions to transfer from and at what fraction – those with a greater amount of reserve capacity will transfer more. A region is only allowed to export above when it is above the Tight Margin Level.

Total Transfer Capability (TTC) was used and is the sum of the Base Transfer Level and the First Contingency Incremental Transfer Capability. These were derived from scheduled interchange tables or approximated from actual line flows. It should be noted that the TTC does not represent a single line, but rather multiple connections between regions. It is similar to path limits used by many entities but may have different values.

Due to data and privacy limitations, the Canadian power system was not modeled directly as a combination of generation capacity and demand. Instead, actual hourly imports were used from nearly 20 years of historical data, along with recent trends (generally less transfers available during peak hours), to develop daily limits on transfer capabilities. See Appendix B for more details on Canadian transfer limits.

1.5 Perfect Capacity Additions

To understand how much capacity may need to be added to reach approximate reliability targets, we tuned two scenarios by adding hypothetical perfect capacity to reach the reliability threshold based on NUSE.[22] Today, NERC uses a threshold of 0.002% to indicate regions are at high risk of resource adequacy shortfalls. In addition, several system operators, including the Australia Energy Market Operator and Alberta Electric System Operator, are using NUSE thresholds in the range of 0.001% to 0.003%. Several U.S. entities are considering lower thresholds for U.S. power systems in the range of 0.0001% to 0.0002%. [23]

For this analysis, we target NUSE below 0.002% for each region to align with NERC definitions. We iteratively ran the model, hand-tuning the "perfect capacity" to be as small as possible while reaching NUSE values below 0.002% in all regions.[24] As the work was done by hand with a limited number of iterations (15), this should not be considered the minimum possible capacity to accomplish these targets. Further, because the perfect capacity can be located in various places, there would be multiple potential solutions to the problem. These scenarios represent the approximate quantity of perfect capacity each region would require (beyond announced retirements and mature generation additions only) that would lead to Medium or Low risk based on the NERC metrics for USE.

Due to some regions with zero USE, the tuned cases do not reach the same level of adequacy, where the national average is 0.00045% vs. 0.00013%. Due to transmission and siting selection of perfect capacity, there could be many solutions.

22. We are not using the standard term "expected unserved energy" because we are not running a probabilistic model, so we do not have the full understanding of long-term expectations

23. MISO, "Resource Adequacy Metrics and Criteria Roadmap," December 2024. https://cdn.misoenergy.org/Resource%20Adequacy%20Metrics%20and%20Criteria%20Roadmap667168.pdf.

24. NERC, "Evolving Criteria for a Sustainable Power Grid," July 2024. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Evolving_Planning_Criteria_for_a_Sustainable_Power_Grid.pdf.

2 Regional Analysis

This section presents more regional details on resource adequacy according to this analysis. For each of the nine Regional Transmission Organizations (RTOs) and sub-regions, comprehensive summaries are provided of reliability metrics, load assumptions, and composition of generation stacks.

2.1 MISO[25]

In the current system model and the No Plant Closures cases, MISO did not experience shortfall events. MISO's minimum spare capacity in the tightest year was negative, showing that adequacy was achieved by importing power from neighbors. In the Plant Closures case, MISO experienced significant shortfalls, with key reliability metrics exceeding each of the threshold criteria defined for the study.

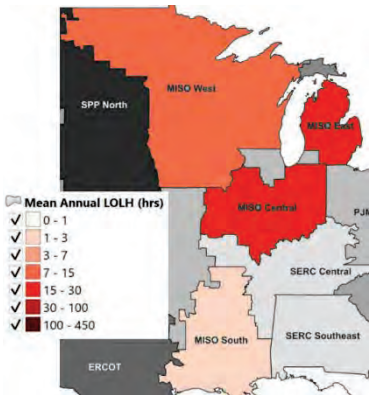


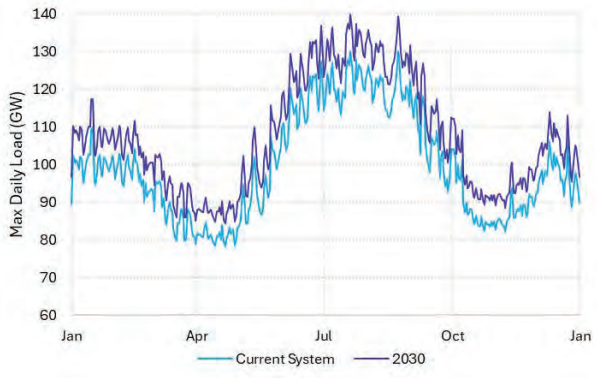
Table 2. Summary of MISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	37.8	-	-
Normalized Unserved Energy (%)	-	0.0211	-	-
Unserved Load (MWh)	-	157,599	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	124	-	-
Normalized Unserved Load (%)	-	0.0702	-	-
Unserved Load (MWh)	-	524,180	-	-

Load Assumptions

MISO's peak load was roughly 130 GW in the current model and projected to increase to roughly 140 GW by 2030. Approximately 6 GW of this relates to new data centers being installed (12% of U.S. total).

25. Following the initial data collection for this report, MISO issued its 2025 Summer Reliability Assessment. Based on that report, NERC revised evaluations from its 2024 LTRA and reclassified the MISO footprint from being an 'elevated risk' to 'high risk' in the 2028–2031 timeframe, depending on new resource additions/retirements. While DOE's analysis is based on the previously reported figures, DOE is committed to assessing the implications of updated data on overall resource adequacy and providing technical updates on findings, as appropriate.



Subregion	2024	2030
MISO-W	37,913	40,981
MISO-C	35,387	39,243
MISO-S	36,476	38,596
MISO-E	23,167	23,758
Total	**130,136**	**139,846**

Figure 10. MISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 207 GW.[26] In 2030, 21 GW of new capacity was added leading to 228 GW of capacity in the No Plant Closures case. In the Plant Closures case, 32 GW of capacity was retired such that net retirements in the Plant Closures case were -11 GW, or 196 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
MISO-W	71,612	67,453	77,605
MISO-C	51,982	47,735	58,823
MISO-S	54,511	52,756	59,710
MISO-E	29,213	28,105	32,255
Total	**207,319**	**196,049**	**228,393**

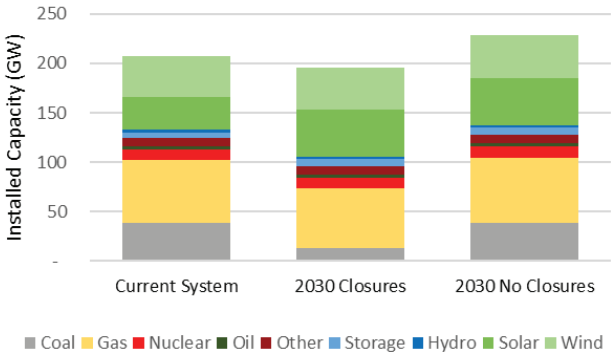


Figure 11. MISO Generation Capacity by Technology and Scenario

MISO's generation mix was comprised primarily of natural gas, coal, wind, and solar. In 2024, natural gas comprised 31% of nameplate, wind comprised 20%, coal 18%, and solar 14%. In 2030, most retirements come from coal and natural gas while additions occur for solar, batteries, and wind. In addition, the model assumed 3 GW of rooftop solar and 8 GW of demand response.

26. The total installed capacity numbers reported in this regional analysis section do not reflect the generating capability of all resources during stress conditions.

Table 3. Nameplate Capacity by MISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**37,914**	**64,194**	**11,127**	**2,867**	**8,717**	**5,427**	**2,533**	**32,826**	**41,715**	**207,319**
MISO-W	12,651	13,608	2,753	1,491	2,613	200	777	8,109	29,411	**71,612**
MISO-C	15,050	10,307	2,169	494	2,211	1,272	769	12,361	7,350	**51,982**
MISO-S	5,493	31,052	5,100	589	2,469	54	845	8,315	596	**54,511**
MISO-E	4,720	9,227	1,105	292	1,424	3,901	143	4,042	4,359	**29,213**
Additions	**0**	**2,535**	**0**	**330**	**0**	**1,929**	**0**	**14,354**	**1,926**	**21,074**
MISO-W	0	537	0	172	0	374	0	3,552	1,358	**5,993**
MISO-C	0	407	0	57	0	934	0	5,103	339	**6,841**
MISO-S	0	1,226	0	68	0	9	0	3,868	27	**5,199**
MISO-E	0	364	0	34	0	611	0	1,831	201	**3,042**
Closures	**(24,913)**	**(6,597)**	**0**	**(324)**	**(140)**	**(16)**	**(83)**	**0**	**(272)**	**(32,345)**
MISO-W	(8,313)	(1,398)	0	(168)	(56)	0	(25)	0	(192)	**(10,152)**
MISO-C	(9,889)	(1,059)	0	(56)	(7)	(3)	(25)	0	(48)	**(11,088)**
MISO-S	(3,609)	(3,191)	0	(67)	(55)	(0)	(28)	0	(4)	**(6,954)**
MISO-E	(3,102)	(948)	0	(33)	(21)	(13)	(5)	0	(28)	**(4,150)**

2.2 ISO-NE

In the current system model and the No Plant Closures case, ISO-NE did not experience shortfall events. The region maintained adequacy throughout the study period through reliance on imports. In the Plant Closures case, ISO-NE still did not exceed any key reliability thresholds, despite moderate retirements. This finding is partly due to the absence of additional AI or data center load growth modeled in the region. Accordingly, no additional perfect capacity was deemed necessary by 2030 to meet the study's reliability standards.

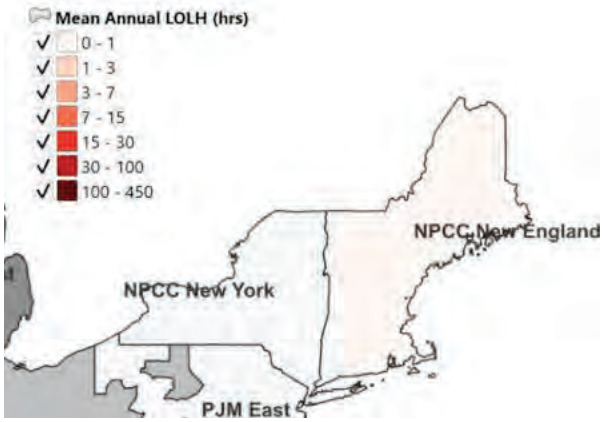
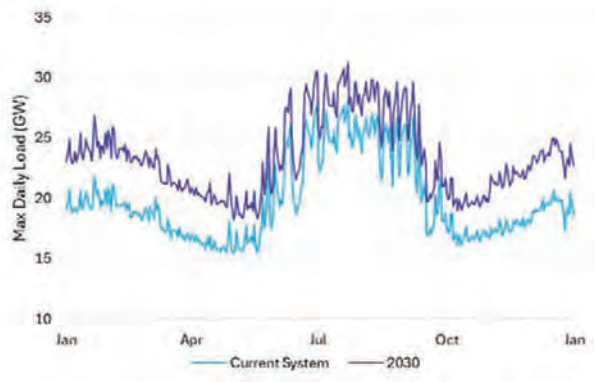


Table 4. Summary of ISO-NE Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	-	-	-
Normalized Unserved Energy (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	-	-	-
Normalized Unserved Load (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
Max Unserved Load (MW)	-	-	-	-

Load Assumptions

ISO-NE's peak load was roughly 28 GW in the current model and projected to increase to roughly 31 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
ISO-NE	28,128	31,261
Total	**28,128**	**31,261**

Figure 12. ISO-NE Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 40 GW. In 2030, 5.5 GW of new capacity was added leading to 45.5 GW of capacity in the No Plant Closures case. In the Plant Closures case, 2.7 GW of capacity was retired such that net generation change in the Plant Closures case was +11 GW, or 42.8 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ISO-NE	39,979	42,845	45,534
Total	**39,979**	**42,845**	**45,534**

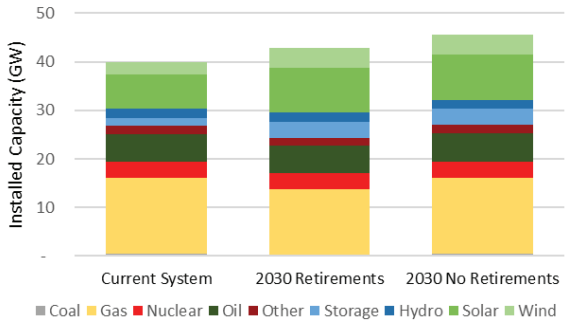


Figure 13. ISO-NE Generation Capacity by Technology and Scenario

ISO-NE's generation mix was comprised primarily of natural gas, solar, oil, and nuclear. In 2024, natural gas comprised 39% of nameplate, solar comprised 17%, oil 14%, and nuclear 8%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed nearly 2 GW of rooftop solar and 1.6 GW of energy storage.

Table 5. Nameplate Capacity by ISO-NE Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**541**	**15,494**	**3,331**	**5,710**	**1,712**	**1,628**	**1,911**	**7,099**	**2,553**	**39,979**
ISONE	541	15,494	3,331	5,710	1,712	1,628	1,911	7,099	2,553	**39,979**
Additions	**0**	**90**	**0**	**181**	**0**	**1,607**	**0**	**2,183**	**1,495**	**5,555**
ISONE	0	90	0	181	0	1,607	0	2,183	1,495	**5,555**
Closures	**(534)**	**(1,875)**	**0**	**(203)**	**(77)**	**0**	**0**	**0**	**0**	**(2,690)**
ISONE	(534)	(1,875)	0	(203)	(77)	0	0	0	0	**(2,690)**

2.3 NYISO

In both the current system model and the No Plant Closures case, NYISO maintained reliability and did not exceed any shortfall thresholds. Adequacy was preserved through reliance on imports. In the Plant Closures case, NYISO experienced shortfalls but average annual LOLH remaining well below the 2.4-hour threshold and NUSE under the 0.002% standard. The worst weather year produced only 6 hours of lost load and a peak unserved load of 914 MW. Given the modest impact of retirements and no additional AI/data center load modeled, the study concluded that NYISO would not require additional perfect capacity to remain reliable through 2030.

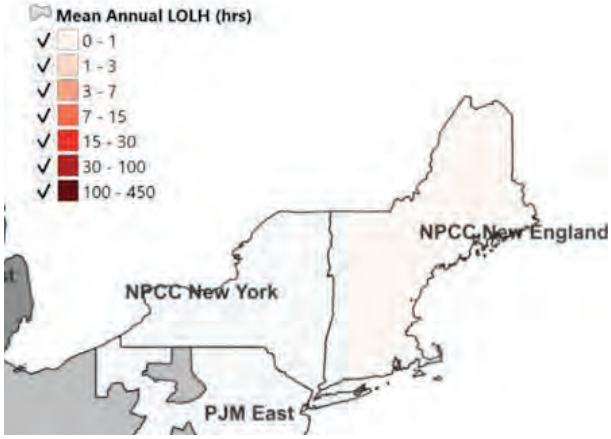
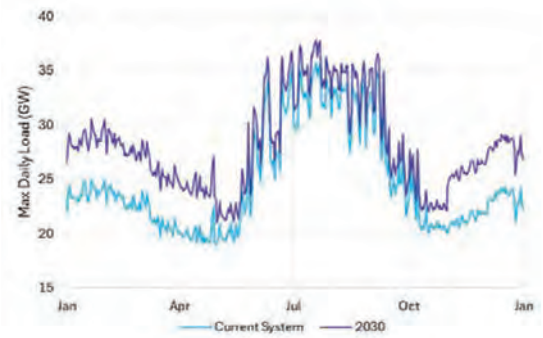


Table 6. Summary of NYISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.2	0.5	-	-
Normalized Unserved Energy (%)	0.00001	0.0001	-	-
Unserved Load (MWh)	18	209	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	2	6	-	-
Normalized Unserved Load (%)	0.0001	0.0013	-	-
Unserved Load (MWh)	216	2,505	-	-
Max Unserved Load (MW)	194	914	-	-

Load Assumptions

NYISO's peak load was roughly 36 GW in the current system model and projected to increase to roughly 38 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
NYISO	35,669	37,844
Total	**35,669**	**37,844**

Figure 14. NYISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 46 GW. In 2030, 5.5 GW of new capacity was added leading to 51 GW of capacity in the No Plant Closures case. In the Plant Closures case, 1 GW of capacity was retired such that net generation in the Plant Closures case was +4 GW, or 50 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
NYISO	45,924	50,396	51,444
Total	**45,924**	**50,396**	**51,444**

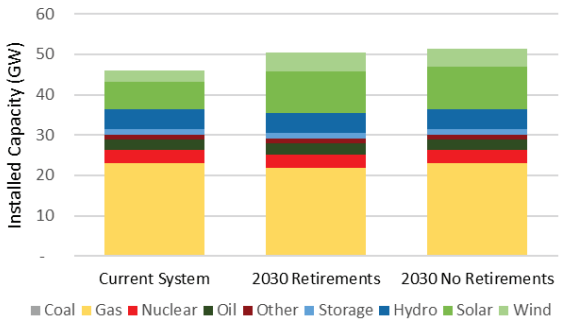


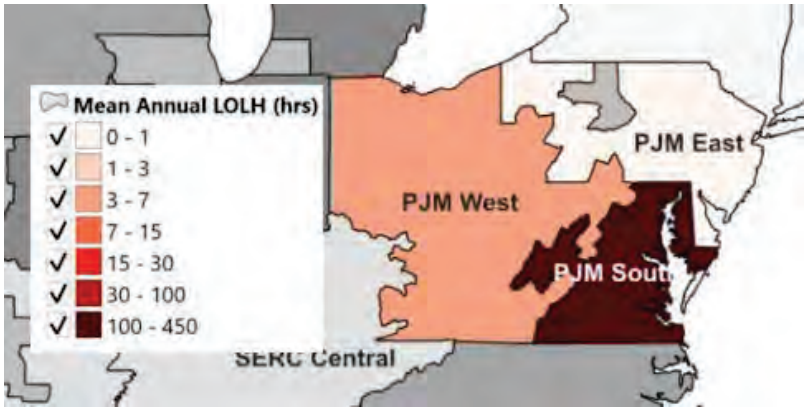
Figure 15. NYISO Generation Capacity by Technology and Scenario

NYISO's generation mix was comprised primarily of natural gas, solar, and hydro. In 2024, natural gas comprised 50% of total nameplate generation, solar comprised 14%, and hydro 11%. In 2030, most retirements come from natural gas while additions occur for solar and wind. The model assumed 6 GW of rooftop solar and nearly 1 GW of demand response.

Table 7. Nameplate Capacity by NYISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**0**	**22,937**	**3,330**	**2,631**	**1,194**	**1,460**	**4,915**	**6,749**	**2,706**	**45,924**
NYISO	0	22,937	3,330	2,631	1,194	1,460	4,915	6,749	2,706	**45,924**
Additions	**0**	**0**	**0**	**15**	**0**	**0**	**0**	**3,604**	**1,902**	**5,521**
NYISO	0	0	0	15	0	0	0	3,604	1,902	**5,521**
Closures	**0**	**(1,030)**	**0**	**(19)**	**0**	**0**	**0**	**0**	**0**	**(1,049)**
NYISO	0	(1,030)	0	(19)	0	0	0	0	0	**(1,049)**

2.4 PJM



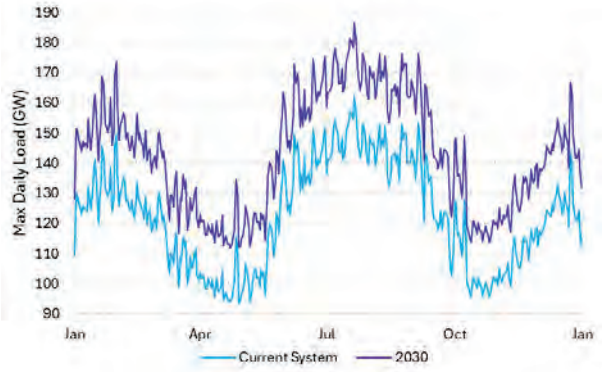
In the current system model, PJM experienced shortfalls, but they were below the required threshold. In the No Plant Closures case, shortfalls increased dramatically, with 214 average annual LOLH and peak unserved load reaching 17,620 MW, indicating growing strain even without retirements. In the Plant Closures case, reliability metrics worsened significantly, with annual LOLH surging to over 430 hours per year and NUSE reaching 0.1473%—over 70 times the accepted threshold. During the worst weather year, 1,052 hours of load were shed. To restore reliability, the study found that PJM would require 10,500 MW of additional perfect capacity by 2030.

Table 8. Summary of PJM Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	2.4	430.3	213.7	1.4
Normalized Unserved Energy (%)	0.0008	0.1473	0.0657	0.0003
Unserved Load (MWh)	6,891	1,453,513	647,893	2,536
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	29	1,052	644	17
Normalized Unserved Load (%)	0.0100	0.4580	0.2703	0.0031
Unserved Load (MWh)	82,687	1,453,513	647,893	2,536
Max Unserved Load (MW)	4,975	21,335	17,620	4,162

Load Assumptions

PJM's peak load was roughly 162 GW in the current system model and projected to increase to roughly 187 GW by 2030. Approximately 15 GW of this relates to new AI/DC being installed (29% of U.S. total), primarily in PJM-S.



Subregion	2024	2030
PJM-W	81,541	92,378
PJM-S	39,904	51,151
PJM-E	41,003	43,118
Total	**162,269**	**186,627**

Figure 16. PJM Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 215 GW. In 2030, 39 GW of new capacity was added leading to 254 GW of capacity in the No Plant Closures case. In the Plant Closures case, 17 GW of capacity was retired such that net generation in the Plant Closures case was +22 GW, or 237 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
PJM-W	114,467	123,100	135,810
PJM-S	39,951	48,850	50,667
PJM-E	60,221	64,848	67,027
Total	**214,638**	**236,798**	**253,504**

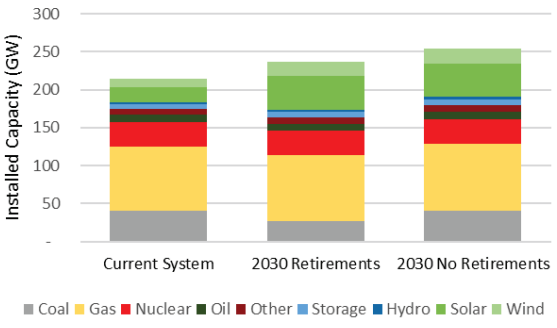


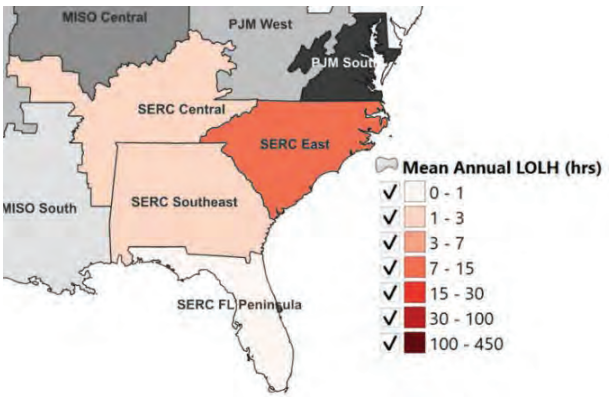
Figure 17. PJM Generation Capacity by Technology and Scenario

PJM's generation mix was comprised primarily of natural gas, coal, and nuclear. In 2024, natural gas comprised 39% of nameplate, coal comprised 19%, and nuclear 15%. In 2030, most retirements come from coal and some natural gas and oil while significant additions occur for solar plus lesser additions of wind, storage, and natural gas. The model assumed 9 GW of rooftop solar and 7 GW of demand response.

Table 9. Nameplate Capacity by PJM Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**39,915**	**84,381**	**32,535**	**9,875**	**8,248**	**5,400**	**3,071**	**19,495**	**11,718**	**214,638**
PJM-W	34,917	39,056	16,557	1,933	3,926	383	1,252	6,379	10,065	**114,467**
PJM-S	2,391	15,038	5,288	3,985	2,303	3,085	1,070	6,430	360	**39,951**
PJM-E	2,608	30,287	10,690	3,956	2,019	1,932	749	6,686	1,294	**60,221**
Additions	**0**	**4,499**	**0**	**32**	**317**	**1,938**	**0**	**24,991**	**7,089**	**38,866**
PJM-W	0	2,082	0	6	135	855	0	12,176	6,089	**21,343**
PJM-S	0	802	0	13	102	726	0	8,856	218	**10,717**
PJM-E	0	1,615	0	13	81	357	0	3,958	783	**6,806**
Closures	**(13,253)**	**(1,652)**	**0**	**(1,790)**	**(11)**	**0**	**0**	**0**	**0**	**(16,706)**
PJM-W	(11,593)	(765)	0	(350)	(1)	0	0	0	0	**(12,710)**
PJM-S	(794)	(294)	0	(722)	(6)	0	0	0	0	**(1,817)**
PJM-E	(866)	(593)	0	(717)	(3)	0	0	0	0	**(2,179)**

2.5 SERC



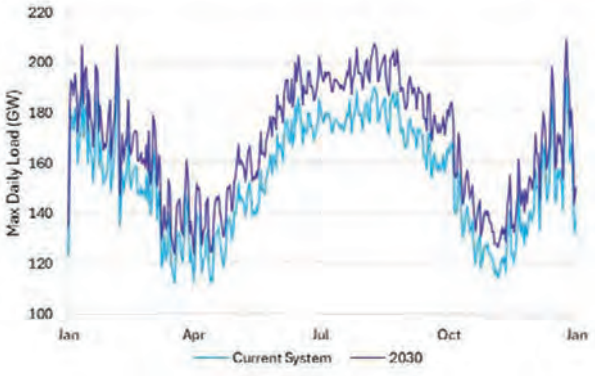
In the current system model and the No Plant Closures case, SERC maintained overall adequacy, though some subregions—particularly SERC-East—faced emerging winter reliability risks. In the Plant Closures case, shortfalls became more severe, with SERC-East experiencing increased unserved energy and loss of load hours during extreme cold events, including 42 hours of outages in a single winter storm. The analysis identified that planned retirements, combined with rising winter load from electrification, would stress the system. To restore reliability in SERC-East, the study found that 500 MW of additional perfect capacity would be needed by 2030. Other SERC subregions performed adequately, but continued monitoring is warranted due to shifting seasonal peaks and fuel supply vulnerabilities.

Table 10. Summary of SERC Reliability Metrics

Reliability Metric		2030 Projection		
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.3	8.1	1.2	0.8
Normalized Unserved Energy (%)	0.0001	0.0041	0.0004	0.0002
Unserved Load (MWh)	489	44,514	3,748	2,373
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	4	42	14	10
Normalized Unserved Load (%)	0.0006	0.0428	0.0042	0.0026
Unserved Load (MWh)	5,683	465,392	44,977	2,373
Max Unserved Load (MW)	2,373	19,381	6,359	5,859

Load Assumptions

SERC's peak load was roughly 193 GW in the current system model and projected to increase to roughly 209 GW by 2030. Approximately 7.5 GW of this relates to new AI/DCs being installed (14% of U.S. total).



Subregion	2024	2030
SERC-C	50,787	52,153
SERC-SE	48,235	54,174
SERC-FL	58,882	62,572
SERC-E	51,693	56,313
Total	**193,654**	**209,269**

Figure 18. SERC Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 254 GW. In 2030, 26 GW of new capacity was added leading to 279 GW of capacity in the No Plant Closures case. In the Plant Closures case, 19 GW of capacity was retired such that net generation change in the Plant Closures case was +7 GW, or 260 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SERC-C	53,978	54,014	59,660
SERC-SE	67,073	64,768	69,478
SERC-FL	72,714	83,127	86,173
SERC-E	59,914	58,513	63,973
Total	**253,680**	**260,423**	**279,285**

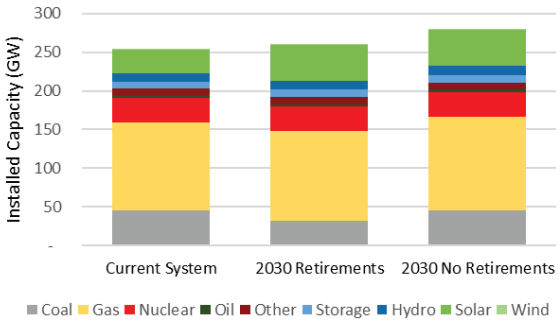


Figure 19. SERC Generation Capacity by Technology and Scenario

SERC's generation mix was comprised primarily of natural gas, coal, nuclear, and solar. In 2024, natural gas comprised 45% of nameplate, coal comprised 18%, nuclear 12%, and solar 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar and some storage. The model assumed 3 GW of rooftop solar and 8 GW of demand response.

Table 11. Nameplate Capacity by SERC Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**45,747**	**113,334**	**31,702**	**4,063**	**8,779**	**7,469**	**11,425**	**30,180**	**982**	**253,680**
SERC-C	13,348	20,127	8,280	148	1,887	1,884	4,995	2,328	982	**53,978**
SERC-SE	13,275	29,866	8,018	915	2,493	1,662	3,260	7,584	0	**67,073**
SERC-FL	4,346	47,002	3,502	1,957	3,198	538	0	12,172	0	**72,714**
SERC-E	14,777	16,340	11,902	1,044	1,202	3,384	3,170	8,096	0	**59,914**
Additions	**0**	**6,898**	**0**	**0**	**381**	**2,254**	**0**	**16,073**	**0**	**25,606**
SERC-C	0	4,831	0	0	0	80	0	771	0	**5,682**
SERC-SE	0	906	0	0	19	0	0	3,135	0	**4,059**
SERC-FL	0	1,161	0	0	218	1,670	0	10,410	0	**13,459**
SERC-E	0	0	0	0	144	504	0	1,757	0	**2,405**
Closures	**(14,075)**	**(4,115)**	**0**	**(672)**	**0**	**0**	**0**	**0**	**0**	**(18,862)**
SERC-C	(4,465)	(1,181)	0	0	0	0	0	0	0	**(5,646)**
SERC-SE	(5,160)	(124)	0	(176)	0	0	0	0	0	**(5,460)**
SERC-FL	(1,495)	(1,071)	0	(480)	0	0	0	0	0	**(3,046)**
SERC-E	(2,955)	(1,739)	0	(16)	0	0	0	0	0	**(4,710)**

2.6 SPP

In the current system model, SPP experienced shortfalls, but they were below the required threshold. Adequacy was preserved through reliance on imports. In the No Plant Closures case, SPP experienced persistent reliability challenges, with average annual LOLH reaching approximately 48 hours per year and peak hourly shortfalls affecting up to 19% of demand. In the Plant Closures case, system conditions deteriorated further, with unserved energy and outage hours increasing substantially. These shortfalls were concentrated in the northern subregion, which lacks the firm generation and import capacity needed to meet peak winter demand. The analysis determined that 1,500 MW of additional perfect capacity would be needed in SPP by 2030 to restore reliability.

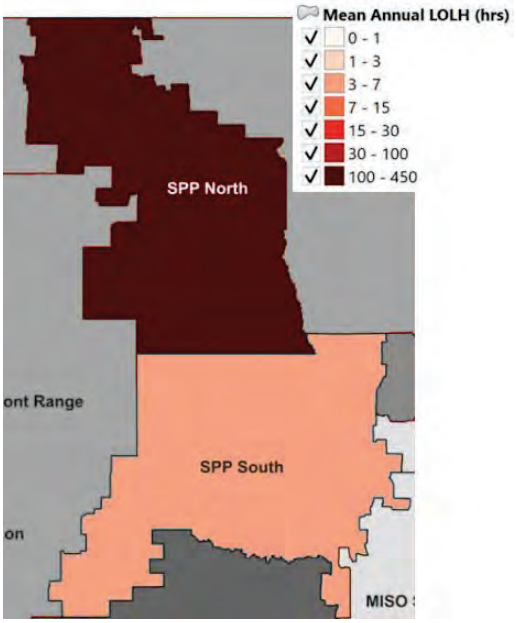
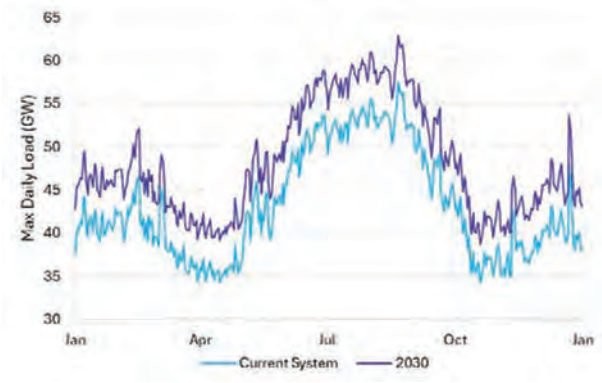


Table 12. Summary of SPP Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	1.7	379.6	47.8	2.4
Normalized Unserved Energy (%)	0.0002	0.0911	0.0081	0.0002
Unserved Load (MWh)	541	313,797	27,697	803
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	20	556	186	26
Normalized Unserved Load (%)	0.0022	0.2629	0.0475	0.0027
Unserved Load (MWh)	6,492	907,518	163,775	9,433
Max Unserved Load (MW)	606	13,263	2,432	762

Load Assumptions

SPP's peak load was roughly 57 GW in the current system model and projected to increase to roughly 63 GW by 2030. Approximately 1.5 GW of this relates to new AI/DCs being installed (3% of U.S. total).



Subregion	2024	2030
SPP-N	12,668	14,676
SPP-S	44,898	48,337
Total	**57,449**	**62,891**

Figure 20. SPP Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 95 GW. In 2030, 15 GW of new capacity was added leading to 110 GW of capacity in the No Plant Closures case. In the Plant Closures case, 7 GW of capacity was retired such that net generation change in the 2030 Plant Closures case was +8 GW, or 103 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SPP-N	20,065	20,679	22,385
SPP-S	75,078	82,451	88,064
Total	**95,142**	**103,130**	**110,449**

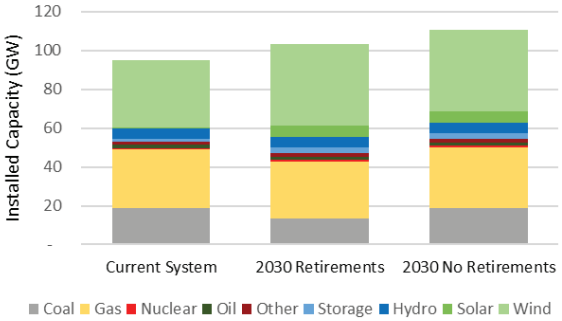


Figure 21. SPP Generation Capacity by Technology and Scenario

SPP's generation mix was comprised primarily of wind, natural gas, and coal. In 2024, wind comprised 36% of nameplate, natural gas comprised 32%, and coal 20%. In the 2030 case, most retirements come from coal and natural gas while additions occur for wind, solar, storage, and natural gas. The model assumed almost no rooftop solar and 1.3 GW of demand response.

Table 13. Nameplate Capacity by SPP Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**18,919**	**30,003**	**769**	**1,626**	**1,718**	**1,522**	**5,123**	**774**	**34,689**	**95,142**
SPP-N	5,089	3,467	304	504	519	8	3,041	91	7,041	**20,065**
SPP-S	13,829	26,536	465	1,121	1,199	1,514	2,082	683	27,649	**75,078**
Additions	**0**	**1,094**	**0**	**7**	**462**	**1,390**	**0**	**5,288**	**7,066**	**15,306**
SPP-N	0	126	0	2	114	11	0	633	1,434	**2,320**
SPP-S	0	968	0	5	348	1,379	0	4,655	5,632	**12,987**
Closures	**(5,530)**	**(1,732)**	**0**	**(56)**	**0**	**0**	**0**	**0**	**0**	**(7,318)**
SPP-N	(1,488)	(200)	0	(17)	0	0	0	0	0	**(1,705)**
SPP-S	(4,042)	(1,532)	0	(39)	0	0	0	0	0	**(5,613)**

2.7 CAISO+

In the current system and No Plant Closures cases, CAISO+ did not experience major reliability issues, though adequacy was often maintained through significant imports during tight conditions. In the Plant Closures case, however, the region faced substantial shortfalls, particularly during summer evening hours when solar output declines. Average LOLH reached 7 hours per year, and the worst-case year showed load shed events affecting up to 31% of demand. The NUSE exceeded reliability thresholds, signaling the system's vulnerability to high load and low renewable output periods.

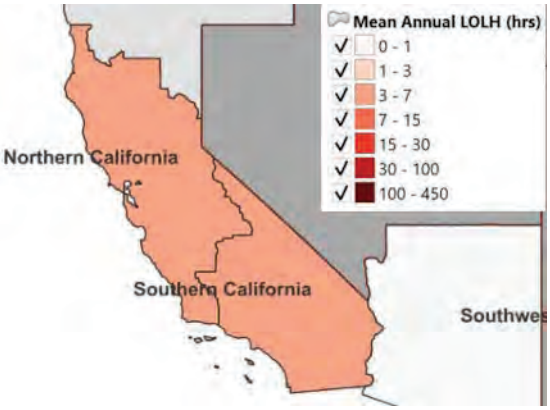
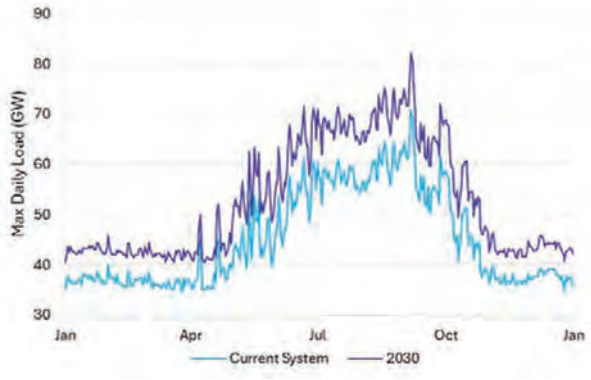


Table 14. Summary of CAISO+ Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	6.8	-	-
Normalized Unserved Energy (%)	-	0.0062	-	-
Unserved Load (MWh)	-	23,488	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	21	-	-
Normalized Unserved Load (%)	-	0.0195	-	-
Unserved Load (MWh)	-	73,462	-	-
Max Unserved Load (MW)	-	12,391	-	-

Load Assumptions

CAISO+'s peak load was roughly 79 GW in the current system model and projected to increase to roughly 82 GW by 2030. Approximately 2 GW of this relates to new AI/DCs being installed (4% of U.S. total).



Subregion	2024	2030
CALI-N	29,366	34,066
CALI-S	41,986	48,666
Total	**70,815**	**82,146**

Figure 22. CAISO+ Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 117 GW. In 2030, 14 GW of new capacity was added leading to 131 GW of capacity in the No Plant Closures case. In the Plant Closures case, 8 GW of capacity was retired such that net closures in the Plant Closures case were +6 GW, or 123 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
CALI-N	47,059	48,897	52,501
CALI-S	69,866	74,041	78,308
Total	**116,925**	**122,938**	**130,809**

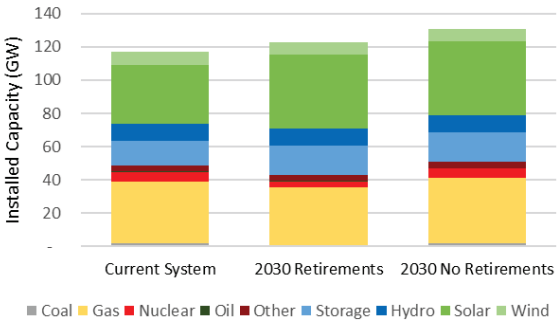


Figure 23. CAISO+ Generation Capacity by Technology and Scenario

CAISO+'s generation mix was comprised primarily of natural gas, solar, storage, and hydro. In 2024, natural gas comprised 32% of nameplate, solar comprised 31%, storage 13%, and hydro 9%. In 2030, most retirements come from coal, natural gas, and nuclear while additions occur for solar and storage. The model assumed 10 GW of rooftop solar and less than 1 GW of demand response.

Table 15. Nameplate Capacity by CAISO+ Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**1,816**	**37,434**	**5,582**	**185**	**3,594**	**14,670**	**10,211**	**35,661**	**7,773**	**116,925**
CALI-N	0	12,942	5,582	165	1,872	4,639	8,727	11,759	1,373	**47,059**
CALI-S	1,816	24,492	0	20	1,722	10,031	1,483	23,902	6,400	**69,866**
Additions	**0**	**2,126**	**0**	**0**	**92**	**3,161**	**0**	**8,507**	**0**	**13,885**
CALI-N	0	735	0	0	44	757	0	3,906	0	**5,442**
CALI-S	0	1,391	0	0	48	2,404	0	4,600	0	**8,442**
Closures	**(1,800)**	**(3,771)**	**(2,300)**	**0**	**0**	**0**	**0**	**0**	**0**	**(7,871)**
CALI-N	0	(1,304)	(2,300)	0	0	0	0	0	0	**(3,604)**
CALI-S	(1,800)	(2,467)	0	0	0	0	0	0	0	**(4,267)**

2.8 West Non-CAISO

In both the current system and No Plant Closures cases, the West Non-CAISO region maintained adequacy on average. In the Plant Closures case, the region's reliability declined, with annual LOLH increasing and peak shortfalls in the worst year affecting up to 20% of hourly load in some subregions. While overall NUSE normalized unserved energy remained just above the 0.002% threshold, specific areas, especially those with limited local resources and constrained transmission, exceeded acceptable risk levels. These reliability gaps were primarily driven by increasing reliance on variable energy resources without sufficient firm generation.

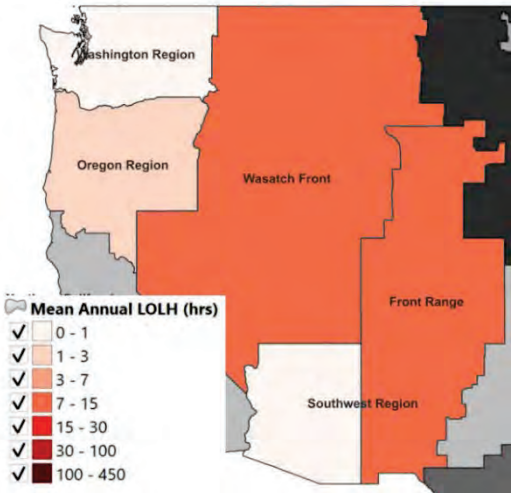
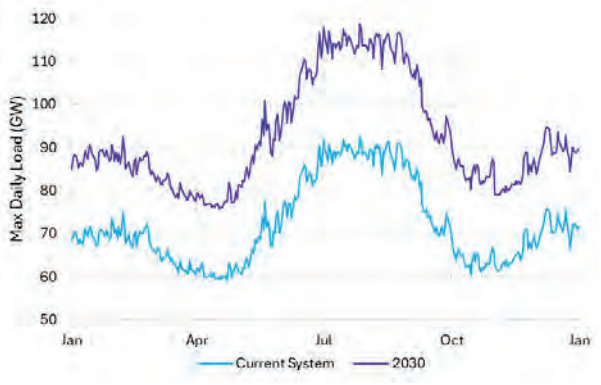


Table 16. Summary of West Non-CAISO Reliability Metrics

Reliability Metric	Current System	2030 Projection		
		Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	17.8	-	-
Normalized Unserved Energy (%)	-	0.0032	-	-
Unserved Load (MWh)	-	21,785	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	47	-	-
Normalized Unserved Load (%)	-	0.0098	-	-
Unserved Load (MWh)	-	66,248	-	-
Max Unserved Load (MW)	-	5,071	-	-

Load Assumptions

West Non-CAISO's peak load was roughly 92 GW in the current system model and projected to increase to roughly 119 GW by 2030. Approximately 12 GW of this relates to new AI/DCs being installed (24% of U.S. total).



Subregion	2024	2030
WASHINGTON	20,756	23,187
OREGON	11,337	16,080
SOUTHWEST	23,388	30,169
WASATCH	27,161	35,440
FRONT R	20,119	24,996
Total	**92,448**	**118,657**

Figure 24. West Non-CAISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 178 GW. In 2030, 29 GW of new capacity was added leading to 207 GW of capacity in the No Plant Closures case. In the Plant Closures case, 13 GW of capacity was retired such that net generation change in the Plant Closures case was 16 GW, or 193 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
WASHINGTON	35,207	36,588	37,573
OREGON	19,068	21,689	22,081
SOUTHWEST	42,335	47,022	49,158
WASATCH	42,746	45,175	50,251
FRONT R	38,572	43,011	47,844
Total	**177,929**	**193,485**	**206,908**

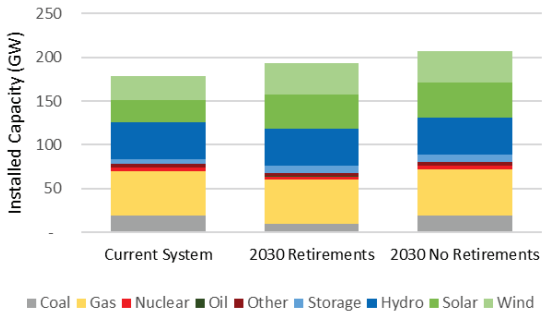


Figure 25. West Non-CAISO Generation Capacity by Technology and Scenario

West Non-CAISO's generation mix was comprised primarily of natural gas, hydro, wind, solar, and coal. In 2024, natural gas comprised 28% of nameplate, hydro comprised 24%, wind 15%, solar 13%, and coal 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar, wind, storage, and natural gas. The model assumed 6 GW of rooftop solar and over 1 GW of demand response.

Table 17. Nameplate Capacity by West Non-CAISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**19,850**	**49,969**	**3,820**	**644**	**4,114**	**5,104**	**42,476**	**24,652**	**27,298**	**177,929**
WASHINGTON	560	3,919	1,096	17	595	489	24,402	1,438	2,690	**35,207**
OREGON	0	3,915	0	6	456	482	8,253	2,517	3,440	**19,068**
SOUTHWEST	4,842	17,985	2,724	323	1,316	2,349	1,019	8,093	3,685	**42,335**
WASATCH	7,033	14,061	0	87	1,433	1,194	7,587	7,299	4,052	**42,746**
FRONT R	7,415	10,089	0	211	314	590	1,215	5,306	13,432	**38,572**
Additions	**0**	**2,320**	**0**	**1**	**8**	**2,932**	**0**	**14,759**	**8,959**	**28,979**
WASHINGTON	0	246	0	0	0	109	0	1,059	952	**2,366**
OREGON	0	246	0	0	0	150	0	1,399	1,218	**3,013**
SOUTHWEST	0	309	0	0	0	2,338	0	3,578	599	**6,823**
WASATCH	0	884	0	0	7	233	0	4,946	1,435	**7,505**
FRONT R	0	634	0	0	0	102	0	3,779	4,756	**9,271**
Closures	**(9,673)**	**(2,540)**	**0**	**(6)**	**(311)**	**(170)**	**(627)**	**0**	**(95)**	**(13,422)**
WASHINGTON	(317)	(195)	0	(0)	(66)	(28)	(369)	0	(11)	**(986)**
OREGON	0	(195)	0	(0)	(58)	0	(125)	0	(14)	**(392)**
SOUTHWEST	(1,185)	(951)	0	0	0	0	0	0	0	**(2,136)**
WASATCH	(3,978)	(699)	0	(2)	(178)	(89)	(115)	0	(16)	**(5,077)**
FRONT R	(4,194)	(501)	0	(4)	(8)	(53)	(18)	0	(54)	**(4,832)**

2.9 ERCOT

In the current system model, ERCOT exceeded reliability thresholds, with 3.8 annual Loss of Load Hours and a NUSE of 0.0032%, indicating stress even before future retirements and load growth. In the No Plant Closures case, conditions worsened as average LOLH rose to 20 hours per year and the worst-case year reached 101 hours, driven by data center growth and limited dispatchable additions. The Plant Closures case intensified these risks, with average annual LOLH rising to 45 hours per year and unserved load reaching 0.066%. Peak shortfalls reached 27% of demand, with outages concentrated in winter when generation is most vulnerable. To meet reliability targets, ERCOT would require 10,500 MW of additional perfect capacity by 2030.

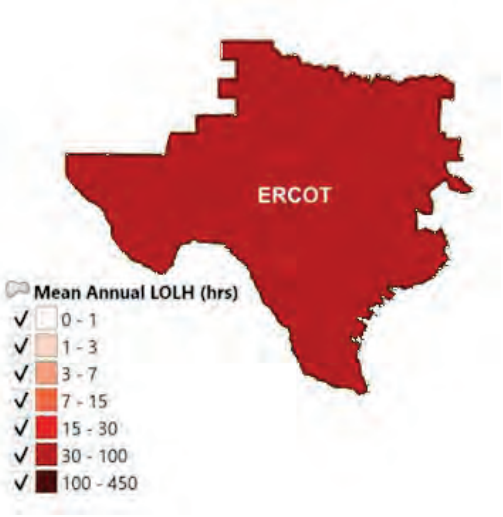
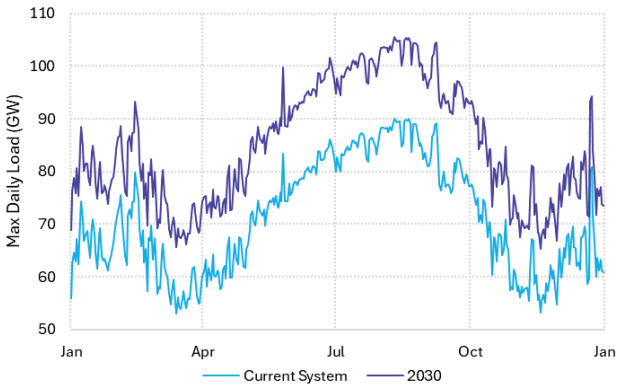


Table 18. Summary of ERCOT Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	3.8	45.0	20.3	1.0
Normalized Unserved Energy (%)	0.0032	0.0658	0.0284	0.0008
Unserved Load (MWh)	15,378	397,352	171,493	4,899
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	30	149	101	12
Normalized Unserved Load (%)	0.0286	0.02895	0.01820	0.0098
Unserved Load (MWh)	136,309	1,741,003	1,093,560	58,787
Max Unserved Load (MW)	10,115	27,156	23,105	8,202

Load Assumptions

ERCOT's peak load was roughly 90 GW in the current system model and projected to increase to roughly 105 GW by 2030. Approximately 8 GW of this relates to new data centers being installed (62% of U.S. total).



Subregion	2024	2030
ERCOT	90,075	105,485
Total	**90,075**	**105,485**

Figure 26. ERCOT Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 157 GW. In 2030, 55 GW of new capacity was added leading to 213 GW of capacity in the No Plant Closures case. In the Plant Closures case, 4 GW of capacity was retired such that net generation change in the Plant Closures case was +51 GW, or 208 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ERCOT	157,490	208,894	212,916
Total	**157,490**	**208,894**	**212,916**

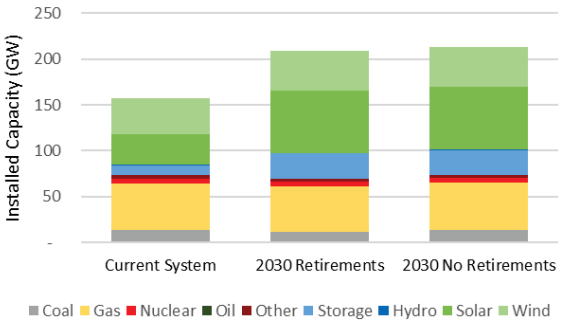


Figure 27. ERCOT Generation Capacity by Technology and Scenario

ERCOT's generation mix was comprised primarily of natural gas, wind, and solar. In 2024, natural gas comprised 32% of nameplate, wind comprised 25%, and solar 22%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed 2.5 GW of rooftop solar and 3.5 GW of demand response.

Table 19. Nameplate Capacity for ERCOT and by Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**13,568**	**50,889**	**4,973**	**10**	**3,627**	**10,720**	**583**	**33,589**	**39,532**	**157,490**
ERCOT	13,568	50,889	4,973	10	3,627	10,720	583	33,589	39,532	**157,490**
Additions	**0**	**569**	**0**	**0**	**0**	**16,538**	**0**	**34,681**	**3,638**	**55,426**
ERCOT	0	569	0	0	0	16,538	0	34,681	3,638	**55,426**
Closures	**(2,000)**	**(2,022)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**(4,022)**
ERCOT	(2,000)	(2,022)	0	0	0	0	0	0	0	**(4,022)**

Appendix A - Generation Calibration and Forecast

The study team started with the grid model from the NERC ITCS, which was published in 2024 with reference to NERC 2023 LTRA capacity.[27] This zonal ITCS model serves as the starting point for the network topology (covering 23 U.S regions), transmission capacity between zones, and general modeling assumptions. The resource mix and retirements in the ITCS model were updated for this study to reflect the various 2030 scenarios discussed previously. Prior to developing the 2030 scenarios, the study team also updated the 2024 ITCS model to ensure consistency in the current model assumptions.

2024 Resource Mix

Because there were noted changes in assumed capacity additions between the 2023 and 2024 LTRAs[28], the ITCS model was updated with the 2024 LTRA data, provided directly by NERC to the study team. The 2024 LTRA dataset, reported at the NERC assessment area level—which is more aggregated in some areas than the ITCS regional structure (covering 13 U.S. regions; see Figure A.1)—includes both existing resource capacities[29] and Tier 1, 2, and 3 planned additions for each year from 2024 to 2033. As explained below, to incorporate this data into the ITCS model, a mapping process was developed to disaggregate generation capacities from the NERC assessment areas to the more granular ITCS regions by technology type. To preserve the daily or monthly adjustments to generator availability for certain categories (wind, solar, hybrid, hydropower, batteries, and other) by using the ITCS methods, the nameplate LTRA capacity was used. For all other categories (mostly thermal generators), summer and winter on-peak capacity contributions were used.

27. NERC, “Interregional Transfer Capability Study (ITCS).” https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf.

28. NERC, “2024 Long-Term Reliability Assessment,” December, 2024, 24. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

29. Capacities are reported for both winter and summer seasonal ratings, along with nameplate values.

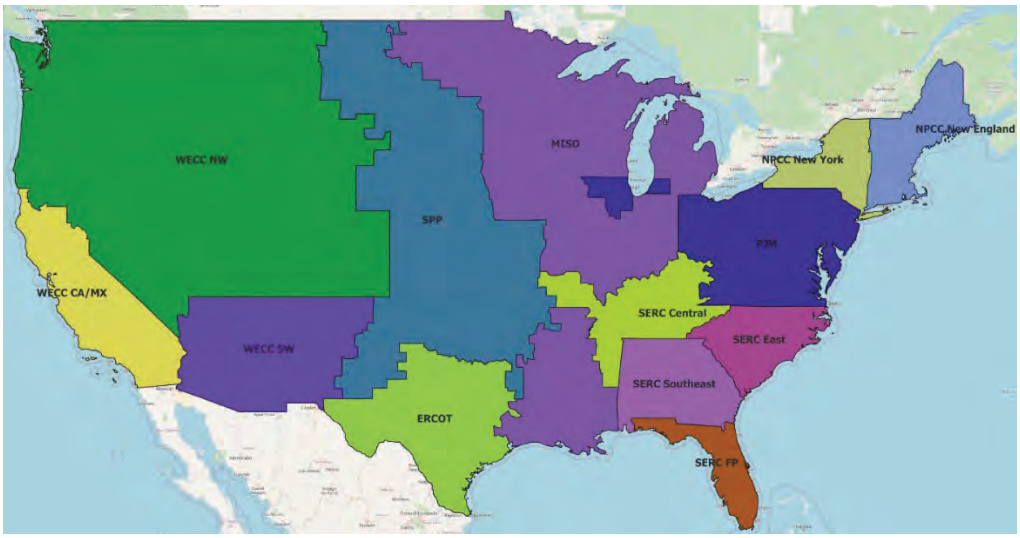


Figure A.1. NERC assessment areas.

To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant-level data were used to tabulate the generation capacity for each ITCS region and NERC assessment area. The geographical boundaries for the NERC assessment areas and the ITCS regions were constructed based on ReEDS zones.[30] Disaggregation fractions were then calculated by technology type using the combined existing capacity and planned additions through 2030 from EIA 860 data as of December 2024. Specifically, to compute each fraction, an ITCS region's total (existing plus planned) capacity was divided by the corresponding total capacity across all ITCS regions within the same mapped NERC assessment area and fuel type group:

$$Fraction_{rf} = \frac{Capacity_{rf}}{\sum_{r' \in ITCS(R)} Capacity_{r'f}} \quad \textit{(Equation.1)}$$

Where $Capacity_{rf}$ is the capacity of fuel type f in ITCS region r and $ITCS(R)$ is the set of all ITCS regions mapped to the same NERC assessment area R. The denominator is the total capacity of that fuel type across all ITCS regions mapped to R.

Note that in cases where NERC assessment areas align one-to-one with ITCS regions, no mapping was required. Table A.1 summarizes which areas exhibited a direct one-to-one matching and which required disaggregation (1-to-many) or aggregation (many-to-one) to align with the ITCS regional structure.

An exception to this general approach is the case of the Front Range ITCS region, which geographically spans across two NERC assessment areas—WECC-NW and WECC-SW—resulting in two-to-one mapping. For this case, a separate allocation method was used: Plant-level data from EIA 860 were analyzed to determine the proportion of Front Range capacity located in each NERC area. These proportions were then used to derive custom weighting factors for allocating capacities from both WECC-NW and WECC-SW into the Front Range region.

30. NREL, "Regional Energy Development System," https://www.nrel.gov/analysis/reeds/.

Table A.1. Mapping of NERC assessment areas to ITCS regions.

NERC Area	ITCS Region	Match
ERCOT	ERCOT	1 to 1
NPCC-New England	NPCC-New England	1 to 1
NPCC-New York	NPCC-New York	1 to 1
SERC-C	SERC-C	1 to 1
SERC-E	SERC-E	1 to 1
SERC-FP	SERC-FP	1 to 1
SERC-SE	SERC-SE	1 to 1
WECC-SW	Southwest Region	1 to 1
MISO	MISO Central	1 to 4
MISO	MISO East	
MISO	MISO South	
MISO	MISO West	
SPP	SPP North	1 to 2
SPP	SPP South	
WECC-CAMX	Southern California	1 to 2
WECC-CAMX	Northern California	
WECC-NW	Oregon Region	1 to 3
WECC-NW	Washington Region	
WECC-NW	Wasatch Front	
WECC-NW	Front Range	2 to 1
WECC-SW	Front Range	

Table A.2 and Figure A.2 show the same combined capacities by ITCS region and NERC planning region, respectively.

Table A.2. Existing and Tier 1 capacities by NERC assessment area (in MW) in 2024.

2024 Exsting + Tier 1			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**143,035**	**330,342**	**82,793**	**26,771**	**3,624**	**-**	**991**	**19,607**	**3,298**	**28,980**	**72,757**	**94,364**	**25,753**	**24,367**	**856,682**
	ISONE	**Total**	541	15,494	3,331	5,710	818	-	233	1,571	57	1,911	3,386	2,553	661	3,713	39,979
	MISO	**Total**	**37,914**	**64,194**	**11,127**	**2,867**	**613**	**-**	**329**	**4,396**	**1,031**	**2,533**	**29,777**	**41,715**	**7,775**	**3,049**	**207,319**
		MISO-W	12,651	13,608	2,753	1,491	244	-	2	-	200	777	7,368	29,411	2,367	741	71,612
		MISO-C	15,050	10,307	2,169	494	32	-	152	773	499	769	10,587	7,350	2,026	1,774	51,982
		MISO-S	5,493	31,052	5,100	589	243	-	117	49	5	845	8,024	596	2,109	291	54,511
		MISO-E	4,720	9,227	1,105	292	94	-	57	3,574	327	143	3,799	4,359	1,273	243	29,213
	NYISO	**Total**	-	22,937	3,330	2,631	334	-	-	1,400	60	4,915	1,039	2,706	860	5,710	45,924
	PJM	**Total**	**39,915**	**84,381**	**32,535**	**9,875**	**851**	**-**	**-**	**5,062**	**338**	**3,071**	**10,892**	**11,718**	**7,397**	**8,603**	**214,638**
		PJM-W	34,917	39,056	16,557	1,933	112	-	-	234	149	1,252	5,780	10,065	3,814	599	114,467
		PJM-S	2,391	15,038	5,288	3,985	479	-	-	2,958	127	1,070	3,932	360	1,824	2,498	39,951
		PJM-E	2,608	30,287	10,690	3,956	260	-	-	1,870	62	749	1,180	1,294	1,759	5,506	60,221
	SERC	**Total**	**45,747**	**113,334**	**31,702**	**4,063**	**989**	**-**	**83**	**6,701**	**768**	**11,425**	**26,959**	**982**	**7,707**	**3,221**	**253,680**
		SERC-C	13,348	20,127	8,280	148	36	-	-	1,784	100	4,995	2,308	982	1,851	20	53,978
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	115	3,260	7,267	-	2,069	317	67,073
		SERC-FL	4,346	47,002	3,502	1,957	310	-	83	-	538	-	10,121	-	2,804	2,051	72,714
		SERC-E	14,777	16,340	11,902	1,044	219	-	-	3,369	15	3,170	7,263	-	983	833	59,914
	SPP	**Total**	**18,919**	**30,003**	**769**	**1,626**	**20**	**-**	**345**	**477**	**1,044**	**5,123**	**703**	**34,689**	**1,353**	**71**	**95,142**
		SPP-N	5,089	3,467	304	504	1	-	185	-	8	3,041	84	7,041	333	7	20,065
		SPP-S	13,829	26,536	465	1,121	19	-	160	477	1,037	2,082	619	27,649	1,020	64	75,078
ERCOT	**Total**		**13,568**	**50,889**	**4,973**	**10**	**163**	**-**	**-**	**-**	**10,720**	**583**	**31,058**	**39,532**	**3,464**	**2,531**	**157,490**
	ERCOT	**Total**	13,568	50,889	4,973	10	163	-	-	-	10,720	583	31,058	39,532	3,464	2,531	157,490
WEST	**Total**		**21,666**	**87,403**	**9,403**	**829**	**1,565**	**4,093**	**106**	**4,536**	**15,238**	**52,687**	**44,042**	**35,071**	**1,944**	**16,271**	**294,854**
	CAISO+	**Total**	**1,816**	**37,434**	**5,582**	**185**	**726**	**2,004**	**35**	**3,514**	**11,156**	**10,211**	**25,614**	**7,773**	**829**	**10,047**	**116,925**
		CALI-N	-	12,942	5,582	165	465	1,049	9	1,967	2,672	8,727	6,723	1,373	349	5,036	47,059
		CALI-S	1,816	24,492	-	20	261	955	26	1,547	8,484	1,483	18,891	6,400	480	5,011	69,866
	Non-CA WECC	**Total**	**19,850**	**49,969**	**3,820**	**644**	**839**	**2,089**	**71**	**1,022**	**4,082**	**42,476**	**18,428**	**27,298**	**1,115**	**6,224**	**177,929**
		WA	560	3,919	1,096	17	352	-	-	140	350	24,402	1,052	2,690	243	386	35,207
		OR	-	3,915	-	6	293	21	-	-	482	8,253	2,145	3,440	141	372	19,068
		SOUTHWEST	4,842	17,985	2,724	323	102	1,047	-	176	2,173	1,019	5,641	3,685	168	2,452	42,335
		WASATCH	7,033	14,061	-	87	56	1,011	61	444	750	7,587	5,625	4,052	305	1,674	42,746
		FRONT R	7,415	10,089	-	211	36	10	10	262	328	1,215	3,966	13,432	258	1,340	38,572
		Total	**178,268**	**468,635**	**97,169**	**27,610**	**5,353**	**4,093**	**1,096**	**24,144**	**29,256**	**82,249**	**147,856**	**168,966**	**31,161**	**43,169**	**1,309,026**

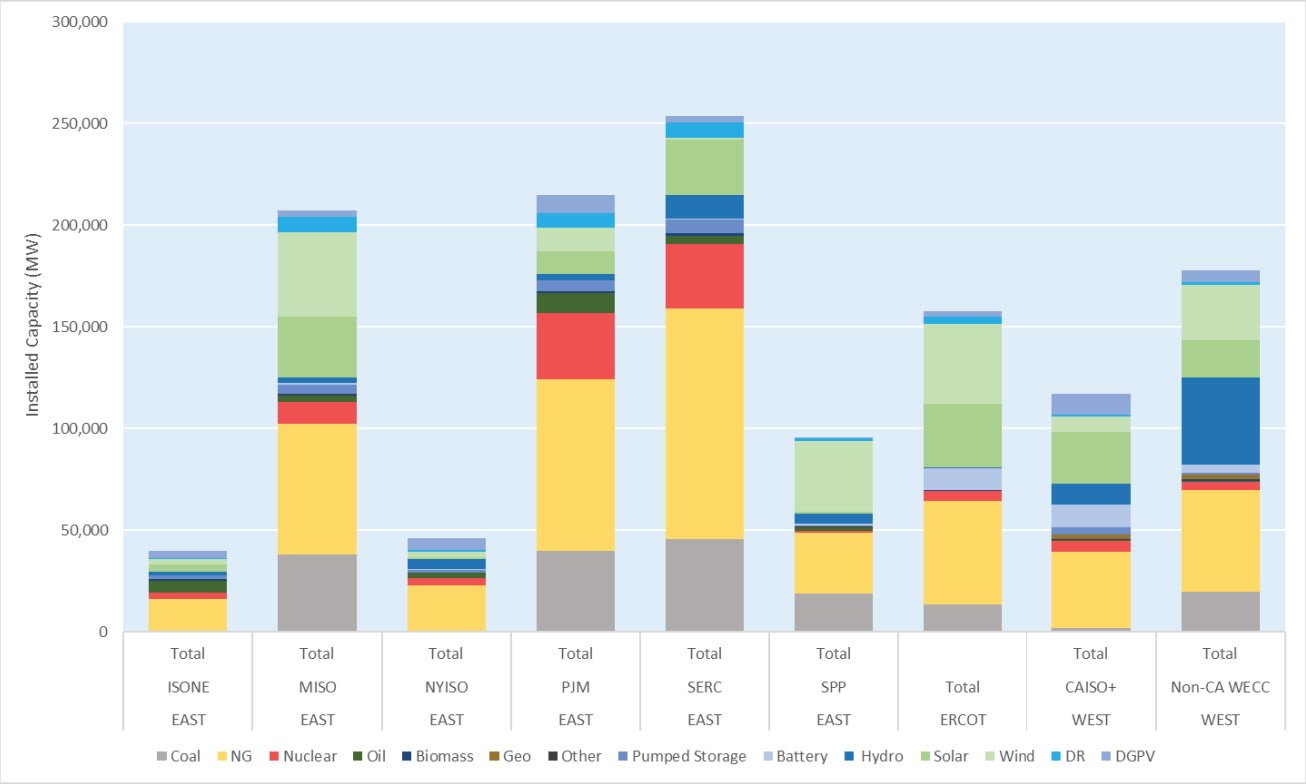


Figure A.2. Existing and Tier 1 capacities by NERC assessment area in 2024.

Forecasting 2030 Resource Mixes

To develop the 2030 ITCS generation portfolio, the study team added new capacity builds and removed planned retirements.

(i) *Tier 1*: Assumes that only projects considered very mature in the development pipeline—such as those with signed interconnection agreements—will be built. This results in minimal capacity additions beyond 2026. The data are based on projects designated as Tier 1 in the 2024 LTRA data for the year 2030.

Retirements

To project which units will retire by 2030, the study team primarily used the LTRA 2024 data and cross-checked it with EIA data. The assessment areas were disaggregated to ITCS zones based on the ratios of projected retirements in EIA 860 data. The three scenarios modeled are as follows:

(i) *Announced*: Assumes that in addition to confirmed retirements, generators that have publicly announced retirement plans but have not formally notified system operators have also begun the retirement process. This is based on data from the 2024 LTRA, which were collected by the NERC team from sources like news announcements, public disclosures, etc.

(ii) *None*: Assumes that there are no retirements between 2024 and 2030 for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirements contribute to resource adequacy challenges in regions where rapid AI and data center growth is expected.

Generation Stack for Each Scenario

Finally, when summing all potential future changes, the team arrived at a generation stack for each of the various scenarios to be studied. The first figure provides a visual comparison of all the cases, which vary from 1,309 GW to 1,519 GW total generation capacity for the entire continental United States, to enable the exploration of a range of potential generation futures. The tables below provide breakdowns by ITCS region and by resource type.

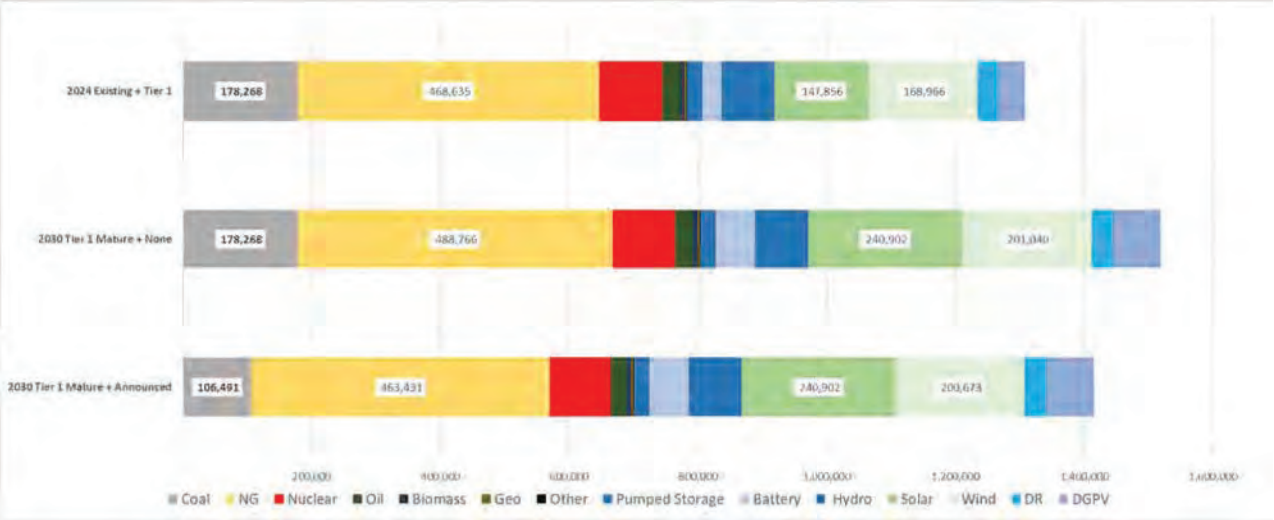


Figure A.9. Comparison of 2030 generation stacks for the various scenarios.

Table A.4. 2030 generation stack for Tier 1 mature + announced retirements.

2030 Tier 1 Mature + Announced			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**84,730**	**328,457**	**82,793**	**24,272**	**3,473**	**-**	**991**	**19,591**	**12,415**	**28,897**	**126,849**	**113,568**	**26,837**	**36,768**	**889,641**
	ISONE	**Total**	7	13,708	3,331	5,687	741	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	42,845
	MISO	**Total**	**13,001**	**60,132**	**11,127**	**2,873**	**473**	**-**	**329**	**4,380**	**2,960**	**2,450**	**44,132**	**43,369**	**7,775**	**3,049**	**196,049**
		MISO-W	4,338	12,747	2,753	1,494	188	-	2	-	574	751	10,920	30,577	2,367	741	67,453
		MISO-C	5,161	9,655	2,169	495	25	-	152	770	1,433	743	15,690	7,642	2,026	1,774	47,735
		MISO-S	1,883	29,087	5,100	591	187	-	117	49	14	817	11,892	619	2,109	291	52,756
		MISO-E	1,619	8,643	1,105	293	72	-	57	3,561	938	138	5,630	4,531	1,273	243	28,105
	NYISO	**Total**	-	21,907	3,330	2,628	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	50,396
	PJM	**Total**	**26,662**	**87,228**	**32,535**	**8,117**	**917**	**-**	**-**	**5,062**	**2,276**	**3,071**	**33,530**	**18,807**	**7,638**	**10,955**	**236,798**
		PJM-W	23,323	40,373	16,557	1,589	120	-	-	234	1,004	1,252	17,793	16,153	3,939	762	123,100
		PJM-S	1,597	15,546	5,288	3,276	516	-	-	2,958	853	1,070	12,105	577	1,883	3,181	48,850
		PJM-E	1,742	31,309	10,690	3,252	280	-	-	1,870	419	749	3,632	2,076	1,816	7,012	64,848
	SERC	**Total**	**31,672**	**116,117**	**31,702**	**3,391**	**989**	**-**	**83**	**6,701**	**3,021**	**11,425**	**38,360**	**982**	**8,088**	**7,893**	**260,423**
		SERC-C	8,883	23,777	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	54,014
		SERC-SE	10,321	28,127	8,018	899	424	-	-	1,548	618	3,260	9,024	-	2,213	317	64,768
		SERC-FL	2,851	47,092	3,502	1,477	310	-	83	-	2,208	-	16,717	-	3,022	5,865	83,127
		SERC-E	9,617	17,122	11,902	868	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	58,513
	SPP	**Total**	**13,389**	**29,365**	**769**	**1,576**	**20**	**-**	**345**	**477**	**2,434**	**5,123**	**5,991**	**41,755**	**1,815**	**71**	**103,130**
		SPP-N	3,602	3,394	304	489	1	-	185	-	18	3,041	717	8,475	447	7	20,679
		SPP-S	9,787	25,971	465	1,087	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	82,451
ERCOT	**Total**		**11,568**	**49,436**	**4,973**	**10**	**163**	**-**	**-**	**-**	**27,258**	**583**	**62,406**	**43,169**	**3,464**	**5,864**	**208,894**
	ERCOT	**Total**	11,568	49,436	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	208,894
WEST	**Total**		**10,193**	**85,538**	**7,103**	**823**	**1,427**	**3,983**	**106**	**4,366**	**21,330**	**52,060**	**51,648**	**43,935**	**1,981**	**31,931**	**316,424**
	CAISO+	**Total**	**16**	**35,789**	**3,282**	**185**	**726**	**2,059**	**35**	**3,514**	**14,316**	**10,211**	**27,112**	**7,773**	**866**	**17,055**	**122,938**
		CALI-N	-	12,373	3,282	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	48,897
		CALI-S	16	23,416	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	74,041
	Non-CA WECC	**Total**	**10,177**	**49,749**	**3,820**	**639**	**701**	**1,924**	**71**	**852**	**7,014**	**41,849**	**24,536**	**36,162**	**1,115**	**14,876**	**193,485**
		WA	243	3,971	1,096	16	286	-	-	111	459	24,033	1,404	3,631	243	1,092	36,588
		OR	-	3,967	-	6	238	18	-	-	632	8,128	2,865	4,644	141	1,051	21,689
		SOUTHWEST	3,657	17,343	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	47,022
		WASATCH	3,055	14,247	-	86	45	850	61	355	983	7,472	7,512	5,470	305	4,733	45,175
		FRONT R	3,221	10,222	-	208	30	8	10	209	430	1,197	5,296	18,133	258	3,789	43,011
		Total	**106,491**	**463,431**	**94,869**	**25,106**	**5,063**	**3,983**	**1,096**	**23,958**	**61,003**	**81,539**	**240,902**	**200,673**	**32,282**	**74,563**	**1,414,959**

Table A.5. 2030 generation stack for Tier 1 mature + no retirements.

2030 Tier 1 Mature + No Retirements			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**143,035**	**345,459**	**82,793**	**27,336**	**3,701**	**-**	**991**	**19,607**	**12,415**	**28,980**	**126,849**	**113,840**	**26,837**	**36,768**	**968,610**
	ISONE	**Total**	541	15,584	3,331	5,891	818	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	45,534
	MISO	**Total**	**37,914**	**66,729**	**11,127**	**3,197**	**613**	**-**	**329**	**4,396**	**2,960**	**2,533**	**44,132**	**43,641**	**7,775**	**3,049**	**228,393**
		MISO-W	12,651	14,145	2,753	1,662	244	-	2	-	574	777	10,920	30,768	2,367	741	77,605
		MISO-C	15,050	10,714	2,169	551	32	-	152	773	1,433	769	15,690	7,690	2,026	1,774	58,823
		MISO-S	5,493	32,278	5,100	657	243	-	117	49	14	845	11,892	623	2,109	291	59,710
		MISO-E	4,720	9,592	1,105	326	94	-	57	3,574	938	143	5,630	4,560	1,273	243	32,255
	NYISO	**Total**	-	22,937	3,330	2,646	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	51,444
	PJM	**Total**	**39,915**	**88,880**	**32,535**	**9,907**	**928**	**-**	**-**	**5,062**	**2,276**	**3,071**	**33,530**	**18,807**	**7,638**	**10,955**	**253,504**
		PJM-W	34,917	41,138	16,557	1,939	122	-	-	234	1,004	1,252	17,793	16,153	3,939	762	135,810
		PJM-S	2,391	15,840	5,288	3,998	522	-	-	2,958	853	1,070	12,105	577	1,883	3,181	50,667
		PJM-E	2,608	31,902	10,690	3,969	284	-	-	1,870	419	749	3,632	2,076	1,816	7,012	67,027
	SERC	**Total**	**45,747**	**120,232**	**31,702**	**4,063**	**989**	**-**	**83**	**6,701**	**3,021**	**11,425**	**38,360**	**982**	**8,088**	**7,893**	**279,285**
		SERC-C	13,348	24,958	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	59,660
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	618	3,260	9,024	-	2,213	317	69,478
		SERC-FL	4,346	48,163	3,502	1,957	310	-	83	-	2,208	-	16,717	-	3,022	5,865	86,173
		SERC-E	14,777	17,246	11,902	1,044	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	63,973
	SPP	**Total**	**18,919**	**31,098**	**769**	**1,632**	**20**	**-**	**345**	**477**	**2,434**	**5,123**	**5,991**	**41,755**	**1,815**	**71**	**110,449**
		SPP-N	5,089	3,594	304	506	1	-	185	-	18	3,041	717	8,475	447	7	22,385
		SPP-S	13,829	27,504	465	1,126	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	88,064
ERCOT	**Total**		**13,568**	**51,458**	**4,973**	**10**	**163**	**-**	**-**	**-**	**27,258**	**583**	**62,406**	**43,169**	**3,464**	**5,864**	**212,916**
	ERCOT	**Total**	13,568	51,458	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	212,916
WEST	**Total**		**21,666**	**91,849**	**9,403**	**829**	**1,565**	**4,156**	**106**	**4,536**	**21,330**	**52,687**	**51,648**	**44,030**	**1,981**	**31,931**	**337,717**
	CAISO+	**Total**	**1,816**	**39,560**	**5,582**	**185**	**726**	**2,059**	**35**	**3,514**	**14,316**	**10,211**	**27,112**	**7,773**	**866**	**17,055**	**130,809**
		CALI-N	-	13,677	5,582	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	52,501
		CALI-S	1,816	25,883	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	78,308
	Non-CA WECC	**Total**	**19,850**	**52,289**	**3,820**	**645**	**839**	**2,097**	**71**	**1,022**	**7,014**	**42,476**	**24,536**	**36,257**	**1,115**	**14,876**	**206,908**
		WA	560	4,166	1,096	17	352	-	-	140	459	24,402	1,404	3,642	243	1,092	37,573
		OR	-	4,161	-	6	293	22	-	-	632	8,253	2,865	4,658	141	1,051	22,081
		SOUTHWEST	4,842	18,294	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	49,158
		WASATCH	7,033	14,945	-	88	56	1,018	61	444	983	7,587	7,512	5,486	305	4,733	50,251
		FRONT R	7,415	10,723	-	212	36	10	10	262	430	1,215	5,296	18,187	258	3,789	47,844
		Total	**178,268**	**488,766**	**97,169**	**28,175**	**5,429**	**4,156**	**1,096**	**24,144**	**61,003**	**82,249**	**240,902**	**201,040**	**32,282**	**74,563**	**1,519,243**

Appendix B - Representing Canadian Transfer Limits

Introduction

The reliability and stability of cross-border electricity interconnections between the United States and Canada are critical to ensuring continuous power delivery amid evolving demands and variable supply conditions. In recent years, increased integration of wind and solar generation, coupled with extreme weather events, has introduced significant uncertainties in regional power flows.

This report describes the development and implementation of a machine learning (ML)-based model designed to project the maximum daily energy transfer (MaxFlow) across major United States–Canada interfaces, such as BPA–BC Hydro and NYISO–Ontario. Leveraging 15 years of high-resolution load and generation data, summarizing it into key daily statistics, and training a robust eXtreme Gradient Boosting (XGBoost) regressor can allow data-driven predictions to be captured with quantified uncertainty.

The project team provided percentile-based forecasts—25, 50, and 75 percent—to support both conservative and strategic planning. The conservative methodology (25 percent) was used for this report to ensure availability when needed.

The subsequent sections detail the methodology used for data processing and feature engineering, the architecture and training of the predictive model, and the validation metrics and feature importance analyses used. Future enhancements could include incorporating weather patterns, neighboring-region dynamics, and fuel-specific generation profiles to further strengthen predictive performance and support grid resilience.

Methodology

This section describes the ML approach used to build the MaxFlow prediction model.

Dataset Collection and Preparation

Data were collected for hourly and derived daily load and generation over a 15-year period (2010–2024), comprising 8,760 hourly observations annually. Hourly interconnection flow rates were collected for the same years across all major United States–Canada interfaces.[1–17]

Underlying Hypothesis

The team hypothesized that the MaxFlow between interconnected regions is critically influenced by regional load and generation extrema (maximum and minimum) and their variability. These statistics reflect grid stress conditions, influencing interregional energy flow. Additionally, nonlinear interactions due to imbalances in adjacent regions further affect energy transfer dynamics.

Regression Model

The XGBoost regression model was chosen because of its ability to capture complex, nonlinear relationships, regularization capability to prevent overfitting, high speed and performance, fast convergence, built-in handling of missing data, and ease of confidence interval approximation.

XGBoost builds many small decision trees, one after another. Each new tree learns to correct the mistakes of the previous ensemble by focusing on which predictions had the greatest error. Instead of creating one large, complex tree, it combines many simpler trees—each making a modest adjustment—so that, together, they capture nonlinear patterns and interactions. Regularization (penalties for tree size and leaf adjustments) prevents overfitting, and a "learning rate" scales each tree's contribution so that improvements are made gradually. The final prediction is simply the sum of all those small corrections.

Model Training, Validation, and Assessment

Figure B.1 shows the data analysis and prediction process, which ties together seven stages—from raw CSV loading through outlier filtering, feature engineering, projecting to 2030, rebuilding 2030 features, training an XGBoost model, and finally making and evaluating the 2030 flow forecasts with quantiles. Each stage feeds into the next, ensuring that the features used for training mirror exactly those that will be available for future (2030) predictions.

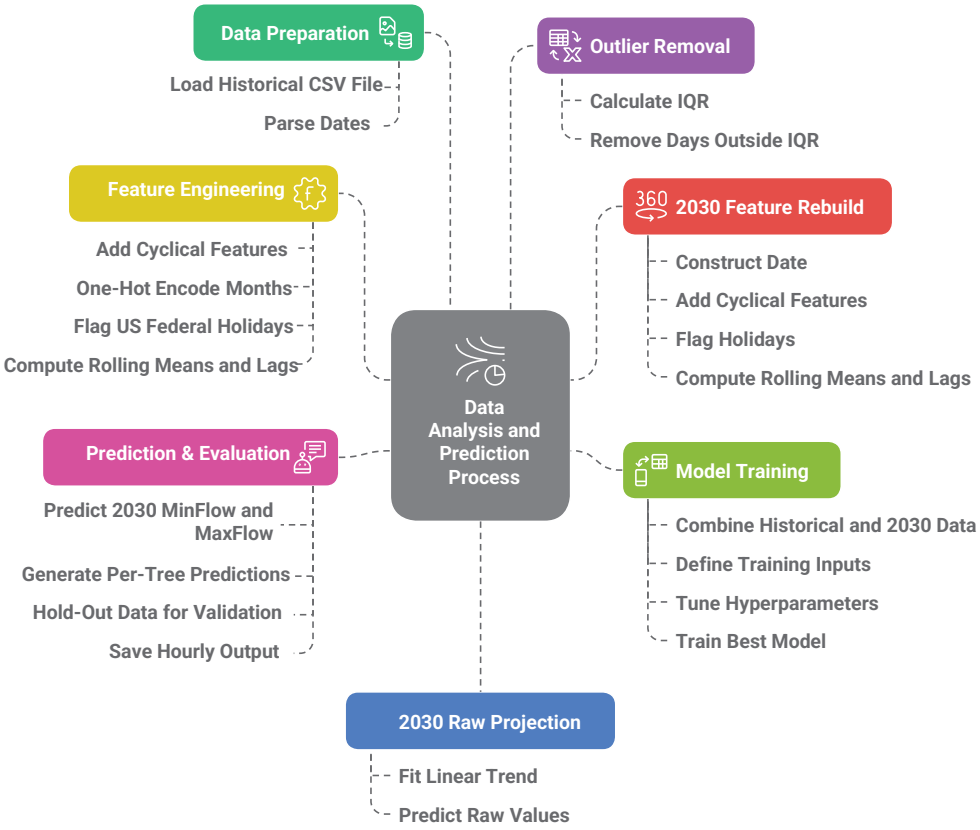


Figure B.1. Data analysis and prediction process.

Example Feature Importance for Predicting MaxFlow from Ontario to NYISO

The trained ML/XGBoost model can be used for predicting the desired year's MaxFlow. In addition, feature importance analysis can be added to assess the contribution of each variable.

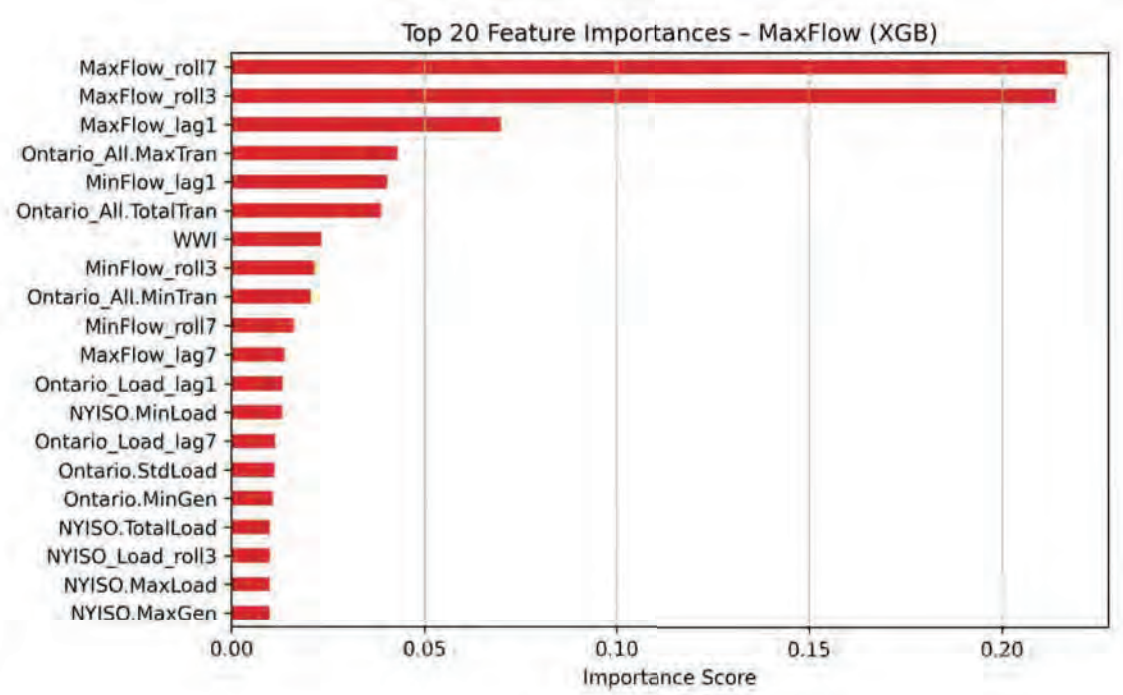


Figure B.2. Feature importance for predicting the hourly maximum energy transfer (MaxFlow) between NYISO and Ontario. XGB = eXtreme Gradient Boosting.

The feature importance plot shows that MaxFlow rolling/lagging features and Ontario_All.MaxTran are the dominant predictors of MaxFlow, meaning temporal patterns and Ontario's peak transfer capacity strongly influence interregional flow limits. Weather-related variables (WWI, e.g., temperature, humidity, etc.) and Ontario_All.TotalTran also rank highly. The 2030 MaxFlow prediction plot shows seasonal fluctuations, with higher values early and late in the year. The red shaded area represents a 95 percent confidence interval for the predictions.

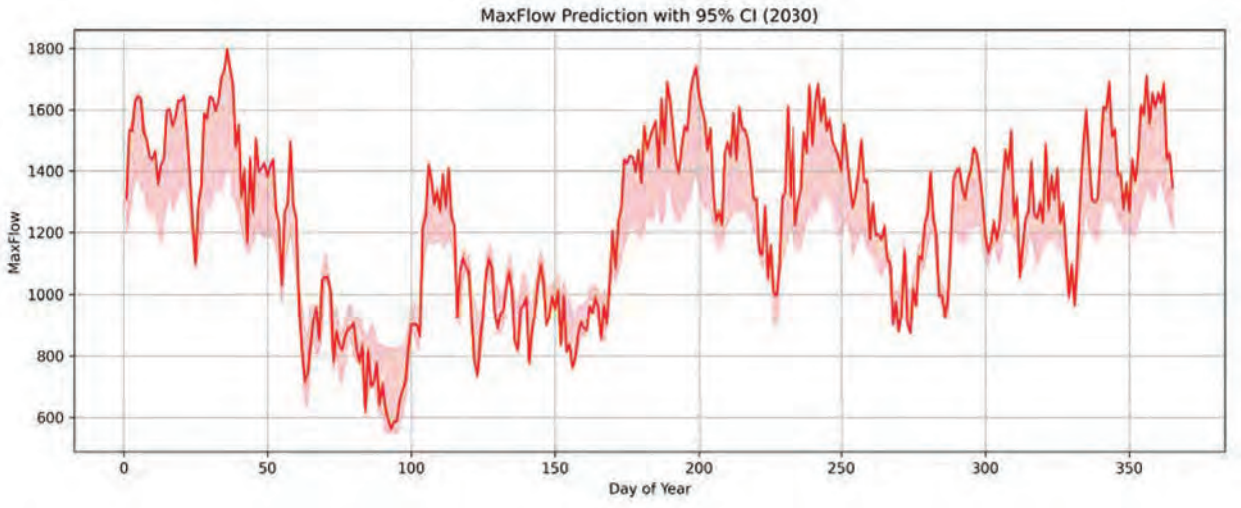


Figure B.3. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI).

Model Performance

Validating model performance on unseen data is essential to ensure the model's reliability and generalizability. The following evaluation examines how well the XGBoost model predicts minimum energy transfer (MinFlow) and MaxFlow on the validation split, highlighting strengths and areas for improvement.

Rigorous performance evaluation is a fundamental step in any ML workflow. From quantifying error metrics (root mean square error and mean absolute error) and goodness-of-fit (R^2) on both training and validation splits, it is possible to identify overfitting, assess generalization, and guide model refinement. Table B.1 shows XGBoost model performance for the Ontario–NYISO transfer limit.

Table B.1. eXtreme Gradient Boosting model performance for the Ontario–NYISO transfer limit.

Metric	Value	Explanation
MinFlow RMSE (Train)	69.2528	Root mean square error (RMSE) on training data for minimum energy transfer (MinFlow)
MinFlow R^2 (Train)	0.9651	R^2 on training data for MinFlow (higher → better fit)
MinFlow RMSE (Validation)	163.6642	RMSE on held-out data for MinFlow
MinFlow R^2 (Validation)	0.8073	R^2 on held-out data for MinFlow (higher → better generalization)
MaxFlow RMSE (Train)	114.4234	RMSE on training data for maximum energy transfer (MaxFlow)
MaxFlow R^2 (Train)	0.8838	R^2 on training data for MaxFlow (higher → better fit)
MaxFlow RMSE (Validation)	144.9614	RMSE on held-out data for MaxFlow
MaxFlow R^2 (Validation)	0.8178	R^2 on held-out data for MaxFlow (higher → better generalization)

Overall, the XGBoost model delivers excellent in-sample as well as out-of-sample accuracy. Similar outputs are available for each transfer limit.

Maximum flow predictions: Ontario to New York

Ontario and NYISO are connected through multiple high-voltage interconnections, which collectively provide a total transfer capability of up to 2,500 MW, subject to individual tie-line limits. Table B.2 outlines the data sources, preparation process, and assumptions used in creating datasets for the prediction models.

Table B.2. Ontario to New York transmission flow data and assumptions overview.

	Description
Data source	https://www.ieso.ca/power-data/data-directory
Data preparation	IESO public hourly inter-tie schedule flow data can be accessed for the years spanning from 2002 to 2023.
Assumptions	Positive flow indicates that Ontario is exporting to NY, and negative flow indicates that Ontario is importing from NY.

Figure B.4 illustrates the historical monthly MaxFlow for Ontario from 2007 through 2024, alongside 2030 projected quartile scenarios (Q1, Q2, and Q3). Analyzing these trends helps assess future reliability and facilitates capacity planning under varying conditions.

Historical monthly peaks (2007–2023) reveal a clear seasonal cycle for ONT–NYISO transfers: flows typically increase in late winter/early spring (February–April) and again in late fall/early winter (November–December). Over 16 years, the average spring peaks hovered around 1,700–1,900 MW, with occasional spikes above 2,200 MW. The 2030 forecast for Q1, Q2, and Q3 aligns with this pattern, predicting a springtime peak near 1,800 MW, a summer trough around 1,400 MW, and a modest late-summer uptick near 1,500 MW.

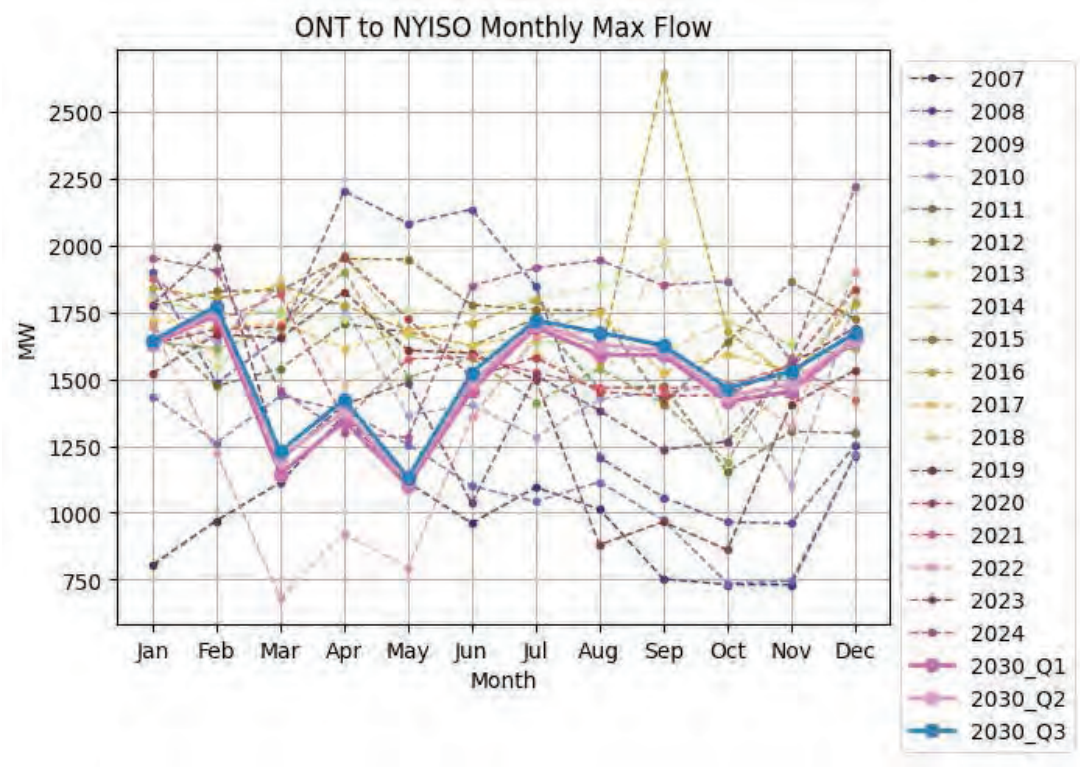


Figure B.4. Monthly maximum energy transfer between Ontario (ONT) and New York (NYISO).

The team used robust validation metrics to justify these results. When trained on daily data from the 2010–2024 period—incorporating projected 2030 loads, seasonal flags, and holiday effects—the XGBoost model achieved $R^2 > 0.80$ and a root mean square error below 150 MW on an unseen 20 percent hold-out dataset. Moreover, the 95 percent confidence intervals for monthly maxima were narrow (approximately ±150 MW), demonstrating low predictive uncertainty. A comparison of predicted maxima with historical extremes revealed that 2030 forecasts consistently fell within (or slightly above) the previous window of variability, implying realistic demand-driven behavior. In summary, the close alignment with historical peaks, strong cross-validated performance, and tight confidence bands collectively validate the results.

Discussion

The reason that the team used ML/XGBoost to approximate the 2030 transfer profiles was to ensure that there would be no violations or inconsistencies between transfer limits, load, and generation. The 15 years of data used were sufficient for having the models learn historical relationships and project them forward to 2030 to capture the underlying trends in load,

generation, and their interactions. The use of such an extensive dataset justifies using ML to establish consistent transfer profiles.

However, in some regions, like Ontario to NYISO, the available data encompassed a shorter time period, and the relationships were only partially captured because of a lack of neighboring-region data. In such cases, it was necessary to incorporate additional predictors, such as rolling and lag features from the transfer limits. Although the direct use of transfer limit data to project future transfer limits would typically be avoided, these engineered features help improve predictions when data coverage is sparse and the model's goodness-of-fit is low.

In all cases, the ML models ensured that these historical relationships were not violated, maintaining internal consistency among load, generation, and transfer limits. Overall, the team relied on ML when long-term data were available for training and projecting load and generation profiles. Rolling and lag features were used to reinforce the model when data availability was limited, but always with the goal of upholding consistent physical relationships in the 2030 projections.

Supplementary Plots for Additional Transfers

This section presents figures and tables showing results and source data information for each transfer listed below:

(iii) Pacific Northwest to British Columbia

(iv) Alberta to Montana

(v) Manitoba to MISO West

(vi) Ontario to MISO West

(vii) Ontario to MISO East

(viii) Ontario to New York

(ix) Hydro-Quebec to New York

(x) Hydro-Quebec to New England

(xi) New Brunswick to New England

The figures show the daily MaxFlow for each transfer that was considered in this analysis.

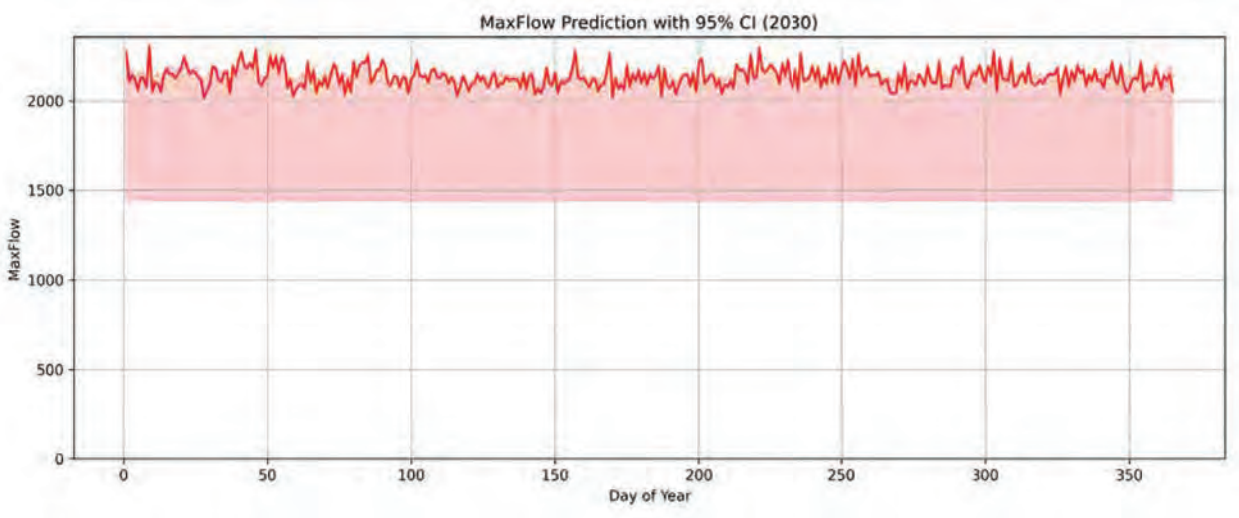


Figure B.5. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between British Columbia and the Pacific Northwest.

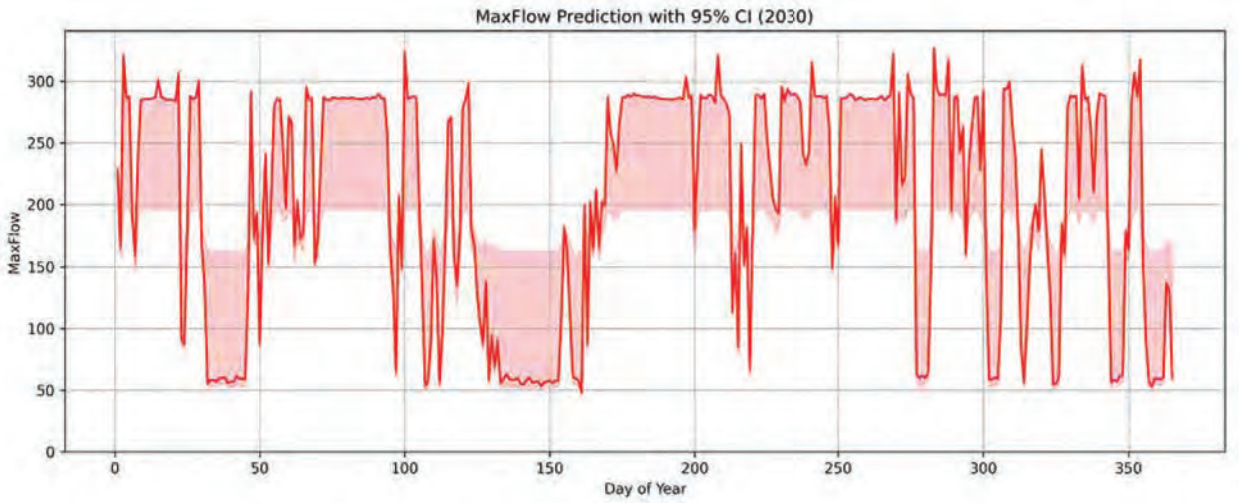


Figure B.6. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between AESO and Montana.

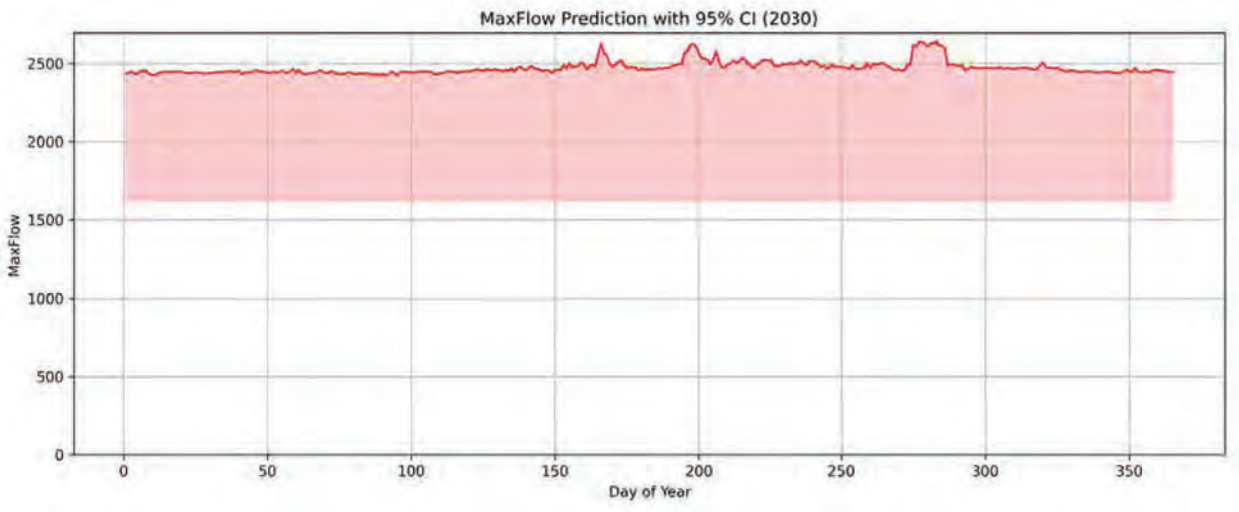


Figure B.7. Projected 2030 maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Manitoba and MISO.

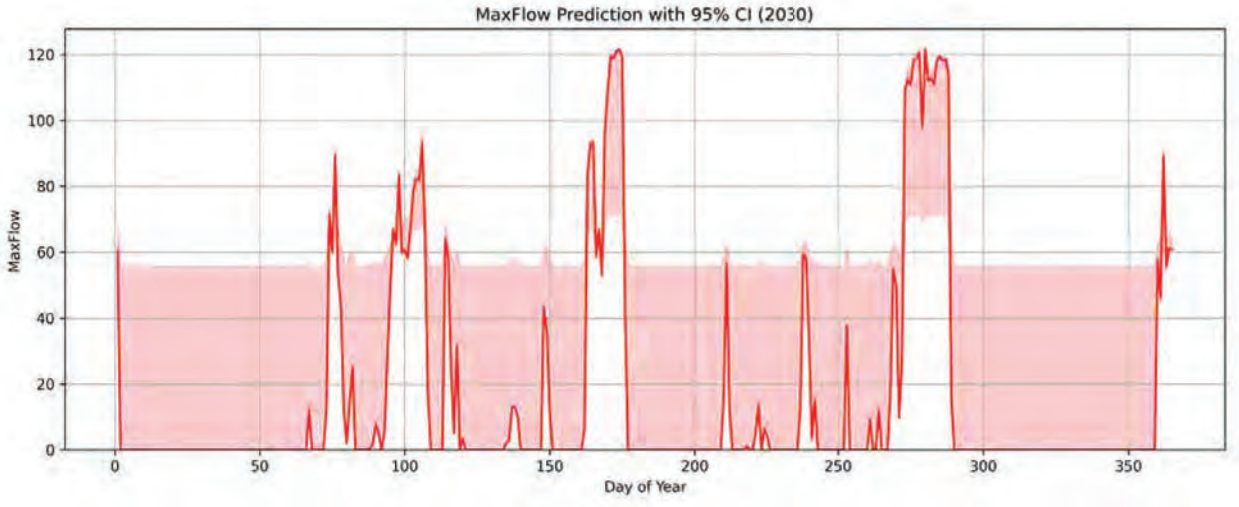


Figure B.8. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO West.

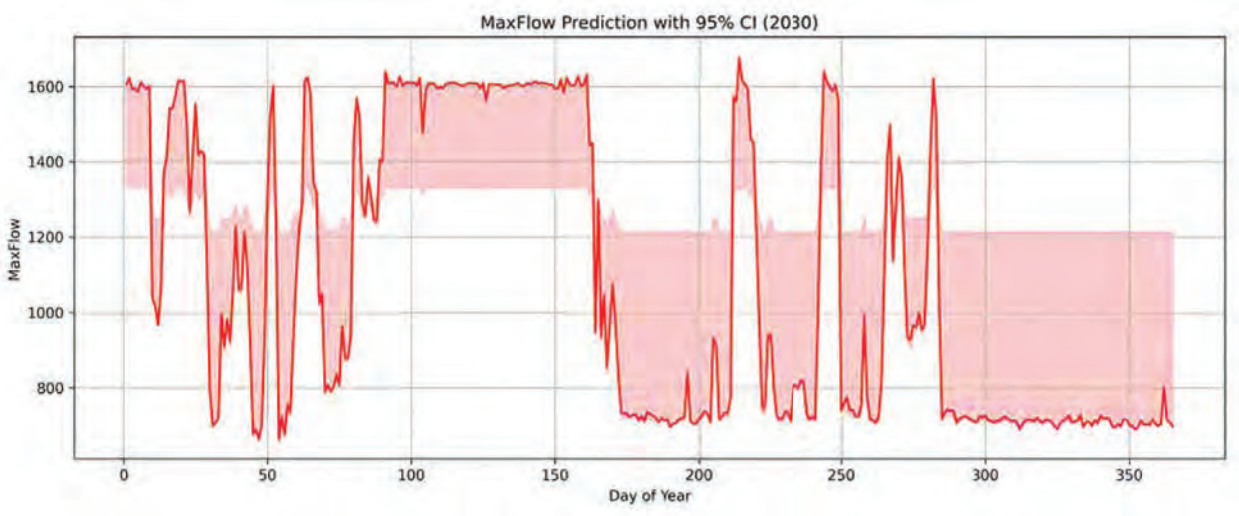


Figure B.9. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO East.

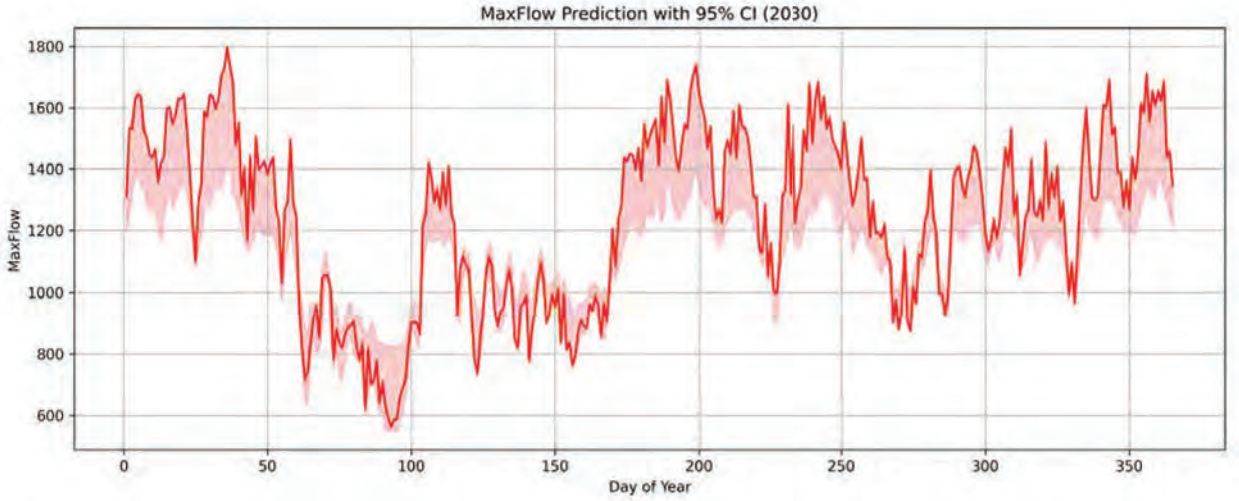


Figure B.10. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and New York.

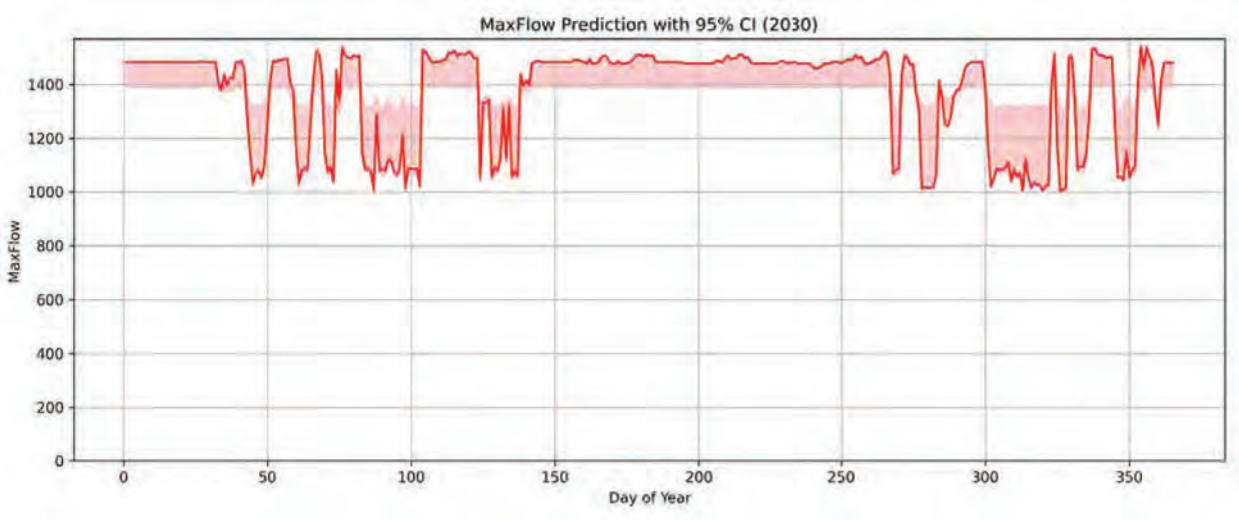


Figure B.11. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New York.

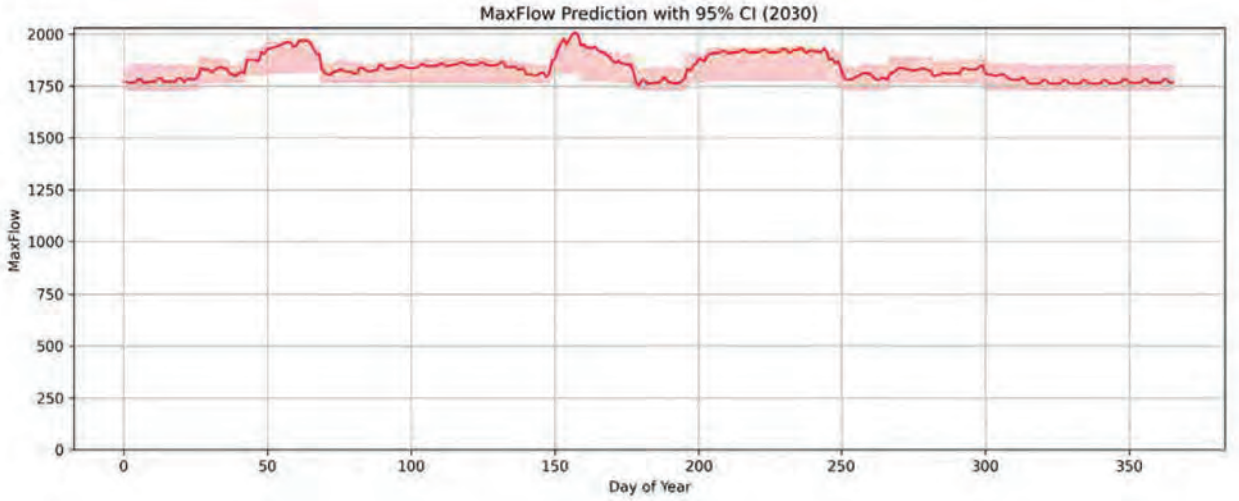


Figure B.12. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New England.

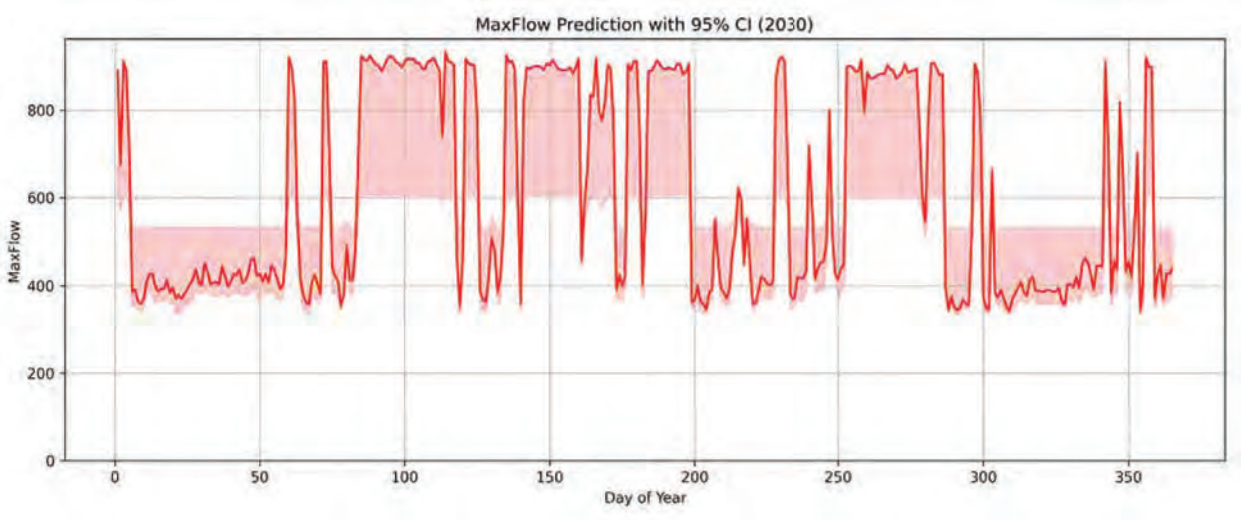


Figure B.13. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between New Brunswick and New England.

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EO 14262

Federal Register / Vol. 90, No. 70 / Monday, April 14, 2025 / Presidential Documents 15521

Presidential Documents

Executive Order 14262 of April 8, 2025

Strengthening the Reliability and Security of the United States Electric Grid

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered:

Section 1. *Purpose.* The United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and an increase in domestic manufacturing. This increase in demand, coupled with existing capacity challenges, places a significant strain on our Nation's electric grid. Lack of reliability in the electric grid puts the national and economic security of the American people at risk. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy from all available electric generation sources and the integrity of our Nation's electric grid.

Sec. 2. *Policy.* It is the policy of the United States to ensure the reliability, resilience, and security of the electric power grid. It is further the policy of the United States that in order to ensure adequate and reliable electric generation in America, to meet growing electricity demand, and to address the national emergency declared pursuant to Executive Order 14156 of January 20, 2025 (Declaring a National Energy Emergency), our electric grid must utilize all available power generation resources, particularly those secure, redundant fuel supplies that are capable of extended operations.

Sec. 3. *Addressing Energy Reliability and Security with Emergency Authority.* (a) To safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply is necessary to prevent a complete grid failure, the Secretary of Energy, in consultation with such executive department and agency heads as the Secretary of Energy deems appropriate, shall, to the maximum extent permitted by law, streamline, systemize, and expedite the Department of Energy's processes for issuing orders under section 202(c) of the Federal Power Act during the periods of grid operations described above, including the review and approval of applications by electric generation resources seeking to operate at maximum capacity.

(b) Within 30 days of the date of this order, the Secretary of Energy shall develop a uniform methodology for analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy. This methodology shall:

(i) analyze sufficiently varied grid conditions and operating scenarios based on historic events to adequately inform the methodology;

(ii) accredit generation resources in such conditions and scenarios based on historical performance of each specific generation resource type in the real time conditions and operating scenarios of each grid scenario; and

(iii) be published, along with any analysis it produces, on the Department of Energy's website within 90 days of the date of this order.

(c) The Secretary of Energy shall establish a process by which the methodology described in subsection (b) of this section, and any analysis and results it produces, are assessed on a regular basis, and a protocol to identify which generation resources within a region are critical to system reliability. This protocol shall additionally:

(i) include all mechanisms available under applicable law, including section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region; and

(ii) prevent, as the Secretary of Energy deems appropriate and consistent with applicable law, including section 202 of the Federal Power Act, an identified generation resource in excess of 50 megawatts of nameplate capacity from leaving the bulk-power system or converting the source of fuel of such generation resource if such conversion would result in a net reduction in accredited generating capacity, as determined by the reserve margin methodology developed under subsection (b) of this section.

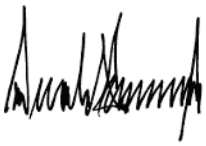
Sec. 4. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.



THE WHITE HOUSE,
April 8, 2025.

[FR Doc. 2025–06381
Filed 4–11–25; 8:45 am]
Billing code 3395–F4–P

Available at (accessed on 5/27/2025):
https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid



U.S. DEPARTMENT of ENERGY

For more information, visit:
energy.gov/topics/reliability

DOE/Publication Number • July, 7 2025

Exhibit 16

July 11, 2025

GridLab Analysis: Department of Energy Resource Adequacy Report

Overview:

This memo provides a high-level overview of the recently released Department of Energy (DOE) Resource Adequacy Report, released on July 7, 2025. This report is a result of the Executive Order from the Trump Administration on Strengthening the Reliability and Security of the Grid, which directed the agency to develop and publish a methodology for "analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy."

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

Bottomline of the DOE report:

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

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

DOE Report Analysis - Key Takeaways:

- The report is based on three key assumptions: (1) the amount of load that will be added to the grid over the next five years, (2) the number of plants assumed to retire, and (3) the amount of new capacity added to the grid. The study used aggressive assumptions regarding load growth and retirements, but conservative assumptions about how much new generation capacity will be added, even assuming no new resources after 2026.
    - Load Growth: The report assumes 50 GW of data center load and allocates it regionally. It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact. The DOE report then adds 51 GW of non-data center load, which means overall load growth by 2030 is 101 GW or 15%. For comparison, EIA assumed 6% growth in their Annual Energy Outlook 2025 high growth case. This is very aggressive load growth, although not necessarily unreasonable, as it is collected from each of the RTOs and utilities.
    - Retirements: The report assumed 104 GW of retirements by 2030, with 3/4 of this coal and 1/4 gas. But the most recent data from the U.S. Energy Information Administration released in June (the EIA 860) has just **half** of this capacity retiring. In the report, the DOE assumed these 50 GW of likely retirements, but included another 50 GW of *announced* retirements, inconsistent with their assumption around capacity additions. Most likely many plants will choose not to retire due to the changing regulatory and economic landscape, driven by the administration's policies.
    - Capacity Additions: The report assumes just 22 GW of new "firm" capacity (narrowly defined as gas) is added which is based on NERC

LTRA "Tier 1" - projects with a very high likelihood of success. The report assumes no projects are built post 2026, which is not realistic for a report forecasting to 2030. A more reasonable assumption for capacity additions is the EIA 860 released in June, which has 35 GW of gas additions, and another 53 GW of batteries - **88 GW of firm additions by 2030.**

- The study ignores both utility plans for meeting increased load growth and how markets will respond. In fact, markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that will likely add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.
- This national report attempts to address what is primarily a regional issue with regional solutions. A handful of regions face pressure due to rising load growth, and those regions have already enacted plans to address this growth. For example, MISO, SPP and PJM have all instituted "fast track" processes to get firm generation online (gas and batteries), which is expected to install 43 GW of new resources by 2030. The DOE report, however, shows just 13.5 GW of new firm resources in those three regions.

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

	DOE Report	EIA 860
Load growth:	101 GW	N/A
Capacity Additions	209 GW	200 GW
Gas Capacity Additions	22 GW	35 GW
Battery Capacity Additions	31 GW	53 GW
Retirements	104 GW	52 GW

Conclusion:

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

Exhibit 17



Enough Energy

A Review of DOE's Resource Adequacy Methodology

Jennifer Danis
Christoph Graf, Ph.D.
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July 2025

Institute *for*
Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

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

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

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Executive Summary

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

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

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

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

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

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

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

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

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

- *Resource Adequacy Targets:* DOE's use of a multi-metric standard—2.4 hours of lost load per year and 0.002% normalized unserved energy—is consistent with best practices, but the choice of values is not. Neither value is appropriately justified based on a cost-benefit framework, and the use of a one-size-fits-all target for the entire country ignores regional differences. Additionally, DOE inappropriately attempts to label PJM as currently resource inadequate even though the region achieves DOE's own target according to DOE's modeling.

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

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

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

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

Introduction

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

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

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

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

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

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

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

Part 1: Best Practices for Resource Adequacy

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

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

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

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

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

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

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

Step 1: Pick a Resource Adequacy Target

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

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

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

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

Metrics

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

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

12 *Id.* at 39, 41.

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

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

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

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

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

The Multi-Metric Approach

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

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

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

17 *Id.* at 3.

18 *Id.* at 10.

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

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

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

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

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

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

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

26 *Id.* at 18.

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

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

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

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

Accounting for Tail Risks

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

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27 *Id.* at 9.

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

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

30 *Id.*

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

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

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

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

35 *Id.* at 8.

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

37 *Id.* at 3.

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

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

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

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

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

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

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

Values

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

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

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

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

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

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

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

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

48 *Id.* at 8.

49 *Id.* at 38.

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

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

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

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

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

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

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

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

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

55 *Id.* at 42.

56 *Id.*

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

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

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

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

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

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

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

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

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

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

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

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

67 *Id.* at 40.

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

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

Step 2: Conduct Resource Adequacy Modeling

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

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

Temporal Scope

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

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

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

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

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

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

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

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

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

Inputs

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

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

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

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

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

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

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

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

81 *Id.* at 10.

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

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

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

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

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

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

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

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85 *Id.*

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

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

88 *Id.* at 32.

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

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

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

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

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

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

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

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

Step 3: Accreditation

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

104 *Id.*

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

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

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

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

109 *Id.* at 37–38.

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

111 *See* Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 11 ("Increasingly, periods of risk are driven by correlation among many components that are often weather-related, including high load, low renewable resource availability, drought, and correlated outages and fuel supply disruptions from the fossil fuel generators."); N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 91 ("If resource performance were to occur at the levels expected during average winter days, the system should be able to serve these high loads. However, resource performance from thermal resources on very cold days, especially natural gas resources, is more likely to be poor. This, coupled with poor performance from solar

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

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

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

Reference Margin Levels

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

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

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resources, results in very low total electricity supply and causes loss-of-load events in the ProbA analysis. The winter load-loss events tend to occur during morning and evening demand peaks and coincide with poor thermal performance and poor solar performance.").

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

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

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

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

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

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

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

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

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

Effect of Particular Resources

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

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

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

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

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

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

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

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

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

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

Part 2: DOE's *Resource Adequacy Report*

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

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

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

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

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

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

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

126 *Id.* at 8.

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

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

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

Resource Adequacy Targets

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

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

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

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

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

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130 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4, 14 ("This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.").

131 *Id.* at 4.

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

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

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

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

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

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

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

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

Resource Adequacy Modeling

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

Deterministic Model

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

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

139 *Id.* at 9.

140 *Id.* at 7.

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

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

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

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

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

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

Outage Threshold

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

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

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

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

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

Inputs

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

Additions

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

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

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152 *Id.* at 105 tbl.8.4

153 *Id.*

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

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

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

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

158 *See id.* at 137.

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

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

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

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

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159 *Id.*

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

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

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

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

164 Donnie Bielak, PJM, Reliability Resource Initiative: Additional Summaries 2 (2025), https://perma.cc/Y2AB-3CEM; Donnie Bielak, PJM, Reliability Resource Initiative: Results Summary 6 (2025), https://perma.cc/MYQ8-Y53G. *See also* Ric O'Connell, *supra* note 156 ("The study ignores both utility plans for meeting increased load growth and how markets will respond. In fact, markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that will likely add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.").

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

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

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

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

Retirements

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

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

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

170 *Id.* at 12.

171 *Id.*

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

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

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

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

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

Load

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

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

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

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

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

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

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

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

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

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

Interregional Imports

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

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

Accreditation & Reference Margin Levels

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

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

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

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183 *See id.* at 9, 17.

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

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

186 *Id.* at 17–24.

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

188 *Id.* at 15522.

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

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

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

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

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

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

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

Part 3: Next Steps

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

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

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

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194 16 U.S.C. § 824o(a).

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

196 16 U.S.C. § 824o(d)(5), (e)(3).

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

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

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

200 16 U.S.C. § 824(b)(1).

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

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

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

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

> DOE does not intend these regulations to replace prudent utility planning and system expansion. This intent has been reinforced in the final rule by expanding the "Definition of Emergency" to indicate that, while a utility may rely upon these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself.[209]

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

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

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

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

206 16 U.S.C. § 824a(c)(1).

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

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

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

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

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

The DOE study itself cautions, "the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[214] Despite DOE's press statement asserting that the study's methodology can help guide "guide Federal reliability interventions,"[215] presumably to address the EO's mandate that DOE find a way to routinize further 202(c) emergency orders,[216] the study reports a fundamental limitation for doing so: It does not find any near-term reliability risk from current levels of resource adequacy.

The study itself states that, "one of the key takeaways from this study process is the underscored 'call to action' for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our

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

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

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

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

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

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

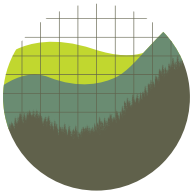
216 *See* Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

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

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

Conclusion

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



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Exhibit 18

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

I. INTRODUCTION

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

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

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

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

[3] *Id.* at vi.

[4] *Id.* at i.

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

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

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

II. STATEMENT OF ISSUES

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

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

III. INTERVENTION

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

A. Natural Resources Defense Council

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

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

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

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

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

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

B. The Ecology Center

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

C. Environmental Defense Fund

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

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

D. Environmental Law and Policy Center

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

E. Public Citizen

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

F. Sierra Club

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

G. Vote Solar

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

IV. BACKGROUND

A. Executive Orders

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

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

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

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

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

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

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

[12] Grid EO Section 3(a).

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

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

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

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

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

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

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

B. RAR

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

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

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

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

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

[22] *Id.* at 7.

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

[24] *Id.* at i.

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

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

Notwithstanding the statement in the RAR that DOE intends to use the "methodology to identify at-risk region(s) and guide reliability interventions," e.g., Section 202(c) Orders,[29] other portions of the RAR make clear that it can't and shouldn't be used as a basis for interventions, specifically not issuance of 202(c) Orders. First and foremost, the reliability projections in the RAR focus on conditions five years from now and concede that there are not current grid conditions that fit within Section 202(c)'s definition of an "emergency." Second, the Department candidly concedes the RAR's lack of robustness: "DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level. The DOE study team built the methodology and analysis upon the best data that was available. However, entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience."[30]

C. Section 202(c) Orders

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

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[26] RAR, Ex. 1 at vi.

[27] *Id.*

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

[29] *See* Dep't of Energy, *Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security* (July 7, 2025), https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security ("The methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act.").

[30] RAR, Ex. 1 at i.

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

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

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

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

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

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

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

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

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

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

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

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

[35] 16 U.S.C.§ 824a(c)(2).

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

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

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

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

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

D. Existing Mechanisms Ensure Resource Adequacy

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

1. Vertically integrated utilities

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

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

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

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

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

[44] *Id.*

[45] *Id.*

[46] *Id.*

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

2. Competitive markets

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

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

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

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

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

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

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

3. FERC and NERC Reliability Regulation

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

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

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

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

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

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

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

V. ARGUMENT

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

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

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

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

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

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

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

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

[61] 42 U.S.C. § 7111 *et seq.*

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

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

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

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

[63] 16 U.S.C. §§ 824a(c), 824o-1.

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

[65] RAR, Ex. 1 at vi.

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

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

[68] 42 U.S.C. § 7113.

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

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

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[69] 16 U.S.C. § 824(a).

[70] *Id.* § 824(b)(1).

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

[72] *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (2009) (under Section 201(b), states retain the right "to require retirement of existing generators" or to "take any other action in their role as regulators of generation facilities."). *See also Devon Power LLC et al.*, 109 FERC ¶ 61,154, P 47 (2004) ("Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.").

[73] 16 U.S.C. § 824a(b).

[74] 16 U.S.C. § 824o.

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

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

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

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

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

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

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

[79] *See* 42 U.S.C. § 7172(a)(1)(B).

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

[81] 42 U.S.C. § 7253.

[82] 42 U.S.C. § 7253.

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

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

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

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

[87] 42 U.S.C. § 7174.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The Act's text empowers the Department to require generation only in an "emergency;"[100] the Act primarily reserves authority over generation to the states, allocating more limited federal regulatory power to different agencies, *see section* A above. The statute itself does not define "emergency." At the time Congress enacted Section 202(c), Webster's New International Dictionary of the English Language (1930) defined "emergency" as a "*sudden* or *unexpected* appearance or occurrence . . . An *unforeseen* occurrence or combination of circumstances which calls for *immediate* action or remedy; *pressing* necessity; exigency."[101] Contemporary dictionaries similarly define "emergency" as demanding imminence: an emergency

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

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

[100] 16 U.S.C. § 824a(c).

[101] Emphasis added.

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

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

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

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

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

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

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

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

[106] 16 U.S.C. § 824a(c).

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

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

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

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

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

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

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

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

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

[111] *Id.*

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

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

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

[115] 16 U.S.C. § 824o.

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

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

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

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

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

[118] *Id.* § 824o(d)(2)-(4).

[119] *Id.* § 824o(e).

[120] *Id.* § 824o(i)-(j).

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

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

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

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

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

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

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

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

[125] 10 C.F.R. § 205.371

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

normal peak load requirements based upon use of all of its otherwise available resources so that it *is* unable to supply adequate electric service to its customers."[127]

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

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

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

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

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

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

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

[130] 46 Fed. Reg. at 39,985–86.

[131] 574 F.2d at 613.

[132] *Id.*

[133] *Id.*

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

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

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

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

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[134] *Id.* at 614.

[135] *Id.*

[136] *Id.*

[137] *Id.* at 615.

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

[139] *Id.*

[140] *Id.*

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

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

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

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

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

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

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

[143] *Id.*

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

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

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

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

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

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

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

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

[148] Grid EO at 2.

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

[150] RAR, Ex. 1 at 7.

[151] *Id.* at 1.

[152] *Id.* at 7.

[153] *Id.*

[154] *Id.*

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

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

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

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

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

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[155] 16 U.S.C. § 824a(a).

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

[157] 16 U.S.C. § 824a(a).

[158] 16 U.S.C. § 824o(a)(3).

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

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

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

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[159] RAR, Ex. 1 at i.

[160] *Id.*

[161] *Id.*

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

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

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

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

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

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

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

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

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

[166] *Id.*

[167] *Id.*

[168] *Id.* at 2669.

[169] OMB Guidelines 2019 Update at 4.

[170] *Id.*

[171] DOE IQA Guidelines 2019 Update at 16.

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

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

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

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

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

[173] DOE IQA Guidelines 2019 Update at 22.

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

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

[176] DOE IQA Guidelines 2019 Update at 7.

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

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

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

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

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

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

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

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

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

[181] RAR, Ex. 1 at 2.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[192] *Id.*

[193] RAR, Ex. 1 at 17 ("Given the rapid emergence of AI/DC loads, additional steps were taken to account for this category of demand. It is difficult to determine how much AI/DC load is already embedded in NERC [Long-Term Reliability Assessment] forecast, for example, the 2024 [Long-Term Reliability Assessment] saw more than 50GW increase from 2023, signaling a major shift in utility expectations. To benchmark existing AI/DC contribution, DOE assumed base 2023 AI/DC load equaled the EPRI low-growth case of 166 TWh.").

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

3. Assumptions about supply are unsupported.

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

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

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

[195] RAR, Ex. 1 at 5.

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

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

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

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

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

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

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

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

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

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

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

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

[203] RAR, Ex. 1 at 12.

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

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

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

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

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

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

[207] *Id.*

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

[209] NERC defines Tier 2 resources as those having one of the following characteristics: "Signed/approved Completion of a feasibility study, Signed/approved Completion of a system impact study, Signed/approved Completion of a facilities study, Requested Interconnection Service Agreement, Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)." NERC, 2024Long Term Reliability Assessment, 137 (Dec. 2024, updated July 15, 2025) https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

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

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

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

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

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[211] *Id.*

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

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

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

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

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

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

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

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[216] RAR, Ex. 1 at 12.

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

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

[219] *Id.*

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

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

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

[223] *Id.* at 21.

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

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

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

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

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

[225] RAR, Ex. 1 at 12.

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

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

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

[229] *Id.*

[230] *Id.*

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

6. DOE inconsistently applies its own methodology.

Several of the findings in the RAR are inconsistent with the methodology that DOE develops. For instance, DOE states that "[a]nalysis of the current system shows all regions except ERCOT have less than 2.4 hours of average loss of load per year and less than 0.002% NUSE" (the standards DOE developed for this study).[231] DOE further explains that "[w]hen looking at metrics in the worst weather years, regions meet or exceed additional criteria. All regions experienced less than 20% of lost load in any hour."[232] Despite these clear findings, DOE goes on to state that "PJM, ERCOT, and SPP experienced significant loss of load events during 2021 and 2022 winter storms Uri and Elliot which translated into more than 20 hours of lost load," and asserts that this "results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load."[233] As an initial matter, the PJM system did not experience any lost load due to resource inadequacy during Winter Storms Uri or Elliott.[234] Second, DOE's focus on whether a region had lost load or a risk of lost load in a particular weather year is inconsistent with DOE's own articulation of its resource adequacy standards, as "average indicators" assessed across all scenarios and years.[235] As the IPI notes, these standards are "not a requirement that must be achieved in each and every scenario."[236]

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[231] RAR, Ex. 1 at 7.

[232] *Id.*

[233] *Id. See also Id.* at 9 ("For the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM, which experiences shortfalls due to the winter storm Elliot historical weather year.").

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

[235] RAR, Ex. 1 at 5.

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

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

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

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

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

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

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[237] 5 U.S.C. §§ 553(b), (c).

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

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

[240] 10 C.F.R. §§ 205.371; 205.373.

[241] 42 U.S.C. § 4332(C).

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

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

VI. CONCLUSION

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

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

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

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Exhibit 19

Order No. 202-25-7

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

Order No. 202-25-3

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

Order No. 202-25-3, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until August 21, 2025. That order was based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO). Specifically, I determined that MISO likely faced tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. I determined that the continued operation of the Campbell Plant would provide additional generation capacity during these periods which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety. I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability. My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[2] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply

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[1] *See Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation*, Consumers Energy (June 23, 2021), https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation. As a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline.

[2] *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, at 16 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf (NERC 2025 Summer Reliability Assessment).

shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.[3]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[4] Additionally, EIA stated, "[t]ypically, Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[5] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it was not projected to be available during the peak demand period this summer.[6]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts and Consumers acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."[7]

Fourth, MISO's Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[8] While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and these results "reinforce the need to increase capacity."[9]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-3 continue, both in the near and long term. The summer season has not yet ended, and the production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO this summer. That need is evidenced by the fact that the Campbell Plant was called on by MISO to generate large amounts of electricity during the heat wave that hit MISO this past June. According

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[3] *Id.*
[4] *Michigan State Profile and Energy Estimates*, U.S. Energy Info. Admin. (Oct. 17, 2024), https://www.eia.gov/state/print.php?sid=MI.
[5] *Id.*
[6] The start-up of Palisades is scheduled for the fourth quarter of 2025.
[7] NERC 2025 Summer Reliability Assessment at 16.
[8] *Planning Resource Auction—Results for Planning Year 2025–2026,* Midcontinent Independent System Operator, Inc., 13 (May 29, 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf. (MISO Planning Resource Auction – Results for Planning Year 2025-26).
[9] *Id*. at 2,12.

to the U.S. Environmental Protection Agency's data, over the month of June, the Campbell Plant generated approximately 664,000 MWh, running at 61% capacity.[10] In fact, between June 11 and August 18, MISO issued dozens of alerts to manage grid reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits. MISO issued alerts for the Central Region on at least 40 of the 69 days between June 11 and August 18. In June, MISO issued alerts affecting the Central Region on 18 days, including an Energy Emergency Alert (EEA) level 1 ("Max Gen Step 1b") on June 23 to enable MISO to take emergency action to ensure grid stability, including bringing additional resources online.[11] The Central Region had alerts on 21 days in July, including one Max Generation Warning on July 29 and two Max Generation Alerts on July 28 and 29.[12] Two Capacity Advisory Initiate alerts have been issued in August to date.[13] Moreover, the May 2025 NERC Summer Reliability Assessment referenced a Seasonal Outlook issued by the National Oceanic and Atmospheric Administration (NOAA), which estimates that much of the Midwest has a 33%-40% chance to experience above-normal temperatures this summer.[14] The Seasonal Outlook released by NOAA on July 17, 2025, increased this estimate for much of the region to a 40%-50% chance.[15]

MISO's resource adequacy problems are not limited to the summer. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[16] MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round

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[10] *See, Custom Data Download, EPA CAMPD (Clean Air Markets Program Data),* *https://campd.epa.gov/data/custom-data-download* *(search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >>Apply >>"2025" and "June." The data can then be filtered to only include the Campbell Plant.)*

[11] An Energy Emergency Alert is an alert declared by the Transmission Provider in accordance with the NERC Operating Manual associated with the Transmission Provider's inability to provide for the Energy and Operating Reserve requirements of the MISO Balancing Authority Area. For more information, see MISO, FERC Electric Tariff, Module A, § 1.E (Definitions) (92.0.0). For more information on Energy Emergency Alert levels, see North American Electric Reliability Corporation. (n.d.). *EOP-011-1 Emergency Operations*. https://www.nerc.com/pa/stand/reliability%20standards/eop-011-1.pdf.

[12] A Max Gen Alert occurs when MISO is forecasting a potential capacity shortage. A Max Gen Warning is a warning to prepare for a possible Max Gen Event. *See* MISO Operating Procedures, https://efis.psc.mo.gov/Document/Display/9379 (20180920).

[13] A Capacity Advisory alert is an advisory issued based on the potential for limited operating capacity margins (<5%) in the following 2-3 days. *See* MISO Operating Procedures, https://efis.psc.mo.gov/Document/Display/9379 (20180920).

[14] NERC 2025 Summer Assessment at 9.

[15] *Seasonal Outlook*, NOAA Climate Prediction Ctr., (July 17, 2025), https://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=1.

[16] M*idcontinent Independent System Operator, Inc.*, FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. Midcontinent Independent System Operator, Inc., 180 FERC ¶ 61,141 (2022).

concern."[17] MISO noted that over 60 percent of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[18]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[19] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projects that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[20]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative.*"[21] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[22]

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

The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Michigan.[23]

On June 6, 2025, subsequent to the issuance of Order No. 202-25-3, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy

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[17] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).
[18] *Id.* at 3-4.
[19] *Attributes Roadmap*, MISO (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[20] *Id.* at 11.
[21] *MISO's Response to the Reliability Imperative*, MISO (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.
[22] *Id.* at 12.
[23] MISO Planning Resource Auction – Results for Planning Year 2025-26 at 13.

planning reserve margin requirements.[24] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[25] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[26] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[27]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[28] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[29]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[30] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three year grace period to commence commercial operations.[31] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[32] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

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[24] *2025 OMS-MISO Survey Results*, OMS and MISO (Updated June 6, 2025) https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.
[25] *Id.* at 2.
[26] *Id.* at 7.
[27] *Id.* at 9.
[28] *Id.* at 7, 9.
[29] *Id.*
[30] M*idcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).
[31] 192 FERC ¶ 61,064 at P 84.
[32] *See generally, US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P Global (May 2025), US gas-fired turbine wait times as much as seven years; costs up sharply | S&P Global. "With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."

Order 202-25-3 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[33] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[34] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[35]

The Department's July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[36] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[37] In addition, as just one example, Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[38]

Grid operators—including MISO itself—have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the

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

[34] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[35] *Id*.

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

[37] Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan*, (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

[38] *See Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center*, Data Center Dynamics (August 05, 2025), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-to-provide-1gw-of-power-to-new-hyperscale-data-center/ (quoting Consumers Energy CEO Garrick Rochow).

changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[39] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[40] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[41]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[42] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and accelerated retirements of generation facilities supporting the issuance of Order No. 202-25-3 will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest under FPA section 202(c).

To ensure the Campbell Plant will be available if needed to address emergency conditions, the Campbell Plant shall remain in operation until November 19, 2025.[43]

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[39] Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce, Subcommittee on Energy, 119th Cong. (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), at 5, https://democrats-energycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-media-document/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf.

[40] *Id.* at 6.

[41] *Id.* at 7.

[42] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b) (2018).

[43] 16 U.S.C. § 824a(c)(4).

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

A. From August 21, 2025, MISO and Consumer Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

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

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

D. By September 4, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

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

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

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

H. This Order shall be effective from 00:00 Eastern Daylight Time (EDT) on August 21, 2025, and shall expire at 00:00 EDT on November 19, 2025, with the exception of applicable compliance obligations in paragraph D.

I. Issued in Norfolk, Virginia at 8:50pm Eastern Daylight Time on this 20th day of August 2025.

Chris Wright
Secretary of Energy

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

Michigan Public Service Commissioners
Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

Exhibit 20

Department of Energy
Washington, DC 20585

Order No. 202-25-8

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

Order No. 202-25-4

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

Order No. 202-25-4, issued pursuant to FPA section 202(c), required that the Eddystone Units remain in operation for 90 days, until August 28, 2025. That order was based on my determination that emergency conditions existed in the PJM region. I explained that there was a potential shortage of electric energy and shortage of facilities for generation of electric energy. I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety. I determined that the operational availability and economic dispatch of the Eddystone Units is necessary to best meet the emergency and serve the public interest. My determination was based on a number of different facts.

First, in congressional testimony, PJM's president and CEO recently stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of dispatchable resources, and other factors.[1] He stated that, through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM's interconnection queue.[2] Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

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[1] *Keeping the Lights On: Examining the State of Regional Reliability*, Before the *H. Comm. on Energy and Com., S. Comm. on* Energy, 119th Cong. (Mar. 25, 2025) (testimony of Mr. Manu Asthana, President and CEO of PJM Interconnection) (Asthana Test.) at 4-5, available at https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf.
[2] *Id.*

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."[3] In its February 2023 assessment "*Energy Transition in PJM: Resource Retirements, Replacements & Risks* (Four Rs Report)," PJM highlighted increasing reliability risks in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.[4]

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."[5]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-4 continue, both in the near and long term. The summer season has not yet ended, and the production of electricity from the Eddystone Units will continue to be critical to maintaining reliability in PJM this summer. This need is evidenced by the fact that the Eddystone Units were called on by PJM to generate electricity during heat waves that hit the region in June and July.

According to U.S. Environmental Protection Agency data, the Eddystone Units generated over 17,000 MWhs during the month of June.[6] Further, over a period of hot weather from June 23 to June 26, Unit 3 ran for a total of 65 hours and Unit 4 ran for a total of 59 hours.[7] During a hot weather period from July 28 to July 30, Unit 3 ran for 39 hours and Unit 4 ran 8 hours.[8]

Over the course of the summer, PJM has issued Hot Weather Alerts and/or Maximum Generation Alerts (EEA 1) covering a total of 20 days, including days in June, July, and August.[9] The hot weather may continue in the near term, as the Seasonal Outlook released by the National Oceanic and Atmospheric Administration (NOAA) on August 21, 2025, projects between a 40%

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[3] *PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing* Risk, PJM Interconnection, L.L.C. (May 9, 2025), https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/.

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

[5] *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 (2025).

[6] *See Custom Data Download, EPA CAMPD* (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (search criteria Emissions >> Monthly >> Unit (default) >>Apply >>"2025" and "June" (search date Aug. 22, 2025).

[7] *See PJM daily reports to DOE under Order No. 202-25-4, June 24-27, 2025.*

[8] *See PJM daily reports to DOE under Order No. 202-25-4, July 29-31, 2025.*

[9] *See* PJM Emergency Procedures Postings for the period between June 1 and August 31, *Emergency Procedures*, https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf (search range set to: effective from 06/01/2025 until 08/31/2025).

and 60% probability of above-normal temperatures in the Mid-Atlantic region, which includes the PJM region, over the next three calendar months.[10]

The evidence also indicates that there is a potential longer term resource adequacy emergency in the PJM region.

In its news release expressing support for Order No. 202-25-4, PJM explained that it has "repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers."[11]

PJM has indeed voiced these concerns for years. In its February 2023 Four Rs Report, PJM cautioned that 40 GW of thermal generation are at risk of retirement by 2030.[12] PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for renewable projects is approximately five percent.[13] PJM determined that the pace of new capacity additions "would be insufficient to keep up with expected retirements and demand growth by 2030."[14] PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.

More recently, in its December 2024 RRI filing with FERC, PJM stated that "[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report . . . ."[15] PJM warned that its "resource adequacy concerns are increasing at an extraordinary pace."[16] PJM went on to explain, its "resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers" and that its preliminary analysis shows "substantial increases [in load additions] since the 2024 forecast" for both the summer and winter seasons.[17] According to PJM, "load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence."[18] Although the RRI process will help expedite the construction of needed

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[10] *Seasonal Outlook*, NOAA Climate Prediction Ctr., (Aug. 21, 2025), https://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=1.
[11] *PJM Statement on the U.S. Department of Energy 202(c) Order of May 30*, PJM (May 31, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/2025-releases/20250531-doe-202c-statement-to-defer-retirements-of-certain-generators.pdf.
[12] Four Rs Report, *supra* n. 4, at 2.
[13] *Id.*
[14] *Id.* at 16, Table 1.
[15] *PJM Interconnection, L.L.C.*, FERC Docket No. ER25-712, Tariff Revisions for Reliability Resource Initiative at 10 (Dec. 13, 2024).
[16] *Id.*
[17] *Id.* at 10-11. *See also id.* at 13 ("the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements…").
[18] *Id.* at 14.

new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.[19]

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM's Director, Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as "extraordinary" and "unprecedented," stating that it "could not have been foreseen as recently as a year ago."[20] Mr. Bielak expressed the opinion that the "rapid" retirement of thermal generation resources, "extreme" forecasted load growth, and "delays in new generation resources achieving commercial operation," would adversely affect resource adequacy throughout PJM's electricity grid.[21]

The North American Electric Reliability Corporation (NERC) has raised similar concerns. According to NERC's 2024 Long Term Reliability Assessment, "PJM could face future resource adequacy challenges, impacting system reliability and PJM's ability to serve load."[22] NERC assessed the PJM region at an elevated risk starting in 2026,[23] explaining that "[r]esource additions are not keeping up with generator retirements and demand growth."[24] NERC stated that the loss-of-load hour (LOLH) and expected unserved energy (EUE) risks are concentrated in the winter months (especially January), in both 2026 and 2028.[25]

Order 202-25-4 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[26] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[27] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure,

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[19] *See id.*, Attachment C (Affidavit of Mr. Donald Bielak) ¶ 18-19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, "could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner.").
[20] *Id*. at 12.
[21] *Id*. at 7.
[22] *2024 Long-Term Reliability Assessment*, North American Electric Reliability Corporation at 92 (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf at 92.
[23] *Id.* at 4.
[24] *Id.* at 7.
[25] *Id.* at 91-92.
[26] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (Strengthening the Reliability and Security of the United States Electric Grid), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliabilityand-security-of-the-united-states-electric-grid/.
[27] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (Declaring a National Energy Emergency), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[28]

The Department of Energy's (Department) July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. It concludes, "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[29] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.[30] As of December 2024, Dominion Energy has 40.2 GW of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.[31] Regarding the PJM region, the Department's analysis performed this year in collaboration with the national labs modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced coal, gas, and oil generation retirements.[32] Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a max unserved load hours of approximately 21.335 GW.[33]

Grid operators, including PJM, have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the United States House of Representatives Committee on Energy and Commerce, Manu Asthana, President and CEO, PJM, testified that there was a "growing resource adequacy concern . . . impacting a significant part of our country."[34] Mr. Asthana explained that the "rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from industrial growth."[35] Mr. Asthana noted that, "though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening." Therefore, Mr. Asthana stated that PJM

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[28] *Id.*
[29] *See also* Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, U.S. Department of Energy (July 2025), at 1, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.
[30] *See PPL Corporation Q2 2025 Investor Update*, PPLC Corporation (July 31, 2025) at 7, https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINAL.pdf
[31] *See* Dominion Energy Virginia, Q4 2024 Earnings Call (Feb. 12, 2025), at 18, https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slides-vTCII.pdf.
[32] *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy (July 2025), at 28, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.
[33] *Id.* at 27.
[34] Asthana Test. at 4.
[35] *Id*.

"encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability."[36]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[37] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and accelerated retirements of generation facilities supporting the issuance of Order No. 202-25-4 will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Eddystone Units is necessary to best meet the emergency and serve the public interest under FPA section 202(c).

To ensure the Eddystone Units will be available if needed to address emergency conditions, the Eddystone Units shall remain in operation until November 26, 2025.[38]

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

A. From 5:03PM EDT on August 28, 2025, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.

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

[36] *Id.* at 10.
[37] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b) (2018).
[38] 16 U.S.C. § 824a(c)(4).

compliance with the allowances contained in this Order.

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

D. By September 12, 2025, PJM is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

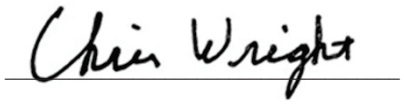
E. Constellation Energy is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

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

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Eddystone Units shall not be considered capacity resources.

H. This Order shall be effective from 5:03 PM Eastern Daylight Time (EDT) on August 28, 2025, and shall expire at 00:00 EST on November 26, 2025, with the exception of applicable compliance obligations in paragraph D.

I. Issued in Washington, D.C., at 7:11 PM Eastern Daylight Time on this 27th day of August 2025.



Chris Wright
Secretary of Energy

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

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

Exhibit 21

Department of Energy
Washington, DC 20585

September 5, 2025

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RE: August 8, 2025 Submission

To Whom It May Concern:

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

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

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

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

Sincerely,

Tina Francone
Director of the Grid Deployment Office, Acting

Exhibit 22

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY

Order No. 202-25-3B
ORDER ADDRESSING ARGUMENTS RAISED ON REHEARING

(Issued September 8, 2025)

1. On May 23, 2025, pursuant to section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] the Secretary of Energy (Secretary) issued an order (Emergency Order) determining that "an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes . . . ."[3] In the Emergency Order, the Secretary determined that "additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c)."[4] Requests for rehearing were filed by Public Interest Organizations (PIOs);[5] Michigan Attorney General Dana Nessel (Michigan AG); the States of Minnesota and Illinois (Minnesota and Illinois); and the Organization of MISO States (OMS).[6] Comments were filed by the Michigan Public Power Agency (MPPA) and the Maryland Office of People's Counsel (Maryland OPC).

2. On July 28, 2025, the Department of Energy (DOE) issued a notice of denial of rehearing by operation of law and providing for further consideration (DOE Notice). However, as provided in sections 202(c) and 313(a) of the FPA,[7] we are modifying the discussion in the Emergency Order and continue to reach the same result in this Order, as discussed below.[8]

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[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b)

[3] Department of Energy Order No. 202-25-3 (May 23, 2025) (Emergency Order).

[4] *Id.* at 2.

[5] Sierra Club, Natural Resources Defense Council, Michigan Environmental Council, Environmental Defense Fund, Environmental Law and Policy Center, Vote Solar, Public Citizen, Union of Concerned Scientists, the Ecology Center, and Urban Core Collective refer to themselves collectively as Public Interest Organizations.

[6] OMS also filed a notice of clarification to identify which of its members voted in support of filing only a petition to intervene and which of its members voted in support of filing a petition to intervene and a request for rehearing.

[7] 16 U.S.C. § 824a(c); 16 U.S.C. § 825*l*(a). In the context of FPA section 202(c) orders, the DOE interprets FPA section 313's references to "the Commission" to mean the DOE.

[8] *See Allegheny Def. Project v. FERC*, 964 F.3d 1, 16-17 (D.C. Cir. 2020). The Department is not

I. Background

3. In the Emergency Order, the Secretary determined that "an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest."[9]

4. The Emergency Order provided substantial support for the Secretary's emergency determination. The Emergency Order explained that, in its 2025 Summer Reliability Assessment, the North American Electric Reliability Corporation (NERC) indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[10] The Emergency Order observed that multiple generation facilities in Michigan have retired in recent years, specifically identifying the closures of two nuclear plants—Big Rock Point and Palisades. The Emergency Order explained that the retirement of the Campbell Plant would further decrease the amount of available dispatchable generation in the Midcontinent Independent System Operator, Inc. (MISO) service territory, noting that a combined 1,575 MW of natural gas and coal-fired generation had retired since the summer of 2024.[11] The Emergency Order stated that MISO's 2025/2026 Planning Resource Auction results indicated that, for the North/Central sub-regions, "new capacity additions were insufficient to offset the negative impacts of accreditation, suspensions/retirements and external resources" and that, while the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance[;]" and the results "reinforce the need to increase capacity."[12]

5. In the Emergency Order, the Secretary determined that continued operation of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination was based on the insufficiency of dispatchable capacity

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changing the outcome of the Emergency Order. *See Smith Lake Improvement & Stakeholders Ass'n v. FERC*, 809 F.3d 55, 56-57 (D.C. Cir. 2015).

[9] Emergency Order at 1.

[10] *Id.* (quoting *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, at 16 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf (NERC 2025 Summer Reliability Assessment). The Emergency Order stated that NERC anticipates "elevated risk of operating shortfalls" notwithstanding Consumers Energy's acquisition of a 1,200 MW natural gas power plant in Covert, Michigan. *Id.* at 1-2.

[11] *Id.*

[12] *Id.* (citing MISO, *Planning Resource Auction Results for Planning Year 2025-26* (Apr. 2025). After the Emergency Order was issued, on May 29, 2025, MISO posted a corrected version of the presentation, which is available here: https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

and an anticipated increase in demand during the summer months, resulting in a risk to public health and safety caused by the potential loss of power to homes and local businesses in areas that may be affected by curtailments or outages. The Emergency Order was limited in duration to align with the emergency circumstances. In recognition of potential conflict with environmental standards and requirements and consistent with FPA section 202(c), the Secretary placed specific conditions on the operation of this necessary additional generation.[13]

II. Discussion

1. The Secretary's Authority to Require the Campbell Plant to Continue to Operate

6. Michigan AG, PIOs, Minnesota and Illinois, and OMS argue that the Emergency Order impermissibly exceeds the Secretary's statutory authority under FPA section 202(c) in various respects.[14] For instance, Michigan AG and PIOs argue that the Emergency Order, in effect, impermissibly asserts the authority to further its policy decisions by managing issues unrelated to addressing emergencies but rather concerning resource adequacy and electric generation facilities—issues which are reserved for the states and the Federal Energy Regulatory Commission (FERC), pursuant to other provisions in the FPA.[15] Minnesota and Illinois additionally contend that the Emergency Order impermissibly intrudes on the states' authority to make plant retirement decisions.[16]

7. Minnesota and Illinois also assert that section 202(c) has been used sparingly to address retirements like the Campbell Plant, and "only when requested by the operator or local government" in the context of an emergency.[17]

8. In a related argument, OMS asserts that the Emergency Order did not adequately consult with or incorporate the findings of MISO and other relevant state regulatory bodies, which they claim have primary jurisdiction over resource planning, sitting, and cost recovery for utilities operating in their states.[18]

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[13] Emergency Order at 2-3.

[14] Michigan AG Pet. § IV.B; PIO Pet. § IV.C; Minnesota and Illinois Pet. § V.E; OMS Pet. § B.

[15] *See* Michigan AG Pet. § IV.B.i (citing 16 U.S.C. § 824(b)(1) and 16 U.S.C. §§ 824d, 824e); PIO Pet. at 44 (citing 16 U.S.C. § 824(a)); *id*. at 45 (citing *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 281 (2016)).

[16] Minnesota and Illinois Pet. at 27.

[17] *Id.* at 24.

[18] *Id.* at 30-31.

9. Minnesota and Illinois also assert that the Emergency Order, subparagraph E, impermissibly calls for state governments to assist in its execution.[19] In particular, Minnesota and Illinois claim that the Emergency Order's directive that "the relevant governmental authorities are directed to take such action"—*i.e.*, effectuate the dispatch and operation of the Campbell Plant's units—unlawfully violates the Tenth Amendment of the United States Constitution.[20]

The DOE's Determination

10. There is no dispute that the Secretary has the statutory authority under FPA section 202(c) to (1) determine that an emergency exists, and then (2) exercise his judgment to address that emergency. Rather, Petitioners claim that the Secretary exceeded that authority in directing MISO and Consumers Energy to undertake specific actions to keep the Campbell Plant in operation. As explained below, these claims have no merit.

11. Section 201(b)(1) of the FPA specifically reserves authority over "facilities used for the generation of electric energy" for the states "*except as specifically provided* in this subchapter."[21] Section 202(c) constitutes one such carve out. It grants the Secretary the "authority, either upon [the Secretary's] own motion or upon complaint, with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in [the Secretary's] judgment will best meet the emergency and serve the public interest." Congress thus purposely provided discretion in section 202(c) to require changes to the operation of the U.S. electricity system on a temporary basis, including changes to the operations of electric generation facilities.

12. Michigan AG and PIOs attempt to avoid this clear grant of authority by arguing that the Emergency Order addresses issues unrelated to emergencies but rather concern resource adequacy.[22] But placing a different label on the Secretary's action cannot change the fact that actions taken in the Emergency Order fall squarely within the authority granted by section 202(c). By its terms, that section specifically applies to the potential "shortage of electric energy or of facilities for the generation or transmission of electric energy," which is exactly the situation that led to the issuance of the Emergency Order. And section 202(c) specifically authorizes the Secretary to "require by order . . . such generation . . . of electric energy as in [the Secretary's] judgment will best meet the emergency and serve the public interest," which is exactly the action the Emergency Order requires.

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[19] *Id.* at 31.

[20] *Id.*

[21] 16 U.S.C. § 824(b)(1) (emphasis added).

[22] *See* Michigan AG Pet. § IV.B.i (citing 16 U.S.C. § 824(b)(1) and 16 U.S.C. §§ 824d, 824e); PIO Pet. at 44 (citing 16 U.S.C. § 824(a)); *id*. at 45 (citing *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 281 (2016)).

13. Nor is there any requirement under section 202(c), as Minnesota and Illinois and OMS suggest,[23] for the Secretary to consult with the impacted states prior to issuing a section 202(c) order. Section 103 of the DOE Organization Act requires consultation with states "where practicable."[24] In an emergency situation, it is often not practicable to consult with the states and relevant state agencies prior to taking emergency action. This point is further supported by the plain language of section 202(c), which specifically authorizes DOE to issue an emergency order "with or *without notice*."[25]

14. Finally, the argument that the Emergency Order violates the Tenth Amendment[26] is incorrect. The Emergency Order provides that "[t]he extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so."[27] Had the Emergency Order directed State governments or their instruments to take such an action, there would, of course, be a constitutional issue, grounded perhaps in regards to the 10th Amendment, but even more directly in the anti-commandeering clause. But that was not the intended endpoint, however, for the avoidance of doubt, we provide clarification that the Order does not direct State governments or their instrumentalities to take such actions.

15. Here, there is no state tariff provision which governs wholesale energy sales. DOE clarifies that the relevant authorities to which the Emergency Order refers are MISO and FERC. DOE is not requiring state governmental authorities to take any action with respect to the Emergency Order.

2. The Secretary's Authority to Determine the Existence of an Emergency

16. Michigan AG, PIOs, Minnesota and Illinois, and OMS each raise similar arguments that the Emergency Order failed to meet the legal definition of an "emergency" within the meaning of FPA section 202(c).[28] For instance, Michigan AG argues that, while section 202(c) "permits some measure of flexibility with respect to what type of events may cause the emergency, allowing for 'other causes' beyond those enumerated," it only authorizes action during extraordinary

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[23] *See, e.g.*, Minnesota and Illinois Pet. § V.E; OMS Pet. at 4.

[24] 42 U.S.C. § 7113.

[25] 16 U.S.C. § 824a(c)(1) (emphasis added).

[26] Minnesota and Illinois Pet. at 31-32.

[27] Emergency Order at 3.

[28] Michigan AG Pet. § IV.A; PIO Pet. § IV.A.1; Minnesota and Illinois Pet. § V.B; OMS Pet. §§ II.A, D.

circumstances.[29] Michigan AG,[30] PIOs,[31] and Minnesota and Illinois[32] cite to the definition of "emergency" in DOE's regulations at 10 C.F.R. § 205.371 and argue that the Emergency Order exceeded the scope of that definition. Michigan AG[33] and PIOs[34] also cite to various dictionary definitions of "emergency" to assert the same point.

17. Further, Michigan AG,[35] PIOs,[36] and Minnesota and Illinois[37] each rely on *Richmond Power and Light v. FERC*, 574 F.2d 610 (D.C. Cir. 1978), and *Otter Tail Power Co. v. Federal Power Commission*, 429 F.2d 232 (8th Cir. 1970), for the proposition that courts have interpreted section 202(c) narrowly to apply only to temporary emergencies requiring an imminent response.

The DOE's Determination

18. In enumerating emergency powers in section 202(c), Congress accorded the Secretary discretion to determine the existence of an emergency. The statute's plain text grants the Secretary authority to respond, in certain circumstances, to emergencies posing dire threats to the Nation's electric infrastructure. Specifically, the Secretary "*shall* have authority" to act "*whenever* the [Secretary] determines that an emergency exists."[38] Next, the statute sets forth three different categories of emergencies where section 202(c) action is permissible. An emergency may exist "by reason of [1] a sudden increase in the demand for electric energy, or [2] 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 [3] other causes."[39]

19. Section 202(c)(1) delegates a wide degree of latitude for the Secretary to determine the existence of an emergency, "either upon its own motion or upon complaint, with or without notice,

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[29] Michigan AG Pet. at 24.

[30] Michigan AG Pet. at 26.

[31] PIO Pet. at 28-29.

[32] Minnesota and Illinois Pet. at 22-23.

[33] Michigan AG Pet. at 25.

[34] PIO Pet. at 26.

[35] Michigan AG Pet. at 25-26.

[36] PIO Pet. 26-27.

[37] Minnesota and Illinois Pet. at 24.

[38] 16 U.S.C. § 824a(c)(1) (emphases added).

[39] *Id.* (brackets added).

hearing, or report." Beyond providing exemplar categories of where an "emergency exists," the statute is silent on any additional requirements that must be satisfied. Here, as is evident from the face of the Emergency Order, and as is consistent with section 202(c)'s text and prior DOE practice, the Secretary exercised his authority under section 202(c) and determined, in his statutory discretion and substantive expertise, 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."[40]

20. The argument that the Secretary can act only when a shortage of electricity is "imminent" makes no sense in the context of his statutory authority under section 202(c) to act to address a "shortage of . . . facilities for the generation . . . of electric energy." As a general matter, some retired generation facilities generally cannot be brought back online in a matter of days. If the Secretary was required to wait until a blackout is "imminent" before addressing a shortage of generation facilities, he will be unable to take any meaningful action to address the blackout. Determining to take action before the retirement of the Campbell Plant, which was necessary to ensure that it would be available to produce electric energy to prevent blackouts in summer peak load periods, falls well within the Secretary's statutory discretion.

21. The definition of "emergency" contained in DOE's regulations at 10 C.F.R. § 205.371 does not supersede the discretion section 202(c) affords to the Secretary to "determine[] that an emergency exists." In any event, those regulations specifically provide that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations." Accordingly, the Secretary's emergency determination is entirely consistent with the governing statutory requirements in section 202(c) and the DOE's regulations.

22. Similarly, the dictionary definitions cited by Michigan AG[41] and PIOs[42] are not persuasive. Those definitions cannot limit the discretion Congress expressly delegated to the Secretary in section 202(c).

23. The arguments made by Michigan AG,[43] PIOs,[44] and Minnesota and Illinois[45] based on the *Otter Tail Power* and *Richmond Power and Light* decisions likewise are misguided. *Otter Tail Power* did not limit the Secretary's section 202(c) discretion or the meaning of "emergency" because the court held that section 202(c) *did not apply* to the case. Instead, *Otter Trail Power*

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[40] *See* Emergency Order at 1.

[41] Michigan AG Pet. at 25.

[42] PIO Pet. at 26.

[43] Michigan AG Pet. at 25-26.

[44] PIO Pet. 26-27.

[45] Minnesota and Illinois Pet. at 24.

involved section 202(b) of the FPA dealing with permanent interconnection (and not an "emergency" within the meaning of section 202(c)).[46] In *Richmond Power and Light*, the Court of Appeals for the D.C. Circuit held that the Federal Power Commission (FPC) did not abuse its discretion in *declining* to invoke its emergency powers under section 202(c).[47] The court determined that the FPC had discretion to choose a temporary, voluntary program rather than issue an order pursuant to section 202(c), as the circumstance, in the FPC's discretion, did not warrant the use of emergency authority.[48]

24. A more relevant decision is *Board of Trade of the City of Chicago v. Commodity Futures Trading Commission*.[49] In that case, the Court of Appeals for the Seventh Circuit recognized the broad powers of the Commodity Futures Trading Commission (CFTC) to issue emergency actions under section 8a(9) of the Commodity Exchange Act (7 U.S.C. § 12a(9)). Through section 8a(9), the CFTC issued an emergency order for the Board of Trade to suspend trading in a certain wheat futures contracts, citing transportation and warehouse shortages and potential market manipulation.[50] In response, the Board of Trade sought an injunction against the order, arguing that no emergency existed. The district court granted a preliminary injunction, and the CFTC appealed.[51] In its decision to vacate and remand the district court's preliminary injunction, the Seventh Circuit concluded that Congress intended to grant the CFTC discretion in making emergency determinations under the Commodity Exchange Act.[52] The court reasoned: "Congress recognized that regulation of the volatile futures markets could be accomplished effectively only through the use of an expert Commission, that situations could occur suddenly for which the traditional enforcement powers would be an inadequate response, and that therefore the Commission should have emergency powers, the exercise of which is committed to the expertise and discretion of the Commission."[53] In addition, "[t]he fact that the Commission is authorized by Congress to take emergency action is, in itself, a suggestion of Congressional intent to commit

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[46] *See Otter Tail Power Co. v. Federal Power Commission*, 429 F.2d 232 (8th Cir. 1970) (*Otter Tail Power)* (rejecting petitioner's contention that "any proceedings in the instant case must be dealt with in compliance with § 202(c)").

[47] *See Richmond Power and Light v. FERC*, 574 F.2d 610 (D.C. Cir. 1978) (*Richmond Power and Light*) at 615.

[48] *Id.* at 614-15.

[49] *Board of Trade of the City of Chicago v. Commodity Futures Trading Commission*, 605 F.2d 1016, 1025 (7th Cir. 1979)

[50] *See Board of Trade of the City of Chicago v. Commodity Futures Trading Commission*, 605 F.2d 1016, 1025 (7th Cir. 1979) at 1018.

[51] *Id.* at 1019-20.

[52] *Id.* at 1023-25.

[53] *Id.* at 1025.

such actions to the Commission's discretion."[54] Given the similarities between FPA section 202(c) and section 8a(9) of the Commodity Exchange Act, the *Board of Trade* decision confirms the conclusion that Congress intended to grant the Secretary broad discretion to determine when his emergency powers should be applied to protect the public interest.[55]

25. Finally, the assertion of Minnesota and Illinois that the Emergency Order is "novel" and contravenes prior practice wherein section 202(c) was used to address retirements "only when requested" has no merit.[56] On its face, section 202(c)(1) authorizes the Secretary to act "*either upon its own motion or upon complaint*." It is undisputed that section 202(c) has been used in the past to address generation retirements. Under the statute, it is irrelevant whether a utility requested that the Secretary take this action.

26. In sum, the Secretary acted within his authority to determine the existence of an emergency and the statutory meaning of "emergency" has been satisfied here. In its 90-year history, no court has questioned the Secretary's (or, prior to its dissolution in 1977, the FPC's)[57] discretion in this respect, much less overturned the Secretary's determination that an emergency exists. The absence of such circumstances underscores the Secretary's authority as expressly delegated in the statute.

3. The Factual Basis to Support the Secretary's Emergency Determination

27. Michigan AG, PIOs, Minnesota and Illinois, and OMS also raise similar objections that there is no factual basis to support the Emergency Order, and that the Secretary is required to submit substantial evidence in support of his emergency determination.[58]

28. *First*, Michigan AG, PIOs, Minnesota and Illinois, and OMS criticize the Emergency Order's references to the 2025 NERC Summer Reliability Assessment.[59] For instance, Michigan AG claims that the Emergency Order fails to explain (1) how NERC's assessment supports an emergency finding, as NERC did not put MISO in the high-risk category; (2) why NERC's designation of "elevated" risk represents a sudden or unexpected circumstance, as MISO has been

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[54] *Id.* at 1023.

[55] *See id.* at 1023-25.

[56] *See* Minnesota and Illinois Pet. at 24.

[57] The FPC was dissolved in 1977, and the FPC's functions were split between FERC and the Department, with the Secretary retaining FPA section 202(c) power.

[58] Michigan AG Pet. §§ IV.A(ii), IV.C; PIO Pet. § IV.A.2; Minnesota and Illinois Pet. § V.A; OMS Pet. § II.A.

[59] Michigan AG Pet. at 27-29, 37; PIO Pet. 32-35; Minnesota and Illinois Pet. at 19-20; OMS Pet. at 2-3. OMS also contends that NERC's long-term and seasonal assessments are unreliable and inconsistent. OMS Pet. at 3.

at this risk level or higher for years; and (3) why the "potential tight reserve margins" identified by NERC constitute an emergency, as MISO exceeded the NERC reference margin level in the 2020-2025 period.[60]

29. *Second*, Michigan AG and PIOs contend that the retirement of the Campbell Plant was not unexpected or sudden, and that generation retirement does not constitute an emergency.[61] Michigan AG further states that MISO approved the retirement of the Campbell Plant after an extensive process.[62]

30. *Third*, Michigan AG, PIOs, and Minnesota and Illinois also assert that the April 2025 MISO Planning Resource Auction does not demonstrate the existence of an emergency.[63] For example, according to Michigan AG, the Emergency Order ignored MISO's conclusion that the 2025/2026 Planning Resource Auction "demonstrated sufficient capacity at the regional, subregional and zonal levels."[64]

31. Minnesota and Illinois also contend that the Emergency Order failed to consider MISO's purported history of performance in several extreme weather events and, according to Minnesota and Illinois, MISO currently is not afflicted by any unexpected outage or extreme weather event.[65]

The DOE's Determination

32. The exigencies that Section 202(c) is designed to address necessarily require that the Secretary's determination is informed by the facts available at the time and by his sound expert judgment as to what situations constitute an emergency. The statute's express exclusion of any notice, hearing, or report requirements prior to issuance of a section 202(c) order confirms the commonsense fact that the Secretary must exercise his section 202(c) authority expeditiously and with broad discretion in responding to emergency situations.

33. In any event, the Secretary's determination that an emergency exists is supported by the factual evidence and the exercise of the Secretary's judgment. The Emergency Order identified the ongoing emergency "in portions of the Midwest region of the United States due to a shortage

[60] Michigan AG Pet. at 37.

[61] *Id.* at 30, 37; PIO Pet. 29-30.

[62] Michigan AG Pet. at 39

[63] *Id.* at 30-32, 38; PIO Pet. at 30-32; Minnesota and Illinois Pet. at 20-21.

[64] Michigan AG Pet. at 39 (citing Attachment B, MISO, Planning Resource Auction, Results for Planning Year 2025 – 2026 (April 2025) at 12).

[65] Minnesota and Illinois Pet. at 22.

of electric energy, a shortage of facilities for the generation of electric energy, and other causes."[66] Consistent with this determination, the Emergency Order explains the need to increase capacity to meet the increasingly high demands and decreasing generation output.[67]

34. In 2021, Consumers Energy announced that it planned a "speed closure" of the Campbell Plant in 2025, years before the end of its scheduled design life.[68] Specifically, the Campbell Plant was scheduled to retire on May 31, 2025, and thus would not be operational in August, the month the Secretary anticipated heightened demand on the grid.[69] In the Emergency Order, the Secretary noted that the Campbell Plant's retirement was part of an ongoing trend, which has seen 1,575 MW of natural gas and coal-fired generation retired since the summer of 2024, further decreasing the amount of dispatchable generation within MISO's service territory.[70] Although MISO and Consumers Energy have incorporated the Campbell Plant's planned retirement into their supply forecasts, as well as Consumers Energy's acquisition of an existing 1,200 MW natural gas power plant in Covert, Michigan, NERC's 2025 Summer Reliability Assessment still anticipated "elevated risk of operating reserve shortfalls."[71]

35. Michigan AG, PIOs, Minnesota and Illinois, and OMS mischaracterize the 2025 NERC Summer Reliability Assessment's designation of "elevated risk" for the MISO region. This assessment reflects NERC's determination that "resources will not be sufficient to meet operating reserves" in the event of "extreme peak-day demand with normal resource scenarios" or "normal peak-day demand with reduced resources."[72] The NERC assessment of "elevated risk" suggests that there will be significant strain on the grid in the MISO service area even in normal operating conditions. If the Secretary had waited to act until the conditions identified by NERC arose, it would have been too late for him to take any effective action.

36. Petitioners note that MISO and Consumers Energy have incorporated the Campbell Plant's planned retirement into their supply forecasts and acquired a 1,200 MW natural gas power plant in Covert, Michigan. However, NERC's 2025 Summer Reliability Assessment anticipated

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[66] *See* Emergency Order at 1.

[67] *See id.* (noting recent closures of generation facilities in Michigan and uncertain near-term future of generation from the Palisades nuclear power plant).

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

[69] Emergency Order at 1.

[70] *Id*.

[71] *Id.* (citing NERC 2025 Assessment).

[72] NERC 2025 Assessment at 10.

"elevated risk of operating reserve shortfalls" even including the Covert Plant's capacity.[73] The fact that Consumers Energy acquired this existing plant to replace the Campbell Plant did not forestall the emergency.

37. Similarly, MISO's approval of the retirement of the Campbell Plant came before NERC's 2025 Summer Reliability Assessment, which took into account increased demand projections.

38. Michigan AG, PIOs, and Minnesota and Illinois' respective criticisms[74] of the Secretary's reliance on the April 2025 MISO Planning Resource Auction ignore that MISO stated that the summer months reflected the "highest risk and a tighter supply-demand balance" and the results of the auction "reinforce the need to increase capacity."[75] In addition, the May 2025 NERC assessment referenced a Seasonal Outlook issued by the National Oceanic and Atmospheric Administration (NOAA) on April 17, 2025, which estimated that much of the Midwest had a 33%-40% chance to experience above-normal temperatures in the summer.[76] DOE also notes that a Seasonal Outlook released by the NOAA on June 19, 2025 increased this estimate to a 40%-50% chance of above-normal temperatures.[77]

39. Similarly, the argument of Minnesota and Illinois that the MISO region does not face current "extreme" weather events misses the mark.[78] The Emergency Order was based on the facts known at the time it was issued in May 2025, including the projected potential for a shortage of capacity in the summer identified by NERC. In other words, the Secretary was required to act before the shortage actually occurred. Moreover, contrary to the contentions of Minnesota and Illinois, the conditions that actually existed in the summer following issuance of the Emergency Order further confirm the ongoing emergency and sudden increased threats to energy reliability. In June 2025, MISO issued alerts affecting the Central Region on 18 days. For instance, on June 23, 2025, MISO issued an Energy Emergency Alert 1 for the North and Central Regions "[d]ue to the hot weather and high demand" during a heat dome over the eastern portion of the United States.[79] In fact, between June 11 and August 18, MISO issued dozens of alerts to manage grid

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[73] Emergency Order at 1 (citing to NERC 2025 Assessment).

[74] Michigan AG Pet. at 30-32, 38; PIO Pet. at 30-32; Minnesota and Illinois Pet. at 20-21.

[75] *Planning Resource Auction Results for Planning Year 2025-26,* MISO (Apr. 2025). (Corrected and reissued on 05/29/25) available at https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

[76] NERC 2025 Assessment at 9.

[77] *Seasonal Outlook,* NOAA Climate Prediction Ctr., (July 17, 2025), https://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=1.

[78] Minnesota and Illinois Pet. at 22.

[79] *See* MISO Energy Emergency Alert 1 (June 23, 2025),

reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits. MISO issued alerts for the Central Region on at least 40 of the 69 days between June 11 and August 18.

40. In addition, the Secretary took section 202(c) action in the context of a National Energy Emergency declared by the President in the months prior to the Emergency Order. In executive orders dated January 20, 2025, and April 8, 2025, the President underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. The President recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[80] In view of the National Energy Emergency, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," the President explained 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 an increase in domestic manufacturing."[81] Significantly, Executive Order 14262 specifically ordered the Secretary to draw upon "all mechanisms available under applicable law, *including section 202(c) of the Federal Power Act*, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region."[82] The executive orders informed the Secretary's decision and action, in addition to the other factors outlined in the Emergency Order and this Order.

41. Grid operators, including MISO itself, have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025 hearing before the House Committee on Energy and Commerce, Jennifer Curran, the Senior Vice President of Planning and Operations for MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[83] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers

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https://x.com/MISO_energy/status/1937172353118548150.

[80] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025).

[81] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025).

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

[83] Keeping the Lights On: Examining the State of Regional Grid Reliability Hearing Before the House Committee on Energy and Commerce, Subcommittee on Energy, 119th Cong. (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), at 5, witness-testimony_curran_eng_gridoperators_03.25.2025.pdf.

to support artificial intelligence."[84] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[85]

42. Finally, DOE's assessment reveals that, 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. The action taken in the Emergency Order requiring the Campbell Plant to continue to operate before its planned retirement on May 31, 2025 addresses that risk.[86]

43. In sum, the Secretary's determination in the Emergency Order that continued operations of the Campbell Plant fully complies with section 202(c).

4. Potential Environmental Impacts

44. Michigan AG and Minnesota and Illinois raise similar arguments that the Emergency Order fails to comply with section 202(c)'s requirement to ensure that any order "to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation and minimizes any adverse environmental impacts."[87] In particular, Michigan AG and PIOs argue that the Emergency Order fails to identify any specific criteria or conditions for ensuring compliance with environmental regulations or limiting environmental impact.[88]

The DOE's Determination

45. Section 202(c)(2) requires the Secretary to ensure that any section 202(c) order that may result in a conflict with a requirement of any environmental law or regulation to the "maximum extent practicable, [be] consistent with any applicable . . . environmental law or regulation and minimize[] any adverse environmental impacts." Contrary to Michigan AG and Minnesota and Illinois' contentions, the Emergency Order contains certain limitations to minimize the hours of operation and adverse environmental impacts. Specifically, the Emergency Order requires that "[a]ll operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible,"[89] and requires daily reporting from MISO on "whether the Campbell

[84] *Id.* at 6.

[85] *Id.* at 7.

[86] NERC 2025 Summer Reliability Assessment

[87] Michigan AG Pet. at 52 (citing 16 U.S.C. § 824a(c)(2)); Minnesota and Illinois Pet. at 13 (citing 16 U.S.C. § 824a(c)(2)).

[88] Michigan AG Pet. at 54-55; PIO Pet. at 47.

[89] Emergency Order at 3, Ordering Paragraph C.

Plant has operated in compliance with the allowances contained in this Order."[90] These reporting requirements provide a mechanism for the DOE to obtain information concerning any adverse environmental impacts of the Emergency Order, and DOE may modify the Emergency Order to require additional actions as the Secretary deems appropriate.

46. Michigan AG and Minnesota and Illinois argue that the Emergency Order is not tailored to respect environmental considerations, of particular concern to Michigan AG and Minnesota and Illinois are the potential environmental impacts that may be produced by the Campbell Plant.[91] Michigan AG and Minnesota and Illinois provide examples of certain conditions that in their view would, presumably, satisfy the requirements of the statute (*e.g.*, direction to optimize use of pollution control equipment or avoid operations during air quality episodes).[92] These conditions, however, are not required by statute. Congress did not prescribe in section 202(c) how the Department was to fulfill its obligations concerning consistency with environmental laws and minimization of adverse effects. Moreover, Congress recognized, by including the phrase "to the maximum extent practicable," that emergency circumstances would at times make compliance with all Federal, state, and local environmental requirements and minimization of all potential adverse environmental impacts infeasible. This phrase provides the Secretary with discretion in fulfilling its obligations under section 202(c). Accordingly, the Emergency Order's limits on duration and the conditions that authorize only the additional generation necessary and require the operation of the plant to comply with environmental laws to the maximum extent feasible, as well as the reporting requirements that allow DOE to monitor MISO's compliance with the Emergency Order and the environmental impacts such that DOE could take additional action as the Secretary deems appropriate, were sufficient to satisfy its obligation under section 202(c)(2) to ensure that the Emergency Order, to the maximum extent practicable, is consistent with applicable environmental laws and minimizes adverse environmental impacts.

5. Authority to Order Economic Dispatch

47. Michigan AG and Minnesota and Illinois assert that DOE does not have the authority under 202(c)(1) to order the utilization of economic dispatch of the Campbell Plant as a response to an emergency, and that economic dispatch is not an effective or rational measure to address resource shortages.[93] Accordingly, Michigan AG and Minnesota and Illinois contend that economic dispatch is not in the "public interest," as required under section 202(c).[94] In addition, PIOs contend that the Emergency Order's economic dispatch requirement is ambiguous and vague.[95]

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[90] *Id.*, Ordering Paragraph B.

[91] Michigan AG Pet. at 54-55; Minnesota and Illinois Mot. at 26-27.

[92] Michigan AG Pet. at 54; Minnesota and Illinois Mot. at 26-27.

[93] Michigan AG Pet. § IV.D; Minnesota and Illinois Pet. § V.G.

[94] Michigan AG Pet. At

[95] PIO Pet. at 42-43.

Michigan AG asserts that Consumers Energy can subvert the economic dispatch requirement by offering the Campbell Plant on a "must run" status.[96] Michigan AG asserts that, if this happens, the costs to ratepayers will not have been minimized.[97]

The DOE's Determination

48. As noted, section 202(c)(1) affords the Secretary discretion as to what remedy "will best meet the emergency and serve the public interest." The statute expressly delegates the decision on the appropriate remedy to the Secretary's "judgment" (similar to the express delegation to "determine[] that an emergency exists"). In the Emergency Order, the Secretary soundly exercised his judgment in directing "additional dispatch of the Campbell Plant [] necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c)."[98] "This determination [was] based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety," as discussed above.[99]

49. The Emergency Order directs MISO and Consumers Energy to "take all measures necessary to ensure that the Campbell Plant is available to operate."[100] The Emergency Order then directs MISO "to take every step to employ economic dispatch of the [facility] to minimize [the] cost to ratepayers."[101] The DOE disagrees with arguments that economic dispatch is not effective or rational in this case. The directive regarding economic dispatch ensures that the Campbell Plant can be dispatched instead of more costly generation (if available), reducing electricity costs and serving the public interest. The directive recognizes the fact that MISO uses "a production cost modeling software that produces a unit commitment and security-constrained economic dispatch while optimizing production costs."[102] DOE clarifies, however, that to the extent operational (including safety) limitations prevent the Campbell Plant from being economically dispatched, offering the Campbell Plant on a must run basis may be necessary to ensure the units are available to operate. Under those circumstances, such operation would be consistent with

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[96] Michigan AG Pet. at 49.

[97] *Id.*

[98] Emergency Order at 2.

[99] *Id.*

[100] *Id.*, Ordering Paragraph A.

[101] *Id.*

[102] *MISO Economic Planning Whitepaper* (Oct. 3, 2024), at 3, https://cdn.misoenergy.org/MISO%20Economic%20Planning%20Whitepaper651689.pdf

minimizing the cost to ratepayers because a price taker can decrease (but cannot increase) the market price.

6. Best and Appropriate Means for Addressing the Emergency

50. The Michigan AG and PIOs raise similar arguments that the Campbell Plant is neither the best nor an appropriate means of alleviating the capacity shortfall addressed by the Emergency Order.[103] In particular, Michigan AG and PIOs argue that DOE was required to consider alternatives and evaluate other possible methods for addressing the emergency, which they argue the Emergency Order failed to do.[104] They further argue that there are alternative means by which DOE could have addressed the emergency.[105]

51. PIOs additionally argue that the Emergency Order fails to consider the various policies of the FPA.[106] Specifically, PIO's argue that the Emergency Order fails to provide a reasoned basis for its determination that additional dispatch of the Campbell Plant is necessary to best meet the emergency.[107] PIOs further contend that the Emergency Order does not examine the expense or environmental impact of running the Campbell Plant, or address how the Campbell Plant can meet the emergency.[108]

The DOE's Determination

52. The Secretary, in issuing the Emergency Order, adhered to the process established in FPA section 202(c) in exercising his judgment in directing MISO and Consumers Energy to undertake specific actions as to the Campbell Plant.[109] There is no dispute that the Secretary, as the presidentially-appointed and Senate-confirmed head of the Department (*see* 42 U.S.C. § 7131), is the appropriate individual to determine the existence of an emergency within the meaning of section 202(c) and exercise "[the Secretary's] judgment" as to what Department actions "best meet the emergency and serve the public interest."[110] As discussed above, the Secretary exercised his discretion in responding to an emergency pursuant to an express delegation of authority under

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[103] Michigan AG Pet. at 41; PIO Pet. at 36-37.

[104] Michigan AG Pet. at 41; PIO Pet. at 36-37.

[105] Michigan AG Pet. at 41; PIO Pet. at 41.

[106] PIO Pet. at 37.

[107] *Id.* at 37-41.

[108] *Id.*

[109] *See generally* Emergency Order.

[110] 16 U.S.C. § 824a(c)(1).

section 202(c). Further, as explained below, there is no basis to grant rehearing to review the Secretary's exercise of his judgment in prescribing the required response to the emergency.

53. As noted above, section 202(c)(1) affords the Secretary discretion as to what remedy "will best meet the emergency and serve the public interest." The statute expressly delegates the decision on the appropriate remedy to the Secretary's "judgment" (similar to the express delegation to "determine[] that an emergency exists"). Here, the Secretary soundly exercised his judgment in directing "additional dispatch of the Campbell Plant [] necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c)."[111] "This determination [was] based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety."[112]

54. That Petitioners have now, after the fact, identified alternatives they deem to be better and more appropriate solutions to the emergency is irrelevant. Section 202(c)(1) delegates a wide degree of latitude for the Secretary to determine the existence of an emergency and to order the means to address such emergency. It does not require the Secretary to engage in a lengthy weighing of options or explanation of the Secretary's actions prior to issuing an emergency order. Indeed, such a process would defeat the very purpose of the emergency power.

7. NEPA Concerns

55. Michigan AG claims that the Emergency Order violates the National Environmental Policy Act (NEPA), as any orders issued under section 202(c) that affect the quality of the environment are considered "major federal actions"[113] that require compliance with NEPA standards and requirements.[114] According to the Michigan AG, these requirements include the "issuance of an environmental impact statement, environmental assessment, categorical exclusion, or special environmental analysis."[115]

56. Michigan AG further asserts that in other section 202(c) orders, DOE has previously sought to comply with NEPA through categorical exclusions, such as categorical exclusion B4.4 for "power management activities," or special environmental assessments—neither of which has been undertaken nor would apply in this instance.[116] Lastly, Michigan AG argues that DOE would not be justified in seeking an extension of the Emergency Order beyond 90 days under section

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[111] Emergency Order at 2.

[112] *Id.*

[113] Michigan AG Pet. at 55-56 (citing 42 U.S.C. § 4336e(10)).

[114] *Id*. at 55-56.

[115] *Id*. at 56 (citing 10 C.F.R. § 1021.102(b)).

[116] *See id*.

202(c)(3), considering "[a]ny justification that NEPA can be sidestepped to address an emergency need fades as DOE's orders extend beyond the initial 90-day period."[117]

The DOE's Determination

57. We disagree with Michigan AG's contention that the DOE "is acting contrary to its own NEPA regulations and to its obligations under NEPA."[118] Although DOE has previously followed the procedures provided in the Department's NEPA regulations governing emergency actions, as described in 10 C.F.R. § 1021.343 (for example, by preparing a special environmental analysis after the issuance of a section 202(c) order), recent amendments to NEPA clarify that agencies are "not required to prepare an environmental document with respect to a proposed agency action if… the preparation of such document would clearly and fundamentally conflict with the requirements of another provision of law."[119] As DOE recently explained in its NEPA Implementing Procedures, "NEPA does not apply to DOE's issuance of emergency Orders pursuant to section 202(c) of the Federal Power Act (16 U.S.C. 824a(c)) because preparing an environmental document under NEPA's generally applicable provisions would clearly and fundamentally conflict with the emergency provisions in the Federal Power Act."[120]

58. As discussed above, under FPA section 202(c), Congress explicitly authorized the Secretary to "with or without . . . report" exercise certain emergency authorities. Requiring compliance with the analytic and procedural demands of preparing an environmental document under NEPA prior to issuing a section 202(c) emergency order fundamentally conflicts with the authorization for emergency action contemplated by FPA section 202(c) and the Congressional authorization to exercise such authorities without report. Accordingly, DOE has determined, in consultation with the Council on Environmental Quality, that "NEPA does not apply to DOE's issuance of emergency orders pursuant to section 202(c) . . . because preparing an environmental document under NEPA's generally applicable provisions would clearly and fundamentally conflict with the emergency provisions in the Federal Power Act."[121]

59. Furthermore, as stated above, section 202(c) specifically provides alternative measures for affording environmental protection by requiring the Secretary to ensure that any such order "to the maximum extent practicable, is consistent with any applicable Federal, state, or local

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[117] *Id*. at 57-58.

[118] *Id.* at 56.

[119] *See* 42 U.S.C. § 4336(a)(3); *see also* Fiscal Responsibility Act of 2023, Pub. L. No. 188-5, § 321(b), 137 Stat. 10, 39 (2023).

[120] *National Environmental Policy Act* (*NEPA) Implementing Procedures*, U.S. Department of Energy, 6 (June 30, 2025), https://www.energy.gov/sites/default/files/2025-06/2025-06-30-DOE-NEPA-Procedures.pdf.

[121] *See id.*

environmental law or regulation and minimizes any adverse environmental impacts."[122] Again, those environmental obligations were met through the conditions imposed via the Emergency Order's limitation on the duration of the emergency operations, authorization of only the additional generation necessary, requirement that the operation of the plant to comply with environmental laws to the maximum extent feasible, and the requirement that MISO reports to the Department on MISO's compliance with the Emergency Order and corresponding environmental impacts, if any.

8. Deprivation of Fair Notice and Adequate Record

60. PIOs claim that DOE failed to comply with its own procedures to post filings on DOE's 202(c) website within twenty-four hours of receipt, depriving the public of fair notice and a meaningful opportunity to comment.[123] According to PIOs, DOE has not posted materials related to the Emergency Order that it has received, such as "a letter from counsel for Consumers Energy, which stated that MISO and Consumers Energy have not been able to reach agreement on the rate issues relating to the May 23, 2025 Order," among other things.[124] PIOs also argue that DOE's failure to follow these procedures "deprives the public and Public Interest Organizations of fair notice and an adequate record."[125]

The DOE's Determination

61. The subject of the letter PIOs reference was certain rate issues relating to the Emergency Order, as Consumers Energy and MISO have not been able to agree on appropriate rate issues relating to Emergency Order. Because the letter pertained to rate issues, DOE referred the issues to FERC pursuant to 10 C.F.R. § 205.376, by its own letter dated June 13, 2025.[126] Moreover, the letter and other materials identified by PIOs were submitted to the Department after the Emergency Order was issued and, as a result, had no bearing on the issuance of the Emergency Order.

9. Lack of Cost Allocation and Cost Recovery Framework

62. OMS claims that the Emergency Order disclaims responsibility for cost recovery to the FERC, while directly incurring costs through the continued operation of the Campbell Plant. OMS argues that this creates legal, jurisdictional, and equity concerns, by assigning costs to those not

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[122] 16 U.S.C. § 824a(c)(2).

[123] PIO Pet. at 50.

[124] *Id*.

[125] *Id.* (citing *United States v. Nova Scotia Food Prods. Corp.*, 568 F.2d 240, 249 (2d Cir. 1977)).

[126] *See* Ltr. from DOE to FERC, *Consumers Energy Company et al. v. Midcontinent Independent System Operator, Inc.*, FERC Docket. No. EL25-90 (June 13, 2025). In its letter, DOE described the contents of the prior letter from Consumers Energy, explaining that, "[o]n June 10, 2025, DOE received a letter from counsel for Consumers which stated that MISO and Consumers have not been able to reach agreement on the rate issues relating to the [Emergency Order]." *Id.* at 2.

causing the costs or receiving the benefits.[127] Further, OMS alleges the Emergency Order violates FPA sections 205 and 206, which OMS characterizes as requiring rates to be "just and reasonable and not unduly discriminatory or preferential."[128] Lastly, OMS alleges the Emergency Order violates "Cost Causation Principles" as held by courts.[129]

63. MPPA similarly claims it must be able to recover costs incurred due to compliance with the Emergency Order and operating the Campbell Plant beyond the retirement date of May 31, 2025, considering MPPA owns 4.80% of Unit No. 3 of the Campbell Plant and is therefore responsible for a portion of its operating and maintenance costs.[130]

64. According to MPPA, any alterations to the original directive could impact its financial recovery.[131] Additionally, MPPA is an intervenor in a related FERC complaint seeking cost recovery for the Campbell Plant owners and actively supports that complaint.[132] As such, MPPA's interests are unique and not adequately represented by other parties, and it requests party status in this DOE proceeding to ensure its concerns are addressed.[133]

The DOE's Determination

65. Petitioners' arguments are misguided. FPA section 202(c) does not impose any obligation on the Secretary to address cost allocation issues on the face of an emergency order. In any event, MISO's existing tariff already establishes how the costs of all generators dispatched by MISO ordinarily are to be allocated. Nothing in the Emergency Order held otherwise.

66. To the extent that the owners of the Campbell Plant desired additional compensation beyond what MISO's existing tariff provides, FPA section 202(c)(1) provides that: "[i]f the parties affected by [an emergency order issued pursuant to section 202(c)] fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party."

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[127] OMS Pet. at 4.

[128] *Id*. at 5.

[129] *Id*.

[130] MPPA Comments at 1-2.

[131] *Id*. at 2.

[132] *Id*.

[133] *Id*.

67. Consistent with this statutory provision, DOE's regulations concerning generation of electricity to alleviate an emergency shortage of electric power address the procedures that DOE will follow when relevant entities are not able to agree on the rate issues arising from an order issued by DOE pursuant to section 202(c):

> The applicant and the generating or transmitting systems from which emergency service is requested are encouraged to utilize the rates and charges contained in approved existing rate schedules or to negotiate mutually satisfactory rates for the proposed transactions. In the event that the DOE determines that an emergency exists under section 202(c), and the "entities" are unable to agree on the rates to be charged, the DOE shall prescribe the conditions of service and refer the rate issues to the [FERC] for determination by that agency in accordance with its standards and procedures.[134]

68. On June 6, 2025, Consumers Energy filed a complaint (Complaint) pursuant to sections 202(c), 306, and 309 of the FPA and Rule 206 of FERC's Rule of Practice and Procedure, proposing revisions to the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) to add a provision (Proposed Tariff Provision) to allocate the costs of keeping the Campbell Plant in operation, in response to the Emergency Order.[135] On June 13, 2025, DOE promptly issued a referral on cost allocation to FERC, pursuant to 10 C.F.R. § 205.376, in Docket Nos. EL25-90 and AD25-14.[136] The referral letter specified that "DOE is not referring to the Commission any other matters, including, but not limited to, DOE's finding of an emergency, the prescription of conditions of service, or any other matter arising from DOE's exercise of its authority under section 202(c). In an order issued August 15, 2025, in Docket Nos. EL25-90 and AD25-14, FERC granted the Complaint and determined that the Proposed Tariff Provision is just and reasonable.[137] FERC directed MISO to make a compliance filing, within 30 days of the date of the order, and to adopt the Proposed Tariff Provision.[138]

69. Thus, the cost allocation process established in the Emergency Order worked exactly as contemplated by section 202(c) and DOE's implementing regulations.

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[134] 10 C.F.R. § 205.376.

[135] *Consumers Energy Company et al. v. Midcontinent Independent System Operator, Inc.*, FERC Docket No. EL25-90 (June 6, 2025) (*citing* 16 U.S.C. §§ 824a(c), 825e, 825h, and 18 C.F.R. § 385.206 (2024) (Consumers Energy argued FPA sections 202(c) and 309 provide ample support for their request but moved for Section 206 relief in the alternative)).

[136] *See* Ltr. from DOE to FERC, *Consumers Energy Company et al. v. Midcontinent Independent System Operator, Inc.*, FERC Docket Nos. EL25-90 and AD25-14 (June 13, 2025).

[137] *See Consumers Energy Co. v. Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,158 (2025).

[138] *Id.* at 18.

III. Procedural Issues

1. PIOs' Request for a Stay

70. PIOs move for a stay of the Emergency Order pending resolution of judicial review. In support of their request, PIOs contend that (i) absent a stay, they will be irreparably harmed by the Emergency Order, (ii) a stay will not harm any other interested parties, and (iii) the public interest favors a stay.[139]

The DOE's Determination

71. In considering a request for a stay, agencies consider (1) whether the party requesting the stay will suffer irreparable injury without a stay; (2) whether issuing a stay may substantially harm other parties; and (3) whether a stay is in the public interest.[140]

72. By its terms, the Emergency Order terminated on August 21, 2025. Consequently, the stay request is now moot.

73. In any case, DOE finds that a stay is not warranted here because issuing a stay will substantially harm other parties and therefore is not within the public interest. Specifically, the Emergency Order was issued to address a shortage of electric energy, a shortage of facilities for the generation of electric energy in the Midwest region of the United States. As discussed above, this determination is based on the insufficiency of dispatchable capacity and anticipated demand, and the risk to public health and safety presented by the potential loss of power to homes and local businesses in areas that may be affected by curtailments or outages. Imposition of a stay undoubtedly may harm those citizens residing in the Midwest region of the United States who would face potentially critical electric energy shortages, and therefore the stay is contrary to the public interest.

2. Motions to Intervene

74. Michigan AG, PIOs, Minnesota and Illinois, MPPA, and Maryland OPC each moved to intervene in this proceeding, citing various alleged interests which may be affected by the outcome of this proceeding.[141]

The DOE's Determination

75. The motions to intervene are hereby granted for Michigan AG, PIOs, Minnesota and Illinois, and MPPA, but DOE takes no position on whether they are "aggrieved" parties for

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[139] PIO Pet. at 51-53.

[140] *Nken v. Holder*, 556 U.S. 418, 434, 436 (2010); *Ohio v. EPA*, 603 U.S. 279, 291 (2024).

[141] *See* Michigan AG Pet. at 2-3; PIO Pet. at 5-11; Minnesota & Illinois Pet. at 3-8; OMS Pet. at 1-2; Maryland OPC Comments at 1-3; MPPA Comments at 1-2.

purposes of FPA section 313.[142] The motion to intervene by Maryland OPC is denied as DOE maintains that Maryland OPC is not an "aggrieved" party for purposes of FPA section 313.[143]

* * * * *

The Emergency Order is hereby modified upon the issuance of this Order and the result sustained, as discussed in the body of this Order.

Issued at 6:40pm Eastern Daylight Time on this 8th day of September 2025.

Chris Wright

Chris Wright

Secretary of Energy

[142] *See* 16 U.S.C. § 825*l*(b) ("Any party to a proceeding under this chapter aggrieved by an order issued by the Commission in such proceeding may obtain a review of such order in the United States court of appeals for any circuit wherein the licensee or public utility to which the order relates is located or has its principal place of business, or in the United States Court of Appeals for the District of Columbia, by filing in such court, within sixty days after the order of the Commission upon the application for rehearing, a written petition praying that the order of the Commission be modified or set aside in whole or in part.").

[143] *See*, Resp. in Opp'n to Maryland Office of People's Counsel Mot. to Intervene. *People of the State of Michigan v. U.S. Department of Energy*, No. 25-1162 (D.C. Cir. Sept. 4, 2025).

Exhibit 23

Department of Energy
Washington, DC 20585

Order No. 202-25-10

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in 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.

Order Nos. 202-25-4 and 202-25-8

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

Order No. 202-25-4, issued pursuant to FPA section 202(c), required that the Eddystone Units remain in operation for 90 days, until August 28, 2025. Subsequently, Order No. 202-25-8, issued pursuant to FPA section 202(c), required the Eddystone Units remain in operation for 90 days, until November 26, 2025. Those orders were based on my determination that emergency conditions existed in the PJM region. I explained that there was a potential shortage of electric energy and a shortage of facilities for generation of electric energy. I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety. I determined that the operational availability and economic dispatch of the Eddystone Units was necessary to best meet the emergency and serve the public interest. My determination was based on a number of different facts.

First, in congressional testimony, PJM's president and CEO recently stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of dispatchable resources, and other factors.[3] Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics

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[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] *Keeping the Lights On: Examining the State of Regional Reliability*, Before the *H. Comm. on Energy and Com., S. Comm. on* Energy, 119th Cong. (Mar. 25, 2025) (testimony of Mr. Manu Asthana, President and CEO of PJM) (Asthana Test.) at 4-5, available at https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf.

of resources in PJM's interconnection queue.[4] 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."[5] In its February 2023 assessment "*Energy Transition in PJM: Resource Retirements, Replacements & Risks* (Four Rs Report)," PJM highlighted increasing reliability risks in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.[6]

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."[7]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-4 and Order No. 202-25-8 continue, both in the near and long term.[8] The production of electricity from the Eddystone Units will continue to be critical to maintaining reliability in PJM over the coming winter months. According to U.S. Environmental Protection Agency data, the Eddystone Units

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[4] *Id.*; *see also PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 15 (2025) (*PJM Interconnection*) (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.").

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

[6] *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, PJM (Four Rs Report) at 1, (Feb. 24, 2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjmresource-retirements-replacements-and-risks.ashx.

[7] *PJM Interconnection*, 190 FERC ¶ 61,084 at P 14.

[8] Further, it likely would be difficult for the oil-fired 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. Further, 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.

generated 26,434 MWh between June 2025 and September 2025,[9] providing vital generation capacity to the region. Over the course of the summer, PJM issued Hot Weather Alerts and/or Maximum Generation Alerts (EEA 1) to manage grid reliability covering a total of 20 days, including days in June, July, and August.[10]

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.[11] and in PJM's 2025 Long-Term Load Forecast, PJM noted that "20-year annualized growth rate in the 2025 Long-Term Load Forecast for the winter peak is up to 2.4%."[12] 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.[13]

The evidence also indicates that there is a potential longer term resource adequacy emergency in the PJM region.

In a news release expressing support for Order No. 202-25-4, PJM explained that it has "repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers."[14]

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[9] *See Custom Data Download, EPA CAMPD* (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (search criteria Emissions >> Monthly >> Unit (default) >>Apply >>*"2025" and "June, July, August, September."* The data can then be filtered to only include the Eddystone Generating Station.

[10] *See* PJM Emergency Procedures Postings for the period between June 1 and August 31, *Emergency Procedures*, https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf (search range set to: effective from 06/01/2025 until 08/31/2025).

[11] *Jan. 22 Update: Extreme Cold Produces PJM Record for Winter Electricity Demand*, PJM (Jan. 22, 2025), https://insidelines.pjm.com/jan-22-update-extreme-cold-produces-pjm-record-for-winter-electricity-demand/.

[12] *2025 Long-Term Load Forecast Report Predicts Significant Increase in Electricity Demand*, PJM Interconnection, L.L.C. (Jan. 30, 2025), https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/.

[13] *2026/27 BRA IRM, FPR, and ELCC Class Ratings: Shift Towards More Winter Risk*, PJM Resource Adequacy Planning Special Planning Committee, 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.

[14] *PJM Statement on the U.S. Dept. of Energy 202(c) Order of May 30*, PJM Interconnection, L.L.C. (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 indeed voiced these concerns for years. In its February 2023 Four Rs Report, PJM cautioned that 40 GW of thermal generation are at risk of retirement by 2030.[15] PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for renewable projects is approximately five percent.[16] PJM determined that the pace of new capacity additions "would be insufficient to keep up with expected retirements and demand growth by 2030."[17] PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.

More recently, in its December 2024 RRI filing with FERC, PJM stated that "[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report . . . ."[18] PJM warned that its "resource adequacy concerns are increasing at an extraordinary pace."[19] PJM went on to explain, its "resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers" and that its preliminary analysis shows "substantial increases [in load additions] since the 2024 forecast" for both the summer and winter seasons.[20] 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."[21] 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.[22]

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."[23] Mr. Bielak expressed the opinion that the "rapid" retirement of thermal generation resources, "extreme" forecasted load growth, and "delays in new generation resources achieving commercial operation," would adversely affect resource adequacy throughout PJM's electricity grid.[24]

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[15] Four Rs Report at 2.

[16] *Id*.

[17] *Id.* at 16, Table 1.

[18] *PJM Interconnection, L.L.C.*, FERC Docket No. ER25-712, Tariff Revisions for Reliability Resource Initiative at 10 (Dec. 13, 2024).

[19] *Id*.

[20] *Id.* at 10-11. *See also id.* at 13 ("the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements . . . .").

[21] *Id.* at 14.

[22] *See id.*, Attachment C (Affidavit of Mr. Donald Bielak), at PP 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.").

[23] *Id*. at P 10.

[24] Id. at P 12.

On February 11, 2025, FERC accepted PJM's RRI filing.[25] In its order on rehearing, FERC concluded, "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."[26]

NERC has raised similar concerns. According to NERC's 2024 Long Term Reliability Assessment, "PJM could face future resource adequacy challenges, impacting system reliability and PJM's ability to serve load."[27] NERC assessed the PJM region at an elevated risk starting in 2026,[28] explaining that "[r]esource additions are not keeping up with generator retirements and demand growth."[29] NERC stated that the loss of-load hour (LOLH) and expected unserved energy (EUE) risks are concentrated in the winter months (especially January), in both 2026 and 2028.[30]

Order Nos. 202-25-4 and 202-25-8 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[31] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[32] 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."[33]

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[25] *PJM Interconnection*, 190 FERC ¶ 61,084 at P 263.
[26] *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,085, at P 25 (2025).
[27] *Long-Term Reliability Assessment*, North American Electric Reliability Corporation, at 92 (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20 Assessment_2024.pdf at 92.
[28] *Id.* at 4.
[29] *Id.* at 7.
[30] *Id.* at 91-92.
[31] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (Strengthening the Reliability and Security of the United States Electric Grid), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-thereliabilityand-security-of-the-united-states-electric-grid/.
[32] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (Declaring a National Energy Emergency), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.
[33] *Id*.

The Department of Energy's (Department) July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. It concludes, "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[34] 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.[35] 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.[36] Regarding the PJM region, the Department's analysis performed this year in collaboration with the national labs modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced coal, gas, and oil generation retirements.[37] Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a max unserved load of approximately 21.335 GW.[38]

Grid operators, including PJM, have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the United States House of Representatives Committee on Energy and Commerce, Manu Asthana, President and CEO, PJM, testified that there was a "growing resource adequacy concern . . . impacting a significant part of our country."[39] 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

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

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

[36] *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-slidesvTCII.pdf.

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

[38] *Id.* at 27.

[39] Asthana Test. at 4.

industrial growth."[40] 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.[41] 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."[42]

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

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[43] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-4 and 202-25-8 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 emergency arising from increased demand, determined shortage, and other causes and serve the public interest under FPA section 202(c).

To ensure the Eddystone Units will be available if needed to address emergency conditions, the Eddystone Units shall remain in operation until February 24, 2026.[44]

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[40] *Id.*
[41] *Id.* at 9-10.
[42] *Id.* at 10.
[43] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).
[44] 16 U.S.C. § 824a(c)(4).

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

A. From November 26, 2025, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.

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

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

D. By December 11, 2025, PJM is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Constellation Energy is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, 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 law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Eddystone Units shall not be considered capacity resources.

H. This Order shall be effective from 00:00 PM Eastern Standard Time (EST) on November 26, 2025, and shall expire at 00:00 EST on February 24, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 2:30PM EST on this 25th day of November 2025.

Chris Wright

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

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

Exhibit 24

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2025–2026 Winter Reliability Assessment

November 2025



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Preface

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

Reliability | Resilience | Security

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

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



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

About this Assessment

NERC's *2025–2026 Winter Reliability Assessment* (WRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the WRA presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS.

The reliability assessment process is a coordinated evaluation between the Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas.

This report reflects an independent assessment by the ERO Enterprise (i.e., NERC and the six Regional Entities) and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming winter period.

Key Findings

This WRA covers the upcoming three-month (December–February) winter period, providing an evaluation of the generation resource and transmission system adequacy necessary to meet projected winter peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional risks. The following findings are the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as the potential operational concerns that may need to be addressed for the upcoming winter.

Two trends affecting resource adequacy across the BPS for the upcoming winter are rising electricity demand forecasts and a continued shift in the resource mix characterized by the retirement of thermal generators and growth in battery resources. After years of flat or low (~1%) peak demand growth, the aggregate peak demand for all NERC assessment areas has risen by 20 GW (2.5%) since the previous winter. Nearly all assessment areas are reporting year-on-year demand growth; some are forecasting increases near 10%. Total BPS resources have also increased since last winter, but by a smaller amount of 9.4 GW. This number includes the net change in generating capacity as well as additional demand response. These demand and resource changes are described in **Escalating Winter Demand** and **Resource Trends** sections.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operating concerns that should receive attention for Winter 2025–2026:

1. **All areas are assessed as having adequate resources for normal winter peak-load conditions (i.e., the area's 50-50 peak forecast). However, more extreme winter conditions extending over a wide area could result in electricity supply shortfalls.** Prolonged, wide-area cold snaps can drive sharp increases in electricity demand and threaten reliable BPS generation and the availability of fuel supplies for natural-gas-fired generation. Four severe arctic storms have descended to cover much of North America since 2021, causing regional demand for electricity and heating fuel to soar and exposing generation and fuel infrastructure in temperate areas to freezing conditions.[1] The following areas face risks of electricity supply shortfalls during periods of more extreme conditions this winter (see **Figure 1**):

    - **NPCC-Maritimes**: The peak demand forecast has fallen slightly (-1.6%) in the NPCC-Maritimes assessment area, contributing to higher reserves compared to the 2024–2025 winter. Maritimes is projected to have an Anticipated Reserve Margin (ARM) of 16.9%, which is 270 MW below the area's Reference Margin Level of 20% . New Brunswick has long-term energy contracts that can be used to mitigate resource adequacy challenges through the purchase of energy on a day-ahead basis. NPCC's all-hours probabilistic assessment for the NPCC Region included the simulation of both a base case (i.e., normal 50/50 demand) and highest peak load scenario (having an approximate 7% chance of occurring), for both an expected and a low-likelihood, reduced-resource condition. The preliminary results of this assessment indicate that operators in Maritimes are likely to require emergency operating mitigations and/or energy emergency alerts (EEA) during above-normal demand or low-resource output conditions.
    - **NPCC-New England**: A lower peak demand forecast and additional resources from demand response and firm imports offset recent generator retirements, resulting in little change to the NPCC-New England ARM for this winter. New England continues to closely monitor regional energy adequacy, particularly during extended cold snaps where constrained natural gas pipelines contribute to rapid depletion of stored fuel supplies. ISO-NE's deterministic winter scenario analysis shows limited exposure to energy shortfalls this winter. In New England, winter energy concerns are highest in scenarios when stored fuels are rapidly depleted; during these periods, timely replenishment is critical to minimizing the potential for energy shortfalls.
    - **SERC-East**: The winter peak demand forecast has increased by 700 MW (1.6%) since last winter, while winter firm capacity has declined, resulting in lower reserves. SERC-East has changed from a summer-peaking area to potentially peaking during both summer and winter. This is due to the continued addition of solar photovoltaic (PV) generation that shaves off summer peak demand and a trend toward electrification of heating that drives up winter peak demand. All-hours probabilistic analysis from SERC found some load-loss hours (<0.1 hrs) and small amounts of expected unserved energy, with the highest risk occurring during above-normal peak demand and early morning hours when solar output is absent.
    - **SERC-Central:** Additional demand response and flat load growth since last winter is offsetting declining resource capacity (down 1,120 MW), resulting in little change to the ARM at 30.5%. There are adequate resources for normal winter peak demand; however, higher levels of demand that can occur during extreme cold temperatures can result in insufficient reserves that operators would need to manage with non-firm imports and potential energy emergencies.
    - **Texas RE-ERCOT:** Strong load growth from new data centers and other large industrial end users is driving higher winter electricity demand forecasts and contributing to continued risk of supply shortfalls. For the upcoming winter season, Texas RE-ERCOT is expected to continue facing reserve shortage risks during the peak load hour and high-

[1] See detailed reports on the January 2024 and January 2025 Arctic Storms, Winter Storm Elliott, and Winter Storm Uri.

net-load hours, particularly under extreme load conditions that accompany freezing temperatures. Elevated forced outage of thermal resources and reduced output from intermittent resources during these conditions exacerbates the risk of supply shortfalls. In winter, peak demands typically occur before sunrise and after sunset coinciding with the unavailability of solar generation making the system dependent on wind generation and dispatchable resources. Data centers are altering the daily load shape due to their round-the-clock operating pattern, lengthening peak demand periods. Additional battery storage and demand-response resources since last winter help mitigate shortfall risks. However, with the continued flattening of the load curve, maintaining sufficient battery state of charge will become increasingly challenging for extended periods of high loads, such as a severe multi-day storm like Winter Storm Uri.

- **WECC-Basin**: There is sufficient capacity in the area for expected peak conditions; however, Balancing Authorities (BA) are likely to require external assistance during extreme winter weather that causes thermal plant outages, adverse wind turbine conditions, and natural gas fuel supply issues for area internal resources. External assistance may not be available during region-wide extreme winter conditions. With an expected winter peak demand of 11.1 GW, under an extreme combination of generator derates and outages, the region could be short 1.6 GW before imports. Forecasted net internal demand has increased 1% since last year, with little change in winter capacity. Note that the WECC-Basin assessment area includes Utah, southern Idaho, and a portion of western Wyoming. In prior WRA reports, this part of the BPS was included as part of the WECC-NW assessment area. The *2025–2026 WRA* includes a new assessment area map for the Western Interconnection. The new assessment area boundaries provide reliability risk information in more geographic detail for the United States and Mexico.
- **WECC-NW**: Like WECC-Basin, there is sufficient capacity in the area for expected peak conditions; however, BAs are likely to require external assistance during extreme winter weather that causes thermal plant outages and adverse wind turbine conditions for area internal resources. External assistance may not be available during region-wide extreme winter conditions. Winter peak demand for the area is forecast to be 2.9 GW higher (9.3%) compared to last year. Over 3 GW of new resources have been in development for the assessment area this year, primarily battery storage, solar PV, and wind resources. Delays that threaten timely completion of these resource additions will make the area more reliant on imports to meet peak demand.

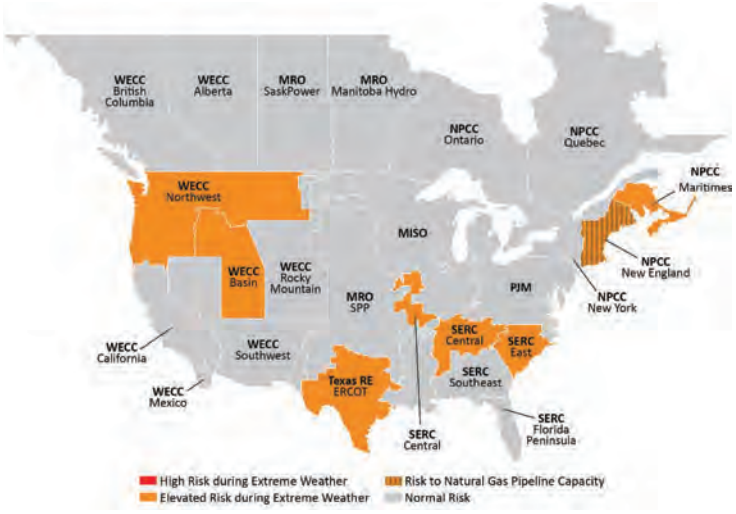


Figure 1: Winter Reliability Risk Area Summary

2. **The performance of natural gas production and supply infrastructure during peak winter conditions will again have a significant effect on BPS reliability.** Natural gas is an essential fuel for electricity generation in winter. Winter fuel supplies for thermal generators must be readily available during the periods of high electricity and natural gas demand that accompany extreme cold weather. Yet these periods are the most challenging for natural-gas-fired Generator Operators to obtain sufficient fuel and delivery. Natural gas production often falls off in extreme winter temperatures as supply infrastructure is affected by freezing issues, and Generator Operators that fail to secure firm fuel delivery are frequently unable to access fully subscribed pipelines. Evidence from the past two winters indicates notable improvement in the delivery of natural gas to BPS generators since winter storms Elliott and Uri with overall less natural gas production decline during cold weather and fewer natural gas infrastructure

force majeures.[2] Still, natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America, resulting in uneven application of protections and continued supply risks during extreme conditions. Furthermore, timing misalignments between the natural gas and electric markets continue to challenge generator fuel procurement in advance of severe winter conditions that occur over winter holiday weekends. As winter approaches, NERC encourages all entities across the gas-electric value chain—from production to the burner tip—to take all necessary preparations for extreme cold and keep natural gas flowing and the lights on.

3. **Cold weather Reliability Standards first introduced in 2023 have been improved prior to the upcoming winter and address recommendations from winter storms Elliott and Uri.** In September 2025, the Federal Energy Regulatory Commission (FERC) approved EOP-012-3 with an effective date of October 1, 2025, concluding the development of Reliability Standards for generator cold weather preparedness.[3] The EOP-012 Reliability Standard contains requirements for generator freeze protection measures, cold weather preparedness plans, and operator training. Among the improvements in the new version are enhanced and expanded requirements to ensure that Generator Owners (GO) are implementing corrective actions to address known issues affecting their ability to operate in cold weather in a timely manner. NERC collects data on the winterization of generating units, which, in conjunction with NERC's monitoring of BPS performance and analysis of cold weather events, helps determine the effectiveness of Reliability Standards. NERC submitted to FERC its first annual *Cold Weather Data and Analysis* informational filing in October 2025.[4] Based on the data reported this year, 96% of the total net winter capacity reported extreme cold weather temperatures (ECWT) at or below 32 degrees Fahrenheit, triggering winter preparedness measures under the Cold Weather Preparedness Standard, and 99% of total net winter capacity in the continental US reporting the ability to operate at the calculated ECWT. As the first such report, this *Cold Weather Data and Analysis* filing provides a benchmark for future analysis.

Recommendations

To reduce the risks of energy shortfalls on the BPS this winter, NERC recommends the following:

- Reliability Coordinators (RC), BAs, and Transmission Operators (TOP) in the elevated risk areas identified in the key findings should review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially high generator outages and extreme demand levels. Operators should review NERC's Resources on Cold Weather Preparations.
- GOs should complete winter readiness plans and checklists prior to December, deploy weatherization packages well in advance of approaching winter storms, and frequently check and maintain cold weather mitigations while conditions persist.
- BAs should be cognizant of the potential for short-term load forecasts to underestimate load in extreme cold weather events and be prepared to take early action to implement protocols and procedures for managing potential reserve deficiencies. Proactive issuance of winter advisories and other steps directed at generator availability contributed to improved reliability during cold weather events of the past two winters.
- RCs and BAs should implement generator fuel surveys to monitor the adequacy of fuel supplies. They should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions.
- Generator Owners/Operators of natural-gas-fired units should maintain awareness of potential extreme cold weather developing over holiday weekends and the implications for fuel planning and procurement that may result given the natural gas purchase close dates that precede long holiday weekends.
- State and provincial regulators can assist grid owners and operators in advance of and during extreme cold weather by maintaining awareness of BA, natural gas pipeline, and gas local distribution company (LDC) operational public announcements and notices, amplifying public appeals for electricity and natural gas conservation, and supporting requested environmental and transportation waivers.

[2] See *January 2025 Arctic Events | A System Performance Review*, April 2025
[3] See NERC's Statement on FERC September Open Meeting for summary and link to FERC's order.
[4] See 2025 Cold Weather Data Collection and Analysis Informational Filing

Risk Highlights

Escalating Winter Demand

Winter electricity demand is rising at the fastest rate in recent years, particularly in areas where data center development is occurring. After several years of low (~1%) growth, total internal demand for the BPS is forecast to increase by 20.2 GW (2.5%) over last winter's forecast. The changes in forecasted net internal demand for each assessment area are shown in **Figure 2** below.[5] Assessment areas develop these forecasts based on historical load and weather information as well as future projections. Most assessment areas are projecting an increase in peak demand. SaskPower, PJM, the U.S. Southeast, and parts of the U.S. West have the largest increase in peak demand forecasts.

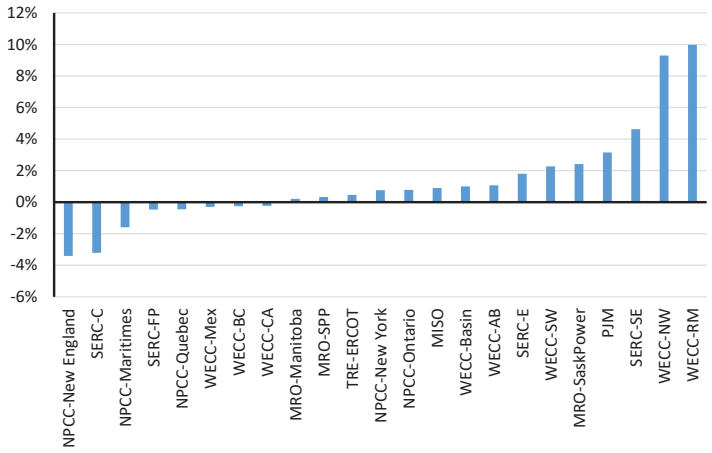


Figure 2: Change in Net Internal Demand—Winter 2025–2026 Forecast Compared to Winter 2024–2025 Forecast

[5] See **Data Concepts and Assumptions** section for demand definitions.

Resource Trends

BPS resources are growing, but at a slower rate than demand is rising. Battery and solar facilities were the leading resource types added to the BPS since last winter. Solar resources, however, often do not supply output during hours of peak winter demand. Growth in demand response is also contributing to BPS resources for the upcoming winter. **Table 1** shows the total change in BPS resources since last winter. For battery, solar, and wind resources, the table includes change in both nameplate (installed) capacity as well as the change in on-peak demand capacity, which is the capacity that resources are expected to provide in their area during the time of peak demand. For assessment-area specific information see **Variable Energy Resource Contributions** section.

Table 1: BPS Resource Change from Winter 2024–2025 to Winter 2025–2026

Resource	Net Change Nameplate Capacity (MW)	Net Change Peak Demand Capacity (MW)
Total Generator Capacity		1,335
Battery	19,659	11,121
Solar	11,097	1,176
Wind	-562	-14,238
Thermal and Hydro		3,276
Demand Response		8,112
Total Resources		9,447

Total BPS resources for serving winter peak demand, including generating capacity and demand response, have increased since last winter by 9,447 MW. Sizeable additions in battery resources and some new natural gas-fired generators contribute to the increase in resource capacity. However, the increase is offset by lower on-peak capacity values for wind resources, which are the result of revised valuations of wind resource capability at peak demand hours in some areas.[6] As a result, BPS generator capacity for winter peak demand makes up only a small portion of the total BPS increase. Generation accounts for 1,335 MW of the total 9,445 MW increase, while the larger share comes from demand response programs. Area specific information on demand response is provided in the **Demand and Resource Tables**.

The recent trend in resource additions is contributing to higher risk of electricity supply shortfalls in winter. BA operators are likely to face higher winter demand without a comparable increase in supply resources. Furthermore, the types of resources that are growing the most-- battery resources and

[6] Since last winter, ERCOT and MISO have implemented new methods for determining capacity contributions that result in lower wind and solar resources contributions at peak demand. See ERCOT's Resource Adequacy page and MISO's *Planning Year 2025-2026 Wind and Solar Capacity Credit Report*.

demand response—have unique characteristics that operators will need to account for and could limit the use of these resources in extreme winter conditions. Battery energy is reliable when it can be dispatched and has sufficient charge for the period it is needed, yet little time to recharge can be expected during extreme winter weather. System operators will need good visibility on battery state of charge and should anticipate that some extreme winter events will cause these resources to become depleted when needed. Demand response is limited by contract terms, which typically specify how often and for how long the resource may be used. Other resource types are also challenged in winter (see **Thermal Generator Fuel Adequacy and Security**). As BAs grapple with higher demand in most parts of the BPS, they will do so with resources that are becoming increasingly complex to dispatch especially in winter.

Thermal Generator Fuel Adequacy and Security

The performance of the thermal generator fleet remains critical to winter BPS operations. Winter fuel supplies for thermal generators must be readily available during periods of high demand and extreme cold weather. Generally, fuel adequacy for the thermal generating fleet is bolstered through strategic infrastructure investments and fuel stockpiling that increases the certainty of having fuel on hand that can be converted to electricity when needed. Because of this, winter performance of thermal generators is inextricably linked to extraction, processing, storage, and delivery infrastructure for a variety of fuels. Fuel supply risks have been noted in recent years' WRAs related to coal and natural gas availability and illustrate the interconnected nature of these critical energy infrastructure systems.

BPS stakeholders across North America note multiple fuel-related issues that are being monitored entering the winter season. For example, while coal represents a waning share of the overall resource mix, it continues to play an important role in meeting demand during extreme winter weather events, and oil inventories at dual-fuel gas-oil generators lessen risks related to natural gas deliverability in infrastructure-constrained regions, especially during the winter. Notably, it is infeasible or prohibitively costly to stockpile natural gas locally at power plants, and this exposes the BPS to the risk profile of the constituent systems that comprise the supply and delivery of this just-in-time fuel.

Natural Gas Generator Fuel Supplies

Natural gas generators remain a crucial part of on-peak resources meant to meet winter electricity demand across much of North America. While many Generator Owners and Operators secure backup fuel supplies at critical gas-fired generators, particularly in the northeastern United States and Florida, large contributions to the on-peak winter resource mix by single-fuel natural-gas-fired generators remain across North America (see **Figure 3**).

Natural gas generator performance can be threatened when natural gas supplies are insufficient or when natural gas infrastructure is unable to maintain the flow of fuel to critical generators. Grid operators continue to acknowledge and enhance their winter planning processes to firm up their fuel supplies and guard against natural gas disruptions, but winter storms Uri and Elliott demonstrated that combinations of natural gas flow restrictions and supply insufficiency can occur regardless of whether cold temperatures are common or uncommon in the region and can affect more than one BA area concurrently.

Many BPS areas that regularly experience cold weather events, like New England, have adopted mitigating technologies to lessen the impact of natural gas shortages through generator dual-fuel capability and stored backup fuel. In those areas, prolonged cold weather events present a risk of rapid depletion of stored backup fuel. Robust regional and distributed storage investments and winter planning for timely fuel replenishment are critical to minimizing potential energy shortfalls in the operational time frame in these areas.

Natural gas and electricity infrastructures have the added complexity of interdependence. Electricity is used to power some facilities, such as compressor stations and processing plants that make up natural gas infrastructure. These interdependencies mean that reliability events that originate on one system have the potential to affect the other and worsen the overall event magnitude or duration.

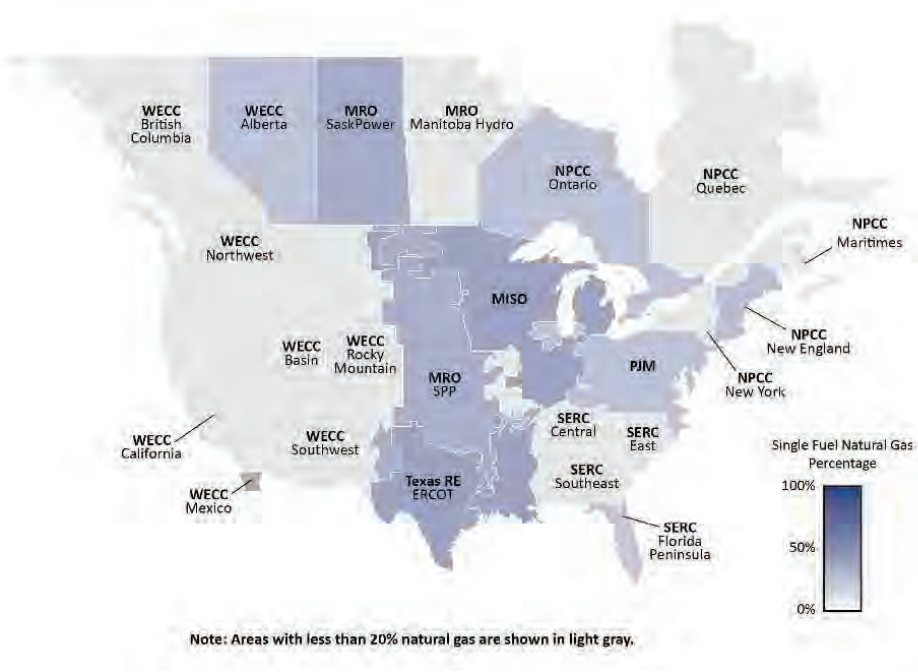
Natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America. Texas is an exception, where the Railroad Commission of Texas adopted rules to require critical natural gas facilities to implement weather-related emergency preparation measures.[7] Lack of consistent standards for natural gas infrastructure protections will result in uneven application of freeze protections and continued supply risks during extreme conditions in many areas.

These considerations have driven higher levels of coordination to ensure sustained reliable operation of the natural gas and electricity systems. While a FERC and ERO staff review of system performance during the January 2025 arctic events[8] details improvements in electric and natural gas coordination since winter storms Uri and Elliott, the review also identifies continuing gaps between the electricity and natural gas industries that remain entering the 2025–2026 Winter season. These include natural gas scheduling challenges during winter holiday weekends, market time frame and process incompatibility, and electric power entities' lack of visibility into operational impact data from natural gas producers and suppliers.

[7] See Railroad Commission of Texas weatherization rule.

[8] FERC, NERC Issue Report on System Performance During the January 2025 Arctic Weather | Federal Energy Regulatory Commission

The U.S. Energy Information Administration (EIA)[9] anticipates a slightly milder winter than last year across much of the United States, especially in the Northeast, leading to a projection that households will consume approximately 2% less natural gas than last winter. Working natural gas storage inventories are about 5% above the previous five-year average in the United States heading into the winter season. The EIA attributes this relative surplus in part to robust production this summer and lower-than-expected natural gas consumption by power generators.



Single-Fuel Natural-Gas-Fired Generation

	Winter Capacity (GW)	Contribution to Total Winter Resource Mix
MISO	63.9	38%
TRE-ERCOT	53.0	38%
WECC-MX	2.2	34%
MRO-SaskPower	2.5	34%
SPP	33.4	32%
NPCC-New England	12.1	24%
PJM	60.9	23%
WECC-AB	13.9	23%
NPCC-Ontario	8.0	23%
SERC-FP	45.6	21%
WECC-CA	35.9	18%
WECC-SW	21.5	17%
WECC-Basin	4.9	16%
WECC-RM	6.2	14%
SERC-C	17.0	13%
SERC-SE	21.5	13%
WECC-NW	8.7	12%
SERC-E	11.3	9%
NPCC-New York	5.0	8%
NPCC-Maritimes	0.5	7%
MRO-Manitoba	0.3	4%
WECC-BC	0.1	1%
NPCC-Quebec	0.0	0%

Figure 3: Single-Fuel Natural-Gas-Fired Generation Capacity Contribution to the 2025–2026 Winter Generation Mix

[9] See the U.S. Energy Information Administration's Winter Fuels Outlook 2025–26

Risk Assessment Discussion

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

Table 2: Seasonal Risk Assessment Summary

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

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

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins (ARM), which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins with typical forced outage levels and for the most extreme seasonal risk scenarios are provided in Table 3.

Table 3: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Reserve Margin with Typical Outages	Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	49.5%	22.3%	3.7%
MRO-Manitoba	13.7%	11.4%	6.1%
MRO-SaskPower	35.1%	29.0%	16.1%
MRO-SPP	56.5%	29.4%	16.9%
NPCC-Maritimes	16.9%	12.5%	-4.7%
NPCC-New England	58.9%	45.4%	8.7%
NPCC-New York	78.2%	52.4%	16.2%
NPCC-Ontario	28.6%	21.8%	13.2%
NPCC-Québec	15.2%	15.1%	5.0%
PJM	35.6%	24.8%	15.6%
SERC-C	30.5%	22.4%	-0.9%
SERC-E	21.9%	17.5%	3.0%
SERC-FP	41.7%	28.3%	25.6%
SERC-SE	39.7%	24.7%	17.7%
TRE-ERCOT	36.0%	25.2%	-20.0%
WECC-AB	35.2%	32.4%	10.0%
WECC-Basin	29.6%	19.7%	-21.1%
WECC-BC	25.9%	25.8%	15.4%
WECC-CA	82.3%	73.7%	57.9%
WECC-Mex	83.1%	79.4%	52.9%
WECC-NW	30.9%	29.5%	-8.5%
WECC-RM	61.7%	53.2%	10.0%
WECC-SW	104.4%	90.1%	50.1%

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

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 3**, each assessment area's ARMs are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Areas highlighted in orange in **Figure 1** above have been identified as having resource adequacy or energy risks for the winter and are included in the **Key Findings** section's discussion that follows. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced-outage margin is the same as the ARM, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the winter season. Results are summarized in **Table 5**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include loss of load expectation (LOLE), loss of load hours (LOLH), expected unserved energy (EUE), and the probabilities of energy emergency alert (EEA) declarations (see **Table 4** for a description of EEA levels).

Table 4: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	• The BA is experiencing conditions in which all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required operating reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum operating reserve requirements.
EEA 3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum operating reserve requirements.

Energy Emergency Alerts

The combination of above-normal generation outages, low resource output, and peak loads as occurred during the extreme cold weather events of Winter Storm Uri in 2021 and Winter Storm Elliott in 2022 are ongoing winter reliability risks. When supply resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ EEAs to maintain balance between available capacity and energy and real-time demand. A description of each EEA level is provided above.

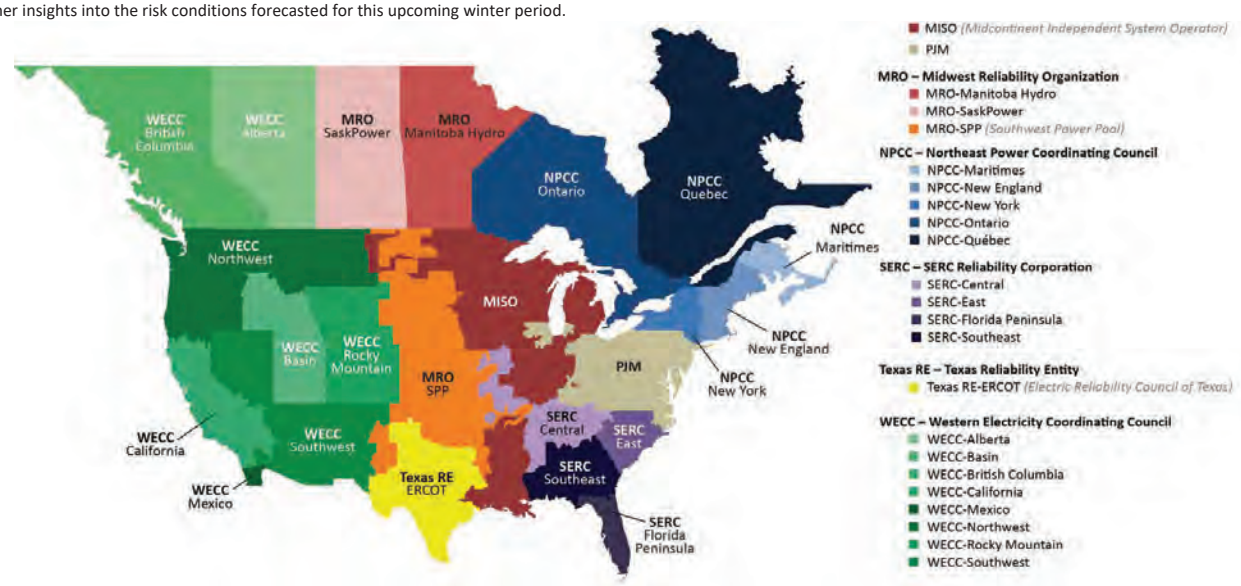
Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	Deterministic	MISO does not provide a probabilistic assessment for the WRA. MISO applies a deterministic look at expected system conditions, looking at generation availability under typical and extreme outages and looking at a typical 50/50 load forecast and an extreme 90/10 load forecast. For the upcoming winter season, under an extreme outage and extreme 90/10 load forecast, this is the riskiest scenario for the MISO footprint. This scenario produces the shortest actual reserve margin for January.
MRO-Manitoba	Probabilistic study for the NERC Probabilistic Assessment (ProbA)	Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 *Long-Term Reliability Assessment* (LTRA) found no load-loss or unserved energy hours for 2026.
MRO-SaskPower	Probability-based capacity adequacy assessment	SaskPower's probabilistic assessment for the 2025–2026 Winter indicates that risk of shortfalls is lower than the previous winter. LOLH for an elevated risk scenario for the 2025–2026 Winter season is 0.08 hours. The month with the highest LOLH is December (0.05 hours).
MRO-SPP	NERC 2024 ProbA	Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
NPCC	NPCC conducted an all-hour probabilistic reliability assessment that included detailed neighbor modeling and consisted of a base case and severe case examining low resources, reduced imports, and higher loads. The assessment evaluates the probabilistic indices of LOLE, LOLH, and EUE. The highest peak load scenario has an approximately 7% probability of occurring.	
NPCC-Maritimes	The Maritimes Area low-likelihood resource case assumed: wind derated by 50% for every hour in December through February and a 50% natural gas capacity curtailment for December through February (dual-fuel units assumed reverting to oil) and reduced transfer capabilities.	The preliminary assessment indicates that established operating procedures are not sufficient to maintain a balance between electricity supply and demand. Under highest peak load levels, the Maritimes Area shows a notable likelihood of utilizing its operating procedures such as reducing 30-minute reserves, initiating interruptible loads, and reducing 10-minute reserves to maintain system reliability during the upcoming winter period.
NPCC-New England	The New England Area low-likelihood resource case assumed: 500 MW of additional maintenance outages, ~4,513 MW of gas-fired generation unavailable due to fuel supply constraints, and 50% reduced import capabilities of external ties.	The preliminary results of this assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand
NPCC-New York	The New York Area low-likelihood resource case assumed: ~500 MW of extended maintenance in southeastern New York, 600 MW of cable transmission reduction across HVdc facilities, and ~5,000 MW of generation unavailable due to fuel delivery issues.	The preliminary results of this assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period, for all the scenarios modeled.
NPCC-Ontario	An energy assessment for the Ontario Assessment Area was conducted for two scenarios: firm resources and firm demand with expected weather, and planned resources with planned demand with expected weather.	No cumulative LOLH or EUE risks were identified over the entire November-to-April winter season for both scenarios modeled.

Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Québec	The Québec Area low-likelihood resource case assumed 1,000 MW of generation reductions.	The preliminary results of this assessment indicate that established operating procedures are sufficient to maintain a balance between electricity supply and demand if needed. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period for all the scenarios modeled
PJM	Probabilistic study for the NERC Probabilistic Assessment (ProbA)	Probabilistic study for 2025–2026 Winter is not provided for the WRA. PJM performed probabilistic analysis for 2026-2027 winter as part of the 2024 ProbA summarized in NERC's 2024 LTRA. The results of this study indicate risk of load loss (<0.1 hours) and unserved energy during winter months. For the upcoming winter, load-loss hours are expected to be less than this value because forecasted load is lower and anticipated resource capacity is higher than the case studied for the 2024 ProbA.
SERC	Based on the 2024 NERC Probabilistic Assessment (ProbA) base-case result. SERC's assessment used 38 years of historical load shapes to assess the resource adequacy of years 2026 and 2028, primarily based on data from the 2024 Long Term Reliability Assessment (LTRA).	
SERC-Central		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
SERC-East		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found a small number of load-loss hours (<0.1) and EUE (61 MWh / 1 ppm) for 2026.
SERC-Florida Peninsula		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found negligible load-loss hours and EUE.
SERC-Southeast		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
Texas RE-ERCOT	ERCOT Probabilistic Reserve Risk Model	ERCOT's probabilistic risk assessment indicates a 2% probability of having to declare EEAs during the January forecasted winter peak day (which coincides with the highest reserve shortage risk) and a controlled load shed probability of 1.8%. ERCOT defines low-risk hours as when the probability of an EEA is less than 10%.
WECC	The resource adequacy work performed at WECC used the Multi-Area Variable Resource Integration Convolution (MAVRIC) model for the 2025 LTRA. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and ProbA.	
WECC-AB		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Basin		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-BC		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.

Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-CA		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Mexico		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Rocky Mountain		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-NW		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026. Results for a case where new resource additions are not completed for the upcoming winter found some EUE and LOLH.
WECC-SW		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.

Regional Assessments Dashboards

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



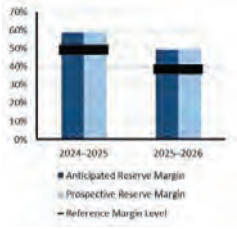


MISO

The Midcontinent Independent System Operator, Inc. (MISO) is an independent, not-for-profit organization responsible for operating the bulk electric power system and administering wholesale electricity markets across 15 U.S. states and the Canadian province of Manitoba. MISO ensures the reliable delivery of electricity to approximately 45 million people by managing regional transmission operations as well as energy and ancillary services markets and advising on long-term resource planning. The MISO footprint includes 39 Local BAs and more than 550 market participants. MISO operates one of the world's largest organized electricity markets, with its members operating a system that consists of over 77,000 miles of transmission lines and approximately 1,888 generating units. The peak electricity demand on the MISO system currently occurs during the summer season. MISO's footprint lies across three regional entities (MRO, RF, and SERC), but MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

- MISO expects limited risk in the 2025–26 Winter season as MISO was able to procure 6.1% more resources through the annual planning reserve auction than required by its minimum resource adequacy target. A further 3.3 GW of resources were available but not chosen to be committed for the winter season.
- Some risk has been identified for this upcoming winter season. In a high generation outage and high winter load scenario reliability is expected to be maintained by reliance upon operational mitigations that include non-firm energy transfers into the system, energy-only resources not subject to a must-offer requirement that may still offer into the energy markets, load-modifying resources, and internal transfers that exceed the Sub-Regional Import/Export Constraint (SRIC/SREC) between the MISO North/Central and South areas.
- MISO continues to coordinate with neighboring RCs and BAs to improve situational awareness and vet any needs for energy transfers to address extreme system conditions.
- MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency.
- MISO has implemented a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons.

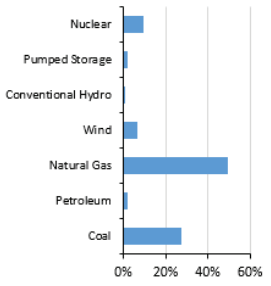
On-Peak Reserve Margin[10]



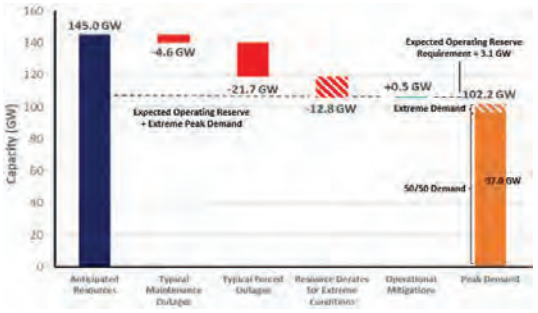
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed demand scenarios. Above-normal winter peak load combined with generator outages from freezing or fuel supply issues and low wind output result in the need to employ operating mitigations (i.e., demand response and transfers).

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: 50/50 net internal demand and additional demand during extreme weather conditions (e.g., Winter Storm Enzo) using member submitted data and historical load data

Typical Maintenance Outages: Rolling three-year winter average of peak-day maintenance and planned outages

Typical Forced Outages: Three-year average of all peak-day outages that were not planned

Resource Derates for Extreme Conditions: Represents derates aligning with the most extreme hour of each of the past 3 years,

Operational Mitigations: Non-firm energy transfers into the system, energy-only resources that do not have a must-offer requirement, or internal transfers that exceed the SRIC/SREC between the MISO North/Central and South regions

[10] The MISO Risk Scenario Assessment for the 2025-26 Winter Season is not directly comparable to that for the 2024-25 Winter Season as methodology improvements have been implemented.



MRO-Manitoba Hydro

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

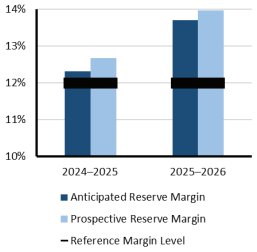
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Winter 2025–2026.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even under continued drought conditions.
- Manitoba Hydro is experiencing well below-average water supply conditions; however, the Manitoba Hydro system is designed and operated such that reliable operations can be maintained under extreme drought.
- The ARM for Winter 2025–26 exceeds the 12% RML.

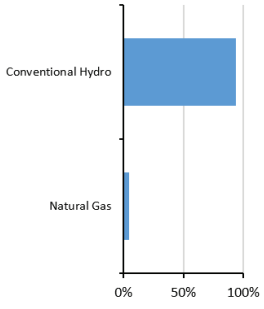
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

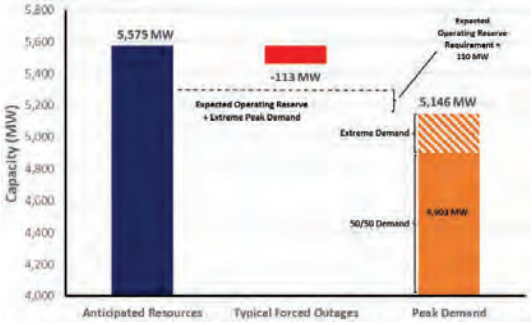
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Typical Forced Outages: Accounts for average forced outages



MRO-SaskPower

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

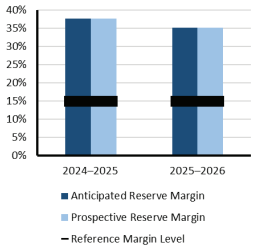
Highlights

- Saskatchewan experiences its peak load during the winter months due to extreme cold weather.
- Based on the planned maintenance, typical forced outages from historical data, and expected renewable generation under the normal and extreme demand conditions, SaskPower does not anticipate any reliability issues during the 2025–2026 Winter.
- During extreme winter conditions, SaskPower would utilize available demand-response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions to manage the situation.

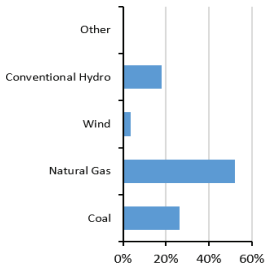
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

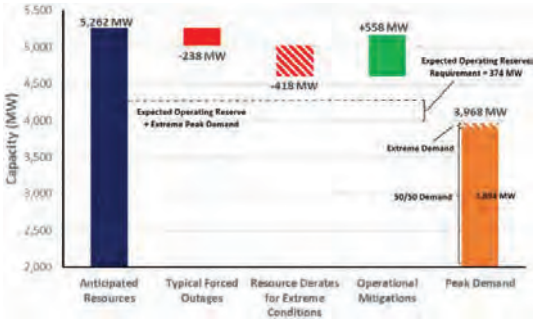
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Based on the historical load variability, SaskPower calculates a probability density function for load to simulate various scenarios that include extreme conditions.

Typical Forced Outages: Estimated using SaskPower forced outage model

Resource Derates for Extreme Conditions: Wind capacity is derated by 96% due to the cut-out of most wind farms below -30°C. Solar generation is expected to be fully unavailable under extreme conditions.

Operational Mitigations: Includes the non-firm import capability (360 MW) and generators in layup status (167 MW) that can be brought online with one to five days' notice; additional demand-side resources are estimated based on other demand response programs and non-firm loads that require 15 minutes to 2 hours of notification



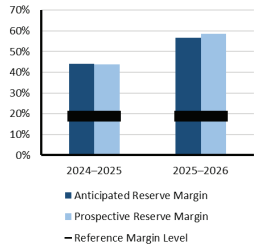
MRO-SPP

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

Highlights

- SPP anticipates that planning reserves are adequate for the upcoming winter season even as SPP continues to set new winter season load records.
- SPP does not anticipate any emerging reliability issues impacting the area for the 2025–2026 Winter season but realizes that interruptions to fuel supply combined with higher penetration of variable energy resources could create unique operation challenges.
- SPP continues to work at enhancing communications and operator preparedness with neighboring regions to address potential electric deliverability issues associated with extreme weather events.
- To minimize conservative operations, EEAs, and mid-range forecast error uncertainty response in wind forecasts, SPP implemented several new operational mitigation processes and procedures to deal with high-impact real-time areas of reliability concern.
- SPP has proposed numerous resource adequacy initiatives, including addressing EUE standards, fuel assurance, winter planning reserve margins, outage policies, demand response, and accreditation; all were recently approved by FERC.

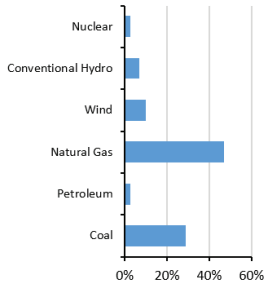
On-Peak Reserve Margin



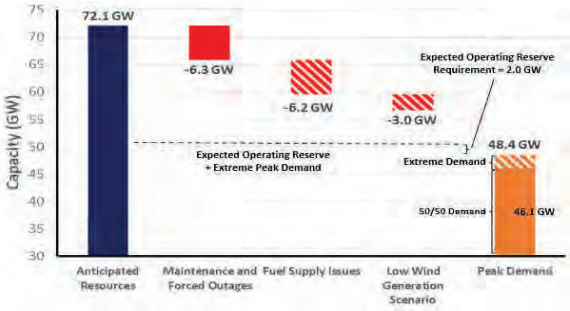
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast using historical data

Maintenance and Forced Outages: A capacity derate of 6.3 GW for maintenance outages, forced outages, and performance in extreme weather based on historical data

Fuel Supply Issues: BA derate of 6.2 GW based on MW capacity of gas-fired generators experiencing fuel supply issues in winter storm Elliott.

Low Wind Generation Scenario: 3 GW of wind potentially off-line when temperatures fall below their cold weather performance packages



NPCC-Maritimes

NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. state of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly 1.9 million people. The New Brunswick Power Corporation (NB Power) is the balancing authority for New Brunswick, Prince Edward Island, and the northern portion of Maine. Nova Scotia Power Inc. (NSPI) is the balancing authority for Nova Scotia. NB Power's system is electrically interconnected with NPCC-Québec and NPCC-New England, and the electric systems in the provinces of Nova Scotia and Prince Edward Island have ties with New Brunswick but no direct ties with other assessment areas. Peak electricity demand in NPCC-Maritimes occurs during the winter season.

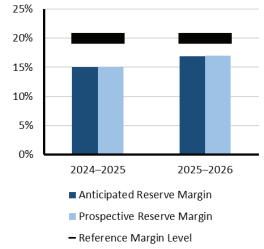
Highlights

- The Maritimes has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind, dual-fuel oil/gas, tie benefits, and biomass with no one type making up more than about 27% of the total capacity in the area.
- The Maritimes has long-term energy contracts in place for its winter supply and can purchase additional energy in the day-ahead and in real time as required.
- As part of the winter planning and preparation process, dual-fueled units will have sufficient supplies of heavy fuel oil stored on site to enable sustained operation in the event of natural gas supply interruptions.

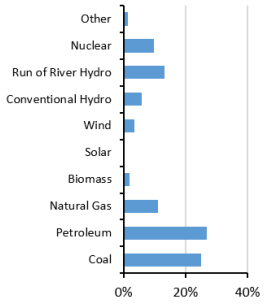
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response, transfers, appeals) and EEAs. NPCC probabilistic analysis indicates some risk of unserved energy and LOLH under high demand or low resource scenarios.

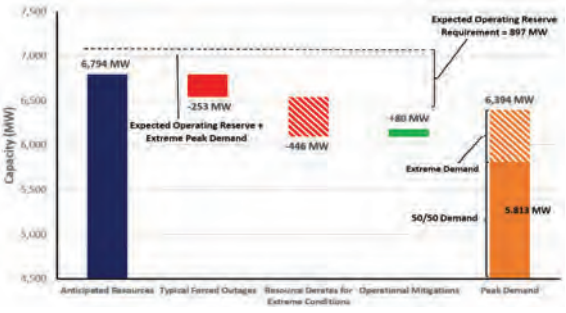
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Scenario peak load with adjustment calculated by adding a 10% margin of error to the peak internal demand forecast taken from the *Long-Term Reliability Assessment* (LTRA) for the 2025–2026 Winter period (aligns with the all-time winter peak, which occurred on February 4, 2024)

Typical Forced Outages: Based on historical operating experience

Resource Derates for Extreme Conditions: Based on ambient temperature thermal derates, wind derated to zero, as well as natural gas capacity derated by 50% due to supply issues

Operational Mitigations: Based on emergency operations and planning procedures in place including fuel switching



NPCC-New England

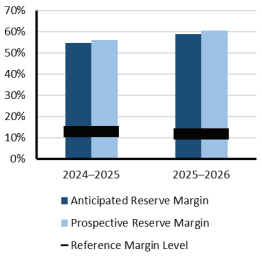
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New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

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

Highlights

- ISO-NE expects to meet its regional resource adequacy requirements this 2025–2026 Winter operating period without calling upon operating procedures to maintain a balance between electricity supply and demand.
- A standing concern is whether there will be sufficient energy available to satisfy electricity demand during an extended cold spell given the existing resource mix, fuel delivery infrastructure, and expected fuel arrangements without considerable effort to replenish stored fuels (i.e., fuel oil and liquefied natural gas (LNG)).
- ISO-NE expects to have sufficient capacity resources to meet the 2025–2026 50/50 and 90/10 winter peak demand forecast of 19,616 MW and 21,125 MW, respectively, for the weeks beginning January 10, January 17, and January 24.
- ISO-NE has recently developed the Regional Energy Shortfall Threshold (REST) as an effort to quantify the tolerable risk of energy shortfall during extreme events. Within the 0.25% highest-risk scenarios, the REST thresholds are 3.0% normalized EUE over 72-hour periods and 18.0 hours over 21-day periods.
    - ISO-NE does not anticipate exceeding the REST criteria for Winter 2025–2026.

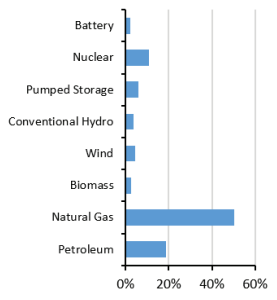
On-Peak Reserve Margin



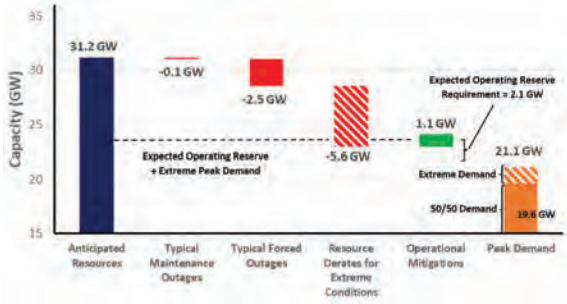
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed demand scenarios. Above-normal winter peak load combined with high generator outages could result in the need for operating mitigations (i.e., demand response and transfers). Prolonged extreme cold weather events that result in depletion of stored fuels can lead to resource shortfalls.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast capturing the region's coldest day in the last 30 years using current and future load models

Typical Maintenance Outages: Based on historical weekly averages

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

Resource Derates for Extreme Conditions: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply and cold weather-related outages

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



NPCC-New York

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

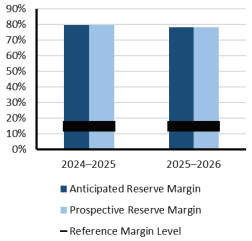
Highlights

- New York is presently a summer-peaking area, and no emerging reliability issues are anticipated during the 2025–26 Winter assessment period.
- Expected resources meet operating reserve requirements under the assessed demand and resource scenarios. A scenario involving an extended cold snap that causes above-normal demand and diminished natural gas supplies would result in low but sufficient reserves.
- The preliminary results of the NPPCC winter probabilistic assessment indicate that operating procedures are not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOL,H or EUE risks were indicated over the December–February winter period for all the scenarios modeled.

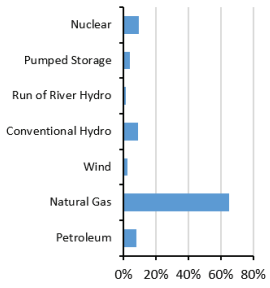
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed demand and resource scenarios.

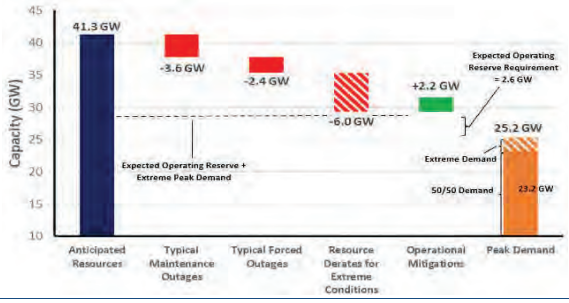
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Typical Maintenance Outages: Based on planned scheduled maintenance

Typical Forced Outages: Based on 5–year averages from GADS data.

Resource Derates for Extreme Conditions: Potential natural gas generation at risk if non-firm supply is unavailable in a period of extended cold weather. Based on a 2025 analysis, approximately 6,307 MW of gas generation with non-firm fuel supplies could be unavailable.

Operational Mitigations: Based on NYISO operating procedures



NPCC-Ontario

NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of almost 16 million people. The Independent Electricity System Operator (IESO) is the balancing authority for the province of Ontario. NPCC-Ontario is electrically interconnected with NPCC-Québec, MRO-Manitoba, MISO, and NPCC-New York. Peak electricity demand in NPCC-Ontario occurs during the summer season.

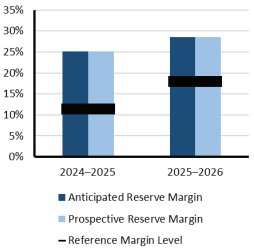
Highlights

- As Ontario is a summer-peaking province, there is typically a lower risk of reliability issues during the winter than the summer. However, Ontario regularly experiences extreme cold weather in the winter.
- NPCC-Ontario is well prepared for Winter 2025–2026, and IESO expects that the electric system will remain reliable with reserve margins well above required levels.
- Operators and forecasters in Ontario work closely with neighboring jurisdictions to manage extreme weather events.
- Natural-gas-fired generators in Ontario are supplied by pipelines with access to the Enbridge Gas Dawn Hub and its associated storage facilities, which significantly reduces natural gas deliverability and reliability concerns by connecting those systems to several major gas transportation corridors, enabling access to multiple supply basins.

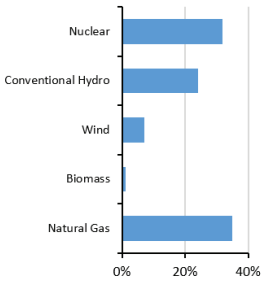
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

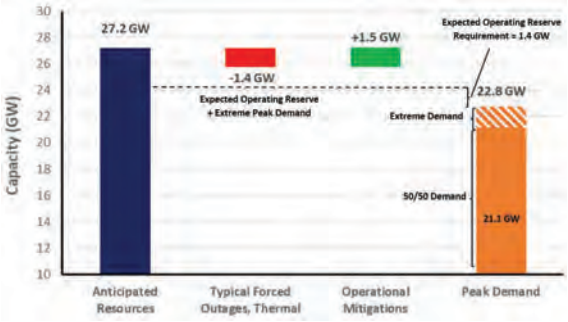
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand from 31 years of winter demand history

Typical Forced Outages, Thermal: Based on analysis of a rolling five-year history of actual forced outage data.

Operational Mitigations: Imports anticipated from **neighbors** during emergencies



NPCC-Québec

NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the four electric Interconnections in North America. It is a predominately hydroelectric-generation-based system that is electrically interconnected with NPCC-Ontario, NPCC-New York, NPCC-New England, and NPCC-Maritimes. Peak electricity demand in NPCC-Québec occurs during the winter season.

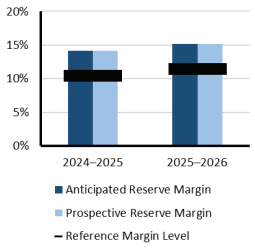
Highlights

- NPCC-Québec projects adequate capacity margins above its reference reserve requirements and that system resource adequacy will be maintained for the province for the 2025–26 Winter assessment period.
- No hydropower performance issues are expected during extreme cold because of design criteria for cold weather.
- No fuel supply or transportation issues are anticipated for the upcoming winter season.
- While a slight decrease in net firm transfers has occurred since last winter (-89 MW), significant increases in demand-side management programs (+450 MW year-over-year) have been realized over the same period and are expected to compensate for this winter's modest expected load growth.

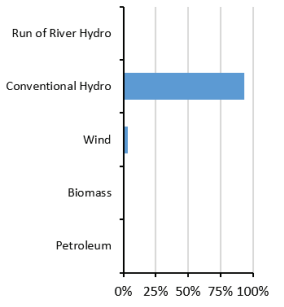
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

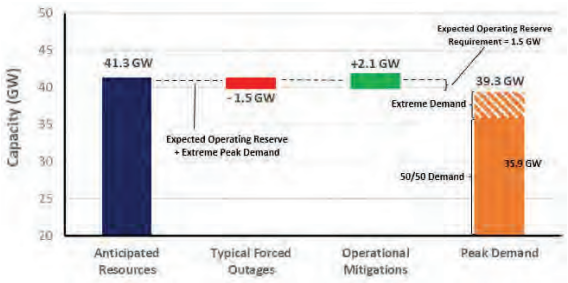
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 8:00 a.m.

Demand Scenarios: Demand forecasts include demand-side resources. The demand side resources are the same for the 50/50 and extreme demand scenarios. The extreme load forecast is determined at two standard deviations higher than the mean, which has a 6.06% probability of occurrence.

Extreme Derates: Maintenance outages and other deratings are already included in existing-certain capacity calculation. Wind capacity is 64% derated

Typical Forced Outages: Unplanned outages are 1,500 MW.

Operational Mitigations: Operational mitigations include imports from neighboring areas and reduction of reserves



PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM's footprint covers approximately 369,054 square miles and with an approximate population of 67 million people. PJM is the area's BA, Transmission and Resource Planner, interchange authority, TOP, transmission service provider, and RC. PJM is electrically interconnected with MISO, NPCC-New York, SERC-Central, and SERC-East. Peak electricity demand in PJM occurs during the summer season.

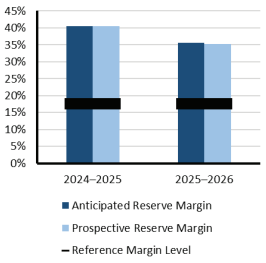
Highlights

- Due to the low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with highest loss-of-load risk remains the hour with highest forecasted demand.
- PJM is expecting little capacity adequacy risk during Winter 2025–2026 and expects around 35% installed reserves, which is above the target IRM of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- Last winter, PJM hit a new all-time winter peak, but generator preparations anticipating congestion and tight capacity projections led to sufficient reserves throughout the demand event and PJM's transmission system performed well.
- The decrease in reserves from Winter 2024–2025 is due to load increases and retirement of generation without like (non-solar dispatchable) replacement generation.

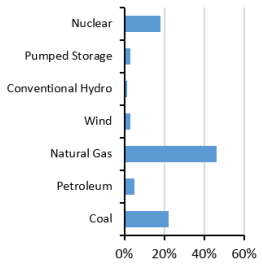
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

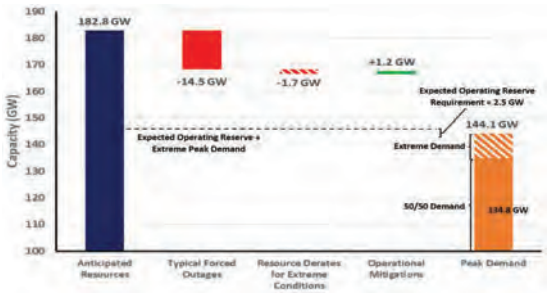
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Typical Forced Outages: Based on historical data and trending

Resource Derates for Extreme Conditions: Reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: accounts for an estimated value based on operational / emergency procedures



SERC-Central

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

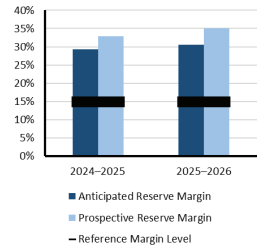
Highlights

- SERC-Central is transitioning from a summer-peaking area to a dual-peaking system.
- For the 2025–2026 Winter, SERC-Central projects a sufficient level of resources to serve the expected load under median weather and typical system operating conditions, based on the 2024 NERC ProbA base-case results.
- Most entities across SERC-Central report that fuel security is strong since it is supported by firm natural gas contracts, storage resources, and reliable pipeline capacity. Coal inventories are projected to remain within operational ranges necessary to meet winter demand.
- Following lessons from Winter Storm Elliott, one SERC-Central entity raised its winter Planning Reserve Margin target to 26% and updated preparedness programs with improved heat trace capabilities.

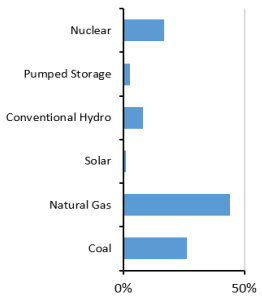
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand. A severe cold weather event that extends to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

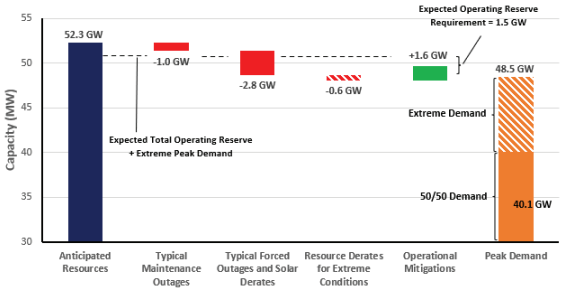
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Typical Maintenance Outages: Data collected through a survey of members for expected outages during December through February

Typical Forced Outages and Solar Derate: Includes any weighted average forced-outage rates on-peak that are not factored into the anticipated resources calculation . Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Entity-provided values for low likelihood extreme conditions

Operational Mitigations: A total of over 1.6 GW based on operational/emergency procedures



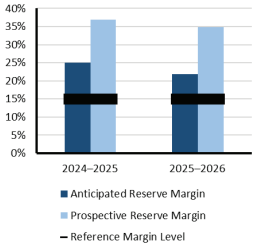
SERC-East

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

Highlights

- SERC-East is transitioning from a summer-peaking area to potentially peaking during both summer and winter. This shift is attributed to the continued addition of solar PV generation, which reduces summer peak demand, and a trend toward electrification of heating, which drives up winter peak demand.
- For the 2025–2026 Winter, the SERC-East region projects a sufficient level of resources to serve the expected load under median weather and typical system operating conditions, based on the 2024 NERC ProbA base-case results.
- Fuel supplies and transportation remain stable, and entities anticipate maintaining adequate coal and oil inventories with no reported changes to fuel procurement or operator plans for the upcoming winter.
- Probabilistic Base Case Results (Median Weather): EUE is 61.95 MWh and LOLH is 0.06 hours/year. EUE values are likely due to higher winter peaks and/or lower supply of capacity that can meet early winter morning demand.
- Mitigation measures for extreme conditions include voltage reduction (25–50 MW) and load-shedding programs that cover up to 30% of system load.

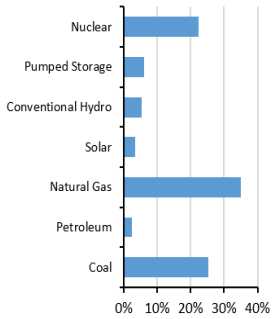
On-Peak Reserve Margin



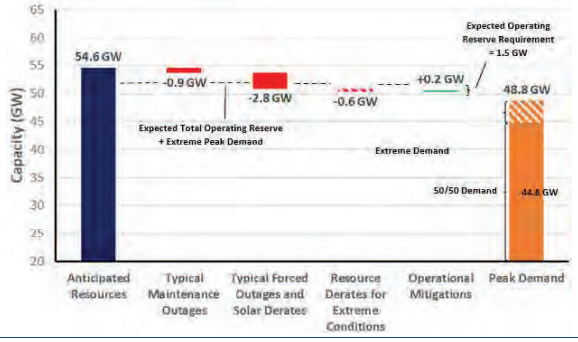
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal demand scenarios. A severe cold weather event extending to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Maximum historical generation outages (excluding 2022–2025)

Operational Mitigations: A total of 0.2 GW based on operational/emergency procedures



SERC-Florida Peninsula

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

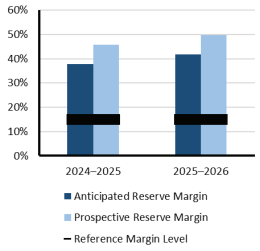
Highlights

- SERC-Florida Peninsula is a summer-peaking assessment area.
- Florida Peninsula entities have not identified any emerging reliability issues for the upcoming 2025–26 Winter season with an ARM projected at 39%, well above the RML, while the 2024 NERC ProbA base-case results project a sufficient level of resources to serve the expected load under median weather and typical system operating conditions (EUE is 1.09 MWh and LOLH is 0.00 hours/year).
- Many entities report strong fuel security, supported by firm natural gas contracts, storage resources, reliable pipeline capacity, and actively managed coal and oil inventories, which are projected to remain within operational ranges to meet winter demand.
- Florida Peninsula entities do not assume non-firm external assistance from neighboring areas during extreme conditions.

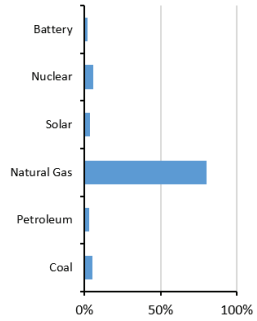
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

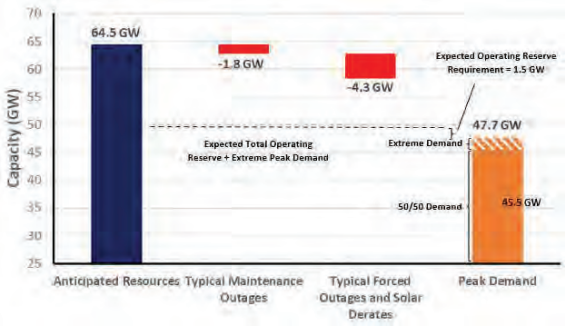
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Entity-provided values for low likelihood extreme conditions



SERC-Southeast

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

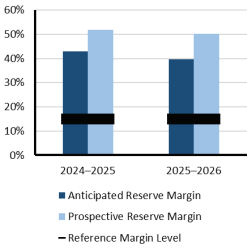
Highlights

- SERC-Southeast is trending towards becoming slightly winter-peaking.
- For the 2025–2026 Winter, SERC-Southeast entities report no emerging reliability concerns and expect to have adequate resources, supported by firm natural gas transportation contracts, diverse fuel portfolios, and sufficient on-site coal inventories to serve the expected load under typical system operating conditions. The 2024 NERC ProbA base-case results in EUE and LOLH are both 0.00.
- While most SERC-Southeast BAs expect to have adequate resources, supported by firm natural gas transportation contracts, diverse fuel portfolios, and sufficient on-site coal inventories, one BA highlights potential risks related to natural gas transportation capacity, citing high pipeline utilization, competition for delivered gas, and ratable flow requirements. Mitigation strategies include securing third-party gas supply, adding dual-fuel capability, and implementing coal inventory management.
- Entities have made refinements such as replacing specific 230 kV circuit breakers and increasing monitoring frequencies for critical plant systems after January 2025 winter events.

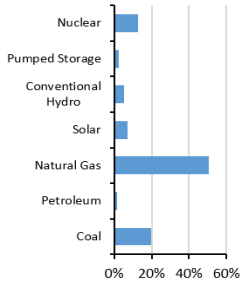
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

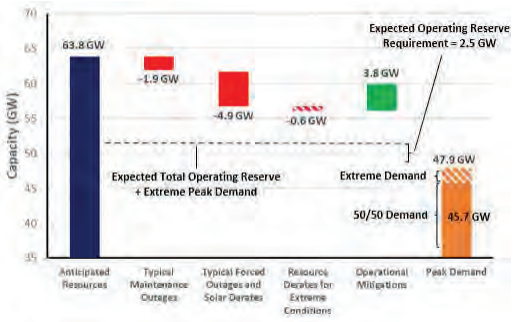
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

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

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Maximum historical generation outages

Operational Mitigations: A total of 3.8 GW based on operational/emergency procedures



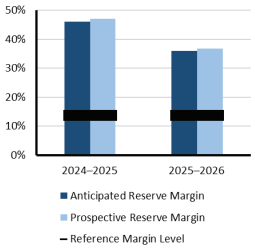
Texas RE-ERCOT

ERCOT is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking and covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas power grid.

Highlights

- Given expected system conditions, an ARM of 36% and RML of 13.75%, ERCOT expects to have sufficient operating reserves for the peak hour ending 8:00 a.m.
- ERCOT does not expect any significant fuel supply issues for the winter.
- ERCOT has conducted 2,028 generation resource and transmission service provider (TSP) winter weatherization inspections since Winter 2021–2022.
- Winter peak demands typically occur before sunrise and after sunset when solar generation is not available. Significant battery storage mitigates these risks.
- ERCOT's probabilistic risk assessment indicates a 2% probability of having to declare EEAs during the January forecasted winter peak day (which coincides with the highest reserve shortage risk) and a controlled load shed probability of 1.8%. ERCOT defines low-risk hours as when the probability of an EEA is less than 10%.
- Increased load growth in west Texas combined with "no solar" and low wind conditions can cause transmission lines into this area to become heavily loaded. ERCOT has introduced improved dynamic line ratings that allow for greater transfers at colder temperatures and periods of low irradiance.

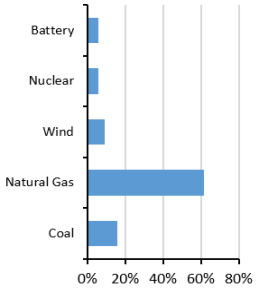
On-Peak Reserve Margin



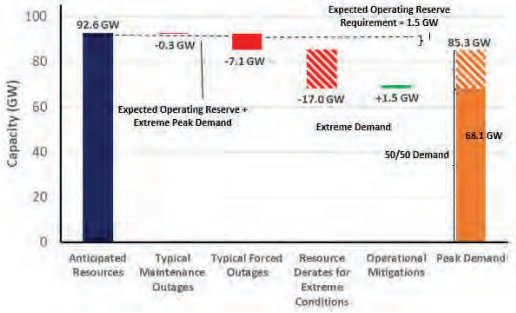
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

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

Demand Scenarios: Presumes weather conditions comparable to Winter Storm Uri. The adjustment is calculated as the difference between the 100th percentile and 50th percentile values from ERCOT's Probabilistic Reserve Risk Model (PRRM) simulated load outcome distribution for hour ending 8:00 a.m.

Typical Maintenance Outages: Based on historical winter data and consideration of ERCOT's allowed maximum system daily planned outage capacity

Typical Forced Outages: Based on a probability distribution created using historical ERCOT Outage Scheduler data for the last three Januarys.

Resource Derates for Extreme Conditions: Weather-related thermal and wind outages based on Winter Storm Uri levels, adjusted for reductions due to weatherization standards. Also includes high non-weather-related outages.

Operational Mitigations: Additional potential capacity from switchable generation and imports



WECC-Alberta

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

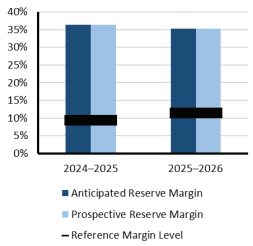
Highlights

- At an extreme winter peak of 12,982 MW, with extreme forced outages at 530 MW and derates for extreme conditions bringing wind energy availability down by 1,800 MW and hydroelectricity by 88 MW, the required reserves are 759 MW and are sufficiently met, even with low availability.
- Demand is expected to increase 1.1% from last winter with the existing-certain installed capacity having increased 23%.
- Solar availability is down because 1,000 MW of PV moved from originally expecting to come on-line in 2024 as Tier 1 resources to Tier 2s mostly anticipated to come on-line in 2025, but with less certainty.

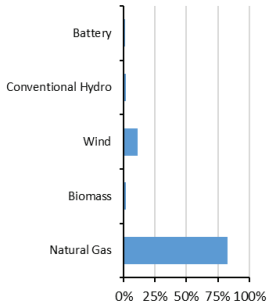
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

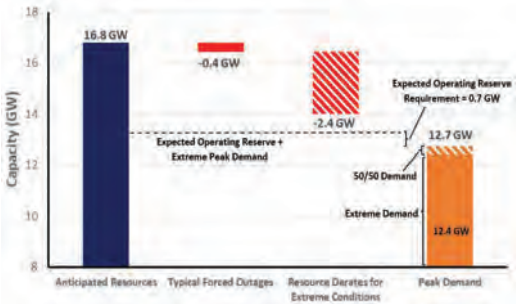
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS data

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern BA area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025-26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA*.

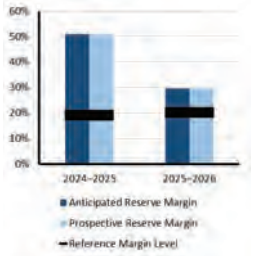
Highlights

- At an extreme winter peak of 11.1 GW under an extreme combination of derates and outages, the region could be short 1.0 GW before imports and is expected to need to rely on transfers.
- Net internal demand is expected to increase 1% since last year, with total internal demand up 1.8% being offset by a doubling of controllable and dispatchable demand response.
- Tier 1 resources have declined and do not appear to be offset by increases in existing-certain generation resource capacity. Nameplate wind has increased by almost 18% and solar by almost 30%. Hydro is also up over 7% in total installed capacity.
- Reliance on imports is expected to be required to maintain resource adequacy during extreme peak demand and extreme derate conditions.

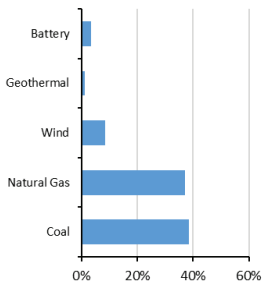
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal peak demand combined with high generator outages in extreme conditions results in the need for external assistance to maintain reserves.

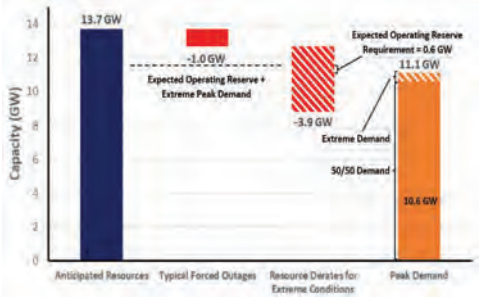
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Extreme Derates: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



WECC-British Columbia

WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and RC for the province of British Columbia and is the principal supplier of electricity for the province. BC Hydro is a provincial Crown corporation and, under provincial legislation, is responsible for the oversight of the British Columbia BES and its interconnections. BC Hydro operates an integrated system supported by 30 hydroelectric plants, approximately 80,000 kilometers of transmission and distribution lines, and 125 contracts with independent power producers. BC Hydro's transmission system has two interties with neighboring areas: the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta). Peak electricity demand on the BC Hydro system currently occurs during winter.

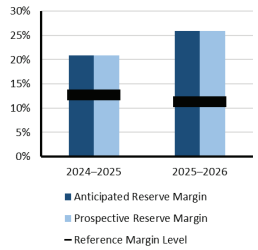
Highlights

- Peak demand is expected to remain about the same as last winter.
- There are about 200 MW more (47%) planned Tier 1 resources for this winter than last.
- Solar nameplate capacity has increased from 2 MW to 17 MW since last winter and hydroelectric nameplate capacity is up more than 5%, or 1,366 MW.

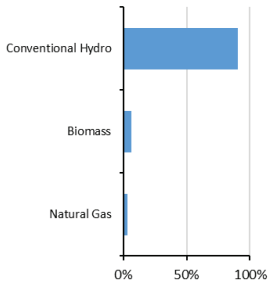
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal and extreme demand scenarios.

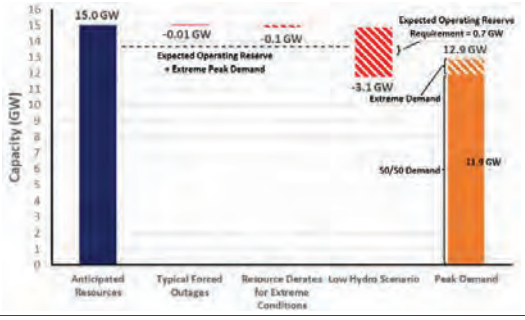
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

Low Hydro Scenario: Estimated derate for lower hydro output



WECC-California

WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, the Los Angeles Department of Water and Power, the Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

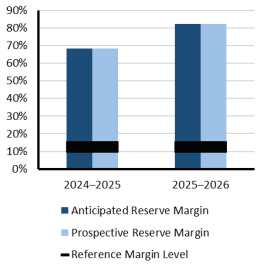
Highlights

- Operating reserve margins are met before imports in all winter resource availability scenarios.
- On-peak demand is expected to remain about the same as last winter. Demand-side management is down about 10%.
- Existing-certain capacity is up almost 5%, while planned Tier 1 resources are up more than 2 GW. The total wind nameplate capacity is up almost 27% and solar almost 13%. Hydro is down 4%.
- No reliance on imports is expected to be required to maintain resource adequacy for Winter 2025–2026.

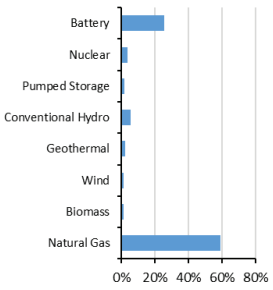
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

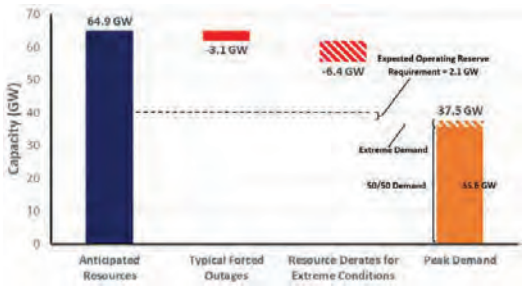
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



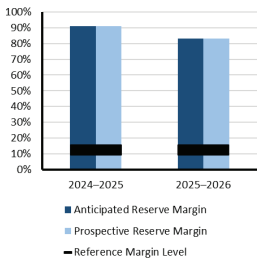
WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes CENACE. It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

Highlights

- As a summer-peaking region, operating reserve margins are met before imports in all scenarios.
- Planned Tier 1 resources are down 100% to zero as expected resources have either been brought on-line to move into existing or, in the case of some natural gas, have been delayed until 2026 and moved into Tier 2.
- The existing-certain on peak reserve margin is down by 5.2%, and the anticipated and prospective reserve margins are down by 7.8%; however, since Mexico is heavily summer-peaking, the 83% reserve margin still exceeds the RML of 12.5%, which remains unchanged.

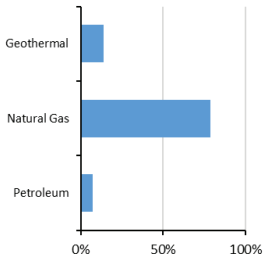
On-Peak Reserve Margin



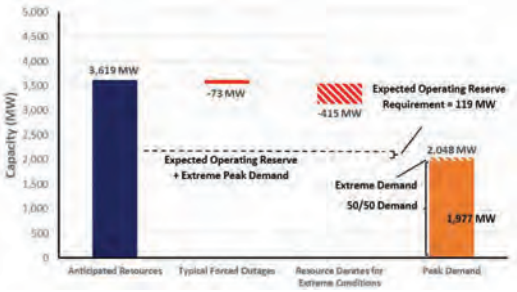
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

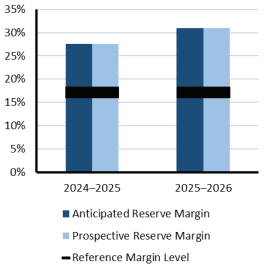
Highlights

- The Northwest has historically been a mixed season-peaking region.
- Operating reserve margins are expected to be met after imports in all winter scenarios.
- Total and net internal demand are up 9.3% with the primary drivers being data centers, residential electrification, transportation electrification, and semiconductor manufacturing.
- Large coal unit retirements and conventional hydro unit retirements are attributable to the reduction in existing certain capacity of 10.5%; however, planned Tier 1 resources have soared over 580%, from 463 MW to over 3 GW.
- Nameplate wind capacity is up over 3 GW (26%) and solar nameplate capacity is up nearly 2,690 MW (134%), which has also increased the solar availability on the peak hour.
- An increase in firm imports is seen in the model, 6.1 GW, absorbing the reduction in existing certain capacity of 4 GW.

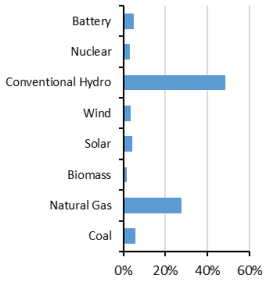
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal peak demand combined with high generator outages in extreme conditions results in the need for external assistance to maintain reserves.

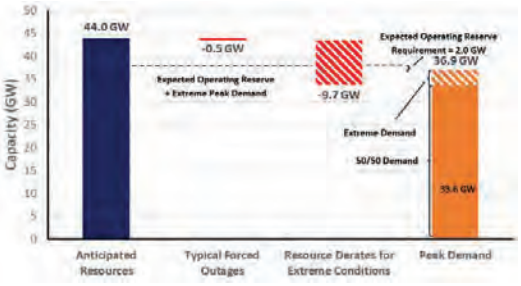
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period. This value includes 6.8 GW of hydro derates.



WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

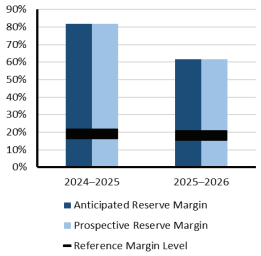
Highlights

- In Rocky Mountain, operating reserve margins are expected to be met before imports in all winter scenarios.
- Total and net internal demand are up almost 1%. The primary drivers are data centers and commercial and industrial customer growth.
- Planned Tier 1 resources are up over 84%, from almost 200 MW to over 365 MW. Solar nameplate capacity is up 27%; however, on-peak solar energy availability is down 100% due to the shift to after sunset. Expected hydro on peak energy availability is also down by around a quarter on the peak hour. Existing-Certain, Anticipated, and Prospective Reserve Margins are all down by over 20% on the peak hour; however, the region still maintains resource adequacy with margins hovering around 60% compared to the RML of 18%.
- No reliance on imports is expected to be required to maintain resource adequacy under combined extreme peak and extreme derated conditions.

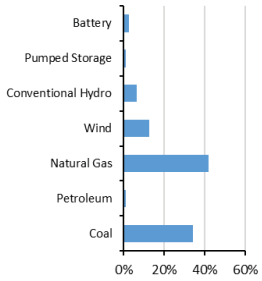
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

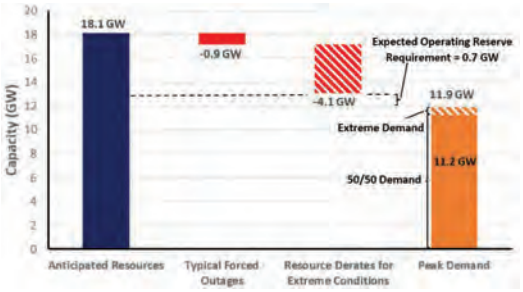
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity. *Note The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

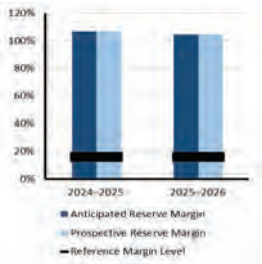
Highlights

- The Southwest is anticipated to be resource adequate under all winter expected and extreme energy availability and demand scenarios before imports.
- Total internal demand is expected to be up 1.5% and net internal demand up 2.3% since last winter. The primary drivers for load growth are data centers and industrial and residential electrification. Controllable and dispatchable demand response is down nearly half, by 163 MW.
- Planned Tier 1 resources are down over 19% as some have moved into existing certain, which is up almost 3%, over 1 GW, and other projects have experienced delays.
- Wind nameplate is up 12%, 470 MW, correlating to on-peak energy availability from wind increasing almost 11%, by 114 MW, while solar nameplate is up 27% or over 2.5 GW.

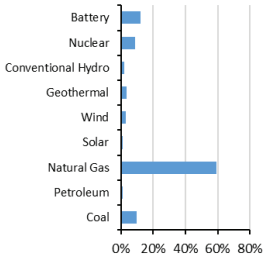
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

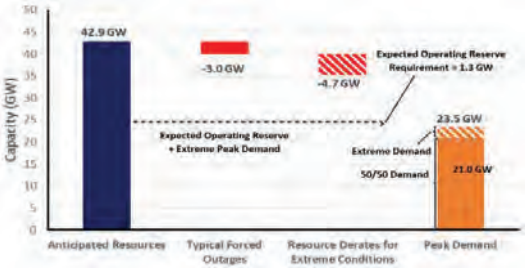
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

Data Concepts and Assumptions

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

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[11] or total internal demand for the summer and winter of each year.[12]
• Total internal demand projections are based on normal weather (50/50 distribution)[13] and are provided on a coincident[14] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.
Resource Assumptions
Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (VER) (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.
Anticipated Resources: • **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market. • **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements. • **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.
Prospective Resources: Includes all anticipated resources plus the following: **Existing-Other Capacity**: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

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

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

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

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

Reserve Margin Descriptions

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

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

Seasonal Risk Scenario Chart Description

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

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

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

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

Resource Adequacy

The ARM, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[15] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. NPCC-Maritimes marginally does not meet its RML for the upcoming winter. Other than NPCC-Maritimes, all assessment areas have sufficient ARMs to meet or exceed their RML for the 2025 winter as shown in **Figure 4**.

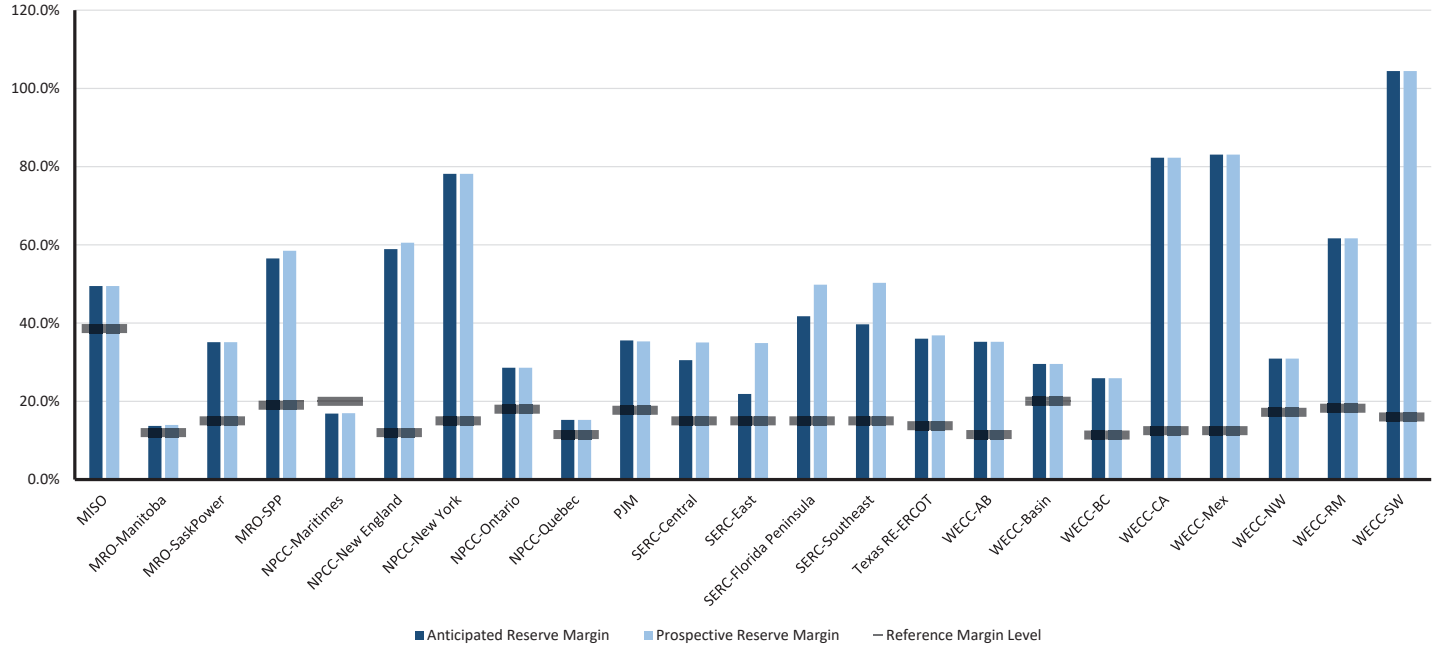


Figure 4: Winter 2025–2026 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

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

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast ARMs from the 2024–2025 Winter to the 2025–2026 Winter. All areas except NPCC-Maritimes remain above their RMLs for 2025–2026 Winter. The Canadian winter-peaking systems, which include MRO-Manitoba, MRO-SaskPower, NPCC-Maritimes, NPCC-Québec, WECC-Alberta, and WECC-British Columbia, may have reserve margins that are near RMLs but are unlikely to experience high outage rates from their winterized generators. Additional details are provided in the Data Concepts and Assumptions section.

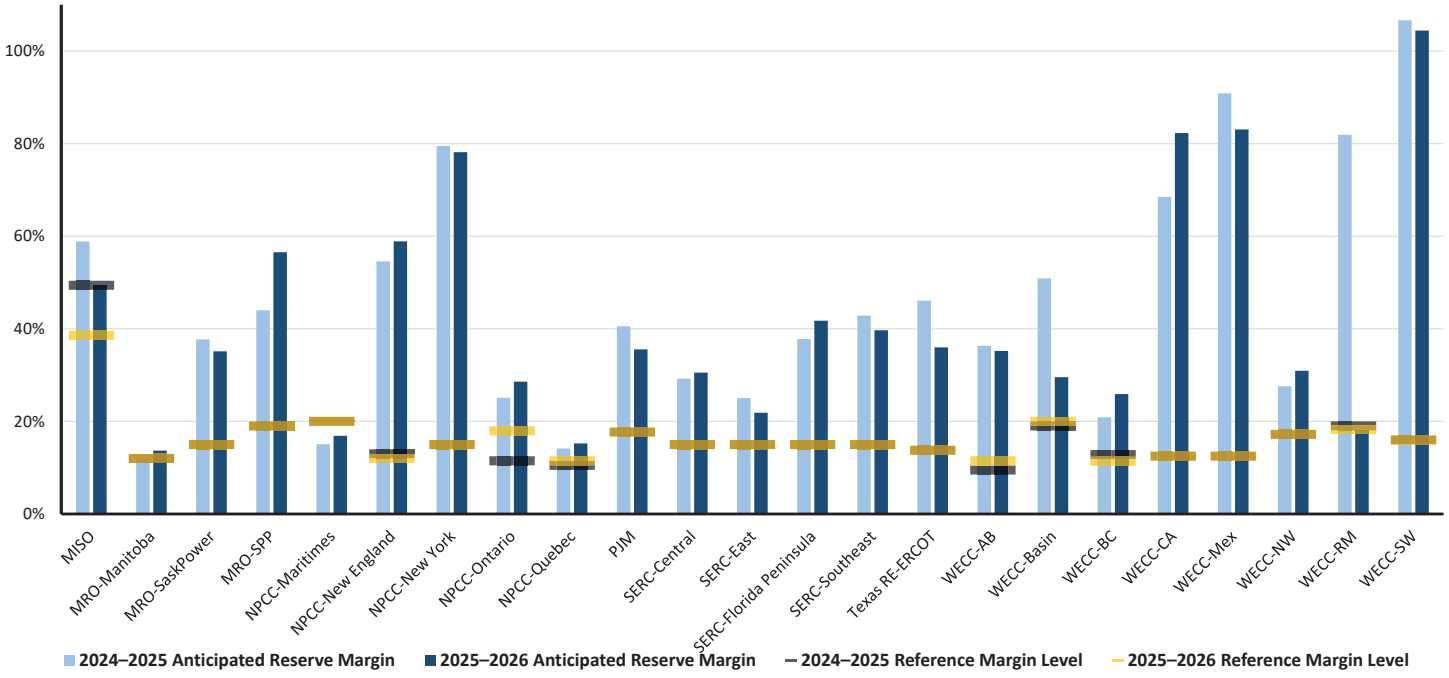


Figure 5: Winter 2024–2025 and Winter 2025–2026 Anticipated Reserve Margins Year-to-Year Change

Demand and Resource Tables

Peak demand and supply capacity data (i.e., resource adequacy data) for each assessment area are as follows in each table.

MISO			
Demand, Resource, and Reserve Margins	**2024–2025 WRA[16]**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	102,353	105,249	2.8%
Demand Response: Available	6,219	8,250	32.7%
Net Internal Demand	96,134	96,999	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	150,407	142,880	-5.0%
Tier 1 Planned Capacity	122	0	0.0%
Net Firm Capacity Transfers	2,310	2,113	-8.5%
Anticipated Resources	152,717	144,993	-5.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	152,839	144,993	-5.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	58.9%	49.5%	-9.4
Prospective Reserve Margin	59.0%	49.5%	-9.5
Reference Margin Level	49.4%	38.6%	-10.8

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,788	47,168	3.0%
Demand Response: Available	1,128	1,091	-3.3%
Net Internal Demand	45,926	46,077	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	67,252	71,074	5.7%
Tier 1 Planned Capacity	0	1087	0.0%
Net Firm Capacity Transfers	-1,116	-32	-97.1%
Anticipated Resources	66,136	72,129	9.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	66,090	73,029	10.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.0%	56.5%	12.5
Prospective Reserve Margin	43.9%	58.5%	14.6
Reference Margin Level	19.0%	19.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,852	3,944	2.4%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,802	3,894	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,946	4,972	0.5%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	5,236	5,262	0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	5,236	5,262	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.7%	35.1%	-2.6
Prospective Reserve Margin	37.7%	35.1%	-2.6
Reference Margin Level	15.0%	15.0%	0.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	4,814	4,903	1.8%
Demand Response: Available	0	0	0.0%
Net Internal Demand	4,814	4,903	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,924	5,688	-4.0%
Tier 1 Planned Capacity	10	0	-100.0%
Net Firm Capacity Transfers	-527	-113	-78.5%
Anticipated Resources	5,407	5,575	3.1%
Existing-Other Capacity	18	13	-26.8%
Prospective Resources	5,425	5,588	3.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.3%	13.7%	1.4
Prospective Reserve Margin	12.7%	14.0%	1.3
Reference Margin Level	12.0%	12.0%	0.0

[16] MISO-provided updated data post 2024-25 WRA publication.

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	6,167	6,061	-1.7%
Demand Response: Available	259	248	-4.4%
Net Internal Demand	5,907	5,813	-1.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	6,647	6,704	0.9%
Tier 1 Planned Capacity	6	88	0.0%
Net Firm Capacity Transfers	145	1	-99.0%
Anticipated Resources	6,798	6,794	-0.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	6,798	6,800	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.1%	16.9%	1.8
Prospective Reserve Margin	15.1%	17.0%	1.9
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,651	20,056	-2.9%
Demand Response: Available	343	440	28.2%
Net Internal Demand	20,308	19,616	-3.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	30,030	29,935	-0.3%
Tier 1 Planned Capacity	194	0	-100.0%
Net Firm Capacity Transfers	1,161	1,235	6.4%
Anticipated Resources	31,385	31,170	-0.7%
Existing-Other Capacity	306	322	5.2%
Prospective Resources	31,691	31,492	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	54.5%	58.9%	4.4
Prospective Reserve Margin	56.1%	60.5%	4.5
Reference Margin Level	13.0%	12.0%	-1.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	23,800	24,200	1.7%
Demand Response: Available	802	1,027	28.1%
Net Internal Demand	22,998	23,173	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,522	40,080	-1.1%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	759	1,203	58.5%
Anticipated Resources	41,281	41,283	0.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	41,281	41,283	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	79.5%	78.2%	-1.3
Prospective Reserve Margin	79.5%	78.2%	-1.3
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,898	22,013	0.7%
Demand Response: Available	915	868	-5.2%
Net Internal Demand	20,982	21,146	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,652	27,319	2.5%
Tier 1 Planned Capacity	0	294	#DIV/0!
Net Firm Capacity Transfers	-450	-420	-6.7%
Anticipated Resources	26,202	27,193	3.8%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	26,202	27,193	3.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.1%	28.6%	3.5
Prospective Reserve Margin	25.1%	28.6%	3.5
Reference Margin Level	11.5%	18.0%	6.5

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	40,512	40,799	0.8%
Demand Response: Available	4,451	4,902	10.9%
Net Internal Demand	36,061	35,897	-0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	41,560	41,698	0.3%
Tier 1 Planned Capacity	73	61	0.0%
Net Firm Capacity Transfers	-479	-390	-18.6%
Anticipated Resources	41,154	41,368	0.5%
Existing-Other Capacity	-479	0	0.0%
Prospective Resources	41,154	41,368	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.1%	15.2%	1.1
Prospective Reserve Margin	14.1%	15.2%	1.1
Reference Margin Level	10.5%	11.5%	1.0

PJM			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	136,328	140,827	3.3%
Demand Response: Available	5,616	5,998	6.8%
Net Internal Demand	130,712	134,829	3.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	179,216	178,335	-0.5%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	4,502	4,448	-1.2%
Anticipated Resources	183,718	182,783	-0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	183,718	182,452	-0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	40.6%	35.6%	-5.0
Prospective Reserve Margin	40.6%	35.3%	-5.2
Reference Margin Level	17.7%	17.7%	-12.3

SERC-Central			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,895	42,875	0.0%
Demand Response: Available	1,497	2,809	87.6%
Net Internal Demand	41,397	40,067	-3.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,578	50,454	-2.2%
Tier 1 Planned Capacity	0	0	0%
Net Firm Capacity Transfers	1,922	1,847	-3.9%
Anticipated Resources	53,500	52,301	-2.2%
Existing-Other Capacity	1,498	1,810	20.8%
Prospective Resources	54,998	54,111	-1.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.2%	30.5%	1.3
Prospective Reserve Margin	32.9%	35.1%	2.2
Reference Margin Level	15.0%	15.0%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,005	45,703	1.6%
Demand Response: Available	982	888	-9.6%
Net Internal Demand	44,023	44,815	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	54,379	54,460	0.1%
Tier 1 Planned Capacity	72	11	-84.3%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	55,045	54,622	-0.8%
Existing-Other Capacity	5,209	5,832	12.0%
Prospective Resources	60,254	60,453	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.0%	21.9%	-3.2
Prospective Reserve Margin	36.9%	34.9%	-2.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,494	48,628	0.3%
Demand Response: Available	2,780	3,127	12.5%
Net Internal Demand	45,714	45,501	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	62,579	63,502	1.5%
Tier 1 Planned Capacity	15	692	4510.0%
Net Firm Capacity Transfers	400	300	-25.0%
Anticipated Resources	62,994	64,494	2.4%
Existing-Other Capacity	3,673	3,671	0.0%
Prospective Resources	66,667	68,165	2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.8%	41.7%	3.9
Prospective Reserve Margin	45.8%	49.8%	4.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,308	47,056	3.9%
Demand Response: Available	1,638	1,365	-16.7%
Net Internal Demand	43,670	45,691	4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	62,805	63,339	0.9%
Tier 1 Planned Capacity	765	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	62,378	63,828	2.3%
Existing-Other Capacity	3,920	4,847	23.7%
Prospective Resources	66,298	68,675	3.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.8%	39.7%	-3.1
Prospective Reserve Margin	51.8%	50.3%	-1.5
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	73,193	77,387	5.7%
Demand Response: Available	5,447	9,330	71.3%
Net Internal Demand	67,746	68,057	0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	98,712	89,977	-8.8%
Tier 1 Planned Capacity	239	1351	464.9%
Net Firm Capacity Transfers	20	1,235	6075.0%
Anticipated Resources	98,971	92,562	-6.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	99,691	93,137	-6.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	46.1%	36.0%	-10.1
Prospective Reserve Margin	47.2%	36.9%	-10.3
Reference Margin Level	13.75%	13.8%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,280	12,411	1.1%
Demand Response: Available	0	0	0.0%
Net Internal Demand	12,280	12,411	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,535	16,658	23.1%
Tier 1 Planned Capacity	3206	124	-96.1%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	16,740	16,782	0.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	16,740	16,782	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.3%	35.2%	-1.1
Prospective Reserve Margin	36.3%	35.2%	-1.1
Reference Margin Level	9.5%	11.5%	2.0

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,568	10,758	1.8%
Demand Response: Available	85	170	100.0%
Net Internal Demand	10,483	10,588	1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,213	13,183	-0.2%
Tier 1 Planned Capacity	2,605	533	-79.5%
Net Firm Capacity Transfers	0	0	0%
Anticipated Resources	15,817	13,717	-13.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	15,817	13,717	-13.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	50.9%	29.6%	-21.3
Prospective Reserve Margin	50.9%	29.6%	-21.3
Reference Margin Level	19.0%	20.0%	1.0

WECC-CA			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	36,441	36,281	-0.4%
Demand Response: Available	743	666	-10.4%
Net Internal Demand	35,698	35,615	-0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	55,380	57,923	4.6%
Tier 1 Planned Capacity	4,757	6,997	47.1%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	60,138	64,920	8.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	60,138	65,920	8.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	68.5%	82.3%	13.8
Prospective Reserve Margin	68.5%	82.3%	13.8
Reference Margin Level	12.5%	12.5%	0.0

WECC-BC			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,966	11,936	-0.3%
Demand Response: Available	0	0	0.0%
Net Internal Demand	11,966	11,936	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,870	14,389	3.7%
Tier 1 Planned Capacity	433	637	47.0%
Net Firm Capacity Transfers	164	0	-100.0%
Anticipated Resources	14,467	15,026	3.9%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	14,467	15,026	3.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.9%	25.9%	5.0
Prospective Reserve Margin	20.9%	25.9%	5.0
Reference Margin Level	12.8%	11.4%	-1.5

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	1,983	1,977	-0.3%
Demand Response: Available	0	0	0%
Net Internal Demand	1,983	1,977	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,733	3,619	-3.0%
Tier 1 Planned Capacity	52	0	-100.0%
Net Firm Capacity Transfers	0	0	0%!
Anticipated Resources	3,784	3,619	-4.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	3,784	3,619	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	90.8%	83.1%	-7.8
Prospective Reserve Margin	90.8%	83.1%	-7.8
Reference Margin Level	12.5%	12.5%	0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	30,748	33,604	9.3%
Demand Response: Available	30	30	0.0%
Net Internal Demand	30,718	33,574	9.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	38,729	34,671	-10.5%
Tier 1 Planned Capacity	463	3,152	581.5%
Net Firm Capacity Transfers	0	6,136	100%!
Anticipated Resources	39,192	43,959	12.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	39,192	43,959	12.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	30.9%	3.3
Prospective Reserve Margin	27.6%	30.9%	3.3
Reference Margin Level	17.2%	17.2%	0.0

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,481	11,501	9.7%
Demand Response: Available	282	285	1.1%
Net Internal Demand	10,199	11,216	10.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	18,356	17,768	-3.2%
Tier 1 Planned Capacity	199	366	84.3%
Net Firm Capacity Transfers	0	0	0%
Anticipated Resources	18,555	18,134	-2.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	18,555	18,134	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	81.9%	61.7%	-20.3
Prospective Reserve Margin	81.9%	61.7%	-20.3
Reference Margin Level	19.0%	18.2%	-0.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,844	21,147	1.5%
Demand Response: Available	340	177	-47.9%
Net Internal Demand	20,504	20,970	2.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	38,991	40,135	2.9%
Tier 1 Planned Capacity	3,381	2,733	-19.2%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	42,372	42,868	1.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	42,372	42,868	1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	106.6%	104.4%	-2.2
Prospective Reserve Margin	106.6%	104.4%	-2.2
Reference Margin Level	16.0%	16.0%	0.0

Variable Energy Resource Contributions

Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity and may vary widely year to year based on the identified risk hour. In many areas, winter demand peaks in the early morning hours or early evening resulting in little or no electrical resource output from solar PV resources and wide variability in wind availability. The following table shows the capacity contribution of existing wind and solar PV resources at the identified risk hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS.

BPS Variable Energy Resources On-Peak Capacity Contributions by Assessment Area

	Wind			Solar			Run of River Hydro		
Assessment Area/Interconnection (* - includes all hydro)	Nameplate Wind (MW)	Expected Wind (MW)	Expected Share of Nameplate (%)	Nameplate Solar PV (MW)	Expected Solar (MW)	Expected Share of Nameplate (%)	Nameplate Hydro (MW)	Expected Hydro (MW)	Expected Share of Nameplate (%)
MISO	30,247	8,772	29%	13,726	686	5%	2,351	1,404	60%
MRO-Manitoba Hydro	259	52	20%	0	0	0%	202	0	0%
MRO-SaskPower	816	433	53%	30	0	13%	884	703	80%
MRO-SPP	35,714	7,198	20%	1,197	457	38%	114	72	63%
NPCC-Maritimes	1,635	241	15%	155	10	6%	1,357	1,283	95%
NPCC-New England	2,675	455	17%	3,620	0	0%	3,742	1,453	39%
NPCC-New York	2,586	737	29%	627	0	0%	974	596	61%
NPCC-Ontario	4,943	1,971	40%	478	0	0%	0	0	0%
NPCC-Québec	4,024	1,426	35%	10	0	0%	445	445	100%
PJM*	13,318	5,463	41%	15,732	1	0%	8,134	7,900	97%
SERC-Central	1,324	370	28%	1,576	455	29%	4,991	4,027	81%
SERC-East	0	0	0%	7,068	1,792	25%	3,010	2,951	98%
SERC-Florida Peninsula	0	0	0%	12,058	2,151	18%	0	0	0%
SERC-Southeast	0	0	0%	8,670	4,461	51%	3,258	3,258	100%
Texas RE-ERCOT	40,629	7,833	19%	35,609	660	2%	579	566	98%
WECC-AB*	5,712	1,919	34%	2,206	0	0%	894	285	32%
WECC-Basin*	5,932	1,148	19%	3,853	62	2%	2,667	1,473	55%
WECC-BC*	747	85	11%	17	0	0%	17,752	13,560	76%
WECC-CA*	9,382	682	7%	28,328	0	0%	15,740	4,572	29%
WECC-Mex	40	4	11%	350	0	0%	0	0	0%
WECC-NW*	14,744	1,319	9%	4,695	1,556	33%	32,915	18,502	56%
WECC-RM*	5,681	2,265	40%	3,521	0	0%	3,251	1,327	41%
WECC-SW*	4,303	1,182	27%	12,139	391	3%	3,117	948	30%
EASTERN INTERCONNECTION	93,517	25,692	27%	64,937	10,013	15%	29,017	23,647	81%
QUÉBEC INTERCONNECTION	4,024	1,426	35%	10	0	0%	445	445	100%
TEXAS INTERCONNECTION	40,629	7,833	19%	35,609	660	2%	579	566	98%
WECC INTERCONNECTION	46,541	8,605	19%	55,108	2,008	4%	76336	40667	53%
INTERCONNECTION TOTAL:	**184,711**	**43,556**	**23%**	**155,664**	**12,685**	**8%**	106,377	65,325	61%

Review of Winter 2024–2025 Capacity and Energy Performance

The meteorological winter across the contiguous United States had an average temperature of 34.1 degrees F—1.9 degrees above average—ranking in the warmest third of NOAA's historical record. Total winter precipitation in the US was 5.87 inches, 0.92 of an inch below average, ranking in the driest third of the December–February climate record.[17] Most of Canada experienced temperatures at least 2°C above the baseline average with the Maritime provinces, southern Ontario, and the Canadian west coast recording temperature departures nearer the baseline average while a small region in southern Saskatchewan recorded temperatures just slightly below the baseline average.[18]

In February 2025, FERC and NERC and its Regional Entities launched a joint review of the BPS' performance during the January 2025 arctic events, which comprised Winter Storms Blair, Cora, Demi, and Enzo.[19] The week of January 19–25, 2025 was the third coldest winter week (spanning Sunday through Saturday) across the United States since 2000. Between January 21 and 22, 2025, natural gas demand peaked at 150 Bcf/day, electric demand peaked at 683 GW, and unplanned outages peaked at 71,022 MW. Nevertheless, during the January 2025 arctic events, manual load shed was not required. The January 2025 arctic events had lower observed hourly wind chill temperatures in pockets of the Northeast, the Louisiana Gulf, California, and the Southwest compared to Winter Storms Uri, Elliott, Gerri, and Heather. During the January 2025 arctic events, the most extreme storm relative to typical weather was Winter Storm Enzo—a Gulf and Southern storm. On January 20, 2025, a burst of snow, sleet, and freezing rain developed across Texas and Louisiana late in the day. A mixture of sleet and freezing rain fell from Austin to San Antonio and to the southernmost point of Texas. By the early morning hours of January 21, 2025, for the first time in history, a blizzard warning was issued for southwest Louisiana and the southeastern-most point of Texas. Snow fell in Gulf cities in Texas, southern Mississippi, southern Alabama, and western Florida. On January 21, 2025, Baton Rouge recorded 7.6 inches of snowfall, making it the city's snowiest day since recordkeeping began in 1892, while New Orleans saw its snowiest day on record, with a total of 8.0 inches. Temperatures plunged to single digits in Louisiana. Temperatures in some parts of the state fell to levels not seen in more than 125 years.

The review team engaged with 10 electric entities across the Eastern and Texas Interconnections to gather the information necessary to provide a high-level overview of the BPS' performance during the cold weather events. Based on the data and interviews that the team reviewed, electric generators appear to have performed better during the January 2025 arctic events because of additional generator commitments, improved preparedness, increased situational awareness, and the implementation of lessons learned from previous extreme cold weather events and prior report recommendations. The natural gas system also performed better overall, serving record levels of natural gas demand and experiencing only minor production declines and short-duration force majeure events.

On October 1, 2025, NERC submitted to the Federal Energy Regulatory Commission its first *Cold Weather Data Annual Report*. This report includes a review of forced outage data from GADS for the winter 2024–2025 period indicating performance consistent with historical performance as reported in NERC's annual *State of Reliability* report. This is within the normal range of capacity that occurs across the fleet. During the Winter 2024–2025 period, the highest amount of capacity in a forced outage state for all reasons occurred on January 20, 2025, with 68,519 MW across all regions. The outages occurring over January 20, 2025, were analyzed as part of the joint FERC, NERC, and Regional Entity *2025 System Performance Review*. The joint FERC, NERC, and Regional Entity *2025 System Performance Review* found a reduction in peak coincident unplanned generator outages for the four 2025 winter storms reviewed compared to past winter storms; however, this review also noted that it was not an exact comparison due to prior winter storms having different characteristics.

Eastern Interconnection–Canada and Québec Interconnection

No EEAs were needed during the previous winter season. One entity plans to make a slight increase to the demand-response program based on last winter's operations.

[17] Despite Arctic air outbreaks, U.S. had warm, dry winter on average | National Oceanic and Atmospheric Administration
[18] Climate Trends and Variations Bulletin – Winter 2024/2025 - Canada.ca
[19] https://www.ferc.gov/media/report-january-2025-arctic-events-system-performance-review-ferc-nerc-and-its-regional

Eastern Interconnection–United States

Several entities indicated that generators performed better during the January 2025 arctic events than in previous winter storms. For example, TVA stated that generator performance within its footprint was stable, with minimal natural gas delivery issues. Southeastern RC detailed that no major fuel-related outages occurred. FRCC noted that generator performance was strong during this period. The significant characteristics of Winter Storm Enzo in the Southern and Gulf states were freezing precipitation and snow accumulation, especially in regions where those conditions rarely occur. In FRCC, only the northern portion of Florida experienced severe arctic weather including freezing precipitation and snowfall (record-setting, in some cities) that were abnormal for the region even though certain northern cities have faced cold temperatures in the past. In Florida, entities experienced energy emergencies caused by extended generation outages from hurricanes Milton and Helene, compounded by unusually high loads from cold weather. Entities were able to serve native load and firm delivery obligations, though non-firm sales were curtailed during certain events. ISO-NE, NYISO, and PJM all generally described the January 2025 arctic events as having cold temperatures but overall weather conditions that were similar to a winter without a major storm.

MISO emerged from Winter 2024–2025 without turning to emergency procedures despite the wide-ranging winter storms from January 6 to 9 and again from January 20 to 22. Generators continue to prioritize scheduling planned or maintenance outages to the shoulder seasons of fall and spring to maximize unit availability for the winter season. Also, extreme cold weather outage adders were added to the LOLE model to make sure that winter storm risks are included in planning. In PJM, demand reached a new all-time winter peak on January 22, 2025, of 143,714 MW with sufficient reserves. PJM did call an EEA1 on January 22, 2025, however reserves remained adequate. PJM had less than 3% load forecast error over the peak days of the January cold weather events. Reliability cases were conducted, and units with extended start times were evaluated and started early to ensure units were on-line before extreme cold weather settled in. PJM had a 9.24% forced outage rate on the peak day, a relatively low forced outage rate for the weather experienced. There were also very few gas production problems; however, market issues prevented proper scheduling because of the four-day holiday weekend.

In SERC-Central, entities reported only limited impacts from Winter 2024–2025 coldest weather and made minor adjustments. One entity declared conservative operations ahead of peak conditions but experienced no emergencies. One entity raised its winter Planning Reserve Margin target to 26% following lessons learned from Winter Storm Elliott. Corrective actions were implemented due to isolated equipment issues, including improved heat trace capabilities and adding heat trace equipment to the cold weather critical component list. During the previous winter season, some SERC-Florida Peninsula entities experienced energy emergencies caused by extended generation outages from hurricanes Milton and Helene, compounded by unusually high loads from cold weather. Despite these challenges, entities were able to serve native load and firm delivery obligations, though non-firm sales were curtailed during certain events.

Texas Interconnection–ERCOT

There were no energy emergencies for the Texas RE-ERCOT region last winter and no conditions that prompted changes in operating procedures. Winter Storm Kingston, which occurred in February 2025, was the only storm where ERCOT utilized firm fuel supply service resources (FFSS), a firm-fuel product that provides additional grid reliability and resiliency during extreme cold weather and compensates generation resources that meet a higher resiliency standard. A maximum FFSS deployment of 470 MW occurred on February 19 between the hours 13:10 and 17:02. Two other storms, Enzo and Cora, impacted ERCOT in January 2025, but these storms did not cause any system reliability issues.

Western Interconnection

Between January 11 and 17, 2024, a prolonged Arctic outbreak impacted British Columbia, Alberta, and the U.S. Pacific Northwest, driving record electricity demand and widespread reliability challenges. Four U.S. Northwest BAs and one Canadian BA declared energy emergencies, underscoring two core vulnerabilities: Inadequate capacity during evening peak hours (4 to 8 p.m.) and Insufficient fuel supply (limited hydro availability) across multiple days.

Although temperatures were comparable to the December 2022 cold snap, WECC-Northwest peak demand rose two percentage points to 6% over then, with BC Hydro and AESO both setting new all-time records. The U.S. Northwest relied heavily on imports—averaging 4,745 MW during peaks and 5,241 MW across all hours, mostly from the Southwest and Rockies. California remained a net importer, providing little relief. Market prices in the Northwest reached or neared caps across most hours, indicating persistent scarcity rather than short-term peaks. Overall, the January 2024 event illustrated capacity alone does not ensure resilience. Sustained energy availability with interregional flexibility (both physical and market-based) will be key to maintaining reliability through the 2025–2026 and future winter seasons.

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
MISO	Jan. 21	18:00	108,888*	96,134 100,395	101,655	-977	18,468	16,761	0	519	17,010
MRO-Manitoba Hydro	Jan. 20	08:00	5,132	4,814 5,060	5,292	-277	142	52	N/A	0	146
MRO-SaskPower	Dec. 18	18:00	3,785	3,802 3,897	3,641	-231	664	368	0	3	0
MRO-SPP	Feb. 20	08:00	47,981	45,926 47,054	40,898	-1,424	4,886	4,783	255	36	9,272
NPCC-Maritimes	Jan. 22	07:00	5,810	5,907 6,498	4,266	-1,174	368	261	3	5	*
NPCC-New England	Jan. 21	18:00	19,607	20,308 21,814	17,686	-1,896	285	329	4	23	624
NPCC-New York	Jan. 22	19:00	23,521	22,998 24,023	18,932	-4,589	654	728	0	0	4,835

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	Peak Demand Date	Peak Demand Hour	Demand[1] (MW)	WRA Peak Demand Scenarios[2] (MW)	Generation[1] (MWh)	Transfers[1] (MW)	Wind – Actual[1] (MWh)	Wind – Expected[3] (MW)	Solar – Actual[1] (MWh)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)
NPCC-Ontario	Jan. 22	18:00	21,940	20,951 22,179	24,250	2,990	3,693	1,914	0	0	*
NPCC-Québec	Jan. 22	08:00	37,178	36,061 39,545	39,514	-766	1,463	1,449	0	0	*
PJM	Jan. 22	09:00	144,420	130,712 144,939	152,142	7,731	3,704	3,620	3,076	1	8,663
SERC-C	Jan. 22	08:00	47,815	41,397 47,062	40,898	-6,921	563	176	214	455	1,538
SERC-E	Jan. 23	08:00	47,130	44,023 47,662	41,810	-5,323	0	0	145	2,526	1,830
SERC-FP	Jan. 25	08:00	43,974	45,714 54,239	41,702	-557	0	0	362	1,684	2,824
SERC-SE	Jan. 22	08:00	46,490	43,670 45,116	48,227	1,741	0	0	592	3,861	2,210

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
TRE-ERCOT	Feb. 20	08:00	80,560	73,193[5] 90,405[5]	79,960	-191	9,397	15,697	1,586	15	5,742
WECC-AB	Dec. 18	17:00	12,241	12,280 12,635	12,711	-470	3,175	1,867	4	0	*
WECC-BC	Feb 3	18:00	11,359	11,996 12,749	11,415	44	70	279	0	0	839
WECC-CA/MX	Dec. 12	15:00	35,555	35,359 36,823	31,925	-4,669	4,021	569	11,547	0	1,627
WECC-NW	Feb. 12	08:00	54,278	58,001 62,230	48,437	-920	2,607	7,876	1,494	2,198	3,281
WECC-SW	Feb. 13	16:00	22,969	16,177 17,777	25,087	2,117	2,741	1,065	1,599	182	1,496
Highlighting Notes:			Actual peak demand in the highlighted areas met or exceeded extreme scenario levels				Actual wind output in highlighted areas was significantly below seasonal forecast.		Actual solar output in highlighted areas was significantly below seasonal forecast.		Actual forced outages above or below forecast by factor of two

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	Peak Demand Date	Peak Demand Hour	Demand[1] (MW)	WRA Peak Demand Scenarios[2] (MW)	Generation[1] (MWh)	Transfers[1] (MW)	Wind – Actual[1] (MWh)	Wind – Expected[3] (MW)	Solar – Actual[1] (MWh)	Solar – Expected[3] (MW)	Forced Outages Summary[4] (MW)

Table Notes:
[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities.
[2] See NERC *2024–2025* WRA demand scenarios for each assessment area. Values are the normal winter peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.
[3] Expected values of wind and solar resources from the *2024–2025 WRA*.
[4] Values from NERC Generator Availability Data System for the 2024–2025 winter hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024–2025 winter risk period scenarios in the *2024–2025 WRA*.
[5] Texas RE-ERCOT peak demand scenarios are obtained by adding expected demand response (5.4 GW for winter 2024-2025) to the demand scenarios found on p. 29 of the 2024-2025 WRA.
*Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

Errata

December 2025

- Corrections made to the VER Table (page 50): Hydro values for WECC NW, Western Interconnection Total, and Total

Exhibit 25



PJM Winter Outlook: Adequate Power Supplies Available To Serve Growing Demand Under Expected Conditions

Reserve Margins Continue To Tighten; Generator Performance Crucial

November 3, 2025

(Valley Forge, PA – Nov. 3, 2025) – PJM and its members have sufficient resources to serve the 67 million people in its footprint this winter under expected conditions, though electricity demand continues to outpace the addition of new generating resources.

PJM, the grid operator for 13 states and the District of Columbia, expects to have 180,800 MW of operational capacity to serve a forecasted peak electricity demand of approximately 145,700 MW, which would set a new record if reached. This expectation is based on PJM and the PJM resources continuing to take operational steps to improve generator performance during extreme winter conditions.

PJM reached an all-time winter high of 143,700 MW on Jan. 22 of this year, 2,000 MW less than this winter's forecast peak. PJM has added approximately 4,800 MW of new generation (nameplate capacity) since last winter, most of it solar; that translates to approximately 1,000 MW more operational capacity for the 2025–2026 winter.

PJM forecasts a generation reserve margin of 7,500 MW, after taking into account expected generation outages, electricity exports and other factors. This is down from 8,700 MW last year. This margin factors in winter generation performance that has improved since Winter Storm Elliott; that margin could shrink further if generators perform poorly.

"The grid is set up to keep the power flowing reliably this winter under forecast conditions, but the tightening of our margins will begin to impact us in the next few years if it continues," said Aftab Khan, Executive Vice President – Operations, Planning and Security. "PJM is working on multiple levels with all of our stakeholders to reverse this trend of demand growing faster than we can add generation."

To develop its winter scenario forecasts, PJM analyzes expected electricity demand, weather predictions and other factors. The National Weather Service predicts a slightly warmer winter for the

Atlantic seaboard, with typical temperatures – but above-average precipitation – in PJM's midwestern states of Illinois, Indiana, Kentucky, Michigan and Ohio.

PJM also expects to remain reliable through several more extreme, but less likely, cold weather scenarios in which lower amounts of power generation are available and there is more demand within PJM or in external systems in need of PJM's assistance for reliability. PJM's scenario analyses include load of up to 150,300 MW; those studies show that system reliability is maintained under most scenarios, including expected outages. Significantly higher levels of generator outages, however, such as those that occurred during Winter Storm Elliott (~46,000 MW), could leave the system vulnerable to power outages.

PJM and stakeholders take a number of actions to prepare for cold weather, outlined in its Cold Weather Preparation Guideline and Checklist, contained in Manual 14D, Attachment N. These protocols incorporate lessons learned from past severe events, including Winter Storm Elliott (2022), Winter Storm Uri (2021) and Winter Storm Enzo (2025).

This year, PJM will request generators provide extreme cold weather temperature data per standards approved by the North American Electric Reliability Corporation (NERC) on Oct. 1. PJM continues to build its database of minimum operating temperatures for its generation fleet to better understand the limitations of certain generators in extreme cold.

PJM will also perform unannounced operational tests of generators that have not run for several weeks leading into the winter. These tests are performed in advance of extreme weather or high system demand to help ensure that these resources are fully functional and ready to operate when needed.

PJM and ReliabilityFirst, which oversees reliability for NERC in much of the PJM footprint, will double the number of winter preparedness site visits to 30 generation facilities, ensuring that winterization best practices and lessons learned are shared systemwide.

During the fall, PJM meets with regulators and neighboring system operators to review winter preparations. PJM also conducts weekly operational review meetings during the winter with major natural gas pipelines to coordinate operations serving the natural gas fleet.

"Generator performance will be critical to maintaining reliability this winter," said Michael Bryson, Sr. Vice President – Operations. "We are encouraged by the work we have seen by generation owners to fortify their units for winter operations, and we will continue to focus on communication and coordination that help us understand how PJM can help to mitigate gas scheduling challenges or other generator limitations."

Exhibit 26

Winter Storm Elliott

Event Analysis and Recommendation Report

July 17, 2023

For Public Use

Contents

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Executive Summary

Winter Storm Elliott hit the eastern United States over the Dec. 23–25 weekend and tested the reliability of much of the Eastern Interconnection. Precipitous temperature drops and powerful winds caused widespread generator failures and froze up natural gas supplies while driving up electricity demand, leading to power outages in some of PJM's neighbors.

PJM and its members were able to maintain the reliability of the system, serve customers and even support neighboring systems during some periods, which was a significant accomplishment. Specifically, PJM operators were able to avoid electricity interruptions throughout this event. Nevertheless, PJM operators had to implement multiple emergency procedures and a public appeal to reduce energy use to maintain reliability in the PJM footprint serving 13 states and the District of Columbia.

Advanced Planning

As documented in this report, PJM was prepared for the 2022/2023 winter, as well as Winter Storm Elliott, based on the information available, and conducted extensive preparations and communications with members, adjacent systems and the natural gas industry in advance of the storm, in addition to the regular steps PJM takes each year to prepare for winter.

PJM's annual pre-winter analysis indicated that PJM would have enough generation to meet load even under a combination of extreme and unlikely conditions, including pipeline disruptions similar to those previously seen under similar winter conditions, close-to-zero wind/solar generation, high generation outages and extreme weather. Despite numerous refinements to both the capacity market rules and winter preparation requirements that came out of the 2014 Polar Vortex, Winter Storm Uri in 2021, and other recent examples of increasingly extreme weather patterns, Winter Storm Elliott created a convergence of circumstances that strained the grid.

PJM's load forecasts for Dec. 23 and Dec. 24 were approximately 8% under the actual peak. The modeling challenges that resulted in this under-forecast are detailed in this report. Given the operational uncertainty, PJM operators scheduled prudently on both days (in excess of the actual load plus reserve requirements).

Operations and Generator Performance

Elliott's rapidly falling temperatures coincided with a holiday weekend that combined to produce unprecedented demand for December. This was further complicated by unexpectedly high resource unavailability and/or failures to perform.

On the first day of the storm, Dec. 23, the stress on PJM's neighbors began to signal extreme conditions headed for the region PJM serves. The Southwest Power Pool (SPP) set a new winter peak that day; the Tennessee Valley Authority (TVA) experienced the highest 24-hour electricity demand supplied in its history. PJM exported energy to TVA, Duke Carolinas and Duke Energy Progress before having to curtail most exports during peak conditions in the face of emergency conditions.

PJM's forecast for Dec. 23 was about 127,000 MW, and load came in at about 136,000 MW. This demand level is approximately 25,000 MW above a typical winter peak day. In preparation for this day, PJM had approximately 158,000 MW of operating capacity based on what was scheduled in the Day-Ahead Market plus available generation able to be called upon in real time. PJM was able to meet this load with the help of a Maximum Generation Action and Demand Response. Looking to Dec. 24, the coldest day of the weekend, PJM operators decided to schedule conservatively in terms of reserves (the electricity supplies that are not currently being used but can be quickly available in the case of an

unexpected loss of generation). Based on the information it had received from generation resources, PJM anticipated that approximately 155,700 MW of generation should have been available for Dec. 24.

Complications arose on Dec. 24 resulting from the unanticipated failure of generation resources that were called into the operating capacity on that day. At one point, almost a quarter of the generation capacity – 47,000 MW – was on forced outages. While generators are required to provide updates on their operating parameters, including operating status, ramp times and fuel availability, in 92% of generator outages, PJM operators had an hour's notice or less – in most cases, PJM was informed of outages when dispatchers called generators to request them to turn on.

When examined over the entire generation fleet, gas generators accounted for 70% of the outages on Dec. 24. Most outages were caused by equipment failure likely resulting from the extreme cold, though broader issues of gas availability also contributed to the outages.

Market Outcomes

Elliott was the first wide-scale use of PJM's Capacity Performance rules, which were introduced in 2016 as a market tool to incent generator performance following the 2014 Polar Vortex – a similar event characterized by extreme cold weather and high forced outage rates. The high outage rates for generators during Winter Storm Elliott resulted in substantial Non-Performance Charges that are part of Capacity Performance rules. As of this report, PJM estimates there are approximately $1.8 billion in Non-Performance Charges based on the current rules. Those charges are allocated to suppliers that exceeded their committed capacity level.

Outreach

PJM's communications and government policy teams relayed critical situation updates in a timely fashion; short operational update videos from PJM leadership were used to reach a wide audience by television, print and digital media, while external-facing personnel used the same videos to update their important state and federal contacts. The Call for Conservation was widely amplified by Transmission Owners, regulators and even governors' offices on social and traditional media, and PJM is looking at strategies to build on that effective partnership.

Recommendations Overview

The analysis of PJM's experience during Winter Storm Elliott confirms the decisions by PJM planners and operators in preparing for and navigating through the storm, including communications, emergency procedures, and the scheduling and management of interchange in support of the Eastern Interconnection. In addition, the capacity market's performance rules were implemented as written in the Tariff and manuals.

At the same time, Elliott also provides some clear lessons for PJM and its stakeholders that drive the 30 recommendations contained in this report. These recommendations are broadly focused on:

- Addressing winter risk with enhancements to market rules, accreditation, forecasting and modeling
- Improving generator performance through winterization requirements, unit status reporting and testing/verification
- Tackling long-standing gaps in gas-electric coordination, including timing mismatches between gas and electric markets, the liquidity of the gas market on weekends/holidays, and the alignment of the electricity market with gas-scheduling nomination cycles
- Evaluating how the Performance Assessment Interval (PAI) system of rewarding or penalizing generator performance is impacted by exports of electricity to other regions, whether excusal rules can be simplified, PAI

triggers need to be refined, and if the contributions of Demand Response and Energy Efficiency are accurately valued

- Pursuing opportunities with Generation Owners, other members and states to improve education, drilling and communication regarding PJM's emergency procedures, Call for Conservation and PAIs

Many of these recommendations, as indicated in the chart below, are currently being developed through the Critical Issue Fast Path – Resource Adequacy process or through other forums.

Recommendations

ID	Category	Recommendation	Type	Status
1	Resource Performance	Evaluate needed enhancements to the generator Cold Weather Checklist and the Cold Weather Operating Limit reporting practices used to prepare for cold weather to help improve generator cold weather performance in the future. Incorporate lessons learned as necessary to improve these checklists to include validation procedures. Evaluate reasons why the information provided by Curtailment Service Providers regarding their ability to curtail load was not accurate. Incorporate lessons learned as necessary to include validation procedures.		Under internal PJM review
2	Emergency Procedures	Reinforce PJM and member steps and expectations in Manual 13 for operation during emergency procedures through additional training and manual clarifications. Specific focus on: • Existing actions in Cold Weather Advisory and Cold Weather Alert regarding winterization and staffing procedures • Criteria, sequencing, and communication of alerts, warnings and actions • Consideration of potential opportunities to clarify member expectations in M-13		New
3	Operating Reserves	Evaluate triggers for increasing the Operating Reserve Requirements in advance of the operating day based on risks imposed by projected extreme temperatures, unusual temperature changes, load uncertainty, solar/wind uncertainty, generator performance uncertainty, OFOs, etc.		Pending internal process change
4	Load Forecast	Evaluate opportunities for improvements to the extreme weather load forecast processes and methodology with independent and peer analysis.		Under internal PJM review
5	Unit Parameters	PJM will provide additional training relating to the use of Parameter Limited Schedules (PLS) and price schedules. The focus of the training will include the time to start parameters for the various schedule types and the use of PLS parameters. The intended training audience is for anyone managing and updating the PLS and price schedules.		New

ID	Category	Recommendation	Type	Status
6	Unit Status	Evaluate the Temporary Exception and Real-Time Value processes that require gas-fired generators to either update their operating parameters, or confirm that no updates are needed, when Cold Weather Advisories, Alerts, Conservative Operations, or pipeline OFOs are issued that may impact their ability to procure gas outside of standard nomination timelines. Make improvements to ensure accurate offer information from generation resources.		Under discussion at the Electric Gas Coordination Senior Task Force (EGCSTF)
7	Gas Electric Coordination	Develop solutions to address near-term gas generator unavailability resulting from gas and electric market timing issues, particularly during periods of cold temperatures and high winter demand.		Under discussion at the EGCSTF
8	Gas Electric Coordination	Explore opportunities to increase alignment between the scheduling of natural gas-fired resources with nomination cycles.		Under discussion at the EGCSTF
9	Gas Electric Coordination	Evaluate the current multi-day commitment process for use during expected critical high demand periods so as to analyze the costs and benefits of providing greater certainty of fuel supply procurement through the critical period, with a focus on weekends when the gas commodity market can be less liquid.		Under discussion at the EGCSTF
10	Gas Electric Coordination	Provide recommendations to FERC to investigate weekend gas supply liquidity to facilitate increased gas procurement ability during weekend/holiday periods.		Under discussion at the EGCSTF
11	Gas Electric Coordination	Work with states to discuss opportunities to increase prioritization of natural gas for usage in electricity production for resources behind LDCs.		Under discussion at the EGCSTF
12	Gas Electric Coordination	Explore opportunities to better align submitted offer data to true availability of natural gas resources.		Under discussion at the EGCSTF
13	Gas Electric Coordination	Evaluate the ability to include fuel-specific information in the capacity accreditation model. Consider including items such as: 1. Different levels of fuel security, including dual-fuel capability, firm gas and non-firm gas 2. Minimum requirements for onsite fuel		Under discussion in the CIFP process
14	Unit Status	Evaluate options for requiring generators to provide procurement information to PJM in real time and day ahead to provide greater situational awareness to PJM regarding the ability and timeliness of procuring fuel.		Under discussion at the EGCSTF
15	Voltage Reduction	Review and update, as necessary, the expected load reduction achieved during a Voltage Reduction Action due to changing composition of load. This recommendation specifically focuses on the Voltage Reduction Summary table in Manual 13.		New

ID	Category	Recommendation	Type	Status
16	Reserve Performance	Evaluate opportunities to increase the performance of Synchronized Reserves to achieve the desired response. This may include levels procured, procurement practices, compensation or other aspects of the Reserve Market design.		Stakeholders notified that PJM's reserve requirement will be increased to 1.3 times the largest contingency MW effective May 19 until further notice
17	Reserve Pricing and Penalties	Evaluate the current Reserve Market design to ensure reserve products, estimated reserve capabilities on resources, procurement practices and timelines, quantities procured, performance incentives, etc., align with operational needs and that prices and performance incentives are similarly aligned.		Issue charge planned for August
18	Cost Offer Verification	Distribute training on the Cost Offer Verification process to members (standard email or similar notification) before cold weather events and send alerts to update MIRA ahead of time.		New
19	CIFP	Evaluate how risk modeling in the reliability analysis used in the capacity market can be improved to better account for the drivers of reliability risk experienced in the winter.		Under review at the CIFP
20	CIFP	Evaluate reforms to capacity market rules and incentives to improve the performance of resources, including: • Review the Capacity Performance construct, with consideration of financial risks. • Strengthen capacity accreditation and qualification criteria (e.g., winterization/fuel assurance). • Evaluate opportunities to improve testing rules to complement assessments during actual reliability events, including frequency of the tests, defined guidelines for test success/failure, and penalties for test failure. • Evaluate current practices in other ISO/RTOs for requiring generator inspections and implement any best practices.		Under review at the CIFP
21	CIFP	Evaluate opportunities to align the incentives from the capacity market via PAIs with real-time operating conditions, particularly with regard to PAI triggers.		PJM filed changes to the PAI triggers on May 30. Discussions will continue as part of the larger reforms in the CIFP process.
22	CIFP	Evaluate if and how exports should be accounted for in the balancing ratio.		Under review at the CIFP
23	CIFP	Reevaluate what happens in the scenario that a resource has not submitted a valid offer.		Under review at the CIFP
24	CIFP	Explore opportunities to refine and simplify excusal rules to reduce manual and case-by-case review processes.		Under review at the CIFP

ID	Category	Recommendation	Type	Status
25	CIFP	Review the M&V calculations of Energy Efficiency and Demand Resources for PAIs to assess if the determination of actual performance and bonus accurately reflects the reliability benefit provided.		Under review at the CIFP
26	CIFP	Evaluate the performance issues regarding NRBTMG, and provide recommendations on enhancing its performance or altering its participation in the capacity market.		Reviewed at the May 8 DISRS Stakeholder group
27	CIFP	Explore opportunities for further education on PAIs, such as providing periodic training sessions.		In Progress
28	Call for Conservation	Evaluate opportunities to enhance Public Notification Language in Attachment A of Manual 13 regarding Call for Conservation to better direct the appeal to all customers, not just residential. Establish a process for annual review of state alert contacts, and explore additional opportunities to further amplify PJM's message through state communication channels, up to and including Emergency Alert Systems.		In Progress
29	Outreach	Operations, Corporate Communications and SGP will seek ways to enhance communications, specifically looking at timeliness, relevance and clarity of information provided along with curating and updating of appropriate contacts for each audience and channel for messaging.		In Progress
30	Drills & Exercises	Operations, Corporate Communications and SGP will also strengthen their periodic drilling with states, Transmission Owners and other members by: 1) Finding opportunities to include states in PJM crisis exercises; 2) Providing education on PJM emergency procedures and Call for Conservation during summer and winter operations drills; 3) Following up with parties not represented at drills to make sure they are aware and contacts are up to date.		In Progress

Legend for Type

- Operational Change
- Market Construct Process Change or Addition
- Process Improvement
- Training and awareness improvement

About This Report

Purpose

The purpose of this analysis and subsequent report is to review the events up to and during Winter Storm Elliott, assess the actions of PJM and its members during those times, and look for lessons learned and associated recommendations to help improve grid reliability.

Analysis Process

The review process performed for this report was driven by the Human Performance and Operating Experience (HP&OE) program at PJM. The HP&OE program promotes excellence in human performance through behaviors that support reliable grid operations, fair and efficient energy markets, and infrastructure planning. The goals of this program are to:

- Reduce the frequency and impact of human error
- Share and learn from internal and external events
- Analyze events to identify corrective actions to prevent and reduce impacts of adverse events
- Ensure that processes and procedures are executed correctly to achieve the desired results

The fundamental aspects of the HP&OE program are:

- Prevention: Reduce errors that lead to events
- Detection: Identify potential issues across the organization
- Correction: Learn from events through event analysis and completion of remedial actions

To conduct this review and event analysis, PJM employed the Learning Teams analysis tool. Learning Teams are utilized in the industry as a collaborative event analysis best practice because it focuses on bringing people together to better understand an event with the basis on learning and identifying successes and improvements.

PJM conducted multiple different focused area Learning Team sessions with subject matter experts and independent participants across various areas of PJM to allow for open and collaborative discussions. The Facilitation Team followed a structured and consistent methodology with a focus on the event itself, and additionally on the timeline and decisions leading into the event, which allowed all members of the team to share their perspective. From the Learning Team sessions, successes and opportunities for improvement were identified that lead to recommendations for future analysis of enhancements to rules and procedures. The recommendations from PJM's Learning Team's sessions on Winter Storm Elliott are contained in this report. The recommendations are then tracked through the HP&OE program until they are resolved.

Organization of This Report

This report outlines the operational preparations that PJM takes in advance of winter generally, and took for Winter Storm Elliott during the Dec. 23–25 holiday weekend specifically, including emergency procedures, communications with members and forecasting. It documents the operating conditions PJM operators faced and the actions they took, and it details the working of the PJM markets just before and during the storm. The Conclusion summarizes the processes and forums that will be used to act on the set of recommendations. For definitions of industry terms, consult the PJM Glossary on PJM.com.

Advance Preparations

Each year, PJM performs winter readiness assessments and exercises in advance of the cold weather months. These assessments include power flow analyses that simulate potential conditions on the power system for expected and extreme winter conditions, as well as a capacity "waterfall chart" to determine if adequate capacity is expected to be available based on various stress cases. This analysis is known as the Winter Operations Assessment Task Force Study.

In 2021, in light of the severe cold weather issues experienced in Texas during February 2021, PJM initiated an analysis that resulted in numerous additional improvements to its winter preparedness efforts. Those improvements included approving rules to assist Transmission Owners (TOs) in identifying and prioritizing service to critical facilities in emergencies, prohibiting Load Management programs from including any critical gas infrastructure, further improving information sharing with the natural gas industry, and confirming that TOs were prepared to rotate outages if load shedding was required.

PJM also collects data on generating resource fuel inventory, supply and delivery characteristics, emissions limitations, and minimum operating temperatures via the Seasonal Fuel Inventory and Emissions Data Request (PJM Manual 14D, Section 7.35) and also via Periodic Fuel and Emissions Data Requests issued as needed throughout the season. Furthermore, PJM validates that Generation Owners have adequately prepared for winter by requiring that they confirm they have completed the Cold Weather Preparation Guideline and Checklist.

Also, as a result of increasing supply chain risks to fuel deliveries, PJM initiated a weekly fuel and non-fuel consumables data request for all generators that utilize coal or oil as their primary or backup fuel. Capturing this data more frequently allows PJM to better understand any fuel supply, supply chain or transportation issues that could impact generators. Due to the continued concern with supply chain issues, the practice was extended through all of 2022, including the winter of 2022. Current system conditions do not necessitate this weekly data request but will be re-initiated, if necessary. These rule changes provided better visibility into generators' supply of fuels and other material critical to their operation and enhance the flexibility those generators need to rebuild their supplies when facing shortfalls beyond their control. The data requests did not identify any issues.

As described above, PJM prepares extensively for the peak winter season, including the following key annual activities:

- PJM Winter Operations Assessment Task Force Study
- Generation Resource Cold Weather Preparation Guideline and Checklist
- Cold Weather Resource Operational Exercise
- Pre-Winter Emergency Procedures Drill
- PJM Winter Readiness Meeting

This section details PJM's processes leading up to the storm, including regular winter preparations, issuing Cold Weather Advisories and Cold Weather Alerts, and other activities taken during the week of Dec. 18 in advance of Dec. 23 and Dec. 24.

PJM Winter Operations Seasonal Study

The PJM Operations Assessment Task Force (OATF) consists of representatives from PJM and PJM Transmission Owners. This team, under the direction of PJM, conducts seasonal studies for the summer and winter periods. Each

study analyzes the PJM system with the transmission and generation configuration approximating the expected conditions for that study period.

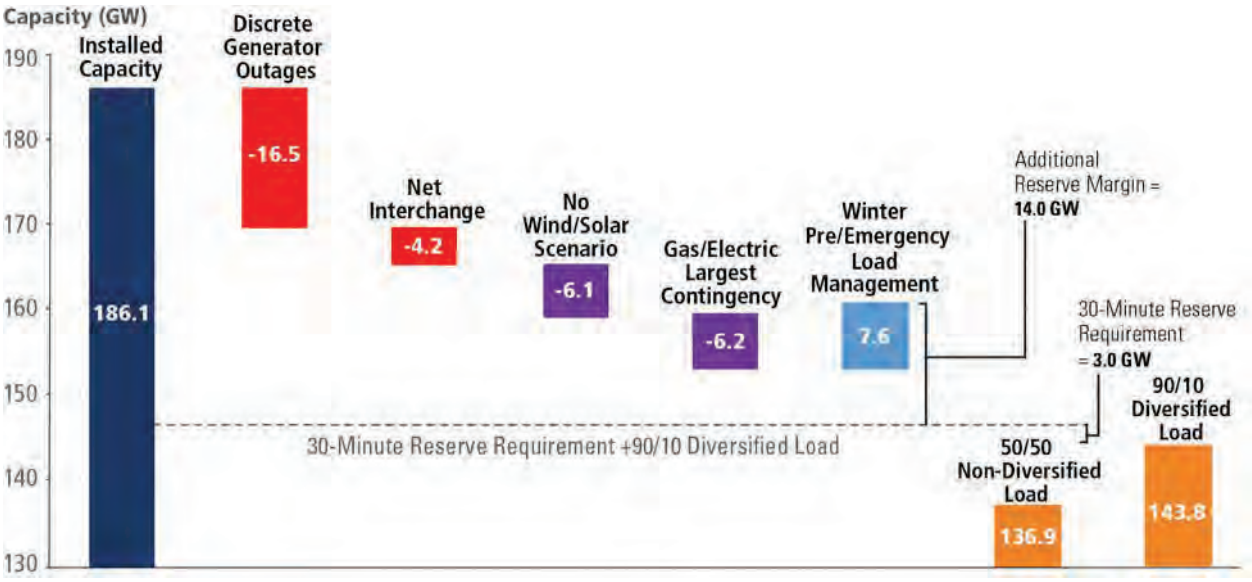
The study conditions include forecasted demand based on forecast weather and estimated outages, as well as a series of more extreme scenarios, including, but not limited to:

- External contingencies that could impact PJM reliability
- The loss of more than one bulk electric system (BES) element (N-1-1 relay trip conditions)
- A Maximum-Credible Contingency Analysis (e.g., loss of a substation, loss of multiple lines in a common right of way)
- An import capability analysis
- An extreme (90/10) load forecast study
- A solar and wind generation sensitivity study
- A gas pipeline disruption study

The results of this analysis indicated that there was sufficient generation for the 2022/2023 winter period to meet the demand under all studied conditions. The process for conducting the OATF study is documented in PJM Manual 38, Operations Planning, Attachment A.

As shown in Figure 1, PJM projected that more than adequate capacity should have been available for the 2022/2023 winter period.

Figure 1. Projected Capacity for 2022/2023 Winter Period



The OATF study is reviewed at the System Operations Subcommittee (SOS) and the Operating Committee (OC).

Generation Resource Operational Exercise

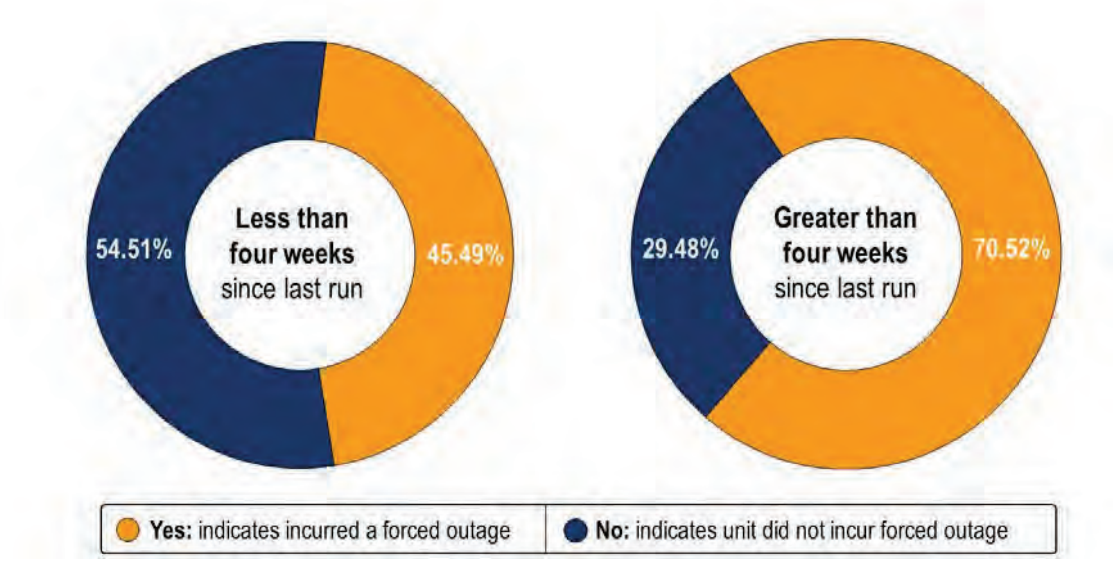
Following the 2014 Polar Vortex, PJM made several changes to its Cold Weather Operating Procedures, including establishing a Generation Resource Operational Exercise Program and a Generation Resource Cold Weather Checklist. The Generation Resource Operations Exercise Program is intended to enhance unit performance during cold weather operations and encourage generating units to be prepared for extreme cold weather and can start and run on alternate fuels, if necessary. The exercise assists in the identification and correction of start-up and fuel-switching problems (PJM Manual 14D, Section 7.5).

PJM also recommends that Generation Owners conduct an operational exercise prior to the onset of cold weather to validate a unit's cold weather operations. Specifically, PJM recommends that Generation Owners self-schedule any of their resources that have not operated in the eight weeks leading up to Dec. 1 to determine whether they are capable of reliably operating on both primary and alternate fuel and responding to PJM's dispatch instructions. Generation Owners are requested to submit an informational eDART ticket with a cause of "Cold Weather Preparation Exercise" to document that the generation resource has been scheduled to operate under the cold weather operational exercise.

The charts in Figure 2 present the forced outage rates during Elliott for units that had not run in the weeks leading up to the event. A four-week time period was used as the cutoff for the performance analysis. Those units that had not run in more than four weeks had higher forced outage rates. This data demonstrates that generators that had run in the few weeks prior to Winter Storm Elliott performed better than those that did not. As a result, PJM believes consideration should be given to making this currently recommended exercise a requirement.

When reviewing generator performance for units that did not operate for four weeks prior to Winter Storm Elliott, 70.5% of units incurred a forced outage during the event. This data supports continuing or expanding the Generation Resource Operational Exercise described in PJM Manual 14D, Section 7.5.1, which is currently recommended, but not required for Generation Owners to perform.

Figure 2. Forced Outages Versus Last Run Time



Generation Resource Cold Weather Preparation Checklist

Similarly, the Generation Resource Cold Weather Checklist (presented in PJM Manual 14D, Section 7.5 and Attachment N), or a similar one developed and maintained by the Generation Owner, should be used annually prior to the local

National Oceanic and Atmospheric Administration (NOAA) first frost date to prepare its generation resources for extreme cold weather event operations.

This checklist includes verification by Generation Owners that they have performed everything from increasing staffing for weather emergencies to performing required maintenance activities to prepare equipment for winter conditions. This checklist was first developed and issued to Generation Owners in 2014 and is updated annually as new industry lessons learned are published by NERC and others. For this winter, the checklist was updated to require information about a generating unit's cold weather operating limits. This was added as a result of the lessons learned from Winter Storm Uri.

The checklist identifies and prioritizes components, systems and other areas of vulnerability that may experience freezing problems or other cold weather operational issues such as safety staffing, equipment preparation, fuel preparation and environmental preparation; as well notes the actions to be taken when cold weather is forecast and actions during cold weather. Between Nov. 1 and Dec. 15 of each year, the Generation Owner is required to verify via eDART that the represented generation resources have completed the items on the checklist, or a substantially equivalent one developed by the Generation Owner. Ahead of Winter Storm Elliott, 99% of the generation resource owners in the PJM region verified that they completed the items on the Generation Resource Cold Weather Preparation Checklist or equivalent.

Table 1 summarizes the Cold Weather Checklist responses:

Table 1. Cold Weather Checklist Response Summary 2022

	Unit Count	Installed Capacity (MW)
Yes – Using Generation Owner Equivalent Guideline and Checklist	1,043	179,332
Yes – Using PJM Guideline and Checklist	270	16,974
No	52	1,262
No Response	37	238

The Cold Weather Checklist is discussed in the System Operations Subcommittee (SOS), Operating Committee (OC) and Market Reliability Committee (MRC). Additional information on generation performance is presented in the Operating Day section of this report.

Transmission Outage Deferrals

Transmission outage deferrals are an approved measure to promote the ability to transfer power across the RTO and promote an abundance of caution to be as prepared as possible. When PJM issues a Cold Weather Alert, PJM recalls/cancels non-critical transmission maintenance outages. Specifically, the following transmission outages were deferred or returned to service early:

- BLACKOAK-HATFIELD (eDART # 1053409 12/19 – 12/22) outage request was denied due to a conflict and cold weather.
- Two major outages returned to service early on Dec. 23. PJM was in close coordination with the TOs for the return of Mt. Storm-Valley 500 kV and the Malizewski-Marysville 765 kV lines.

Due to emergency procedures and multiple day-ahead outage approval processes, these lines were requested to be in service for Dec. 23.

Cold Weather Advisory

In advance of the mandatory North American Electric Reliability Corporation (NERC)[1] Winterization Standard becoming effective on April 1, 2023, PJM established the Cold Weather Advisory. A Cold Weather Advisory provides an early notice that forecast temperatures may call for a Cold Weather Alert. The early notification of an Advisory is intended to provide PJM members ample time to gather information required by NERC standards EOP-011, Emergency Preparedness and Operations, IRO-010 RC Data Specification and Collection, and TOP-003 Operational Reliability Data. Members are to take any necessary precautions to prepare generating facilities for cold weather operations. PJM attempts to issue the advisory as far in advance as possible, typically within three to five days, but given fluctuating and changing weather forecasts, advisories could be issued up to 24 hours in advance.

Members are expected to perform the following actions upon the issuance of a Cold Weather Advisory:

- Prepare to take freeze protection actions, such as erecting temporary windbreaks or shelters, positioning heaters, verifying heat trace systems, or draining equipment prone to freezing.
- Review weather forecasts to determine any forecasted operational changes and notify PJM of any changes.
- Update Markets Gateway by entering unit-specific operation limitations associated with cold weather preparedness, including the following limitations:
  - Generator capability and availability
  - Fuel supply and inventory concerns
  - Fuel switching capabilities
  - Environmental constraints
  - Generating unit minimums (design temperature, historical operating temperature or current cold weather performance temperature as determined by an engineering analysis)

PJM conducted a Cold Weather Advisory drill on Dec. 16, 2022. In advance of the drill at the December OC and the SOS meetings, PJM reviewed the objective of the upcoming drill and the expected member actions to be performed during the drill.[2]

Pre-Winter Emergency Procedures Drill

Pursuant to PJM Manual 13, PJM conducts emergency procedure drills prior to every summer and winter that include PJM, Generation Owners and Transmission Owners, and are focused on capacity shortage events. The drill encourages all entities to be familiar with the required actions and communications required for each emergency procedure, up to and including load shed action, as specified in PJM Manual 13, Emergency Operations.

On Nov. 3, 2022, PJM conducted the 2022 Winter Emergency Procedures Drill, testing established procedures for capacity shortages in accordance with conservative operations. Participants included PJM Operations, Dispatch staff and personnel from PJM Corporate Communications/State Government Policy, Local Control Centers and Market Operations Centers.

[1] NERC is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. NERC develops and enforces NERC Reliability Standards, which define the reliability requirements for planning and operating the North American bulk power system.
[2] Cold Weather Advisory Process, PJM System Operations Subcommittee, Dec. 2, 2022.

The following emergency procedures were implemented in the simulation stage of the drill: Cold Weather Alert, Low Voltage Alert, Maximum Generation Emergency Alert, Unit Startup Notification Alert, Primary Reserve Alert, and a Voltage Reduction Alert. All emergency procedure warnings and actions were issued as part of the drill to encourage participants to properly notify government agencies and to exercise internal communications for each member company.

Information about the drill scenario is contained in a packet sent to external participants and in a script for PJM staff. PJM also offers an eLearning module each year in support of the drill. This online training course, available via the PJM Learning Management System on the PJM website, provides an overview of the emergency procedures that participants may encounter during the drill exercise.

The plans for the drill are reviewed at the Dispatcher Training Subcommittee (DTS), the SOS and the OC.

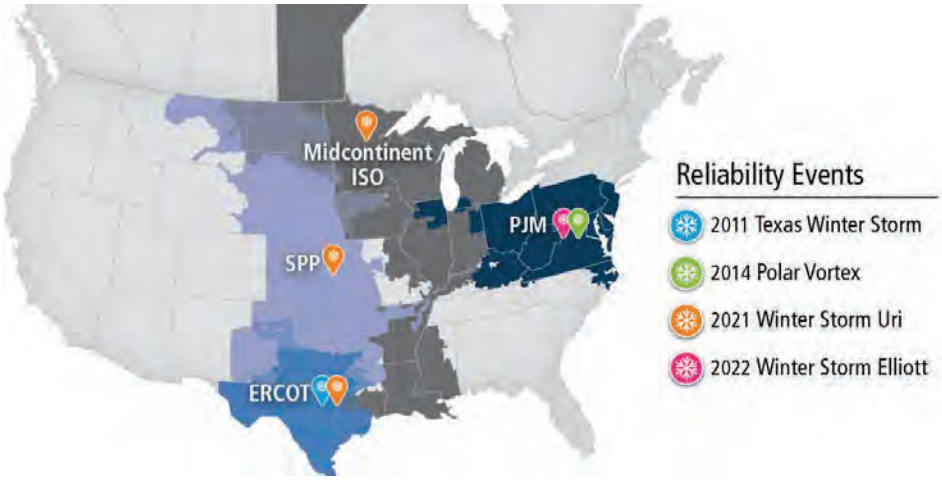
Reliability Analysis Used in the Capacity Market

PJM performs several reliability studies that inform the clearing of the capacity market.

- Installed Reserve Margin (IRM) Study – Study run by PJM that determines the amount of reserves beyond the peak load necessary to maintain a Loss of Load Expectation (LOLE) of one event in 10 years
- Capacity Emergency Transfer Objective (CETO)/Capacity Emergency Transfer Limit (CETL) Studies – Studies run by PJM to determine if the transmission system is capable of delivering enough energy to Locational Deliverability Areas (LDA) to meet reliability targets
- Accreditation – Calculation performed by PJM to determine how much capacity a resource can sell as a percentage of its nameplate capacity

These studies all assume that the reliability risk PJM may face aligns with peak loads, which typically occur in the summer. The assumption behind coinciding reliability risk with peak loads is that if enough capacity is scheduled for the expected peak load, it will also be sufficient for all other hours in the year. However, recent history in PJM and other RTO/ISOs indicates that reliability risk also occurs outside of the peak load and may be trending away from the peak to something else. Figure 3 presents the recent reliability events outside the peak load periods.

Figure 3. Recent Reliability Events



Finding the causes behind these events is important to determine how PJM's reliability risk modeling may need to be adjusted to better capture the likelihood, severity and patterns of risk. PJM and stakeholders are already working on identifying and modeling these new risks.

PJM Winter Readiness Meeting

PJM also conducts an internal, cross-divisional meeting each fall to review each PJM department's preparedness for winter operations. It includes discussions and presentations by PJM's Operations, Markets and Planning divisions. The following topics are addressed in these cross-divisional meetings:

- Weather and load forecast outlook
- Review of winter OATF study (including base case parameters, peak load study results and sensitivity studies)
- Potential gas/electric concerns for upcoming peak period
- Interconnection projects update (including key project upgrades and delays, generation additions and retirements, review of additional reactive resources coming online, generation preparation, outage and performance updates)
- Review of NERC Standard FAC-014, Requirement 6, list of multiple facility contingencies (if any) that result in stability limitations
- Review of any specific concerns or questions from PJM's Dispatch, Reliability Engineering and Markets personnel

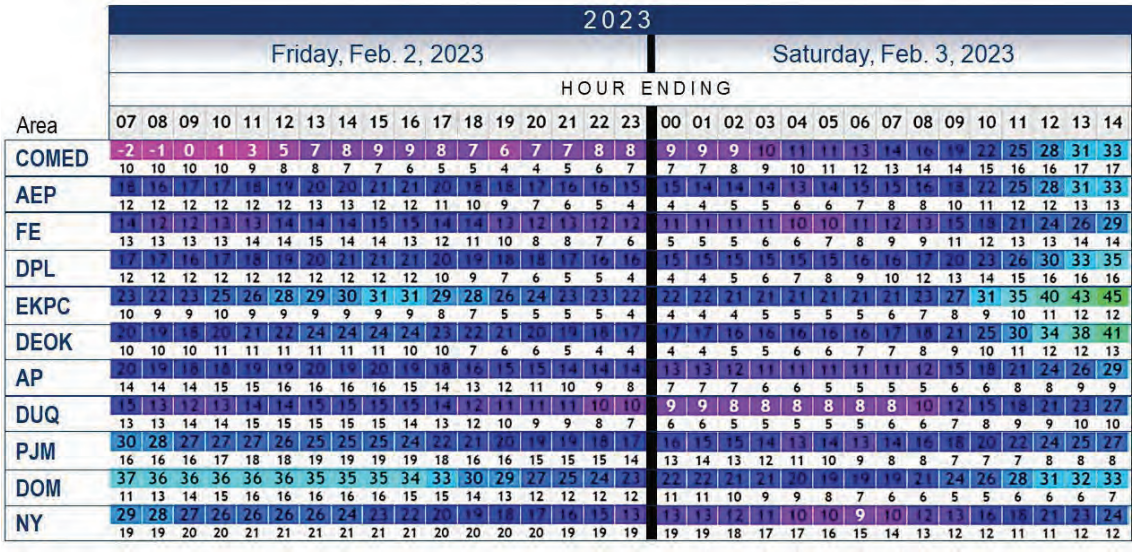
Preparations Ahead of Winter Storm Elliott

In preparation for Winter Storm Elliott, PJM performed the established load forecast planning process, issued Advisories and Alerts, and coordinated activities with both the adjacent systems and the natural gas industry. PJM also planned for the commitment of resources needed to meet the Dec. 23 and Dec. 24 operating days' demand and reserve requirements.

Load Forecast Planning Process

PJM uses a vendor tool to view forecast weather conditions up to 14 days out. At six days out, PJM begins to receive hourly weather forecast data from three separate vendors for 28 weather stations dispersed throughout the PJM region. This data is visualized in a heat map tool used by PJM system operators and engineers. Figure 4 presents a sample of the heat map tool for Feb. 2 and Feb. 3, 2023. This is an example of a wintertime heat map and does not present the actual temperatures from Winter Storm Elliott.

Figure 4. PJM Heat Map Tool Example



PJM's forecast team and Dispatch leadership also receive detailed weather forecast reports from vendors at various time horizons warning of extreme weather conditions. The PJM forecast team reviews and synthesizes data from all of these sources and delivers daily verbal reports on upcoming weather at the daily Dispatch morning meeting. The PJM forecast team supplements this communication with email summaries and dialogue with PJM system operators.

The load forecast is first performed six days out using a performance-weighted average of the three weather vendor forecasts as inputs. A suite of models trained on three years of historical data generate separate load forecasts that are then combined into one ensemble forecast using another weighted average system. Both the ensemble forecast and individual model forecasts are updated each hour as load actuals and updated weather forecast data is received.

To create the next-day load forecast, PJM Operations support staff reviews weather conditions and recent load forecast performance each day, then integrates this information with known strengths, weaknesses and biases of each model to identify adjustments to the forecast. The support staff then communicates the recommended adjustments to Dispatch, and the two groups collaborate to finalize the forecast. Extra attention is given to holidays, where the models have increased forecast error due to closures of schools and businesses and altered human behavior. Starting at least two days out, the team analyzes model error and weather conditions from that holiday in previous years, then calculates adjustments to counter repeated model biases.

The relationship between load and temperature can change with time, as behind-the-meter solar, data centers, and new types of appliances are connected to the system. PJM monitors these changes, continually evaluates load patterns to assess impacts, and retrains and enhances the models, as needed. Staff analyzed electric heating statistics from the Energy Information Administration and determined that there does not appear to be a significant transition to electric heating in the PJM footprint that would have caused under-forecasting of winter load.

The PJM Operations staff conducted the following load forecasting activities in advance of the Winter Storm Elliott event:

Date	PJM Team	Activity
Mon. Dec. 19:	Forecast	• Alerted PJM Dispatch of upcoming blizzard conditions and extreme cold via email • Met to discuss holiday forecasts (with extra support from other staff)
Tues.–Fri. Dec. 20–23	Forecast	• Delivered verbal updates on approaching storm risks at the daily Dispatch morning meeting
Wed.–Fri. Dec. 21–23	Forecast	• Provided on-site support, meeting daily with dispatchers to support adjusting the forecast
Thurs. Dec. 22	Dispatch + Forecast	• Collaborated on the load forecast for Dec. 23, increasing the peak forecast to 127,000 MW from the original forecast of 124,600 MW
	Forecast	• Created the preliminary forecast for Dec. 24 with a maximum peak of 124,000 MW
Fri. Dec. 23	Dispatch + Forecast	• Collaborated on load forecast for Dec. 24

Date	PJM Team	Activity
	Forecast	• At the time of the forecast's creation, the actual load on Dec. 23 was coming in lower than the forecast. When the team began assessing the forecast for Dec. 24, they observed that the actual load was coming in lower than the previous day's forecast. This led the team to determine that holiday impacts were causing the load to come in low and that effect would persist into Dec. 24. • The PJM forecast team created the preliminary load forecast for Dec. 26.
Sat.–Mon. Dec. 24–26	Forecast	• Continued to provide load forecasting guidance and support to Dispatch

Emergency Procedures Issued and Actions Taken in Advance of Operating Day

PJM is responsible for determining and declaring that an emergency is expected to exist, exists or has ceased to exist in any part of the PJM RTO or in any other Control Area that is interconnected directly or indirectly with the PJM RTO. PJM directs the operations of the PJM members, as necessary, to manage, allocate or alleviate an emergency. PJM also is responsible for transferring energy on the PJM members' behalf to resolve an emergency, as well as executing agreements with other Control Areas interconnected with the PJM RTO for the mutual provision of service to meet an emergency.

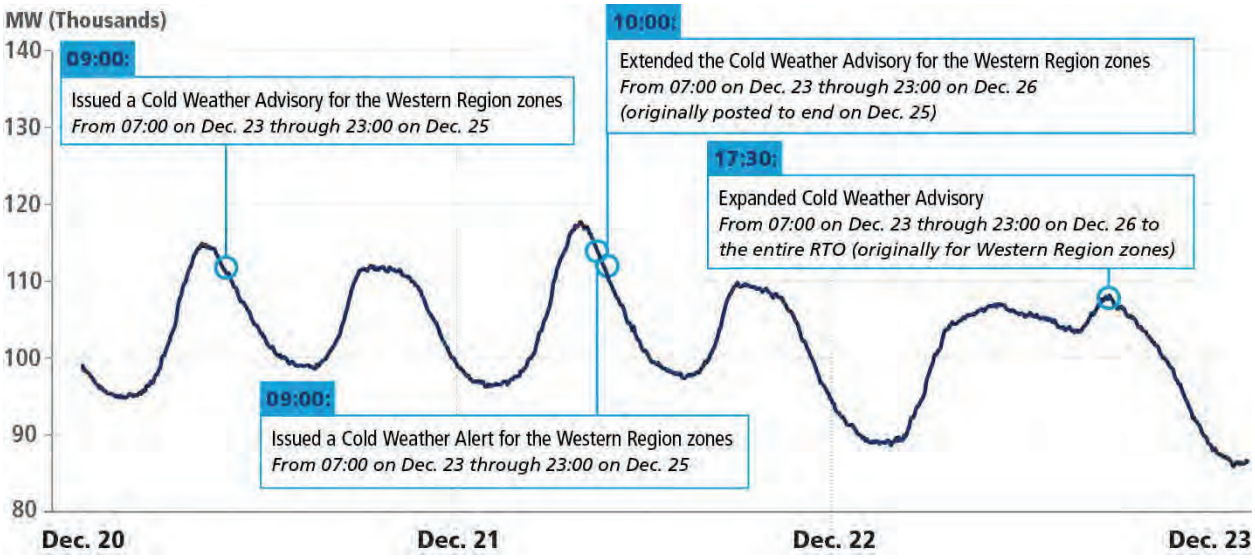
As described in PJM Manual 13, Section 2.3, PJM has established three emergency procedure levels for capacity shortages, as well as an advisory level.

Figure 5. Emergency Procedure Levels



To maximize PJM's ability to operate reliably during periods of extreme and/or prolonged severe weather conditions, procedures are necessary to keep all affected system personnel aware of the forecast and/or actual status of the system and to promote the maximum levels of resource availability are attained. PJM issued both advisories and alerts in the days leading up to Dec. 23 and Dec. 24, as presented in Figure 6:

Figure 6. Cold Weather Alerts and Advisories for Dec. 23 and 24



PJM initiated the following steps in advance of the Dec. 23 and Dec. 24 operating days:

- At 09:00 on Dec. 20, PJM issued a Cold Weather Advisory for the Western Region zones from 07:00 on Dec. 23 through 23:00 on Dec. 25. Members are to take any necessary precautions to prepare generating facilities for cold weather operations, including the following actions:
- Erecting temporary windbreaks or shelters, positioning heaters, verifying heat trace systems, or draining equipment prone to freezing
- Updating Markets Gateway by entering unit-specific operating limitations associated with cold weather preparedness (i.e., generator capability and availability, fuel supply and inventory concerns, environmental constraints)
- At 09:00 on Dec. 21, PJM issued a Cold Weather Alert for the Western Region zones from 07:00 on Dec. 23 through 23:00 on Dec. 25. At 10:00 on Dec. 21, PJM also extended the Cold Weather Advisory for the Western Region zones from 07:00 on Dec. 23 through 23:00 on Dec. 26. The purpose of a Cold Weather Alert is to prepare personnel and facilities for expected extreme cold weather conditions. PJM generally issues a Cold Weather Alert when the forecast weather conditions approach minimum or actual temperatures of 10 degrees Fahrenheit or below. PJM can initiate a Cold Weather Alert at higher temperatures if PJM anticipates increased winds or if PJM projects a portion of gas-fired capacity is unable to obtain spot market gas during load pick-up periods. When a Cold Weather Alert is issued, members are to perform the following actions:
- Update their unit parameters, including the Start-up and Notification, Min Run Time, Max Run Time, Eco Min, Eco Max, etc., in Markets Gateway.

- Report to PJM Dispatch any resource limited facilities, as they occur, via Markets Gateway.
- Determine whether alternate fuel will be made available to PJM for dispatch. If made available, any known alternate fuel resource limitations will be communicated via Markets.
- Based on direction received from PJM, call in or schedule personnel in sufficient time to ensure that all combustion turbines and diesel generators that are expected to operate are started and available for loading when needed for the morning pick up.
- At 17:30 on Dec. 22, PJM expanded its Cold Weather Advisory from 07:00 on Dec. 24 through 23:00 on Dec. 26 for the entire RTO. Given the expected weather, PJM was very prudent in developing the operating plans for Dec. 23, as presented throughout this section.

Figure 7 presents the expected member actions for the Advisories and Alerts that were issued in advance of the Dec. 23 and Dec. 24 operating days:

Figure 7. Expected Member Actions for Advisories and Alerts for Dec. 23 and Dec. 24

Dec. 20, 2022

Cold Weather Advisory for Western Region From Dec. 23–26 (Later Expanded to Entire RTO)

- Prepare to take freeze-protection actions, such as erecting temporary windbreaks or shelters, positioning heaters, verifying heat trace systems, or draining equipment prone to freezing.
- Review weather forecasts, determine any forecasted operational changes, and notify PJM of any changes.
- Members are to update PJM with operation limitations associated with cold weather preparedness. Operating limitations include: generator capability and availability, fuel supply and inventory concerns, fuel switching capabilities, environmental constraints, generating unit minimums.

Dec. 21, 2022

Cold Weather Alert Issued for the Western Region for Dec. 23–26 (Later Expanded to Entire RTO)

- Generation dispatchers review fuel supply/delivery schedules in anticipation of greater-than-normal operation of units.
- Generation dispatchers monitor and report projected fuel limitations to PJM dispatcher and update the unit Max Run field in Markets Gateway if less than 24 hours of run time remaining.
- Generation dispatchers contact PJM Dispatch if it is anticipated that spot market gas is unavailable, resulting in unavailability of bid-in generation.

Coordination With Adjacent Systems

In addition to its internal preparations for peak conditions, PJM also coordinates with adjacent systems prior to possible emergency conditions. This coordination can occur through the regional reliability entity responsible for compliance with NERC standards in that region or with the neighboring entity itself.

PJM participates in a daily morning conference call with adjacent systems at 03:30 during which peak load estimates, reserve requirements and estimated loads are discussed. Participants on the call include Tennessee Valley Authority (TVA), Virginia-Carolina (VACAR), Midcontinent Independent System Operator (MISO), PJM and Florida Reliability Coordinating Council (FRCC). There is also a call at 05:00 that PJM conducts with NYISO and a daily call at 08:00 with MISO. Load projections, reserves and anticipated daily challenges are discussed on these calls as well.

During the aforementioned calls, expected conditions were reviewed, and load projections and expected reserve quantities were shared. Members of the Northeast Power Coordinating Council (NPCC), the regional reliability entity for New York ISO (NYISO), ISO New England (ISO-NE), Independent Electricity System Operator (IESO), the Canadian Maritimes, and New Brunswick Power, were anticipating large temperature drops from the incoming arctic air mass and temperatures to be in the single digits. Council members coordinated anticipated operating conditions from multiple transmission facilities that tripped from previous ice storms that had impacted Canadian entities. These transmission facilities limited the entities' ability to export energy to adjacent areas. Members of the NPCC were anticipating tight operating conditions from the reduction of imports and anticipated higher loads from the incoming arctic air mass and agreed to conduct further calls and coordination throughout the duration of the storm.

PJM also met with SERC Reliability Corporation members to review expected conditions and share information to prepare for the event. SERC members were in close coordination throughout the event as well. The FRCC issued conservative operations on Friday, Dec. 23. TVA was managing capacity concerns as they lost units over the midnight period from extreme cold conditions. TVA declared conservative operations on Dec. 23 and EEAs up to an EEA 3 at 05:12 on Dec. 23. Southwest Power Pool (SPP) issued a cold weather advisory along with a resource advisory. On Dec. 23, SPP set a new winter peak of 47, 214 MW. Its previous winter peak was 43,661 MW.

PJM met with MISO to prepare for the event. MISO was monitoring the Arctic air mass forecasted to move into the footprint beginning Dec. 21 and Dec. 22 that was pushing temperatures below normal. MISO was not anticipating any capacity or reliability concerns.

MISO's Outage Coordination Team was evaluating all planned transmission outages, in the event some may need to be delayed due to the cold temperatures. MISO continued to closely monitor the numerous gas pipelines' cold weather notices, and Operational Flow Orders (OFOs) for any potential impact to generation. MISO declared a maximum generation warning for its southern region on Dec. 23 from 09:15 until 13:00 as well as for its entire footprint from 17:30 to 22:00 EST on Dec. 23. PJM had two coordination calls with MISO on each day of the event to exchange information, one at 03:30 and one at 08:00.

The Southern Company Balancing Authority declared an EEA 1 at 01:09 and EEA 2 at 05:33 due to lower-than-optimal generation reserves. The Southern Company Balancing Authority received 1,000 MW of emergency energy from Florida Power & Light and 100 MW of emergency energy from MISO.

As described later in this report, PJM coordinated extensively with TVA throughout the event to coordinate interchange transactions and system conditions. PJM ran studies to simulate additional interchange being exported to its neighbors. PJM will continue to participate in seasonal assessments and preparedness with its neighbors and seek opportunities to enhance coordination with neighbors.

Coordination With Natural Gas Industry

Prior to each winter season, PJM, along with fellow members of the ISO/RTO Council Electric Gas Coordination Task Force, meet with the pipeline industry to review the upcoming winter and discuss mutual preparedness activities.

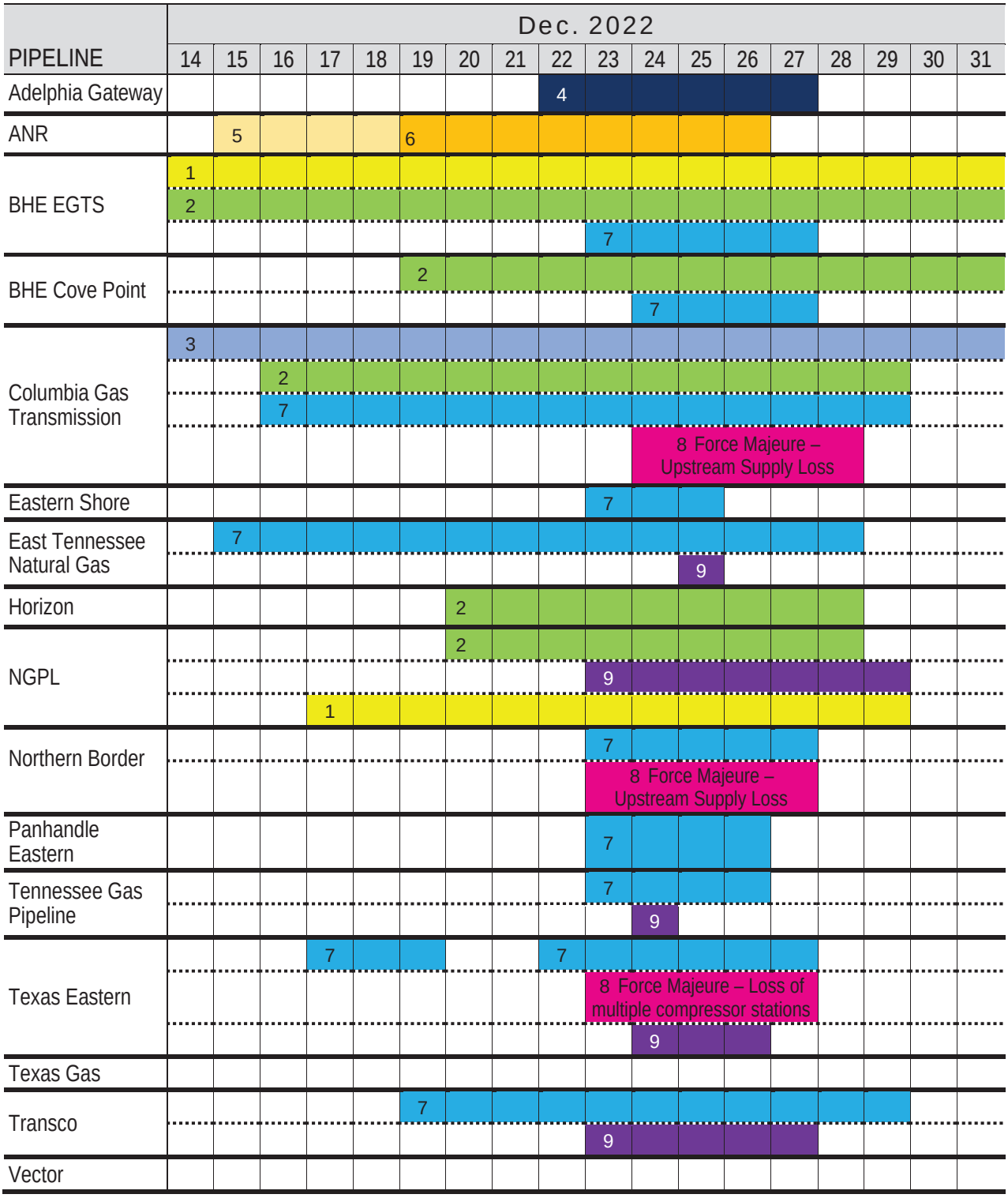
In addition to daily team meetings to review pipeline conditions and operational impacts, the PJM Gas-Electric Coordination Team conducts weekly operational calls during the winter months (November through March) with all of the major interstate natural gas pipelines within the PJM service territory. These interstate pipelines serve generation resources directly and also serve local gas distribution companies (LDCs), which in turn serve a smaller subset of PJM generators behind the LDC citygates. The purpose of these calls is to assess mutual system conditions. This includes reviewing load forecasts for both the electric and gas systems, any system outages that might impact service to

generators, active and pending pipeline capacity restrictions, and any gas generation pipeline nomination anomalies. As a result of FERC's issuance of Order 787, PJM established a Memorandum of Understanding (MOU) with nine of the major pipelines in 2015 and has individual agreements in place with the majority of pipelines and multiple LDCs. During critical gas pipeline capacity-constrained periods, LDCs have the ability to interrupt gas supply to certain gas-fired generators that are served behind the LDC citygates as generators are served at a lower priority level than core residential customers that are considered human needs customers. As such, it is important for PJM to understand when those generators may be interrupted, and for those generators subject to interruption to effectively communicate that information to PJM in a timely manner.

With respect to gas-electric coordination activities leading up to Winter Storm Elliott, these calls with the pipelines began early in the week immediately preceding the impacts of Elliott, and at that point, most of the pipelines had provided notification on their electronic bulletin boards announcing various cold weather alerts and system restrictions. This was in the form of OFOs and Ratable Take Requirements. OFOs are issued to enforce daily balancing rules requiring customer imbalances (difference between nominated gas volume and burned gas volume) to stay within a certain tolerance percentage. Ratable Take Requirements mandate that customers deliver and burn their gas at uniform hourly rates. Pipelines take these actions to mitigate large swings in system pressures. These restrictions gradually increased throughout the week, and by Friday morning, all pipelines had active notices of varying degrees. Operationally, all pipelines appeared to be well prepared for the cold, and even on the morning of Friday, Dec. 23, reports from the pipelines indicated that line pack was high, systems were ready and that load had not yet begun to pick up significantly, particularly in eastern zones.

Figure 8 provides a summary of the pipeline restrictions that were in place from Dec. 14 through Dec. 31.

Figure 8. Interstate/Infrastructure Pipeline Restrictions



	Pipeline Notice
1	Restrictions on Non-Firm Contracts Customers with interruptible transportation contracts at higher risk of not being able to schedule adequate pipeline capacity
2	Ratable Take Requirement Pipeline requiring customers to supply and burn gas at uniform hourly rates to avoid excessive pressure fluctuations
3	Critical Day (Transport Deliveries/Storage Withdrawals) Pipeline requiring customers to stay within their transportation and storage contractual requirements
4	Action Alert (Daily Balancing) Requires customers to ensure that their supply and demand is balanced at the end of each 24-hour gas day within the tolerances provided by the pipeline Tariff provisions
5	Phase 1 Cold Weather Advisory Alerting customers of pending cold temperatures and tightening system conditions
6	Phase 2 Cold Weather Extreme Conditions Requires customers to abide by their specific contract and rate provisions and to burn gas on a uniform hourly basis as their contracts direct; interruptible contracts at greater risk of having service cut
7	Daily Balancing OFO Requires customers to ensure that their supply and demand is balanced at the end of each 24-hour gas day within the tolerances provided by the pipeline Tariff provisions
8	Force Majeure Declared when there an event outside of the pipeline's control occurs that may render service unavailable to certain customers regardless of contractual arrangements (e.g., loss of compressor station)
9	Loss of Upstream Supply As a result of less gas coming into the pipeline due to upstream supply failures, pipelines provide notice that risk of downstream pressure loss and customer nomination cuts are increasing.

On the gas commodity supply side, nearly all of the natural gas consumed by generation in PJM originates in the Marcellus and Utica shale in the Appalachian region. Historically, loss of supply due to gas production well freeze-offs during cold snaps has not been as severe as compared to gas basins in the south central and southwestern United States. This was confirmed during outreach with a sample of producers after Winter Storm Uri in February 2021. While Uri did not have a major direct impact on PJM, there was a desire to get out ahead of the issues to determine if the supply losses experienced during Uri could occur in the Appalachian region. The feedback from those producers indicated that gas production and midstream processing and transport were much more hardened against cold temperatures compared to the same facilities in the south and southwest. Typical losses due to well freeze-off conditions range from around 2 to 3 Bcf (billion cubic feet) per day in the Appalachian region and this was the general assumption going into Elliott. In the end, the actual supply loss was closer to 10 Bcf, which significantly challenged the ability for natural gas-fired resources to procure fuel, likely leading to a portion of the outages on these resources.

It is important to note that while PJM coordinates with the natural gas industry prior to and during events such as Winter Storm Elliott, the tools used by PJM system operators to commit and dispatch resources relies on the availability and

offer data submitted for each generator. If the generator availability and offer data is not consistent with the resource's true capability, PJM operators are left with an inaccurate view of the true capability of the fleet.

Day-Ahead Market and Reliability Assessment Commitment Results

The PJM Energy Market consists of two markets: a Day-Ahead Market and a Real-Time Market. Two days prior to an operating day, PJM begins to set up the conditions, such as the expected outages and conditions for the operating day, in the model for the Day-Ahead Energy Market. (The two-settlement market mechanism is described in more detail in Appendix A.)

The Day-Ahead Market is cleared so that the cost to serve demand (physical and virtual) is minimized, while respecting the physical operating limits of the transmission system. Commitments in the Day-Ahead Market are financially binding on participants. Any differences between day-ahead commitments and what occurs in the operating day is addressed in the Real-Time Market. The PJM Day-Ahead Market utilizes the bid-in load from the Load Serving Entities, as well as virtual bids from Market Participants.

Capacity resources are required to offer into the Day-Ahead and Real-Time markets with accurate reporting of their availability and unit parameters, which include but are not limited to, start time, ramp rate, and minimum output and maximum output. In addition, resources can and do update their offers in both of these markets to reflect their actual fuel and operating costs.

For each operating day, PJM performs reliability analysis and develops an operating plan. PJM performs two reliability analyses a day ahead of the operating day. The first analysis, performed by the PJM reliability engineers, is an input into the PJM Day-Ahead Market performed prior to closing at 11:00. The second reliability analysis, called Reliability Assessment Commitment (RAC), is performed after the Day-Ahead Market clears and includes the commitments made in the Day-Ahead Market. After 16:15, PJM begins the RAC run, which commits adequate generation to meet the PJM forecasted demand plus reserves, while minimizing start-up and no-load cost. The focus of this commitment is reliability, and the objective is to minimize start-up and no-load costs for any additional resources that are committed. Using the most up-to-date weather forecast, load forecast, transmission facility and generator availability, and other information, PJM commits additional generation, if necessary, to satisfy both expected loads and the needed reserves for the operating day. This includes scheduling additional resources during the operating day that did not have a Day-Ahead Market commitment. PJM scheduled 4,411 MW of combustion turbines (CTs) between Dec. 23 and Dec. 24.

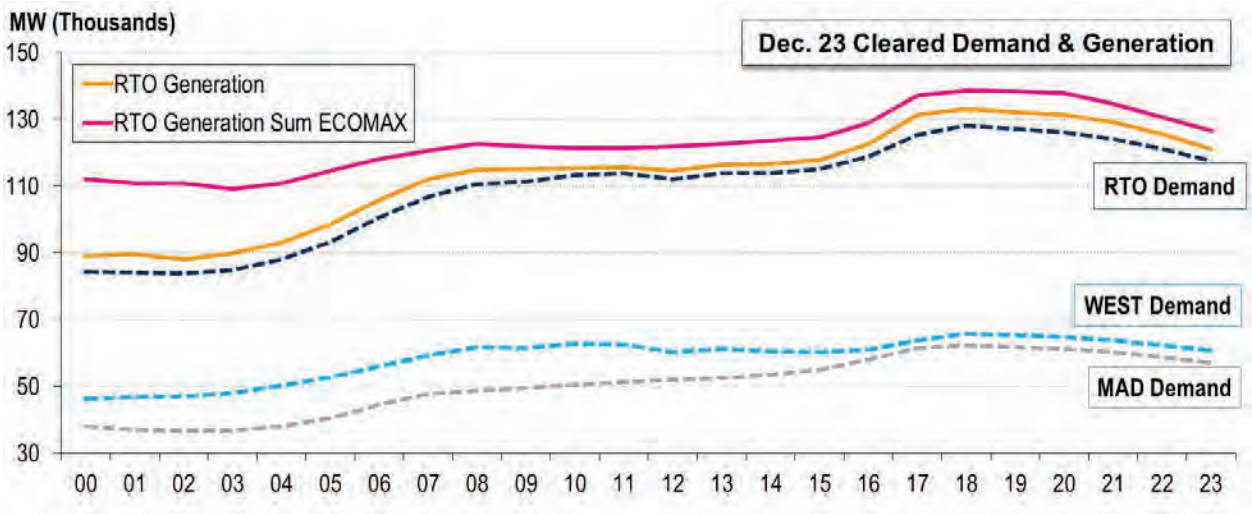
PJM also performs additional reliability analysis to confirm transmission facilities are operated within their equipment limits when committing generation. During severe winter weather events, PJM communicates extensively with both Generation Owners and gas pipeline operators to adequately understand the likelihood that natural gas-fueled generators are able to procure the gas needed to operate. PJM may perform additional resource commitment runs, as necessary, based on updated PJM load forecasts and updated resource availability information. It is important to note that these resource commitment runs use available offer data submitted into Markets Gateway by Generation Owner/operators. If the offer information is not accurate, the commitment results and operating plan PJM develops may be inadequate. Following these commitment runs, PJM sends out individual generation commitment updates to specific Generation Owners only.

The outcome of all of these processes is a set of resource commitments expected to be able to maintain reliability during the operating day.

Dec. 23

PJM's Dec. 23 operating day plan was prudent, given the expected. PJM scheduled the system such that almost 29,000 MW of reserve capacity was available to meet load and generation contingencies, and to support neighboring systems, according to the information submitted by Market Participants. Figure 9 presents the cleared day-ahead demand, and the generation committed to meet that demand, plus reserves for Dec. 23 operating day.

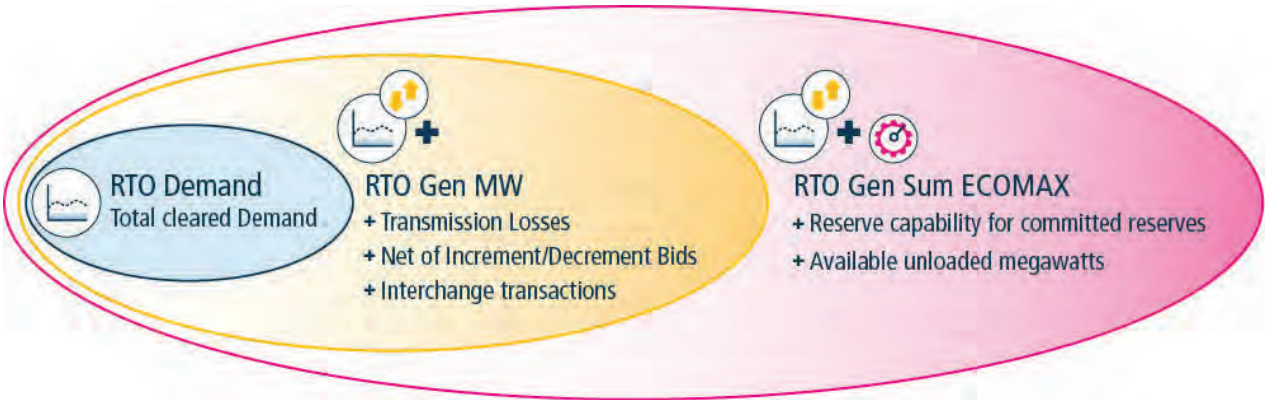
Figure 9. Dec. 23 Cleared Demand and Generation from Day-Ahead Market



In Figure 9:

- RTO Demand is the total cleared demand in the Day-Ahead Market, which includes fixed demand and cleared price-sensitive demand. The RTO Demand is not the same as the PJM Load Forecast.
- RTO Gen MW is the total generation megawatts loaded (or cleared) in the Day-Ahead Market. It includes all cleared generation. This value is greater than the RTO Demand because it accounts for transmission losses, the net of increment and decrement bids, and interchange transactions in or out of the PJM Balancing Authority.
- RTO Gen Sum ECOMAX is the total sum of all online generation resource's economic maximums committed in the Day-Ahead Market. This value is larger than the RTO Gen MW because it includes reserve capability for committed reserves and unloaded megawatts not explicitly needed in the clearing process but are available due to the mix of resources committed in the Day-Ahead Market.

Figure 10. Cleared Demand & Generation Representation



For the Dec. 23 operating day, the Day-Ahead Market committed 133,165 MW of generation for energy (yellow line in Figure 9), with 5,474 MW of unloaded generation (magenta line in Figure 9), including approximately 11,000 MW of combustion turbines (CTs) scheduled economically and 1,270 MW committed for reliability purposes to control constraints. PJM also scheduled an additional 3,168 MW in the RAC runs. In addition, there was another approximately 16,000 MW in CTs available for dispatch in real time that were not committed in the Day-Ahead Market.

Entering the operating day on Dec. 23, PJM had approximately 158,000 MW of operating capacity with a projected peak load of around 127,000 MW. Based on the Day-Ahead Market results, PJM did not anticipate the need to run a significant amount of additional CTs on Dec. 23 or Dec. 24. However, as more and more generating resources started to report their unavailability to PJM during the evening peak on Dec. 23 and through the early morning hours of Dec. 24, PJM Dispatch began scheduling additional CTs to come online.

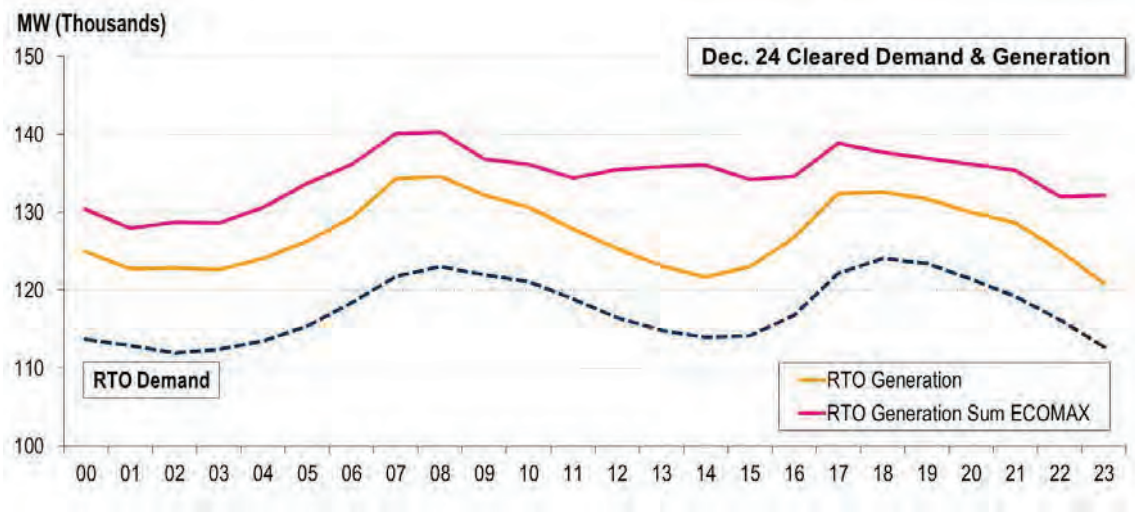
As early as Dec. 20, generation resource operating limitations and minimum operating, design or performance temperature were submitted to PJM in advance of the cold weather event after PJM declared a Cold Weather Advisory. All of the generator-submitted data was taken into consideration, with PJM forecasting a significant surplus of generation leading into the Dec. 23 operating day. This included accounting for a historical average of generator forced outages through cold weather events. As such, PJM did not declare a Unit Startup Notification Alert or commit any long lead generation or recall maintenance outages to meet capacity forecasts. As described in the Operating Day section of this report, in 92% of cases where generators failed to perform, PJM either had little or no notice, and very few resources provided updated parameters to reflect fuel supply constraints or other unit issues.

Dec. 24

Prior to the operating day of Dec. 24, PJM issued a Cold Weather Advisory on Dec. 20 for the period of Dec. 23 to 26. PJM then issued a Cold Weather Alert for the entire RTO on Dec. 23, effective for Dec. 24. The operating plan for Dec. 24 was updated based on operating conditions experienced on Dec. 23. Load forecasts were updated, and unit commitments' needs were updated based on generating resources that experienced forced outages throughout the day on Dec. 23.

Figure 11 presents the cleared day-ahead demand and committed generation to meet that demand, plus reserves for the Dec. 24 operating day.

Figure 11. Dec. 24 Cleared Demand & Generation from Day-Ahead Market



For Dec. 24, the Day-Ahead Market committed 134,615 MW of generation for energy (yellow line in Figure 11), with an additional 5,672 MW of unloaded generation (magenta line in Figure 11). PJM committed resources based on the RAC runs and for reliability. PJM also committed additional resources, based on unit availability and other parameters in Markets Gateway. In total, approximately 6,000 MW of additional capacity for Dec. 24 was committed, beyond what was committed in the Day-Ahead Market, to support the anticipated loads and reserve requirements. In addition, there were another 9,500 MW in CTs available for dispatch in real time, as communicated by generators to PJM. This results in a total of approximately 155,700 MW in operating capacity for Dec. 24.

PJM system operators knew that there was going to be uncertainty in the load forecast as a result of the extreme weather. In addition to accounting for weather and load uncertainty, PJM scheduled additional reserve resources in anticipation of generator failures. Generation failures often increase somewhat during bitter-cold conditions – recent history indicates on the order of 5% to 10%. On Dec. 24, several generating resources were committed in the Day-Ahead Market but were not available in the operating day due to forced outages. The decision was therefore made to operate prudently by scheduling additional reserves. Generation performance, including generation resources that were committed in the Day-Ahead Market but were not available in the operating day, is presented in the Operating Day section of the report.

Utilizing these commitments, as well as the generator parameters of units that did not have Day-Ahead Market commitments, but were reporting to PJM as available with short notice, PJM anticipated that approximately 155,700 MW of generation would be available for Dec. 24.

Operating Day

The Operating Day section of the report details the events and actions PJM initiated during the operating days of Dec. 23 and Dec. 24 to maintain reliability and not shed load. It describes the emergency procedures issued and actions taken, the public Call for Conservation, the Disturbance Control Standard event, as well as the generation and Demand Response performance, real-time interchange, and gas availability issues.

On Dec. 23 and Dec. 24, PJM remained reliable, was able to serve its customers, and was able to support neighboring areas to the south and minimize the amount of load shed in these external areas. PJM reliably met the demand on both

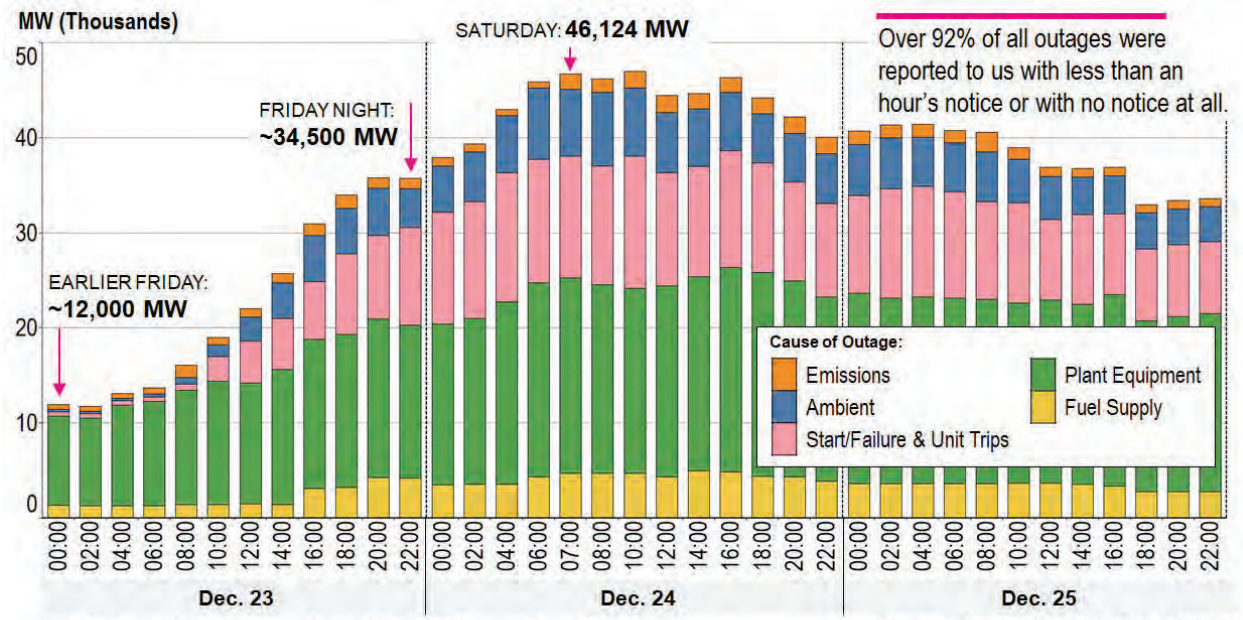
Dec. 23 and Dec. 24 by employing several emergency procedures and utilizing market signals to incent response from the supply and demand side resources. Although the 136,010[3] MW peak load on the evening of Dec. 23 was not one of PJM's top 10 peak winter load days, it essentially matched the forecasted 50/50 peak load for the 2022/2023 winter season (approximately 25,000 MW above an average winter day).

As described in the Advanced Planning section, going into the Dec. 23 operating day, PJM had over 158,000 MW of operating capacity with a projected peak load of around 127,000 MW, resulting in over 30,000 MW of reserves. Based on the Day-Ahead Market results, PJM did not anticipate the need to run a significant amount of additional generation on Dec. 23 or Dec. 24. However, as more and more generating resources started to report their unavailability to PJM during the evening peak on Dec. 23 and through the early morning hours of Dec. 24, PJM Dispatch began scheduling additional generators to come online.

Emergency Procedures Issued and Actions Taken During Dec. 23 and Dec. 24

As the extreme cold front moved into the PJM region throughout Dec. 23, the load shape looked more like a summer day, with a lower morning valley that ramped up throughout the day. Coincident with the increasing demand, PJM began experiencing rapidly increasing levels of forced generation outages, as shown in Figure 12. Additional information on generation performance is presented in later in this section.

Figure 12. Forced Outages by Cause



Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

Source: GADS as of March 1, 2023. Wind and solar unit outages are not included in the data.

The conditions of Winter Storm Elliott led to PJM requesting the loading of Synchronized Reserve generation on five separate occasions during Dec. 23 and Dec. 24. Four of these events were called in response to a low Area Control Error (ACE) caused by increasing load and generation tripping and start failures. One of the events was called in direct response to the loss a generating unit. Five Synchronized Reserve Events over a two-day period is extremely unusual. All five of the events on Dec. 23 and Dec. 24 exceeded 10 minutes in duration, which is again extraordinary. Since the start of 2021, there have been 47 Synchronized Reserve Events, of which only 17 (36%) were more than 10 minutes in

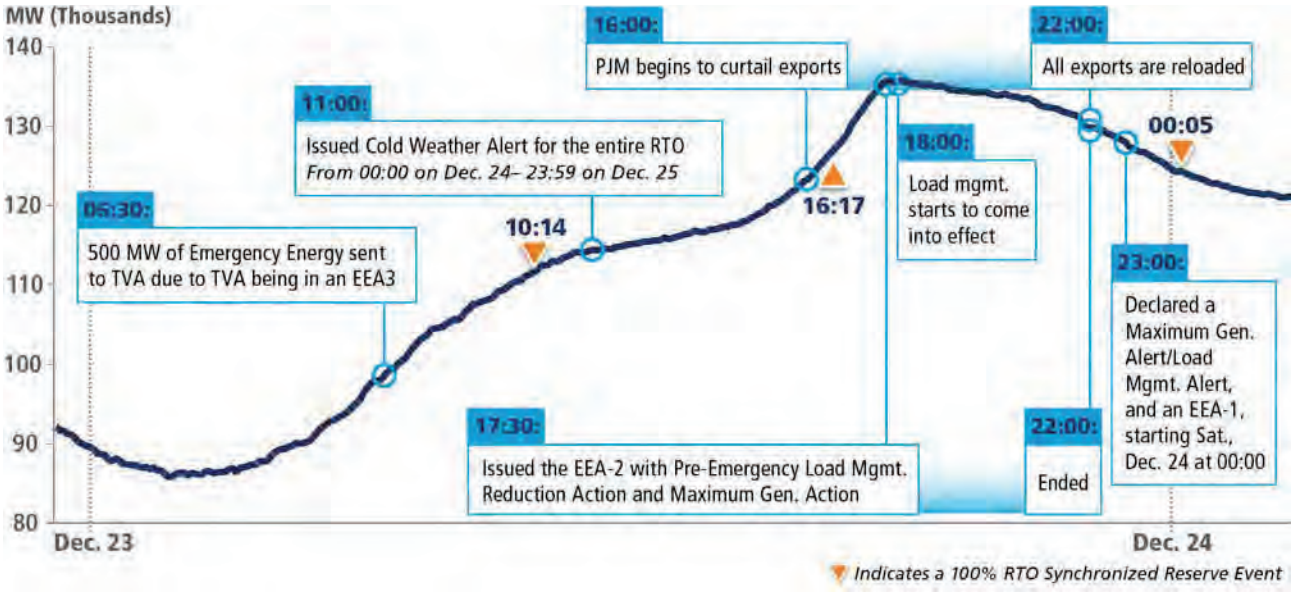
[3] The Dec. 23 peak of 136,010 MW incorporates Demand Response as part of the total.

duration, and five of these 17 occurred during Winter Storm Elliott. Additional information on Synchronized Reserve Events and Reserve performance is presented in the Markets Outcomes section of this report.

Dec. 23

PJM system operators initiated several actions on Dec. 23 as load continued to increase. Figure 13 presents the PJM emergency procedures initiated, as well as the PJM load and the Synchronized Reserve Events, for Dec. 23.

Figure 13. Dec. 23 Emergency Procedures



Early in the morning on Dec. 23, PJM was exporting energy to adjacent areas and tracking under the load forecast. At 06:30, PJM provided 500 MW of emergency energy to TVA, who had issued a NERC Energy Emergency Alert Level 3 (EEA3), which is issued when the Balancing Authority, in this case TVA, is unable to meet the minimum contingency reserves requirements. At 10:00 on Dec. 23, PJM conducted an SOS-Transmission call to inform Transmission Owners of anticipated system conditions and the operating plan for the day.

	Dec. 23 HE 05
Outages	13,449 MW
Interchange	7,517 MW
Load	88,237 MW

At 10:14 on Dec. 23, PJM deployed Synchronized Reserves to recover low ACE caused by increasing load combined with generation resources tripping offline and failing to start. At this time, total PJM reserves were approximately 1,500 MW. At 11:00 on Dec. 23, PJM issued a Cold Weather Alert for the entire RTO from 00:00 on Dec. 24 through 23:59 on Dec. 26.

Beginning around 14:00 on Dec. 23, generation continued to trip or fail to start at a rate of approximately 1,800 MW per hour. This posed a challenge for PJM's ability to deliver exports to neighbors. During this period, the operational situation was strained for a number of reasons:

	Dec. 23 HE 13
Outages	24,032 MW
Interchange	8,283 MW
Load	115,048 MW

- PJM's ACE was dropping and trending significantly below zero, indicating insufficient generation to support load due to generator outages and failures. PJM found that it was unexpectedly and rapidly exhausting its operating and Primary Reserves because of the unexpected generator outages.
- PJM had put generation resources on notice, through Advisories and Alerts, of PJM's need for them to be prepared to run. PJM relied on Generator Owner/operator-submitted data and believed these reserves were available. In

many cases, this data did not reflect the actual capability of the generator and PJM would only learn of the generation resource failures at the time PJM was expecting these resources to begin to run.

- A Disturbance Control Standard (DCS) event, discussed later in this report, was also unfolding during this same time period.

Late in the afternoon of Dec. 23, temperatures continued to drop rapidly, and load continued to increase very quickly. During this period of operational uncertainty and deteriorating system conditions, PJM took additional emergency steps it determined were necessary to preserve the reliability of the system. Despite margins being incredibly tight, no load was shed.

Shortly after 16:00, PJM began cutting non-firm exports, consistent with PJM Manual 13. Export transactions had been decreasing throughout the afternoon, but by 16:00, it was evident PJM could no longer support non-firm exports. Given the trends in ACE, the high outage rates being observed in real time, and the time it would take for the impacts of the capacity recalls to be known, PJM Dispatch believed capacity recalls alone were insufficient to stabilize the system.

	Dec. 23 HE 15
Outages	26,672 MW
Interchange	6,732 MW
Load	117,143 MW

While the export transactions were being curtailed, at 16:17, PJM entered into another Synchronized Reserve Event due to low ACE caused by increasing load and generation resources tripping and failing to start. PJM deployed Synchronized Reserves for almost two hours, before canceling at 18:09. Load was continuing to increase, and PJM had several additional generation resource trips throughout the Synchronized Reserve Event period. The PJM ACE did not recover until after Demand Response was implemented at 18:00.

Available Synchronized Reserves continued to drop as PJM began calling upon these resources for energy, with many failing to perform at expected levels. At times during this period, PJM was within 1,000 MW of its required Synchronized Reserve level of 1,667 MW. PJM dipped below this required Synchronized Reserve threshold for a portion of the hour ending 18:00 because it was deploying Synchronized Reserves but not getting the expected response.

At 17:30, ACE was very low at nearly -3,000 MW, and the load was continuing to grow. In response, PJM issued a NERC Energy Emergency Alert Level 2 (EEA-2[4]) with Pre-Emergency Load Management Reduction Action and Maximum Generation Action, directing generation resources to operate above their normal maximum output levels. An EEA-2 is issued to ensure all NERC Reliability Authorities understand the potential and actual PJM system emergencies and is typically issued when the following events have occurred: public appeals to reduce demand; voltage reduction; and interruption of non-firm load in accordance with applicable contracts, demand-side management, or utility load conservation measures (NERC Standard EOP-11).

	Dec. 23 HE 16
Outages	28,351 MW
Interchange	6,032 MW
Load	119,375 MW

Certain emergency warnings and actions trigger a Capacity Performance Assessment Interval (PAI). The issuance of the EEA-2 with Pre-Emergency Load Management Reduction Action and Maximum Generation Action triggered the first performance assessment event, requiring PJM to evaluate the performance of all resources located in the Emergency

[4] EOP-011 NERC Energy Emergency Alerts (EEAs):
EEA0 – No Energy Deficiencies
EEA1 – All Available Resources in Use or Anticipated to be In Use; triggered when PJM issues Maximum Generation Emergency Alert)
EEA2 – Load Management Procedures in effect; triggered when PJM issues Emergency Mandatory Load Management Reduction, Voltage Reduction Action, or Deploy All Resources Action (whichever is issued first)
EEA3 – Firm Load Interruption Imminent or in Progress; triggered when PJM issues Manual Load Dump Action

Action area for each applicable five-minute interval. The performance assessment events are described in more detail in the Markets Outcomes section of the report.

PJM also called for 30-minute and 60-minute Emergency Demand Response to be activated. The 30-minute Emergency Demand Response came into effect by 18:00, and the 60-minute Demand Response came into effect by 18:30. PJM did not call for the two-hour Demand Response resources, as these resources would not have been implemented until after the evening peak. Demand Response performance can be difficult to determine in real time due to the lack of visibility of the performance to the system operator. More information on the performance of Demand Response is described later in this section.

	Dec. 23 HE 18
Outages	33,040 MW
Interchange	1,527 MW
Load	130,856 MW

Generation resources continued to trip offline and fail to start, resulting in ACE trending low during the hour ending 18:00. Starting at 17:05, PJM called Northeast Power Coordinating Council (NPCC) for 1,500 MW of shared reserves. NPCC is made up of New York and the six New England states, as well as the Canadian provinces of Ontario, Québec and the Maritime provinces of New Brunswick and Nova Scotia. Shared Reserve Activation is a procedure between the NPCC and the PJM Mid-Atlantic Control Zone to jointly activate a portion of their 10-minute reserve following any of the following situations:

- Generation or energy purchase contingencies equal to or greater than 500 MW (300 MW for the Maritimes) occur under conditions where activation assists in reducing a sustained load/generation mismatch.
- Two or more resource losses below 500 MW (300 MW for the Maritimes) within one hour of each other
- Periods of significant mismatch of load and generation

The objective of Shared Reserve Activation is to provide faster relief of the initial stress on the interconnected transmission system.

Over the evening peak on Dec. 23, PJM attempted to commit additional generating units that reported to PJM as being available to schedule. PJM system operators also considered long-lead-time resources that were beyond the window to be requested to start, which totaled about 3,000 MW. Generator maintenance outages that were recallable totaled about 1,692 MW; however, these are only recallable with 72-hours' notice. (Note: if PJM determines that it must rescind its approval of a Generator Maintenance Outage of a Generation Capacity Resource that is already underway in order to preserve the reliable operation of the PJM region, PJM must provide the member at least 72-hours' advance notice.)

Following the peak at approximately 18:10, PJM began lifting export transaction curtailments. By 22:00, PJM exports had returned to full flow. (Additional information on the real-time interchange is presented later in this section.)

	Dec. 23 HE 22
Outages	36,054 MW
Interchange	3,274 MW
Load	133,096 MW

At 23:00, load began to slowly ramp down, leading PJM to cancel the EEA-2 and the Pre-Emergency Load Management Reduction action at 23:00, ending the first performance assessment event. In addition, at 23:00 on Dec. 23, PJM declared a Maximum Generation Alert/Load Management Alert for Dec. 24, which provides an early alert that system conditions may require the use of the PJM emergency procedures. This is implemented when Maximum Emergency generation is called into the operating capacity or if Demand Response is projected to be implemented. When PJM declares a Maximum Generation Alert/Load Management Alert:

- Member transmission and generation dispatchers are expected to review plans to determine if any maintenance or testing, scheduled or being performed, on any monitoring, control, transmission, or generating equipment can be

deferred or canceled. Transmission and generation dispatchers are expected to suspend any high-risk testing of generating or transmission equipment.

- Member generation dispatchers are expected to report to PJM Dispatch any and all resource-limited facilities as they occur via Markets Gateway and update PJM Dispatch. Member generation dispatchers are also expected to update the "early return time" for any planned generator outages as indicated in PJM Manual 10, Section 2.

PJM also issued a NERC Energy Emergency Alert Level 1 (EEA-1) starting Saturday, Dec. 24, at 00:00, indicating PJM foresees or is experiencing conditions where all available resources are scheduled to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves.

Shortly before midnight on Dec. 23, PJM issued a Call for Conservation for the entire PJM footprint, asking consumers to scale back their energy use, where possible, between the hours of 04:00 on Dec. 24 and 10:00 on Dec. 25.

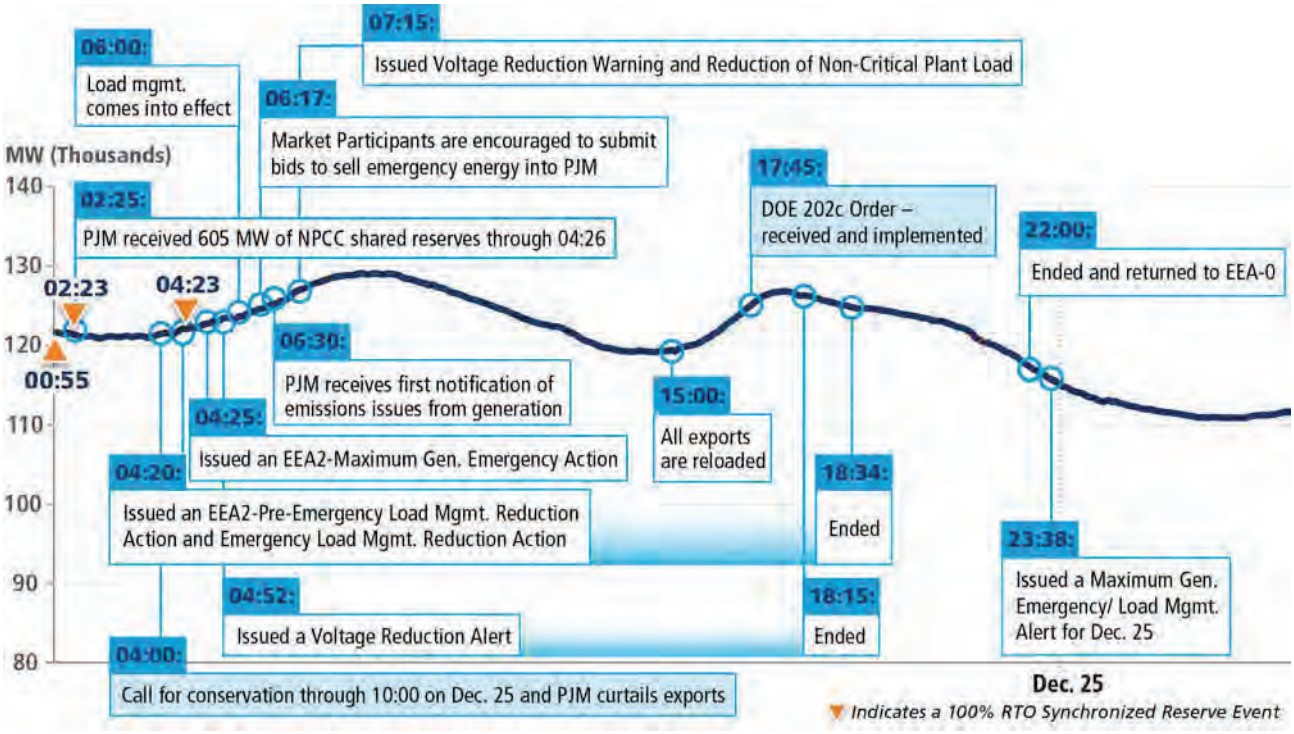
Dec. 24

The high demand for electricity continued after the peak on Dec. 23 and into the overnight period of Dec. 24. In addition to forced outages, approximately 6,000 MW of generators were called but were not online for their expected start time for the Dec. 24 morning peak, with the vast majority of these being gas-fired resources.

The high rates of generator outages also limited PJM's ability to replenish pond levels for pumped storage hydro prior to the morning peak on Dec. 24, leaving PJM with extremely limited run hours for pumped storage generation. Between forced outages, derates, generators not starting on time, and the inability to fill pumped storage hydro ponds, approximately 47,000 MW of the generation fleet in the PJM region was unavailable for the Dec. 24 morning peak. Additionally, the valley load during the early morning hours on Dec. 24 was atypically high. It was approximately 40,000 MW higher than the next-highest valley over the last decade.

PJM system operators took the several actions on Dec. 24 to maintain system reliability and serve load. Figure 14 presents the PJM emergency procedures issued, as well as the PJM load, for Dec. 24.

Figure 14. Dec. 24 Emergency Procedures



At 00:05 on Dec. 24, PJM deployed Synchronized Reserves due to low ACE caused by increasing load and generator trip and start failures. At 02:23, PJM deployed Synchronized Reserves again for approximately one hour to recover from another generation resource trip. At 02:25, PJM received 605 MW of NPCC shared reserves from 02:25 through 04:26. More information on the Synchronized Reserve Events is presented in the Markets Outcomes section of this report.

	Dec. 24 HE 01
Outages	38,368 MW
Interchange	4,604 MW
Load	124,757 MW

During a typical midnight period, load reduces, and PJM would operate pumped storage resources as pumps to fill their ponds so that they have the ability to generate for the upcoming peak. Operating a pumped storage resource in pumping mode increasing load on the system because electricity is consumed to operate the resource as a pump. Given the tight conditions, PJM was not able to pump at any of the pumped storage facilities prior to the morning peak. This left PJM with extremely limited run hours for pumped storage generation. As previously stated, going into the morning peak on Dec. 24, resource unavailability was approximately 47,000 MW, including the unavailability of pumped storage hydro generation.

At 04:20 on Dec. 24, PJM issued an EEA-2 – Pre-Emergency Load Management Reduction Action and Emergency Load Management Reduction Action. In this case, PJM dispatched all Load Management, starting with long lead (120 minute) at 04:20, short lead (60 minute) at 05:00, and quick lead (30 minute) at 05:30. Demand Response performance is described later in this section.

At 04:23, PJM deployed Synchronized Reserves again due to low ACE caused by increasing load and generation resources tripping and start failures. And then at 04:25, PJM issued an EEA-2 – Maximum Generation Emergency Action and began to load Maximum Emergency generation. This triggered the Dec. 24 PAI event. When PJM issues a Maximum Generation Emergency Action:

	Dec. 24 HE 03
Outages	40,243 MW
Interchange	3,322 MW
Load	121,487MW

- Member generation dispatchers are expected to report to PJM all resource-limited facilities as they occur in Markets Gateway and update PJM Dispatch. Generation dispatchers also suspend regulation and load all units to the Maximum Emergency generation level and then notify PJM Dispatch of any Maximum Emergency generation load prior to PJM requested Maximum Emergency generation is loaded.
- Non-Retail Behind-the-Meter Generation (NRBMG) is also loaded. NRBMG performance is described later in this section.

At 04:52, PJM issued a Voltage Reduction Alert. A Voltage Reduction Alert notifies members that a voltage reduction may be required during a future critical period. This alert is issued when the estimated Operating Reserve capacity is less than the forecasted Synchronized Reserve requirement. When PJM issues a Voltage Reduction Alert:

- Member generation dispatchers are expected to order all generating stations to curtail non-critical station light and power.
- Member transmission dispatchers and distribution providers (DPs) are expected to prepare to reduce voltage, if requested.
- Member transmission dispatchers/DPs and curtailment service providers (CSPs) are expected to notify appropriate personnel that there is a potential need to implement load management programs, in addition to interrupting their interruptible/curtailable customers in the manner prescribed by each policy, if it has not already been implemented previously.
- Market Participants are expected to remain on heightened awareness regarding PJM system conditions and the potential need for Emergency Energy Purchases.

At 06:17, PJM requested bids for emergency energy and PJM also repeated a public appeal to conserve energy. Note: PJM did not load emergency imports on Dec. 24.

	Dec. 24 HE 06
Outages	46,036 MW
Interchange	1,437 MW
Load	122,172 MW

At 07:15, PJM issued a Voltage Reduction Warning and Reduction of Non-Critical Plant Load, warning members that the available Synchronized Reserve is less than the Synchronized Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required.

At 07:30, PJM conducted an SOS-Transmission conference call with the PJM Transmission Owners to update their leadership on the situation and indicated PJM was in a very critical operating period, with the potential that PJM may need to shed load. Another SOS-Transmission conference call took place at 10:00.

As PJM approached the morning peak, PJM was a net importer of energy. TVA and Duke were both in an EEA-3 and shedding load. PJM was unable to provide assistance to TVA and Duke, and PJM was receiving assistance primarily from NYISO.

Forced outages of generation continued to increase through the morning peak on Dec. 24, with an estimated level of 41,000 MW of outages and 200 unit trips. Factoring in a number of reserve generators (units that are offline and available – that are called if needed) that missed scheduled start times Saturday morning or operated at less than capacity, combined with PJM's inability to replenish pumped storage based on the lack of availability of generators overnight, PJM was missing approximately 47,000 MW of the generation fleet by the morning peak of Dec. 24, the coldest day of the holiday weekend.

The morning peak for Dec. 24 was approximately 130,000 MW, occurring at 08:30.

As the morning peak was occurring, it was reported to PJM that several generators may need to come offline at or around the evening peak due to emissions restrictions. At this point, PJM contacted the U.S. Department of Energy (DOE) and held several calls to discuss the concerns and options available to ensure the units could remain online if needed. PJM also began outreach to state utility commissions and environmental agencies in states where there was a potential to operate units under a DOE Emergency Order.

Heading into Saturday evening, there was still uncertainty about resource performance. To mitigate the risk of generators coming offline due to emissions limitations, PJM submitted a petition to the DOE Saturday afternoon. At 17:30, the DOE issued an emergency order under Section 202(c) of the Federal Power Act, determining that an electric reliability emergency existed within the PJM region that required intervention by the United States Secretary of Energy to keep the power flowing.

The emergency order was effective Dec. 24 through 12:00 on Dec. 26. The order authorized all electric generating units serving the PJM footprint to operate up to their maximum generation output levels under limited, prescribed circumstances, even if doing so exceeded their air quality or other permit limitations.

Two generating units that fell under the order ran at levels that exceeded a condition in their operating permit. The Department of Energy requires PJM to identify those generators, which were Bethlehem Energy in Bethlehem, Northampton County, Pennsylvania, and York Energy 1 in Peach Bottom Township, York County, Pennsylvania. On Dec. 24, PJM communicated the need to operate these units under the DOE emergency order to the Pennsylvania Department of Environmental Protection. In accordance with the DOE's requests, PJM followed up with communications to the local communities where the plants are located through local media outlets.

The evening peak for Dec. 24 was approximately 136,000 MW. Following the evening peak, PJM started to cancel emergency procedures. At 18:15, PJM canceled the Voltage Reduction Warning and the Reduction of Non-Critical Plant Load. At 18:34, PJM canceled the Voltage Reduction Alert.

	Dec. 24 HE 17
Outages	47,310 MW
Interchange	3,607 MW
Load	120,183 MW

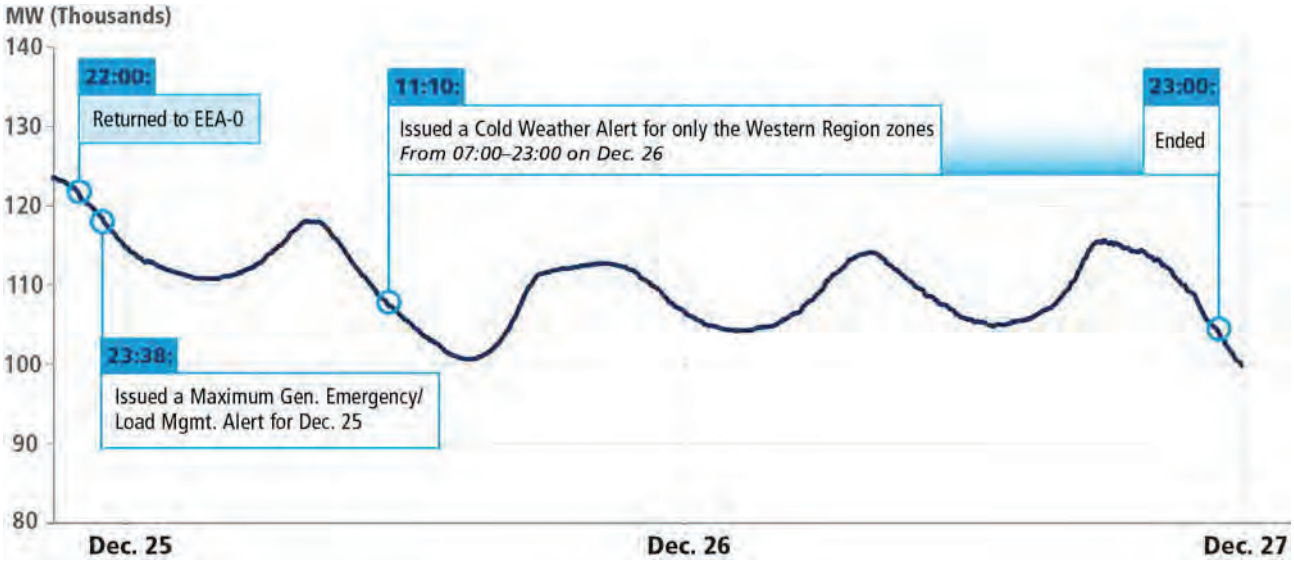
At 22:00 on Dec. 24, PJM canceled the Max Emergency Generation Action. This ended the Dec. 24 PAI. Around 22:00, the Demand Response ended, and PJM backed out of the EEA-2, indicating PJM was able to meet its load and Operating Reserve requirements. PJM's Call for Conservation also ended at this time.

At 22:38 on Dec. 24, PJM issued a Max Emergency Generation Alert for Dec. 25, resulting in PJM going into Dec. 25 in an EEA-1.

Dec. 25 and Dec. 26

On Dec. 25, a Sunday, PJM still had very high loads for a Christmas operating day. The morning peak was approximately 117,000 MW. There was sufficient capacity available to meet this morning peak as well as the evening peak, and PJM returned to EEA-0 at 22:00. Figure 15 presents the PJM emergency procedures, as well as the load for Dec. 24 at 22:00 to Dec. 26 at 23:00.

Figure 15. Dec. 25 and Dec. 26 Emergency Procedures



At 11:10 on Dec. 25, PJM issued a Cold Weather Alert for the Western Region zones only from 07:00 Dec. 25 to 23:00 Dec. 26. At 23:00 on Dec. 26, the Cold Weather Alert ended.

Figure 16 summarizes the emergency alerts, warnings and actions PJM implemented from Dec. 23 through Dec. 26.

Figure 16. Summary of Alerts, Warnings, and Actions Issued on Dec. 23, Dec. 24 and Dec. 25

Action Warning Alert Advisory

MESSAGE TYPE	DEC. 20	DEC. 21	DEC. 22	DEC. 23	DEC. 24	DEC. 25
Cold Weather Advisory			1	1	1	1
Cold Weather Alert				1	1	1
Emergency Load Mgmt Reduction Action				2	3	
Maximum Generation Emergency Action				1	1	
Maximum Generation Emergency/Load Management Alert				1	2	1
Non-Market Post Contingency Local Load Relief Warning	1	1		2	2	1
Post Contingency Local Load Relief Warning	3	3	1	25	26	6
Pre-Emergency Load Mgmt Reduction Action				2	3	
Synchronized Reserve Event				2	3	
Maximum Generation Emergency/Load Management Alert					1	
Voltage Reduction Warning and Reduction of NCPL					1	

As outlined in PJM Manual 13, Section 2.3: Capacity Shortages, "PJM dispatchers have the flexibility of implementing the emergency procedures in whatever order is required to ensure overall system reliability. PJM dispatchers have the flexibility to exit the emergency procedures in a different order than they are implemented when conditions necessitate." As such, PJM Operations evaluated the usage and combination of any and all emergency procedures during Winter Storm Elliott in order to best maintain overall system reliability. While many emergency procedures were issues by PJM throughout the event, some were considered and ultimately not issued.

- Cold Weather Alert – While a Cold Weather Advisory was issued for the entire PJM RTO on Dec. 20 for the operating period of Dec. 23–26, PJM Operations did not declare a Cold Weather Alert for the entire RTO until the Dec. 24 operating day, opting only to declare a Cold Weather Alert for the Western PJM zones for the Dec. 23 operating day. PJM Operations forecasted the potential for cold weather starting on Dec. 23 and, as such, issued the appropriate advisory, while continuing to monitor forecasted temperatures leading up to the operating day. Per PJM Manual 13, Section 3.3.2 Cold Weather Alert, "as a general guide, PJM can initiate a Cold Weather Alert across the RTO or on a Control Zone basis when the forecasted weather conditions approach minimum or actual temperatures of 10 degrees Fahrenheit or below." Outside of the Western zones, temperatures were never forecasted to reach near a minimum of 10 degrees and instead were expected to be several degrees higher at their minimum. As such, it was not appropriate to issue a Cold Weather Alert for the zones outside of the PJM Western footprint until Dec. 24 when the trigger temperatures were forecasted.
- Deploy All Resources Action – The Deploy All Resources Action is a unique emergency procedure with a unique application. Its purpose is to immediately load all available generation and Demand Response following a severe system disturbance to attempt to halt frequency decay. This could lead to unintended loss of system control with regard to energy balance. It is only expected to be used as a means of last resort. This specific emergency procedure was discussed by PJM Operations and decided against implementing for several reasons, as implementing a Deploy All Resource Action could have aggravated some of the thermal and voltage constraints that were being managed. In addition, PJM Operations was manually controlling the output of all pumped hydro facilities during the event. Issuance of this emergency procedure would have removed PJM's controlling ability of these resources and instead would have immediately depleted the pond levels, which were needed to be precisely managed through the event.
- Manual Load Dump Warning, Voltage Reduction Action & Manual Load Dump Action – These three steps constitute the most severe emergency procedures that can be utilized to maintain reliability. While PJM Operations has these steps in the queue to issue, as necessary, system conditions never dictated a need to utilize them. During a conference call held with PJM Transmission Owners at 07:30 on Dec. 24, prior to the most challenging system conditions of the event, which was the Saturday, Dec. 24, morning peak, PJM management made a clear statement for the Transmission Owners to be prepared to respond as quickly as possible to any or all of these emergency procedures as there was the possibility that they could be issued imminently. PJM Operations kept the Voltage Reduction Action in reserve to deploy, if additional generation tripped offline. Per PJM Manual 13, this would have been approximately 1.3% of the RTO load at the time. If a Voltage Reduction Action were issued, it would have been immediately followed with a Manual Load Dump Warning and EEA-3 declaration, as a Manual Load Dump would have been the only remaining emergency procedure to maintain reliability. Then, if required, PJM would have been prepared to issue a Manual Load Dump Action. PJM was ultimately able to maintain reliability through the event without issuance of these three emergency procedures.

Disturbance Control Standard Event

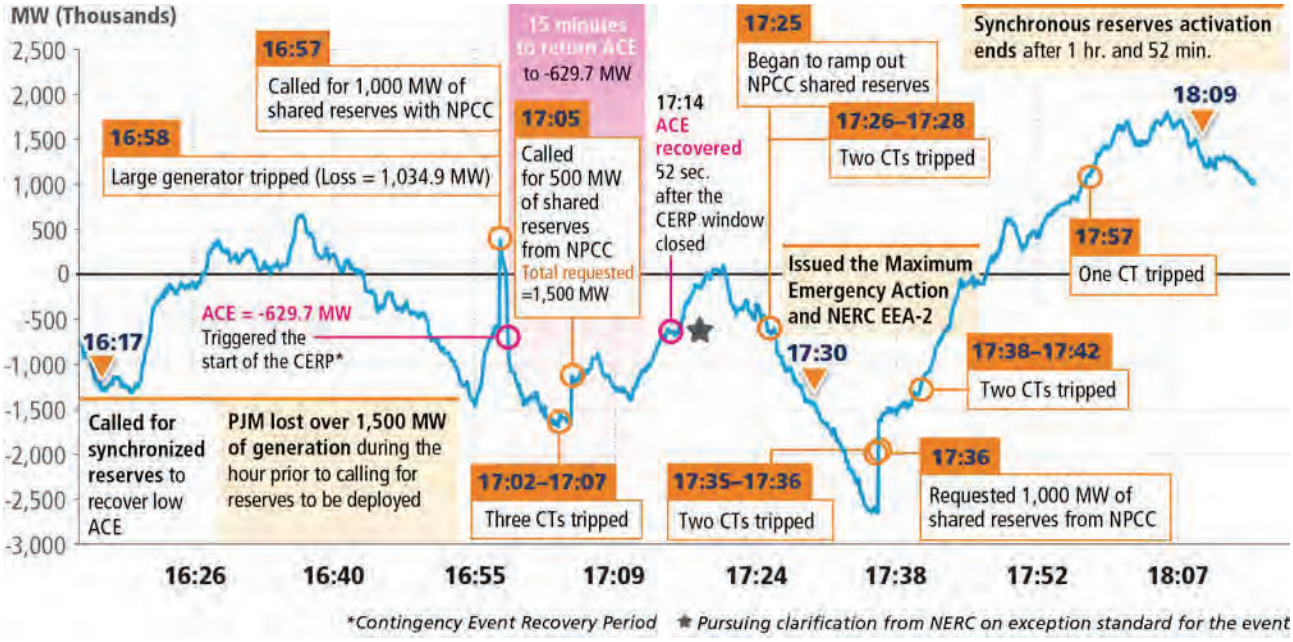
The purpose of the NERC Standard BAL-002, Disturbance Control Performance, is to ensure that PJM, a NERC Balancing Authority, is able to utilize its contingency reserve to balance resources and demand, and to return interconnection frequency to within defined limits following a Reportable Disturbance. NERC defines a Reportable Disturbance as any event that causes an Area Control Error (ACE) change greater than or equal to 80% of a Balancing Authority's or reserve sharing group's most severe contingency. ACE is a measure of how well the Balancing Authority is matching generation to the load. If load and generation are perfectly balanced, the ACE is zero. When a generator within

a Balancing Authority trips offline, the ACE goes down, and can go negative if it was already not above zero by a quantity at least as great as the output of the generator when it tripped. Because generator failures are far more common than significant losses of load and because contingency reserve activation does not typically apply to the loss of load, the application of Disturbance Control Standard (DCS) is limited to the loss of supply and does not apply to the loss of load.

PJM is required to have access to or operate with resource reserves to respond to disturbances. These reserves may be supplied from generation, controllable load, or coordinated adjustments to interchange schedules. The DCS Standard requires PJM to satisfy disturbance recovery criterion within a certain disturbance recovery period for 100% of Reportable Disturbances. The criterion requires PJM to return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the disturbance, a return of ACE is made to its pre-disturbance value. In either case, the disturbance recovery period is 15 minutes after the start of a Reportable Disturbance. Subsequently, PJM must fully restore the Synchronized Reserve within 90 minutes. All contingency losses (i.e., disturbances) with the lesser of 900 MW in the Eastern Interconnection or 80% of the Most Severe Single Contingency must be calculated and reported.

As described below, PJM was not able to recover the ACE within the prescribed 15 minutes. Figure 17 presents PJM's ACE on the evening of Dec. 23 during the DCS event:

Figure 17. ACE During DCS



Heading into the evening peak on Dec. 23, load was increasing rapidly and PJM was ramping the generation fleet to keep up with the increasing load. Load was increasing quicker than PJM was able to ramp generation, and, as a result, the PJM ACE started to go negative. By 16:17 on Dec. 23, ACE was trending at around negative 1,000 MW, indicating low capacity. In response, PJM called for Synchronized Reserves to be loaded to recover from the low ACE. After approximately ten minutes, the ACE partially recovered but, by 16:40, went negative again. By 16:55, the ACE was approximately negative 1,500 MW. At 16:57, PJM called for 1,000 MW of shared reserves from NPCC. At that point, PJM's ACE was 429 MW as a result of PJM deploying reserves for approximately 40 minutes.

Approximately one minute following PJM's call for shared reserves from NPCC, a large generator in PJM tripped, losing approximately 1,035 MW. The Generation Owner reported that the generator was loaded at 850 MW at the time the unit tripped. The loss of this large generation resource was the initiating event with respect to the BAL-002 standard reporting event. Prior to the unit tripping, PJM's ACE was negative 630 MW. After the unit tripped, PJM's ACE dropped below negative 1,500 MW. Per the BAL-002 standard, PJM is required to recover ACE to negative 630 MW within15 minutes.

PJM had been deploying reserves since 16:17. Load on the system was continuing to increase. Between 17:02 and 17:07, additional generation tripped, and, as a result, the ACE continued to decline to approximately negative 1,600 MW. At 17:05, PJM called for an additional 500 MW of shared reserves from NPCC, bringing the total shared reserves from NPCC to 1,500 MW.

By 17:14, the PJM ACE had recovered back to negative 630 MW, ending the DCS event 15 minutes and 52 seconds after the large generator tripped. Although the DCS event had technically ended, controlling the ACE continued to be a challenge. As reflected in Figure 17, the PJM ACE climbed back to around zero about five minutes later but then went negative again. Throughout all of this, PJM continued to deploy reserves and was ramping whatever resources were online and available.

At 17:25, PJM started to ramp out the shared reserves from NPCC, which can only be relied upon for 30 minutes (recall PJM called for shared reserves at 16:57). As load continued to increase and additional generation was lost, the PJM ACE was approaching negative 3,000 MW by 17:34.

At 17:36, PJM requested 1,000 MW of shared reserves from NPCC again, which helped the ACE to begin to recover. The ACE continued to recover until 18:09, at which time PJM ended the call for Synchronized Reserves to be loaded, 1 hour and 52 minutes after PJM began deploying them.

During this period, PJM was ramping generation as quickly as possible and deploying Synchronized Reserves for almost two hours. By 18:00, the rate that the load was increasing slowed as PJM was beginning to see the impact of the Demand Response that was called at 17:30.

PJM evaluated compliance with the BAL-002 standard, and engaged in communications with ReliabilityFirst regarding the matter. This evaluation included the consideration that BAL-002-3 R1.3 provides scenarios in which Responsible Entities are not subject to compliance with BAL-002-3 R1.1, provided certain thresholds are met.

In response to the low response rate and lack of available reserves, PJM will be reviewing procedures to identify triggering conditions that will further increase the amount of reserves that are scheduled leading into the operating day. This will include triggers to potential increase the amount of the Synchronized, Primary and/or Operating Reserves scheduled in the Day-Ahead, RAC and Real-Time market clearing.

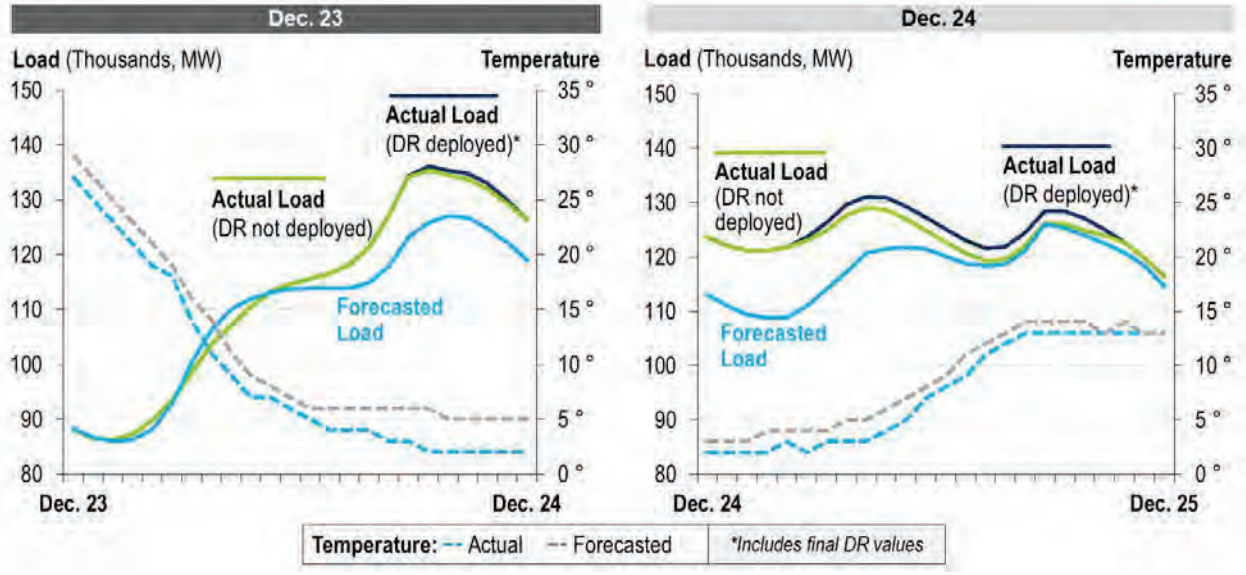
Load Forecast Versus Actual Load

The load forecasts for Dec. 23 and Dec. 24 presented a unique set of challenges. The winter holiday period has historically been a challenging time to forecast due to school vacations, business closures and atypical human behavior patterns, as presented in Figure 19. In the past, over-forecasting was more of an issue than under-forecasting, resulting in the PJM forecast team enhancing processes in recent years to correct for this over-forecasting trend. The winter 2022 holidays were further complicated by the extreme weather and Christmas Eve occurring on a Saturday, which had not occurred since 2016.

On Dec. 23, the forecasted peak load was 126,968 MW, and the actual peak was 136,010 MW, which included Demand Response added back into the load. On Dec. 24, the forecasted peak load was 121,723 MW, and the actual peak was

131,113 MW, which included Demand Response added back into load. On both Dec. 23 and Dec. 24, the actual load came in well higher than forecast, as presented in Figure 18.

Figure 18. Dec. 23 and Dec. 24 Actual Load



The high demand for electricity continued after the peak on Dec. 23 and into Dec. 24. The actual valley load, or low point of demand, on Dec. 24 was significantly greater than originally forecasted as well. The Dec. 24 valley load was higher than any other peak, or high point of demand, for that date over the previous decade, as shown in Figure 19, which presents the holiday load for 2022 and the previous 10 years.

Figure 19. Holiday Load for Previous 10 Years

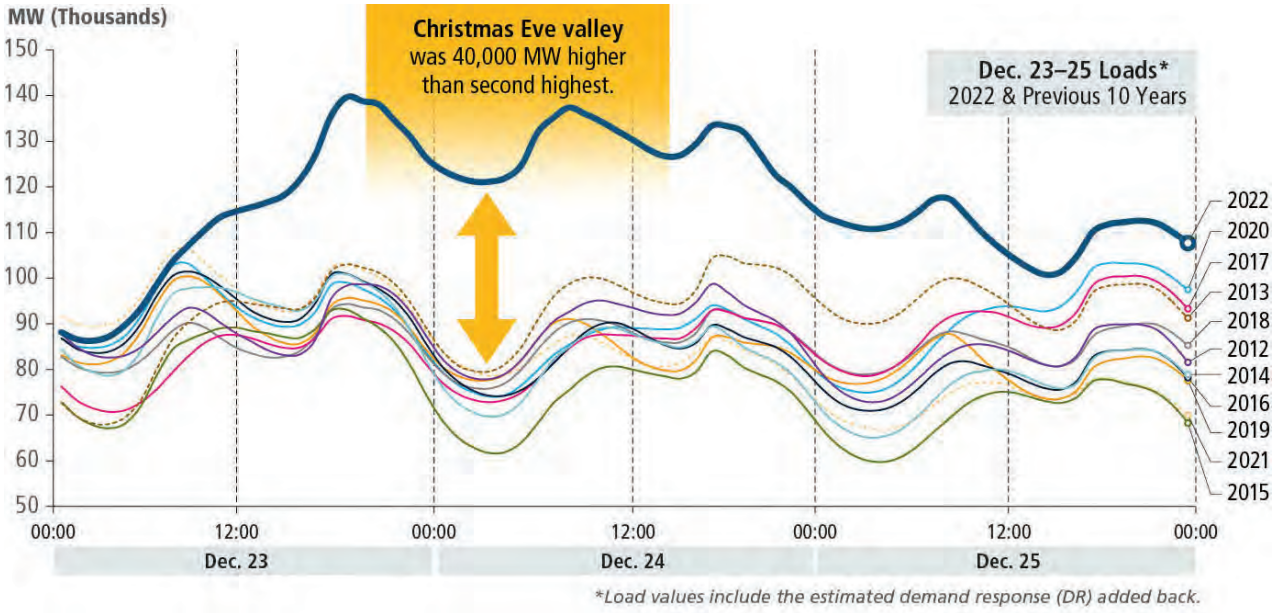
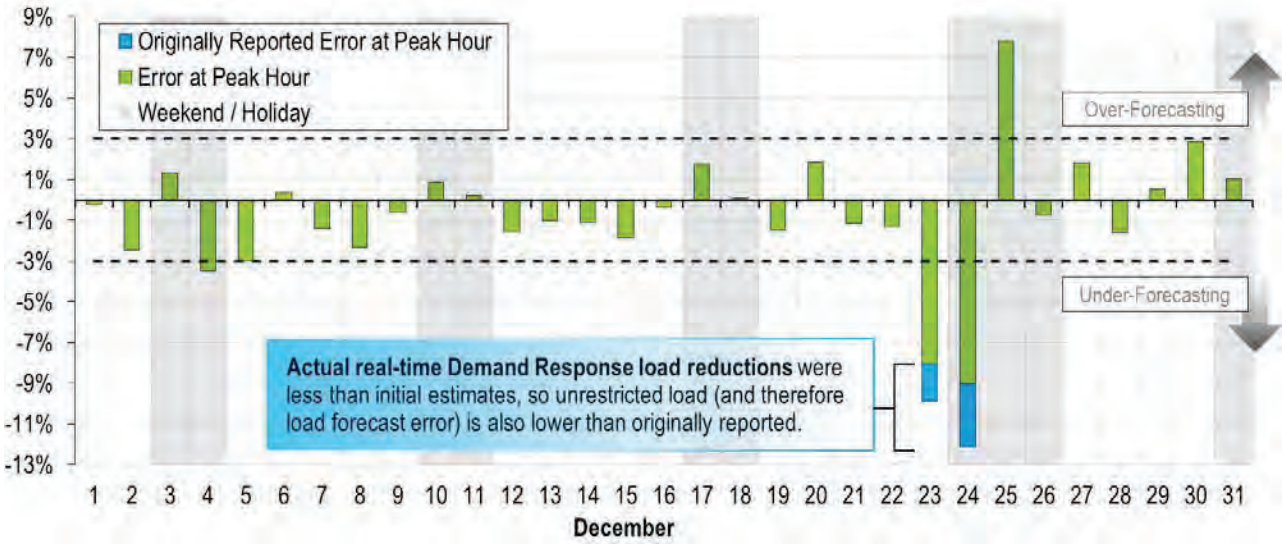


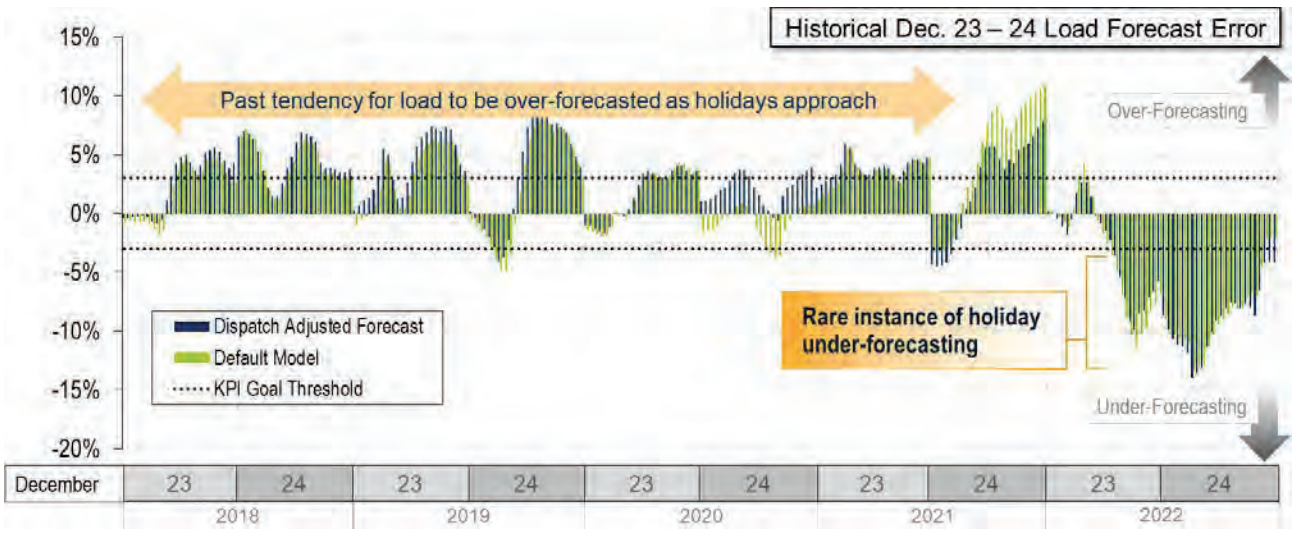
Figure 20 presents graphic presents the daily peak forecast error for December.

Figure 20. December Daily Peak Load Forecast Error



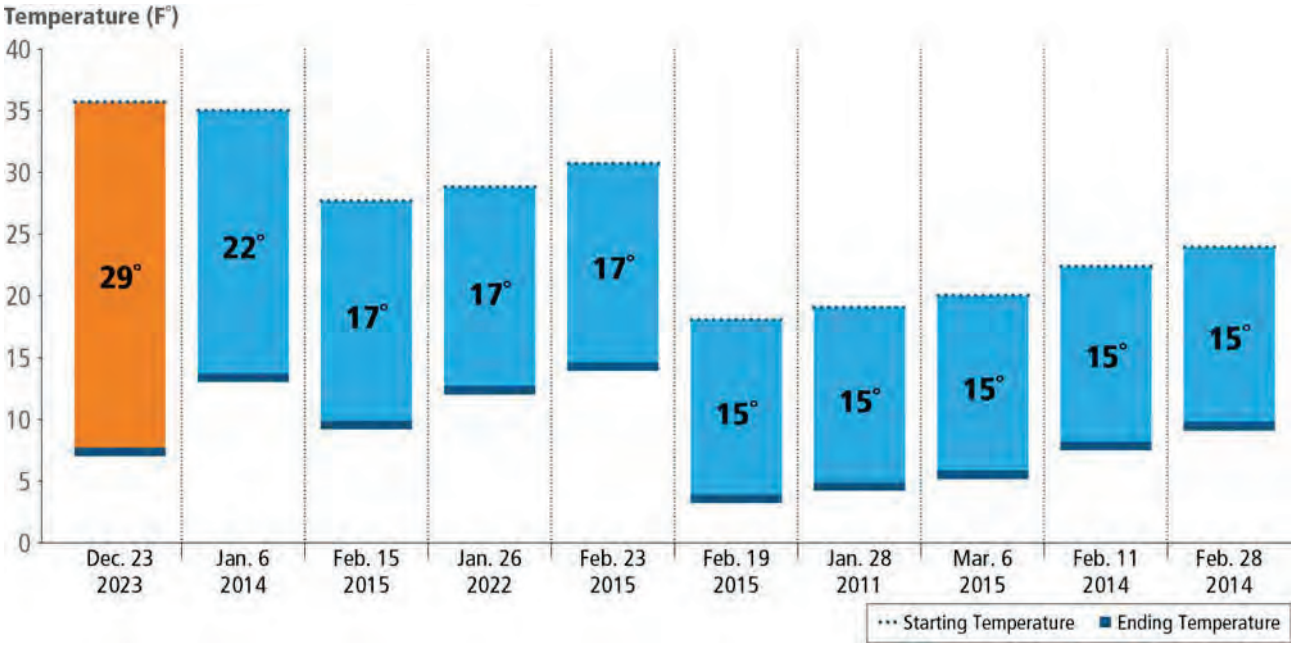
The extreme weather not only included bitter cold temperatures that were outside of the data sample used to train the load forecast models (mid-2019 to mid-2022), but also a rapid temperature drop, strong winds, heavy icing and snowfall, all of which occurred unusually early in this winter. Figure 21 presents the historical load forecast error the past five years.

Figure 21. Historical Dec. 23–24 Load Forecast Error



The load forecast is determined by an algorithm that considers expected weather conditions, day of the week and holidays. The model had not been exposed to the conditions that occurred on Dec. 23, with the confluence of unprecedented cold temperature drops, the holiday and the weekend. Within the PJM footprint, the difference between the high and low temperatures on Dec. 23 was one of the greatest in recorded history, as shown in the Figure 22.

Figure 22. Dec. 23 High and Low Temperatures



In Figure 22, the top and bottom of each bar represent the starting and ending temperature for each day, respectively.

The following primary drivers contributed to the load forecast error observed on Dec. 23 and 24:

- Extreme weather – severe cold and blizzard conditions, the most drastic temperature drop in at least 10 years, and early occurrence of cold weather
- Holiday impacts, which usually result in lower demand levels than normal

While PJM uses a sophisticated set of load forecasting tools and processes, we believe the Dec. 23 and 24 load forecasts highlight a case where two simultaneous conditions, a holiday and extreme weather with very limited analogous history, occurred together to produce atypically large forecast errors. PJM is already engaged with an independent party to further investigate enhancements to the load forecasting process, in general, and related to these specific events.

Emergency Generation and Demand Response Performance

Altogether, a Maximum Generation Action, Demand Response and public Call for Conservation helped address challenging operating conditions on Dec. 23 and 24. This section discusses information regarding the use of emergency resources. Information regarding the Call for Conservation is presented in the Government, Member & Media Outreach section.

PJM issued a Max Generation Action on Dec. 23 between 17:30 and 22:00 and observed a total increase of approximately 2,300 MW as a result of generation resources operating between their economic maximum and emergency maximum limits. Similarly on Dec. 24, PJM issued a Max Generation Action between 04:30 and 22:00 and observed a total increase of approximately 2,800 MW as a result of generation resources operating between their economic maximum and emergency maximum limits.

Demand Response was used to reduce peak loads in the entire PJM region during the winter storm. PJM called on Demand Response two times to address operational challenges with capacity shortages.

As described previously, PJM called for Demand Response on Dec. 23, which was to be implemented by 18:00. Demand Response with a capacity commitment is referred to as Load Management, which is comprised of Pre-Emergency and Emergency Demand Response. Load Management is required to reduce or maintain load at or below the committed value based on PJM dispatch within 30 minutes (quick lead time), 60 minutes (short lead time), or 120 minutes (long lead time). Based on the expected peak for the day, PJM dispatched both the 30-minute and the 60-minute lead resources on the evening of Dec. 23.

In total, PJM dispatched what it anticipated to be 4,336 MW of Load Management on Dec. 23 with 4,007 MW of 30-minute lead resources by 18:00 and another 329 MW of 60-minute lead resources by 18:30. In real-time, Curtailment Service Providers (CSPs) are required to provide estimates of their load reduction capability to PJM since customer load may already be low for other reasons (public appeal to reduce load, normal operating conditions, etc.). These estimates are intended to give PJM operators a quantity of load that will reduce if they deploy a specific category of Load Management. CSPs estimated, and therefore PJM expected, that 4,336 MW of load would be reduced based on the deployment on Dec. 23. PJM estimates, based on after-the-fact customer load data, that actual load reductions were approximately 1,100 MW. In total on Dec. 23, approximately 74% of the Demand Response that PJM operators dispatched and expected to reduce load did not.

As PJM was approaching the morning peak on Dec. 24, given the critical capacity condition, PJM system operators dispatched all Load Management with a total capacity commitment of 7,522 MW at 04:20.

4,007 MW of 30-minute Demand Response was expected to respond at 06:00.	329 MW of 60-minute Demand Response was expected to respond by 06:00.	3,186 MW of 120-minute Demand Response was expected to respond by 06:20.

CSPs estimated, and therefore PJM expected, that approximately 7,400 MW of load would be reduced. Based on after-the-fact customer load data, PJM estimates that actual load reductions from PJM dispatch was approximately 2,400 MW. This corresponds to approximately 68% of the Demand Response PJM operators dispatched and expected to reduce load not performing.

The significant difference between the data provided to PJM about load curtailment capability and the actual performance clearly identify an opportunity and need to improve the rules and processes regarding Load Management capability estimates.

Real-Time Interchange

Interchange transactions take the form of an import, meaning market participants purchase power from a neighboring area and sell into PJM, an export, where power is purchased from PJM and sold to an external area, or a wheel, where power is simultaneously purchased from a neighboring area, scheduled across PJM, and then sold to an external area. PJM is typically a net exporter of energy to neighboring systems, and that remained true in the days preceding Winter Storm Elliott. With this information in mind, PJM operators took a conservative stance in preparing for the Dec. 23 and Dec. 24 operating day and planned for sufficient reserves to meet both forecast internal load and the needs of neighboring systems who rely on support from PJM in the form of interchange transactions and emergency purchases.

As PJM made the decision to issue Cold Weather Advisories and Alerts for these operating days, the bitter cold temperatures traveled across the country from the north and west to the south and east. Early in the day on Dec. 23,

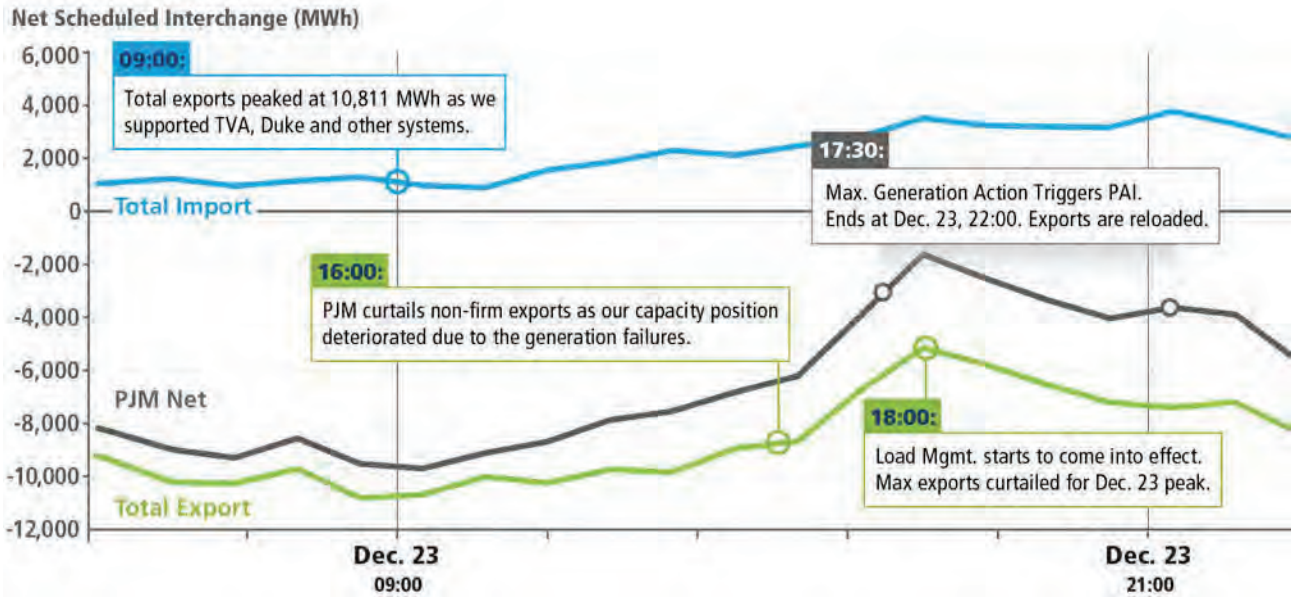
areas to PJM's west and south were already experiencing bitter cold temperatures. PJM was exporting energy throughout the morning and early afternoon on that day. Throughout the Dec. 23 to 24 period, PJM was balancing the extremely tight capacity situation due to the unprecedented amount of generator trippings and forced outages, controlling flows on the AEP-Dominion IROL[5] interface, as well as the extreme system conditions faced by our neighbors to the south.

Dec. 23

At the start of Dec. 23, PJM exported over 8,000 MWh for the hour ending 01:00 and increased that amount over the morning hours to reach almost 11,000 MWh for the hour ending 10:00 (Figure 23). These exports included the supply of emergency energy to TVA during the hours ending 07:00 through 11:00. During hour-ending 13:00, exports started a slight downward trend, and as PJM's capacity position continued to deteriorate, non-firm exports to adjacent areas were ultimately curtailed via a Maximum Generation Emergency Action. PJM system operators initiated the curtailment of non-firm export transactions at hour ending 17:00 by limiting roughly 400 MWh of exports, and quickly jumped to limiting well over 3,000 MWh of transactions each hour from hours ending 18:00 through 20:00. At that point, PJM system operators began a transition out from the heaviest Maximum Generation curtailments, with most transactions resuming full flow by hour-ending 22:00. In anticipation of, and in response to the Minimum Generation Action on Dec. 23, PJM curtailed in total almost 14,000 MWh of exports.

Figure 23 presents the Net Scheduled Interchange on Dec. 23.

Figure 23. Dec. 23 Net Scheduled Interchange



Dec. 24

When current and forecast system conditions indicated reduced availability to support exports on Dec. 24, the Transmission Load Relief (TLR) mechanism was considered as an option to provide relief for the AEP-Dominion IROL interface; however, the resulting analysis showed the need for an excessive volume of tag[6] curtailments on neighboring

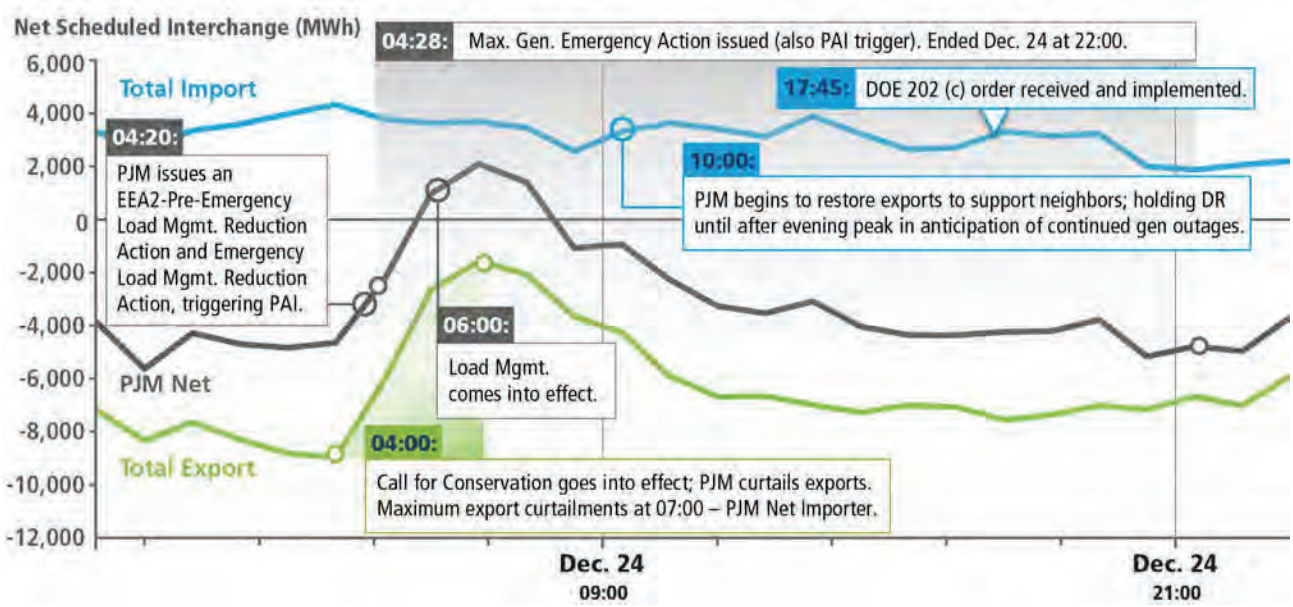
[5] Interconnection Reliability Operating Limit (IROL) is a system operating limit that, if exceeded, could lead to system instability, uncontrolled separation, or cascading that adversely impact the reliability of the bulk electric system.
[6] A tag is information describing a physical Interchange Transaction or Intra-BA Transaction and its participant.

systems that were already experiencing significant issues of their own. PJM system operators concluded that issuing a TLR would create far-reaching impacts across the Eastern Interconnection and likely make system conditions and emergencies worse for our neighbors. PJM also elected to limit curtailment of exports over the midnight period knowing the severe system conditions of our neighbors to the south. This limited PJM's ability to pump hydro stations.

Facing both a capacity emergency and lack of controlling options for AEP-DOM, PJM made the decision to take a more surgical approach and initiated curtailments in anticipation of a Maximum Generation Emergency Action, which was ultimately declared at 04:25. PJM system operators began limiting non-firm exports in hour ending 05:00 and increased the magnitude of curtailments by hour ending 06:00 when they had also begun limit firm exports. The most significant curtailments occurred in hour ending 08:00 with over 4,000 MWh of firm transactions limited and over 5,000 MWh of non-firm exports limited. Both PJM and its capacity deficient neighbors were experiencing peak loads at the same time, and PJM did not have excess capacity to support export requests regardless of the supporting transmission service priority. After the morning peak load, PJM slowly started to lift the limits on exports; however, the duration of this event was much longer than that seen on Dec. 23, with firm curtailments persisting until 12:00 and non-firm curtailments persisting until 15:00. For the event on Dec. 24, PJM curtailed over 45,000 MWh of export transactions. Conversely, PJM observed over 40,000 MWh of import transaction curtailments on Dec. 24, primarily resulting from TLRs issued by neighboring Reliability Coordinators (RCs). At the peak of the curtailments, PJM briefly transitioned to an overall net-importer of energy for several hours on the Dec. 24, with a net schedule of approximately 2,800 MWh into the footprint for hour ending 08:00.

Figure 24 presents the Net Scheduled Interchange on Dec. 24.

Figure 24. Dec. 24 Net Scheduled Interchange

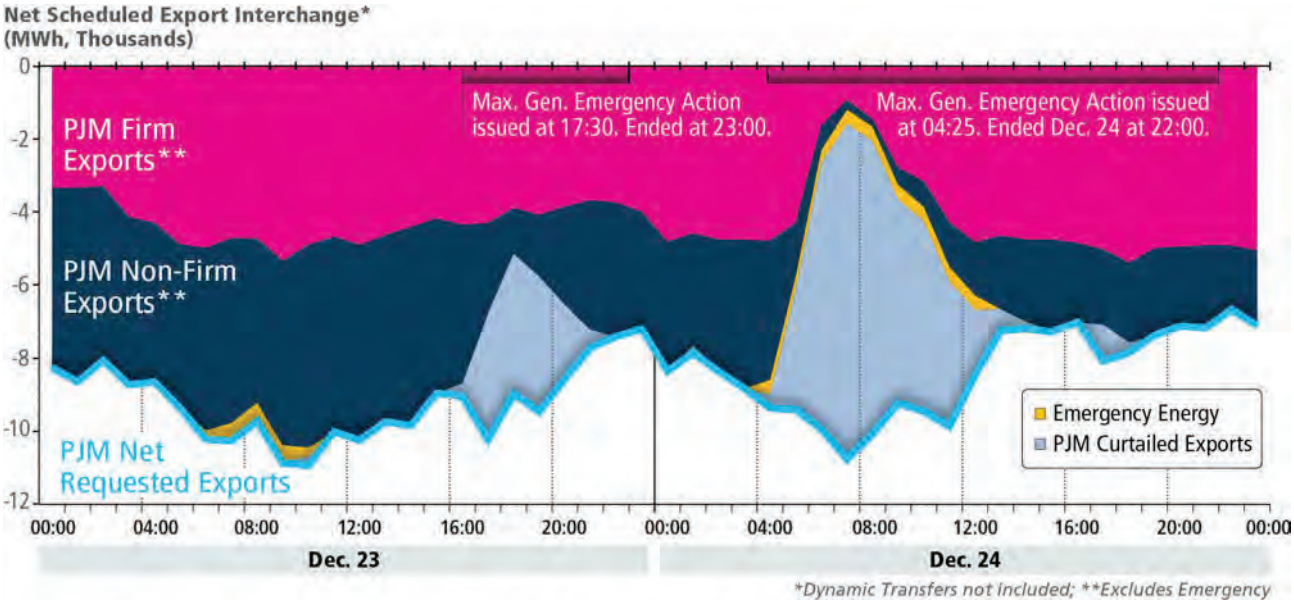


Coordination With Neighbors

As the extreme cold temperatures moved through areas to the southwest of the PJM footprint, neighboring systems began to experience strains. On both Dec. 23 and Dec. 24, PJM coordinated closely with its neighbors to maximize transfers. PJM provided emergency energy to adjacent systems as system conditions allowed on both Dec. 23 and Dec. 24 (Figure 25) before eventually having to reduce exports in order to serve consumers within the PJM footprint.

Transmission constraints also limited PJM's ability to support export transactions across the southern interfaces. These constraints included the pre-contingency emergency thermal limit of the Broadford 765/138 kV transformer and post-contingency transfer limit of the AEP-Dominion IROL interface. Figure 25 presents the Net Scheduled Exports for Dec. 23 through Dec. 24.

Figure 25. Dec. 23 and Dec. 24 Net Scheduled Exports



Comparing the values in Figure 25 to the supply/demand conditions that PJM actually experienced confirms that PJM could not have met system demand only by cutting non-firm exports. On Dec. 23, 2022, at 17:30, PJM issued a Pre-Emergency Load Management Reduction Action for the 30-minute and 60-minute Demand Resources that resulted in load reductions of about 1,100 MW. At the same time, PJM system operators also issued a Maximum Generation Emergency Action that resulted in an average of 2,372 MW of additional generation. In total, these actions had about 3,472 MW of impact. In comparison, non-firm exports were 1,241 MW for hour 18:00 and were 1,683 MWs for hour 19:00. Accordingly, even if the operators had cut all non-firm exports, there would have been a deficit of at least 1,789 MW needed to satisfy PJM load and firm exports. Pre-Emergency and Emergency Actions thus would have been necessary to satisfy capacity needs even if all non-firm exports had been cut.

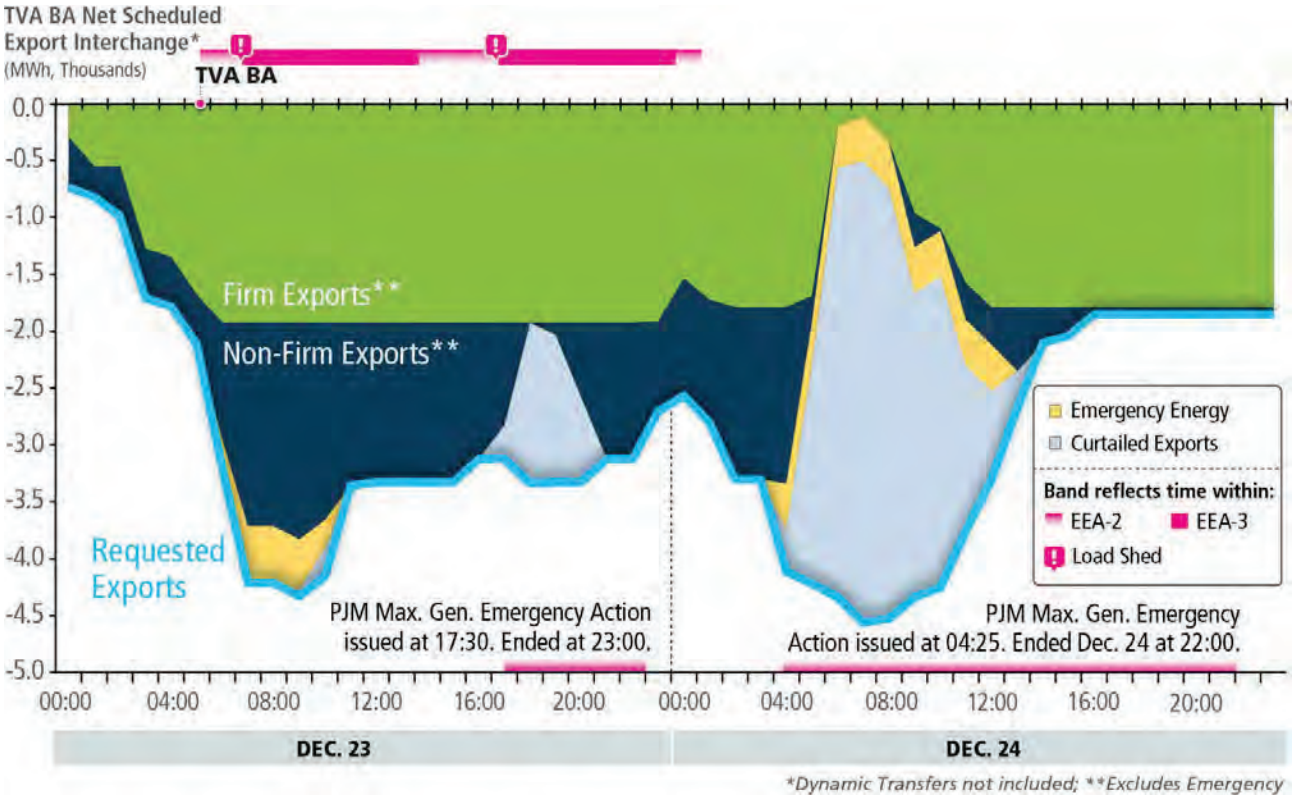
The situation for Dec. 24 is similar. At 04:20, PJM issued a Pre-Emergency Load Management Reduction Action and an Emergency Load Management Reduction Action that covered all Demand Resources and resulted in about 2,400 MW of load reduction. And at 04:28, PJM issued a Maximum Generation Emergency Action that it resulted in an average of about 2,879 MW in additional generation. In total, these actions had 5,279 MW of impact. In comparison, for hour 05:00, non-firm exports were 1,820 MW, falling to a low of 591 MW in hour 8:00 and increasing to a maximum level of 2,359 MW in hour 19:00 before the PAIs ended at 22:00. Accordingly, even if the PJM system operators had cut all non-firm exports there would have been a deficit between about 4,688 MW and 2,920 MW during this period needed to satisfy PJM load and firm exports. Pre-Emergency and Emergency Actions thus would have been necessary even if all non-firm exports had been cut.

Figure 25 also shows that PJM prioritized meeting its own load by cutting exports – both firm and non-firm – when necessary. The graph shows a significant number of hours in which the assistance requested by other regions was not

supplied. This correlates to the periods when PJM needed most of its generation for internal loads notwithstanding that, during some of these times, other regions were seeking emergency supplies.

As presented in Figure 26, PJM was able to assist TVA by providing non-firm exports during times that the TVA system was shedding load, which is represented by the fuchsia bars indicating when TVA was in an EEA-2 or EEA-3. Had PJM not done so, it is likely that TVA would have been required to engage in additional load shedding beyond what actually occurred.

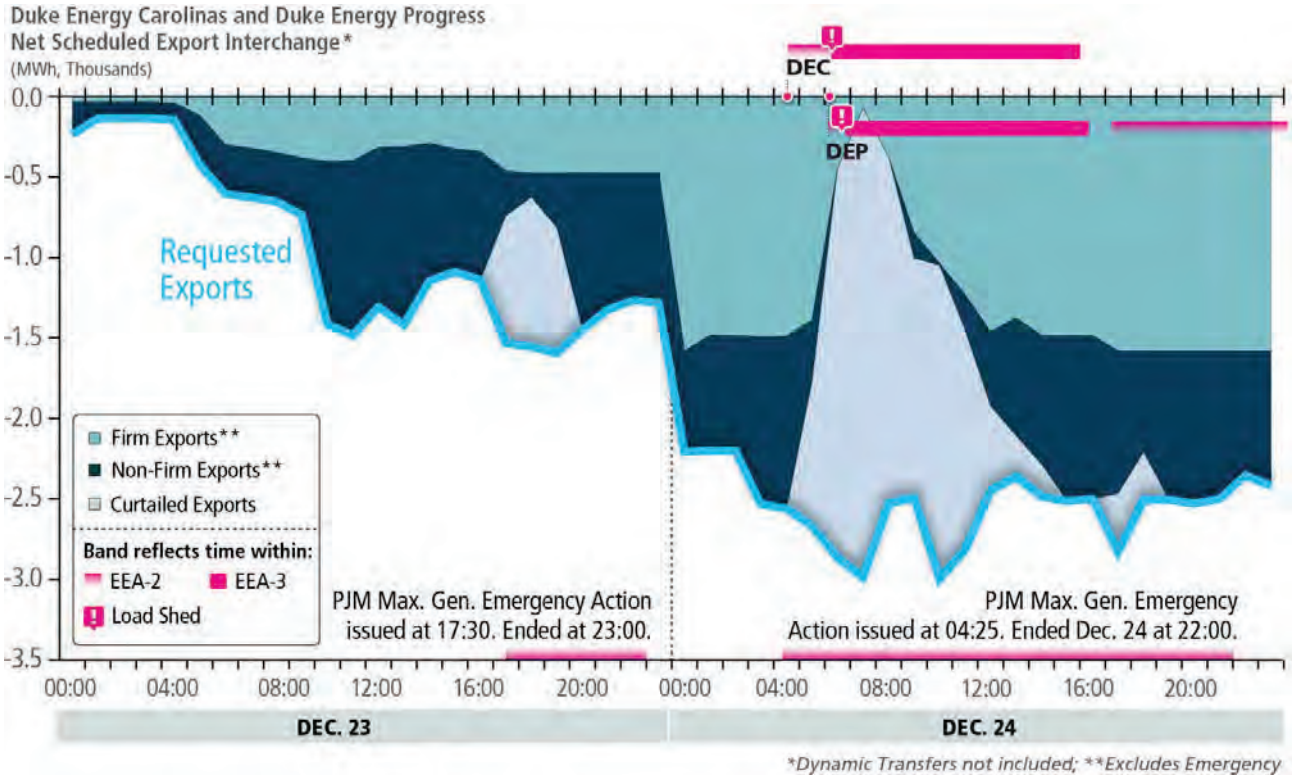
Figure 26. TVA BA Net Scheduled Export Exchange



The non-firm exports supplied to TVA provided assistance during periods when TVA was in a capacity deficient condition.

Similarly, the non-firm exports supplied to Duke Carolinas and Duke Energy Progress provided assistance to those systems when they were experiencing capacity deficient conditions as shown in the Figure 27.

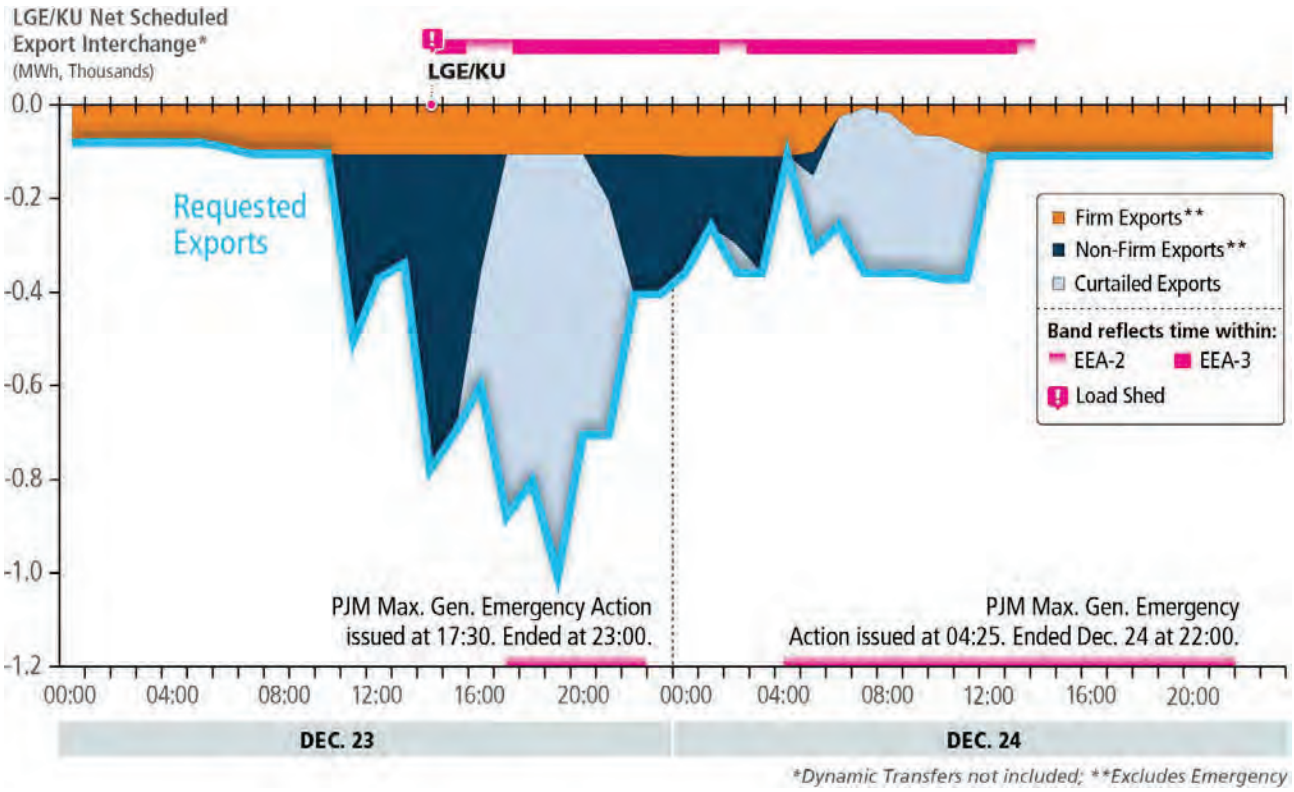
Figure 27. Duke Energy Carolinas & Duke Energy Progress Net Scheduled Export Interchange



As presented in Figure 27, PJM was also able to provide assistance by supplying non-firm exports to Duke Carolinas and Duke Energy Progress when they were shedding load. Again, if PJM had not provided this assistance, it is likely that Duke Carolinas and Duke Energy Progress would also have had to engage in more load shedding.

Lastly, Louisville Gas and Electric Company and Kentucky Utilities Company (LGE/KU) also received non-firm exports when they were experiencing capacity deficit conditions as shown in Figure 28.

Figure 28. LGE/KU Net Scheduled Export Interchange



PJM made non-firm deliveries to LGE/KU when the region was shedding load. Had PJM not made these exports, additional load shedding would likely have been needed.

Generation Performance

Prior to the operating day and Winter Storm Elliott, PJM had issued both Cold Weather Advisories and Cold Weather Alerts. Both procedures notify Generation Owners, Transmission Owners, and all PJM members of impending cold temperatures and to take action. Specifically, Generation Owners must take freeze protection actions, notify PJM of any operational changes or limitations as a result of the imminent cold weather, and update the operational parameters of generation units in Markets Gateway. These unit parameters include the Start-up and Notification Time, Min Run Time, Max Run Time, Eco Min, Eco Max, etc. Having accurate information about these unit parameters, in particular any changes to the start-up and notification times, are critical to PJM's decision making with respect to when a unit is given a commitment to run (i.e., when it is scheduled by PJM). PJM Dispatchers and their tools rely heavily on offer data information submitted by resource owner/operators. Given that 92% of forced outages that occurred were reported to PJM either after they occurred or with less than 60-minutes notice, it suggests that this information was not maintained throughout the event.

PJM started the operating day of Dec. 23 with 12,000 MW of unplanned outages, 4,293 MW of planned outages and 1,692 MW of maintenance outages at the evening peak on Dec. 23. These outages were primarily due to various equipment problems at generation facilities. PJM was tracking the cold temperatures arriving as a result of Winter Storm

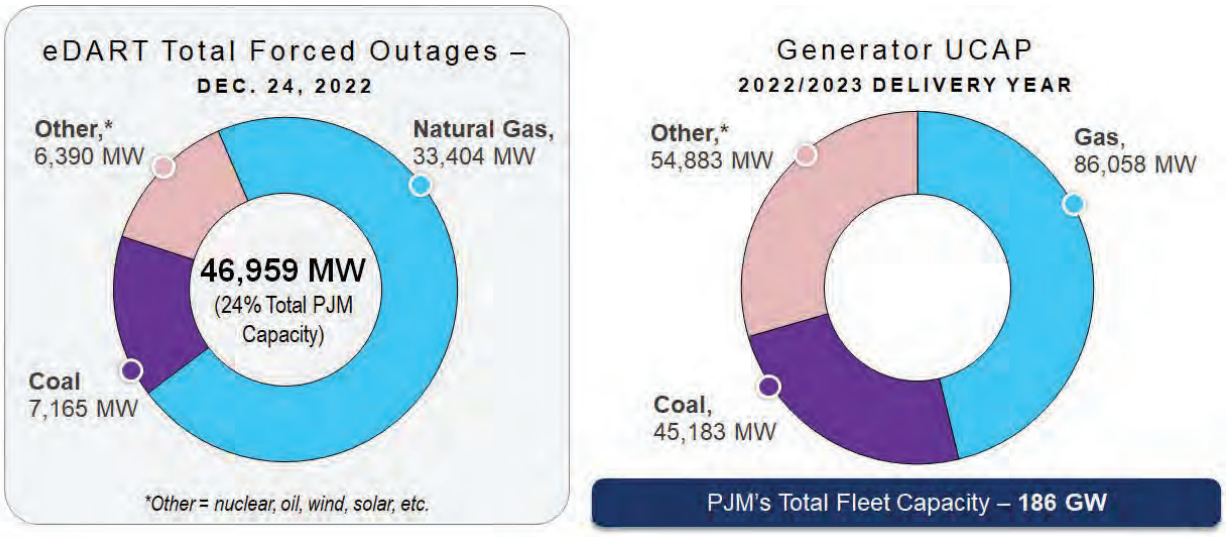
Elliott and did expect additional unplanned generation outages. For reference, the historic forced outage rate for winter is ~4.7%. The peak outage rate for the 2020/2021 winter period was 7.9%[7] and was 7.6%[8] for the 2021/2022 winter period.

While many generators performed well, the overall outage rate was unacceptably high. PJM had approximately 47,000 MW of units on forced outages during the hours when they were most needed. This correlates to a 24% forced outage rate. For comparison, the forced outage rate during the 2013 Polar Vortex was 22%. While a cross section of generation was impacted by the cold weather, gas plants and dual-fuel gas plants made up the majority of outages primarily due to mechanical issues likely resulting from the extreme cold.

Forced Outage Analysis

As presented in Figure 29, the majority of forced outage MW were from natural gas facilities. Approximately 70% of all outages were natural gas, about 16% coal, and the remainder were oil, nuclear, hydro, wind and solar.

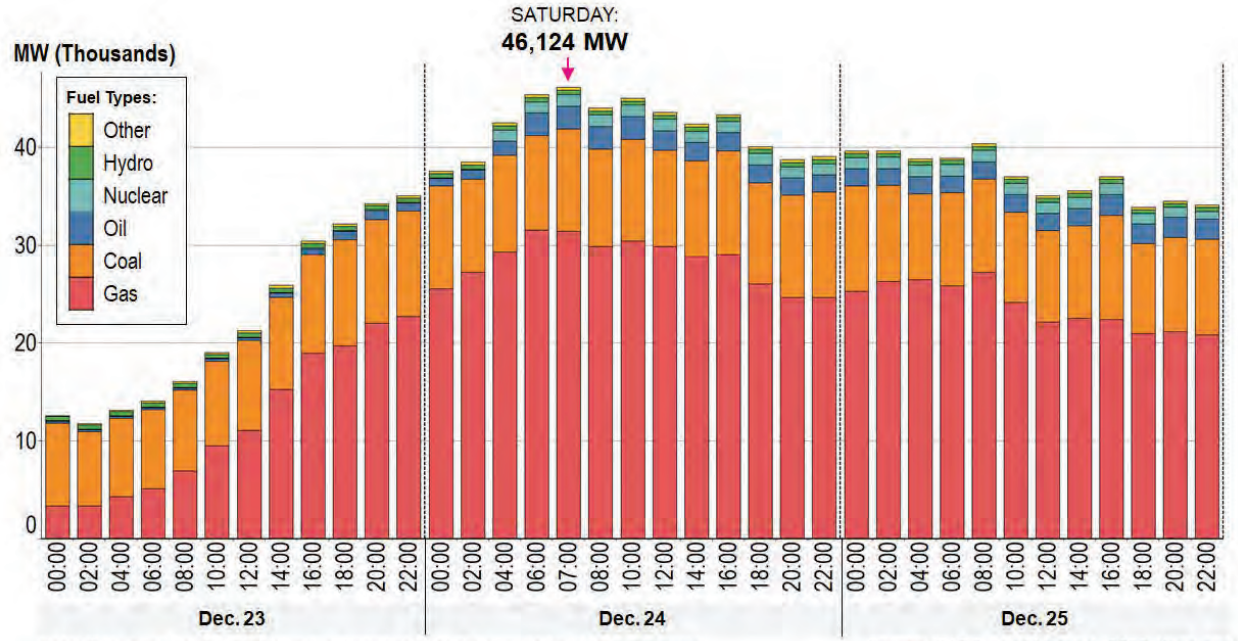
Figure 29. Forced Outages



As shown in the Figure 30, forced outages increased significantly and quickly throughout the day on Dec. 23 and peaked at over 46,000 MW at 07:00 on Dec. 24. Even as forced outage rates declined from the peak, they remained at an unacceptably high level through Dec. 25.

[7] Winter Operations of the PJM Grid: Dec. 1, 2020 – Feb. 28, 2021, PJM Operating Committee, April 8, 2021
[8] Winter Operations of the PJM Grid: Dec. 1, 2021 – Feb. 28, 2022, PJM Operating Committee, April 14, 2022

Figure 30. Dec. 23 and Dec. 24 Forced Outages

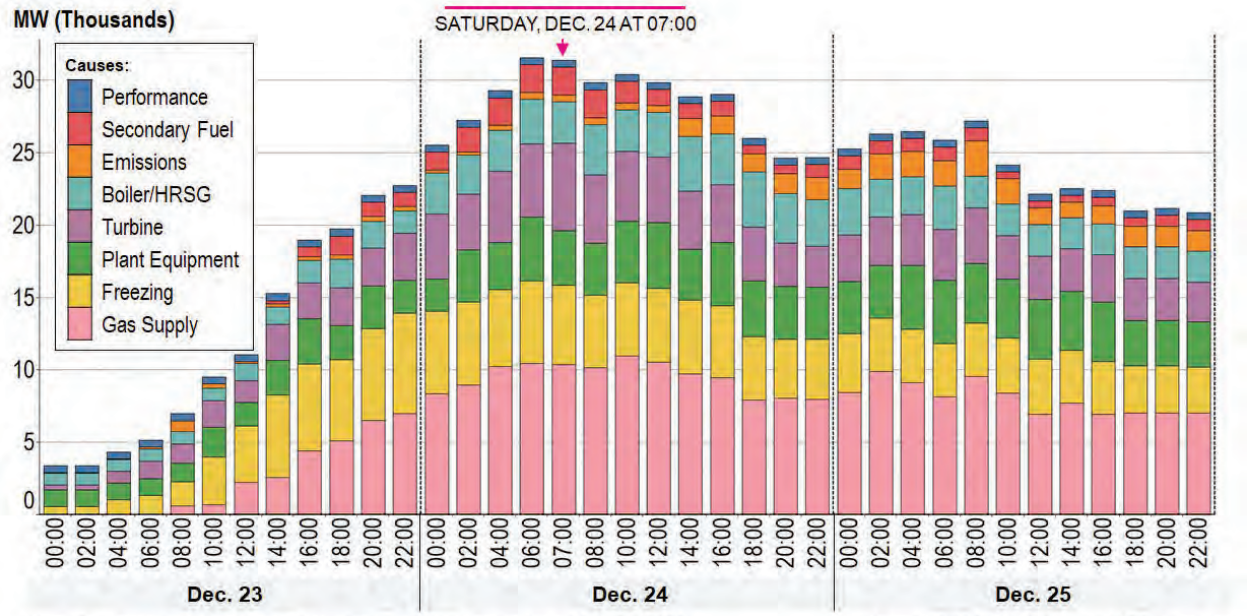


Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

Source: GADS as of March 1, 2023. Wind and solar unit outages are not included in the data.

Looking more closely at the causes for the generation outages by fuel type indicates that various plant and mechanical failures, including freeze-related issues, were the major reasons units were unavailable. Figure 31 presents the gas unit forced outages. As with other resource types, outages on gas units were primarily attributed to physical plant issues (freezing and plant equipment issues), but gas generators also experienced a significant level of gas supply issues. The gas supply-related outages accounted for just over 11,000 MW (approximately 13% of total gas generation capacity) at the peak hour on Dec. 24. By contrast, during the 2014 Polar Vortex, the total gas resources that were unavailable on peak due to gas supply issues was 9,300 MW (approximately 19% of total gas generation capacity).

Figure 31. Dec. 23, 24 and 25 Gas – Forced Outages/Derates by Cause

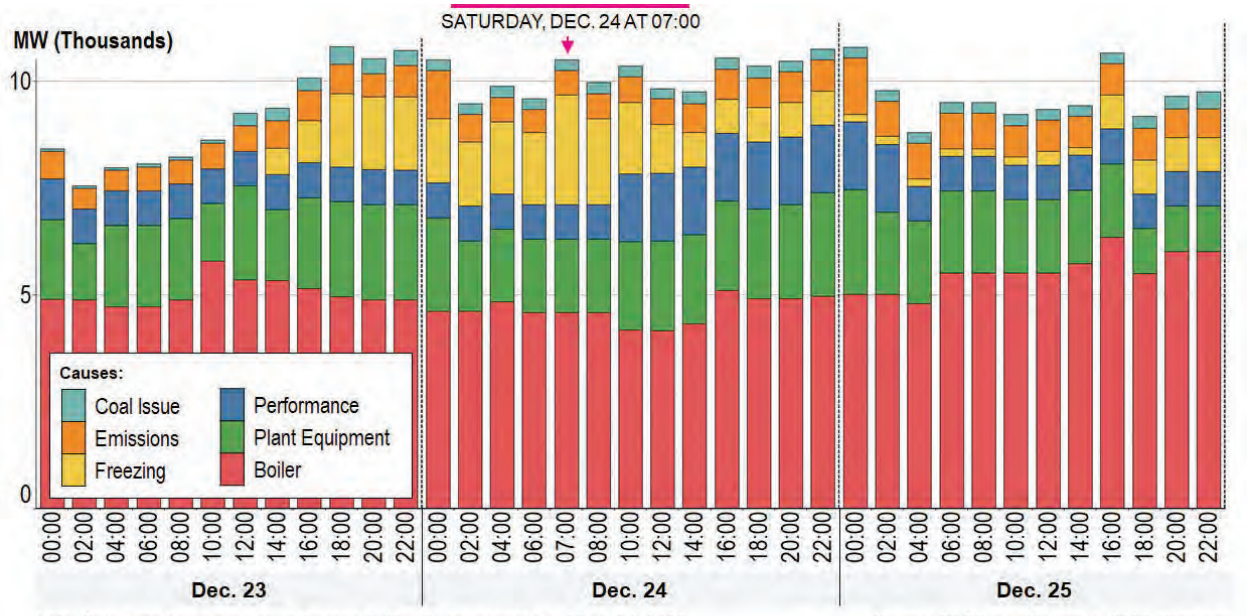


Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

Source: GADS as of March 1, 2023. Wind and solar unit outages are not included in the data.

As presented in Figure 32, for coal units, boiler problems and tube leaks were the primary cause of outages and derates followed by other plant equipment issues. Freezing issues increased starting around 14:00 on Dec. 23 and peaked at approximately 07:00 on Dec. 24.

Figure 32. Dec. 23, 24 and 25 Coal Forced Outages/Derates by Cause

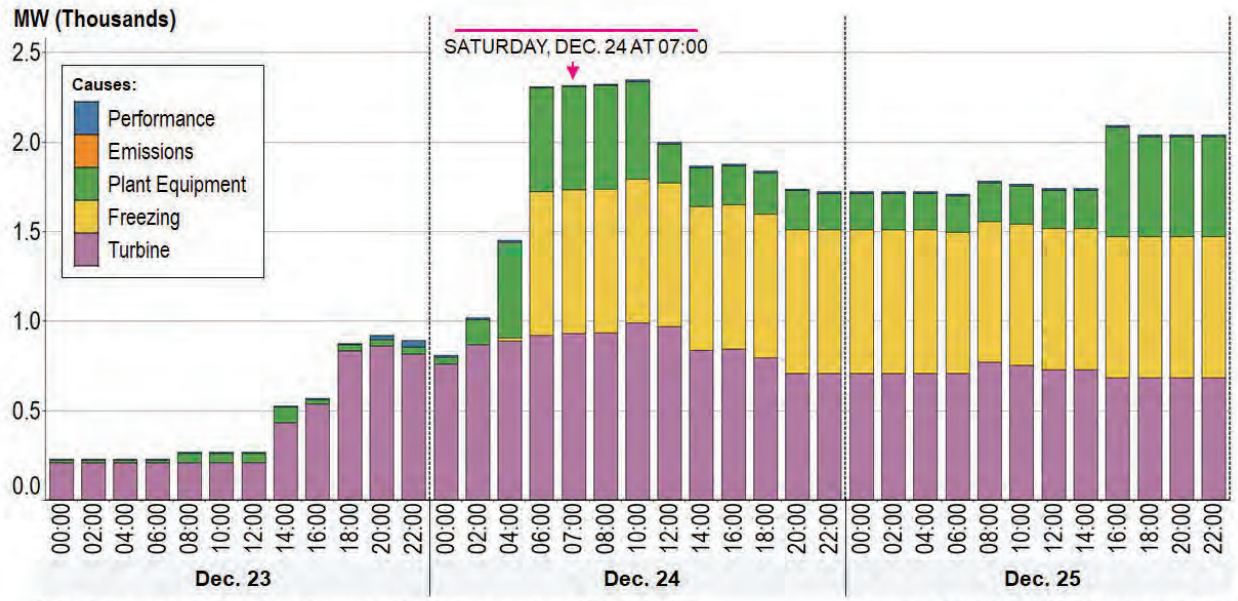


Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

Source: GADS as of March 1, 2023. Wind and solar unit outages are not included in the data.

As shown in Figure 33, for oil units, turbine issues accounted for a large majority of the outages. A significant amount of freeze-related outages and derates were experienced from 06:00 on Dec. 24, and continued throughout the day on Dec. 25.

Figure 33. Dec. 23, 24 and 25 Oil Forced Outages/Derates by Cause

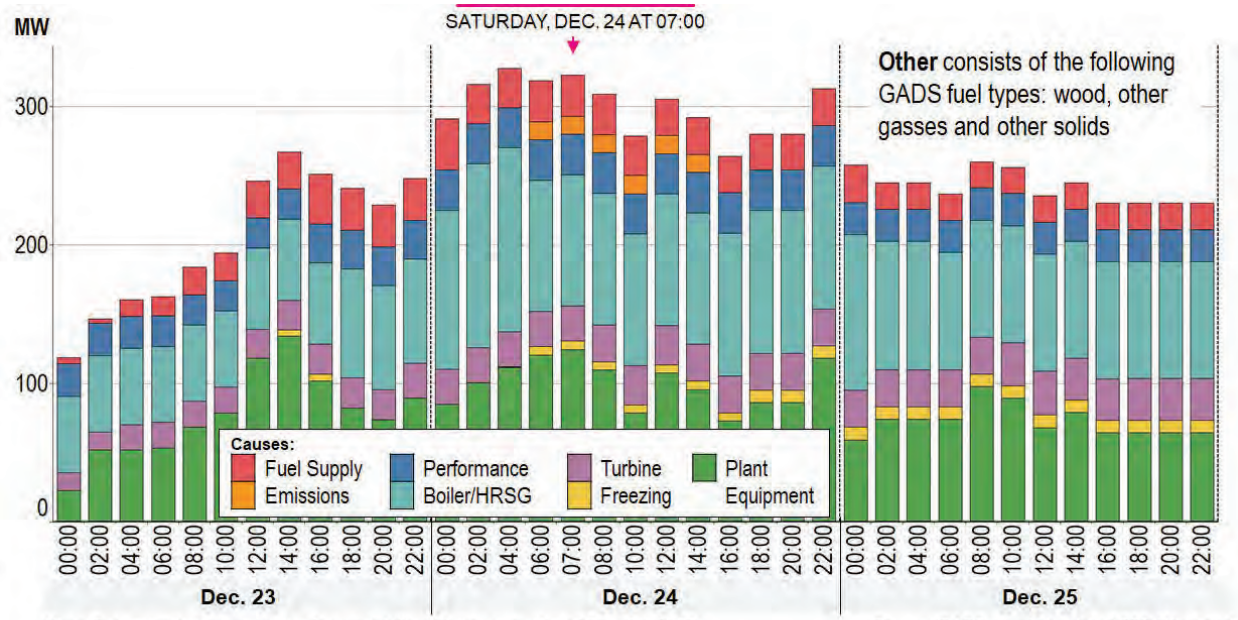


Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

Source: GADS as of March 1, 2023. Wind and solar unit outages are not included in the data.

As presented in Figure 34, for generators fueled by wood, other gases or other solids, most outages/derates were attributed boiler, HRSG and other plant equipment problems.

Figure 34. Dec. 23, 24 and 25 Other – Forced Outages/Derates by Cause

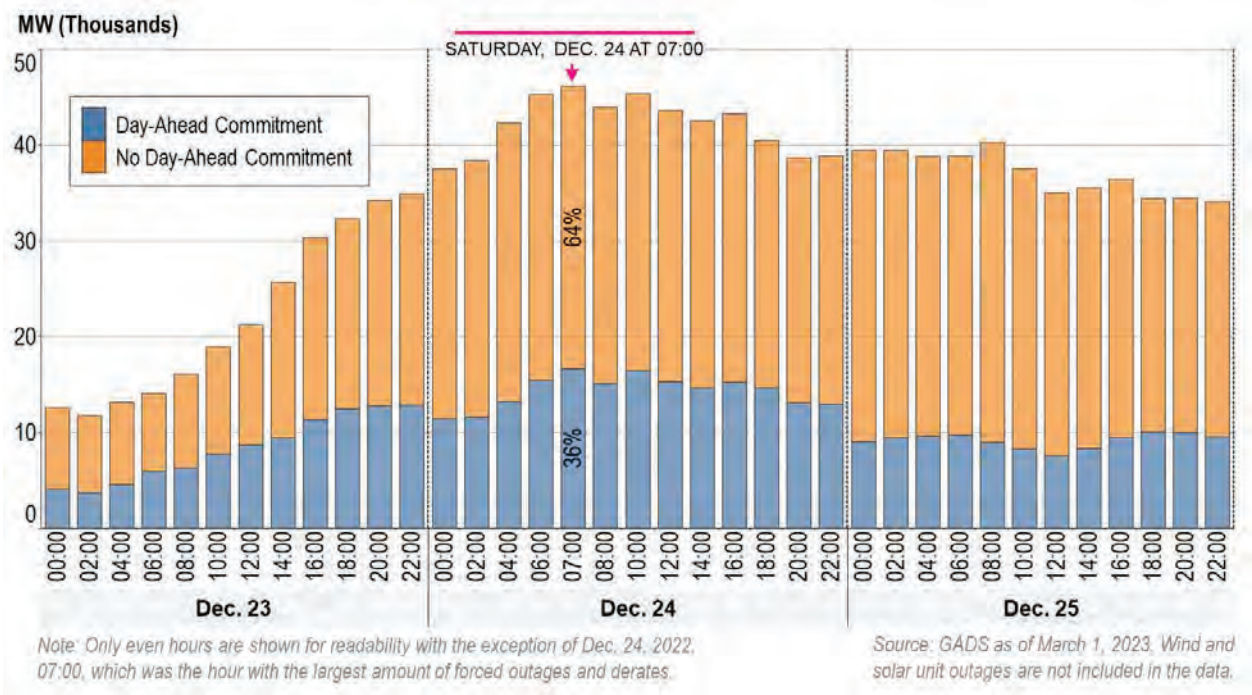


Note. Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

Source: GADS as of March 1, 2023. Wind and solar unit outages are not included in the data.

In addition to the causes of the forced outages and the outages by fuel type, Figure 35 presents the outages for units based on day-ahead commitments. This is an important piece of the puzzle to understand with respect to PJM's planning for the operating day. PJM always expects some resources will fail. On cold weather days in particular, this is considered and noted in PJM Manual 13. However, as Figure 35 shows, over 16,000 MW of generation that was committed in the Day-Ahead Market failed to perform.

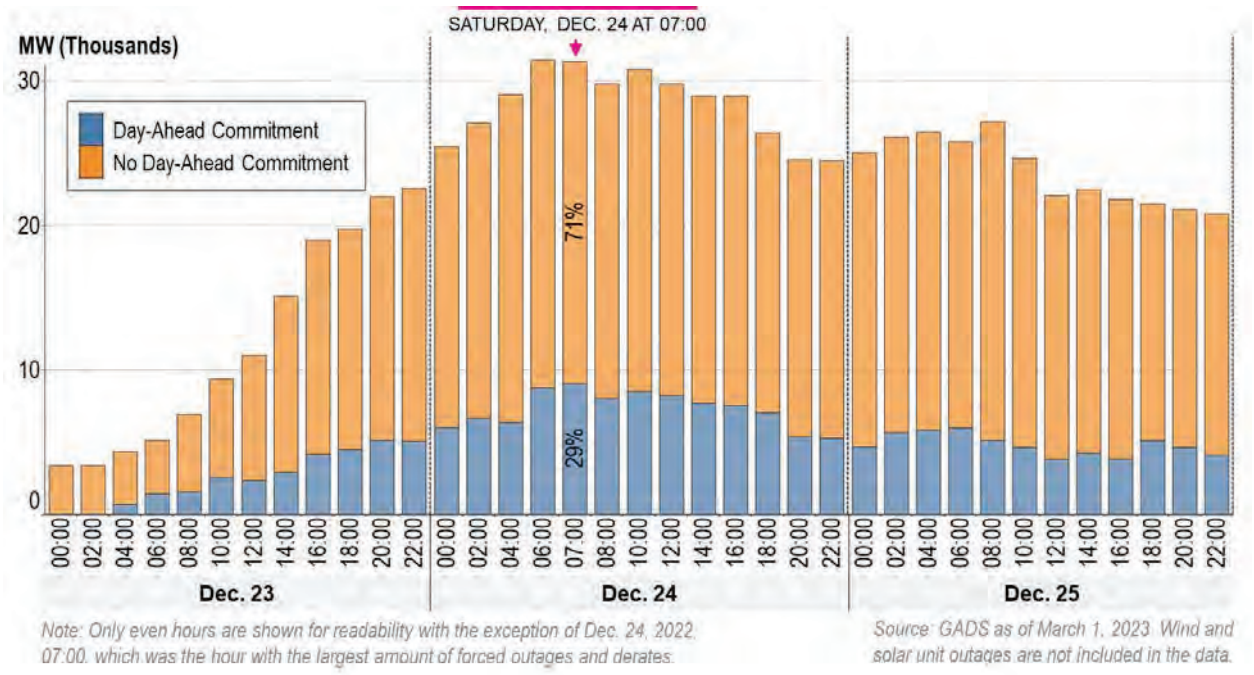
Figure 35. Dec. 23, 24 and 25 Forced Outages With and Without Day-Ahead Market Commitment



When scheduling replacement energy to account for the missing 16,000 MW, PJM was relying on the unit information submitted by Generation Owners to evaluate the amount of available reserves and the timelines needed to schedule those units if/when needed (15-minute notice, 30-minute notice, one-hour notice, etc.) As noted previously, PJM requires Generation Owners to update their parameters to reflect any changes from normal operating condition so that the reserve calculations are accurate. However, in the case of Winter Storm Elliott, these parameters were not updated for many generators. More specifically, the following information was not updated to align with actual operating conditions including longer notification times, extended minimum run times, inflexibility in dispatch range, etc. This was predominately related to gas-fired generators where pipeline restrictions, nomination deadlines and the unavailability of gas supply were not accurately reflected in generator operating parameters, despite having the ability to utilize Temporary Exceptions or Real-Time Values (PJM Manual 11, Sections 2.3.4.3 and 2.3.4.4) to convey this information accurately to PJM.

For the Dec. 23 operating day, only 6% (37 out of 578) of the gas-fired generators in the PJM system submitted increased notification time requirements. All others were reported as available to operate, with their normal operating parameters in place. This lack of timely and accurate information led to extremely challenging conditions for the PJM system operators that continued through the end of the day on Dec. 25. As presented in Figure 36, the failure of so many Day-Ahead Market committed units, coupled with the lack of generator parameter updates, led to a high volume of natural gas generators having no Day-Ahead Market commitment and then becoming forced outages due to lack of fuel.

Figure 36. Dec. 23, 24 and 25 Forced Outages With and Without Day-Ahead Market Commitment



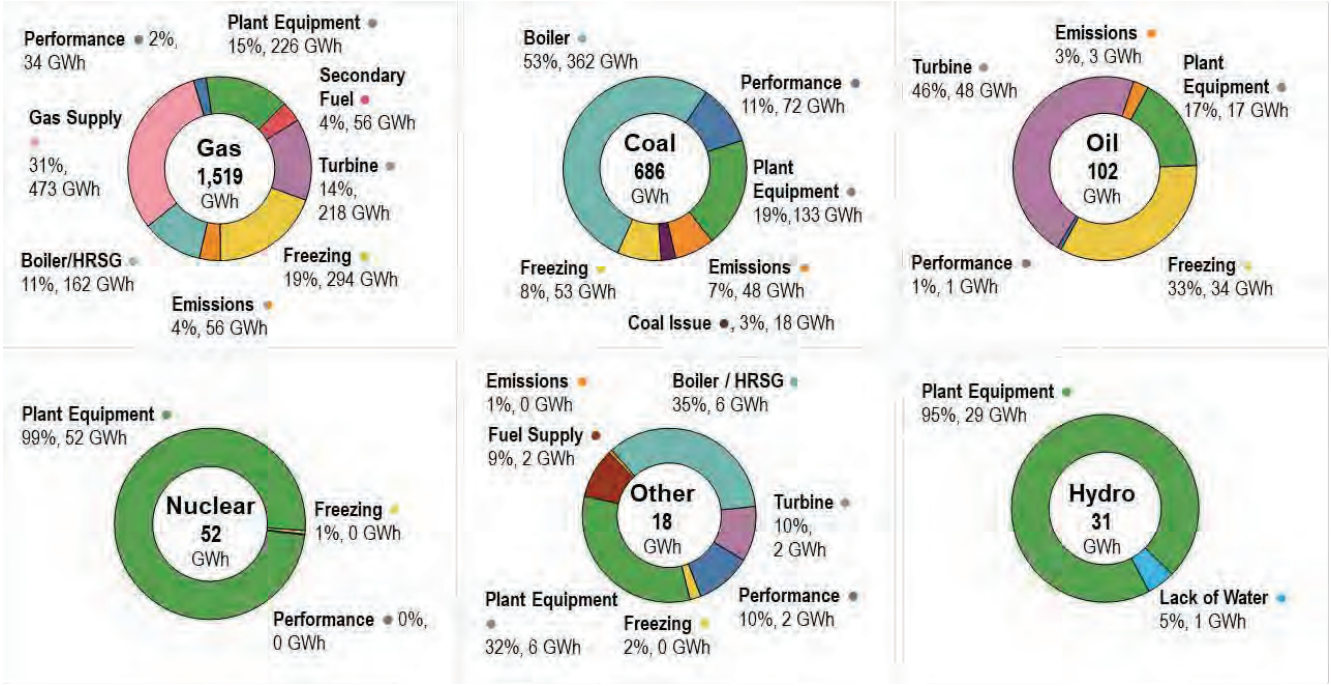
In addition to forced outages, approximately 6,000 MW of steam generation was called but was not online as expected per their time to start for the morning peak on Dec. 24. The vast majority of these resources were gas-fired resources.

The high rates of generator outages also limited PJM's ability to replenish pond levels for pumped storage hydro prior to the morning peak on Dec. 24. That left PJM with extremely limited run hours for pumped storage generation. Between forced outages, derates, generators that did not start on time, and the inability to fill pumped storage hydro ponds, PJM was operating with approximately 47,000 MW of generator unavailability for the Dec. 24 morning peak, including the unavailability of pumped storage resources to generate.

The highest forced outage rate during Winter Storm Elliott was over 24%, which is higher than PJM experienced during the Polar Vortex in 2014. This level of generation outages was unprecedented and not anticipated. PJM, along with the Independent Market Monitor, has undertaken efforts to determine what happened with these generators to understand both why these failures occurred and how to reduce them in the future. This is further discussed later in the report.

To effectively compare resource unavailability by fuel type and by cause during the Winter Storm Elliott event, both the reduction quantity and duration must be considered. While a 1,000 MW forced outage is much larger than a 100 MW forced outage, if the 1,000 MW forced outage only lasts one hour but the 100 MW forced outage lasts one day, then the 100 MW forced outage is a more significant unavailability event. Using MWh as the comparison metric incorporates both the magnitude and duration of the outage to give a more complete picture of the impact. Figure 37 presents the MWh analysis for a duration of Dec. 23 00:00 to Dec. 25 23:59.

Figure 37. Dec. 23, 24 and 25 Forced MWh by Fuel Type and Cause



In Figure 38, total available MWh for the period of Dec. 23 to Dec. 25 was calculated by multiplying GADS Net Dependable Capacity by 72 hours. The MWh outage rates shown in Figure 38 were then overlaid to show availability by fuel type.

Figure 38. Dec. 23, 24 and 25 Availability by Fuel Type

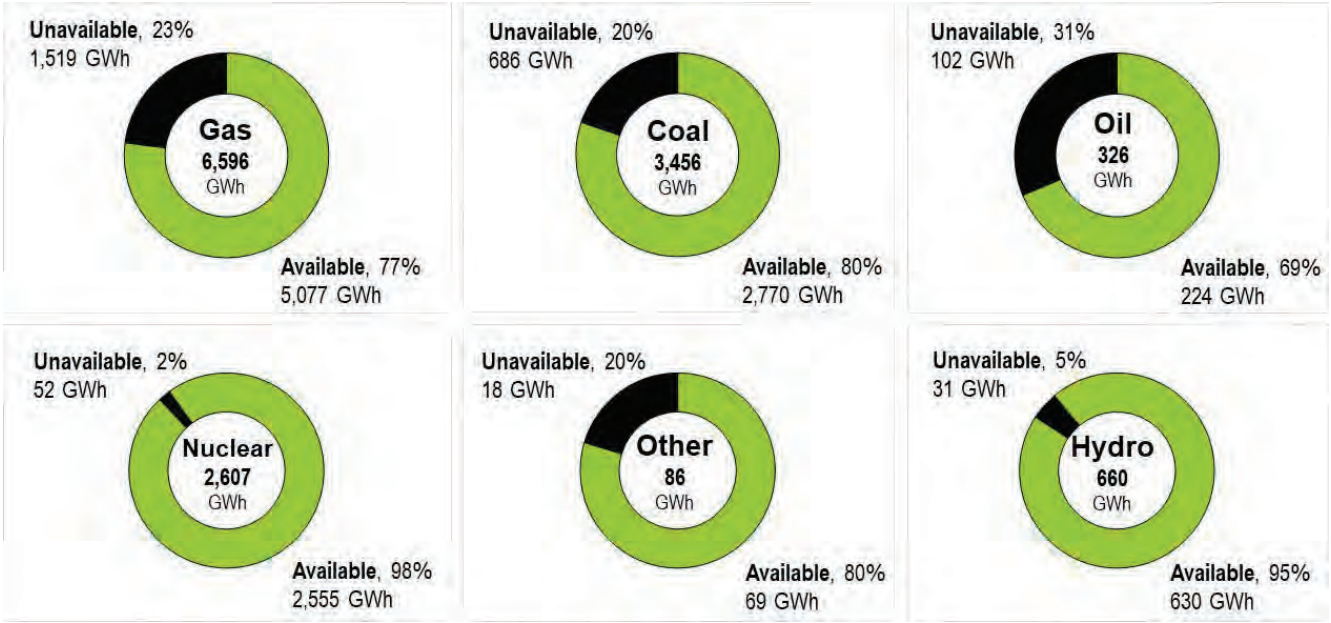
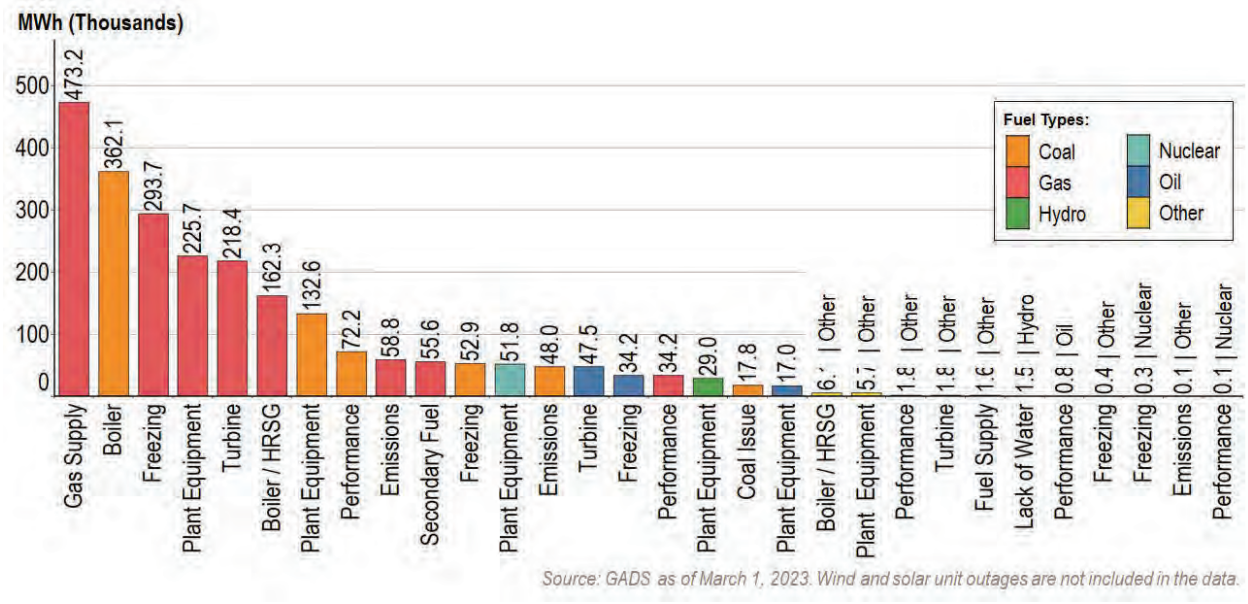


Figure 39 breaks down the outage causes further, considering both fuel type and outage cause. Overall, freezing, plant equipment issues – including boiler, heat recovery steam generator (HRSG) and turbine problems, and emissions make up the majority of outages.

Figure 39. Dec 23, 24 and 25 Forced MWh by Fuel Type and Cause



Generation Cold Weather Operating Limit Analysis

As noted previously, PJM issued a data request in 2022 to capture the Cold Weather Operating Limit (CWOL) for each generating unit. This information indicates the minimum temperature that each unit can reliably operate to. The chart to the left in Figure 40 presents the results of an analysis of the percentage of units that reported in GADs specifically as freeze-related causes for their outages and tripped/failed to start at actual temperatures above or below their reported minimum operating temperature limit. The second chart (in Figure 40) shows a similar analysis, but it uses the effective temperature (i.e., wind chill) instead of the actual temperature. As can be seen, the effective temperature is a better indicator for identifying when generators are at risk of experiencing freeze-related issues. Based on the GADS data, 21,355 MW of generation incurred a forced outage at or above their limit and 18,544 MW experienced a forced outage below their limit.

PJM then expanded this temperature analysis look at specific temperature ranges. The purpose of this analysis was to understand the magnitude of deviations from the reported operating limits. This analysis drilled down to specific temperature ranges where a unit incurred a forced outage at/above or below their CWOL temperature. Note that there is one unit in the 0°F category, indicating that it incurred a forced outage exactly at its CWOL temperature. From the data analyzed, the majority (13,349 MW) of forced outages occurred within 10°F of units' CWOL temperature. Conversely, 17 units (3,113 MW) incurred a forced outage more than 20°F above their CWOL temperature, which may indicate that they either overestimated the capabilities of the unit or did not provide a practical or realistic CWOL temperature to PJM. There were 4,685 MW (five units) that were able to operate 20°F or more below their CWOL temperature.

Figure 40. Cold Weather Operating Limit Comparison Against GADS Reported Outage and Temperature

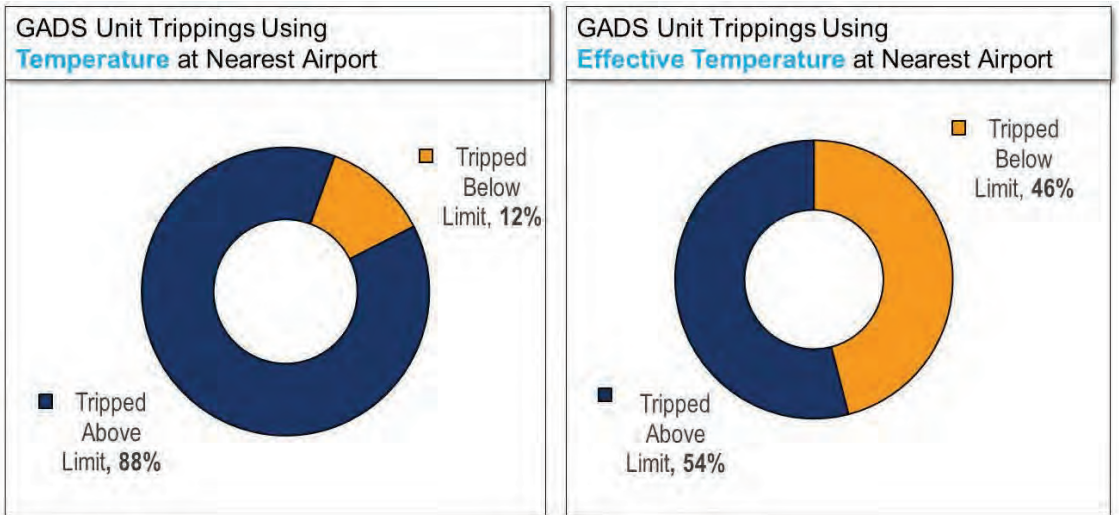
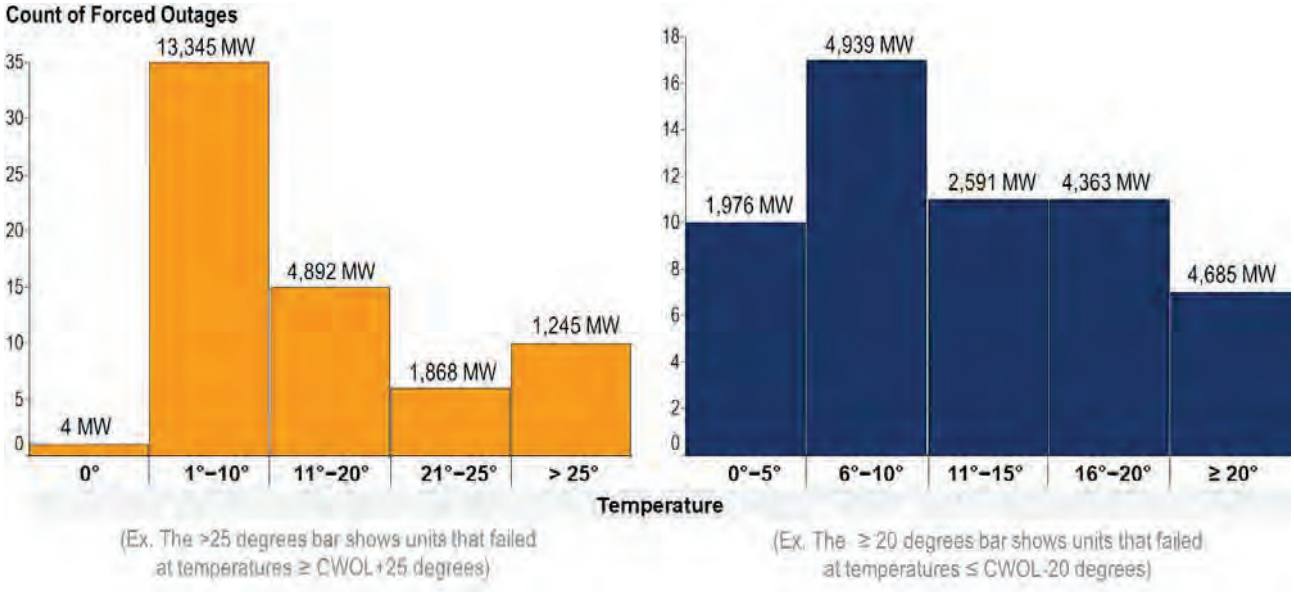


Figure 41 presents a comparison of the effective temperatures experienced by units at the time of a cold weather-related forced outage with their submitted CWOL temperature. The chart to the left presents the MW quantity of the units that failed at different temperatures ranges prior to reaching their CWOL temperature. The chart to the right (presented in blue) presents unit failures below their CWOL temperature.

Figure 41. Temperature Deviations for Weather-Related Forced Outages



Renewable Generation Performance

Figure 42 and Figure 43 represent the performance of both wind and solar resources. Both charts utilize a similar method to represent the maximum potential output, labeled Available ICAP, by taking the total Installed Capacity and subtracting out any generation outages (planned, maintenance and unplanned). The Available UCAP represents the expected performance based upon the capacity value of the Available ICAP. For the 2022/2023 Delivery Year, this value is 13% for wind and 38% for solar.

As shown in Figure 42, wind generation on average performed above its expected capacity. This is not unexpected and something PJM sees on the coldest winter days where the wind speed also increases customer demand due to increased heating needs. However, it should be noted that this does not hold true during the summer where the highest electric demand is coincident with the lack of any wind and its associated cooling effect on air conditioning usage.

Solar, on the other hand, only met or exceeded its capacity expectations during a few hours each afternoon, which was not coincident with the peak electric demand periods. That said, as noted above with wind, it is important to point out that lack of the heating from the sun does coincide with high heating demand in the winter, but the converse is true in the summer. During the peak summer hours, the electric demand is driven by heating from the sun, which is also when solar generation output is at its peak.

Figure 42. Wind Resource Performance

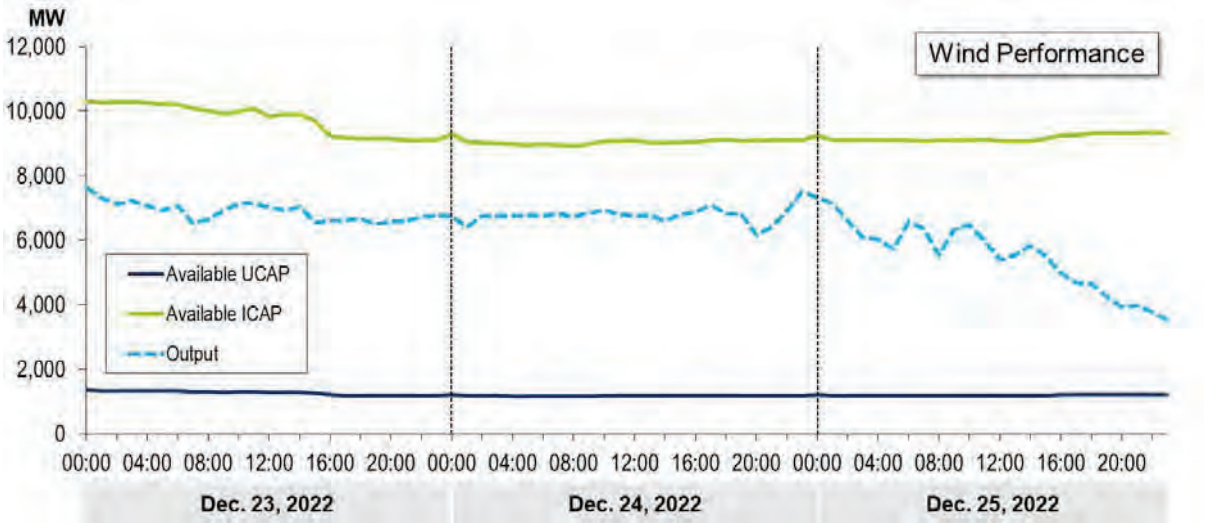
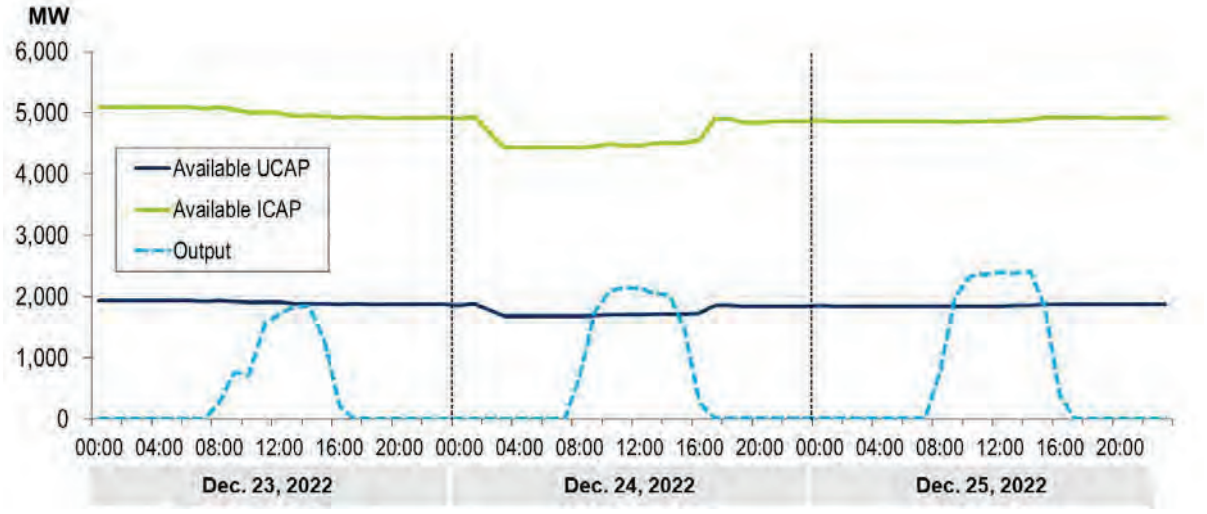


Figure 43. Solar Resource Performance

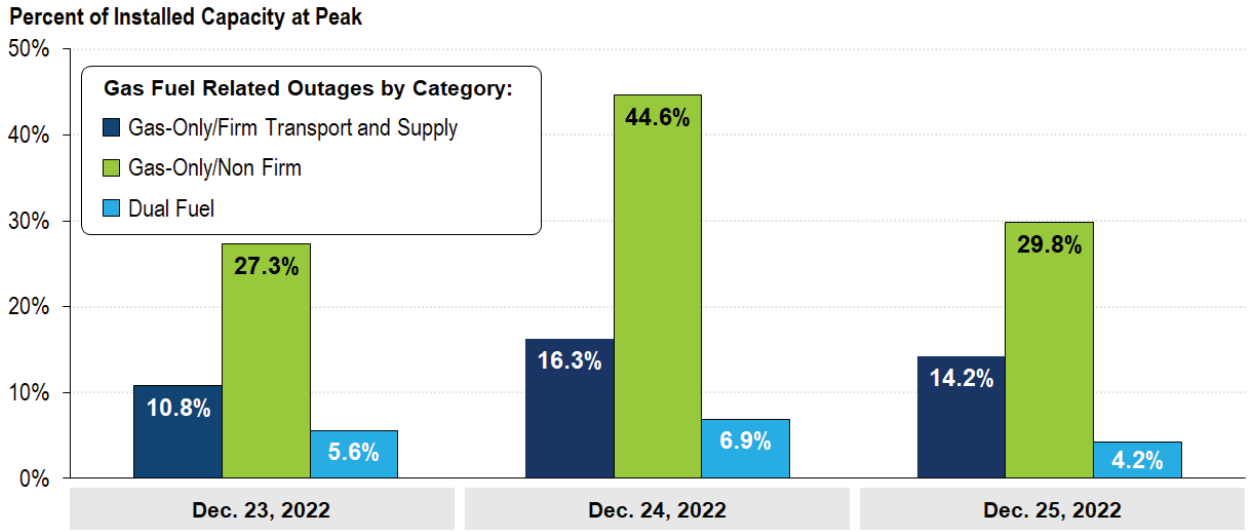


Fuel Security Observations

While PJM has focused on the 24% forced outage rate overall and by fuel type in this report thus far, it is also important to note that 76% of the generation fleet did perform well. In particular, hydro and nuclear had availability rates of 95%

and 98%, respectively, as shown in Figure 36. In addition, wind performance was well above the expected output, as shown in Figure 42. Furthermore, one of the more stark observations is the difference in the performance of gas units with respect to their level of fuel security. As shown in Figure 44, duel-fuel units performed extremely well, with an average forced outage rate of 5.6% with respect to fuel-related outages. Whereas gas units with firm and non-firm fuel supply arrangements experienced forced outage rates of 13.8% and 33.9%, respectively. While this performance data is representative of only the Winter Storm Elliott period, it does highlight the importance of having secure fuel arrangements to minimize the risk of losing access to fuel supply when it is most urgently needed.

Figure 44. Gas Fuel-Related Outages by Category by Percent of Installed Capacity at Peak



Generation Parameter and Outage Reporting Tools

PJM and members use several tools to collect and manage generator outage data, including the following applications:

- Markets Gateway – Markets Gateway is a PJM tool that allows members to submit generation schedules, as well as other information and data needed to conduct business in the Day-Ahead, Regulation and Synchronized Reserve Markets.
- eDART – eDART (Dispatcher Application and Reporting Tool) is a real-time and forward-looking tool that allows Generation and Transmission Owners to submit generation and transmission outage requests. eDART allows its users to manage their outage data by viewing the status of their outages and obtaining outage reports.
- eGADS – The Generator Availability Data System (eGADS) supports the submission and processing of generator outage and performance data as required by PJM and North American Electric Reliability Corporation (NERC) reporting standards. eGADS is an after-the-fact outage reporting tool used to capture more detailed information about generator outages that are submitted several weeks after the outage.

The generation schedules submitted via Markets Gateway are collections of generator parameter operating limits and offer data. There are three types of schedules that can be submitted, as defined in PJM Manual 11, Section 2.3.4:

- Cost-Based Schedule – Cost-based schedules must comply with limits placed on certain parameters In addition, generation resource cost-based energy offers must be developed in accordance with Manual 15: Cost Development Guidelines and PJM's governing documents.

- Price-Based Parameter Limited Schedule (PLS) – Price-based PLS schedules must comply with limits placed on certain parameters. Price-based PLS energy offers may be market based.
- Price-Based Schedule (non-PLS) – Non-PLS price-based schedules are not subject to the parameter limits defined in and may submit market-based energy offers.

Market Sellers of capacity resources are required to submit schedules in Markets Gateway, based on whether the unit is price based or cost based:

- For Price-Based Units: At least one cost-based schedule is parameter limited and a price-based PLS.
- For Cost-Based Units: At least one cost-based schedule is parameter limited. Certain parameters on cost-based and price-based PLS schedules are subject to defined limits.

It is important for Market Participants to ensure the generator parameter operating limits and offer data are up to date in Markets Gateway. In the event that PJM declares a Maximum Generation Emergency; issues a Maximum Generation Emergency Alert, Hot Weather Alert or Cold Weather Alert; or schedules resources based on the anticipation of a Maximum Generation Emergency, Maximum Generation Emergency Alert, Hot Weather Alert, or Cold Weather Alert for all or any part of such operating day, generation resources are committed on the more economic schedule between their price-based PLS and price-based schedule.

Generation resources are required to report outages in advance of the operating day (when known) and in real time through the eDART application. This reporting must include the cause of the outage, as indicated in PJM Manual 14D. Furthermore, PJM also requires more detailed after-the-fact reporting of all outages in the GADs system by the 20th of the following month.

Generation Owners may augment previous eDART submissions to reflect additional forced outages, but retroactive eDART changes to remove or reduce previously submitted forced outages are not permitted as noted in PJM Manual 10, Section 2.2.1. If a Market Participant needs to remove or minimize a forced outage status previously submitted in eDART, such a revision must be submitted via eGADS and not eDART. PJM does not validate data on causes of outages. If a unit is out of service, it could be liable for a penalty. The eGADS outage is reported to NERC.

As part of the Cold Weather Alert, PJM requires generators to update their availability and operating parameters (notification time, start time, unit cost, etc.) in the Markets Gateway and eDART tools. In 92% of cases where generators failed to perform, PJM either had little or no notice, and very few resources provided updated parameters to reflect known fuel supply constraints or other unit issues.

Lack of timely reporting to PJM's eDART system during Winter Storm Elliott presented challenges for PJM Operations Planning. Many eDART outage submittals lacked sufficient details or inaccurate information, such as cause codes, requiring manual review and outage cause categorization for post-event analysis. PJM and Monitoring Analytics observed a large discrepancy (between 5,000 to 10,000 MW, varying over the period of the event in unplanned outage totals upon initial review of outage data in eDART and GADs). Monitoring Analytics issued a notice to Generation Owners with the recommendation to review and update or submit outage tickets in eDART and GADs to capture outages accurately for post-event analysis. Nearly 300 new outage tickets totaling more than 21,000 MWs of reductions and over 100 revisions to prior tickets totaling more than 14,000 MW of reductions were submitted after the Winter Storm Elliott event.

In addition to Operations Planning, the outage data has many additional use cases, including several of the charts and figures in this report. Having accurate and near real-time eDART outage information helps PJM understand the nature of

the outage and a potential return time to bring the unit back in service. The eGADS data are utilized in the capacity market to determine the availability of a resource in megawatts when clearing. Having updated outage information is expected under normal conditions and even more critical during emergency conditions like Winter Storm Elliott.

Gas Availability Issues

During the morning of Friday, Dec. 23, PJM's Gas-Electric Coordination Team held discussions with many of the interstate gas pipelines serving PJM gas generation to assess system operating conditions. At that point, the cold front had not yet arrived in the eastern part of the PJM system, and, in general, the pipelines in that region were reporting strong operating conditions with high line pack and low-to-moderate demand levels. Meanwhile, the severe cold had already entered the central and Western PJM zones where both gas and electric demand had begun to ramp up quickly corresponding to the rapidly dropping temperatures.

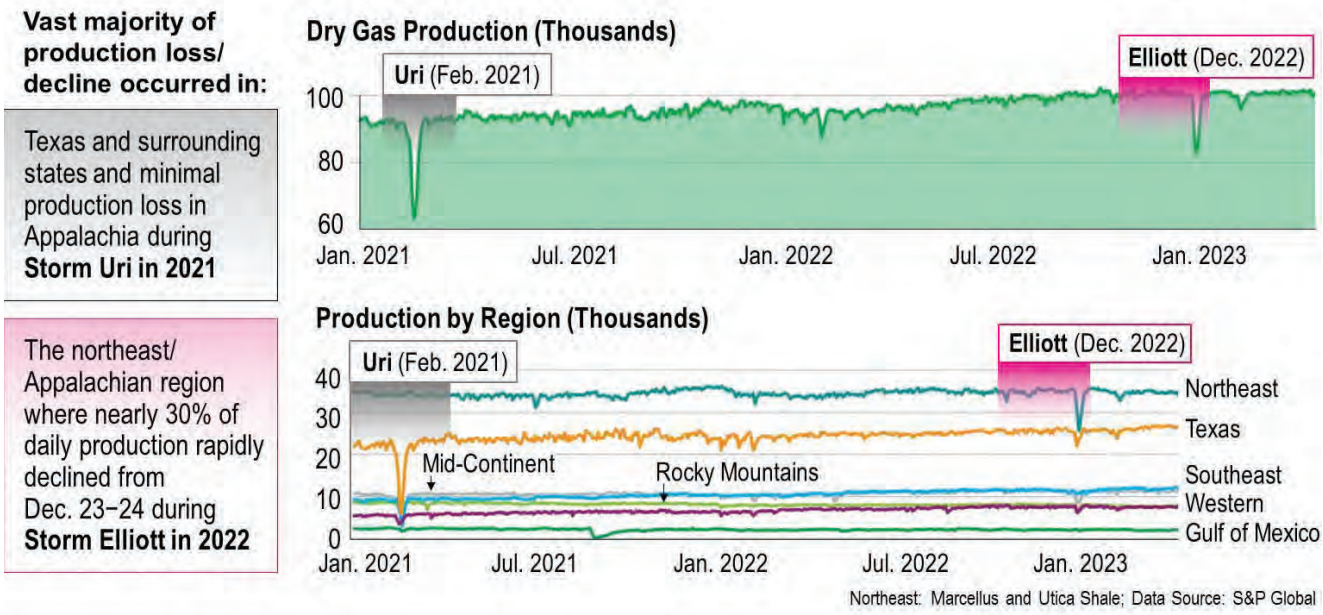
In addition, during this time, several local gas distribution companies (LDCs) began to issue interruption notices for a small number of generators behind their citygates. This is not unexpected during very cold temperatures as LDCs, by nature of their service tariffs, can interrupt gas generation customers in favor of higher priority residential and commercial human needs customers. (Generators served by LDCs make up slightly less than 20% of all gas-fired capacity in the PJM system.) In general, these units are typically smaller combustion turbines with many having dual-fuel capability during the winter months.

The PJM Gas-Electric Coordination Team, as they do each day during the winter months, provided daily gas risk assessment reports to PJM Dispatch to identify which areas of the system may be at higher risk of gas unavailability due to pipeline conditions and restrictions. These assessments also review which units have confirmed gas scheduled on their respective pipelines and compares that to the unit's award commitment to determine if any units haven't scheduled or are short supply. (While gas volumes nominated to generators that are directly connected to interstate pipelines are publically available, nominations to facilities located behind LDC citygates are not and as such not available to PJM. These LDC-served generators represent approximately 20% of the total installed gas generating capacity on the system.) PJM Dispatch uses this information in conjunction with the operating limitations information that the units are providing in eDART and Markets Gateway to have a better understanding of unit availability and which portions of the system are at greater risk of pipeline capacity and gas supply constraints.

While interactions with the pipelines and LDCs are mainly focused on the transportation of natural gas, the supply of natural gas is equally as critical in maintaining reliable fuel deliverability. Natural gas production and midstream facilities, particularly at the wellhead, are subject to freeze-offs during very cold conditions. During Winter Storm Uri in February 2021, there was an extremely large drop in daily gas production due to well freeze-offs in Texas and surrounding states, while very little freeze-off activity occurred in the northeast/Appalachian shale region where most of the gas consumed in PJM originates.

Figure 45 compares natural gas production declines between Uri and Elliott.

Figure 45. Natural Gas Production Declines – Uri Versus Elliott



While there was very little direct impact on PJM during Uri, PJM did reach out to various gas suppliers after Uri to better understand the risk of well freeze-offs and the winterization procedures utilized to mitigate supply loss during cold snaps. The consensus in feedback indicated that natural gas production infrastructure in the northeast was much more hardened and significantly better suited to withstand low temperatures compared to production and processing infrastructure in the south and southwest. Taking that information into consideration and examining past well freeze-offs that actually occurred in the Appalachian region, the best estimate of gas supply loss was around two to three billion cubic feet per day for a one-to-three-day period, which represents approximately 5% to 8% of total northeast daily production. This would not have been unprecedented as it was experienced in prior winter cold snaps, some with temperatures even colder than Elliott. In the end, what ended up occurring was a daily Appalachian gas production loss of 10 to 11 billion cubic feet or approximately 30% of total northeast daily production.

The storm and the rapid onset of cold temperatures heavily impacted natural gas production, particularly in the Marcellus and Utica basins, which are the predominant source of the natural gas procured by gas generation in the PJM footprint. This led to significant loss of gas supply for all downstream gas consumers, particularly larger, more efficient gas-fired power generation units that require nominated supplies flowing at uniform and higher pipeline pressures to operate.

- Supplies from the Appalachian Basin shrank 27% from usual levels, according to reports by Bloomberg.
- Well freeze-offs sent production plunging by more than 20% in Pennsylvania, while output more than halved in Ohio, constraining supplies into the Northeast and the Tennessee Valley.
- There were also losses of pipeline compression that occurred in Ohio and Pennsylvania, which tended to exacerbate gas delivery issues.

Exacerbating the lack of gas supply was the fact that Elliott occurred over a long holiday weekend, which tends to have lower gas supply liquidity. Many gas buyers, especially LDCs and other customers with more predictable gas usage levels, purchase their gas supplies on Friday for the Saturday, Sunday and Monday gas days. Gas generators in many cases need to buy their gas supply each day of the weekend period based on their awarded or anticipated dispatch. With

the majority of gas traded on Friday, the market for gas commodity can become less liquid, resulting in increased supply scarcity and potentially higher intraday gas prices.

Risk of Load Shed

PJM was faced with an unprecedented amount of unplanned generation outages during Winter Storm Elliott. Operations were critical on the evening of Dec. 23 and the morning of Dec. 24. Roughly 47,000 MW of generation was unavailable during the morning hours of Dec. 24. PJM was at an increased risk of load shed approaching the morning peak on Dec. 24. If another large unit was lost or imports from NYISO into PJM were cut, PJM would have considered initiating a Voltage Reduction Action, which would have resulted in approximately 1,700 MW of relief, as captured in PJM Manual 13, Section 2.3 on the Voltage Reduction Summary Table. If necessary, this action would have been followed by a Manual Load Dump Warning to communicate load dump allocations to Transmission Owners, and then a Manual Load Dump Action would be implemented if needed, followed by with the issuance of an EEA-3.

The Voltage Reduction Summary table in PJM Manual 13 should be reviewed with PJM Transmission Owners to confirm current capabilities given the changing composition of load.

Non-Retail Behind-the-Meter Generation (NRBTMG) Performance

The Maximum Generation Emergency Actions issued on Dec. 23 and Dec. 24 triggered the requirement for PJM members to load non-retail behind-the-meter generation[9] (NRBTMG). Although PJM system operators do not directly dispatch NRBTMG units, once a Maximum Generation Emergency Action or Deploy All Resource Action emergency procedure is declared in an area, NRBTMG units located in the area are requested to operate at the unit's maximum net or gross electrical power output, subject to the equipment stress limits for the unit.

Winter Storm Elliott was the first time that PJM evaluated NRBTMG units for emergency event performance. There were 339 NRBTMG units in the RTO that were expected to operate and provide 1,316.1 MW of generation during Winter Storm Elliott. The overall performance of the NRBTMG units in the RTO was also well below expected levels, with NRBTMG unit performance shortfalls totaling 888.8 MW and 635.3 MW for the Dec. 23 and Dec. 24 emergency events, respectively. For both events, the percent performance (i.e., average output during emergency event divided by expected performance) for both the Dec. 23 and Dec. 24 events was less than 50%.

Municipal electric systems, electric cooperatives, and electric distribution companies are permitted to use operating NRBTMG to net against their wholesale load. As a result, the load associated with NRBTMG is not required to carry reserves equal to the target installed reserve margin of 14.9% for the 2022/2023 Delivery Year. NRBTMG units that fail to operate during maximum generation emergency conditions can place an additional strain on the PJM system to provide generation to cover the load that NRBTMG typically serves.

Scheduled outages (full or partial) of NRBTMG units are reported to PJM through the Capacity Exchange tool. PJM does not review or approve NRBTMG scheduled outages. Only scheduled outages during the period of October through May and reported to PJM in advance of an emergency event can be used to excuse the unit for failing to perform as expected and eliminate or reduce their performance shortfall. Excusals for scheduled outages reported in advance of the Dec. 23 and Dec. 24 emergency events were granted to a number of units.

[9] Non-retail behind-the-meter generation (NRBTMG) is behind-the-meter generation that is used by municipal electric systems, electric cooperatives and electric distribution companies to serve load in a wholesale area. A NRBTMG unit delivers energy to a wholesale area's load without using the transmission system.

Failure of NBTMG units in a wholesale area to perform as expected during Winter Storm Elliott does not result in explicit financial penalties to be assessed in a member's PJM bill; however, failure to perform results in implicit penalties to the wholesale area through increased transmission charges for 2024 calendar year and capacity charges for the 2024/2025 Delivery Year. For NRBTMG units in a wholesale area that fail to perform, a netting reduction penalty amount for an emergency event is calculated as 10% of the net unit performance shortfalls in the wholesale area.

A netting reduction penalty amount will reduce the amount of the operating NRBTMG that is allowed to net against the wholesale area load during coincident peak hours during the Nov. 1, 2022, through Oct. 31, 2023, period and result in an upward adjustment to the wholesale area's network service peak load for the 2024 calendar year and obligation peak load value for the 2024/2025 Delivery Year. The total netting reduction penalty amount for the RTO as a result of Winter Storm Elliott was 153.8 MW (89.4 MW for Dec. 23 and 64.4 MW for Dec. 24).

Table 2 summarizes the NRBTMG performance results for the RTO.

Table 2. Dec. 23 and Dec. 24 NRBTMG Performance Results

	Dec. 23, 2022	Dec. 24, 2022
Expected Performance (MW)	1,316.1 MW	1316.1 MW
Unit Performance Shortfalls (MW)	888.8 MW	635.3 MW
Netting Reduction Penalty Amount (MW)	89.4 MW	64.4 MW

Market Outcomes

The Market Outcomes section of the report presents both the Day-Ahead and Real-Time market results for Dec. 23 and Dec. 24, including the ancillary services markets. This section also presents the analysis of Performance Assessment events. Appendix A presents market operations background information.

Day-Ahead Market Results

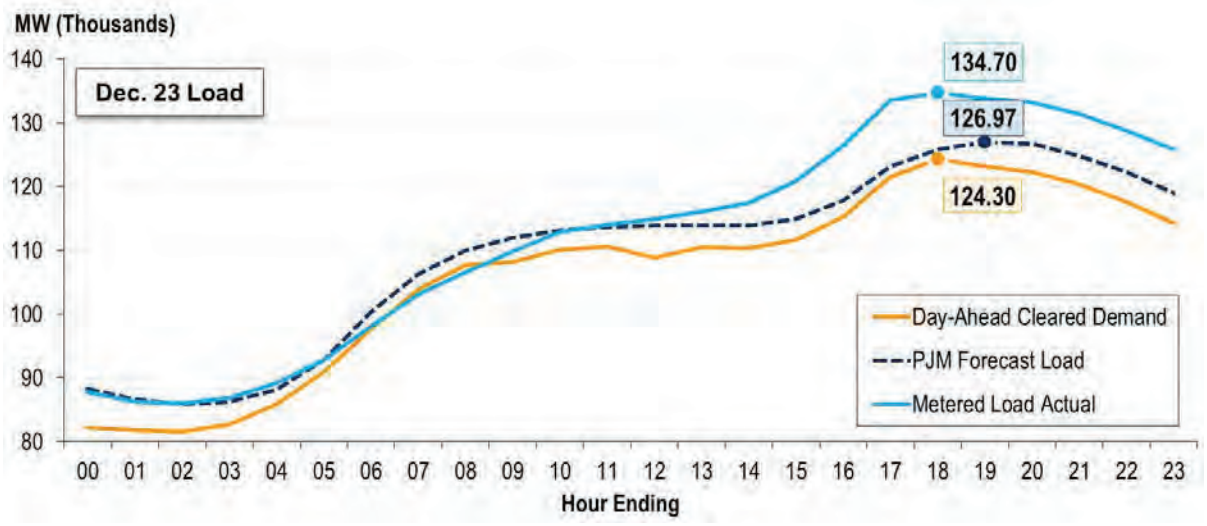
The Day-Ahead Energy Market is a forward market in which hourly clearing prices are calculated for each hour of the next operating day, based on generation offers, demand bids, increment offers, decrement bids, up-to-congestion bids and bilateral transaction schedules submitted into the Day-Ahead Energy Market. Additionally, the Day-Ahead Energy Market also incorporates reliability commitments by PJM system operators and reserve requirements into the analysis. Day-Ahead Energy Market enables participants to purchase and sell energy at binding Day-Ahead LMPs.

The resulting day-ahead hourly schedules, generated by the dispatch run, and Day-Ahead LMPs, generated by the pricing run, represent binding financial commitments to the Market Participants. The Day-Ahead Market settlement is calculated for each Day-Ahead Settlement Interval (currently hourly) based on scheduled hourly quantities resulting from the dispatch run and on Day-Ahead hourly prices resulting from the pricing run.

Day-Ahead Load and Prices

Figure 46 presents the cleared bid demand, including decrement bids and up-to-congestion bids.

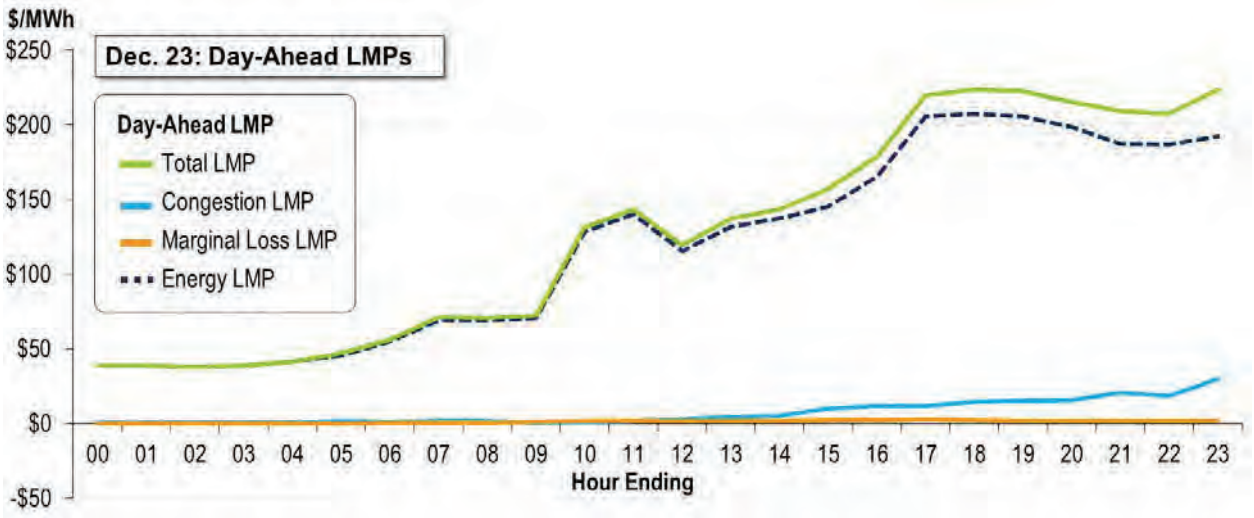
Figure 46. Dec. 23 Day-Ahead Cleared Demand, Forecast Load and Metered Load



For Dec. 23, the day-ahead demand cleared at approximately 124,300 MW, while the actual metered load, including the deployment of Demand Response, came in at approximately 134,700 MW, resulting in a net of approximately 10,400 MW more load in real time than was captured in the Day-Ahead Market cleared demand. PJM's original forecast on Dec. 22 at 18:00 was approximately 126,700 MW, which was about 7,700 MW under the actual load, less Demand Response.

Figure 47 presents the Day-Ahead LMPs for Dec. 23.

Figure 47. Dec. 23 Day-Ahead LMPs

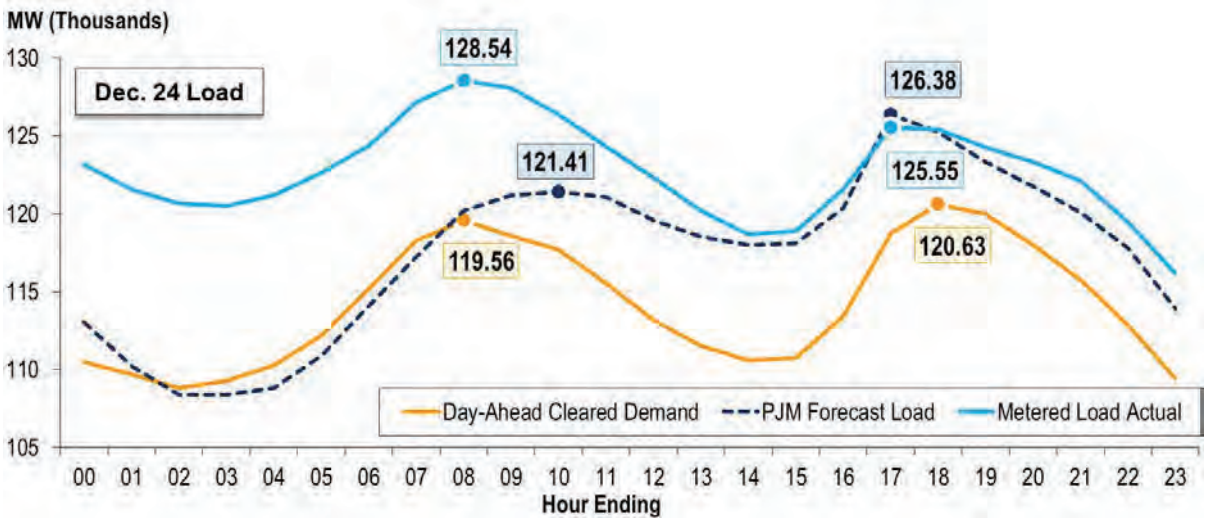


The Day-Ahead LMPs for Dec. 23 were higher than a typical Day-Ahead price, with a peak hourly LMP of $224/MWh. For example, the monthly load-weighted LMP for December 2022 was $93.39/MWh[10]. In the Day-Ahead Market, energy shortage conditions did not occur. LMPs increased in the Day-Ahead Market through the day based on the increasing load levels shown in Figure 47.

[10] Market Monitor Report presentation by Monitoring Analytics. PJM Members Committee Webinar, May 22, 2023.

Figure 48 presents the cleared bid demand, including decrement bids and up-to-congestion bids, and the resulting Day-Ahead prices for Dec. 24.

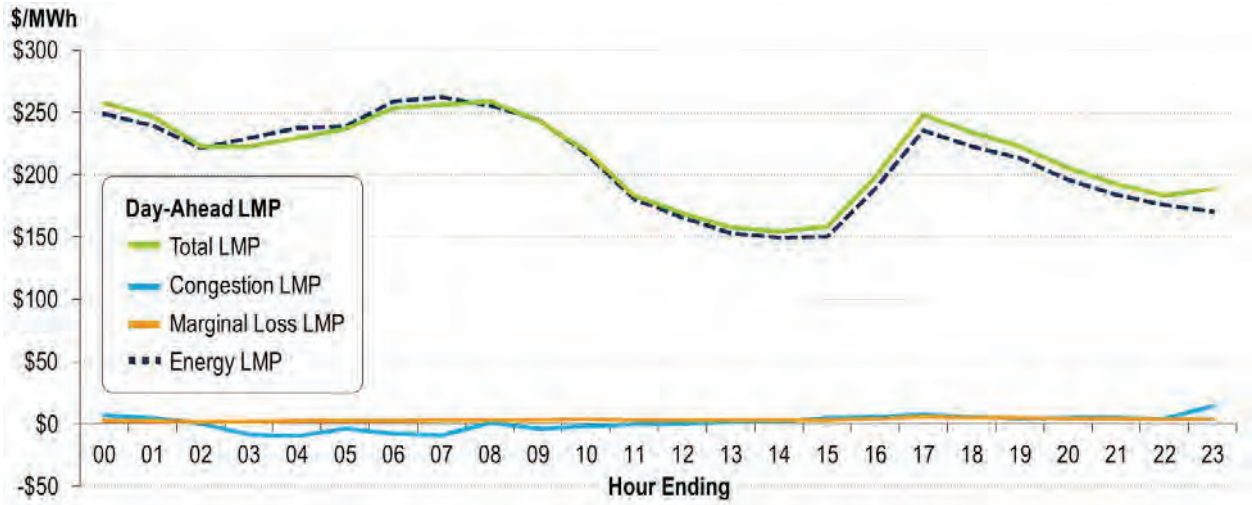
Figure 48. Dec. 24 Day-Ahead Cleared Demand, Forecast Load and Metered Load



On Dec. 24, the day-ahead cleared demand was less than real-time load by approximately 9,000 MW over the morning peak and 4,900 MW over the evening peak.

Figure 49 presents the Day-Ahead LMPs for Dec. 24.

Figure 49. Dec. 24 Day-Ahead LMPs



The Day-Ahead LMPs for Dec. 24 were higher than a typical Day-Ahead price, as noted above, with a peak hourly LMP of $259/MWh. In the Day-Ahead Market, energy shortage conditions did not occur on Dec. 24 either.

Table 3 summarizes the units that were offer-capped in the Day-Ahead Market for the Dec. 23 and Dec. 24 operating days.

Table 3. Dec. 23 & 24 Day-Ahead Offer-Capped Unit Summary

	# of Units	Total MW	Non-Liquid Fuel (MW)	
Dec. 23	32	4,428.1	1,495.5	33.8%
Dec. 24	44	6,444.8	34	0.5%

Virtual Transactions

As described earlier, in the Day-Ahead Market, participants may submit various virtual transactions to hedge risk, mirror physical commitments, or account for their expectations of market conditions. The following three types of virtual transactions are available in the Day-Ahead Market:

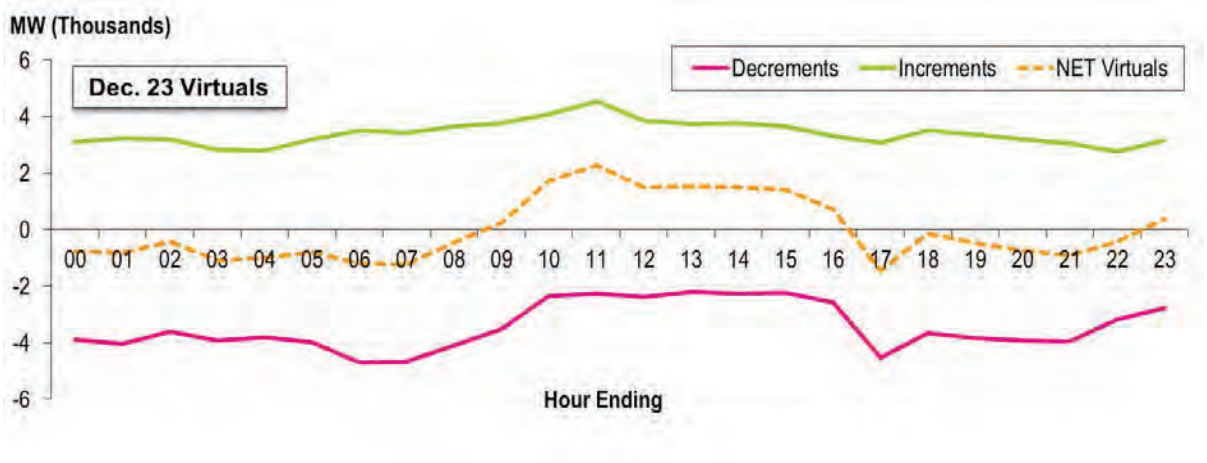
- Increment Offers (INCs) – INCs are submitted in the Day-Ahead Market to sell an amount of energy at a specific location (node) if the Day-Ahead clearing price for that node equals or exceeds the offer price. INCs can be thought of as virtual transactions that emulate generation offers in the Day-Ahead Market. INC transactions are paid the day-ahead LMP for their cleared quantity but must buy out of their position at the real-time LMP. INCs are profitable when the day-ahead LMP is higher than the real-time LMP.

- Decrement Bids (DECs) – DECs are submitted into the Day-Ahead Market as a bid to purchase energy at or below a specified price. DECs can be thought of as virtual transactions that emulate load buy bids in the Day-Ahead Market. DEC transactions pay day-ahead LMP for their cleared quantity and are paid the real-time LMP for the same quantity. Consequently, DECs are profitable when the real-time LMP is greater than the day-ahead LMP.

- Up-to-Congestion Bids (UTCs) – UTCs are bid in the Day-Ahead Market to purchase congestion and losses between two points. UTC bids can be based on the prevailing flow direction where the UTC is buying a position on the Day-Ahead Market congestion, or they can be in the counter-flow direction where they are paid to take a position. The UTC bid consists of a specified source and sink location and a “bid spread” that identifies how much the Market Participant is willing to pay for a congestion-and-loss position between the source and the sink. If the congestion associated with a prevailing flow UTC is less in day-ahead than in real-time, the UTC will be profitable. The opposite is true for counterflow UTCs.

Figure 50 presents the cleared virtual transactions in megawatts, both decrement bids and the increment offers, for the Dec. 23 Day-Ahead Market.

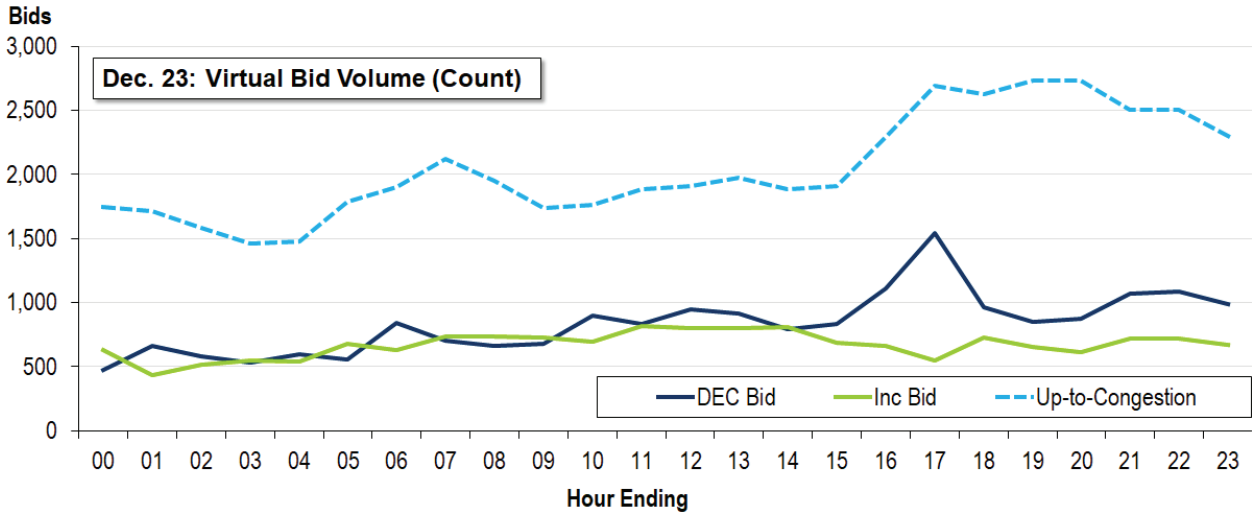
Figure 50. Dec. 23 Cleared Virtual Transactions



As shown in Figure 50, beginning in hour 11 there was approximately 2,000 MW of net virtual generation in the day-ahead solution between hours ending 10:00 and 15:00. Decrement bids in the Day-Ahead Market ranged between 2,200 MW and 4,500 MW and increment offers were between 3,000 MW and 4,500 MW.

Figure 51 presents the virtual transaction volume for Dec. 23.

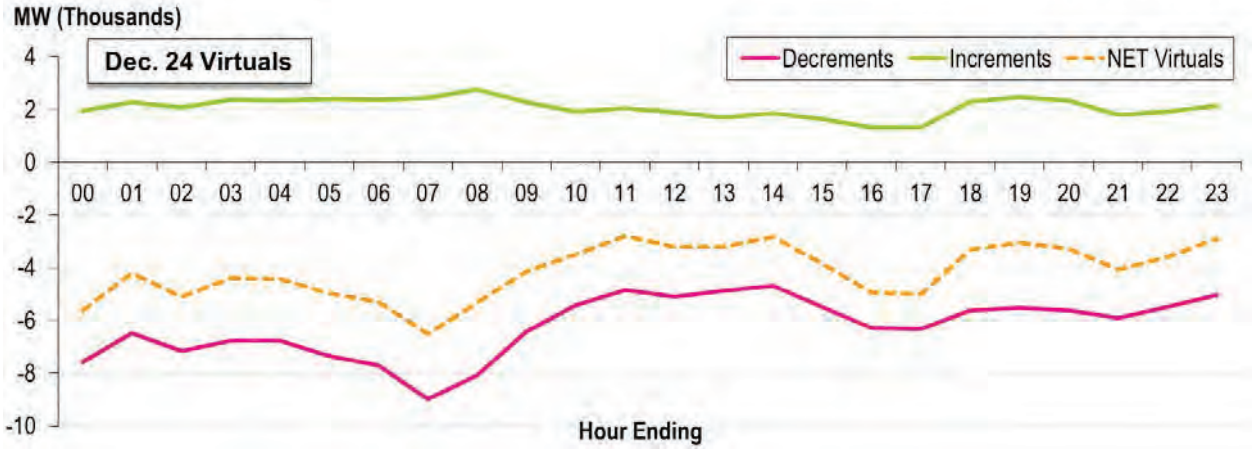
Figure 51. Dec. 23 Virtual Transaction Bid Volume



In the Day-Ahead Market for Dec. 23, there were a maximum of 1,500 individual DEC bids at 15:00 and 814 individual INCs at 11:00.

Figure 52 presents the cleared virtual transactions in megawatts for the Dec. 24 Day-Ahead Market.

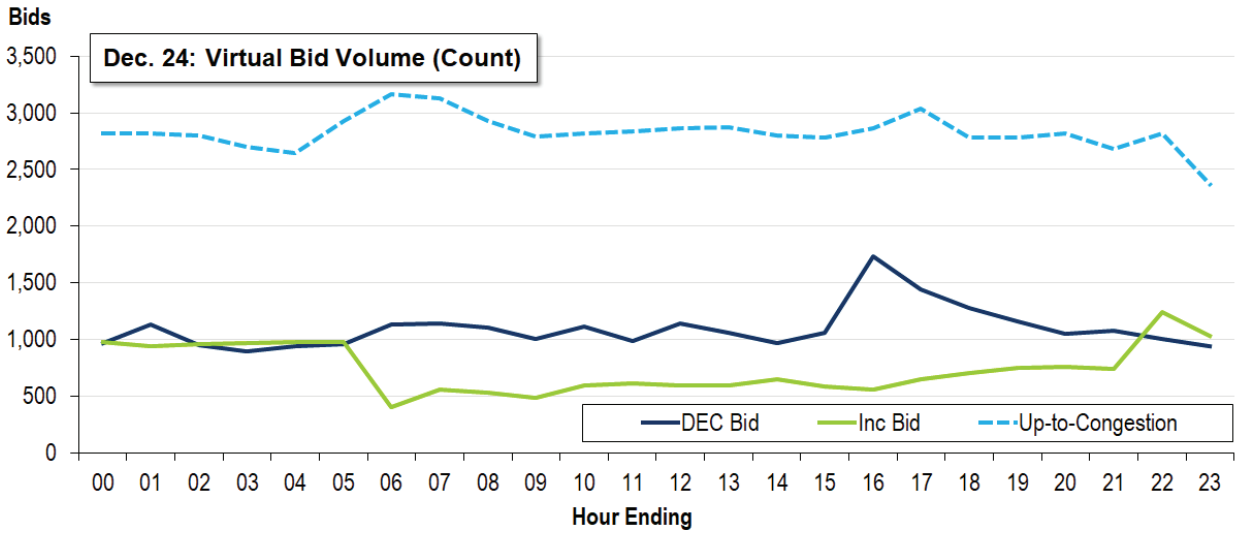
Figure 52. Dec. 24 Cleared Virtual Transactions



As shown in Figure 52, beginning in hour 07:00 there was approximately 6,500 MW of net virtual load in the day-ahead solution. Decrement bids in the Day-Ahead Market totaled approximately 9,000 MW in hour beginning 07:00 and increment bids totaled approximately 2,500 MW beginning in hour 07:00.

Figure 53 presents the virtual transaction volume for Dec. 24.

Figure 53. Dec. 24 Virtual Transaction Bid Volume



In the Day-Ahead Market for Dec. 24, there were a maximum of 1,736 individual DECs at 16:00 and 1,239 individual INCs at 22:00.

In general, demand has been underbid in the Day-Ahead Market on a consistent basis for many years. This is likely in-part due to the desire to purchase some energy on behalf of load at the real-time LMP which can be lower than the day-ahead LMP. This approach carried over to Dec. 23 and Dec. 24, leaving some LSEs exposed to Real-Time Market prices. This could be due to hedging strategies or may be due to uncertainty in load forecasting associated with the expected weather and the holiday weekend. Generators were also exposed to Real-Time Market prices when they were committed in the Day-Ahead Market and were short on their day-ahead commitment in real-time. This can occur when a unit committed in the Day-Ahead Market experiences a forced outage in real-time.

Day-Ahead Reserves

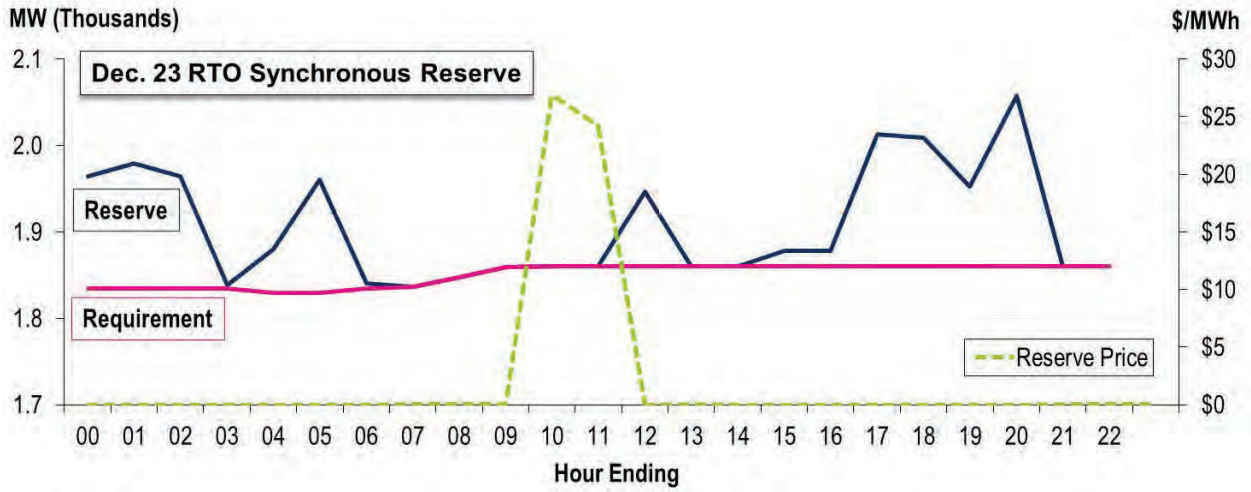
PJM procures resources to meet its reserve requirements, as described earlier in this section, in the Day-Ahead Markets. The clearing of the Day-Ahead Reserve Market results in an hourly price for Synchronized Reserves, Non-Synchronized Reserves and Secondary Reserves for the next day. These prices are posted along with the resource-specific reserve assignments from the dispatch run by 13:30 each day via the PJM Markets Gateway System. The hourly reserve product clearing prices are based upon the offer prices submitted by the committed resources and lost opportunity costs from the pricing run in the Day-Ahead Market clearing software. Lost opportunity cost captures the lost revenues in the Day-Ahead Energy Market a resource may incur by not generating energy but making itself available to provide reserves. For the Dec. 23 and Dec. 24 Day-Ahead Markets, PJM met or exceeded the reserve requirements in all hours.

Offer prices in the PJM reserve markets are limited to the expected value of the non-performance penalty for failing to provide reserves if deployed in real-time. The highest value of the penalty rate was for the month of February 2023, where it was $0.14/MWh.

The reserve markets in the Day-Ahead and Real-Time are modeled such that the highest quality product always has the highest clearing price. For example, the Synchronized Reserve Market Clearing Price (SRMCP) will always be greater than or equal to the Non-Synchronized Reserve Market Clearing Price (NSRMCP) in the same location, because Synchronized Reserve is a higher-quality product than Non-Synchronized Reserve and may be substituted for it. Similarly, the NSRMCP will always be greater than or equal to the Secondary Reserve Market Clearing Price (SecRMCP) in the same location because Non-Synchronized Reserve is a higher quality product than Secondary Reserves and may be substituted for it.

Figure 54 presents the Day-Ahead Synchronized Reserve and prices for Dec. 23.

Figure 54. Dec. 23 Day-Ahead Primary Reserve



PJM met the reserve requirement in the Dec. 23 Day-Ahead Market at zero price, except for the two hours shown in Figure 54. The elevated clearing price for Synchronous Reserves was a result of resources that were backed down to meet the Synchronous Reserve requirement, resulting in non-zero cleared price.

Figure 55 and Figure 56 present Dec. 23 Day-Ahead Primary Reserve and 30-Minute Reserve and prices, respectively.

Figure 55. Dec. 23 30-Minute Reserve and Prices

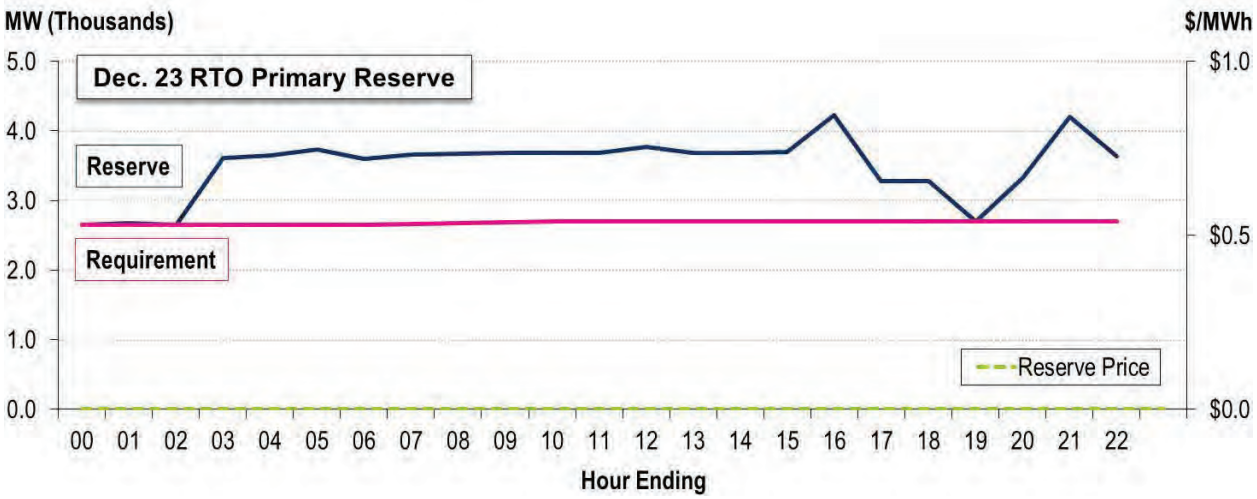
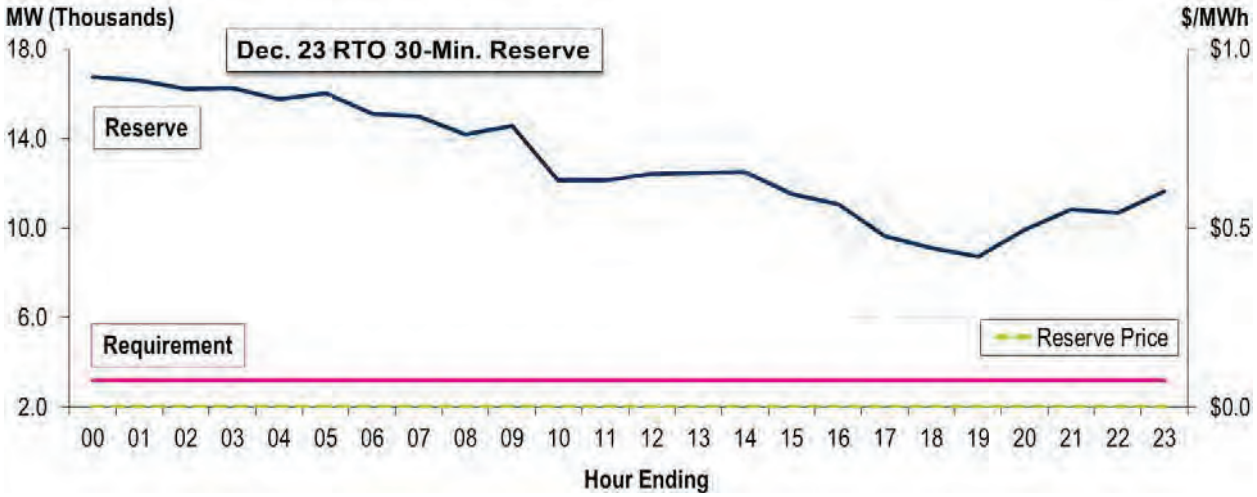


Figure 56. Dec. 23 30-Minute Reserve and Prices



Dec. 23's Day-Ahead Primary Reserve and 30-Minute Reserve prices were zero for all hours, signaling that there were sufficient resources with offers indicating they could meet the requirements to provide those reserves with no adjustment to their schedules in the Day-Ahead Market.

Figure 57, Figure 58 and Figure 59 present the Dec. 24 Day-Ahead Synchronized Reserve, Primary Reserve and 30-Minute Reserve and prices, respectively.

Figure 57. Dec. 24 Day-Ahead Synchronized Reserve

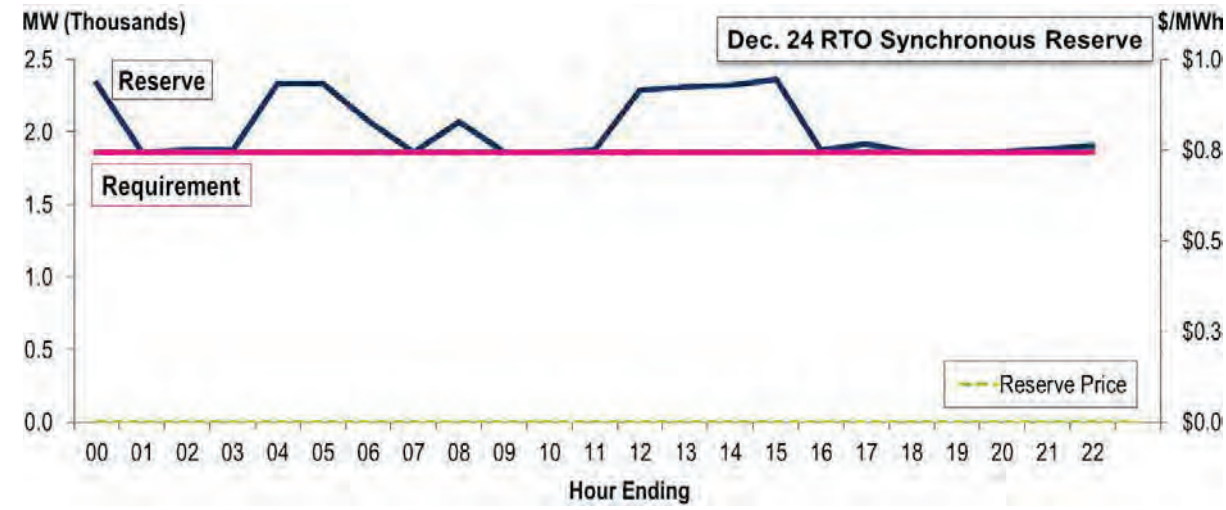


Figure 58. Dec. 24 Day-Ahead Primary Reserve

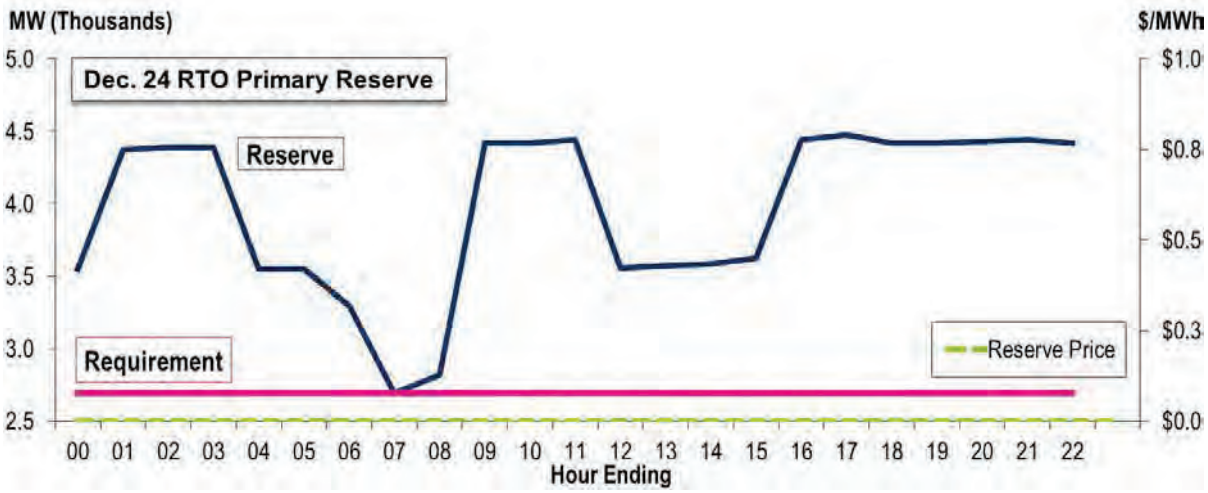
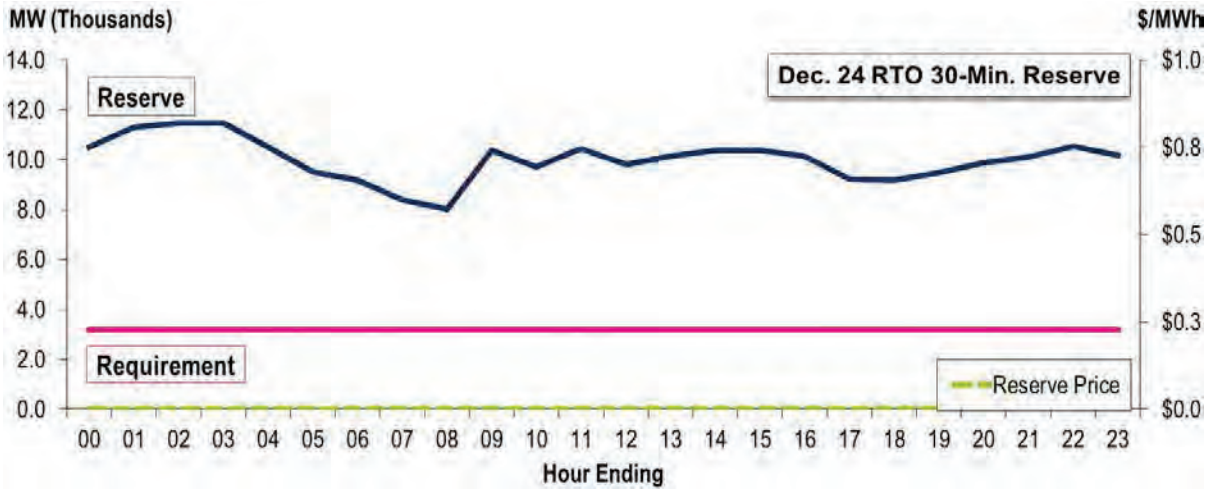


Figure 59. Dec. 24 30-Minute Reserve & Prices



Note that the Dec. 24 Day-Ahead Reserve Requirements were met at zero cost for the entire day, indicating that there were sufficient resources available to meet these requirements without adjusting their schedules based on the offer parameters submitted into the Day-Ahead Market.

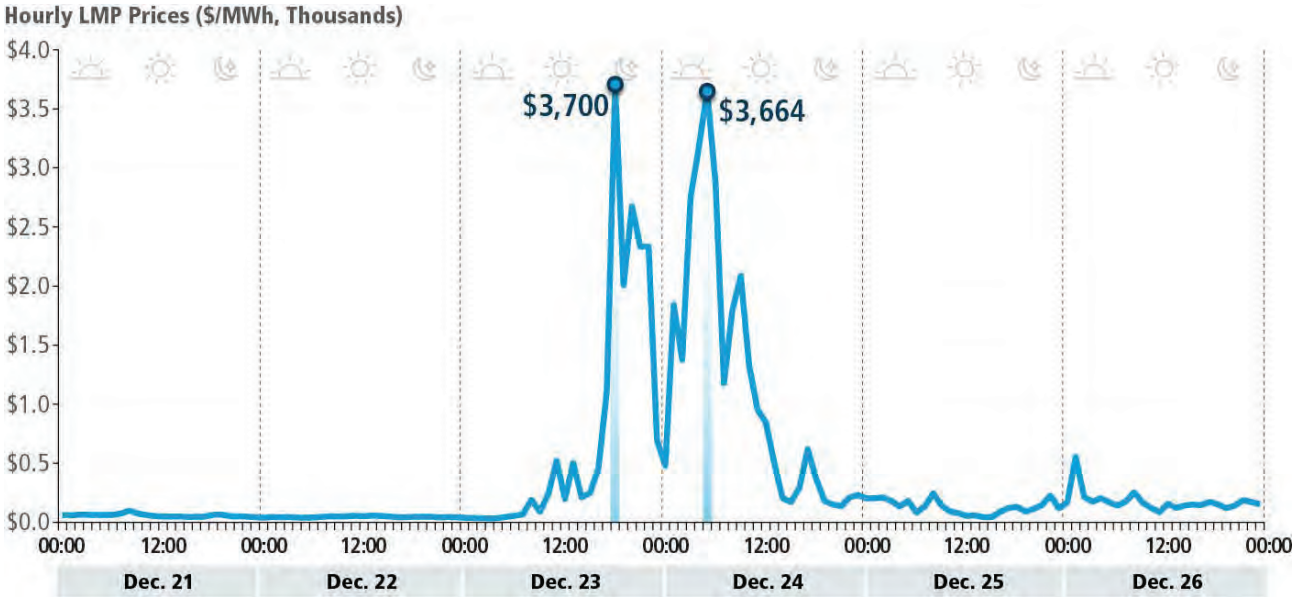
Real-Time Market Results

The Real-Time Energy Market uses the Real-Time Security Constrained Economic Dispatch (RT SCED) program, known as the "dispatch run," to determine the least-cost solution to balance supply and demand. The dispatch run considers resource offers, forecasted system conditions and other inputs in its calculations.

Real-Time LMPs and Regulation and Reserve Clearing Prices are calculated every five minutes by the Locational Price Calculator (LPC) program, in a process referred to as the pricing run, and are based on forecasted system conditions and the latest approved RT SCED program solution. Real-time prices are used to settle quantity deviations from day-ahead schedules in what is referred to as a balancing settlement.

Figure 60 presents the average Real-Time LMPs for Dec. 23 and Dec. 24.

Figure 60. Dec. 23 and Dec. 24 Hourly System Energy Prices



On Dec. 23 and 24, Real-Time LMPs across the system rose as high as $3,700/MWh on both days and were driven by fuel costs, stressed system conditions including reserve shortages, multiple emergency procedures declared by PJM operators, a high generator forced outage rate, and higher-than-expected load. In comparison, the average Real-Time LMP for the month of December 2022 was $122/MWh, while the average LMP for Dec. 21–26 was $386/MWh.

Congestion Impacts

A transmission constraint occurs when a physical limitation of a transmission facility is reached during normal or contingency system operations. When this occurs, the most economic generation cannot be delivered to the load due to physical limitations on transmission facilities. As a result, when there is a transmission constraint, more expensive generation that is electrically closer to the load must be dispatched in order to ensure that flows on transmission facilities are maintained within their operating limits.

To determine which generators have the most cost-effective benefit on relieving a transmission constraint, PJM calculates the dollar-per-megawatt effect of each generator on a transmission constraint and redispatches the lowest cost generators first to control the transmission constraint. The cost that the RT SCED will incur to control a transmission constraint is limited to the level of the Transmission Constraint Penalty Factor (TCPF), typically $2,000/MWh. The TCPF not only caps the cost of controlling actions used to control a transmission constraint but it is also the price level used to indicate that a transmission constraint cannot be controlled. This occurs when the actual or post-contingency flow on a transmission constraint exceeds the limit operators are controlling to.

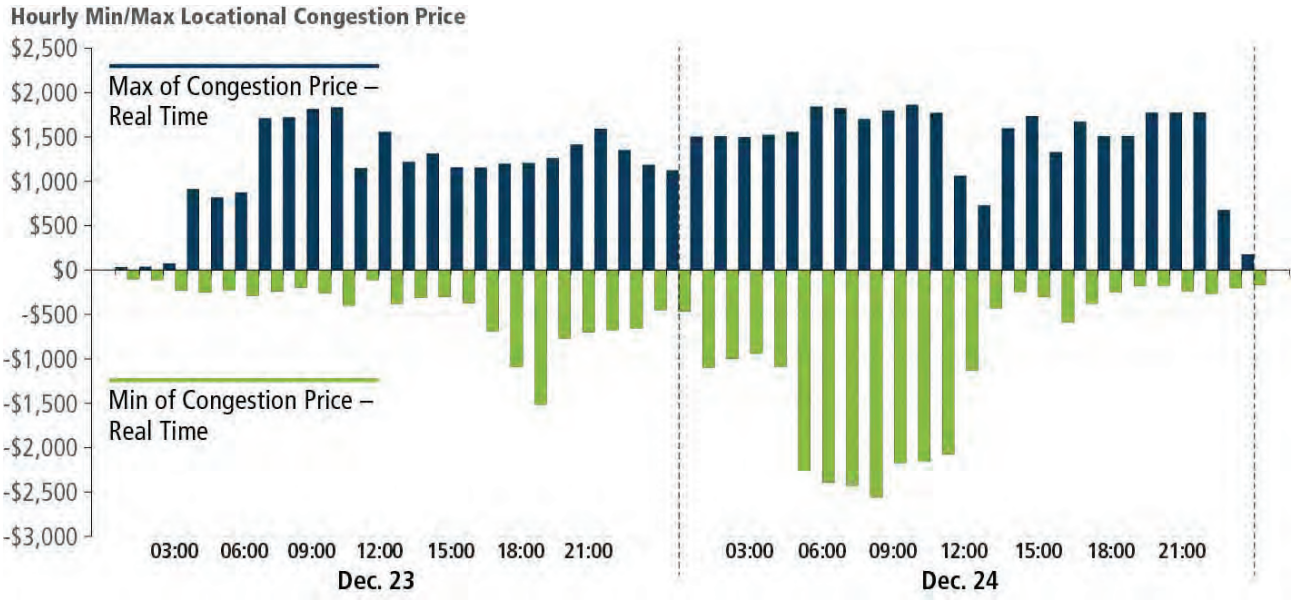
The underlying goal and intent of reflecting the TCPF in LMPs is to provide market signals that incentivize supply and/or load response to help relieve a constraint in the short term, while also incentivizing the development of additional supply, load response and/or transmission upgrades through long-term investments. Use of the TCPF, therefore, generally results in prices that signal short-term responses and longer-term investment that would be beneficial to the reliability of the transmission system and therefore have the intended impact.

On Dec. 23, 27 of the 35 active constraints in SCED bound at TCPF for at least one five-minute interval, indicating multiple locations of local scarcity within the PJM footprint. On Dec. 24, 28 of the 42 active constraints bound at the TCPF for at least one five-minute interval. While PJM maintains the ability to adjust the default level of the TCPF, no adjustments were made during Winter Storm Elliott, as all system constraints were effectively being controlled by resources available to PJM system operators.

The system pricing effects of the TCPF, and congestion in general, is locational. The TCPF is used to determine the Marginal Value of a transmission constraint when sufficient controlling actions do not exist to control the constraint at or below the applicable TCPF.

Figure 61 presents the impacts of congestion on the Real-Time Locational Congestion Price for Dec. 23 and Dec. 24.

Figure 61. Dec. 23 and Dec. 24 Congestion Prices



The locational aspect of load to constraints ultimately impacts pricing, as shown in Figure 62. Zonal prices reached as high as approximately $4,300 on Dec. 24.

Table 4 presents the binding constraints on high-voltage equipment that had a broader system impact on locational pricing on Dec. 23 and Dec. 24.

Table 4. Dec. 23 and Dec. 24 Binding Constraints on High-Voltage Equipment

Equipment Name (500 kV and Above)*	Zone	# of Intervals at TCPF	Dec. 23 (EPT)	Dec. 24 (EPT)
TRANSFER INTERFACE: AEP-DOM	N/A	129	09:35–22:30	00:05–23:50
JUNIATA 1 XFORMER H 500 KV	PPL	73	19:20–21:25	01:30 04:35–09:55
CONASTON-PEACHBOT 5012B 500 KV	BC	21	22:20–23:45	00:40
CABOT-KEYSTONE 5002B 500 KV	APS	1	12:25	
BROADFO2 T6 XFORMER H 765 KV	AEP	28	09:15–11:10 12:30–12:45 12:55	

Note: A complete list of binding constraints is available at Data Miner.

Figure 62 presents the locational impact of congestion for a sample interval on the evening of Dec. 23.

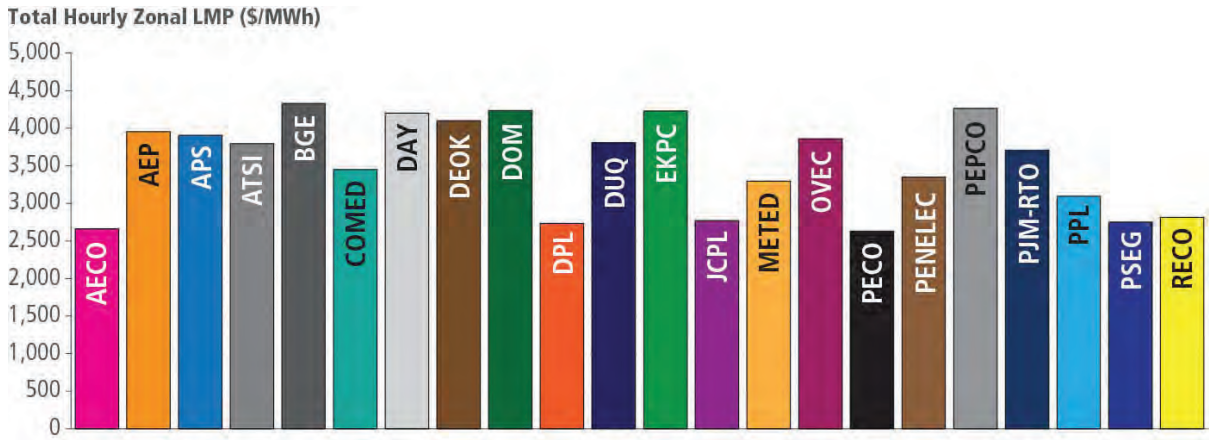
Figure 62. Dec. 23 17:00 Total Hourly Zonal LMP



Given that the System Energy Price cannot rise above $3,700/MWh, the difference can be attributed primarily to the impacts of congestion.

Figure 63 presents the locational impact of congestion for a sample interval on the evening of Dec. 24.

Figure 63. Dec. 24 08:00 Total Hourly Zonal LMP



FTRs were fully funded during the extent of Winter Storm Elliott. From Dec. 23 through Dec. 25, FTR target credits totaled $99,017,903.99. Day-ahead congestion, which is the sum of the target and surplus, over that same time period was $130,319,840.29, resulting in a $33,919,216.32 surplus. For further information on FTR accounting, please see PJM Manual 6, Section 8.

Balancing Congestion is captured in Figure 64 for the period between Dec. 20 and Dec. 26.

Figure 64. Balancing Congestion Dec. 20–26



On Dec. 23, Net Balancing Congestion was $22,134,094 and $23,504,649 for Dec. 24. Net Balancing Congestion is positive for both days, indicating some active real-time constraints were not triggered in the day-ahead solution. The reason for the imbalance is, in part, tied to the lower cleared load in the Day-Ahead Market compared to the actual load realized during the operating days of Dec. 23 and Dec. 24.

Real-Time Load and Prices

On both Dec. 23 and Dec. 24, PJM had insufficient reserves available to meet the reserve requirements. If during the execution of the pricing run, the Locational Pricing Calculator (LPC) determines that a reserve shortage exists, PJM

deems this to be a reserve shortage, triggering shortage pricing. Shortage pricing is a market rule that ensures energy and reserve prices reflect the state of the system, both leading up to and during times of reserve shortages. A reserve shortage occurs when there are insufficient resources available to maintain the balance of generation, load and reserve requirements. PJM implements shortage pricing through the inclusion of the applicable Reserve Penalty Factors in the Real-Time LMP and reserve pricing calculations.

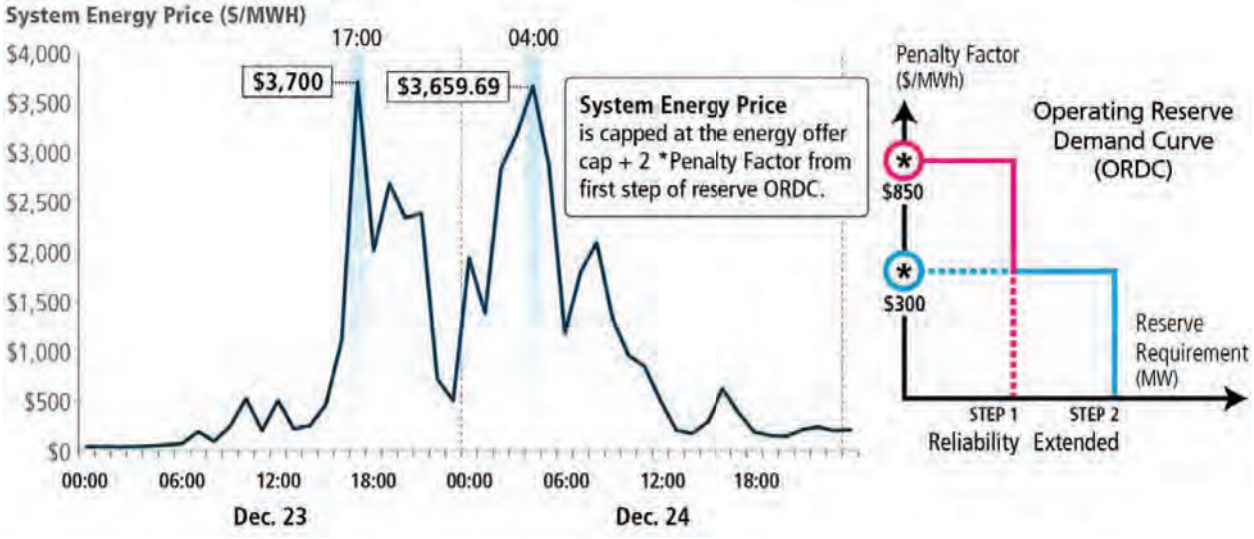
PJM uses Operating Reserve Demand Curves (ORDCs) to set the demand and willingness to pay for each of its reserve products. Like the TCPF, the ORDCs contain Reserve Penalty Factors that function as a cap on the $/MWh cost willing to be incurred to maintain a specific reserve requirement in a specific location. All Reserve Penalty Factors are currently set at either $300/MWh or $850/MWh depending on the segment of the ORDC.

The maximum reserve prices are capped as follows:

- Synchronized Reserves are capped at two times the penalty factor ($1,700).
- Non-Synchronized Reserves are capped at 1.5 times the penalty factor ($1,275).
- Secondary Reserves capped at one time the penalty factor ($850).

Figure 65 presents the System Energy Price on Dec. 23 and Dec. 24:

Figure 65. Dec. 23 and Dec. 24 System Energy Price



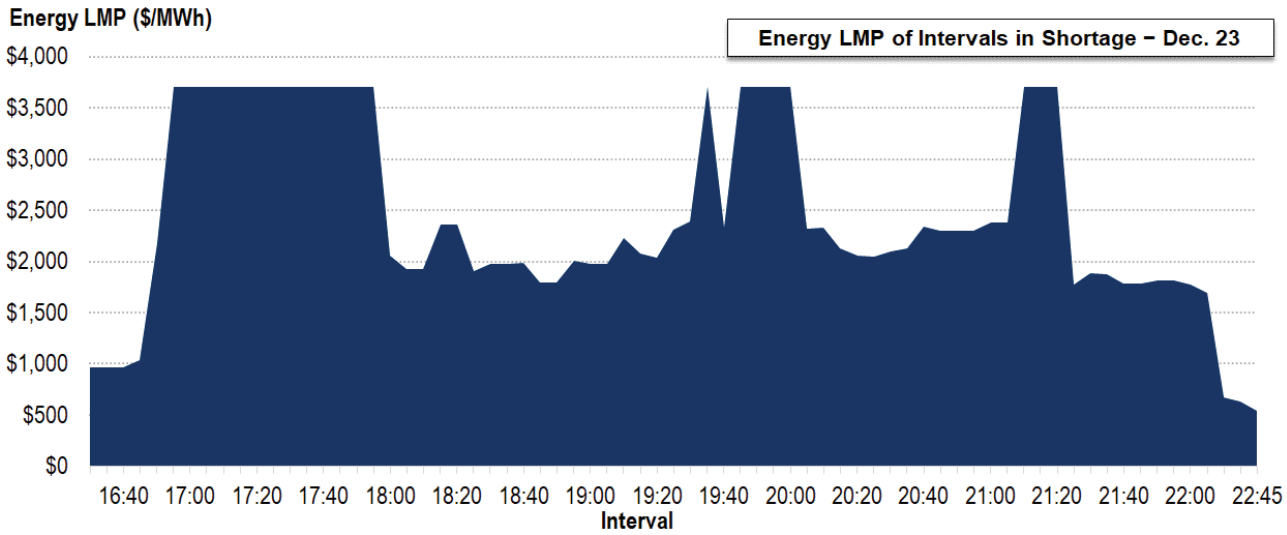
There were 71 shortage intervals approved by PJM Dispatch between 16:30 and 22:45 on Dec. 23. Table 5 reflects the breakdown by Reserve Sub-Zones.

Table 5. Shortage Intervals by Reserve Sub-Zones

	Reserve Penalty Factors
45	MAD & RTO – Primary
21	MAD & RTO – Primary & Synchronized
2	MAD & RTO – Primary & RTO – Synchronized
3	RTO Primary

Figure 66 presents the LMPs during the shortage intervals on Dec. 23.

Figure 66. Dec. 23 LMPs During Shortage Intervals



PJM currently has rules in place that place a cap on the System Energy Price of $3,700/MWh. This cap was reached during various intervals on Dec. 23 as shown Figure 66. Total LMPs exceeded $3,700/MWh in some locations during these shortage intervals due to the addition of congestion and losses.

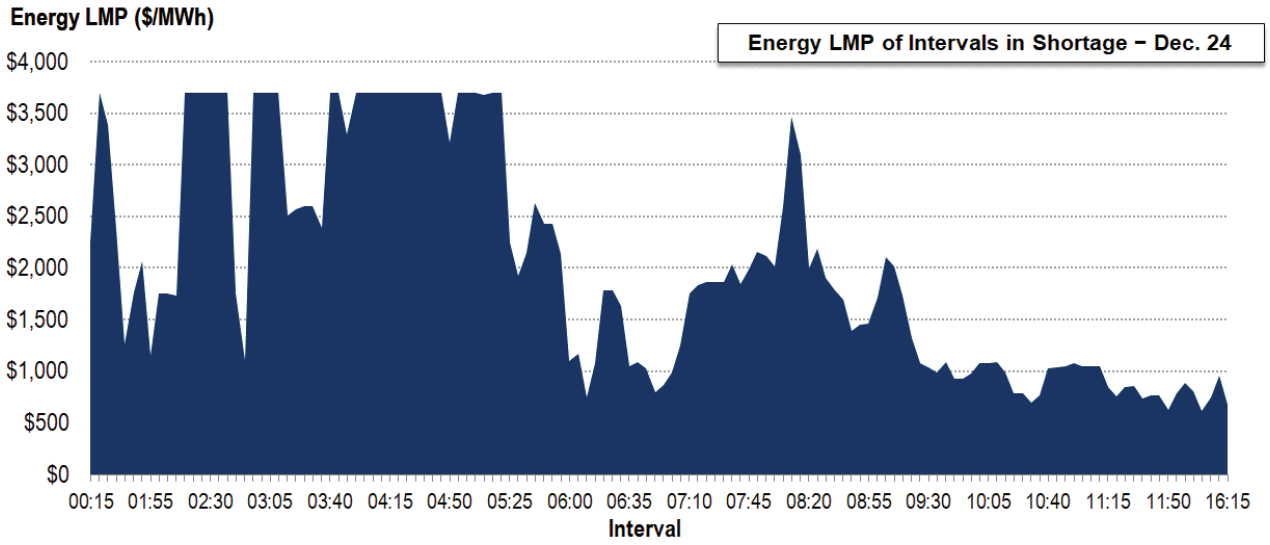
There were 134 shortage intervals approved by PJM Dispatch between 00:15 and 16:15 on Dec. 24. Table 6 presents the breakdown of the shortage intervals by Reserve Sub-Zones.

Table 6. Shortage Intervals by Reserve Sub-Zones

	Reserve Penalty Factors
69	MAD & RTO – Primary
37	MAD & RTO – Primary & Synchronized
16	MAD & RTO – 30-Minute
1	MAD & RTO – Primary & RTO – Synchronized
11	RTO Primary

Similarly, Figure 67 presents the LMPs during the shortage intervals on Dec. 24.

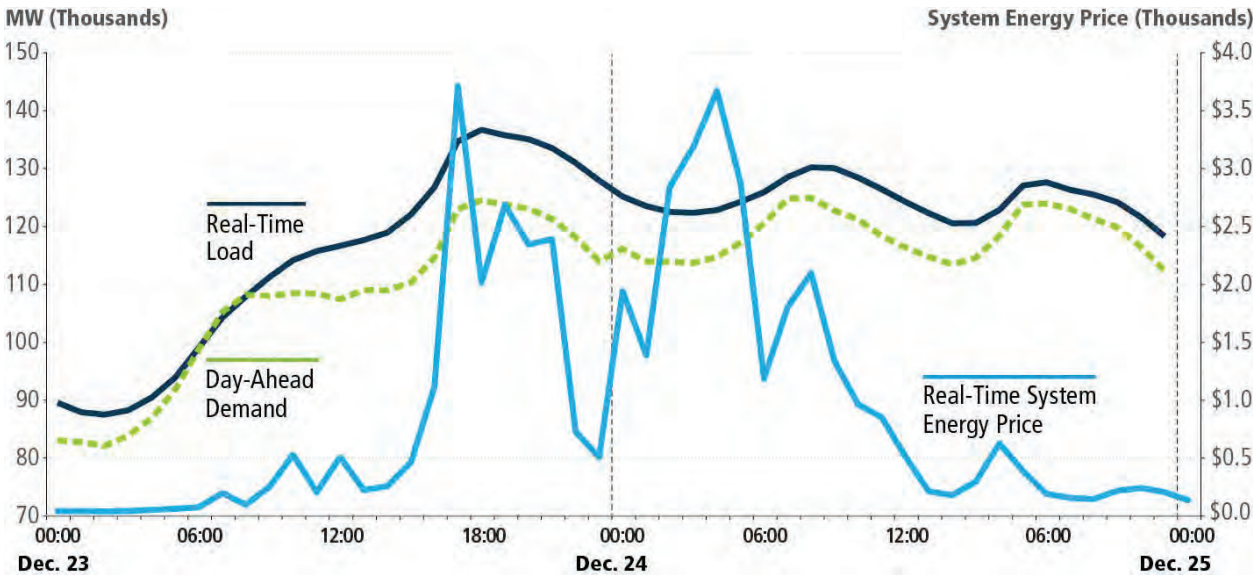
Figure 67. Dec. 24 LMPs During Shortage Intervals



On Dec. 24, the System Energy Price was $3,700/MWh during shortage intervals, as shown in Figure 67. During these intervals, there were locations on the system where LMP exceeded this price level when congestion and losses were also included.

Starting in the evening on Dec. 23, PJM experienced elevated pricing for energy and reserves, consistent with the multiple emergency procedures that were initiated due to extreme system conditions. Factors driving those extreme conditions included higher-than-anticipated loads and unprecedented forced generator outages. As a result, Real-Time Market operations accurately reflected multiple five-minute intervals with strained power balance, locational congestion management and extended periods of shortage pricing. Figure 68 overlays the System Energy Price, day-ahead forecasted load and real-time load.

Figure 68. System Energy Price, Day-Ahead Forecasted Load and Real-Time Load

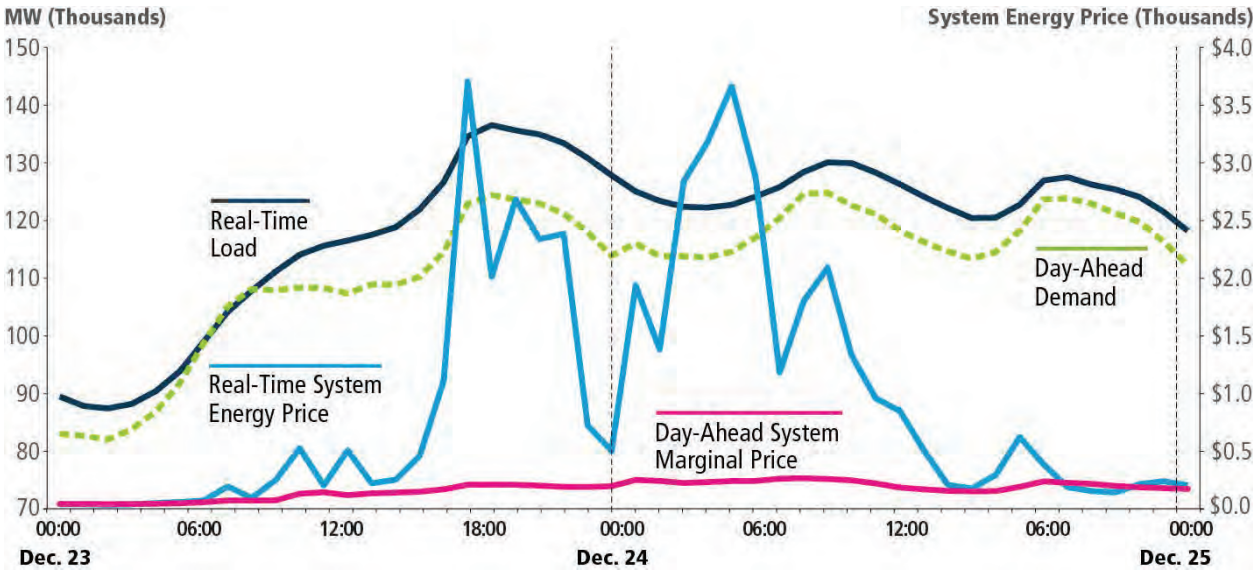


Real-Time LMPs are calculated based on five-minute intervals. Both generation and emergency Demand Response resources can and did set the price.

Day-Ahead Versus Real-Time Prices

Figure 69 presents the average day-ahead hourly load and prices compared to the real-time average load and prices.

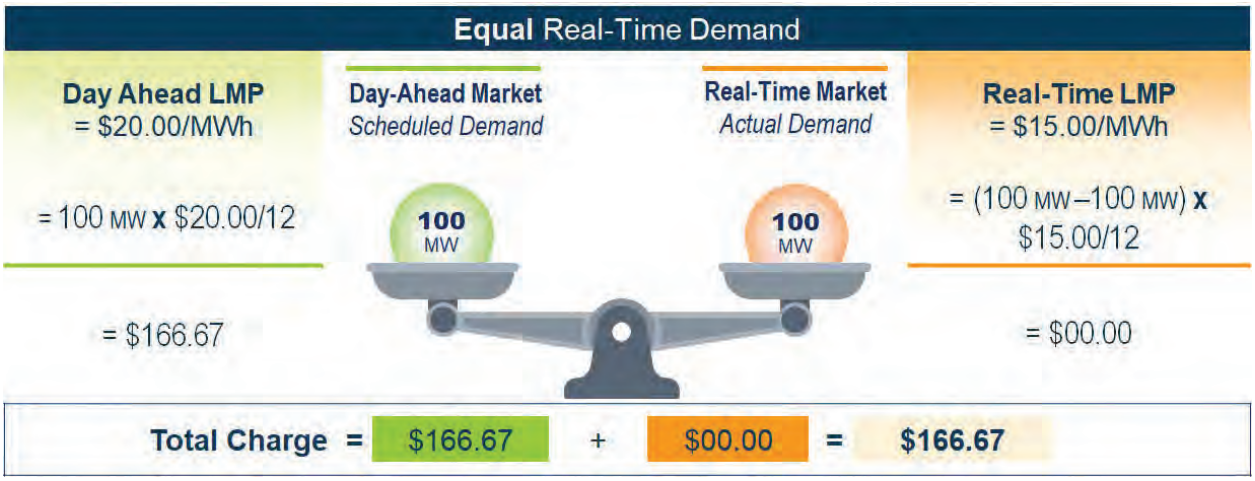
Figure 69. Day-Ahead and Real-Time Load and Day-Ahead and Real-Time Hourly System Energy Price



There is a significant difference between the day-ahead and the actual real-time load (approximately 12,172 MW), as shown in Figure 69. The difference between the Day-Ahead and Real-Time Market prices, due primarily to the unavailability of generation in real-time and under-forecasting of load in day-ahead, creates a potential for exposure to Real-Time pricing. Cleared day-ahead demand for Dec. 23 was 10,400 MW lower than the actual metered load realized at the peak. In comparison, cleared day-ahead demand for Dec. 24 was approximately 9,000 MW lower than the actual metered load realized during the morning peak. The demand that was cleared in the Day-Ahead Market was subject to the Day-Ahead LMP of $207/MWh on Dec. 23 and $262/MWh on Dec. 24. Real-time load that was not hedged in the Day-Ahead Market during the peak periods on these days was exposed to Real-Time LMPs of approximately $3,700 in both instances.

Figure 70 presents an example of a settlement example for an LSE that is fully hedged.

Figure 70. Fully Hedged LSE Settlement Example



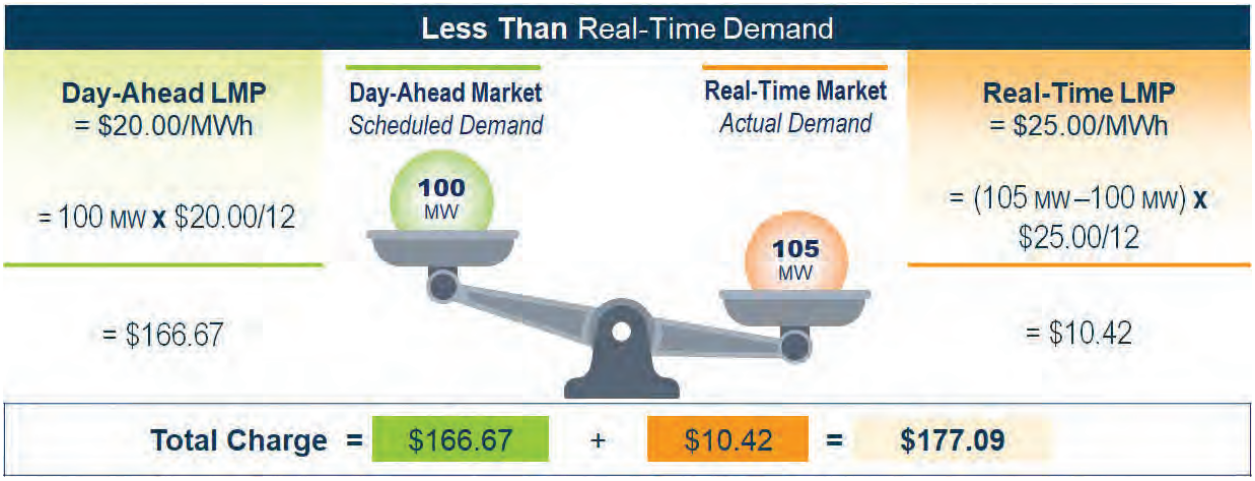
In Figure 70, the LSE submitted a 100 MW bid in the Day-Ahead Market. The Day-Ahead Market cleared at $20.00/MWh. The Day-Ahead Market settlement for this five-minute interval is the day-ahead scheduled demand multiplied by the Day-Ahead LMP divided by 12 (there are 12 five-minute intervals in an hour), or $166.67.

In the Real-Time Market, the LSE's actual demand is 100 MW. The balancing settlement for this five-minute interval is the difference between Real-Time Market actual demand and the Day-Ahead Market scheduled demand, multiplied by the Real-Time Market LMP divided by 12. Since the LSE's Real-Time Market actual demand and the Day-Ahead Market scheduled demand are both 100 MW, the LSE is fully hedged and is not exposed to the Real-Time Market prices. The Real-Time Market settlement is $0.00.

The total charge for this LSE for this sample five-minute interval is the Day-Ahead Market charge plus the Real-Time Market charge, or $166.67.

Figure 71 presents a settlement example for an LSE that is under-hedged.

Figure 71. Under-Hedged Load Settlement Example



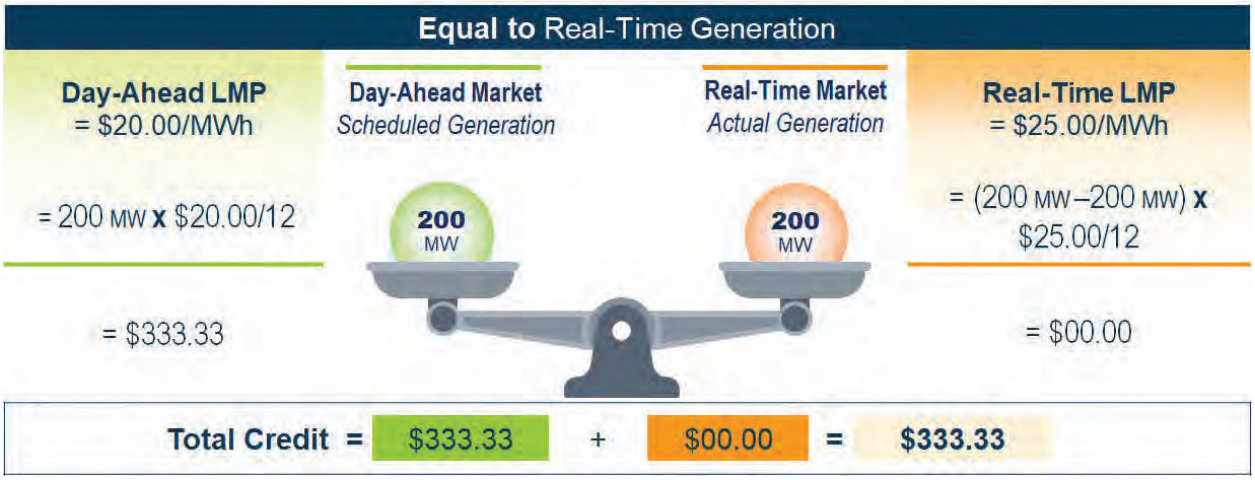
In Figure 71, the LSE submitted a 100 MW bid in the Day-Ahead Market. The Day-Ahead Market cleared at $20.00/MWh. The resulting Day-Ahead Market settlement for this sample five-minute interval is the Day-Ahead scheduled demand multiplied by the Day-Ahead Market LMP, in this case the Day-Ahead Market settlement is $166.67.

In real time, the Load Serving Entity's actual demand is 105 MW, 5 MW greater than the Day-Ahead Market. Therefore, the LSE is exposed to the Real-Time Market prices or is "under-hedged" for the additional 5 MW. The LSE purchases the 5 MW at the Real-Time LMP. The balancing settlement for this sample five-minute interval is the difference between the Real-Time actual demand minus the Day-Ahead Market scheduled demand. In this case, the LSE scheduled 100 MW in the Day-Ahead Market and the actual demand is 105 MW. The Real-Time Settlement is therefore 5 MW multiplied by the Real-Time Market LMP of $25.00/MWh, divided by 12, for a total of $10.41.

The total charge for this LSE for this five-minute interval is the Day-Ahead Market charge plus the Real-Time Market charge, or $177.09

Figure 72 presents a settlement example for a generator that is fully hedged.

Figure 72. Fully Hedged Generator Settlement Example



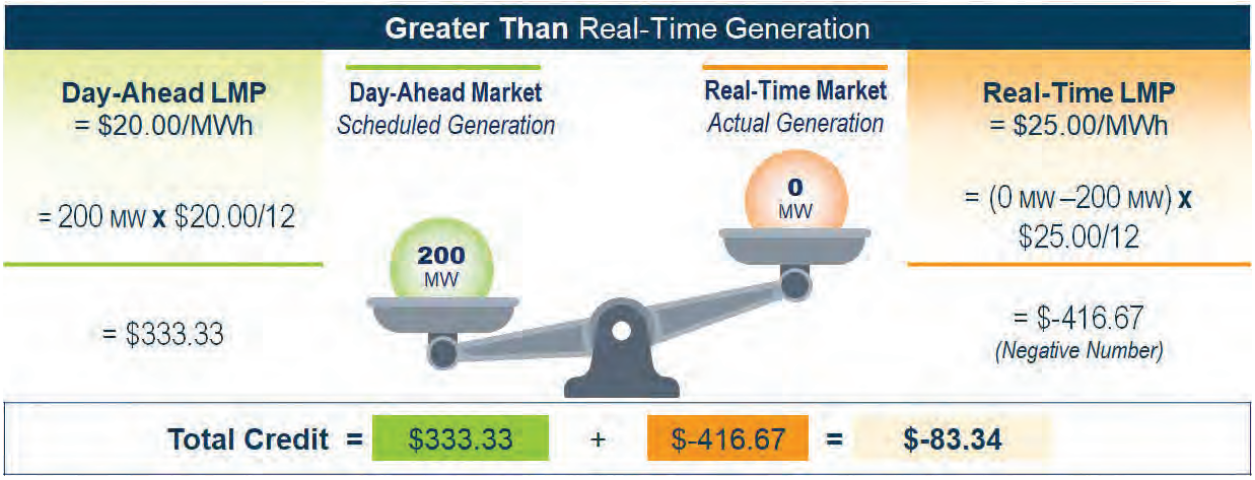
In Figure 72, the Generator submitted a 200 MW offer in the Day-Ahead Market. The Day-Ahead Market cleared at $20.00/MWh. The Day-Ahead Market settlement for the generator is the Day-Ahead Market scheduled generation multiplied by the Day-Ahead Market price, or 200 MW multiplied by $20.00 MW/h, divided by 12. The Day-Ahead Market credit for this generator is $333.33.

In real time, the Generator produced 200 MW. The balancing settlement is the difference between the Real-Time Market actual generation and the Day-Ahead Market scheduled generation. In this case, the generator was committed for 200 MW in Day-Ahead Market and produced 200 MW in real time. The generator is fully hedged (not exposed to real-time prices.) The balancing settlement is therefore $0.00.

The Total Credit for this generator for this five-minute interval is $333.33.

Figure 73 presents a settlement example for a generator that is committed in the Day-Ahead Market and trips during real time.

Figure 73. Day-Ahead Committed Generator That Trips in Real-Time Settlement Example



In Figure 73, the generator submitted a 200 MW offer in the Day-Ahead Market. The Day-Ahead Market cleared at $20.00/MWh. The Day-Ahead Market settlement for the generator is the Day-Ahead Market scheduled generation multiplied by the Day-Ahead Market price, or 200 MW multiplied by $20.00 MW/h divided by 12. The Day-Ahead Market credit for this generator is $333.33.

In real time, the generator tripped and therefore did not produce any energy. The balancing settlement is the difference between the Real-Time Market actual generation and the Day-Ahead Market scheduled generation. In this case, the generator was committed for 200 MW in the Day-Ahead Market but produced 0 MW in the Real-Time Market. The generator needs to buy back the megawatts committed in the Day-Ahead Market at the Real-Time LMP. The balancing settlement for this five-minute interval is the difference between the Real-Time Market actual generation and the Day-Ahead scheduled generation, multiplied by the Real-Time Market LMP (divided by 12). The balancing settlement for this five-minute interval is -$416.67.

The total credit for this generator for this five-minute interval is -$83.34.

Interchange

Figure 74 and Figure 75 provide hourly net interchange values between PJM and neighboring market areas NYISO and MISO along with interface price values for PJM and the neighboring market areas. Interface pricing enables Market Participants to the profitability of scheduling energy transfers between or through neighboring Balancing Authorities.

During periods where the system is stressed and internal supply is close to or inadequate to meet energy and reserve needs, interface prices are used to incentivize Market Participants in neighboring regions to sell available power to PJM to relieve emergency conditions. On Dec. 23 and Dec. 24, interchange flows were generally into PJM from NYISO, which is reflected in the interface prices. Conversely, interchange flows for both days were generally out of PJM to MISO and our southern non-market neighbors [Tennessee Valley Authority (TVA), Louisville Gas and Electric Company and Kentucky Utilities Company (LGE-KU), Duke Energy Progress East (DEP-East), and Duke Energy Progress West (DEP-W)]. In those cases, system conditions were more stressed in the neighboring areas.

Figure 74. NYISO Net Interchange

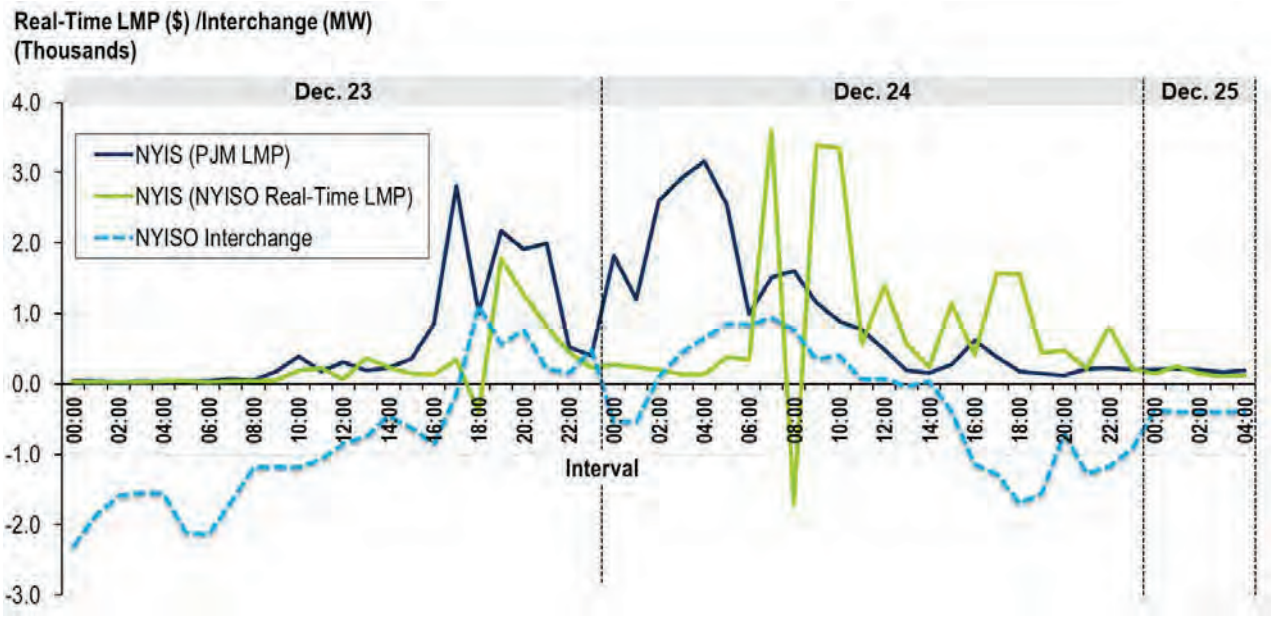


Figure 75. MISO Net Interchange

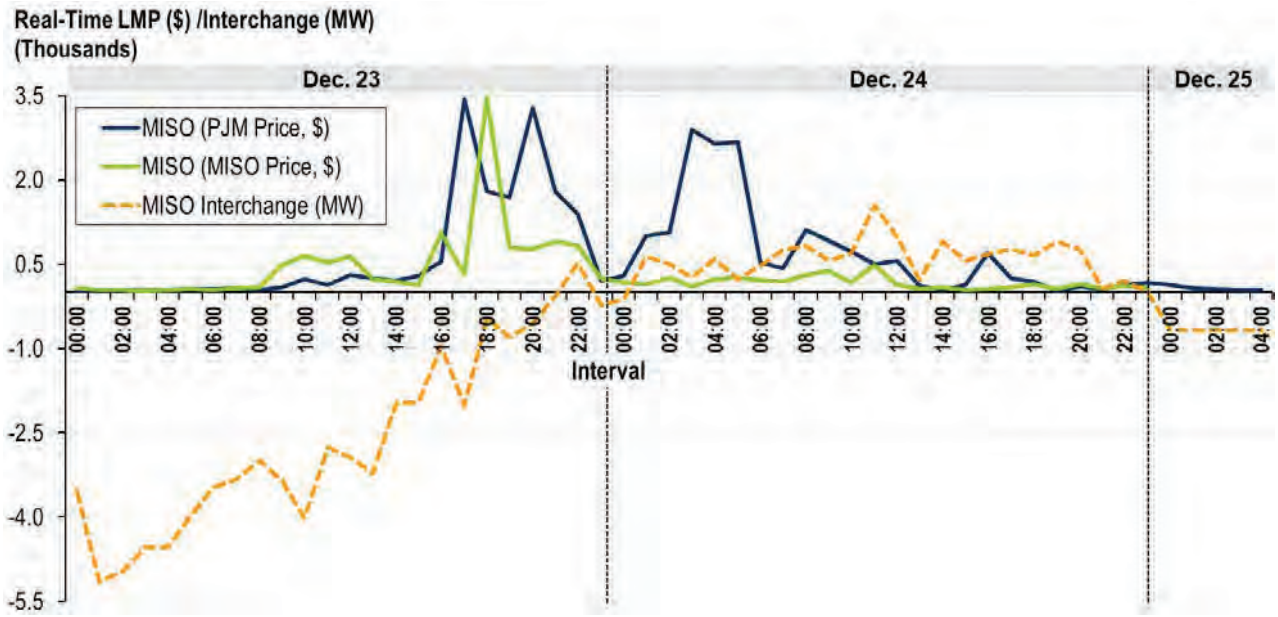


Figure 76 provides hourly net interchange values between PJM and the aggregate net interchange for LG&E-KU, TVA, Duke, DEP-East, and DEP-West, along with interface price values for PJM.

Figure 76. South Net Interchange

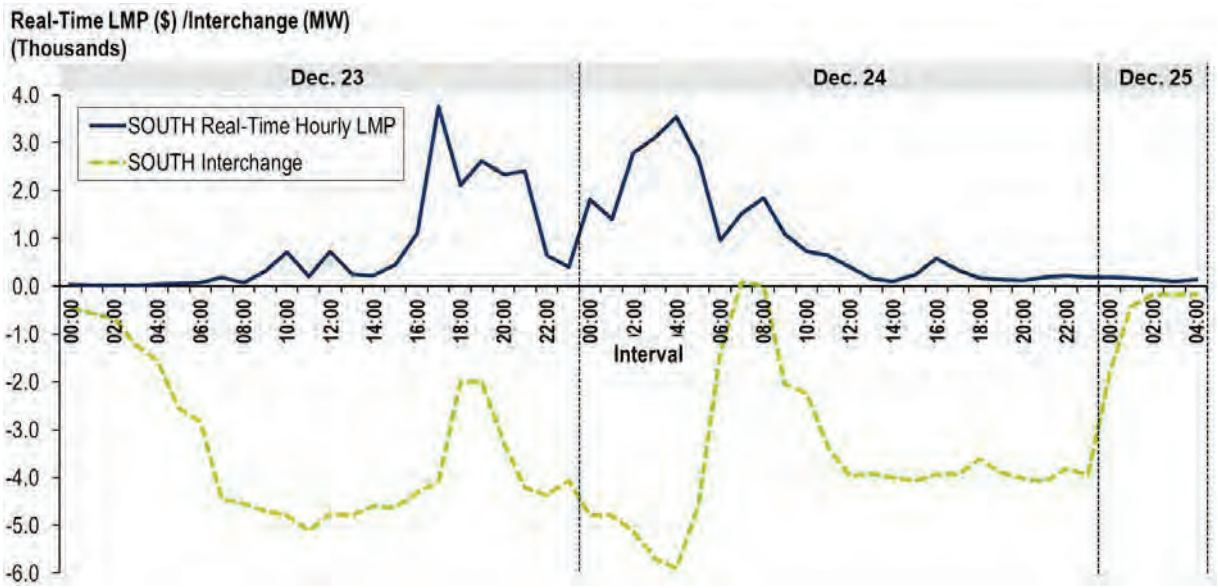
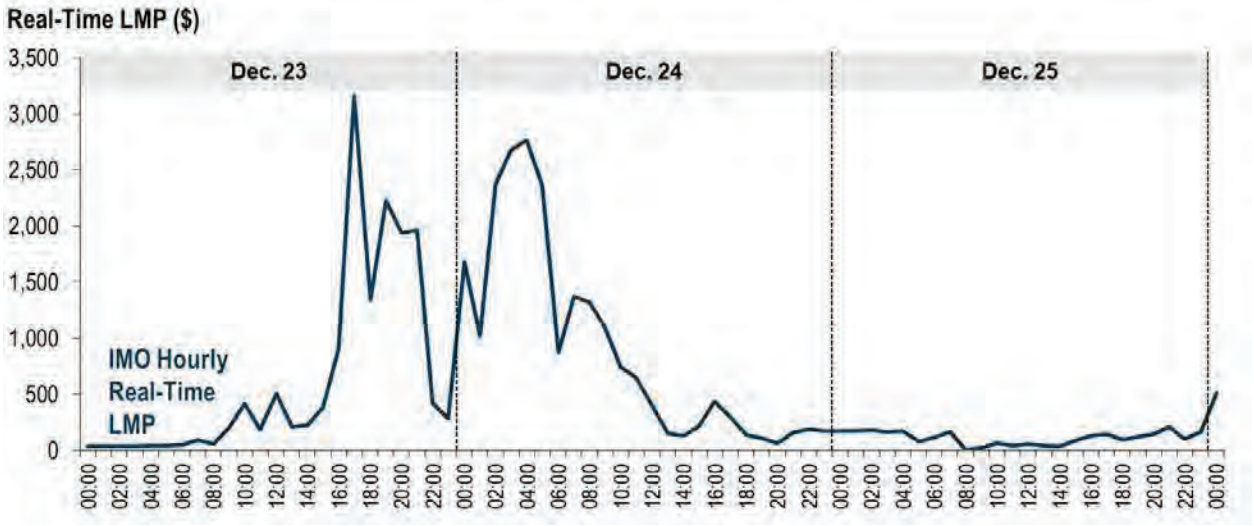


Figure 77 provides hourly pricing for the IMO interface. This information can be used by Market Participants during real time to make energy transfer decisions.

Figure 77. IMO Net Interchange



Ancillary Services: Regulation and Reserves

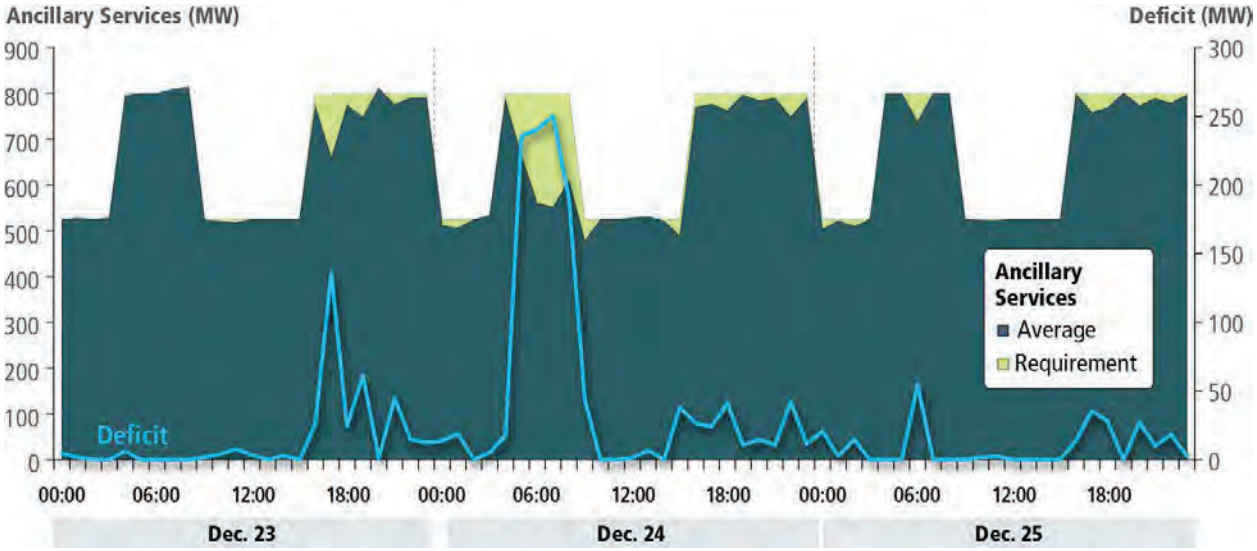
During Winter Storm Elliott, high prices for regulation, synchronized reserve, and Non-Synchronized Reserves occurred at the same time as high Real-Time Energy LMPs. During these stressed conditions, ancillary service prices increased as the reserve margin decreased, and system capacity competed to meet the ancillary services requirement while maintaining power balance.

Regulation Market Results

Regulation service corrects for short-term changes in electricity use that might affect the stability of the power system. It helps match generation and load and adjusts generation output to maintain the desired system frequency of 60 hertz. PJM's Regulation Market aligns compensation with actual performance for resources that provide regulation service. Resources are compensated for their accuracy, speed and precision of response in providing regulation service to the system.

On Dec. 23, as well as Dec. 24, PJM was deficit regulation, as presented in Figure 78, which presents the regulation megawatts, on average, by hour:

Figure 78. Regulation MW, on Average, by Hour

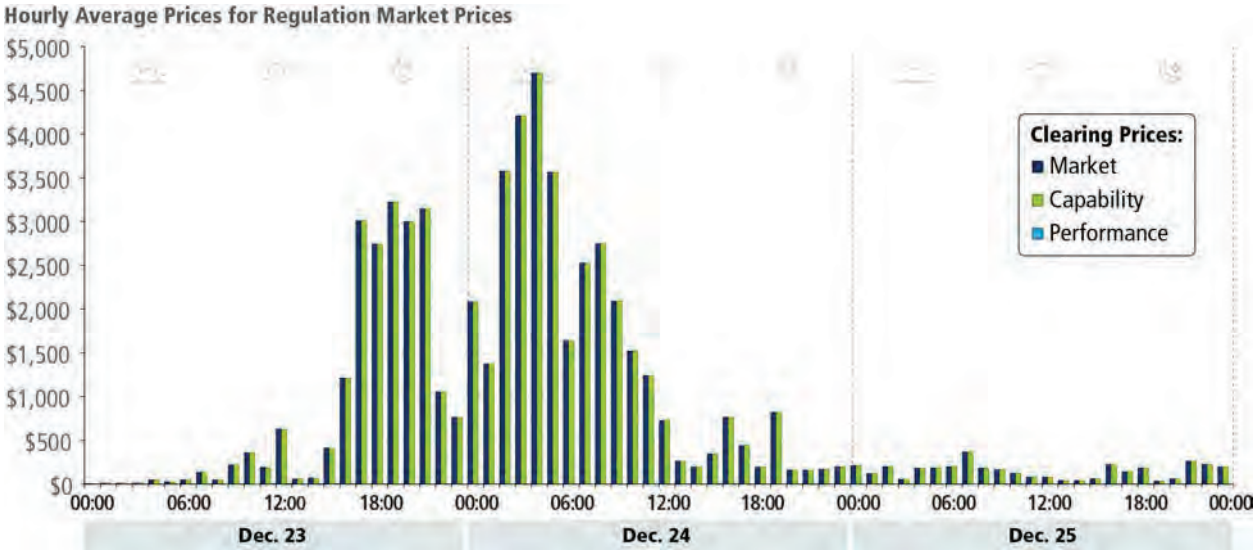


The regulation deficit is caused by the generator availability issues detailed in this report that resulted in a lack of available regulation-capable resources to commit. The regulation price spikes seen on Dec. 23 and Dec. 24 can be attributed to the low performance factor of the marginal unit for regulation as high-performing generators were being used for energy and reserves instead of regulation. High lost opportunity costs (LOC) were also a contributing factor to the high regulation prices. Recall that LOC is intended to capture foregone energy revenues from providing a service other than energy. When those foregone energy revenues are high because energy prices are high, regulation LOC and regulation prices can also be high to ensure resources are incentivized to provide needed regulation and not energy.

Unlike reserves, regulation is not co-optimized with energy in real-time. Similarly, there is also no explicit mechanism for shortage pricing of regulation as there is for reserves. As stated, regulation prices rose and fell roughly in correlation with energy prices during the evening of Dec. 23 and morning of Dec. 24 because of the calculation of regulation lost opportunity costs based on the high LMPs during these periods, not because of the regulation shortages.

Figure 79 presents the hourly average prices for RMCP for Dec. 23, 24 and 25.

Figure 79. Dec. 23, 24 and 25 Hourly Average Prices for RMCP



For more information on how the Regulation Market prices are calculated, please reference Manual 11, Section 3.

Reserve Market Price Trends

Reserves represent the generating capability that is "standing by," ready for service in the event that something happens on the power system, such as the loss of a large generator. The severity of the event determines how quickly the reserves have to be picked up.

In Oct. 2022, PJM implemented Reserve Price formation, resulting in the following changes:

- Consolidation of Tier 1 and Tier 2 Synchronized Reserve products
- Alignment of reserve products in day-ahead and real-time to ensure that the reserves needed for real-time operation are recognized on a forward basis during the scheduling processes for the next operating day
- Flexible modeling of reserve subzones

Figure 80 presents the market clearing prices (MCPs) for Synchronized Reserve (SRMCP), Non-Synchronized Reserve (NSMCP), and Secondary Reserve Market Clearing Price (SecRMCP) for Oct. 2022 through Dec. 2022. Notwithstanding Dec. 2022, the SRMCP, NSRMCP and SecRMCP prices have been at or near $0.00/MWh since the Oct. 2022 implementation of the Reserve Price Formation changes.

Figure 80. SRMCPs, NSMCPs and SecRMCPs

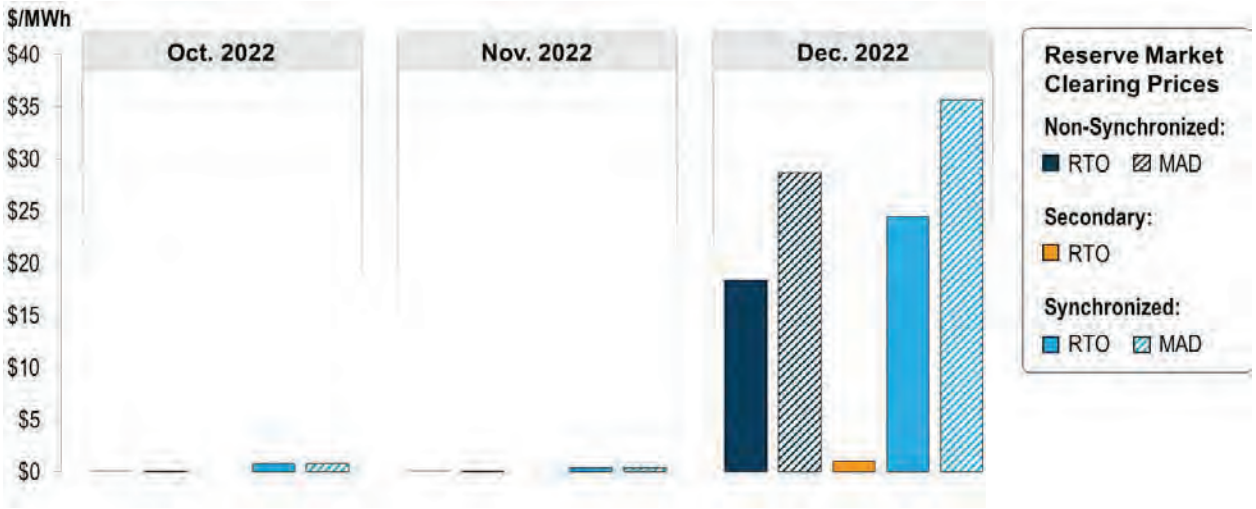


Figure 81 presents daily max and daily average SRMCPs since Oct. 1, 2022. This figure shows that the drivers of the high monthly averages SRMCPs observed in Dec. 2022 and displayed in Figure 80 are driven almost entirely by the operational events and market outcomes related to Winter Storm Elliott.

Figure 81. Shortage Pricing Impacts on SRMCP

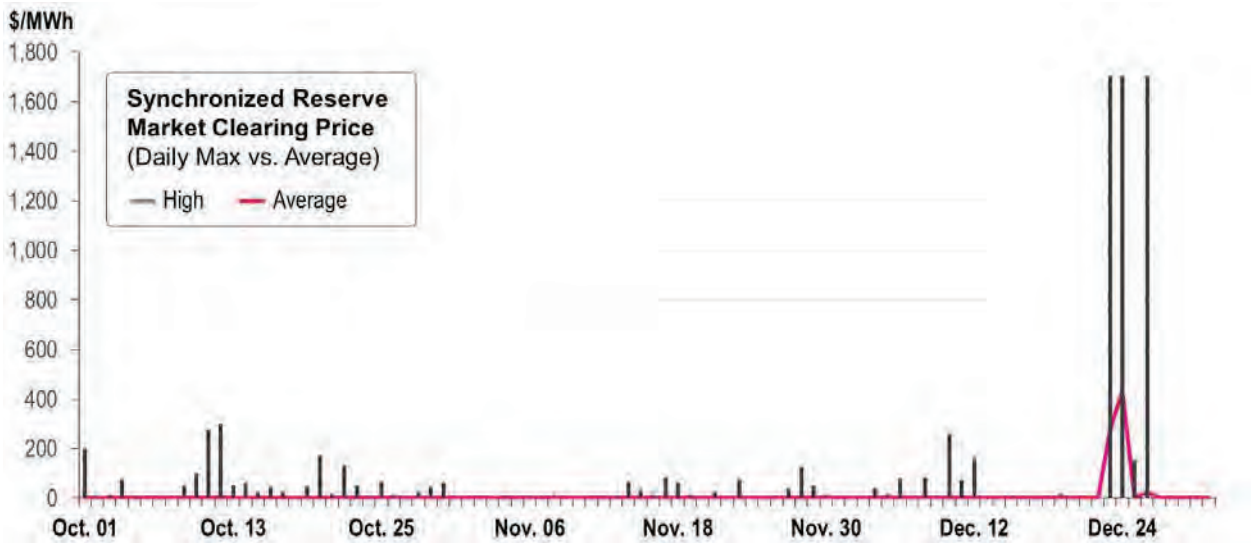
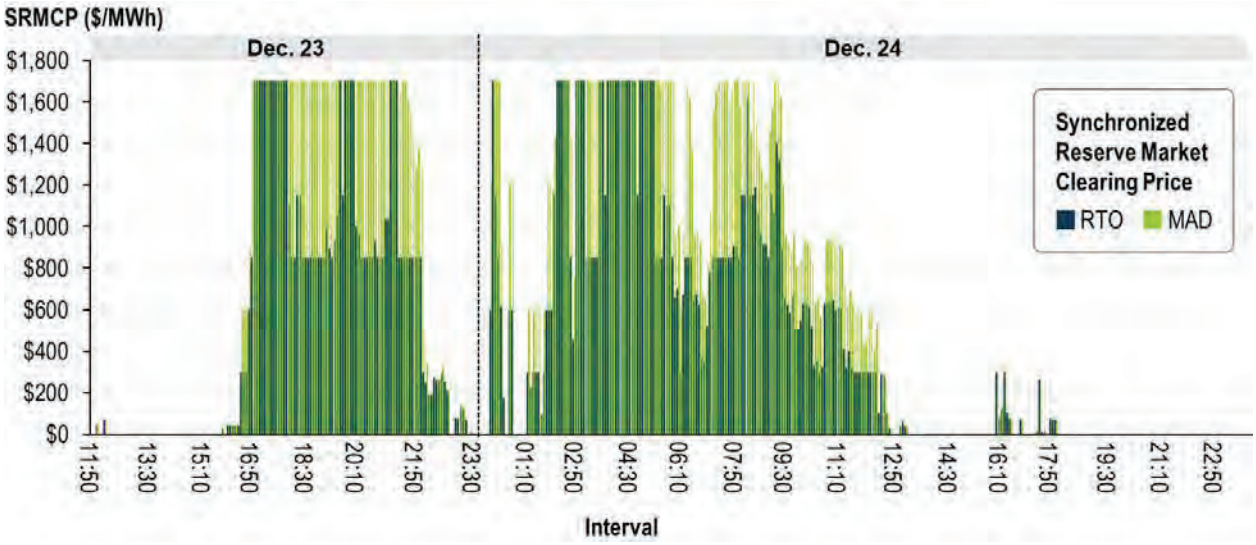


Figure 82 presents the Real-Time SRMCPs for Dec. 23 and Dec. 24.

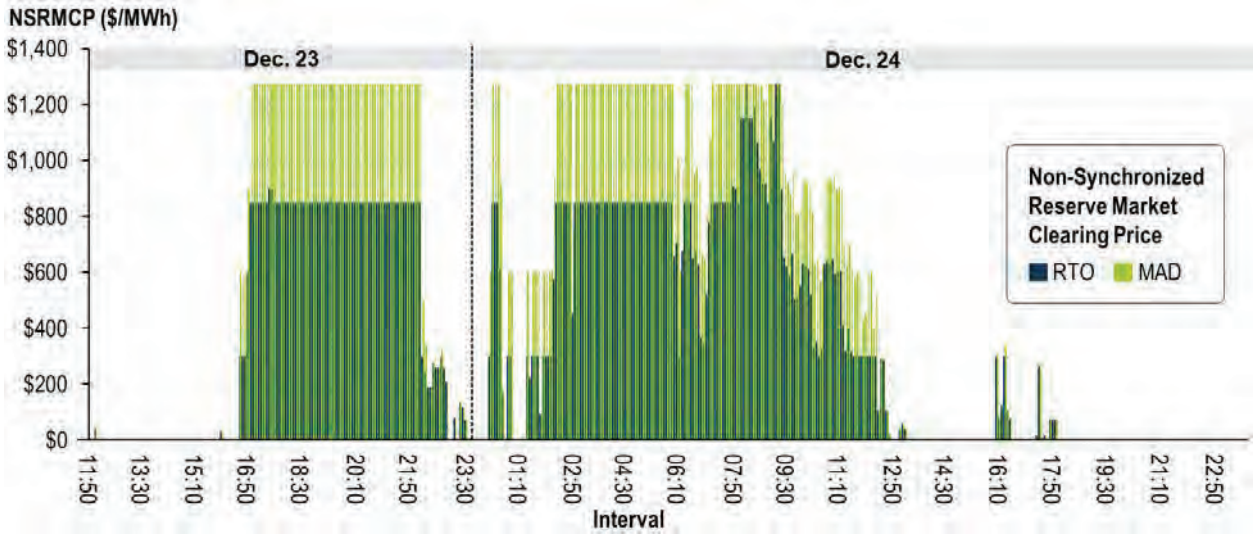
Figure 82. Dec. 23 and 24 Real-Time SRMCPs



The SRMCPs in many intervals are either at a level of $850/MWh or $1,700/MWh depending on the reserve product that was short and the location it was short. The price level of $1,700/MWh represents the price cap that exists for this product.

Figure 83 presents the Real-Time NSRMCPs for Dec. 23 and Dec. 24.

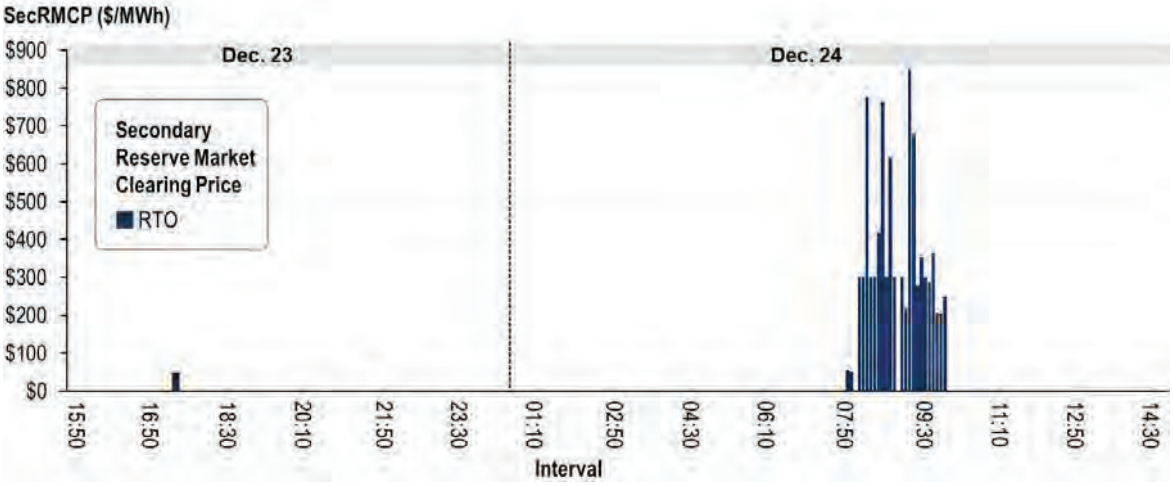
Figure 83. Dec. 23 and Dec. 24 Real-Time NSRMCPs



The Non-Synchronized Reserve Market Clearing Price (NSRMCP) is the clearing price paid to offline resources that can start within 10-minutes and be used to satisfy the Primary Reserve and 30-minute requirements. Market Sellers offer prices for the Non-Synchronized Reserve and Secondary Reserve products are $0.00/MWh; however, a Non-Synchronized Reserves LOC is estimated by the PJM market clearing engines. This LOC represents the foregone revenue an eligible offline resource could have received if had operated, given the forecasted LMP produced by the IT SCED engine. The current price cap Non-Synchronized Reserve is 1.5 times the Reserve Penalty Factor of $850/MWh, or $1,275/MWh.

Figure 84 presents the Real-Time SecRMCPs for Dec. 23 and Dec. 24.

Figure 84. Dec. 23 and Dec. 24 Real-Time SecRMCPs



The SecRMCP was $0.00/MWh of most of the Winter Storm Elliot event except for approximately two hours on Dec. 24. During that period, the SecRMCP reached its price cap of $850/MWh for one interval.

Given the observed issues with reserve performance and availability during Winter Storm Elliott and other inefficiencies PJM believes exist in the design of these markets, PJM believes there is a need to evaluate various aspects of its reserve market design including the products, offer structure, levels procured, performance incentives, and deployment practices to ensure the necessary amount of reserves is being procured, priced by the market and incentivized to perform at a high level. PJM plans to bring a Problem Statement and Issue Charge to Stakeholders to address these items in the near future.

Synchronized Reserve Events and Reserve Performance

As described earlier, Synchronized Reserves are reserve generators that are already synchronized to the grid and can be loaded within 10 minutes. PJM carries enough Synchronized Reserves to cover the unexpected loss of the largest single generation contingency operating on the PJM system at that time, plus a small margin. Typically, this reserve requirement is approximately 1,600 MW.

The conditions of Winter Storm Elliott led to PJM requesting the loading of Synchronized Reserve generation on five separate occasions during the two-day period of Dec. 23 and Dec. 24. Four of these events were called in response to a low ACE caused by increasing load combined with generation tripping and start failures. One of the events was called in direct response to the loss of a unit.

Five Synchronized Reserve Events over a two-day period is very unusual. Note that the average duration between Synchronized Reserve Events in 2021 was 22 days. All five of the events during Winter Storm Elliott exceeded 10 minutes in duration. Two of the events exceeded one hour in duration at 1 hour 51 minutes and 1 hour 27 minutes. The average duration for these five events was 53 minutes and 17 seconds. The average duration of the other 18 Synchronized Reserve Events that occurred in 2022 was 9 minutes and 57 seconds.

System conditions and ACE control prevented the PJM system operators from ending these Synchronized Reserve Events earlier, as all available reserve megawatts were required to support the ACE and provide overall system control. Table 7 provides details of these five events.

Table 7. Five Synchronized Reserve Events

Event Date	Start (EST)	End (EST)	Duration	Zone	Reason	PAI in effect
Dec. 23	10:14	10:25	00:11:07	RTO	Low ACE	No
	16:17	18:09	01:51:29			Yes (17:30–18:09)
Dec. 24	00:05	00:30	00:25:43			No
	02:23	02:54	00:30:35		Unit Trip	No
	04:23	05:51	01:27:32		Low ACE	Yes (04:25–01:27)

PJM measures the response of resources with a Real-Time Synchronized Reserves commitment as detailed in PJM Manual 11, Section 4.5. Note, Day-Ahead Synchronized Reserve commitments are reevaluated in real time, and only those resources that have a real-time commitment are obligated to respond.

For each Synchronized Reserve Event, the magnitude of each resource's response is the difference between the resources' output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, resource output at the start of the event is defined as the lowest telemetered output between one minute prior to and one minute following the start of the event. Similarly, a resource's output 10 minutes after the event is defined as the greatest output achieved between nine and 11 minutes after the start of the event.

Also relevant for the events lasting longer than 10 minutes, all resources must maintain an output level greater than or equal to that which was achieved as of 10 minutes after the event for the duration of the event or 30 minutes from the start of the event, whichever is shorter. The response actually credited to a given resource will be reduced by the amount the megawatt output of that resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. There is no current performance evaluation for events lasting longer than 30 minutes, beyond the initial 30-minute period.

Although not relevant for these events, in cases where an event lasts less than 10 minutes, resources are credited with the amount of reserve capacity they are assigned.

Since PJM's implementation of the Reserve Price Formation changes on Oct. 1, 2022, the entirety of the Synchronized Reserve Requirement is assigned to specific resources in a co-optimization with energy. Resources assigned these reserves each Real-Time interval have an obligation to perform or face a penalty in the amount of non-performance. This penalty consists of two components as follows:

1 | The resource is credited for Synchronized Reserve for the amount that actually responded for all intervals in which the resource had an assignment (either self-scheduled or assigned) on the day the event occurred.

2 | An obligation to refund at the Synchronized Reserve Market Clearing Price the amount of the shortfall for all Real-Time Settlement Intervals that the resource had an assignment for a period of the lesser of a) the average number of days between events or b) the number of days since the resources last non-performance.

Synchronized Reserve response to the five events during Winter Storm Elliott for resources assigned reserves was generally poor.

- The highest response was 86.4% of assignment, as seen during the Dec. 23, 10:14 event, which was the first Synchronized Reserve deployment during Winter Storm Elliott. Not coincidentally, this was also the shortest of the five events at 11:07 minutes.

- The lowest response was 16.8% of assignment, as seen during the Dec. 24, 04:23 event.
- The average response of these five events was 47.8%.
- The average response of assigned Synchronized Reserve since the implementation of the Reserve Price Formation changes on Oct. 1, 2022, excluding these Winter Storm Elliott events, is 49.8%.

Details of the reserve performance for resources assigned Synchronized Reserve can be found in Table 8.

Table 8. Assigned Reserve Performance

			Synch Reserve (MW)			
Event Date	Start (EST)	End (EST)	Assignment	Response (Units with assignment)	Shortfall to Assignment (MW)	Response to Assignment (%)
Dec. 23	10:14	10:25	1,791	1,547	244	86.4%
	16:17	18:09	1,846	945	901	51.2%
Dec. 24	00:05	00:30	1,767	930	837	52.6%
	02:23	02:54	1,665	535	1,130	32.1%
	04:23	05:51	1,007	169	838	16.8%

PJM has observed a drop in performance of approximately 20% for resources assigned Synchronized Reserve (excluding Winter Storm Elliott events) since the implementation of Reserve Price Formation on Oct. 1, 2022. Unrelated to the Winter Storm Elliott response, PJM has taken the following actions to address this drop in performance:

- Continued monitoring of Synchronized Reserve Performance and ACE recovery performance
- Identification of data trends including non-performance by specific resource, resource type and resource owner
- Reach out to resource owners with poor performance to identify causes of this poor performance

In addition to Synchronized Reserve response from resources assigned reserve, PJM typically observes significant response from resources that were not specifically assigned reserve at the time of the Synchronized Reserve event. While the All-Call message that announces a Synchronized Reserve Event requests all resources to load any Synchronized Reserve that they have available, resources without a Synchronized Reserve assignment at the start of the event are under no financial obligation to respond to these events and are not subject to nonresponse penalties for Synchronized Reserves. Since the implementation of Reserve Price Formation on Oct. 10, 2022, unassigned resources no longer receive a Tier 1 bonus for reserves provided.

There was also an over-response from some resources that exceeded their Synchronized Reserve assignment, although this was fairly minimal.

In the Dec. 24, 02:23 event, even with the additional contributions of reserves above assignment and from resources not assigned reserve, the total response still fell short of the system assigned reserve requirement. The response in megawatts from both units with and without Synchronized Reserve assignments are shown below in Table 9.

Table 9. Unit Synchronized Reserve Assignments Unit Synchronized Reserve Assignments Unit Synchronized MW Response With and Without Assignments

				Synch Reserve Unit Response (MW)			
Event Date			Synch Reserve Assignment (MW)	With Assignment	Above Assignment	Without Assignment	Total
Dec. 23	10:14	10:25	1,791	1,547	671	2,447	4,665
	16:17	18:09	1,846	945	161	2,512	3,618
Dec. 24	00:05	00:30	1,767	930	79	1,333	2,342
	02:23	02:54	1,665	535	78	1,006	1,619
	04:23	05:51	1,007	169	7	976	1,152

As described earlier, resources that provide less Synchronized Reserve than their assignment during a Synchronized Reserve Event are required to refund Synchronized Reserve revenue in the amount of the shortfall for the durations specified above. Since the penalties are based on the SRMCP, these penalties were higher than average due to the high SRMCPs during this time. The total retroactive penalties for these five events are listed in Table 10 below.

Table 10. Total Retroactive Penalties for Five Events Dec. 23–24

Event Date	Start (EST)	End (EST)	Synch Reserve Retroactive Penalty $
Dec. 23	10:14	10:25	$8,331.65
	16:17	18:09	$55,156.22
Dec. 24	00:05	00:30	$866,580.05
	02:23	02:54	$384,402.02
	04:23	05:51	$437,698.69

PJM has identified an opportunity for PJM, in conjunction with stakeholders, to evaluate Synchronized Reserve commitment and performance. There is also an identified opportunity to discuss alignment of market incentives with operational decisions. Following the PJM stakeholder process as described in PJM Manual 34, Section 6, PJM staff will bring a Problem Statement and Issue Charge forward to begin engagement with stakeholders on these opportunities.

Cost Offer Verification

As directed by FERC Order 831, effective April 12, 2018, PJM implemented a verification process for cost-based Incremental Energy Offers above $1,000/MWh. A resource's Incremental Energy Offer must be capped at $1,000/MWh or the resource's cost-based Incremental Energy Offer, whichever is higher. Cost-based Incremental Energy Offers are capped at $2,000/MWh for the purpose of calculating LMPs. The costs underlying a cost-based Incremental Energy Offer above $1,000/MWh must be verified before it can be used to calculate LMPs.

If a resource submits an Incremental Energy Offer above $1,000/MWh, and the underlying costs cannot be verified before the market clearing process begins, the offer may not be used to calculate LMPs. In this case, the resource may be eligible for a make-whole payment if it is dispatched and its costs are verified after the fact. Likewise, a resource may also be eligible for a make-whole payment if it is dispatched and its verified cost-based Incremental Energy Offer exceeds $2,000/MWh. All resources, regardless of type, are eligible to submit cost-based Incremental Energy Offers in excess of $1,000/MWh.

PJM uses a screening process to verify the reasonableness of each generation resource's cost-based Incremental Energy Offer segment in excess of $1,000/MWh before it is considered eligible to be used in dispatch or the calculation of LMPs. This screening process is applicable to all generation resources, including those that are Fast-Start capable. Fast-Start capable resources are subjected to an additional screening process.

- Day-Ahead Market Incremental Energy Offers between $1,000/MWh and $2,000/MWh must be submitted prior to the close of the Day-Ahead Market bid period to be screened for eligibility to set LMP in the Day-Ahead Market.
- In the Real-Time Market, a resource's cost-based offer must be submitted at least 65 minutes prior to the start of the operating hour in order for the Incremental Energy Offer segments between $1,000/MWh and $2,000/MWh to be screened for eligibility to set LMP.

PJM uses published index settle prices for the commodity price and cost inputs provided by the Market Seller in the Cost Offer Assumptions (COA) module within the Member Information Reporting Application (MIRA) to calculate the Maximum Allowable Incremental Cost as outlined in the PJM Operating Agreement. Submission to COA, or other system(s) made available is considered submission to PJM and the MMU.

The Market Seller is required to provide heat inputs and performance factors in COA, or other system(s) made available for submission of such data. The heat inputs and performance factors should be provided at least one week prior to the operating day. For each Incremental Energy Offer segment greater than $1,000/MWh, PJM evaluates whether such offer segment exceeds the reasonably expected costs for that generation resource by determining the Maximum Allowable Incremental Cost for each segment in accordance with Section 6.4.3 of Schedule 1 of the PJM Operating Agreement.

- If the cost submitted for the offer segment is less than or equal to the Maximum Allowable Incremental Cost value, then that segment is deemed verified and is eligible to be used in dispatch and to set LMP.
- If the cost submitted for the offer segment is greater than the Maximum Allowable Incremental Cost value, then the cost-based offer for that segment and all segments at an equal or greater price are deemed not verified. Such segments are capped at the greater of $1,000/MWh or the price on the most expensive verified segment for the purposes of dispatch and setting LMP.

PJM notifies the Market Seller of the verification status of each segment upon completion of the screen. The Generation Resource Exception Process is presented in PJM Manual 11, Section 2.3.6.2. The process is triggered infrequently, and PJM is evaluating if there are opportunities to provide additional training on the process.

Table 11 illustrates the number of energy offers in excess of $1,000/MWh received by PJM during Winter Storm Elliott:

Table 11. Energy Offers in Excess of $1,000/MWh

	Number of units with:		
Market Day	Offers above $1,000/day	Schedule ID with offers above $1,000/Day	Exception request approved
Dec. 23	*	*	*
Dec. 24	12	16	12
Dec. 25	49	93	40
Dec. 26	19	28	17

** Due to PJM confidentiality rules, PJM is unable to disclose the counts for Dec. 23.*

All offers above $1,000/MWh received during Winter Storm Elliott were processed in advance of the Real-Time Market and were able to set LMP in real time. Some units with energy offers in excess of $1,000/MWh did set LMP with these offers.

Uplift

To incent generators and Demand Resources to operate as requested by PJM, resources that are scheduled by PJM and follow PJM dispatch instructions are guaranteed to fully recover their costs of operation. Uplift cost is created when market revenues are insufficient to cover the costs of the resources following PJM's direction.

Operating Reserve costs are payments made to economic Demand Resources and generation resources that follow PJM's direction to cover their costs and are the primary form of uplift in PJM. These payments are outside of the market and are not included in the pricing signals that are visible and transparent to Market Participants.

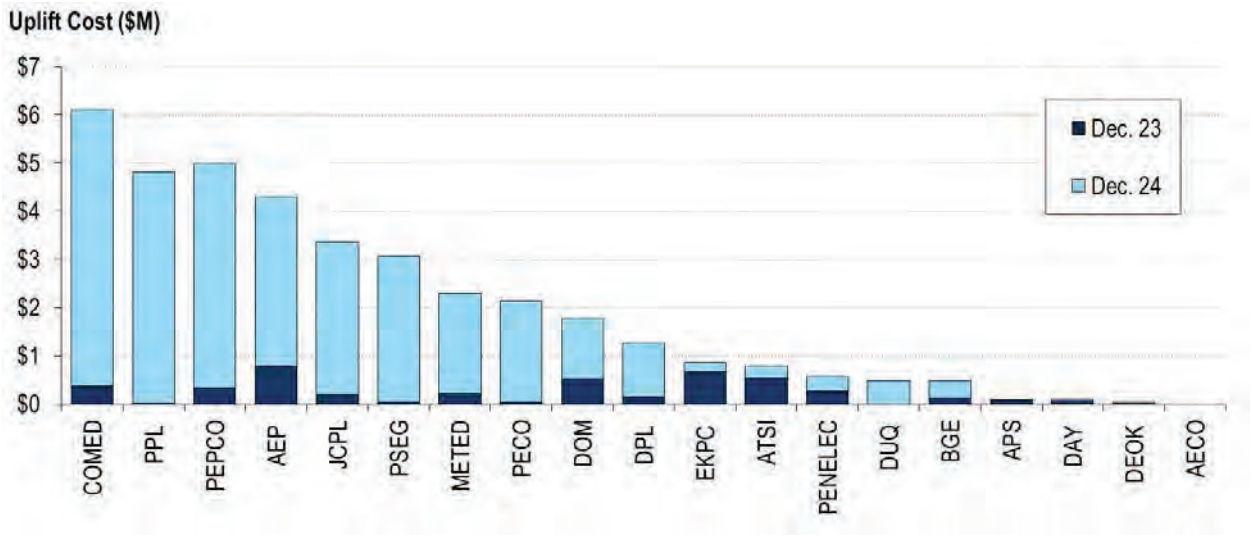
There are two reasons for out-of-market costs:

1 | Units that are running uneconomically at the direction of PJM are made whole to their offers.

2 | Units that are committed in the Day-Ahead Market and did not run in real time at PJM's direction, or had price spikes higher in real time when compared to the day-ahead lost opportunity cost, are made whole to their offers.

The Figure 85 shows the total uplift incurred by zone for Dec. 23 and Dec. 24.

Figure 85. Dec. 23 and Dec. 24 Total Uplift Incurred by Zone



A majority of the uplift cost on Dec. 23 and Dec. 24, as shown Figure 85, was due to generators scheduled by PJM running in real time to meet reliability needs.

Factors that contributed to uplift from this event include:

- Natural Gas Prices – High natural gas prices exacerbated the cost of uplift as the units operating at PJM's direction were more expensive than under more typical conditions.
- Contractual Constraints – Due to restrictions on natural gas deliveries, many resources required PJM to maintain strict megawatt output levels during periods when they were uneconomic to ensure they were

available during peak conditions. Additionally, the lack of alignment between the gas and electric day timing often required PJM to commit to running gas units prior to the Day-Ahead Energy Market.

- Prudent Operations – During Winter Storm Elliott, PJM committed resources for expected extreme system conditions. Such operations are typical during Cold Weather Alerts, resulting in the scheduling of additional reserves to account for increased forced outage rates as identified in the PJM Emergency Operations Manual. Scheduling resources in anticipation of extreme weather conditions and above-average forced outages can lower LMPs resulting in higher uplift levels.
- Interchange Volatility – Variable imports and exports of energy, which reacted to PJM energy prices, affected locational marginal prices and commitment decisions by PJM. The amount of power imported is difficult for PJM to forecast and is not completely under PJM's control; therefore, PJM must schedule internal resources to ensure that adequate generation is available given interchange uncertainty.

In the PJM market design, if a generation resource follows PJM's commitment and dispatch instructions, that generator is able to fully recover its costs for the hours it runs at PJM's direction. Operating Reserve payments are designed to incent resource owners to follow PJM direction to help maintain control of the grid in the most efficient manner possible, and also to ensure adequate operating supply plus additional capability for reserves. Day-ahead and real-time Operating Reserve credits are paid to resource owners; these credits are paid by Market Participants as Operating Reserve charges.

Increased Operating reserve costs are a side effect of running additional generation to support outages or other situations on the grid such as operational uncertainty. Uplift costs can be high when the primary fuel of additional generation being run is also high. During Winter Storm Elliott, generation was needed specifically in the northeastern region of PJM, where there is a large amount of natural gas-fired generation. Operating Reserve payments increased when the additional generation was run. Due to the tight supplies in the natural gas market, many PJM generators were kept online to mitigate the risk of being unable to obtain natural gas after shutting down. Some of these generators were run overnight because they could not shut down and restart again due to fuel or weather issues.

Market Settlement Statistics

The Day-Ahead Market allows participants to purchase and sell energy and reserves at binding day-ahead prices. Generators that are committed in the Day-Ahead Market are paid for energy based on the Day-Ahead LMP. LSEs that clear a demand bid the pay for energy based on the Day-Ahead LMP. Any quantity deviations from quantities cleared in the Day-Ahead Market are settled at the Real-Time LMP in a balancing settlement.

Units that are not committed in the Day-Ahead Market but are committed in the RAC or real-time are paid the Real-Time LMP. In the case of Dec. 23 and 24, Real-Time LMPs reached levels that were substantially higher than those in Day-Ahead. This is because the Real-Time Market is used to balance supply and demand in real time, and there is often more uncertainty about the amount of electricity that will be needed in real time. Phenomenon such as interchange volatility, load forecast uncertainty and generator trips only occur in real-time and therefore only directly influence those prices.

By understanding how balancing settlements work, generators can better manage their risks and ensure that they are adequately compensated for their output. Table 12 presents the divergence between Day-Ahead and Real-Time market prices. While this table is presented from a supply perspective, the fundamentals of the settlement apply to loads as well. That is to say that only those loads that are consuming more in real-time than they procured in the Day-Ahead Market are exposed to the high Real-Time LMPs on Dec. 23 and 24. Typically this is less than 5% of total load.

Table 12. Day-Ahead and Real-Time Market LMPs

	Day-Ahead Market		Peak LMP		Reliability Assessment Commitments (RAC) and Real-Time Commitments
	Loaded Generation (RTO Gen MW Figure 9)	Committed Generation with Outages	Day-Ahead	Real-Time	
Dec. 23	133,165 MW	12,847 MW	$224	$3,707	3,168 MW
Dec. 24	134,615 MW	16,560 MW	$259	$3,664	6,000 MW

The weekly gross billing statistics represent the total charges included in the weekly month-to-date invoices (generally spot market energy, congestion, losses and capacity charges).[11] Spot market energy, transmission congestion and transmission loss charges include positive and negative charges for supply and demand-side billing in a single charge billing line item, rather than separate charge and credit line items, as is the case with most other line items. To account for this difference, only the positive charges billed through these line items are included in the gross billing metric.

PJM's weekly invoices bill activity from the first day of the month through the end of the weekly billing period. The weekly gross billing values are calculated as the difference between the total month-to-date bill for a given week and the month-to-date bill for the prior week. For weeks with fewer than seven days, of which there was one, the gross billing was normalized to represent a seven-day week. Figure 86 presents the weekly gross billings statistics for the few weeks before and after Winter Storm Elliott.

Figure 86. Weekly Gross Billing Statistics

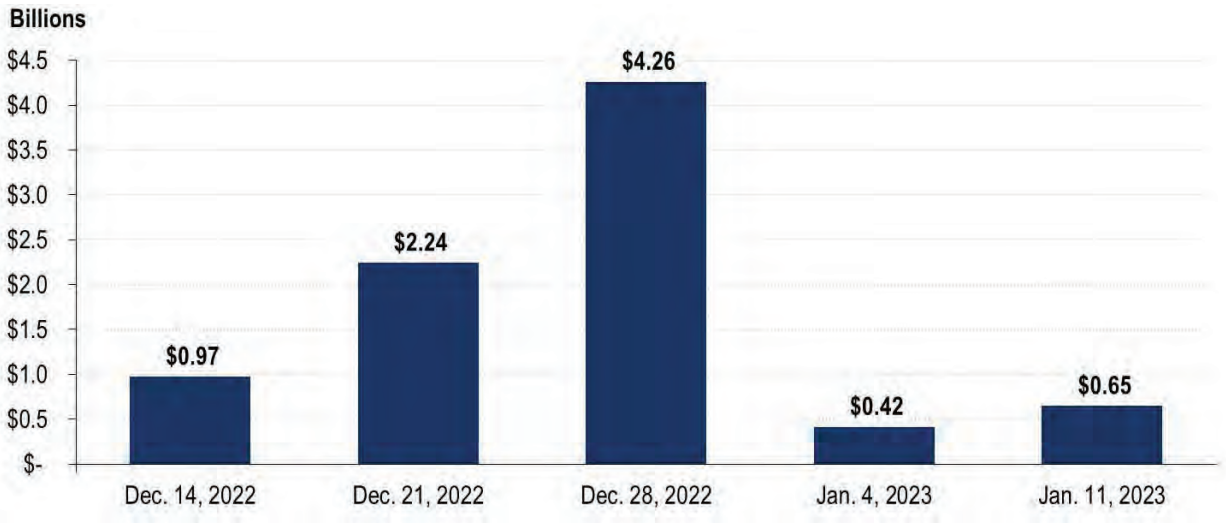
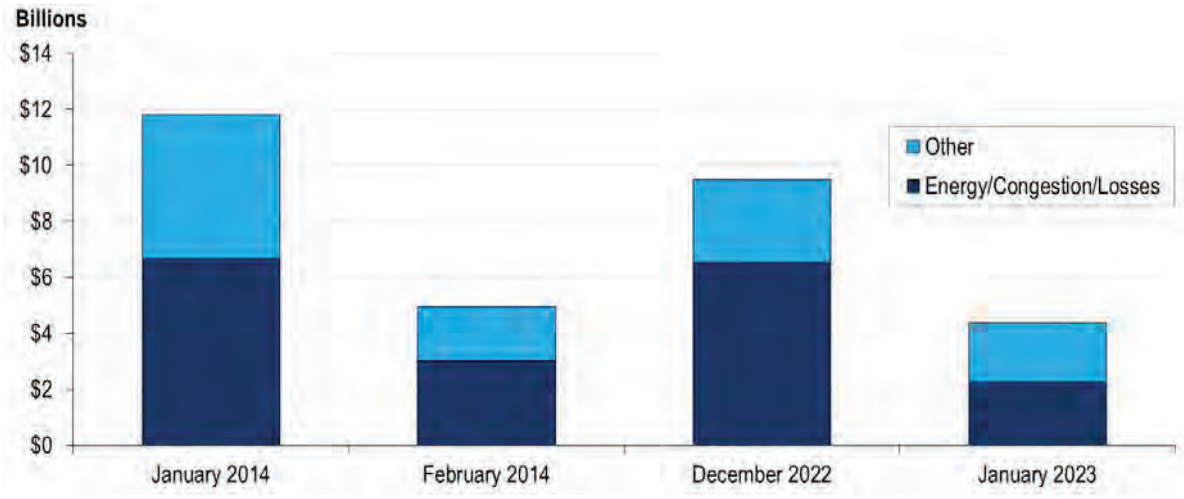


Figure 37 displays gross billing for Dec. 23 and Dec. 24, embedded in the bar chart for the week of Dec. 28. A significant increase in gross billing is observed when comparing the prior two weeks and successive two weeks to the week of Dec. 28. System conditions and operator actions reflecting the status of the RTO resulted in the higher gross billing. A contributing factor can be found in the average temperature for Dec. 23, which was 9.3 degrees Fahrenheit, with an average temperature on Dec. 24 of 7.6 degrees Fahrenheit.

Figure 87 presents the monthly gross billing comparison of Winter Storm Elliott to the 2014 Polar Vortex.

[11] PJM Manual 29, Section 3.2 details the charge line items included in the weekly invoices.

Figure 87. Winter Storm Elliott Monthly Billing vs. 2014 Polar Vortex Monthly Billing



In Figure 87, "Other" includes all billing except for spot market energy, congestion and transmission loss billing, including Schedule 9 and 10 charges, uplift, capacity and FTRs. As observed in the bar chart, gross monthly billing for the 2014 Polar Vortex exceeded gross monthly billing stemming from Winter Storm Elliott. A contributing factor for this difference ties to average temperatures. Average temperature for the month of January 2014 was 24.2 degrees Fahrenheit, with an average temperature of 35.4 degrees Fahrenheit for the month on December 2022.

Performance Assessment Intervals

Note: All data in this section is reflective of the performance assessment information used in the May 2023 billing statement and is being presented for informational purposes only. Nothing in this section may be construed to provide any settled expectations of charges or bonus payments. As such, to the extent adjustments are made subsequent to the May 2023 billing statement, the values herein may differ from those observed on market participants' settlement reports.

Background

The Maximum Emergency Generation Actions issued on Dec. 23 and Dec. 24, 2022, triggered Performance Assessment Intervals (PAIs) that require PJM to evaluate the performance of all resources located in the Emergency Action area for each applicable five-minute interval. The Emergency Action area for the Winter Storm Elliott performance assessment event covered the entire RTO for the intervals designated in Table 13. In total, there were 277 intervals for which performance was assessed. Given the significant number of intervals, most performance assessment data will be presented on an hourly basis (typically an average of the five-minute interval values in the hour) for purposes of this report. Other data will be looked at across the aggregate PAIs, from 17:30 EPT on Dec. 23 to 22:00 EPT on Dec. 24, or across the aggregate PAIs within a day.

Table 13. Impacted Zones for the Performance Assessment Events on Dec. 23 and Dec. 24

Location	Performance Assessment Intervals			Number of Intervals
Entire RTO	Dec. 23 17:30–23:00			66
	Dec. 24 04:25–22:00			211
		Total		277

The resources located in the RTO that were evaluated for this performance assessment event include:

- Generation: All generation resources, inclusive of Capacity Performance (CP) resources, energy-only resources and regulation-only resources
- Demand Response:
  - For Dec. 23, all pre-emergency and emergency DR (also referred to as Load Management) with 30-minute or 60-minute lead times dispatched by PJM
  - For Dec. 24, all pre-emergency and emergency DR dispatched by PJM (this includes all 30-minute, 60-minute and 120-minute lead times)
  - For both dates, some economic DR that was also dispatched or cleared in the energy and ancillary services markets
- Energy Efficiency: All annual Energy Efficiency resources
- Price-Responsive Demand: All price-responsive Demand Resources with a strike price that equaled or was lower than the five-minute LMP at their location

Based on the resource's performance and capacity commitment, resources may be assessed Non-Performance Charges or be eligible for bonus performance credits. Non-performance is determined based on the response of resources to fulfill their capacity commitments during each five-minute PAI, and no netting is permitted across intervals. Any performance shortfall or excess is calculated separately for each resource and each interval. Resources with a shortfall, or delivered energy (or reduction) less than expected based on the capacity commitment, are assessed a financial penalty. Resources demonstrating excess performance, or delivery of energy (or reduction) greater than expected based on the capacity commitment, are eligible for bonus payments.

PJM fielded many questions from Market Participants throughout and following the PAI event relating to the details of PAI business rules, penalty and bonus calculations, and Market Seller expectations during Winter Storm Elliott. This indicated the lack of widespread, detailed knowledge around the PAI process, likely due to the infrequent nature of performance assessments. It also reinforced the need to provide transparency into the PAI settlement process.[12]

PJM previously identified the following existing business rules, among others, that would benefit from more transparency, clarification or additional detail:

- Identification of assessed resources
- Calculation of real-time reserve and regulation assignment
- Calculation of scheduled megawatts for non-performance and bonus determinations

The effort to provide more transparency into the PAI settlement process started at the Market Implementation Committee and was eventually incorporated into the Resource Adequacy Senior Task Force scope. The recent requests for more

[12] Transparency Into PAI Settlements, PJM Issue Tracking, PJM.com

information into the process following Winter Storm Elliott underscore the need for this work to be addressed in the Critical Issue Fast Path – Resource Adequacy discussions.[13]

Balancing Ratio

For each PAI, PJM calculates a balancing ratio that represents the percentage share of total generation capacity commitments needed to support the load and reserves on the system within the Emergency Action area during that interval. This balancing ratio is then used to set the expected performance level of generation CP resources within the Emergency Action area for each PAI.

The balancing ratio is calculated as:

Balancing Ratio (BR) = (Total Actual Generation and Storage Performance + Net Energy Imports + DR Bonus Performance + PRD Bonus Performance) / All Generation and Storage Committed Unforced Capacity (UCAP) Commitments

Where:

- **Total actual generation and storage performance** is the actual metered output of the resources from PowerMeter, adjusted for any real-time regulation or reserves assignment.
- **Net energy imports** are the net energy import quantity during the event reported in ExSchedule, calculated as imports minus exports. This value is set to 0 for any intervals where exports exceeded imports.
- **DR bonus performance** is the net bonus megawatts for over-performing curtailment service providers (CSPs).
- **PRD bonus performance** is the net bonus megawatts for over-performing PRD resources.
- All **generation and storage-committed UCAP** are the sum of the CP commitment UCAP value for all Reliability Pricing Model (RPM) generation resources included in the assessment.

The balancing ratio is expected to align with the system demands during the Emergency Action period. The peak demand was 135,000 MW on Dec. 23 and 130,000 MW on Dec. 24. While these are high loads for the month of December, they are lower than the PJM peak load forecast that is used to establish the RPM reliability requirement (~163,000 MW). The RPM reliability requirement is established as the amount of capacity resources that are required to serve the forecast peak load and installed reserve margin to satisfy the PJM reliability criteria. As a result, it was expected that the balancing ratio would be less than 100%, because the demand during the PAIs was below the total committed capacity for those intervals. The average balancing ratio over the entire performance assessment event was 82.1%. The average balancing ratios for each day of the event are provided in Table 14. The balancing ratios for each five-minute interval of the event are available in Data Miner.[14]

Table 14. Summarized Balancing Ratios (BR) for Performance Assessment Intervals on Dec. 23 and Dec. 24

	Area(s)	Balancing Ratios		
		Average	Min	Max
Dec. 23 17:30–23:00	RTO	85.48%	82.23%	88.54%
Dec. 24 04:25–22:00		81.04%	77.67%	83.96%

[13] Critical Issue Fast Path – Resource Adequacy page

[14] See PJM.com, Performance Assessment Interval Final balancing ratio.

As noted in Real-Time Interchange, PJM was a net exporter of energy to neighboring systems during a significant portion of the PAIs on Dec. 23 and Dec. 24, which impacts the calculation of the balancing ratio in those intervals. During those intervals when exports exceeded imports, the Net Energy Imports figure in the balancing ratio formula is floored at zero. This has the effect of setting the balancing ratio, and subsequently the expected performance levels of committed generation, at a value that reflects both needs of the PJM system plus the assistance provided to neighboring systems in that interval. This result, of setting the balancing ratio and expected performance of committed generation capacity at a level beyond what's needed to satisfy PJM's system demand, warrants further consideration and discussion on the treatment of exports and imports in the balancing ratio and the level to which committed generation capacity should be held accountable during PAIs.

Performance Shortfall

Non-performance is measured by comparing a resource's actual performance to their expected performance to calculate a performance shortfall. This performance shortfall represents the amount of the committed capacity from the resource that was needed during the event but was not delivered to the system. The performance shortfall is calculated as: expected performance minus actual performance.

The expected performance of a resource is its CP commitment, adjusted by the balancing ratio (for generation) to account for the megawatts needed during the PAI. The actual performance of a resource is defined as the output of the resource during the event, accounting for both energy and ancillary services. The energy output is measured by the metered output (or load reduction) of the resource. The ancillary services portion of actual performance is based on the real-time regulation, Synchronized Reserves, Non-Synchronized Reserves or Secondary Reserves on the resource. The calculation for the ancillary service adjustment captures any movement off of the economic basepoint for the resource to provide the service in real time, so that the actual performance calculation credits the resource for any energy megawatts they did not produce in order to provide an ancillary service assignment.

The expected and actual performance calculations for CP resources are based on resource type:

- Generation/Storage:
  - Expected Performance = Capacity Commitment (UCAP) x Balancing Ratio
  - Actual Performance = Metered Energy Output + Reserve/Regulation Adjustment[15]
- Demand Response:
  - Expected Performance = CP Capacity Commitment (ICAP)[16]
  - Actual Performance = Load Reduction + Reserve/Regulation Adjustment[5]
- Price Responsive Demand
  - Expected Performance = CP Capacity Commitment (ICAP)

[15] For calculations for reserve and regulation assignment megawatts factored into actual performance, see the Performance Assessment Settlement Summary on PJM.com.

[16] Capacity Performance Demand Resources are only required to interrupt their load between the hours of 6:00 through 21:00 EPT for the months of November through April. As such, even though the emergency and pre-emergency load management reduction actions on the Dec. 23 did not end until 21:30 and 22:15, respectively, Capacity Performance Demand Resources were not required to curtail consumption beyond 21:00. Expected Performance is 0 MW outside the required hours of curtailment.

  - Actual Performance = Load Reduction

- Energy Efficiency:
  - Expected Performance = CP Capacity Commitment (ICAP)
  - Actual Performance = PJM-Approved Post-Installation Load Reduction

If a resource's expected performance is greater than the actual performance, the resource will be assessed a non-performance penalty, unless the shortfall is excused from the performance shortfall. The reasons for excusal and the megawatts that were excused for the Winter Storm Elliott performance assessment event are discussed in the Excusal section of this paper.

The average initial shortfall across the performance assessment event, prior to excusals, was 38,068 MW. The hourly average data for the expected, actual and shortfall megawatts can be found in Table 15. Notably, actual performance across all resources in the Emergency Action area exceeds expected performance for each five-minute interval, which at first glance seems somewhat contrary to the presence of an initial shortfall. However, this is explained by performance from resources that did not have a performance obligation at the time of the performance assessment event, as well as over-performance by some resources that did have a CP obligation.

Due to the number of CP resources that exceeded the expected performance, energy-only resources that were online and generating, and net energy imports flowing into the RTO during the performance assessment event, the aggregate actual performance in all intervals was greater than the expected performance, resulting in bonus megawatts for each interval of this event.

Table 15. Aggregate Expected, Actual and Initial Shortfall Performance (hourly avg. of five-minute interval totals)

Hour Beginning (EPT)		AVERAGE		
		Expected MW Per Interval	Actual MW Per Interval	Initial Shortfall MW Per Interval
Dec. 23, 2022	17:00	142,502	144,350	35,861
	18:00	147,697	149,537	36,446
	19:00	147,850	149,788	36,566
	20:00	148,011	149,936	36,924
	21:00	147,359	149,726	37,719
	22:00	139,231	141,239	36,559
Dec. 24, 2022	04:00	131,369	133,283	39,552
	05:00	131,661	133,557	39,666
	06:00	141,681	142,127	41,179
	07:00	146,004	145,228	40,926
	08:00	147,220	147,511	39,435
	09:00	146,875	148,993	38,452
	10:00	145,829	147,957	39,210
	11:00	145,045	147,264	39,611
	12:00	144,689	146,911	39,036
	13:00	143,037	145,269	38,164
	14:00	140,860	142,988	38,448
	15:00	141,807	143,929	38,587

Hour Beginning (EPT)		AVERAGE		
		Expected MW Per Interval	Actual MW Per Interval	Initial Shortfall MW Per Interval
	16:00	144,464	146,607	38,653
	17:00	145,637	147,793	37,650
	18:00	145,211	147,327	36,820
	19:00	142,313	144,420	36,317
	20:00	134,636	136,550	34,505
	21:00	132,933	134,927	34,744

Although actual performance exceeded expected performance in aggregate for each interval, non-performance is assessed on an individual resource basis. Therefore, shortfall megawatts and associated Non-Performance Charges were assessed to resources in each of these intervals if their individual resource performance fell short of the expected megawatts. Breaking out the shortfall megawatts to a more granular level, the next few graphs and charts contain only the CP resources that had an initial shortfall. CP resources that have met or exceeded their expected performance, and energy-only resources, are excluded from these data sets. In aggregate, resources with shortfall megawatts provided 27% of their expected megawatts during the event. This aggregate performance was weighed down by the number of capacity resources on full or partial forced outages during the event.

Table 16. Expected, Actual and Initial Shortfall Performance for Under Performing Resources (hourly average of five-minute interval totals)

		AVERAGE		
Hour Beginning (EPT)		Expected MW per Interval	Actual MW per Interval	Initial Shortfall MW per Interval
Dec. 23, 2022	17:00	46,052	10,192	35,861
	18:00	49,254	12,808	36,446
	19:00	48,287	11,722	36,566
	20:00	47,773	10,849	36,924
	21:00	49,873	12,154	37,719
	22:00	47,221	10,662	36,559
Dec. 24, 2022	4:00	50,346	10,793	39,552
	5:00	50,340	10,674	39,666
	6:00	54,181	13,002	41,179
	7:00	54,893	13,967	40,926
	8:00	52,794	13,359	39,435
	9:00	51,993	13,540	38,452
	10:00	52,162	12,952	39,210
	11:00	52,497	12,886	39,611
	12:00	52,563	13,528	39,036
	13:00	54,373	16,209	38,164
	14:00	56,301	17,853	38,448
	15:00	54,230	15,643	38,587
	16:00	52,981	14,328	38,653
	17:00	53,101	15,451	37,650
	18:00	55,288	18,468	36,820
	19:00	54,934	18,616	36,317
	20:00	53,868	19,363	34,505
	21:00	52,893	18,149	34,744

Excusals

A resource's performance shortfall is evaluated for excusals and may be adjusted downward if the shortfall is deemed to be exempt. Megawatts are excused from performance if they were solely unavailable for the following reasons:

- Megawatts were on a PJM-approved planned or maintenance outage.
- Megawatts were not scheduled to operate by PJM, or were scheduled down by PJM, in alignment with the dispatch run LMP resulting from the Security Constrained Economic Dispatch and/or reliability needs.

However, if a resource was needed by PJM and would otherwise have been scheduled by PJM to perform, but was not scheduled to operate, or was scheduled down solely due to: (1) any operating parameter limitations submitted in the resource's offer, or (2) submission of market-based offer higher than cost-based offer, then these megawatts are not excused and will not result in downward adjustment of performance shortfall.

For the Winter Storm Elliott event, the average excused megawatts deemed unavailable solely due to approved maintenance and planned outages were approximately 3,800 MW. The maintenance and planned outages are in line with what can be expected in a typical winter or summer season. These outages are scheduled and approved by PJM and recallable 72 hours in advance. This is the reason these megawatts are deemed to be exempt from performance during their approved outage period. Prior to Dec. 23, PJM did not recall any generation maintenance outages, as load projections did not indicate that would be necessary. Forced outages, or outages that are unscheduled or unplanned, are not exempt from performance requirements; resources on a forced outage with a performance shortfall are assessed Non-Performance Charges.

Megawatts that were not supported by LMP, or were otherwise scheduled down by PJM, are exempt from performance penalties, because their megawatts were not needed to support the system or production of those megawatts when unneeded could have been detrimental to system reliability. It is important to system reliability during a performance assessment event that resources continue to follow PJM direction to help maintain power balance. Resources may not be scheduled by PJM due to economic reasons, such as projected system conditions and locational marginal prices (LMPs) that did not support bringing the resource online; or controlling transmission constraints that supported lowering the unit's output; or the resource is held offline or down by PJM for reserves.

Some instances of PJM manual dispatch instruction or units that were not scheduled required extensive case-by-case review by PJM staff including the review of operator logs, market data, outage data and operator conversations to determine the required level of excusal or bonus.

A more granular breakdown of the excused megawatts for each hour of the event, and the resulting final shortfall, is included in Table 17. This includes shortfalls from generation, Demand Response and Price Responsive Demand resources. Energy Efficiency resources are excluded solely because they did not have any performance shortfalls for this event. As discussed further in the

Netting for Demand Response and Price Responsive Demand section of this paper, while Demand Response and Price Responsive Demand Resources are not eligible for excusals in the same manner as generation resources, their performance shortfalls can be offset by over-performance of other resources. Any shortfall megawatts that were offset by over-performance from other resources have been included in the Average Not Scheduled column in the table below to facilitate complete accounting of final shortfall megawatts across the fleet of capacity resources. [17]

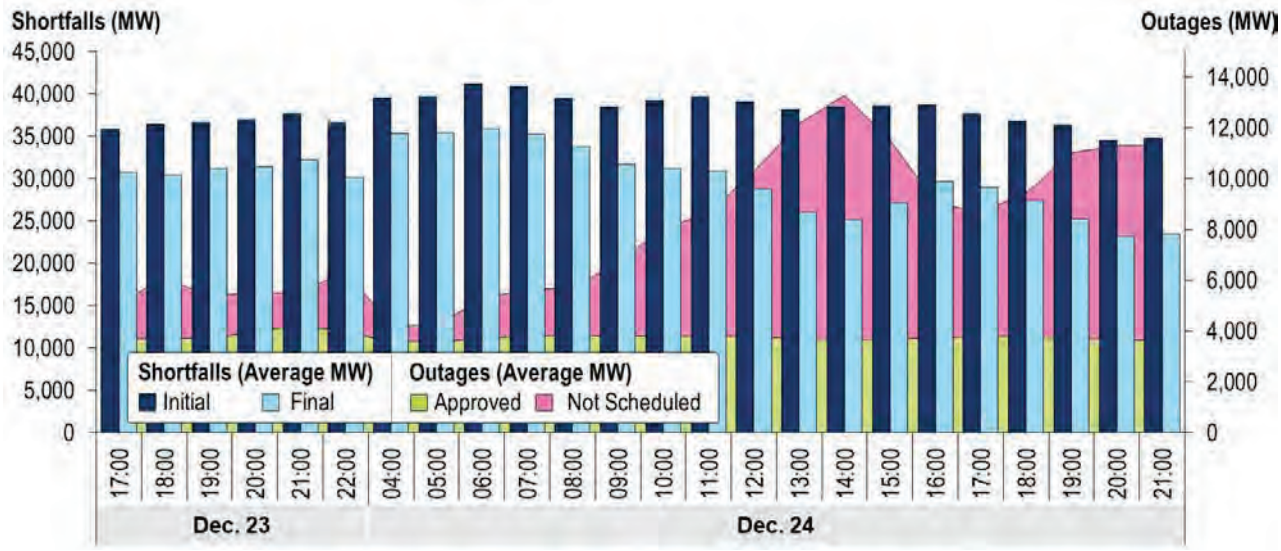
[17] The average DR and PRD shortfall megawatts offset by over-performance by other resources is 230 MW per interval.

Table 17. Initial Shortfall, Excused MW and Final Shortfall (hourly average of five-minute interval totals)

Hour Beginning (EPT)		AVERAGE			
		Initial Shortfall (MW)	Approved Outages (MW)	Not Scheduled (MW)	Final Shortfall (MW)
Dec. 23, 2022	17:00	35,861	3,674	1,469	30,718
	18:00	36,445	3,709	2,351	30,385
	19:00	36,566	3,700	1,694	31,172
	20:00	36,924	3,989	1,505	31,430
	21:00	37,719	4,238	1,262	32,219
	22:00	36,559	3,977	2,418	30,164
Dec. 24, 2022	04:00	39,552	3,581	658	35,313
	05:00	39,666	3,589	642	35,435
	06:00	41,179	3,700	1,572	35,907
	07:00	40,926	3,791	1,860	35,275
	08:00	39,435	3,827	1,826	33,782
	09:00	38,452	3,820	2,887	31,745
	10:00	39,210	3,791	4,219	31,200
	11:00	39,610	3,769	4,902	30,939
	12:00	39,034	3,759	6,528	28,747
	13:00	38,164	3,710	8,441	26,013
	14:00	38,448	3,645	9,634	25,169
	15:00	38,587	3,673	7,852	27,062
	16:00	38,652	3,751	5,305	29,596
	17:00	37,649	3,786	4,885	28,978
	18:00	36,797	3,773	5,644	27,380
	19:00	36,285	3,733	7,277	25,275
	20:00	34,505	3,657	7,640	23,208
	21:00	34,744	3,634	7,645	23,465

The average total excused megawatts in each PAI on Dec. 23 was approximately 5,600 MW per interval. The average for Dec. 24 was higher, at approximately 8,700 MW per interval. Figure 88 shows that planned outages were consistent across all intervals of the event, and that the increase in excusals on Dec. 24 was driven by higher levels of excusals for megawatts not scheduled on Dec. 24 as strain on the system eased throughout the day.

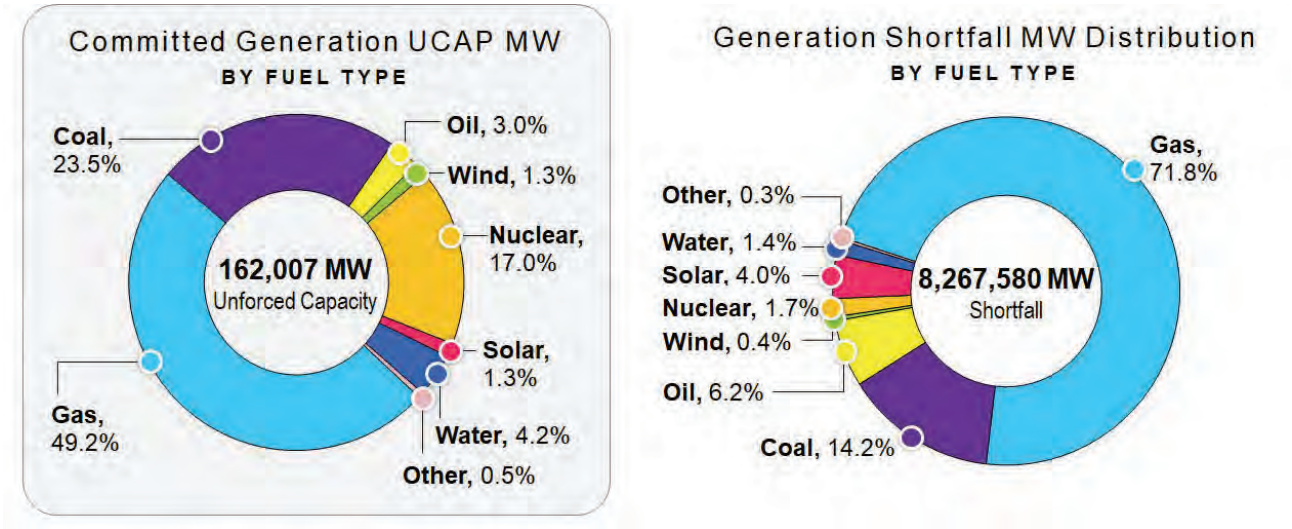
Figure 88. Excusal Megawatts and Final Shortfall MW (hourly average of five-minute interval values)



Generation Shortfall Distribution by Fuel Type

Figure 89 depicts how the final shortfall megawatts for generation resources were distributed across the generation fleet using primary fuel type. Also provided in this figure is the distribution of committed generation capacity megawatts by primary fuel type to assist in understanding how proportionate the shortfall megawatts by fuel type are to that fuel type's share of total committed generation capacity. For example, while gas units make up roughly half of committed generation capacity, they represented 71.8% of all shortfall megawatts, which tracks with the observations in the Operating Day section of this report that gas resources represented the majority of the forced outages during Winter Storm Elliott for the reasons explained therein. Solar resources also had an outsized proportion of the shortfall megawatts compared to their share of committed capacity. This is attributed to the timing of the performance assessment intervals, the majority of which occurred during hours with low levels of solar irradiance. Conversely, wind resources represented an undersized share of the performance shortfall, which tracks their strong performance noted in the Positive Observations section of this paper. The high availability factor of nuclear resources during Winter Storm Elliott resulted in the strong performance of nuclear resources and their undersized share of the shortfall megawatts.

Figure 89. Generation Shortfall MW Distribution by Fuel Type compared to Capacity Commitment



Netting for Demand Response and Price Responsive Demand

Performance shortfalls for Demand Resources deployed during a performance assessment event are evaluated as a group with all other Demand Resources in the same Emergency Action area belonging to the curtailment service provider (CSP) that committed the resource to the capacity market. For the Winter Storm Elliott event, the Emergency Action area encompassed the entire RTO, resulting in initial performance shortfall (positive or negative) of all resources belonging to the CSP being netted to determine a net performance shortfall.

In this manner, over-performance on some resources within a CSP's portfolio is able to offset under-performance on other resources in the same interval. If a CSP has a net positive shortfall of megawatts once the performance of all of its Demand Resources are netted together, the resulting shortfall is allocated to Demand Resources that under-performed pro-rata using their under-compliance megawatts. Based on this netting, a Demand Resource's final shortfall megawatts will be less than its initial shortfall megawatts if other Demand Resources in the portfolio over-performed for the same interval and were able to offset some of its shortfall.

Performance shortfalls for Price Responsive Demand (PRD) resources deployed during a performance assessment event are also evaluated as a group with all other PRD resources belonging to the provider that committed the resource to the capacity market, similar to the netting that occurs for Demand Resources.

The initial and final shortfall megawatts for Demand Resources and PRD resources during this performance assessment event are shown in Table 18. The difference between the initial and final shortfall values is reflective of the DR or PRD over-performance megawatts that was able to offset any performance shortfalls. Megawatts of over-performance that are used to net against under-performance of other resources are not eligible to receive bonus credits. The Demand Response and PRD performance values have been aggregated in the table below to adhere to posting rules around market-sensitive data given the small number of Market Participants with PRD resources.[18] For some hours, the number of combined DR and PRD Market Participants with shortfalls still does not meet the requirements for posting market-sensitive data. The data for those hours has been omitted and marked with **.

[18] PJM Manual 33, Section 6.1

Table 18. DR and PRD Initial and Final Shortfall (hourly average of 5-minute interval values)

Hour Beginning (EPT)		Average DR & PRD Initial Shortfall	Average DR & PRD Final Shortfall
Dec. 23, 2022	17:00	**	**
	18:00	583.8	267.4
	19:00	519.3	197.8
	20:00	526.4	213.7
	21:00	**	**
	22:00	0	0
Dec. 24, 2022	04:00	**	**
	05:00	**	**
	06:00	312.7	14.3
	07:00	528.3	126.3
	08:00	521.5	116.4
	09:00	433.5	38.4
	10:00	382.8	21.6
	11:00	365.3	20.8
	12:00	359.1	22.1
	13:00	337	16.3
	14:00	316.6	15.5
	15:00	315.8	14.8
	16:00	337.7	14.5
	17:00	371.6	16.2
	18:00	357.1	14.9
	19:00	88.6	11.4
	20:00	**	**
	21:00	0	0

Non-Performance Charges

Non-Performance Charge rates are calculated on a modeled RPM Locational Deliverability Area (LDA) basis for the relevant delivery year. The Non-Performance Charge rate for a specific resource is based on the Net Cost of New Entry (Net CONE) ($/MW-day in installed capacity terms) for the LDA in which such resource resides and is calculated as:

Non-Performance Charge Rate ($/MW-5-Minute Interval) =
Net CONE x Number of Days in Delivery Year / 30 Hours / 12 Intervals

The applicable charge rates for the Winter Storm Elliott PAIs for the 2022/2023 Delivery Year are detailed in Table 19.[19]

Table 19. Non-Performance Charge Rates by LDA ($/MW-5-Minute Interval)

Non-Performance Charge Rates by Locational Deliverability Area (LDA)					
ATSI	221.83	DPL-SOUTH	227.29	PS-NORTH	258.34
ATSI-CLEVELAND	221.83	EMAAC	249.60	PSEG	258.34
BGE	217.85	MAAC	235.90	RTO	250.69
COMED	238.54	PEPCO	249.76	SWMAAC	233.81
DAY	217.8	PPL	240.99		
DEOK	215.22				

These charge rates are multiplied by the final performance shortfall in each five-minute interval to determine the non-performance financial penalty for committed capacity resources. The Non-Performance Charge is calculated as:

*Non-Performance Charge = Performance Shortfall MW * Non-Performance Charge Rate*

The Non-Performance Charge for the performance assessment event totals approximately $1.80 billion, which was allocated across roughly 750 resources with final performance shortfall megawatts.

This represents 45% of the $3.97 billion in RPM auction credits paid across all committed capacity resources for the 2022/2023 Delivery Year. When isolating only the resources with shortfalls, the $1.80 billion in Non-Performance Charges represents 83% of the $2.17 billion in RPM auction credits collectively received by these under-performing resources for the 2022/2023 Delivery Year.

The hourly average and total Non-Performance Charges by hour are listed in Table 20.

[19] Modeled LDA Net CONE values for the 2022/2023 Delivery Year are available on PJM.com.

Table 20. Non-Performance Charges by Hour

Hour Beginning (EPT)		Non-Performance Charges ($)	
		Average of Interval-Level	Total Hourly
Dec. 23, 2022	17:00	6,589,973.18	39,539,839.05
	18:00	6,505,727.97	78,068,735.58
	19:00	6,731,000.98	80,772,011.71
	20:00	6,827,351.73	81,928,220.72
	21:00	7,031,512.93	84,378,155.18
	22:00	6,532,125.94	78,385,511.32
Dec. 24, 2022	04:00	7,785,599.61	54,499,197.25
	05:00	7,799,035.09	93,588,421.11
	06:00	7,733,603.22	92,803,238.65
	07:00	7,768,289.54	93,219,474.49
	08:00	7,473,896.14	89,686,753.62
	09:00	7,034,963.27	84,419,559.27
	10:00	6,910,820.64	82,929,847.71
	11:00	6,858,699.63	82,304,395.52
	12:00	6,370,314.53	76,443,774.40
	13:00	5,704,554.02	68,454,648.19
	14:00	5,508,448.92	66,101,387.04
	15:00	5,831,635.11	69,979,621.27
	16:00	6,365,883.24	76,390,598.86
	17:00	6,103,588.46	73,243,061.57
	18:00	5,739,415.91	68,872,990.94
	19:00	5,314,600.31	63,775,203.73
	20:00	4,951,402.92	59,416,835.04
	21:00	5,033,588.91	60,403,066.98
			$1,799,604,549.20

Stop-loss provisions are in place to limit the total Non-Performance Charge that can be assessed on each capacity resource. For CP resources, the maximum yearly Non-Performance Charge is 1.5 times the modeled LDA Net CONE ($/MW-day in installed capacity terms), times the number of days in the delivery year, times the maximum daily unforced capacity committed by the resource from June 1 of the delivery year through the end of the month for which the Non-Performance Charge was assessed. For all CP resources involved in the Winter Storm Elliott performance assessment event, the calculated Non-Performance Charge for the event was below the maximum yearly Non-Performance Charge. Further, for those Demand Response resources that were also subject to the performance assessment event in June 2022 earlier that same delivery year, the cumulative Non-Performance Charge for the delivery year did not exceed the maximum yearly Non-Performance Charge. As a result, it was not necessary to apply the stop-loss provision to any CP resource for the Winter Storm Elliott performance assessment event.

A resource that does not have enough unforced capacity value to cover the RPM commitment on the resource is subject to a Daily Capacity Resource Deficiency Charge. The Daily Capacity Resource Deficiency Charge is equal to the Daily

Deficiency Rate times the Daily RPM Commitment Shortage for generation resource, Demand Resource or Energy Efficiency Resource.[20]

Resources with Daily Capacity Resource Deficiency Charges may also have Non-Performance Charges during a non-performance event. In this case, a cap is placed on the total amount of deficiency-related charges a resource can be assessed. A resource that is subject to a Non-Performance Charge during one or more intervals occurring during a continuous time period of Daily RPM Commitment Shortages is assessed a charge equal to the greater of: a) the total Daily Capacity Resource Deficiency Charges calculated for shortages associated with Capacity Performance commitments for such continuous time period, or b) the total Non-Performance Charges calculated for the Performance Assessment Intervals occurring during such continuous time period.

The sum of the Daily Capacity Resource Deficiency Charges and Non-Performance Charges actually billed for such continuous time period may not exceed the resultant greater of charge. For the Winter Storm Elliott event, approximately $815,000 in Non-Performance Charges were excluded from the performance assessment billing based on this cap on total deficiency-related charges assessed to deficient resources. This $815,000 is not reflected in the values in Table 20.

Fixed Resource Requirement Shortfall Megawatts and Non-Performance Penalties

Resources that have been committed to a Fixed Resource Requirement (FRR) plan have the same obligation to perform during a performance assessment event as resources with RPM capacity commitments.

Shortfall megawatts from resources committed to FRR plans were included in the above tables summarizing resource performance and Non-Performance Charges, where applicable. Market Participants meeting their capacity obligations through FRR plans have the additional option to elect the physical non-performance assessment option.[21]

Entities that elect the FRR physical option are not assessed Non-Performance Charges and are not eligible for bonus performance credits for any performance associated with their FRR commitments. Instead, these entities must commit an additional megawatt quantity to their FRR capacity plan for the next delivery year in an amount equal to the sum of the net positive shortfalls for resources committed to their FRR plan across all five-minute intervals in the performance assessment event, multiplied by the FRR physical penalty rate.

The physical penalty rate is 0.00139 MW / Performance Assessment Interval [i.e., 0.5 MW / 30 PAHs / 12 intervals per hour]. For example, a resource with 1,000 MW of shortfall summed across all five-minute intervals in the performance assessment event would need to commit an additional 1.4 MW of capacity to their FRR plan for the delivery year following the event. In contrast, if the FRR entity for this resource instead chose the financial non-performance assessment option and was subject to the RTO Non-Performance Charge rate of $250.69/MW per five-minute interval, the resource would be assessed a charge of $250,690.

PJM is unable to report on the breakout of FRR Market Participants that have elected the physical non-performance assessment option vs. the financial non-performance assessment option or the penalties assessed to resources within their plans due to the small number of Market Participants utilizing FRR plans and requirements for posting market-sensitive data.[22]

Bonus Performance

A resource with actual performance above its expected performance is considered to have provided bonus performance, and will be assigned a share of the collected Non-Performance Charge revenues in the form of a bonus performance

[20] See PJM Manual 18, Section 9.1.3 for more information about Daily Capacity Resource Deficiency Charges.
[21] Refer to PJM Manual 11, Section 11.8.7 Physical Non-Performance Assessment.
[22] PJM Manual 33, Section 6.1

credit. Bonus performance from a resource represents greater delivered energy (or reductions), in comparison to the amount of the committed capacity from the resource that was needed during the event. Bonus performance is calculated on all over-performing resources as actual performance minus expected performance.

The expected and actual performance calculations for bonus megawatt evaluations are based on resource type:

- Generation/Storage:
  - Expected Performance = CP Commitment (UCAP) x Balancing Ratio
  - Actual Performance = Metered Energy Output + Reserve/Regulation Adjustment[23]
- Demand Response:
  - Expected Performance = CP Capacity Commitment (ICAP)
  - Actual Performance = Load Reduction + Reserve/Regulation Adjustment
- Energy Efficiency:
  - Expected Performance = CP Capacity Commitment (ICAP)
  - Actual Performance = PJM Approved Post-Installation Load Reduction
- Price Responsive Demand
  - Expected Performance = CP Capacity Commitment (ICAP)
  - Actual Performance = Load Reduction
- Net Imports
  - Expected Performance = 0 MW
  - Actual Performance = Sum (Import MW) – Sum (Export MW)

When calculating bonus megawatts, the actual performance for a generation resource is capped at the megawatt level at which such resource was scheduled and dispatched by PJM during the performance assessment event. PJM caps the megawatt level that a resource is eligible to receive bonus credit for to incent resources to follow dispatch in real time to support operations, and not chase potential bonus credits by over-generating. Resources must also have at least one available schedule with an economic minimum, economic maximum and emergency maximum, and at least one segment on the incremental energy offer curve so that PJM can determine the scheduled megawatts used in the determination of the cap. [24]

On average, approximately 2,700 MWh of energy in excess of expected megawatts was not eligible for bonus credits in each interval due to capping or failure to meet the energy offer requirements. PJM observed that a subset of these ineligible megawatts were from renewable resources that provided energy in excess of their expected megawatts. Many of these resources do not submit fuel cost policies and by default agree to be dispatched as a zero-cost resource in the

[23] The reserve/regulation adjustment made for actual performance for bonus purposes is the same as the adjustment made for shortfall calculation purposes. For calculations for reserve and regulation assignment megawatts factored into actual performance, see the Performance Assessment Settlement Summary.
[24] This rule is defined in Manual 11, Section 2.3.7.

absence of an approved fuel-cost policy. As such, these resources did not enter any segments on their Incremental Energy Offer curve and were therefore excluded from bonus payments.

The average bonus megawatts eligible for bonus credits for the Winter Storm Elliott performance assessment event was 34,318 MW per interval. On average, approximately 70% of these megawatts came from CP resources, while 30% came from energy-only resources (including net energy imports). The larger percent of bonus megawatts from the CP resources are driven by those resources being online and generating, and the average 82.1% balancing ratio. On average, resource output in excess of 82.1% of their capacity commitment, up to the megawatt level at which the resource was scheduled and dispatched, can be attributed to over-performance.

Table 21. Bonus Performance Megawatts by Hour by CP Resources and Energy Resources (hourly average of five-minute interval values)

Hour Beginning (EPT)		Average Bonus MW		Average Total Bonus MW
		CP Resources	Energy Resources	
Dec. 23, 2022	17:00	22,988.9	10,128.8	33,117.7
	18:00	23,102.9	10,827.0	33,930.0
	19:00	23,342.9	10,555.7	33,898.6
	20:00	23,825.6	10,312.1	34,137.8
	21:00	25,530.0	10,228.4	35,758.4
	22:00	23,059.9	10,717.0	33,776.9
Dec. 24, 2022	04:00	25,566.7	11,408.0	36,974.8
	05:00	25,850.1	10,984.0	36,834.1
	06:00	25,966.6	10,927.8	36,894.4
	07:00	24,469.0	11,490.8	35,959.9
	08:00	24,406.5	10,500.8	34,907.3
	09:00	25,106.4	9,974.4	35,080.8
	10:00	25,818.1	10,900.9	36,719.1
	11:00	26,328.8	10,850.1	37,178.9
	12:00	25,020.0	10,390.9	35,410.9
	13:00	22,903.1	10,435.4	33,338.6
	14:00	22,955.3	10,782.6	33,737.9
	15:00	24,371.7	10,314.0	34,685.8
	16:00	25,360.7	9,607.9	34,968.7
	17:00	23,723.6	9,569.2	33,292.8
	18:00	21,557.6	10,219.8	31,777.4
	19:00	21,716.6	9,978.6	31,695.2
	20:00	19,887.0	9,678.5	29,565.6
	21:00	21,310.7	8,681.8	29,992.6

Table 21 breaks out the average total bonus megawatts by resource type. On average, 80% of bonus megawatts were produced by generation, 10% came from net import transactions, 5% were produced by Energy Efficiency resources, and 5% were produced by Demand Response and PRD resources.

Energy Efficiency bonus megawatts are a static 1,720.9 MW across each five-minute interval of the entire performance assessment event. Actual performance for Energy Efficiency resources is established by the average demand reduction reported in the last post-installation measurement and verification report submitted by the Market Seller and approved by PJM prior to the delivery year in question.[25] Energy Efficiency resources automatically receive bonus megawatts for demand reduction in excess of their capacity commitment, as demonstrated in the post-installation measurement and verification report when a Capacity Performance event occurs.

The Demand Response and PRD bonus megawatt values include pre-emergency and emergency load management resources as well as economic Demand Resources cleared for energy or ancillary services. Pre-Emergency and Emergency Load Response resources are only required to interrupt their load between the hours of 06:00 through 21:00 EPT for the months of November through April. As such, even though the emergency and pre-emergency load management reduction actions on Dec. 23 did not end until 21:30 and 22:15, respectively, Capacity Performance Demand Resources were not required to curtail consumption beyond 21:00. The expected megawatts from these resources in the hours outside their mandatory curtailment period is 0 MW. One-hundred percent of the load reductions from pre-emergency and emergency load management resources in such hours are therefore counted as bonus megawatts. This is the reason the Average DR and PRD bonus megawatts for hour beginning 22:00 jumps five-fold from the previous hour.

Table 22. Bonus Performance Megawatts Broken Down by Resource Type (hourly average of five-minute interval values)

Hour (EPT Hour Beginning)		Average Bonus MW			
		Generation	Net Imports	EE	DR & PRD
Dec. 23, 2022	17:00	28,350.9	2,849.5	1,720.9	196.40
	18:00	27,965.0	3,490.5	1,720.9	753.50
	19:00	28,023.9	3,243.0	1,720.9	910.70
	20:00	28,410.3	3,032.2	1,720.9	974.20
	21:00	25,926.2	3,158.3	1,720.9	4,952.90
	22:00	27,974.1	3,834.8	1,720.9	247.00
Dec. 24, 2022	04:00	30,731.4	4,392.8	1,720.9	129.50
	05:00	31,103.6	3,897.8	1,720.9	111.70
	06:00	29,108.1	3,953.5	1,720.9	2,111.80
	07:00	28,213.2	4,289.4	1,720.9	1,736.30
	08:00	27,811.6	3,601.9	1,720.9	1,772.90
	09:00	28,422.5	3,084.0	1,720.9	1,853.30
	10:00	29,135.8	3,953.2	1,720.9	1,909.00
	11:00	29,514.4	3,849.5	1,720.9	2,094.10
	12:00	27,890.1	3,631.0	1,720.9	2,168.90
	13:00	25,798.2	3,603.0	1,720.9	2,216.40
	14:00	25,767.6	3,980.7	1,720.9	2,268.60
	15:00	27,083.5	3,610.1	1,720.9	2,271.20
	16:00	27,785.5	3,287.5	1,720.9	2,174.70
	17:00	26,248.9	3,254.7	1,720.9	2,068.20

[25] See PJM Manual 18, Section 4.4.1: Determination of Nominated value of EE Resources for more detail on how the average demand reduction upon which actual performance for Energy Efficiency resources is established.

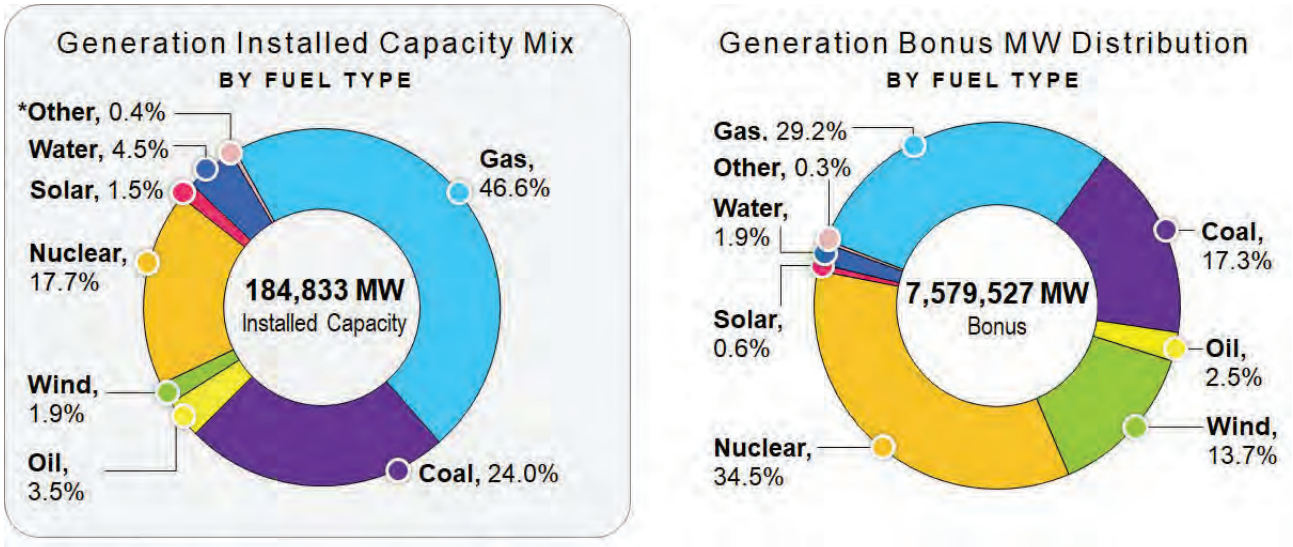
Hour (EPT Hour Beginning)	Average Bonus MW			
	Generation	Net Imports	EE	DR & PRD
18:00	24,265.0	3,670.7	1,720.9	2,120.80
19:00	23,588.6	3,549.7	1,720.9	2,835.90
20:00	23,533.7	3,461.0	1,720.9	849.90
21:00	25,954.5	2,280.0	1,720.9	37.10

Generation Bonus Performance Distribution by Fuel Type

Figure 90 depicts how the bonus performance megawatts from generation resources was distributed across the generation fleet using primary fuel type. Also provided in this figure is the installed capacity mix of the PJM generation fleet by primary fuel type to assist in understanding how proportionate the bonus performance by fuel type is to that fuel type's share of total generation capability. Consistent with their undersized portion of the shortfall megawatt pool, nuclear and wind resources in particular had outsized shares of the bonus performance pool given their strong performance during Winter Storm Elliott. Nuclear resources represented the largest share of bonus performance megawatts at 34.5%, or roughly double their share of the installed capacity mix. This stems from the high availability factor of both committed and uncommitted nuclear generation resources, the latter of which received bonus performance for all megawatts produced up to the level scheduled and dispatched by PJM.

It bears noting that these figures depict the bonus performance megawatts which received a share of bonus credits. As noted above in this section, resources that do not meet the energy offer requirements are not eligible to receive bonus performance credits and are excluded from the bonus performance megawatt values in this section.

Figure 90. Generation Bonus Performance Distribution by Fuel Type compared to Installed Capacity



Bonus Performance Rates and Credits

Total Non-Performance Charges are allocated, at the account level, as bonus performance credit to resources that have bonus megawatts based on their pro-rata share of total bonus performance megawatts. The average $/MW-interval rate across the performance assessment event for bonus megawatts was $188.85, or 75% of the non-performance penalty rate for the RTO. These rates are based on the total Non-Performance Charges assessed.

Table 23. Average Bonus Performance Rate (hourly average of five-minute interval values)

Hour Beginning (EPT)		Total Bonus MW	Total Non-Performance Charge	Bonus $/MW-Interval
Dec. 23, 2022	17:00	33,117.7	6,589,973.18	198.99
	18:00	33,930	6,505,727.97	191.74
	19:00	33,898.6	6,731,000.98	198.56
	20:00	34,137.8	6,827,351.73	199.99
	21:00	35,758.4	7,031,512.93	196.64
	22:00	33,776.9	6,532,125.94	193.39
Dec. 24, 2022	04:00	36,974.8	7,785,599.61	210.57
	05:00	36,834.1	7,799,035.09	211.73
	06:00	36,894.4	7,733,603.22	209.61
	07:00	35,959.9	7,768,289.54	216.03
	08:00	34,907.3	7,473,896.14	214.11
	09:00	35,080.8	7,034,963.27	200.54
	10:00	36,719.1	6,910,820.64	188.21
	11:00	37,178.9	6,858,699.63	184.48
	12:00	35,410.9	6,370,314.53	179.9
	13:00	33,338.6	5,704,554.02	171.11
	14:00	33,737.9	5,508,448.92	163.27
	15:00	34,685.8	5,831,635.11	168.13
	16:00	34,968.7	6,365,883.24	182.05
	17:00	33,292.8	6,103,588.46	183.33
	18:00	31,777.4	5,739,415.91	180.61
	19:00	31,695.2	5,314,600.31	167.68
	20:00	29,565.6	4,951,402.92	167.47
	21:00	29,992.6	5,033,588.91	167.83

Bonus credits paid to over-performing resources are based on Non-Performance Charges collected from under-performers. The bonus rates in the table above assume 100% collection of all Non-Performance Charges. To the extent that an account with under-performing resources is unable to pay their Non-Performance Charges, the total pool of bonus dollars to be paid out is reduced. This is achieved through the use of a bonus holdback.

Because both Non-Performance Charges and bonus credits for a given month are initially billed in the same billing statement, the amount of Non-Performance Charges that may be uncollected is unknown at the time the bill is issued. A bonus holdback is utilized to withhold an estimate of the potential uncollected Non-Performance Charges from the pool of bonus credits that are paid out in the initial bill. This hedges against the risk of paying out bonus credits that exceed the penalties that will actually be collected.

Once financial settlement occurs, PJM adjusts the bonus holdback to reflect observed nonpayment and issues adjustments to true-up the bonus credits paid with the total Non-Performance Charges collected. Ongoing reporting on the expected and actual bonus holdbacks for the billing of the Winter Storm Elliott performance assessment event is conducted at PJM Risk Management Committee meetings.[26] The Settlement Timelines and Results section of this report contains additional details on the total Non-Performance Charges to be billed each month, and therefore total potential bonus credits to be paid, as well as actual Non-Performance Charges collected as of the time this report was issued.

Resources that have been committed to an FRR plan and elected the physical non-performance assessment option had bonus megawatts calculated for the Winter Storm Elliott performance assessment events. These megawatts are not eligible to receive bonus credits. However, they are eligible to net against shortfall megawatts within the FRR entity's portfolio when calculating the amount of additional capacity the FRR entity will be required to carry in the following delivery year's FRR plan as a result of under-performance during the event. The details on the FRR physical bonus megawatts cannot be posted for data confidentiality reasons.[27]

Demand Response and Price Responsive Demand Performance

Detailed performance of DR for the Winter Storm Elliott Performance assessment event is reviewed in the Load Management Performance Report.[28] A summary of these details on performance, shortfall, bonus and penalties are detailed below. The full report can be referenced for more detailed analysis.

Table 24 summarizes Load Management (emergency and pre-emergency Demand Response) performance for the two days. For Dec. 23, all Load Management resources with 30-minute or 60-minute lead times were dispatched by PJM. For Dec. 24, all Load Management resources were dispatched by PJM (this includes all 30-minute, 60-minute or 120-minute lead times). Overall average event performance during the mandatory compliance period (06:00 through 21:00) was 126%. Capacity compliance is primarily measured based on the "firm service level" approach. This is where a resource is committed to maintain load at or below a defined level. The capacity reduction represents the megawatts reduced based on their load levels during the event, compared to their winter peak load. Capacity load reductions can be significantly different from real-time energy load reductions, since load may already be at the committed level before the resource is dispatched. This is the driver for the relatively strong Capacity Performance for this event, versus the relatively weak energy load reduction performance outlined in the Operating Day section of this report.

Table 24. Load Management Event Summary for Dec. 23 and Dec. 24

Date	Product	Average Capacity		
		Committed (MW)	Reduction (MW)	Performance
Dec. 23	Emergency Load Management	186	167	90%
	Pre-Emergency Load Management	4,042	4,907	121%
Dec. 24	Emergency Load Management	287	218	76%
	Pre-Emergency Load Management	6,888	9,035	131%

[26] Risk Management Committee web page at PJM.com
[27] PJM Manual 33, Section 6.1
[28] See Load Management Performance Report section of PJM DR web page.

Table 25 summarizes PRD performance. PRD is required to ensure load is below the committed level when there is a PAI and LMP greater than the strike price provided by the PRD provider. The capacity reduction represents the megawatts reduced based on their load levels during the event, compared to their peak load contribution.

Table 25. PRD Event Summary for Dec. 23 and Dec. 24

Date	Product	Average Capacity Committed (MW)	Average Capacity Reduction (MW)	Performance
Dec. 23	Price Responsive Demand	209	90	43%
Dec. 24	Price Responsive Demand	230	117	51%

The shortfalls from capacity commitments receive Non-Performance Charges, whereas the performance above the commitment level receives a bonus payment. Economic energy reductions and cleared ancillary services offers during the event intervals are eligible for bonus payments. The non-performance penalty and bonus breakdown for DR and PRD is detailed in Table 26. The Load Management and PRD performance values have been aggregated in the table below to adhere to posting rules around market-sensitive data given the small number of Market Participants with PRD resources. [29]

Table 26. DR and PRD Non-Performance Charges and Bonus Credits

Date	Load Management & PRD: Non-Performance Charge ($)	Load Management & PRD: Bonus Credit ($)	Economic Energy / Ancillary Services Bonus Credit ($)
Dec. 23	$2,421,812	$16,193,113.36	$2,546,949.14
Dec. 24	$1,610,469	$62,125,444.36	$5,782,104.47
Total	$4,032,281	$78,318,558	$8,329,054

Settlement Timelines and Results

Non-performance assessments are billed starting three calendar months after the calendar month that included the performance assessment event and are spread across the remaining months in the delivery year. For the Winter Storm Elliott event, this means charges are billed starting in March 2023 and spread in three equal installments through the May 2023 billing statement. However, given the magnitude of the penalties for this event, PJM filed Tariff revisions to provide participants with the option of spreading their Non-Performance Charges across a nine-month period, subject to interest for the additional six months included in this billing option.

Monthly charges are billed by dividing the total dollar amount due for each account by either three or nine months, depending on which billing option the participant selected. Participants electing the nine-month billing option were billed starting in the March 2023 billing statement and will continue to be billed through the November 2023 billing statement. Bonus credits will be paid over the same time frame, with the amount credited each month equal to the amount of Non-Performance Charges collected each month. Based on the aforementioned elections, $524 million, or 30% of the total

[29] PJM Manual 33, Section 6.1

$1.8 billion in Non-Performance Charges for this event, will be billed over a three-month period. The remaining $1,276 million, or 70%, will be billed over a nine-month period and will be assessed $15 million in interest charges. [30]

The following table displays the total charges to be assessed each month, the total Non-Performance Charges that were not collected, and the resulting bonus credits available to be paid to bonus recipients as of June 21, 2023. Ongoing updates will be provided through the PJM Risk Management Committee meetings.

Table 27. Non-Performance Charges and Bonus Credits Invoiced

Billing Month	Total Non-Performance Charges ($)	Total Interest Charges ($)	Total Nonpayment ($)	Total Bonus Credits Paid (including interest) ($)
March 2023	$316,419,632.80	$1,704,168.62	$8,422,793.53	$309,701,007.89
April 2023	$316,419,632.80	$1,704,168.62	$7,877,961.45	$310,245,839.97
May 2023	$316,419,632.80	$1,704,168.62	$7,875,909.02	$310,247,892.40
June 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
July 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
August 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
September 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
October 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
November 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
Total	$1,799,604,549.20	$15,337,517.54	$24,176,664.01 (as of 6/21/2023)	$930,194,740.26 (as of 6/21/2023)

Government, Member and Media Outreach

PJM's Corporate Communications, Federal, and State & Member Services teams are responsible for communicating situation updates to, and answering inquiries from, the general public, stakeholders, and state and federal contacts through direct channels, as well as PJM.com, social media and traditional media. Corporate Communications regularly participates in PJM's annual Operations Winter Emergency Procedures Drill and Summer Emergency Procedures Drill. These drills include a call with Transmission Owner communications departments, in which a PJM Operations supervisor and PJM external communications staff provide a situation update and information on how PJM contacts them if needed in an emergency, including through an emergency alert tool managed by PJM's Business Continuity Department. Corporate Communications conducts a roll call of communicators during these drills and uses the occasion to update its Transmission Owner communicator contact list.

PJM's State Government Policy (SGP) Department prepares for emergency procedure communications and coordination with state emergency contacts throughout the year. These state emergency contacts, categorized by email and phone number (all-call list), are informed by the state agencies within the PJM footprint and serve as the primary point of contact to receive standard PJM emergency procedure notifications, which are sent by the designated on-call SGP employee.

SGP tests its ability to successfully communicate with the state emergency email and all-call lists during PJM's summer and winter emergency drills, as well as other emergency drills, such as the November 2022 Grid Security Drill. These summer and winter drills allow for state emergency contacts to familiarize (or re-familiarize) themselves with PJM's

[30] The interest charges collected on a monthly basis will be allocated to bonus performance credit recipients based on their ratio share of total bonus performance credits (under the assumption of 100% collection of all Non-Performance Charges).

emergency notifications, help PJM test its emergency communication channels with the states, and provide biannual checkpoints for PJM to curate the state emergency contact lists. The state emergency contact lists are also updated on an ad-hoc basis.

PJM external-facing communicators also participate in biannual GridEx exercises and Grid Security Drills, coordinating with both member communicators and other ISOs/RTOs as part of the scenarios.

Beginning with the 2021/2022 winter season, SGP and Operations leadership began holding winter operations calls with the PJM states to discuss winter preparedness and operational developments throughout the winter. The calls continued for the 2022/2023 winter season, with one meeting held with the states on Dec. 15, 2022.

The activation of PJM's crisis communication plans and outreach to members, states and the general public through national/local/social media appeared to help reduce electricity use and ensure the reliability of the grid. Member communicators expressed appreciation for PJM's handling of the media and willingness to do local media interviews. In addition, PJM continues to seek additional feedback on opportunities for better coordination to refine and enhance its crisis communications and outreach procedures.

The outreach by Corporate Communications, State & Member Services, and other PJM employees, and coordinated response by both member companies and state partners was effective. The Call for Conservation, which depends on members to relay the message to their retail customers, and the impact of consumers' resulting efforts, appeared to have led to a reduction in demand. Though it is difficult to measure precisely, electricity demand leveled off over the course of Saturday, and peak demand Saturday evening came in less than what was forecast.

While the conservation effort appeared to be successful, PJM is exploring further opportunities to maximize the reach of such appeals with states and Transmission Owners.

Event Communications

Starting on Dec. 21 through Dec. 23, Corporate Communications published on its news site, Inside Lines, a series of articles noting the Cold Weather Advisory and subsequent Cold Weather Alert updates, and amplified them on social media. On Dec. 23, conditions deteriorated as more generators continued to go offline, resulting in a Call for Conservation.

A Call for Conservation, as outlined in Manual 13, "instructs affected Transmission Owners to request the public to conserve electricity because of developing power supply problems." Transmission Owners are the most logical point of contact for retail customers, with PJM also broadcasting the conservation appeal via news release, PJM.com, social media and traditional media.

The decision to issue a Call for Conservation was made at approximately 23:30 on Friday, Dec. 23, so that both Transmission Owners and PJM's press release would reach any outlets or audiences that could respond late Friday into early Saturday morning and have some impact on the morning peak. PJM Corporate Communications and State & Member Services teams relayed system conditions and the Call for Conservation to the communications staff of PJM Transmission Owners, as well as state regulators and elected officials, throughout Winter Storm Elliott from Dec. 23 to Dec. 25.

Corporate Communications posted a news release on PJM.com at 23:54 and sent the release via email to Transmission Owner communicators, members and media contacts, and posted to Twitter and LinkedIn. PJM reissued the news release to our extensive media and member communicators' contact lists at 05:40, Dec. 24, and retweeted the Call for Conservation news release.

Corporate Communications activated its crisis communications plan at 05:45, Dec. 24, to make sure sufficient resources were available to handle outreach and media response needs Saturday and Sunday.

PJM noted the end of the Call for Conservation on Sunday, Dec. 25, with direct email to members, social media posts and video on PJM.com.

Transmission Owner Communicators

At approximately 21:50, Friday, Dec. 23, before PJM had made the decision to issue a Call for Conservation, PJM Corporate Communications scheduled a meeting with Transmission Owner communicators for 08:30, Saturday, Dec. 24, to provide utility partners a situational update. PJM also directly emailed Transmission Owner communicators the news release shortly after 00:00 Saturday.

This 08:30 Saturday meeting became PJM's main venue to request these members' support in broadcasting the Call for Conservation appeal. More than 30 partners (including elected officials and regulators in addition to members) joined in the effort to amplify the Call for Conservation to their customers, gaining nearly 1 million impressions on Twitter alone. PJM believes that the actions of these members, combined with PJM media outreach, helped to broadcast the Call for Conservation and flatten the load beginning at 07:15 Saturday, when the New Jersey Board of Public Utilities issued the first tweet in response to PJM's call.

PJM held an event review with Transmission Owner communicators on Jan. 9. This discussion informed Corporate Communications' observations and lessons learned from the event. Transmission Owner communicators stated that PJM's willingness to do interviews with local media was helpful to them as they dealt with both distribution outages and the transmission challenges highlighted by the Call for Conservation.

Federal

During the winter storm, PJM's Federal Government Policy group kept in close contact with FERC and the Department of Energy (DOE), consistent with its regular practice when emergency procedures are invoked. Communications are directed to FERC commissioners and their advisors, as well as to staff, throughout the Commission and reports on the system conditions with updates after the morning and evening peaks. In addition, PJM utilizes FERC's emergency notification procedures for such notices. PJM's reporting requirements to FERC are identified in in PJM Manual 13 and NERC Standard EOP-4.

In addition, the Federal Government Policy group similarly reaches out to DOE officials in the office of Cybersecurity, Emergency Security and Emergency Response (CESER) with updates after the morning and evening peaks. These early communications represented an early reach-out prior to PJM seeking to invoke the Section 202(c) process to obtain an emergency order from the Secretary of Energy.

Public/Media

PJM posted three video updates from System Operations leadership at the top of PJM.com homepage. The video was retweeted and reposted by customer-facing members as well as elected officials and regulators, used by State & Member Services to inform key stakeholders, and quoted or captured directly by media for use in broadcasts.

PJM responded to approximately 50 media requests, including at least 20 interviews on Dec. 24 and Dec. 25. PJM worked with customer-facing members' communications departments, who referred inquiries to PJM. In follow-up discussions, these members indicated that PJM's willingness to handle local media requests freed them to handle other pressing issues at the distribution level.

PJM deployed Twitter, LinkedIn and Facebook to draw attention to the video updates provided on PJM.com. Posts promoting the video received more than 300,000 impressions. Total impressions from PJM posts during Winter Storm Elliott were:

Twitter – 519,298	Facebook – 27,368	LinkedIn – 27,182

The PJM Now app is a popular source for system alerts (including emergency procedures) and allows users to track energy use, fuel mix and emissions data. More than 1,800 unique users accessed the app during Winter Storm Elliott, and the app was opened 6,600 times on Dec. 25 – compared with an average daily use of 750 app opens. The PJM Now app experienced unprecedented usage that slowed service during the storm, and PJM's Inside Lines news site went down Saturday because of unprecedented usage. Corporate Communications has taken steps to enhance these platforms so that similar usage levels will not result in the same performance issues as experienced during Winter Storm Elliott.

Between Dec. 23 and Dec. 25, Corporate Communications tracked more than 70 news stories noting PJM's Call for Conservation. This included national and newswire coverage from CNN, the Associated Press and Bloomberg, as well as regional coverage from television, radio and print media throughout the region PJM serves.

States

Heading into Winter Storm Elliott, SGP began its emergency procedure communications with the states on Dec. 21, relaying the issuance of a Cold Weather Alert for the Western Region of PJM on Dec. 23. SGP then communicated the issuance of a second Cold Weather Alert on Dec. 23 for the entire PJM region that began on Dec. 24.

As the storm progressed on Dec. 23 and emergency conditions arose, SGP relayed PJM's emergency procedure positioning to the state emergency email contacts as this information was provided to SGP by PJM's Operations Team. This included the escalation and de-escalation of emergency conditions heading into Dec. 24. SGP also communicated PJM's Dec. 24 Call for Conservation to the states, but instead of sending the conservation message to just the standard state emergency contacts, SGP utilized a broader list of state contacts that also included the emergency contacts.

In addition to member utilities, social media reach was greatly extended by participation of elected officials. Two governors tweeted the Call for Conservation and attracted two of the top three Twitter impression totals. Corporate Communications and SGP are working together to maximize impact from state partners when issuing a conservation appeal.

As SGP continued to provide system condition updates to its state emergency contacts the morning of Dec. 24, these communications progressed to individualized updates to the states via the SGP regulatory managers. Periodic system condition updates continued to be provided to the standard state emergency contacts through Dec. 25, although no new emergency procedures were issued by PJM.

Stakeholders

Figure 91 presents the stakeholder messages made between Dec. 23 and Dec. 25, color-coded by audience. These communications are in addition to direct communications made to generators, Load Serving Entities, Market Participants and others in emergency conditions as well as normal operating situations. General email notifications about the start and end of Performance Assessment Intervals are made for general awareness of all members. Members directly impacted by Performance Assessment Intervals receive separate, direct notifications in real time.

Figure 91. Stakeholder Messages

Type	Audience	Message	Time Sent Dec. 23	Time Sent Dec. 24	Time Sent Dec. 25
	Stakeholders	Notifying the beginning of a Performance Assessment Interval	19:01		
	Transmission Owner communications departments	A winter operation update conference call to be held with PJM Corporate Communications at 08:30, Dec. 24.	21:54		
	Stakeholders	The Maximum Emergency Generation Action has ended at 23:00, Dec. 23, along with the corresponding Performance Assessment Interval.	23:32		
	Stakeholders	The issuance of a public call for electricity conservation shortly before midnight		00:31	
	Stakeholders	General email notification to stakeholders, notifying the beginning of a Performance Assessment Interval		05:19	
	PJM news release distribution list	On public Call for Conservation sent to PJM news release distribution lists		05:40	
	Generation Owners with actual/potential emission restrictions	Update and maintain this information in Markets Gateway for PJM to prepare a 202(c) filing with the Department of Energy.		10:31	
	Stakeholders	PJM's 202(c) filing with the Department of Energy requesting for a finding that an electricity reliability emergency exists within the PJM region		17:38	
	Stakeholders	On the Department of Energy's issuance of the requested emergency order and providing the names, municipalities and zip codes of the generation resources subject to the order		19:27	
	Stakeholders	The Maximum Emergency Generation Action has ended at 20:00, Dec. 24, along with the corresponding Performance Assessment Interval.		22:14	
	Stakeholders	Announcing the end of the public call for electricity conservation			11:54
	Market Participants	Announcing that Dec. 26 Day-Ahead Market results are posted and that the rebid period was extended to 14:45			14:31

Maximum Generation Emergency Action Email
Email Notification
PJM New Release Distribution List
Generation Owner Request
Technical Communication

Conclusion

The observations and recommendations in this report were developed through intensive data gathering, analysis and feedback from various groups regarding areas of study. Learning Teams were convened for operations and markets that included subject matter experts not directly involved in this report, adding their independent evaluation of the research presented.

Extreme events like Winter Storm Elliott offer opportunities to improve our rules, practices, preparations and processes. Following the 2014 Polar Vortex, PJM took important steps to improve reliability by implementing Capacity Performance incentives for generation to perform during emergencies, strengthening winterization rules and refining operating procedures.

In 2021 following the lessons of Winter Storm Uri that impacted Texas and surrounding regions, PJM introduced rules to help Transmission Owners ensure service to critical facilities in emergencies, improve information sharing with the natural gas industry, and strengthen load-shedding preparation and practices. PJM also enhanced data gathering from generating resources, including more frequent fuel and equipment inventory reporting in the face of global supply chain issues. In advance of the 2022/2023 winter, PJM updated its winter preparation generator checklist to include cold weather operating limits.

The 30 recommendations listed at the outset of this report will be acted on through multiple stakeholder forums, including the ongoing Critical Issue Fast Path – Resource Adequacy process that was initiated to produce a set of improvements to PJM capacity market rules by October. Other recommendations will be pursued in various PJM forums to include the Electric Gas Coordination Senior Task Force, Operating Committee and the Market Implementation Committee.

While PJM and its members were able to maintain reliability during Winter Storm Elliott, the increasing volatility of weather patterns and reliance on gas generation underscore the need to advance the performance of operations, planning and markets for the increasing risk presented by the winter season.

Appendix A

Two-Settlement Market Mechanics

As described in the Operating Day section of this report, the PJM Energy Market consists of two markets: a Day-Ahead Market and a Real-Time Market. The Day-Ahead Energy Market offers an opportunity for Market Participants to lock in their positions in advance of an operating day in a financially firm way to reduce their risk of exposure to real-time prices.

Market Participants have until 11:00 the day prior to the operating day to submit their bids and offers for the Day-Ahead Market. Generation resources, regardless of fuel type, fall into one of two categories, Capacity Resources or Energy Resources. If available, all Generation Capacity Resources that have a Reliability Pricing Model (RPM) or Fixed Resource Requirement (FRR) Commitment must submit offer data into the Day-Ahead Market and may elect either to Self-Schedule or offer the resource to PJM for scheduling as a PJM RTO-Scheduled Resource. Several types of entities participate in the Day-Ahead Energy Market.

- Generation Owners submit their offers to supply power and will adjust offers for factors, such as cost of fuel.
- Load Serving Entities will submit bids for their expected need for electricity for the operating day. For a typical operating day, PJM observes approximately 90–95% of real-time load cleared in the Day-Ahead Market with the remainder clearing and settling in the Real-Time Market.
- Market Participants also may submit various “virtual transactions,” which are offers to buy or sell at particular locations that are generally not associated with physical generation or load. Market Participants may use virtual transactions for various reasons including hedging risk on physical positions and arbitraging price differences between the Day-Ahead and Real-Time Markets.

When the Day-Ahead Market closes at 11:00 on the day prior to an operating day, PJM begins the process of clearing the Day-Ahead Market, and the results are made available to Market Participants by 13:30 the day prior to the operating day. The Day-Ahead Market is cleared so that the cost to serve physical and virtual demand is minimized, while still respecting the physical operating limits of the transmission system. Commitments in the Day-Ahead Market are financially binding on participants. Any differences between those commitments and what occurs in the operating day is settled in the Real-Time Energy Market.

Generation and Demand Resources may alter their offers for use in the Real-Time Energy Market during the following periods:

- The Generation Rebidding Period, which is defined from the time the office of interconnection posts the results of the Day-Ahead Energy Market until 14:15
- Starting at 18:30 (typically after the Reliability Assessment and Commitment Run is completed) and up to 65 minutes prior to the start of the operating hour

There are often cases where the load levels cleared in the Day-Ahead Market do not meet the level of forecasted load for the operating day. To address this, PJM has a process called the Reliability Assessment Commitment (RAC) that begins after 16:15, which commits additional supply to meet the forecasted load plus reserves, while minimizing start-up and no-load cost of those commitments. The focus of this commitment is reliability and the objective is to minimize start-up and no-load costs for any additional resources that are committed. Using the most up-to-date weather forecast, load forecast, transmission facility and generator availability, and other information, PJM commits additional supply, if necessary, to satisfy both expected loads and the needed reserves for the operating day.

Leading up to and throughout the operating day, PJM examines updated information and system conditions and acts to continually balance generation with the need for electricity and maintaining adequate reserves to prepare for unexpected issues. PJM manages changes from day-ahead commitments and schedules in the Real-Time Energy Market using the offers from generation resources and Demand Resources to jointly minimize the cost of energy and reserves while maintaining energy balance and respecting the limits of the transmission system. Any differences in supply and demand from the Day-Ahead Energy Market commitments are settled at price levels determined by the Real-Time Energy Market.

Energy and Reserve Market Pricing

Locational Marginal Price (LMP) is defined as the marginal price for energy at the location where the energy is delivered or received and is based on forecasted system conditions and the latest approved Real-Time Security Constrained Economic Dispatch program solution. LMP is expressed in dollars per megawatt-hour ($/MWh). LMPs are determined as an output of the co-optimization of energy and reserves and is the cost to provide the next increment of energy while respecting reserve requirements, transmission constraints and losses.

PJM's real-time dispatch and LMP calculation systems include Operating Reserve Demand Curves (ORDCs) for 30-minute Operating Reserves, Primary Reserves and Synchronized Reserves. During times where an area of PJM is experiencing a reserve shortage, those ORDCs are used to set reserve prices and may have a direct impact on LMPs. Specifically, when the marginal energy megawatts are provided by converting a megawatt of reserves into a megawatt of energy, the resulting LMP takes into account the opportunity cost of that exchange. This direct impact of the ORDCs on LMPs during a reserve shortage is referred to as shortage or scarcity pricing. More information on this is contained in PJM Manual 11.

In performing this LMP calculation, the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer is calculated as the sum of the following three components of LMP:

- System Energy Price – This is the system-wide, unconstrained price. The System Energy Price may include a portion of the defined Reserve Penalty Factors should a reserve shortage exist.
- Congestion Price – This is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings.
- Loss Price – This is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission losses.

LMPs are calculated in both the Day-Ahead Energy Market and the Real-Time Energy Market. The Day-Ahead LMP is calculated based on the Security Constrained Economic Dispatch for the Day-Ahead Market. The Real-Time LMP is calculated based on the approved Security Constrained Economic Dispatch solution for the target dispatch interval.

PJM procures resources to meet the required Reserve Services in the Day-Ahead Reserve Markets:

- Synchronized Reserve Service – Reserve capability that can be converted fully into energy or load that can be removed from the system within 10 minutes of the request from the PJM system operator and must be provided by equipment electrically synchronized to the system. Synchronous Reserves can only be satisfied by online resources that are able to respond in 10 minutes or less.

- Contingency (Primary) Reserve Service – Reserve capability satisfied by online or offline resources that are able to respond in 10 minutes or less. Contingency (Primary) Reserve is reserve capability that can be converted fully into energy or load that can be removed from the system within 10 minutes of the request from the PJM system operator.
- 30-Minute Reserve Service – Reserve capability satisfied by online or offline resources that are able to respond in 30 minutes or less.

Figure 92 presents the relationship among the three reserve services described above.

Figure 92. Reserve Services



Regulation Market

The PJM Regulation Market provides PJM participants with a market-based system for the purchase and sale of the Regulation ancillary service. Resource owners submit specific offers for Regulation Capability and Regulation Performance, and PJM utilizes these offers together with energy offers and resource schedules from the Markets Gateway System as input data to the Ancillary Service Optimizer (ASO), which is an hour-ahead Market Clearing Engine. ASO optimizes the RTO dispatch profile and forecasts LMPs to determine hourly commitments of Regulation to meet the requirement. The Real-Time Security Constrained Economic Dispatch (RT SCED) program jointly optimizes Energy and Reserves subject to transmission constraints, Reserve Requirements and prior committed Regulation.

The five-minute Regulation Market Clearing Price (RMCP) and Regulation Market Performance Clearing Price (RMPCP), are calculated by the Locational Price Calculator and are used to derive the five-minute Regulation Market Capability Clearing Price (RMCCP). These clearing prices are then used in market settlements to determine the credits awarded to providers and charges allocated to purchasers of the Regulation service.

PJM uses resource schedules, Regulation offers, and energy offers from the Markets Gateway System as input data to the ASO to provide the lowest cost alternative for the procurement of Regulation for each hour of the operating day. The lowest cost alternative for this service is achieved through a co-optimization with Synchronized Reserves, Primary Reserves, 30-Minute Reserves and energy. Within the co-optimization, an RTO dispatch profile is forecasted along with LMPs for the market hour. Using the dispatch profile and forecasted LMPs, an opportunity cost, adjusted by the applicable Performance Score and Benefits Factor, is estimated for each resource that is eligible to provide Regulation. The estimated opportunity cost for Demand Resources is zero. The adjusted lost opportunity cost is added to the adjusted regulation capability cost and the adjusted regulation performance cost to make the adjusted total regulation offer cost. The adjusted total regulation offer cost is then used to create the merit order price.

All available regulating resources are then ranked in ascending order of their merit order prices, and the lowest cost set of resources necessary to simultaneously meet the PJM Regulation Requirement, PJM Synchronized Reserve Requirement, PJM Primary Reserve Requirement, and PJM 30-minute Reserve Requirement and provide Energy in that hour is determined. If there is an excess of self-scheduled and zero-cost offers over and beyond the Regulation Requirement, PJM uses resource-specific historic performance scores, selecting those resources with the highest performance scores, as a tie-breaker to determine which set of resources to commit to meet the Regulation Requirement. The least cost set of Regulation resources identified through this process are then committed.

Prices for Regulation are calculated simultaneously with Energy and Reserves every five minutes by the Locational Pricing Calculator (LPC) in the pricing run. The highest merit order price associated with this lowest cost set of resources awarded Regulation becomes the RMCP. The RMPCP is calculated as the highest adjusted performance offer from the set of cleared resources. The RMCCP is the difference between RMCP and RMPCP.

Financial Transmission Rights

Financial Transmission Rights (FTRs) are financial instruments awarded to bidders in the FTR Auction and entitle the holder to receive a stream of revenues (or charges) based on hourly Day-Ahead Congestion Price differences across a path. They provide hedging and protections against future locational energy price differences.

A Market Participant can obtain FTRs in the Annual Auction, Long-Term Auctions, Monthly Auction and secondary market.

PJM awards FTRs based on the capability of the transmission system. There must be adequate revenue from congestion to fund the FTRs that are awarded. Revenue adequacy issues occur when PJM under-collects congestion revenue to fund FTRs.

The hourly economic value of an FTR Obligation is based on the Financial Transmission Right MW reservation and the difference between the Day-Ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right. The hourly economic value of a Financial Transmission Right Obligation is positive (a benefit to the FTR holder) when the Day-Ahead Congestion Price at the point of delivery is higher than the Day-Ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Obligation is negative (a liability to the FTR holder) when the Day-Ahead Congestion Price at the point of receipt is higher than the Day-Ahead Congestion Price at the point of delivery.

The hourly economic value of a Financial Transmission Right Option is based on the Financial Transmission Right MW reservation and the difference between the Day-Ahead Congestion Price at the point of delivery and the point of receipt of the Financial Transmission Right when that difference is positive. The hourly economic value of a Financial Transmission Right Option is positive (a benefit to the FTR holder) when the Day-Ahead Congestion Price at the point of delivery is higher than the Day-Ahead Congestion Price at the point of receipt. The hourly economic value of a Financial Transmission Right Option is zero (neither a benefit nor a liability to the FTR holder) when the Day-Ahead Congestion Price at the point of receipt is higher than the Day-Ahead Congestion Price at the point of delivery.

The total target allocation for a Market Participant for each hour is then the sum of the target allocations for all of the Market Participant's FTRs. Note, if the DA LMPDelivery or the DA LMPReceipt is an aggregate zone, the following formula is used:

$$Target = FTR * \Sigma Load\ Percentage * (DALMPDelivery - i - DALMPReceipt)$$

Where:

- FTR Financial Transmission Rights between the designated Load Aggregation Zone and the designated bus, in megawatts
- Load Percentage – the percentage of the load at time of annual peak associated with each individual load bus in the Load Aggregation Zone designated in the FTR

PJM compares the total of all Transmission Congestion Credit target allocations to the total Transmission Congestion Charges for the PJM Control Area in each hour resulting from the Day-Ahead Market.

- If the total of the target allocations is less than the total Day-Ahead Transmission Congestion Charges, the Day-Ahead Transmission Congestion Credit for each FTR is equal to its target allocation. All excess Day-Ahead Transmission Congestion Charges are distributed at the end of the month.
- If the total of the target allocations is equal to the total Day-Ahead Transmission Congestion Charges, the Day-Ahead Transmission Congestion Credit for each FTR is equal to its target allocation.
- If the total of the target allocations is greater than the total Day-Ahead Transmission Congestion Charges, the Day-Ahead Transmission Congestion Credit for each FTR is equal to its target allocation only for those customer accounts whose total target allocation position for their FTR portfolio is net negative for the hour. Customer accounts whose total target allocation position for their FTR portfolio is net positive for the hour receives a share of the total Day-Ahead Transmission Congestion Charges (including revenues resulting from the collection of the net negative target allocation positions) in proportion to its target allocation. The shortfalls in hourly Day-Ahead Transmission Congestion Credits compared to target allocations may be offset by excess charges from other hours in the end of the month accounting.
- If the total Day-Ahead Transmission Congestion Charges is negative, the Day-Ahead Transmission Congestion Credit for each FTR is equal to its target allocation only for those customer accounts whose total target allocation position for their FTR portfolio is net negative for the hour. If the revenues resulting from the collection of the net negative target allocation positions is more than enough to cover the negative Day-Ahead Transmission Congestion Charge, then any remaining revenues are distributed as Day-Ahead Transmission Congestion Credits to customer accounts whose total target allocation position for their FTR portfolio is net positive for the hour, in proportion to their target allocations. If the revenues resulting from the collection of the net negative target allocation positions is not enough to cover the negative Day-Ahead Transmission Congestion Charge, then no Day-Ahead Transmission Congestion Credits are awarded to customer accounts whose total target allocation position for their FTR portfolio is net positive, and the remaining Day-Ahead Transmission Congestion Charge liability will be subtracted from the total monthly excess prior to the month-end distribution described in the next section. The shortfalls in hourly Day-Ahead Transmission Congestion Credits compared to target allocations may be offset by excess charges from other hours in the end of the month accounting.

Errata

1 | Pages 53 and 54, Figures 35 and 36: Legend colors swapped:

- Orange: No Day-Ahead Commitment
- Blue: Day-Ahead Commitment

2 | Page 73, Figure 60: Y Axis changed to show the increment thousands

Exhibit 27

State	Facility Name	Facility ID	Unit ID	Associated Stacks	Date	Hour	Operating Time	Gross Load (MW)	Steam Load (1000 lb/hr)	SO2 Mass (lbs)	SO2 Mass Measure Indicator	SO2 Rate (lbs/mmBtu)	SO2 Rate Measure Indicator	CO2 Mass (short tons)	CO2 Mass Measure Indicator	CO2 Rate (short tons/mmBtu)	CO2 Rate Measure Indicator	NOx Mass (lbs)	NOx Mass Measure Indicator	NOx Rate (lbs/mmBtu)	NOx Rate Measure Indicator	Heat Input (mmBtu)	Heat Input Measure Indicator	Primary Fuel Type	Secondary Fuel Type	Unit Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Program Code
PA	Eddystone Generating Station	3161	3	CS034	12/24/2022	8	0.28	0		0	Measured	0	Calculated	0.644	Measured	0.08	Calculated	0	Calculated	0	Calculated	8.092	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/24/2022	9	1	0		0.1	Measured	0.002	Calculated	5.3	Measured	0.081	Calculated	0.23	Calculated	0.004	Calculated	65.2	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/24/2022	10	1	0		0.084	Measured	0.002	Calculated	4.4	Measured	0.08	Calculated	0.12	Calculated	0.002	Calculated	54.9	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/24/2022	11	1	0		0.086	Measured	0.001	Calculated	5.1	Measured	0.072	Calculated	0.66	Calculated	0.009	Calculated	70.9	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/24/2022	12	1	0		0.189	Measured	0.001	Calculated	15.6	Measured	0.063	Calculated	5.2	Calculated	0.021	Calculated	248.8	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/24/2022	13	1	0		0.305	Measured	0.001	Calculated	27.1	Measured	0.061	Calculated	17.7	Calculated	0.04	Calculated	442.3	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/24/2022	14	1	0		0.521	Measured	0.001	Calculated	32.7	Measured	0.077	Calculated	19.1	Calculated	0.045	Calculated	423.9	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/24/2022	15	1	0		0.681	Measured	0.001	Calculated	40.6	Measured	0.081	Calculated	29.5	Calculated	0.059	Calculated	501	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/24/2022	16	1	0		0.7	Measured	0.001	Calculated	39.5	Measured	0.081	Calculated	28.3	Calculated	0.058	Calculated	487	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/24/2022	17	1	0		0.7	Measured	0.001	Calculated	39.5	Measured	0.081	Calculated	29.2	Calculated	0.06	Calculated	487.1	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/24/2022	18	1	0		0.7	Measured	0.001	Calculated	39.9	Measured	0.081	Calculated	26.6	Calculated	0.054	Calculated	491.8	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/24/2022	19	1	26		0.9	Measured	0.001	Calculated	56.4	Measured	0.081	Calculated	50.1	Calculated	0.072	Calculated	695.9	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI

State	Facility Name	Facility ID	Unit ID	Associated Stacks	Date	Hour	Operating Time	Gross Load (MW)	Steam Load (1000 lb/hr)	SO2 Mass (lbs)	SO2 Mass Measure Indicator	SO2 Rate (lbs/mmBtu)	SO2 Rate Measure Indicator	CO2 Mass (short tons)	CO2 Mass Measure Indicator	CO2 Rate (short tons/mmBtu)	CO2 Rate Measure Indicator	NOx Mass (lbs)	NOx Mass Measure Indicator	NOx Rate (lbs/mmBtu)	NOx Rate Measure Indicator	Heat Input (mmBtu)	Heat Input Measure Indicator	Primary Fuel Type	Secondary Fuel Type	Unit Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Program Code
PA	Eddystone Generating Station	3161	3	CS034	12/24/2022	20	1	38		1.1	Measured	0.001	Calculated	66.1	Measured	0.081	Calculated	84.7	Calculated	0.104	Calculated	814	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/24/2022	21	1	46		1.2	Measured	0.001	Calculated	71.4	Measured	0.081	Calculated	96.8	Calculated	0.11	Calculated	879.6	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/24/2022	22	1	55		1.2	Measured	0.001	Calculated	69.7	Measured	0.081	Calculated	97	Calculated	0.113	Calculated	859	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/24/2022	23	1	59		1.1	Measured	0.001	Calculated	67.8	Measured	0.081	Calculated	110	Calculated	0.132	Calculated	836.2	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	0	1	60		1.1	Measured	0.001	Calculated	67.5	Measured	0.081	Calculated	107	Calculated	0.129	Calculated	830.9	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	1	1	71		1.2	Measured	0.001	Calculated	74.6	Measured	0.081	Calculated	107	Calculated	0.116	Calculated	919.1	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	2	1	83		1.4	Measured	0.001	Calculated	84.5	Measured	0.081	Calculated	104	Calculated	0.1	Calculated	1040.9	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	3	1	51		1	Measured	0.001	Calculated	62	Measured	0.081	Calculated	87.9	Calculated	0.115	Calculated	764.6	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	4	1	53		1.1	Measured	0.001	Calculated	63.8	Measured	0.081	Calculated	92.8	Calculated	0.118	Calculated	786.1	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	5	1	57		1.1	Measured	0.001	Calculated	66.2	Measured	0.081	Calculated	110	Calculated	0.135	Calculated	816.8	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	6	1	57		1.1	Measured	0.001	Calculated	65.7	Measured	0.081	Calculated	110	Calculated	0.136	Calculated	809.8	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	7	1	69		1.2	Measured	0.001	Calculated	73.5	Measured	0.081	Calculated	109	Calculated	0.12	Calculated	904.8	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI

State	Facility Name	Facility ID	Unit ID	Associated Stacks	Date	Hour	Operating Time	Gross Load (MW)	Steam Load (1000 lb/hr)	SO2 Mass (lbs)	SO2 Mass Measure Indicator	SO2 Rate (lbs/mmBtu)	SO2 Rate Measure Indicator	CO2 Mass (short tons)	CO2 Mass Measure Indicator	CO2 Rate (short tons/mmBtu)	CO2 Rate Measure Indicator	NOx Mass (lbs)	NOx Mass Measure Indicator	NOx Rate (lbs/mmBtu)	NOx Rate Measure Indicator	Heat Input (mmBtu)	Heat Input Measure Indicator	Primary Fuel Type	Secondary Fuel Type	Unit Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Program Code
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	8	1	61		1.2	Measured	0.001	Calculated	69.7	Measured	0.081	Calculated	93.7	Calculated	0.109	Calculated	859.9	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	9	1	55		1.1	Measured	0.001	Calculated	65.5	Measured	0.081	Calculated	87.2	Calculated	0.108	Calculated	807.2	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	10	1	56		1.1	Measured	0.001	Calculated	65.1	Measured	0.081	Calculated	86.6	Calculated	0.108	Calculated	801.9	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	11	1	55		1.1	Measured	0.001	Calculated	65	Measured	0.081	Calculated	86.5	Calculated	0.108	Calculated	800.9	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	12	1	55		1.1	Measured	0.001	Calculated	65	Measured	0.081	Calculated	87.4	Calculated	0.109	Calculated	801.4	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	13	1	55		1.1	Measured	0.001	Calculated	64.6	Measured	0.081	Calculated	90.7	Calculated	0.114	Calculated	795.9	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	14	1	56		1.1	Measured	0.001	Calculated	64.7	Measured	0.081	Calculated	90.9	Calculated	0.114	Calculated	796.8	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	15	1	55		1.1	Measured	0.001	Calculated	64.6	Measured	0.081	Calculated	90.8	Calculated	0.114	Calculated	796.5	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	16	1	56		1.1	Measured	0.001	Calculated	65.2	Measured	0.081	Calculated	90	Calculated	0.112	Calculated	803.8	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	17	1	59		1.126	Measured	0.001	Calculated	67.5	Measured	0.081	Calculated	101	Calculated	0.121	Calculated	832.5	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	18	1	56		1.1	Measured	0.001	Calculated	65	Measured	0.081	Calculated	90.6	Calculated	0.113	Calculated	801.3	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	19	1	56		1.1	Measured	0.001	Calculated	65.1	Measured	0.081	Calculated	90.7	Calculated	0.113	Calculated	802.6	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI

State	Facility Name	Facility ID	Unit ID	Associated Stacks	Date	Hour	Operating Time	Gross Load (MW)	Steam Load (1000 lb/hr)	SO2 Mass (lbs)	SO2 Mass Measure Indicator	SO2 Rate (lbs/mmBtu)	SO2 Rate Measure Indicator	CO2 Mass (short tons)	CO2 Mass Measure Indicator	CO2 Rate (short tons/mmBtu)	CO2 Rate Measure Indicator	NOx Mass (lbs)	NOx Mass Measure Indicator	NOx Rate (lbs/mmBtu)	NOx Rate Measure Indicator	Heat Input (mmBtu)	Heat Input Measure Indicator	Primary Fuel Type	Secondary Fuel Type	Unit Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Program Code
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	20	1	56		1.1	Measured	0.001	Calculated	65.3	Measured	0.081	Calculated	91.8	Calculated	0.114	Calculated	805.2	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	21	1	63		1.2	Measured	0.001	Calculated	70.1	Measured	0.081	Calculated	106	Calculated	0.123	Calculated	864	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	22	1	55		1.1	Measured	0.001	Calculated	64.5	Measured	0.081	Calculated	92.2	Calculated	0.116	Calculated	795.2	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/25/2022	23	1	54		1.1	Measured	0.001	Calculated	64	Measured	0.081	Calculated	90.7	Calculated	0.115	Calculated	788.9	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	3	CS034	12/26/2022	0	0.23	10		0.138	Measured	0.001	Calculated	8.073	Measured	0.081	Calculated	8.16	Calculated	0.082	Calculated	99.521	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	3	0.58	0		0.015	Measured	0.001	Calculated	1.044	Measured	0.07	Calculated	0.46	Calculated	0.031	Calculated	14.848	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	4	1	0		0.033	Measured	0.001	Calculated	2.3	Measured	0.067	Calculated	0	Calculated	0	Calculated	34.3	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	5	1	0		0.025	Measured	0.001	Calculated	1.4	Measured	0.067	Calculated	0	Calculated	0	Calculated	21	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	6	1	0		0	Measured	0	Calculated	1.5	Measured	0.082	Calculated	0	Calculated	0	Calculated	18.2	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	7	1	0		0	Measured	0	Calculated	1.7	Measured	0.082	Calculated	0	Calculated	0	Calculated	20.8	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	8	1	0		0	Measured	0	Calculated	1.7	Measured	0.083	Calculated	0	Calculated	0	Calculated	20.4	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	9	1	0		0	Measured	0	Calculated	1.7	Measured	0.083	Calculated	0.07	Calculated	0.003	Calculated	20.4	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI

State	Facility Name	Facility ID	Unit ID	Associated Stacks	Date	Hour	Operating Time	Gross Load (MW)	Steam Load (1000 lb/hr)	SO2 Mass (lbs)	SO2 Mass Measure Indicator	SO2 Rate (lbs/mmBtu)	SO2 Rate Measure Indicator	CO2 Mass (short tons)	CO2 Mass Measure Indicator	CO2 Rate (short tons/mmBtu)	CO2 Rate Measure Indicator	NOx Mass (lbs)	NOx Mass Measure Indicator	NOx Rate (lbs/mmBtu)	NOx Rate Measure Indicator	Heat Input (mmBtu)	Heat Input Measure Indicator	Primary Fuel Type	Secondary Fuel Type	Unit Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Program Code
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	10	1	0		0.046	Measured	0.001	Calculated	2.7	Measured	0.07	Calculated	0.08	Calculated	0.002	Calculated	38.6	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	11	1	0		0.097	Measured	0.001	Calculated	7.9	Measured	0.064	Calculated	1.15	Calculated	0.009	Calculated	123.8	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	12	1	0		0.101	Measured	0.001	Calculated	8.2	Measured	0.063	Calculated	2.7	Calculated	0.021	Calculated	129.2	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	13	1	0		0.188	Measured	0.001	Calculated	16.4	Measured	0.063	Calculated	10.5	Calculated	0.04	Calculated	261.9	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	14	1	0		0.256	Measured	0.001	Calculated	22.1	Measured	0.063	Calculated	15.8	Calculated	0.045	Calculated	352.6	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	15	1	0		0.515	Measured	0.001	Calculated	31.3	Measured	0.08	Calculated	23.1	Calculated	0.059	Calculated	391.3	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	16	1	0		0.571	Measured	0.001	Calculated	34.5	Measured	0.08	Calculated	24.9	Calculated	0.058	Calculated	430	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	17	1	0		0.584	Measured	0.001	Calculated	35.1	Measured	0.08	Calculated	26.4	Calculated	0.06	Calculated	438.9	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	18	1	0		0.547	Measured	0.001	Calculated	32.8	Measured	0.08	Calculated	22.1	Calculated	0.054	Calculated	410.2	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	19	1	0		0.652	Measured	0.001	Calculated	39.2	Measured	0.08	Calculated	35.2	Calculated	0.072	Calculated	489.1	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	20	1	27		0.935	Measured	0.001	Calculated	56.4	Measured	0.08	Calculated	72.9	Calculated	0.104	Calculated	701	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	21	1	53		1.268	Measured	0.001	Calculated	76.4	Measured	0.081	Calculated	104	Calculated	0.11	Calculated	948.4	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI

State	Facility Name	Facility ID	Unit ID	Associated Stacks	Date	Hour	Operating Time	Gross Load (MW)	Steam Load (1000 lb/hr)	SO2 Mass (lbs)	SO2 Mass Measure Indicator	SO2 Rate (lbs/mmBtu)	SO2 Rate Measure Indicator	CO2 Mass (short tons)	CO2 Mass Measure Indicator	CO2 Rate (short tons/mmBtu)	CO2 Rate Measure Indicator	NOx Mass (lbs)	NOx Mass Measure Indicator	NOx Rate (lbs/mmBtu)	NOx Rate Measure Indicator	Heat Input (mmBtu)	Heat Input Measure Indicator	Primary Fuel Type	Secondary Fuel Type	Unit Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Program Code
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	22	1	54		1.098	Measured	0.001	Calculated	66.1	Measured	0.08	Calculated	92.9	Calculated	0.113	Calculated	821.9	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/24/2022	23	1	58		1.107	Measured	0.001	Calculated	66.8	Measured	0.081	Calculated	109	Calculated	0.132	Calculated	828.9	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	0	1	55		1.063	Measured	0.001	Calculated	64.1	Measured	0.081	Calculated	103	Calculated	0.129	Calculated	796.1	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	1	1	58		1.094	Measured	0.001	Calculated	66	Measured	0.081	Calculated	95.1	Calculated	0.116	Calculated	819.3	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	2	1	79		1.338	Measured	0.001	Calculated	80.6	Measured	0.081	Calculated	100	Calculated	0.1	Calculated	1000.7	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	3	1	52		1.017	Measured	0.001	Calculated	61.2	Measured	0.08	Calculated	87.6	Calculated	0.115	Calculated	761.3	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	4	1	53		1.039	Measured	0.001	Calculated	62.5	Measured	0.08	Calculated	91.6	Calculated	0.118	Calculated	776.6	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	5	1	52		1.05	Measured	0.001	Calculated	63.2	Measured	0.08	Calculated	106	Calculated	0.135	Calculated	785.4	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	6	1	53		1.038	Measured	0.001	Calculated	62.5	Measured	0.081	Calculated	106	Calculated	0.136	Calculated	776.3	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	7	1	84		1.389	Measured	0.001	Calculated	83.8	Measured	0.081	Calculated	125	Calculated	0.12	Calculated	1038	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	8	1	63		1.137	Measured	0.001	Calculated	68.6	Measured	0.08	Calculated	92.9	Calculated	0.109	Calculated	852.3	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	9	1	52		0.999	Measured	0.001	Calculated	60.4	Measured	0.08	Calculated	81	Calculated	0.108	Calculated	750.6	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI

State	Facility Name	Facility ID	Unit ID	Associated Stacks	Date	Hour	Operating Time	Gross Load (MW)	Steam Load (1000 lb/hr)	SO2 Mass (lbs)	SO2 Mass Measure Indicator	SO2 Rate (lbs/mmBtu)	SO2 Rate Measure Indicator	CO2 Mass (short tons)	CO2 Mass Measure Indicator	CO2 Rate (short tons/mmBtu)	CO2 Rate Measure Indicator	NOx Mass (lbs)	NOx Mass Measure Indicator	NOx Rate (lbs/mmBtu)	NOx Rate Measure Indicator	Heat Input (mmBtu)	Heat Input Measure Indicator	Primary Fuel Type	Secondary Fuel Type	Unit Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Program Code
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	10	1	52		1	Measured	0.001	Calculated	60.4	Measured	0.08	Calculated	81.1	Calculated	0.108	Calculated	751	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	11	1	52		1.003	Measured	0.001	Calculated	60.6	Measured	0.08	Calculated	81.3	Calculated	0.108	Calculated	753.2	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	12	1	52		0.994	Measured	0.001	Calculated	60.1	Measured	0.08	Calculated	81.4	Calculated	0.109	Calculated	746.8	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	13	1	52		0.997	Measured	0.001	Calculated	60.3	Measured	0.081	Calculated	85.4	Calculated	0.114	Calculated	749	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	14	1	53		1.006	Measured	0.001	Calculated	60.8	Measured	0.08	Calculated	86.1	Calculated	0.114	Calculated	755.4	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	15	1	52		1.001	Measured	0.001	Calculated	60.5	Measured	0.08	Calculated	85.7	Calculated	0.114	Calculated	752	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	16	1	53		1.008	Measured	0.001	Calculated	60.8	Measured	0.08	Calculated	84.8	Calculated	0.112	Calculated	757.1	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	17	1	57		1.05	Measured	0.001	Calculated	63.4	Measured	0.08	Calculated	95.5	Calculated	0.121	Calculated	788.7	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	18	1	52		0.99	Measured	0.001	Calculated	59.8	Measured	0.08	Calculated	84	Calculated	0.113	Calculated	743.4	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	19	1	51		0.982	Measured	0.001	Calculated	59.3	Measured	0.08	Calculated	83.4	Calculated	0.113	Calculated	737.7	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	20	1	51		0.984	Measured	0.001	Calculated	59.4	Measured	0.08	Calculated	84.2	Calculated	0.114	Calculated	738.8	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	21	1	61		1.091	Measured	0.001	Calculated	65.9	Measured	0.081	Calculated	101	Calculated	0.123	Calculated	818.6	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI

State	Facility Name	Facility ID	Unit ID	Associated Stacks	Date	Hour	Operating Time	Gross Load (MW)	Steam Load (1000 lb/hr)	SO2 Mass (lbs)	SO2 Mass Measure Indicator	SO2 Rate (lbs/mmBtu)	SO2 Rate Measure Indicator	CO2 Mass (short tons)	CO2 Mass Measure Indicator	CO2 Rate (short tons/mmBtu)	CO2 Rate Measure Indicator	NOx Mass (lbs)	NOx Mass Measure Indicator	NOx Rate (lbs/mmBtu)	NOx Rate Measure Indicator	Heat Input (mmBtu)	Heat Input Measure Indicator	Primary Fuel Type	Secondary Fuel Type	Unit Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Program Code
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	22	1	53		1.01	Measured	0.001	Calculated	61	Measured	0.08	Calculated	88	Calculated	0.116	Calculated	758.6	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/25/2022	23	1	54		1.002	Measured	0.001	Calculated	60.6	Measured	0.08	Calculated	86.6	Calculated	0.115	Calculated	753	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/26/2022	0	1	56		1.038	Measured	0.001	Calculated	62.8	Measured	0.081	Calculated	63.9	Calculated	0.082	Calculated	780.1	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/26/2022	1	1	80		1.321	Measured	0.001	Calculated	79.8	Measured	0.081	Calculated	104	Calculated	0.105	Calculated	990.5	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/26/2022	2	1	74		1.26	Measured	0.001	Calculated	76.2	Measured	0.081	Calculated	100	Calculated	0.106	Calculated	945.3	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/26/2022	3	1	75		1.262	Measured	0.001	Calculated	76.3	Measured	0.081	Calculated	100	Calculated	0.106	Calculated	946.7	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/26/2022	4	1	54		1.006	Measured	0.001	Calculated	60.9	Measured	0.08	Calculated	65.1	Calculated	0.086	Calculated	756.9	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/26/2022	5	1	53		1.005	Measured	0.001	Calculated	60.7	Measured	0.08	Calculated	65.7	Calculated	0.087	Calculated	755.4	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/26/2022	6	1	53		1.012	Measured	0.001	Calculated	61.2	Measured	0.08	Calculated	65.4	Calculated	0.086	Calculated	760.7	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/26/2022	7	1	81		1.323	Measured	0.001	Calculated	80	Measured	0.081	Calculated	100	Calculated	0.101	Calculated	992.5	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/26/2022	8	1	74		1.257	Measured	0.001	Calculated	75.9	Measured	0.081	Calculated	91.5	Calculated	0.097	Calculated	942.8	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI
PA	Eddystone Generating Station	3161	4	CS034	12/26/2022	9	1	53		1.006	Measured	0.001	Calculated	60.8	Measured	0.08	Calculated	64.3	Calculated	0.085	Calculated	756.2	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI

State	Facility Name	Facility ID	Unit ID	Associated Stacks	Date	Hour	Operating Time	Gross Load (MW)	Steam Load (1000 lb/hr)	SO2 Mass (lbs)	SO2 Mass Measure Indicator	SO2 Rate (lbs/mmBtu)	SO2 Rate Measure Indicator	CO2 Mass (short tons)	CO2 Mass Measure Indicator	CO2 Rate (short tons/mmBtu)	CO2 Rate Measure Indicator	NOx Mass (lbs)	NOx Mass Measure Indicator	NOx Rate (lbs/mmBtu)	NOx Rate Measure Indicator	Heat Input (mmBtu)	Heat Input Measure Indicator	Primary Fuel Type	Secondary Fuel Type	Unit Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Program Code
PA	Eddystone Generating Station	3161	4	CS034	12/26/2022	10	0.43	39		0.362	Measured	0.001	Calculated	21.887	Measured	0.08	Calculated	18	Calculated	0.066	Calculated	272.319	Measured	Pipeline Natural Gas	Diesel Oil	Tangentially-fired		Other			ARP, CSNOX, CSOSG3, CSSO2G1, MATS, RGGI

Exhibit 28

Department of Energy
Washington, DC 20585

Order No. 202-26-17

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in 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 can run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order Nos. 202-25-04 and 202-25-08, issued pursuant to FPA section 202(c), each required that the Eddystone Units remain in operation for 90 days, until August 28, 2025, and November 26, 2025, respectively. Subsequently, Order No. 202-25-10, issued pursuant to FPA section 202(c), required the Eddystone Units to remain in operation for 90 days, until February 24, 2026. Those orders were based on my determination that emergency conditions existed in the PJM region. 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 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

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] *See, e.g., PJM Interconnection, L.L.C. and Constellation Energy Corp.*, Order No. 202-25-10, at 7 (Nov. 25, 2025).
[4] *See, e.g., id.*
[5] *See, e.g., id.* at 8, Ordering Paragraph A.

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

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[6] *Keeping the Lights On: Examining the State of Regional Reliability: Hearing Before the Subcomm. on Energy of the H. Comm. on Energy & Com.*, 119th Cong., at 4-5 (Mar. 25, 2025) (testimony of Mr. Manu Asthana, President and CEO of PJM) (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 Interconnection*) (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 Inside Lines, *PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing Risk* (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: Resource Retirements, Replacements & Risks*, at 1 (Feb. 24, 2023) (Four Rs Report).

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

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-04, 202-25-08, and 202-25-10 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, 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 (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 most recently demonstrated during Winter Storm Fern, when PJM operated under a cold weather alert and declared conservative operations from January 24 – February 2, 2026. Additionally, on January 27, 2026, PJM declared a Maximum Generation Emergency/ Load Management Alert and an EEA 1.[14] 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] The Department granted PJM's application and issued Order No. 202-26-02 on

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[11] Further, it likely would be difficult for the oil-fired 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. 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.

[12] *See Custom Data Download, EPA CAMPD* (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (search criteria Emissions >> Monthly >> Unit (default) >> Apply >> *"2025" and "June, July, August, September, October, November, December."* The data can then be filtered to include only the Eddystone Generating Station.

[13] *See* PJM, *Emergency Procedures*, https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf (search range set to: effective from 06/01/2025 until 08/31/2025).

[14] *See id.* (search range set to: effective from 01/20/2026 until 02/07/2026).

[15] PJM, *Request for Emergency Order Under Federal Power Act, Section 202(c)*, at 2 (Jan. 24, 2026), https://www.energy.gov/documents/pjm-202c-application-2026-01-24.

January 25, 2026.[16] On January 29, 2026, PJM applied for an extension of Order No. 202-26-02, which was granted by the Department on the same day.[17]

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.[18] 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%."[19] 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.[20]

The evidence indicates that there is also a potential longer term resource adequacy emergency in the PJM region. In a news release expressing support for Order No. 202-25-04, PJM explained that it has "repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers."[21]

PJM has indeed voiced these concerns for years. In its February 2023 Four Rs Report, PJM cautioned that 40 GW of thermal generation are at risk of retirement by 2030.[22] 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

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[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] PJM Inside Lines, *Jan. 22 Update: Extreme Cold Produces PJM Record for Winter Electricity Demand* (Jan. 22, 2025), https://insidelines.pjm.com/jan-22-update-extreme-cold-produces-pjm-record-for-winter-electricity-demand/.

[19] PJM Inside Lines, *2025 Long-Term Load Forecast Report Predicts Significant Increase in Electricity Demand* (Jan. 30, 2025), https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/.

[20] PJM Resource Adequacy Planning Special Planning Committee, *2026/27 BRA IRM, FPR, and 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.

[21] PJM Inside Lines, *PJM Statement on the U.S. Dept. of Energy 202(c) Order of May 30* (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*.

[22] Four Rs Report at 2.

renewable projects is approximately 5%.[23] PJM determined that the pace of new capacity additions "would be insufficient to keep up with expected retirements and demand growth by 2030."[24] PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.[25]

In its December 2024 RRI filing with FERC, PJM stated that "[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report . . . ."[26] PJM warned that its "resource adequacy concerns are increasing at an extraordinary pace."[27] 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.[28] 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."[29] 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.[30]

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."[31] Mr. Bielak expressed the opinion that the "rapid" retirement of thermal generation resources, "extreme" forecasted load growth, and "delays in new generation resources achieving commercial operation," would adversely affect resource adequacy throughout PJM's electricity grid.[32]

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[23] *Id.*

[24] *Id.* at 16, Table 1.

[25] *Id.*

[26] PJM, *Tariff Revisions for Reliability Resource Initiative*, FERC Docket No. ER25-712, at 10 (Dec. 13, 2024).

[27] *Id.*

[28] *Id.* at 10-11. *See also id.* at 13 ("the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements . . . .").

[29] *Id.* at 14.

[30] *See id.*, Attachment C (Affidavit of Mr. Donald Bielak), at PP 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.").

[31] Affidavit of Mr. Donald Bielak at P 10.

[32] *Id.* at P 12.

On February 11, 2025, FERC accepted PJM's RRI filing.[33] 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."[34]

The North American Electric Reliability Corporation (NERC) has raised similar concerns. In its 2025 Long-Term Reliability Assessment, released in January 2026, NERC observes that the PJM region is at high risk of energy shortfalls over the next five years[35] and faces significant reliability challenges as "[c]urrent projections for resource additions do not keep pace with escalating demand forecasts and expected generator retirements."[36] 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."[37] 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."[38]

Order Nos. 202-25-04, 202-25-08, and 202-25-10 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our nation's economy, national security, and foreign policy."[39] 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

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[33] *PJM Interconnection*, 190 FERC ¶ 61,084 at P 263.

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

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

[36] *Id.* at 8.

[37] *Id.* at 16.

[38] *Id.* at 91.

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

commodity markets."[40] 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."[41]

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."[42] 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.[43] 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.[44] 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 coal, gas, and oil generation retirements.[45] 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.[46]

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[40] *Id*.

[41] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

[42] U.S. Dep't of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025) (Resource Adequacy Report), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[43] *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_vFINA L.pdf.

[44] *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-slidesvTCII.pdf.

[45] Resource Adequacy Report at 28.

[46] *Id.* at 27.

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."[47] 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."[48] 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.[49] 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."[50]

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

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[51] 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.

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[47] Asthana Test. at 4.

[48] *Id.*

[49] *Id.* at 9-10.

[50] *Id.* at 10.

[51] 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).

Such is the case here. 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, and 202-25-10 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 in operation through May 24, 2026.[52]

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

A. From February 24, 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 operation of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions.

D. By March 11, 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

[52] 16 U.S.C. § 824a(c)(4).

Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time.

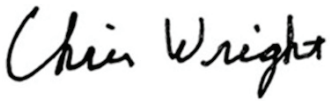
E. Constellation Energy is directed to file with FERC tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

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 February 24, 2026, through May 24, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 23rd day of February 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 Commissioners
Chairman Stephen M. DeFrank
Vice Chair Kimberly M. Barrow
Commissioner Kathryn L. Zerfuss
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora

Exhibit 29



Grid Strategies

Review of NERC's 2025 Long-Term Reliability Assessment

Adria E. Brooks, Michael Goggin, John D. Wilson

March 5, 2026

Prepared for Earthjustice, Natural Resource Defense Council, Sierra Club, and Environmental Defense Fund

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1. Executive Summary
2. Generation resource assumptions
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Executive Summary

The NERC LTRA assesses future regional resource adequacy risk. Re-assessment using a more complete accounting of generation, imports, and demand from other data sources results in lower risk.

Overall, the LTRA resource margins are much tighter than what may occur for four reasons.

First, the LTRA underestimates likely-to-connect power resources. Power resources in advanced development stages are projected to provide enough capacity to resolve the majority of shortfalls identified in the LTRA.

Second, the most significant risk to resource adequacy shortfalls are delays to generator interconnection. Actions that delay interconnection study, permitting, and/or construction for generation facilities increase the likelihood of shortfalls.

Third, the LTRA underestimates imports from one region to another. At levels seen historically during extreme events, these are sufficient to further alleviate resource inadequacy.

Furthermore, additional interregional transmission would lessen shortfall risk. The NERC-identified interregional transfer capability additions would help resolve many of the identified seasonal capacity and energy shortfalls.

Fourth, data centers may require significantly less power than expected. Combined with the other three corrections, this scenario could allow all regions to meet 2030 peak summer load and reserve needs.

With a clearer vision of the future and rapid action, the grid could be even more reliable in five years than it is today.

NERC's 2025 Long-Term Reliability Assessment is too pessimistic. This analysis explores three major categories of input assumptions that impact the regional risks NERC identified.

North American Electric Reliability Corporation (NERC)'s Long-Term Reliability Assessment (LTRA) importantly captures potential reliability issues for a snapshot in time. NERC relies on utility-reported input data in making its assessments. This data, by definition, does not account for national power sector trends or limitations—such as double-counting of prospective demand or generation—that can have large impacts on future risk.

In this analysis we compare NERC's input data and assumptions against other sources to explore how changes to inputs impact the severity of risk identified in the LTRA. We explore three categories of inputs: demand, generation resources, and interregional transmission.

As the LTRA highlights, reserve margins—the difference between electricity demand and available supply—are tightening across the country. We find that while these margins are tightening, the severity of that risk is likely less than reported in the LTRA.

Three major factors:



Generation Resources



Interregional Transmission



Demand for electricity

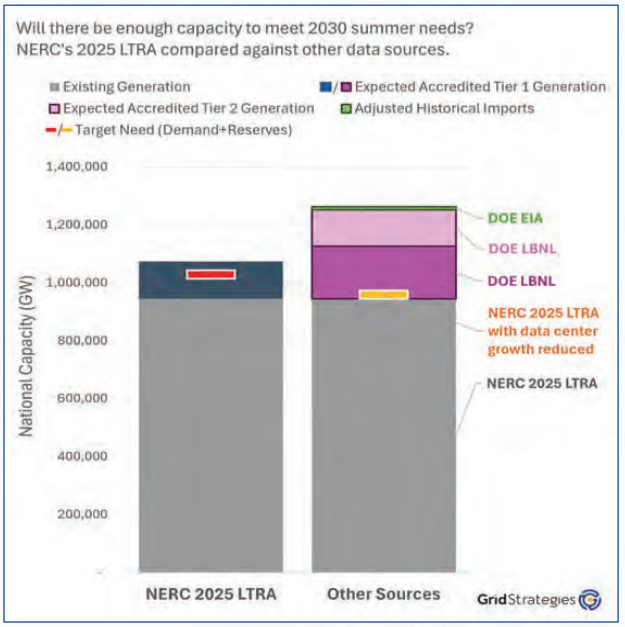
NERC's 2025 LTRA highlights important reliability concerns, but the severity of these concerns depends on the data used.

A reassessment of the LTRA regional seasonal adequacy using a more complete accounting of generation, imports, and demand from other data sources reveals different—and in many cases less dire—risk assessments for some regions.

- The LTRA generation forecast is based on an incomplete accounting of nearly built generation projects. A more reasonable expectation for generation growth can be determined from each region's interconnection queue.
- The LTRA import forecast excludes the opportunity for increased imports from new interregional transfer capability.
- The LTRA demand forecast is supplied by utilities and regional planners. The vast majority of the load growth in the LTRA forecast is based on utility large load forecasts. Some of this load is uncommitted and may not materialize or it may curtail during peak periods.

The combination of low generation, low import, and high demand assumptions used in the 2025 LTRA resulted in resource margins appearing tighter than may actually materialize.

A comparison of the aggregated resource margins from NERC's LTRA and other national, reputable data sources, which account for the above three factors, is shown to the right. This chart is explained in the Methodology.



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SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Wilson, J., et al. (2025; Rand, J. et al. (2025); EIA, "About the EIA-930 data" (accessed Feb. 2026)

Implementing currently available solutions will help all regions alleviate the identified capacity and energy risks.



Resource supply is available to meet rising needs but is encountering roadblocks. Potential solutions include:

- More efficient interconnection queues for all resources
- Permitting certainty and reduced construction delays for needed grid infrastructure
- Adopting reforms to increase coordination between transmission planning and generator interconnection



Additional import capability would help alleviate tight reserve margins. Potential solutions include:

- Appropriately valuing the resource adequacy (capacity) contribution of interregional transmission
- Comprehensive transmission planning processes that consider both firm and non-firm imports
- Acting on NERC's recommended interregional transfer capability additions



Tightening reserve margins are driven primarily by demand growth from large source loads, such as data centers. Potential solutions include:

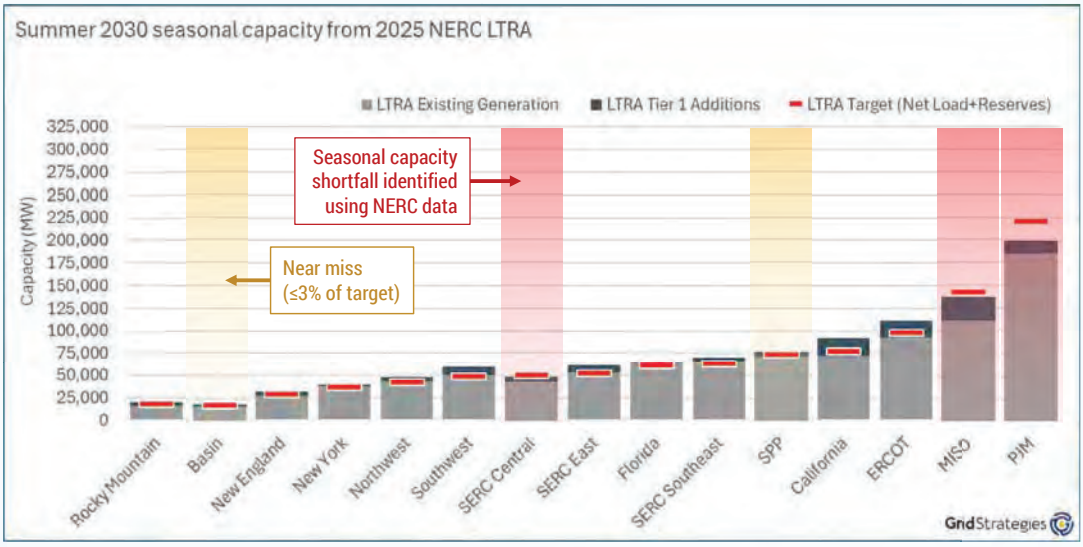
- Reducing the uncertainty and lack of transparency in load forecasts
- Regulatory solutions to connect large loads reliably

Generation Resource Assumptions

NERC only considered resources with executed interconnection agreements when determining shortfall risk.

All resources must undergo interconnection studies to identify any grid upgrades that may be necessary to reliably connect. At the end of the interconnection queue process, an interconnection agreement (IA) is executed. NERC considers any resource that has an executed IA as **Tier 1**.

To be resource adequate, a region must have enough future capacity and imports to meet load and reserve margins ("target"). NERC only counts Tier 1 resources toward future resources in the LTRA. NERC identifies three regions* that may be short of 2030 summer capacity needs using its assumptions. Two regions only exceed their target by less than 3%, marked here as "near miss" regions.



*NERC did not identify SERC Central as a heightened risk region though it is shown to be short of future capacity using the LTRA source data, perhaps because they did not identify elevated energy inadequacy risk despite the seasonal capacity shortfall in the region. We highlight it as elevated risk given the identified seasonal capacity shortfall.

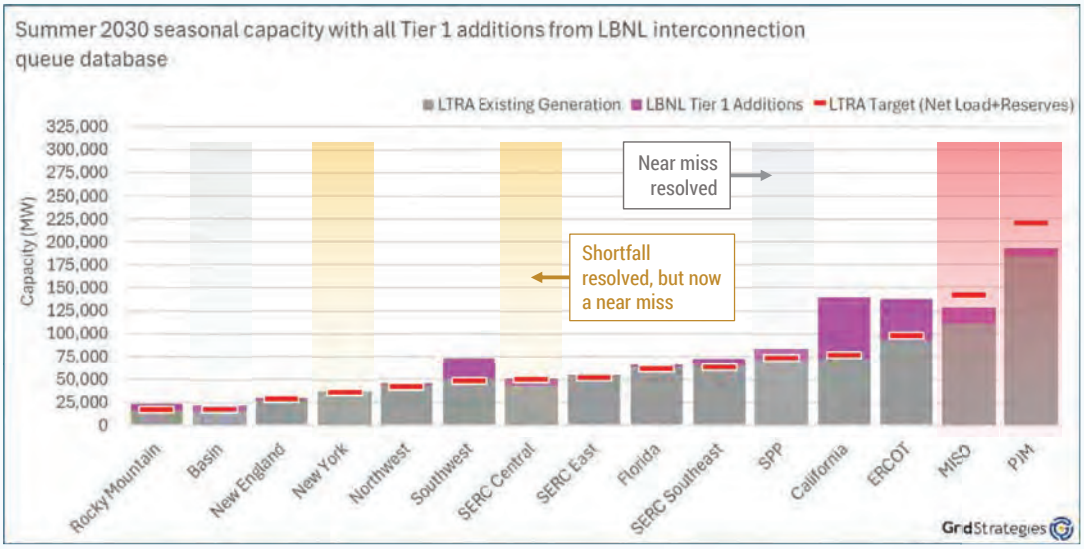
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SOURCE | NERC "2025 LTRA" (2026); NERC "2025 Electricity Supply & Demand (ES&D)" (Jan. 2026)

The amount of resource capacity with executed interconnection agreements in the LTRA is lower than that compiled by LBNL.

The U.S. Department of Energy (DOE)'s Lawrence Berkley National Laboratory (LBNL) tracks interconnection queue data across all regions and is a reputable source of high-quality data. The LBNL data suggests more accredited **Tier 1** resource capacity is available nationwide than is recorded in the LTRA, though regional allocations vary. The mismatch in data could be due to different processing methods, collection periods, and, importantly, resource accreditation methods.*

Using the LBNL data paints a different future risk picture than the LTRA—only two regions show 2030 summer shortfalls. This highlights how sensitive risk assessments are to their input data.



*All LBNL generation capacity used in this analysis has been discounted using regional, seasonal, and resource-specific accreditation methods, to show the expected generation capacity during peak load. Utilities do not uniformly report seasonal or resource-specific accredited capacity to NERC for use in the LTRA, which, as NERC highlights, may inaccurately account for the capacity availability during peak load (LTRA at 9, 44, 60, 71, 76, 122). See the Methodology for more information.

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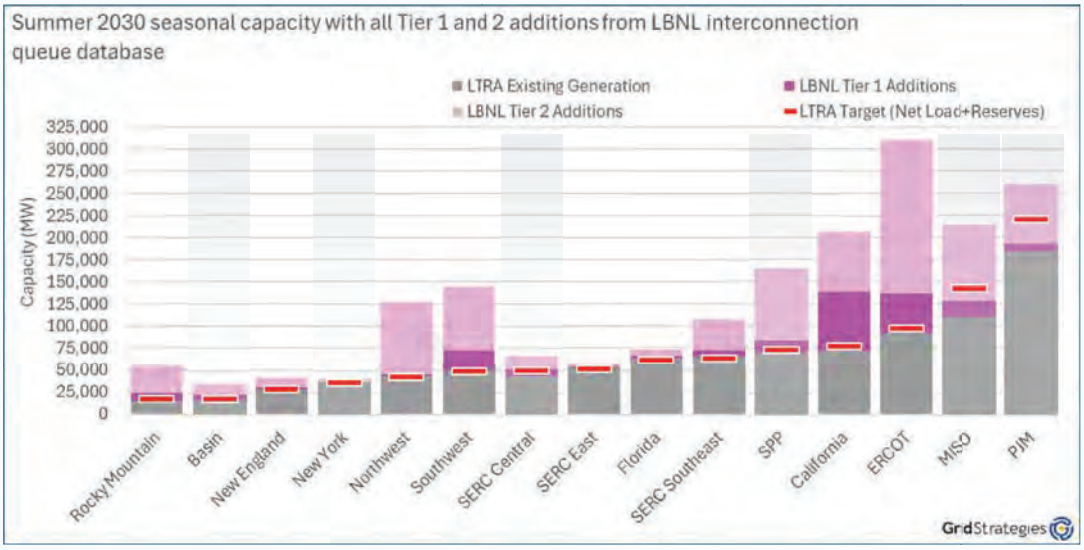
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. "Interconnection Queue Dataset & Summarized Data Files, through 2024" (Aug. 2025)

There are more resources under development in each region than those with executed IAs. Providing a path to interconnection for these resources helps alleviate risk.

NERC considers any resource that has begun system studies, but has not yet completed them, to be a **Tier 2** resource. According to LBNL data, there is nearly five times the accredited Tier 2 resource capacity with planned in-service dates by 2030 nationwide than NERC-counted Tier 1 as well as three times the NERC-counted Tier 2 summer 2030 resource capacity.

NERC does not include any Tier 2 capacity in the LTRA shortfall analysis. Inclusion of this capacity suggests that regions could be at less risk of seasonal shortfalls than illustrated in the LTRA.

But this is only true if there are clear pathways for interconnection of these resources. LBNL research shows that generators are facing increasing delays in the interconnection study and post-study phases. These delays contribute to project cancellations, which is dangerous for seasonal resource adequacy.



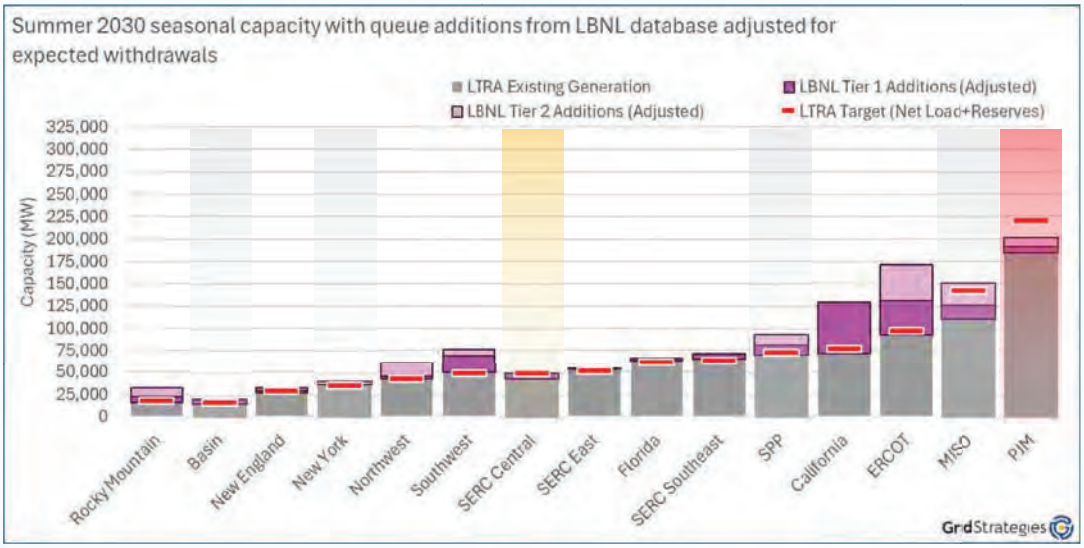
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Even when accounting for likely resource cancellations in the queue and post-queue phases, LBNL data suggests enough resources could connect to meet most regions' 2030 capacity needs.

It is unlikely that all Tier 1 and Tier 2 resources will connect to the grid. LBNL analysis shows as much as 85% of resources that enter the queues fails to connect to the grid ("withdrawal rates"), including facilities with executed IAs.

Rather than omit all Tier 2 data to account for the risk of cancellations (as done in the LTRA), we apply historic region-specific and phase-specific withdrawal rates to the LBNL data to estimate how much may connect to the grid by 2030.

Consideration of likely-to-connect resources currently in the interconnection queues resolves the majority of identified seasonal adequacy shortfalls. The resolution of shortfalls shown here is accomplished without a delay to announced resource retirements.



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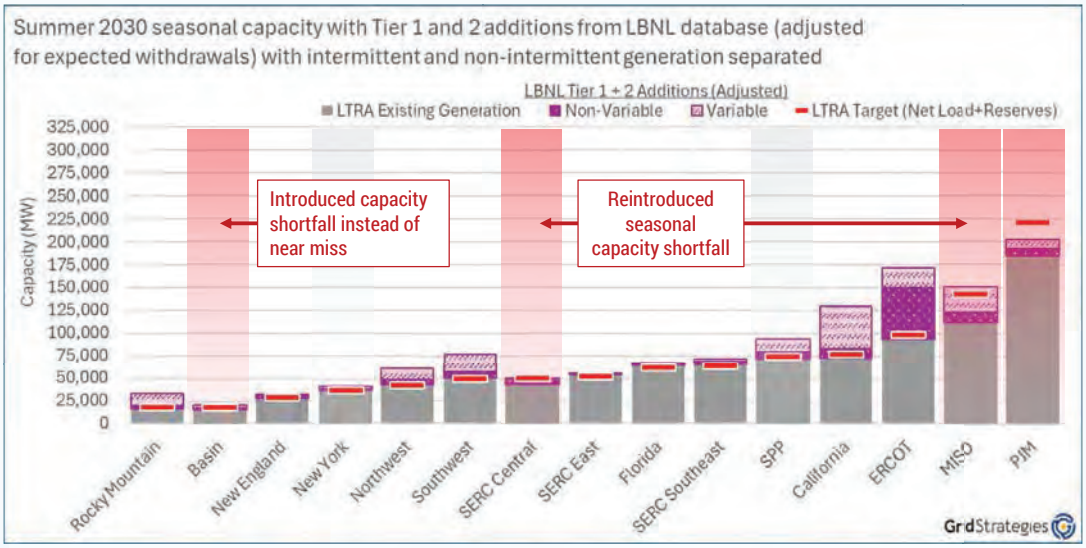
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Delays in the study, permitting, and/or construction phases to resources already in the queues—including wind and solar facilities—could jeopardize meeting regional seasonal capacity needs.

Additional permitting or equipment procurement steps applied to facilities increases their time to interconnection or results in project cancellation outright. Unnecessary hurdles for facilities waiting to interconnect could jeopardize huge amounts of resource capacity in advanced stages of development.

Shown here is the amount of likely-to-connect Tier 1 and 2 resource capacity from the LBNL data, broken out into variable (wind and solar) and non-variable resources.

Actions which delay permitting or construction for variable generation facilities could prevent large portions of the Midwestern, Southeastern, and Western regions from maintaining resource adequacy where they otherwise would be able to.



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SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

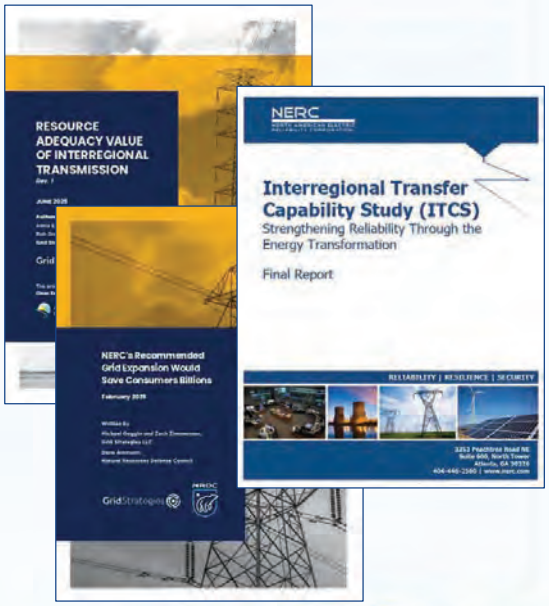
Interregional Transmission Assumptions

Interregional transmission helps to alleviate capacity adequacy concerns, especially during times of grid stress.

One of the many benefits of interregional transmission is the ability to move power between regions during times of grid stress. The availability of imports is primarily due to net load diversity among regions due to timing differences in peak demand and generation unavailability, particularly during severe weather events. Weather patterns and extreme grid events do not impact all regions equally, so there is often spare capacity in a neighboring region that could be shared during times of need. As a result, this benefit will largely persist even if reserve margins in neighboring regions are lower going forward. This phenomenon is well documented in several studies.

The LTRA only includes firm interregional capacity transfers in assessing anticipated reserve margins, which NERC defines as transfers with firm contracts. This ignores the historical role of "non-firm" imports, which are available during extreme events. For example, MISO imported over 13 GW during Winter Storm Uri, of which 5 GW was in turn exported to SPP, imports that literally kept the lights on in those regions.

Sharing of power can only occur, of course, if enough interregional transmission exists to move the available power. NERC acknowledged this in their 2024 Interregional Transfer Capability Study (ITCS) where they measured the amount of interregional transmission capacity that should be added to each region to help support energy adequacy. The ITCS analysis looks at peak grid stress days for each region and determines if excess capacity is likely to be available in neighboring regions during those same hours. It then suggests interregional transmission capacity be added to move that excess generation.



Grid Strategies

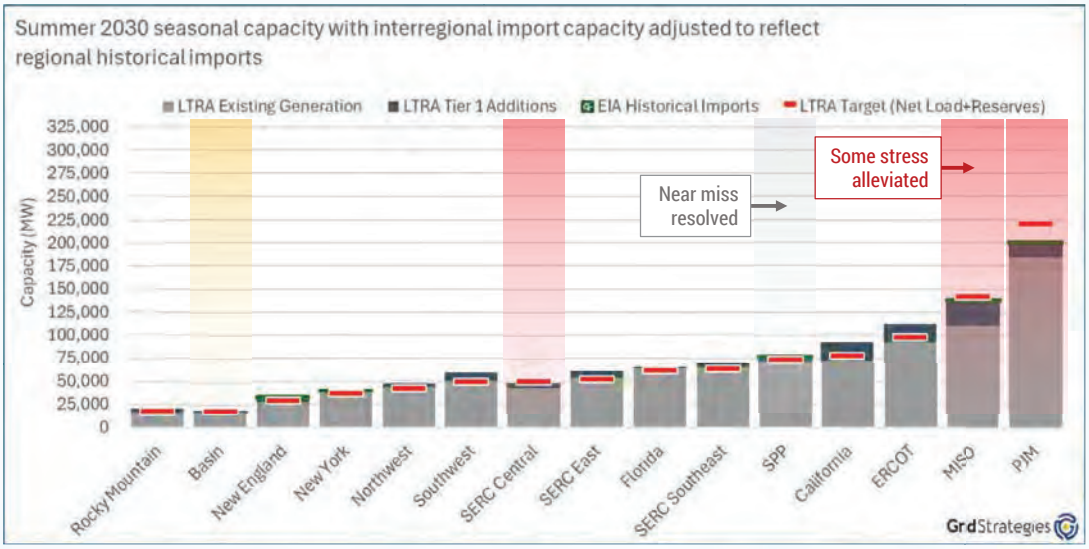
Source | NERC "Interregional Transfer Capability Study" (2024); Goggin, M., Zimmerman, Z., Amman, D., "NERC's Recommended Grid Expansion would Save Consumers Billions" (2025); Brooks, A., Silverstein, A., Gramlich, R., "The Resource Adequacy Value of Interregional Transmission" (2025)

The LTRA only counts firm imports, omitting non-firm imports. Some regional stress is alleviated when combining the LTRA capacity assumptions with historical non-firm import availability.

The LTRA only includes firm interregional capacity transfers in assessing anticipated reserve margins, which NERC defines as transfers with firm contracts. This ignores non-firm imports over interregional transmission lines that have been available during historical grid stress events.

Hourly regional import and export data collected by the U.S. Energy Information Administration (EIA) confirm regions import significantly more during periods of peak demand than the LTRA assumes.

The inclusion of non-firm imports that are historically available during extreme events helps further alleviate resource inadequacy.



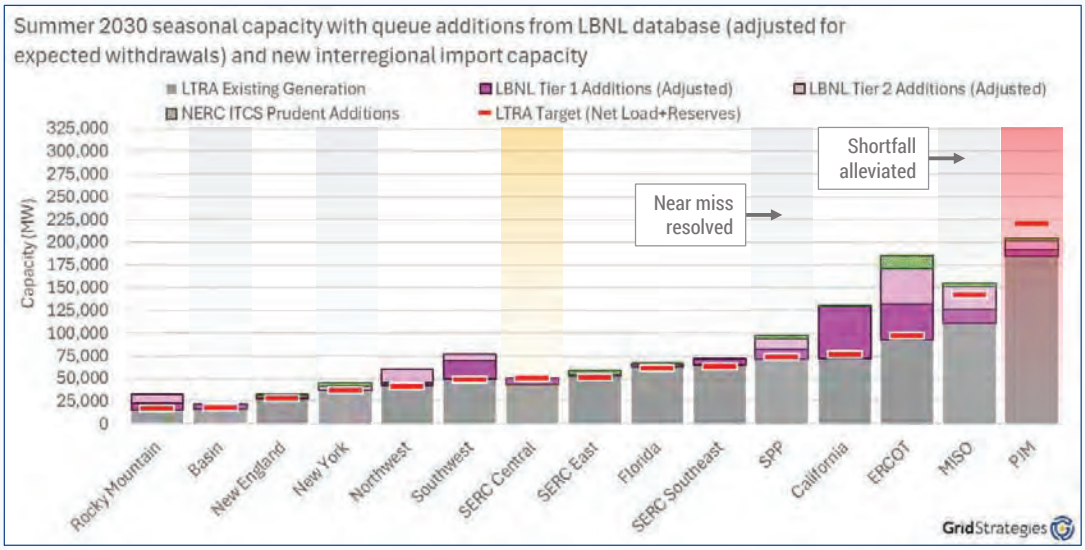
SOURCE | NERC "LTRA" (Jan. 2026); NERC "ES&D" (Jan. 2026); U.S. EIA "About the EIA-930 data" (accessed Feb. 2026)

The combination of NERC-identified increased transfer capability and reasonable resource assumptions from the interconnection queues provides even more security to avoid shortfalls.

The combination of interregional transmission additions suggested by NERC's ITCS and reasonable generation additions using LBNL queue data would provide regions with additional capacity to weather seasonal grid stress events.

The addition of new NERC-identified transfer capability would likely resolve many of the identified seasonal capacity and energy shortfalls.

All transmission takes a long time to develop, but this is especially true for interregional transmission. Unfortunately, the NERC-identified interregional transfer capability additions are unlikely to be built by 2030 under the status quo. Legislative and regulatory action taken now could accelerate the construction of these prudent additions.



Demand Assumptions

The load growth in the LTRA is based on utility projections that, in some cases, are based on overstated assumptions.

NERC compiled the LTRA load growth forecast by rolling up projections from utilities and regional grid operators. Large load forecasts are uncertain and could overstate load growth for several reasons.

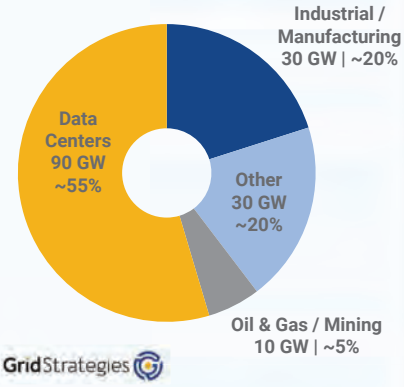
Reliance on customer data: Large load forecasts rely primarily on customer-supplied information.

- Data centers, in particular, are constrained by global supply chains. There is no clear method for individual load forecasts to account for how supply chain constraints will affect specific projects.
- Load forecasts lack visibility into customers' overall business plans. There may be "double counting" as data center operators develop more sites as options than they intend to build. The LTRA includes all loads with "development commitments necessary to drive grid planning studies." In contrast, the LTRA only counts generators that have completed all planning studies and signed an interconnection agreement.
- Many regulated utilities have an incentive to overstate load growth and interconnection success rates to justify additional rate-based investments in generation and other infrastructure.

Time lags: Producing and compiling load growth projections occurs months before the LTRA is released. Mounting delays in large load interconnection and policy changes appear to have slowed load growth since their compilation.

- Load interconnection queue backlogs and long lead times for power transformers and circuit breakers needed for interconnection are likely to delay commercial operation of many large load projects.
- As outlined in the following slides, new large loads from data centers, cryptocurrency mining, and hydrogen electrolysis could each face headwinds that are not fully accounted for in the LTRA.
- Recent policy changes are reducing load growth, such as the recent termination or restriction of federal tax credits for electric vehicles, heat pumps, hydrogen electrolysis, and advanced manufacturing.

Drivers of Load Growth (2025 – 2030)



Load flexibility: Regulations and utility tariffs are beginning to require some large loads to provide demand response or backup generation during periods of peak demand. ERCOT's load forecast includes substantial demand response for crypto mining facilities and assumes that new requirements for large load emergency curtailment would reduce peak demand growth by 84%.

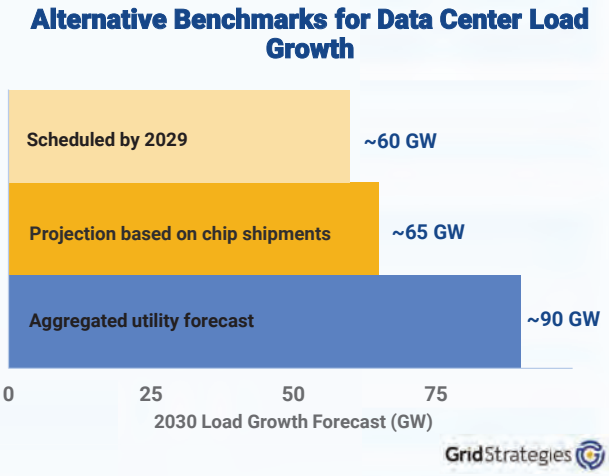
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SOURCE | Wilson, J., et al. "Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers" (Nov. 2025)

Assumed data center load

The LTRA reasonably states that, "New data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years." However, the growth of data centers and their contribution to peak demand may be overstated due to:

- **Supply chain shortages of chips and other key inputs.** TD Cowen estimated that due to chip limitations, U.S. data center growth would be limited to 65 GW (orange bar), about two-thirds of the data center growth assumed for the U.S. alone in the LTRA (blue).
- **Financial constraints.** Wall Street analysts have expressed concerns that expected revenues are insufficient to sustain the overall industry trajectory for AI data center investment.
- **Load flexibility.** Data centers may be able to use local generation and storage resources to reduce or eliminate their on-peak demand for grid power. Additionally, some types of data centers may opt to curtail their demand during peak periods without local supply. Curtailment activities such as these are unlikely to appear in utility forecasts of expected load. These practices may drive up annual energy use.



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SOURCE | TD Cowen, Data Centers, Generative AI, & Power Constraints: The Path Forward (May 2024); Bain & Company, "$2 trillion in new revenue needed to fund AI's scaling trend" (Sept. 2025); Wilson, J., et al. (2025)

Assumed cryptocurrency mining load

Cryptocurrency mining accounts for about 7 GW or 15% of ERCOT's projected large load growth through 2030, though it is likely lower in other regions.

However, cryptocurrency mining data centers are understood to be more speculative than other data center types. Cryptocurrency mining facilities are highly modular and can be readily moved to different sites, even after they have been installed and put into service at a site. Unlike some types of data centers, they do not face major siting constraints due to concerns about latency or access to fiber networks. These factors increase the likelihood of "double counting."

In ERCOT, cryptocurrency mines routinely use demand response or price-sensitive demand bids to curtail demand during peak periods. If properly incentivized to do so, their contribution to peak demand can be reduced or eliminated.

Assumed Hydrogen Electrolyzer Load

Most hydrogen production load is forecast in ERCOT, where planned electrolyzers account for about 8-9 GW or 20% of ERCOT's projected large load growth through 2030. NYISO's load forecast used to include substantial hydrogen production, but it has been adjusted downward. Only a few other load forecasts mention hydrogen production, and at much lower volumes than in ERCOT. According to EIA data, the U.S. had only 116 MW of hydrogen electrolyzers in operation in 2024.

ERCOT's forecast may not reflect a full market response to congressional action to tighten the timeframe for projects to qualify for the Section 45V Clean Hydrogen Production Credit. The credit is now only available for facilities that begin construction by the end of 2027 instead of 2032.

The operation of planned electrolyzers is also difficult to forecast, but they are unlikely to fully contribute to peak load for two reasons:

- The tax credit depends on the carbon-intensity of electricity consumption. This will drive electrolyzers operation to hours with high renewable generation, which are unlikely to be periods of peak net load.
- Regardless of the tax credit, electrolyzers will tend not to operate on-peak because the electricity would be too expensive.

SOURCE | U.S. EIA "Electrolyzers are a small but growing source of U.S. hydrogen production" (2024)

Load flexibility can reduce the capacity needed for large loads

Nearly all the preceding categories of large loads can use demand response, on-site generation and storage, or price-responsive loads to reduce or eliminate their contribution to peak demand.

The LTRA assessment of ERCOT's planning reserve margin assumes that new requirements for large load emergency curtailment would reduce peak demand growth by 84%. Through 2035, as load grows by 59 GW, demand response grows by 50 GW. NERC states that it made this assumption because "signed into law in June 2025, Texas Senate Bill 6 directs the Public Utility Commission of Texas to establish uniform large-load interconnection standards that, among other things, provide ERCOT with new large-load curtailment management tools and ERCOT's authority to direct (or require transmission service providers to direct) large loads to curtail their load prior to and during declared energy emergency situations."

While there is considerable debate about the feasibility for some types of data centers to provide flexibility, ERCOT's requirement shows the potential impact on resource adequacy. Nonetheless, no other load forecasts used to inform the LTRA include similar load flexibility assumptions. As a result, a large share of the projected load growth in the LTRA for other regions could be negated if NERC likewise assumed, as it did for ERCOT, that large loads use some type of flexibility during peak periods. Large loads in these regions could use similar flexibility solutions. For example, Google has signed agreements with utilities to use flexibility to reduce peak load contributions from data centers in Indiana, Nebraska, Arkansas, and the Tennessee Valley Authority footprint (Google 2025).

A recent study estimates 30% of data centers may install flexible capability anyway to curtail during localized transmission system overload or contingency events, as a way to move to the front of lengthy interconnection backlogs by reducing the need for cost- and time-intensive grid upgrades (Thomas 2026). Data centers that are unable to curtail could use behind-the-meter resources during peak periods to reduce or eliminate their reliance on grid power.

SOURCE | Google "How we're making data centers more flexible to benefit power grids" (Aug. 2025); Thomas, M. "Bypassing the Grid: How Data Centers Are Building Their Own Power Plants" (Feb. 2026)

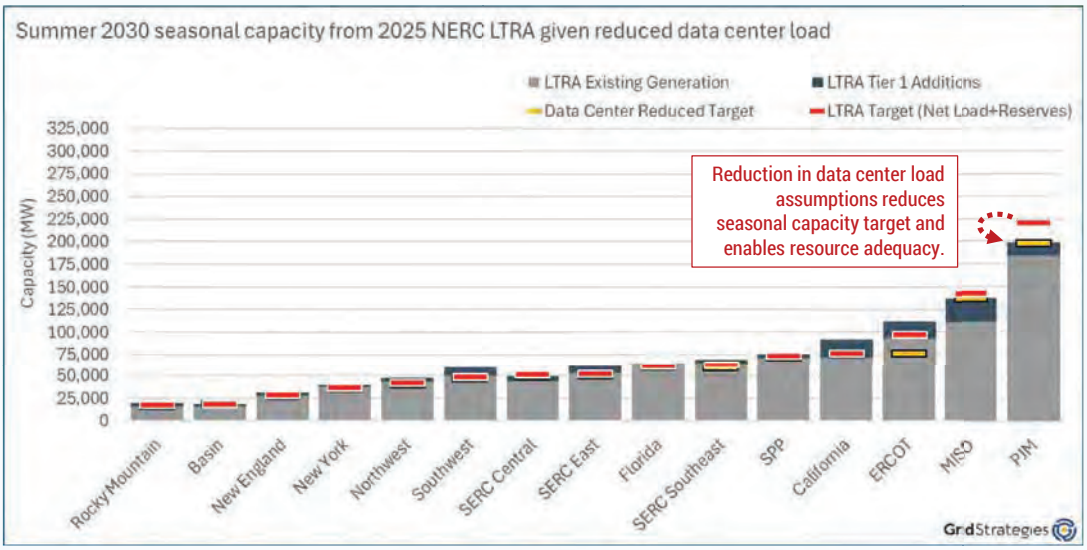
Updating data center load forecasts based on chip-industry forecasts would allow nearly all regions to meet their 2030 target needs

NERC indicates that load growth in several regions is dominated by data centers. To highlight the impacts of uncertainty in data center growth projections in the LTRA, we introduce a scenario which reduces national 2030 data center growth by two-thirds. This reduction is distributed among the regions based on their individual forecasted data center load and is shown as a yellow target in the chart.

A one-third reduction is based on chip industry forecasts and an additional one-third is based on assumed use of on-site generation during peak demand.

Consideration of potential reductions in data center load growth enables all regions to meet their 2030 peak summer load and reserve needs.

Note: If no red target is visible, then the two targets appear to overlap. All regions' net load was reduced.



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SOURCE | NERC "ES&D" (2026); Wilson, J., et al. (2025); Thomas, M. (2026)

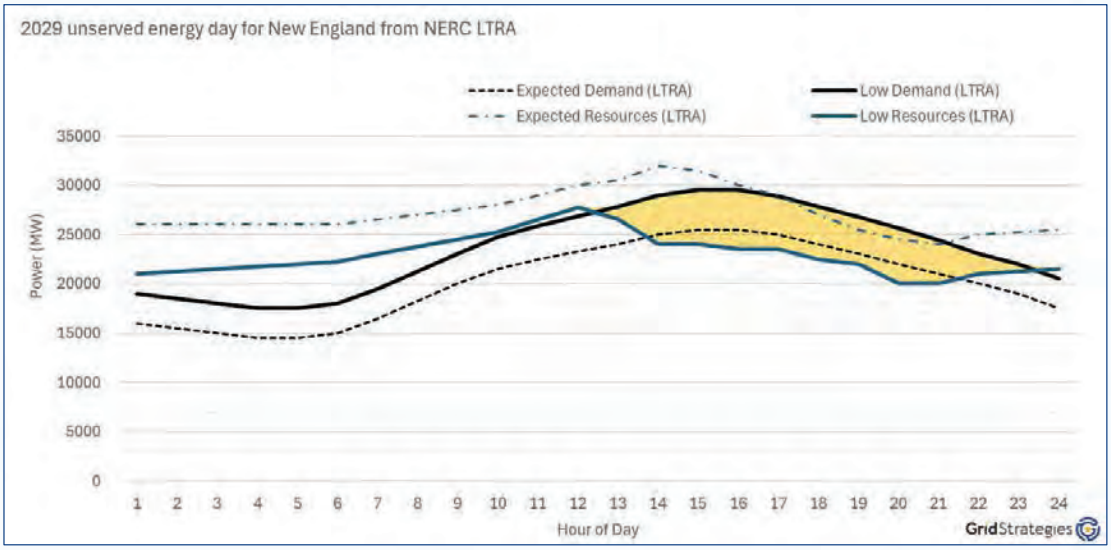
Extreme Event Energy Adequacy

Energy inadequacy risk during extreme events can exist even without seasonal capacity shortfalls. An increase in resource and interregional transfer capability also helps to alleviate extreme event risk.

The risk of energy shortfalls during extreme grid events can exist even without there being a risk of capacity shortfalls when considering only seasonal peak load. It is important to study both capacity and energy adequacy.

For example, NERC found energy shortfalls could occur during extreme heat days in New England,* even though it did not find seasonal capacity shortfalls.

Expected resource production is enough to meet expected demand (dotted lines) on most days, but sensitivity testing shows that the combination of lower-than-expected resources and high demand (solid lines) could result in energy shortfalls (yellow area). Energy shortfalls are often referred to as "unserved energy" or energy inadequacy.



*This figure is a recreation of the extreme event energy analysis shown in the LTRA for New England. We did not independently reproduce this analysis.

GridStrategies

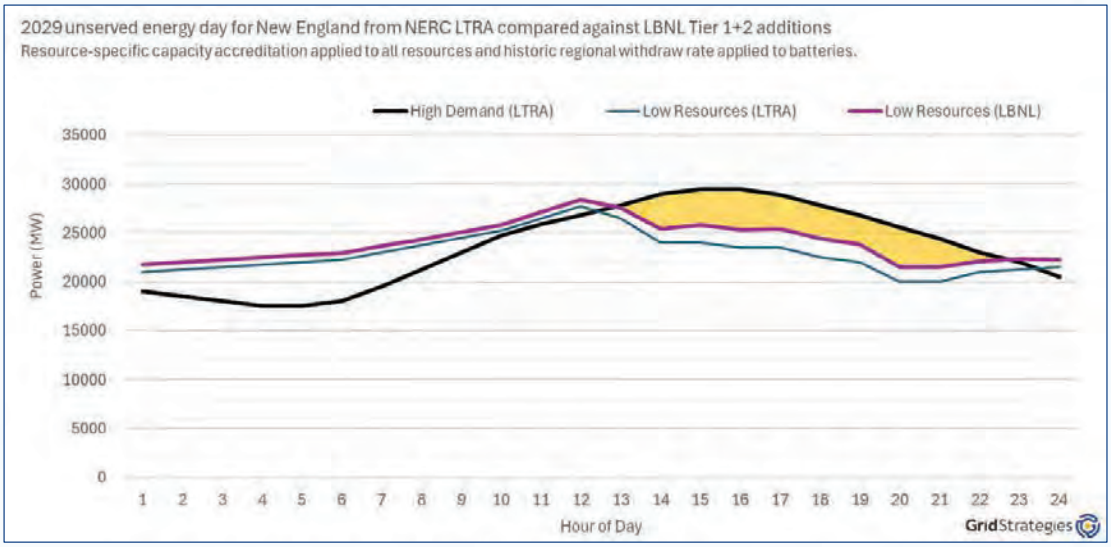
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Using LBNL resource assumptions for New England greatly reduces unserved energy risk during peak load days.

LBNL data records more solar, offshore wind, and storage resources than the NERC data.* Lower-than expected production from the LBNL-identified resource mix (purple line) better matches the times of high demand (black) than the NERC-identified resource mix (blue).

Given accredited, likely-to-connect Tier 1 and 2 resource capacity from LBNL, the amount of potential unserved energy on peak summer days in New England is reduced by nearly 40% of that calculated using NERC data. If capacity had not been reduced by expected withdrawals, the unserved energy shown here would be completely resolved.

Diverse resource mixes—especially those matched to the load profiles of the region—provide major benefits to withstand extreme grid events.



*See the Methodology section for more details.

GridStrategies

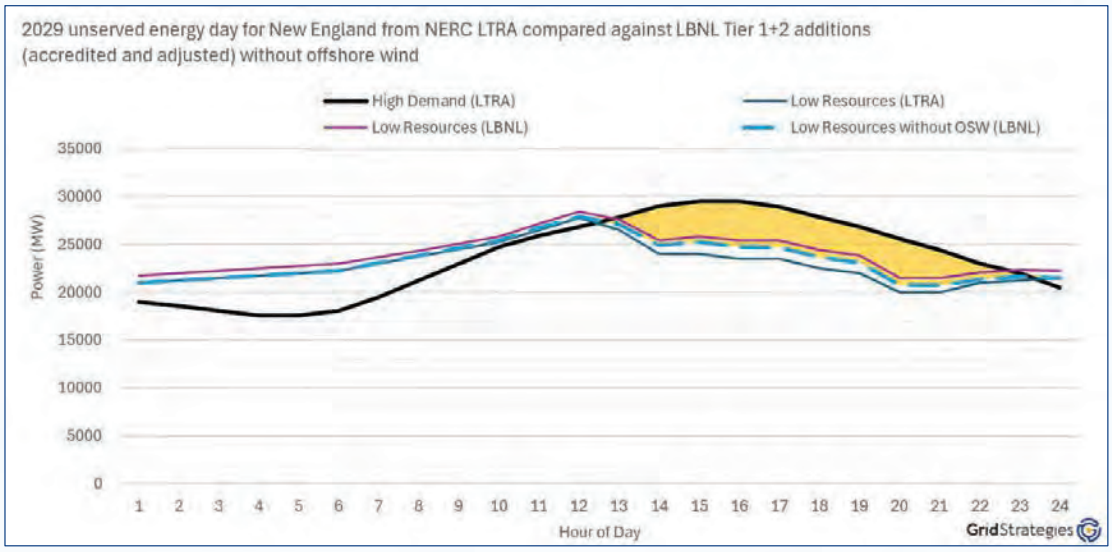
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

As with seasonal capacity adequacy, permitting and/or construction delays of resources with executed IAs are likely to exacerbate energy inadequacy risk during extreme grid events.

Delays of resources progressing through the queues or with executed IAs, whatever the cause, will exacerbate the risk of unserved energy during extreme grid events. Currently, offshore wind is facing additional permitting and construction hurdles. This is especially noteworthy for New England, where strong afternoon offshore wind output could directly reduce unserved energy risk during peak load hours.

Near-term unserved energy risk increases substantially given the delay or cancellation of planned offshore wind generation.

Given the low production of a resource mix without offshore wind (shown as the blue dotted line), the unserved energy risk is only reduced by 20% instead of 40% of that calculated in the LTRA.



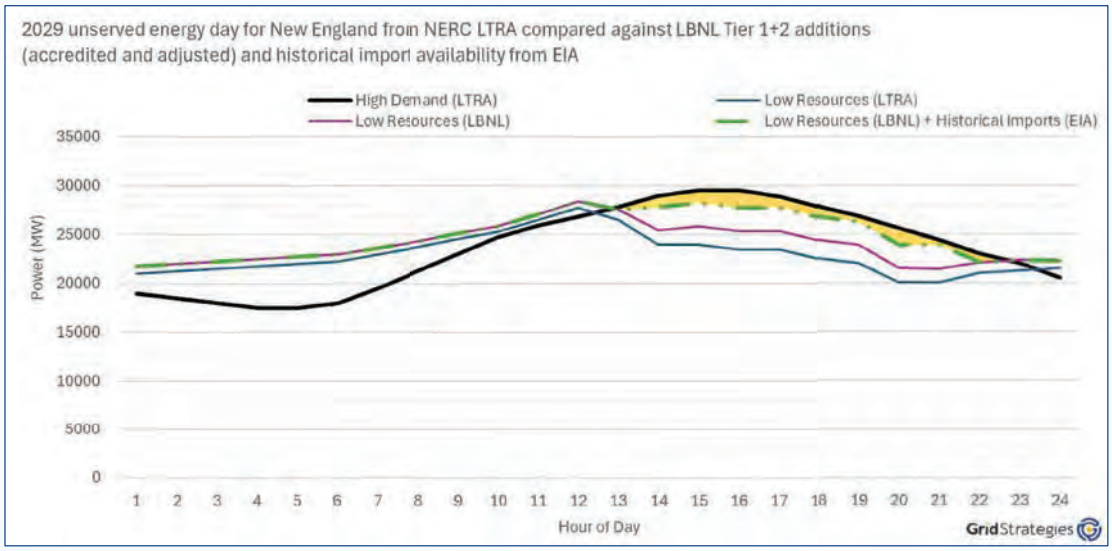
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Interregional transmission designed to move power between regions during times of grid stress further reduces unserved energy risk.

As explained in slides 15-17, NERC only includes firm imports in its seasonal capacity or energy adequacy analysis. This ignores the likelihood of additional "non-firm" imports which are historically available to regions during extreme events. Non-firm imports are those which are not contracted for use during normal operations, but that neighboring regions can export to regions experiencing heightened stress.

Adding the imports which have been historically available to New England during extreme events further reduces expected unserved energy.

The combination of likely-to-connect generation from the interconnection queues and historically available non-firm import data nearly eliminates the unserved energy risk calculated using the LTRA assumptions.



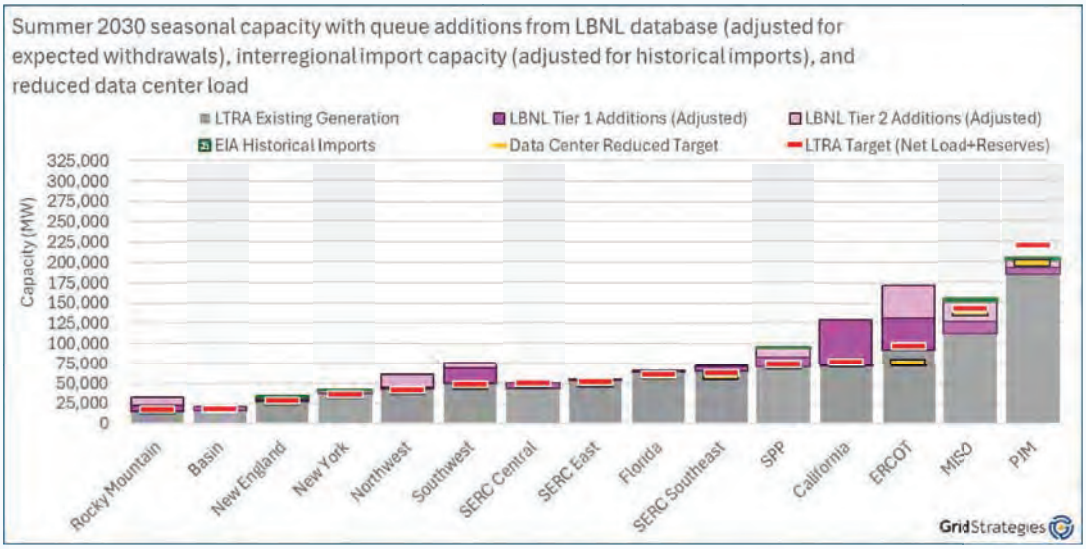
SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

Conclusions and Solutions

In this analysis, we considered different assumptions for generation resource, interregional transmission, and demand than the LTRA. The combination of all three suggest all regions could be resource adequate.

The regional seasonal resource adequacy risks identified in the 2025 NERC LTRA are all resolved when evaluated under different input assumptions:

- Including generation that is actively working through the interconnection queues in each region (Tiers 1 & 2)
- Discounting all generation nameplate capacity by the resource and region-specific accreditation methods
- Discounting generation queue data by historic regional and phase-specific withdraw rates
- Consideration of historic non-firm imports during extreme events
- Including increased interregional transfer capability capacity (albeit low likelihood of 2030 in-service date)
- Reduced data center load to account for microchip industry supply chain constraints and generation flexibility



SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Rand, J. et al. (2025)

While reduced risk is likely given different assumptions, these results should not be taken for granted. Enacting existing solutions is needed to stave off future reliability risk.



Resource supply is available to meet rising needs but is encountering roadblocks. Potential solutions include:

- More efficient interconnection queues for all resources
- Permitting certainty and reduced construction delays for needed grid infrastructure
- Adopting reforms to increase coordination between transmission planning and generator interconnection



Additional import capability would help alleviate tight reserve margins. Potential solutions include:

- Appropriately valuing the resource adequacy (capacity) contribution of interregional transmission
- Comprehensive transmission planning processes that consider both firm and non-firm imports
- Acting on NERC's recommended interregional transfer capability additions



Tightening reserve margins are driven primarily by demand growth from large source loads, such as data centers. Potential solutions include:

- Reducing the uncertainty and lack of transparency in load forecasts
- Regulatory solutions to connect large loads reliably

Methodology

The NERC LTRA assesses each region's ability to meet both its future capacity and energy adequacy needs.

NERC's LTRA importantly captures potential reliability issues for a snapshot in time. Risk is defined by tightening reserve margins—the difference between electricity demand and available supply.

In its 2025 version, NERC identified several regions* as either **High** or **Elevated** risk of not being able to meet their future capacity and energy needs.

Seasonal capacity shortfall risk: MISO, PJM, and SERC-Central (with SPP and Basin on the margin)

Extreme event energy shortfall risk: MISO, PJM, New England, New York, SERC-East, Basin, Northwest, and ERCOT

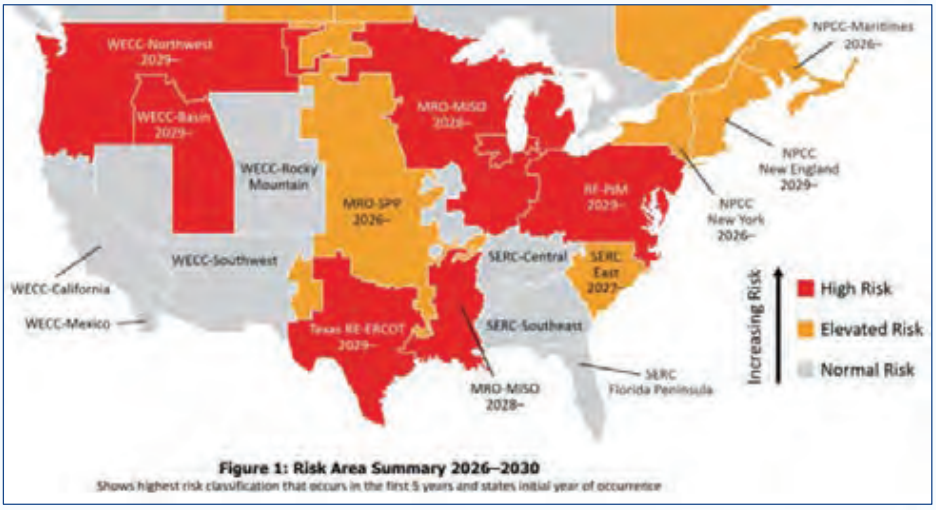


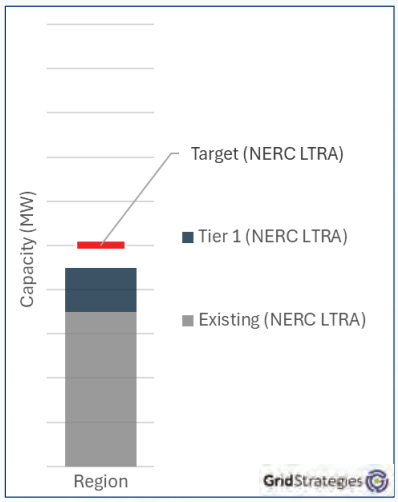
Figure 1: Risk Area Summary 2026–2030
Shows highest risk classification that occurs in the first 5 years and states initial year of occurrence

*NERC did not mark SERC-Central as elevated risk despite showing large seasonal shortfalls while SPP was marked as elevated risk despite having neither seasonal capacity shortalls nor extreme event energy shortfalls.

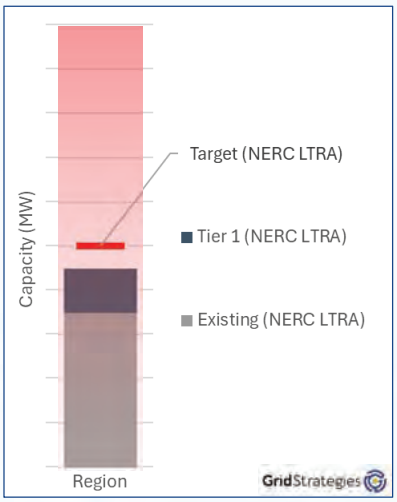
Illustrative walkthrough of seasonal capacity slides

Bar charts showing the existing (light grey) and future (dark blue) resource capacity in each region using NERC LTRA data. The target capacity (red line) is also shown. These charts were created by Grid Strategies using NERC data.

A red highlight is used to signify a shortfall between the existing + future resource capacity and the needed target to meet future load and reserves. A yellow highlight would be used to signify a "near miss."



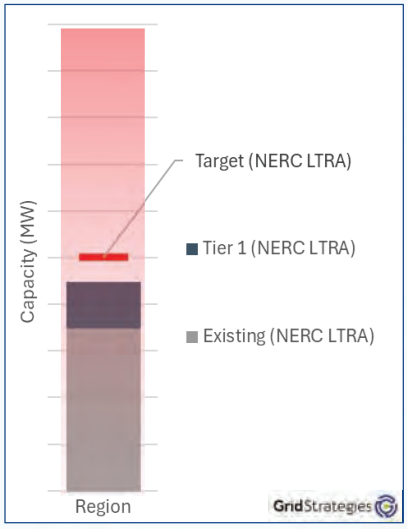
Highlight important features of chart



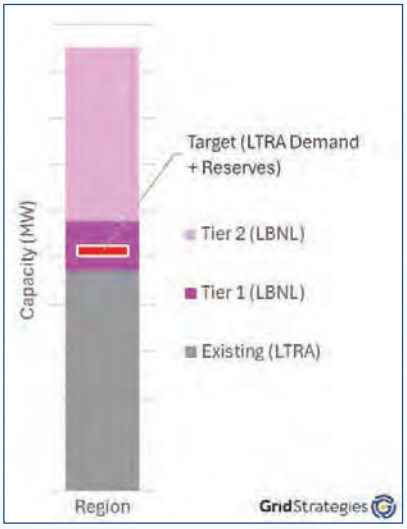
Illustrative walkthrough of seasonal capacity slides

Replace the NERC LTRA resource capacity data with accredited LBNL interconnection queue data (purple) for comparison. Existing and target data is from LTRA and remains unchanged unless specified.

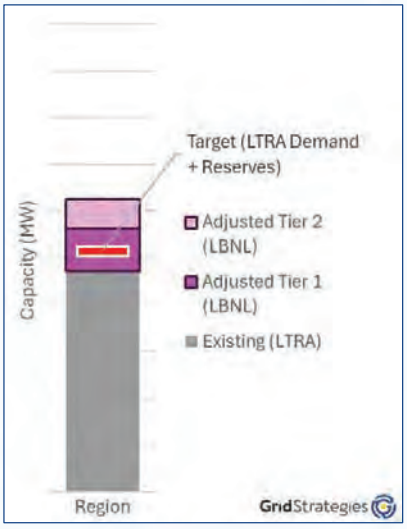
To avoid overcounting queue generation, the LBNL data is discounted based on regional- and study phase-specific withdraw rates.



Replace NERC data with resource-accredited LBNL data



Reduce LBNL data based on expected withdraws



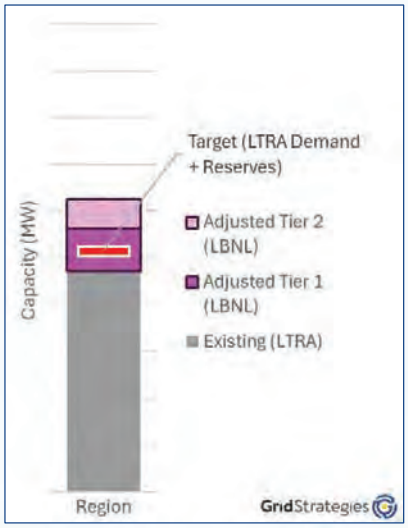
Note red highlight is removed because adequacy has been achieved

GridStrategies

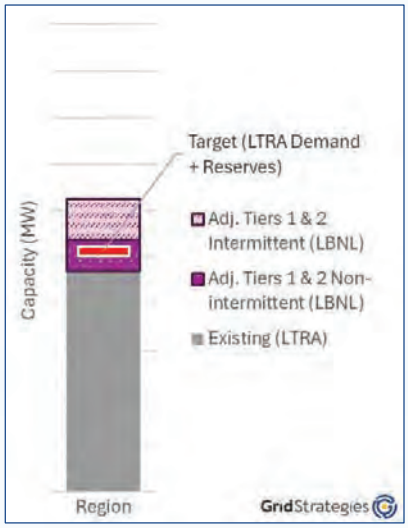
Illustrative walkthrough of seasonal capacity slides

Analyze the LBNL resource data to gain insight into future capacity risk. Purple is still used for LBNL data while different bar borders or pattern are used to indicate interesting features of the data.

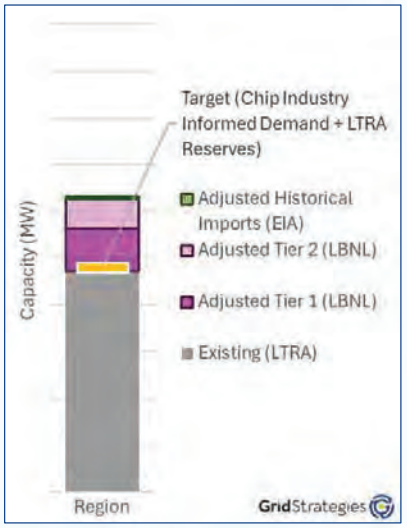
Interregional transfer capability data is adjusted using EIA data to better illustrate available capacity. In some cases, the expected load is changed to match demand forecasts from other sources.



Look at different features of LBNL data



Continue to add more data for analysis



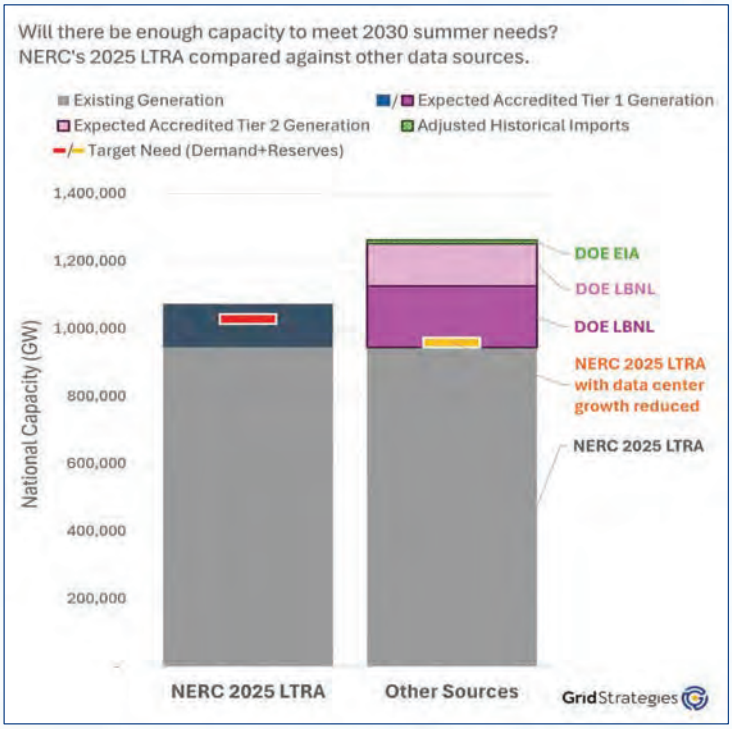
Summary slide of seasonal capacity differences in 2030

On Slide 6, the comparison of NERC 2025 LTRA analysis against our analysis using other sources is meant as an illustrative comparison of the national risk given the use of different credible data sources.

The NERC 2025 LTRA bar was made by summing the forecasted 2030 summer load + reserves (target), existing generation, and Tier 1 data for each region directly from the NERC data.

The target value shown in "Other Sources" was created by applying a one third derate to known data center load growth in all regions. The one-third derate factor is the ratio of estimated data center growth in 2030 from chip shipments to the estimated growth from utility roll-ups as used by LTRA (Wilson, J., et al. 2025). Another one-third derate factor is from the assumption that many data centers are likely to use some form of on-site generation or storage to curtail their peak demand (Thomas, M., 2026). The known data center load growth is from Grid Strategies analysis of total system load growth that is attributable to data centers (Wilson, J., et al. 2025). The impact of this data center growth reduction scenario on individual regions is shown in slide 24.

The generation resources shown in "Other Sources" is the sum of resources available in the LBNL dataset that are reasonably expected to connect by 2030. Adjusted historical imports represent the non-firm imports that have been available during grid stress events from the Energy Information Administration. More detail on the other sources data is provided in subsequent slides.



SOURCE | NERC "2025 LTRA" (2026); NERC "ES&D" (2026); Wilson, J., et al. (2025); Thomas, M. (2026); Rand, J. et al. (2025); EIA, "About the EIA-930 data" (accessed Feb. 2026)

Analysis using LBNL data: Regional assessment areas

The DOE's Lawrence Berkeley National Laboratory collects data from the generation interconnection queues for seven ISOs / RTOs and 49 non-ISO balancing areas (including utilities and Power Marketing Administrations), representing roughly 97% of currently installed U.S. generating capacity. This data is compiled annually with help from Interconnection.fyi and is posted for public view at emp.lbl.gov/queues. The 2025 dataset includes data through the end of 2024.

The 56 entities in the LBNL database were mapped to the NERC LTRA assessment areas by geography (maps to the right). The non-RTO utilities were mapped as follows:

WECC California
- LADWP
- SMUD
- WAPA-SN

WECC Rocky Mtn
- CLPT
- BHCT
- CSU
- PacifiCorp
- PRPA
- PSCo
- TSGT
- WAPA-RM

WECC Northwest
- Avista
- BHP
- BPA
- CPUD
- GrantPUD
- MPC
- NWMT
- PGE
- PSE
- TPU
- WAPA-IS

WECC Basin
- IdahoPower

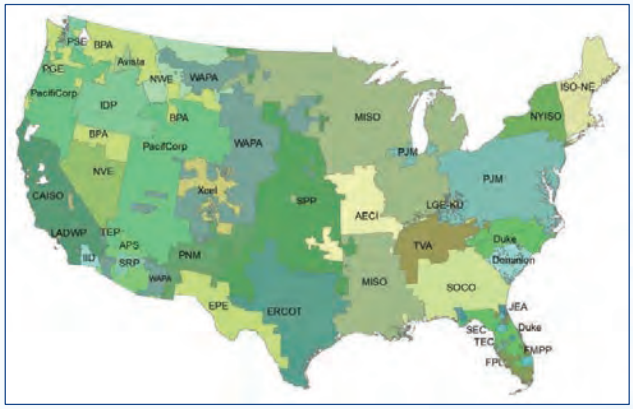
WECC Southwest
- APS
- EPE
- IID
- N-C
- NVE
- PNM
- SRP_ANPP
- SRP
- SRP_Gila
- SRP_PV-PC
- SRP_SWV
- TEP
- WAPA-DSW
- WAPA-MPP

SERC Central
- AEC
- LGE-KU
- TVA

SERC Southeast
- GTC
- SOCO

SERC Florida
- OUC
- TEC
- Duke (FL)

SERC East
- Dominion
- S-C
- Duke (non-FL)



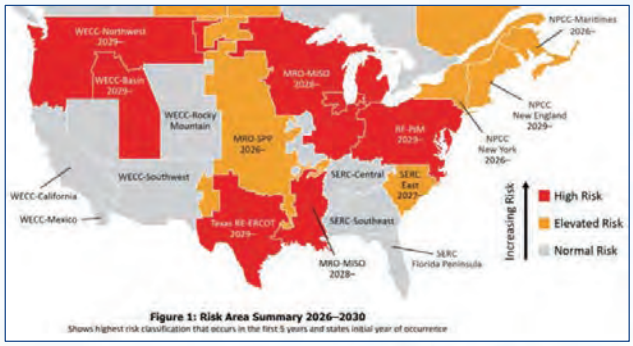


Figure 1: Risk Area Summary 2026–2030
Shows highest risk classification that occurs in the first 5 years and states initial year of occurrence

SOURCE | NERC "2025 LTRA" (2026) and Rand, J. et al. (2025)

Analysis of LBNL data: Generation tier status

LBNL interconnection data is organized by its queue status and study phase in the interconnection queues. Queue status refers to if the facility is completed, withdrawn, or actively progressing through the queues.

NERC organizes in-development generation resources by Tiers, where:

- Tier 1 are resources with executed interconnection agreements
- Tier 2 are any resource that is in the study process, and
- Tier 3 are those that have submitted interconnection requests but are not yet under study.

The cross-walk between LBNL's "Queue Status" and "IA Status Clean" fields and the NERC Tiers used in this analysis are shown to the right. Interconnection requests marked as Active in the Queue Status are organized into Tiers based on their IA Status.

Resources considered in to be in advanced Tier 2 status were those with either "IA Pending" or "Facility Study" status in the LBNL data. Suspended interconnection requests are considered Tier 2 because they have already completed some study phases but have paused their continuation of progress. Requests that un-pause often enter at the same study stage. Requests of Unknown or N/A status are considered Tier 3 because their existence in the database indicates an interconnection request has been made, but whether studies have begun cannot be said for sure.

LBNL Queue Status	NERC Tier
Active	(see IA Status)
Withdrawn	Cancelled
Operational	Operational
Suspended	Tier 2
Unknown	Tier 3

LBNL IA Status Clean	NERC Tier
Withdrawn	Cancelled
Operational	Operational
IA Executed	Tier 1
Construction	Tier 1
IA Pending	Tier 2
Facility Study	Tier 2
Cluster Study	Tier 2
System Impact Study	Tier 2
Feasibility Study	Tier 2
Combined	Tier 2
In Progress (unknown study)	Tier 2
Suspended	Tier 2
Not Started	Tier 3
N/A	Tier 3

SOURCE | NERC "2025 LTRA" (2026) and Rand, J. et al. (2025)

Analysis using LBNL data: Expected withdraw rates

To reduce the likelihood of overcounting generation resources that may not interconnect, we reduced all Tier 1 and 2 resource data in the LBNL queue dataset given region- and status-specific historic withdraw rates.

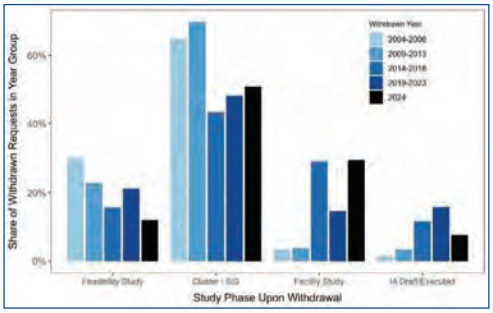
LBNL publishes the completion rates (as of 2024) of all resources in the regional queues that entered the queue between 2000 and 2019. The withdraw rates vary regionally between 64% and 85%. LBNL also provides information about the queue study phase that projects were in when they withdrew. In general, fewer projects withdraw once they reach advanced stages of the interconnection queue process.

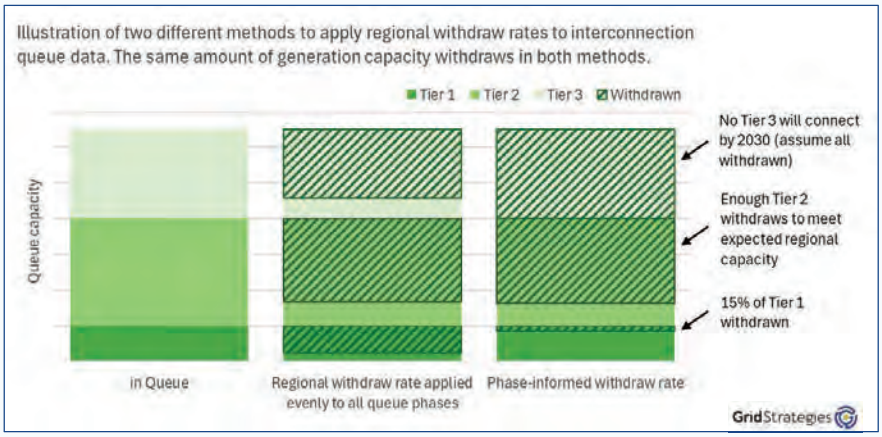
Applying the regional withdraw rates to all generation without regard for its queue location would overly discount generation in Tier 1 and advanced Tier 2 status. Instead, we adjust the amount of generation that is expected to withdraw from each Tier separately. See illustrative figure to the bottom right.

We first calculate the total amount of expected regional withdraws by applying the appropriate withdraw rate to the sum of all Tiers 1, 2, and 3 generation in each region's queue. We assume that 15% of generation in Tier 1 status will withdraw, equivalent to the share of withdrawn requests between 2019 – 2023 in the IA executed phase from LBNL's analysis. Because no generation in Tier 3 is expected to interconnect by 2030, we assume 100% of Tier 3 generation withdraws for every region. The difference between the total amount of expected regional withdraws and that which is assumed to withdraw from Tiers 1 and 3 in each region is applied to the Tier 2 data.

LBNL: Historical completion by region for requests submitted 2000-2019 (as of 2024)

Region	Active	Operational	Withdrawn
CAISO	14%	9%	77%
ERCOT	14%	22%	64%
ISO-NE	8%	18%	74%
MISO	9%	15%	76%
NYISO	7%	8%	85%
PJM	8%	14%	77%
SPP	9%	14%	76%
Southeast	5%	9%	85%
West	13%	9%	79%





SOURCE | Rand, J., et al. (2025)

Analysis using LBNL data: Resource type

LBNL interconnection data is organized by generation resource type. When multiple resource types (e.g., gas and battery storage) are combined into one interconnection request, LBNL lists each resource type. The LBNL database includes a "type_clean" field, which summarizes all types of resources included in the interconnection entry.

These "clean" resource types are organized into a fewer number of categories in our analysis for simplicity. The cross-walk is provided in the two tables to the right.

LBNL Clean Type	Resource Type
Battery	Battery
Offshore Wind+Battery	Battery Hybrid
Other+Battery	Battery Hybrid
Solar+Battery	Battery Hybrid
Solar+Other+Battery	Battery Hybrid
Solar+Wind+Battery	Battery Hybrid
Wind+Battery	Battery Hybrid
Geothermal	Geothermal
Solar+Other	Hybrid
Solar+Wind	Hybrid
Wind+Other	Hybrid
Hydro	Hydro
Offshore Wind	Offshore Wind
Other	Other
Hydrogen	Other Storage
Other Storage	Other Storage
Solar	Solar
Battery+Other Storage	Storage Hybrid
Other+Battery+Other Storage	Storage Hybrid
Solar+Battery+Other Storage	Storage Hybrid
Solar+Wind+Other Storage	Storage Hybrid
Wind	Wind

LBNL Clean Type	Resource Type
Coal	Coal
Gas+Battery	Firm Hybrid
Gas+Battery+Diesel	Firm Hybrid
Gas+Coal	Firm Hybrid
Gas+Diesel	Firm Hybrid
Gas+Oil	Firm Hybrid
Gas+Other	Firm Hybrid
Geothermal+Battery	Firm Hybrid
Hydro+Battery	Firm Hybrid
Oil+Battery	Firm Hybrid
Oil+Coal	Firm Hybrid
Oil+Other	Firm Hybrid
Other+Coal	Firm Hybrid
Other+Diesel	Firm Hybrid
Solar+Diesel	Firm Hybrid
Solar+Gas	Firm Hybrid
Solar+Gas+Battery	Firm Hybrid
Solar+Geothermal	Firm Hybrid
Solar+Hydro	Firm Hybrid
Wind+Gas	Firm Hybrid
Gas	Gas
Diesel	Oil
Oil	Oil
Nuclear	Nuclear

SOURCE | NERC "ES&D" (2026) and Rand, J. et al. (2025)

Analysis using LBNL data: Accredited capacity

No resource will produce electricity at its rated capacity ("nameplate") all the time. To account for this, regions apply an accredited value to a resource to indicate a percentage of the nameplate capacity that can be expected to perform during peak demand. The accredited value of a resource varies by fuel type, season, year, and geographic location.

Each region calculates accredited capacity differently. Some consider historic forced outages of a resource type (which tend to overestimate availability) while others use modeling tools to determine how much load a resource can be expected to carry in future years given numerous system dynamics.

The LBNL interconnection queue database provides nameplate values for all generators in the queues. To ensure only a reasonable amount of new resources are accounted for in our analysis, we seasonally accredit each resource type based on the region-specific method used locally for resource accreditation. If a region does not use seasonal or resource-specific accreditation, a neighboring region's method is used.

Unless otherwise noted:

- Battery Hybrid resources are equivalent to battery resources' accredited values
- Firm Hybrid resources are the average of firm resources' accredited values
- Hybrid resources are the average of wind and solar resources' accredited values
- Other resources are the average of any remaining resources' accredited values not otherwise listed

Region	Accreditation Method & Source	Notes
MISO	2025-2026 DLOL	Summer & winter values. Battery resource uses storage (blended) and storage hybrid uses pumped storage DLOL. MISO values are also used for all other regions' resources that are not otherwise noted.
SPP	ELCC for Summer 2026	Summer values for battery (6-hr), solar, and wind resources. Values also used for WECC-Basin & CAISO summer battery.
SPP	ELCC for Winter 24/25	Winter values for battery (6-hr), solar, and wind resources. Values also used for WECC-Basin & CAISO summer battery.
SPP	25/26 EFORd	Summer & winter values used for all non variable resources. Oil and other resources are RICE with on-site storage, gas is CC. Values also used for ERCOT other; WECC summer other storage.
ISO-NE	CAR-SA: Impact Analysis 1/14/26	Summer & winter values. Used for solar, wind, and hydro resources
ISO-NE	2025 Capacity, Energy, Loads, and Transmission (CELT) Report	Summer & winter values. CELT used for battery, battery hybrid, coal, gas, nuclear, offshore wind, oil, other, and other (pumped) storage resources.
NYISO	2025-2026 Final Capacity Accreditation Factors	Summer values used for both seasons. Rest of state values used for battery (6-hour), hydro, offshore wind, other, other storage (pumped storage), solar, wind.
NYISO	2024 Review of EFORd	Summer & winter values. NYCA values used for coal (steam turbine), gas (CC), nuclear (steam turbine), oil (jet engine). NYISO values are also used for SERC-E summer battery and summer wind.
PJM	2027/2028 ELCC Class Ratings	Summer values used for both seasons for all resources. Battery is 6-hour CSR, battery hybrid is configuration 3, gas is CC, other is waste-to-energy, other storage is other unlimited resources, solar is fixed-tilt, storage hybrid is configuration 1. PJM values also used for SERC-E hydro, nuclear, oil, other, and other storage resources.
ERCOT	25/29 CDR	Summer & winter values for battery (6-hr), other storage (12-hr), solar, and wind. Values also used for SERC-FP and SERC-SE battery.
SERC	2025 CRP Chapter 3	Winter values used for both seasons. 2030 Reference case used for battery (standalone BESS), battery hybrid (synergistic BESS), offshore wind (avg. ELCC for first 800MW), solar (avg. ELCC for first 10 GW of standalone), wind (avg. ELCC for DEP and DEC for first 300 MW).
SERC	2023 Wind ELCC Study	Average ELCC of 5GW and 15GW standalone solar used for all SERC regions' summer solar.
Southwest	E3 2023 Resource Adequacy in the Desert Southwest	2033 values also used for WECC regions' winter battery, summer hydro, summer nuclear, winter and summer wind (unless otherwise stated).
Northwest	E3 2025 Resource Adequacy and the Energy Transition in the Pacific Northwest: Phase 1 Results	Winter values for Greater Northwest used for WECC regions' gas, other storage, solar, wind (unless otherwise stated).
Northwest	E2 2019 Resource Adequacy in the Pacific Northwest	Winter values for 2030 Reference scenario used for WECC regions' coal, geothermal, hydro, nuclear (unless otherwise stated).
CAISO	2026 Net Qualifying Capacity (NQC) for RA Resources	Summer and winter values used for CAISO geothermal, hydro, other (biomass), solar, wind. Values also used for other WECC regions' other, solar, hydro and geothermal (unless otherwise stated).
National	NREL VRE ELCC Study	Median offshore wind used for SERC-FP (SERC), ERCOT, WECC-NW (NorthernGrid), CAISO

Adding historically available interregional transfer capability to the seasonal capability analysis

The EIA historical imports included in the charts on slides 16 and 29 take the difference between the historical import availability (2015 and 2025) from the U.S. EIA Form 930 data and the 2030 firm import assumptions in the LTRA. The last column subtracts imports from demand in all peak hours over the last decade and shows the minimum reduction in in-region generation due to imports.

For New York, an additional 1,250 MW of import availability was added to the EIA Form 930 data to account for the energization of the Champlain Hudson Power Express transmission line.

Comparison of on-peak net imports in four regions as assumed by LTRA against actual, in MW. Exports are negative.

	LTRA 2026 Assumption	LTRA 2030 Assumption	Historical Availability (2015-2025)
MISO	2,809	2,509	5,344
SPP	-18	-78	1,421
ISONE*	567	84	2,464
NYISO	3,405	3,486	2,730†
PJM	3,840	0	2,937‡

*Data for New England (ISONE) predates completion of the 1200 MW New England Clean Energy Connect with Hydro Quebec, so on-peak imports will likely be higher going forward.

† EIA data for New York does not include the Champlain Hudson Power Express, a 1,250 MW line connecting Quebec to New York City that is slated for completion in 2026. Once that is included, NYISO imports should be roughly in line with the LTRA.

‡ The EIA data show PJM was exporting during most peak demand periods over the last decade, so it is not possible to estimate the historical availability of imports for PJM. PJM administratively sets its capacity benefit of ties (non-firm imports) at 1.5% of nameplate generation procured in the capacity market, calculated here as 1.5% for 195,831 MW in the 2025/2026 Base Residual Auction. In its 2023 reserve margin analysis, PJM calculated 6,474 MW in total diversity benefit with its neighbors, much higher than the capacity benefit of ties shown in the table.

SOURCE | EIA, "About the EIA-930 data" (accessed Feb. 2026); PJM, "2025/26 Base Residual Auction Report" (2024); Brooks, A. et al. (2025)

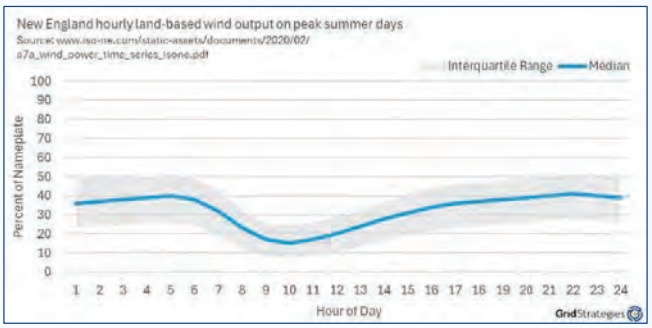
Analysis using LBNL data: New England wind and solar production

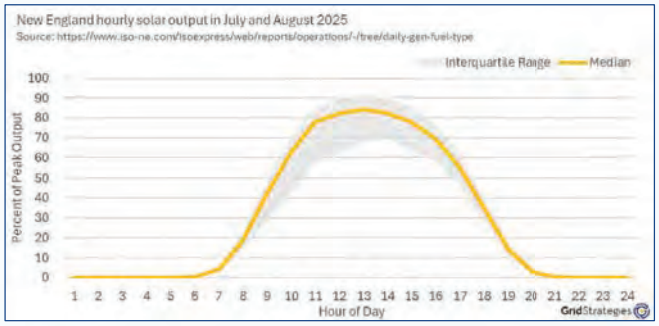
In order to use LBNL data for energy analysis for New England, we compare the amount of Tier 1 and Tier 2 LBNL data against NERC (slide 46). This required an understanding of the generation output in New England during summer months for different resource types.

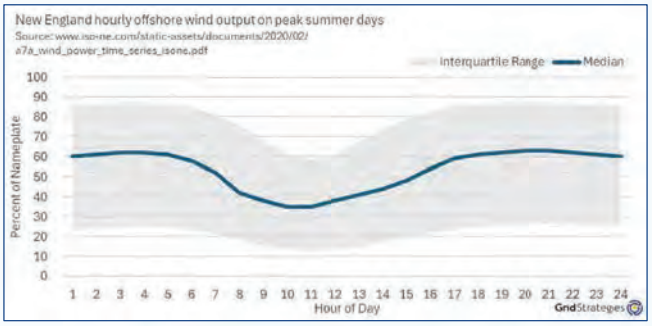
On the right are the hourly median and interquartile range for wind and offshore wind production in New England during peak demand days. This data was collected between 2012 and 2018 by ISONE to help them understand wind output during times of grid stress.

Also shown is the median and interquartile range for average hourly solar output in July and August of 2025, also from data collected by ISONE.

The hourly median data was used to estimate the output of both land-based and offshore wind in New England during peak summer 2029.







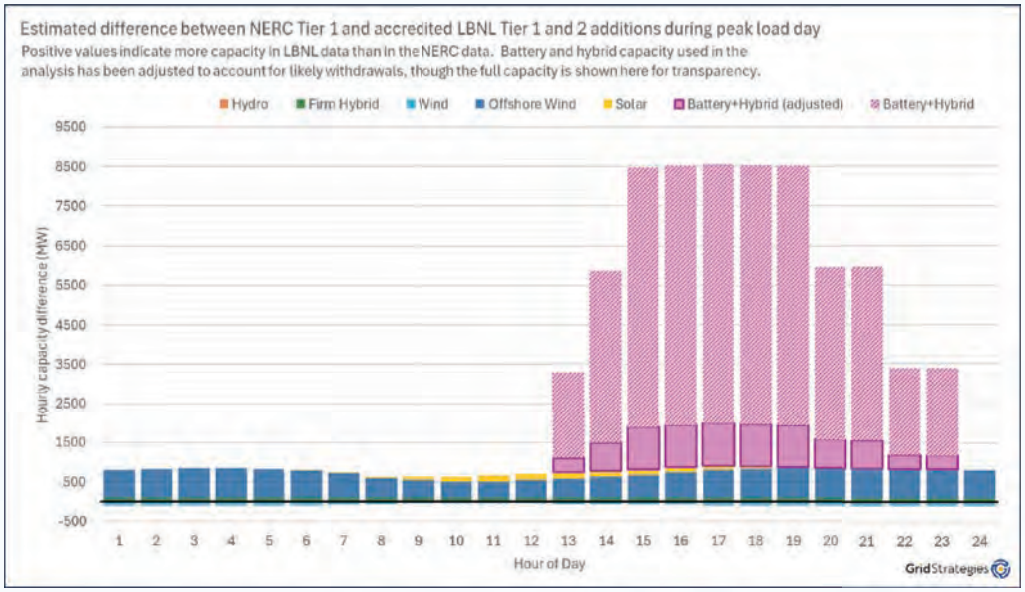
SOURCE | Judd, S. "Wind and Power Time Series Modeling of ISO-NE Wind Plants" (2020); ISONE "2025 Hourly Solar Generation" (2026)

Analysis using LBNL data: New England hourly production

Shown here is the potential change in hourly energy output for New England on peak load days given the different resource mixes between the LBNL and NERC data. Positive values indicate LBNL recorded more capacity for that resource type while negative values indicate NERC recorded more capacity.

As explained on slide 45, we adjusted the hourly production of each resource type to match expected peak day behavior, given regional resource accreditation methods. Battery and battery hybrid resources are expected to discharge at partial capacity for all hours of unserved energy, modulating their output so that no one resource discharges for longer than 6 hours. Given the large quantity of battery and hybrid resources in the LBNL data, these resources were additionally discounted by the historic withdraw rate of the region.

Given the data available, we cannot replicate the energy inadequacy analysis presented in the LTRA exactly. We provide this rough estimate to understand how different generation assumptions would impact unserved energy results.



GridStrategies

SOURCE | NERC "2025 LTRA" (2026); NERC "2024 LTRA" (2025); NERC "ES&D" (2026); Rand, J. et al. (Aug. 2025)

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

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[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]

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[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]

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[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

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[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"

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[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 years[38] 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

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[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

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[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

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[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

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[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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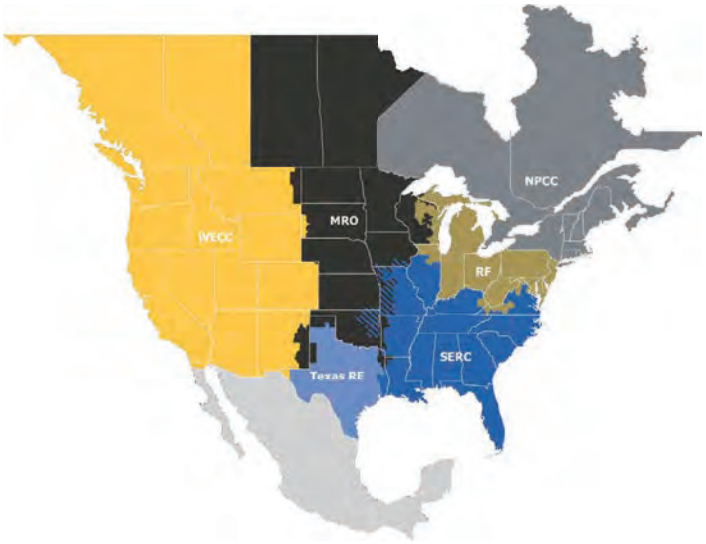
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Preface

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.

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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.

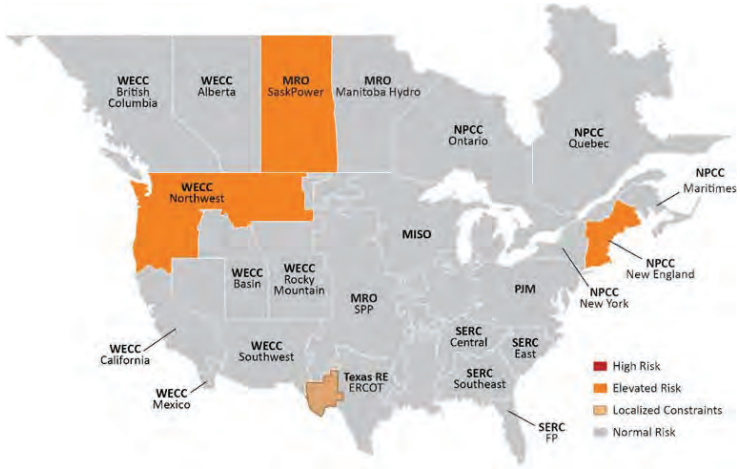
Resource Adequacy Assessment and Energy Risk Analysis

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 Appalaches 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

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 snowpack[5] 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 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 loads[7] 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/rrm/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

- **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 9.4ºF 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.

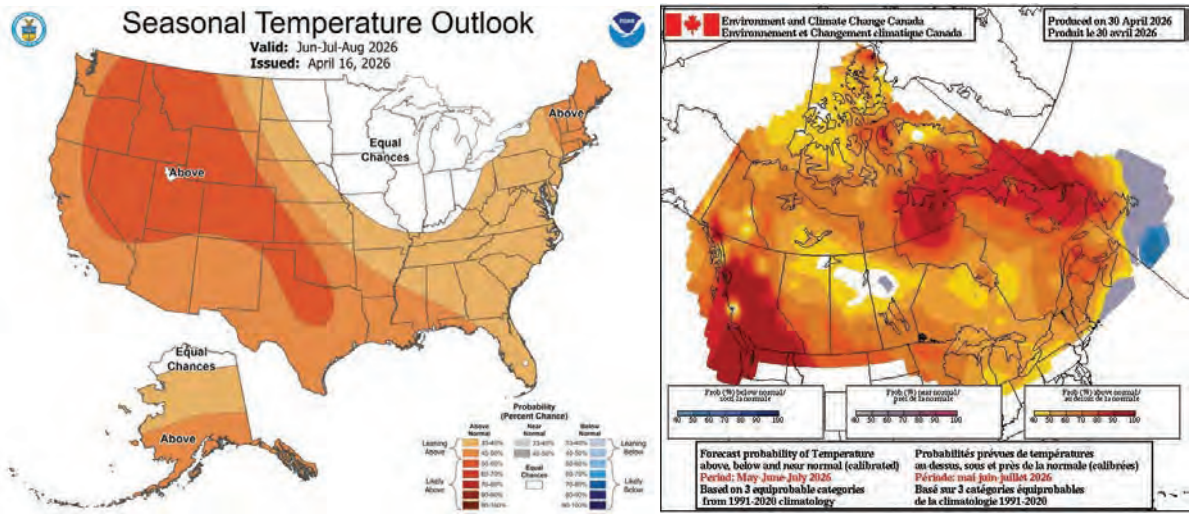


Figure 2: United States and Canada Summer Temperature Outlook[15]

[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.

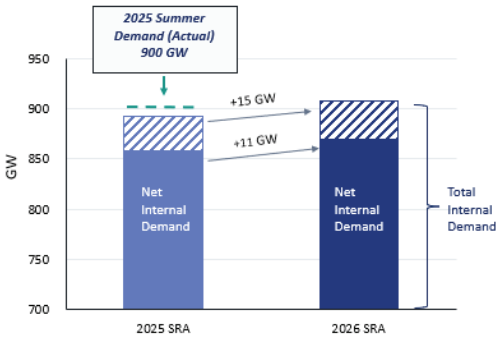


Figure 3: BPS Total and Net Internal Demand
Aggregated Peak Demand from All Assessment Areas

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.

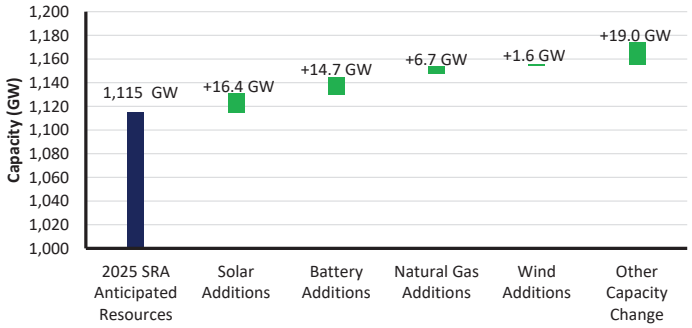


Figure 4: Summer BPS Resource Capacity Change Since 2025

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 Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels • Probabilistic indices exceed benchmarks (e.g., LOLH of 2 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 scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours 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 scenarios**[2] (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 scenarios**[3] (i.e., extreme outage and derate scenarios)
Normal Sufficient operating reserves expected	• 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 scenarios[4]

Table Notes:
[1] The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2] **Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the 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

dashboard 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 of1.178 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

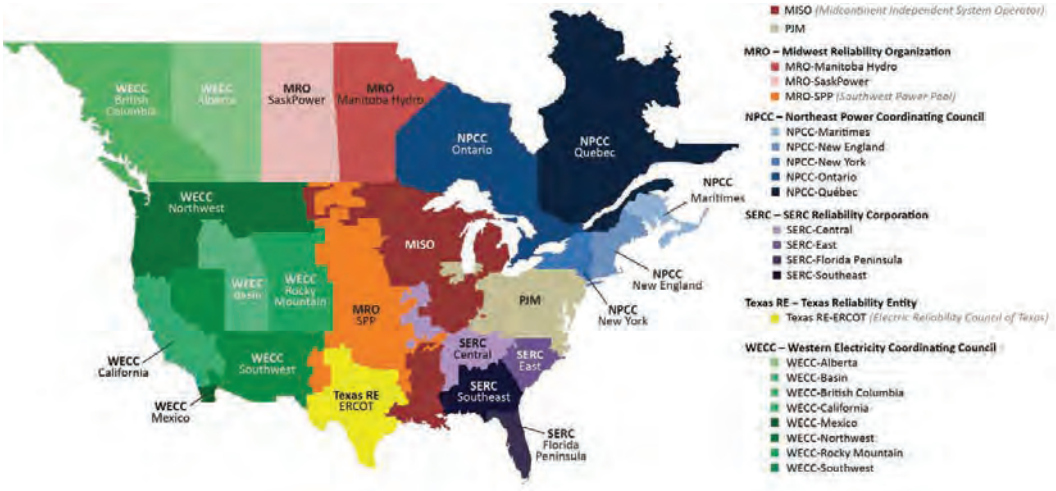
Assessment Area	Type of Assessment	Results and Insight from Assessment
NPCC-New York		The preliminary results of NPCC's probabilistic assessment indicate that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if 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 SERVM 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, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

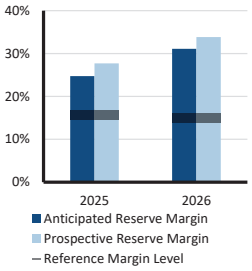
Highlights

- 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.

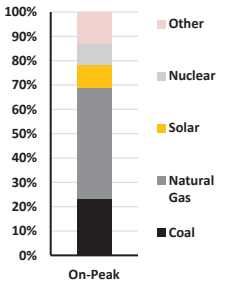
Risk Scenario Summary

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.

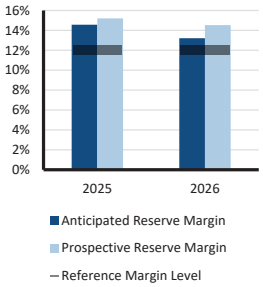
Highlights

- 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.

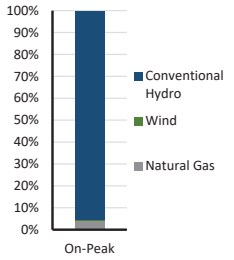
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

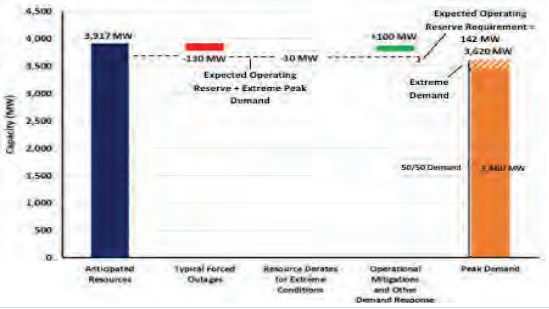
On-Peak Reserve Margin



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.



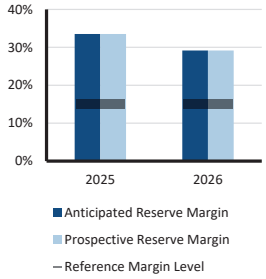
MRO-SaskPower

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.

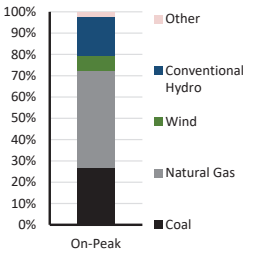
On-Peak Reserve Margin



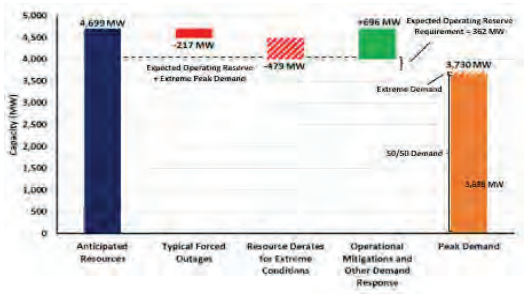
Risk Scenario Summary

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.

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.

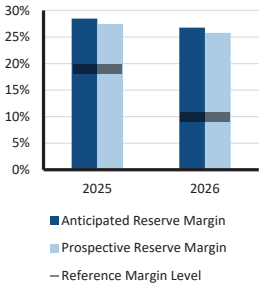
Highlights

- 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.

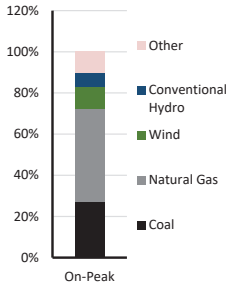
Risk Scenario Summary

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.

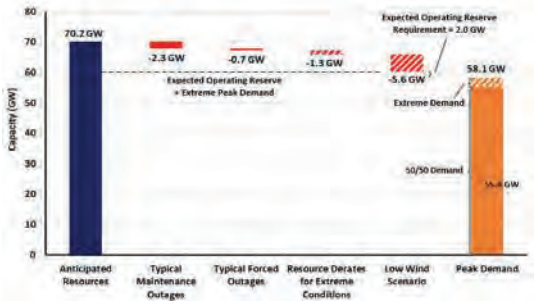
On-Peak Reserve Margin



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.

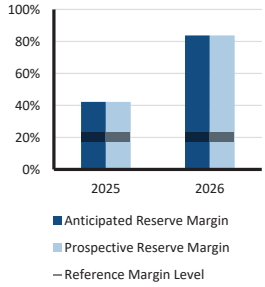
Highlights

- 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.

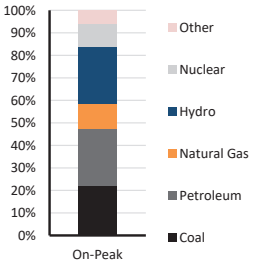
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

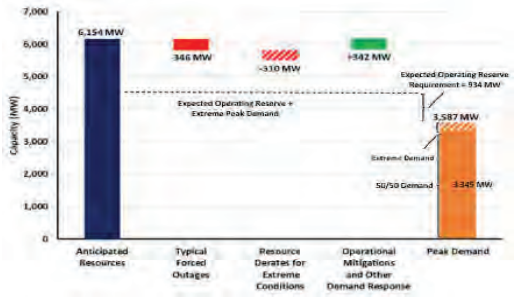
On-Peak Reserve Margin



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

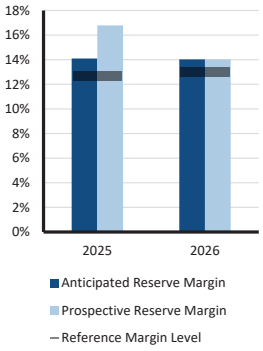
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New 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 Appalaches 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.

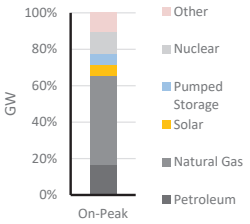
On-Peak Reserve Margin



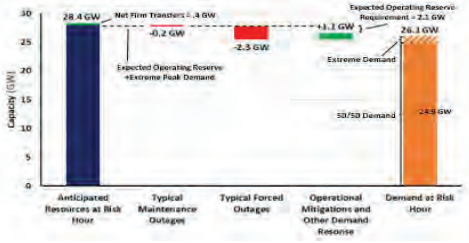
Risk Scenario Summary

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.

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%.

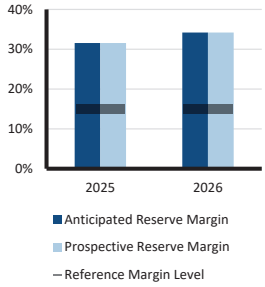
Highlights

- 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

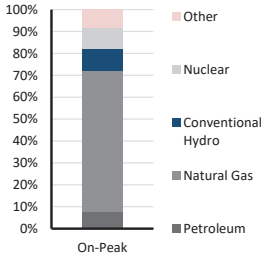
Risk Scenario Summary

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.

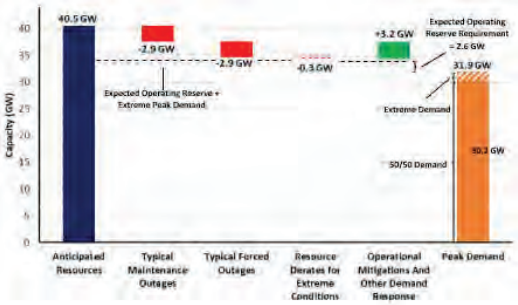
On-Peak Reserve Margin



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.

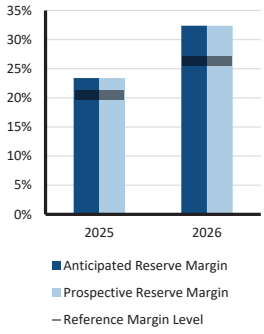
Highlights

- 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.

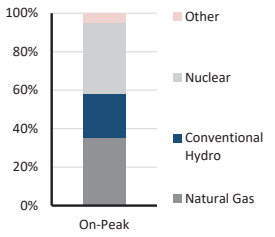
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

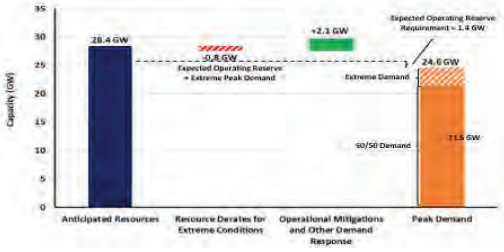
On-Peak Reserve Margin



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.

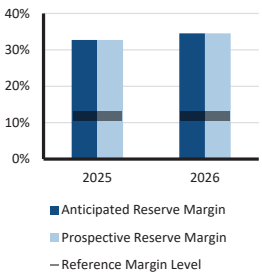
Highlights

- 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.

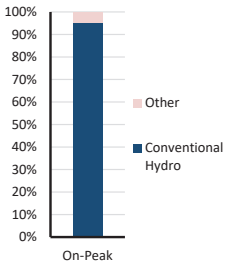
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

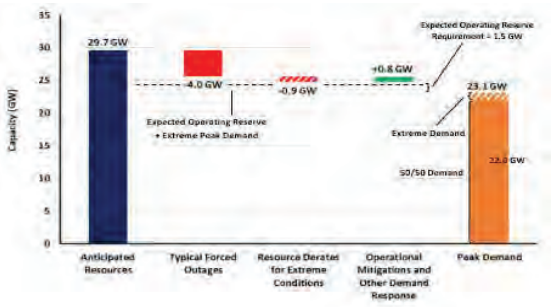
On-Peak Reserve Margin



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.



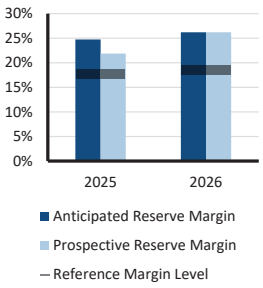
PJM

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.

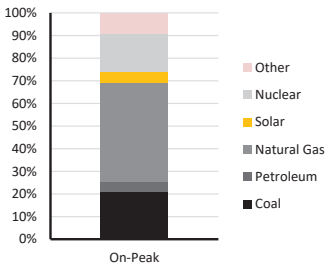
On-Peak Reserve Margin



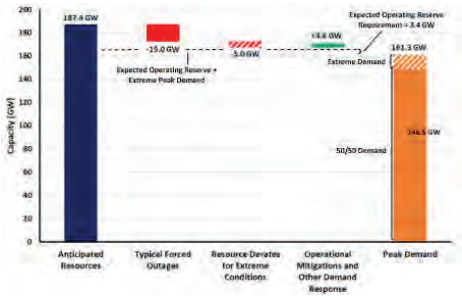
Risk Scenario Summary

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.



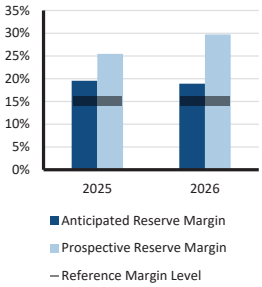
SERC-Central

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.

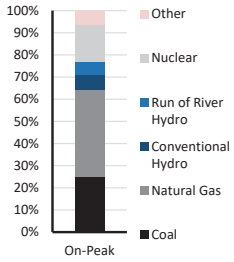
On-Peak Reserve Margin



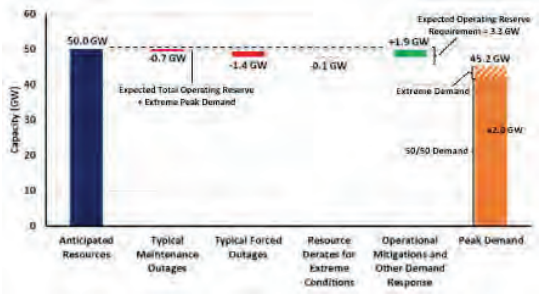
Risk Scenario Summary

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.



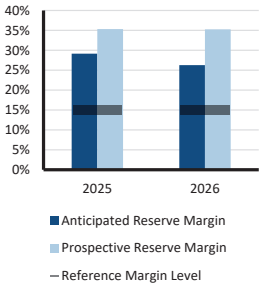
SERC-East

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.

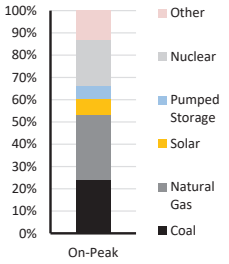
On-Peak Reserve Margin



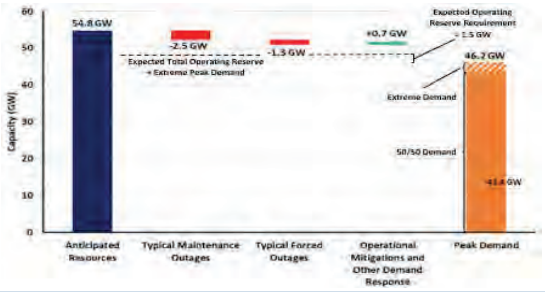
Risk Scenario Summary

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.



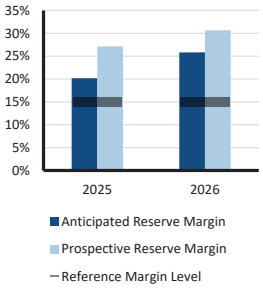
SERC-Florida Peninsula

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.

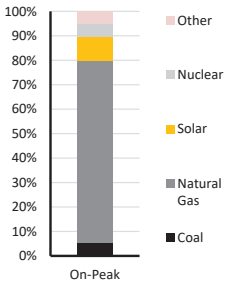
On-Peak Reserve Margin



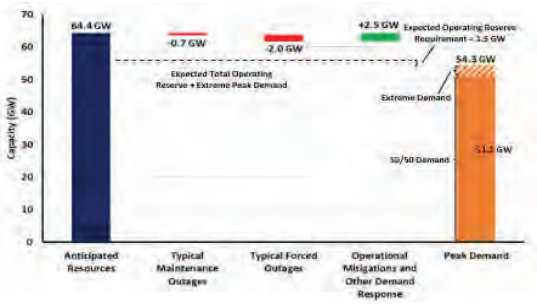
Risk Scenario Summary

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.



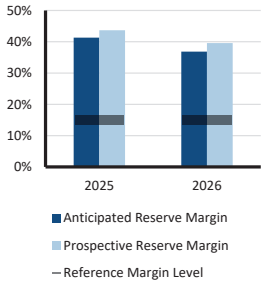
SERC-Southeast

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.

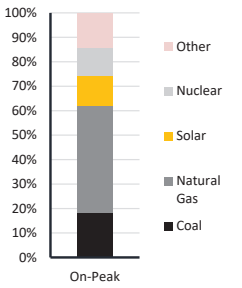
On-Peak Reserve Margin



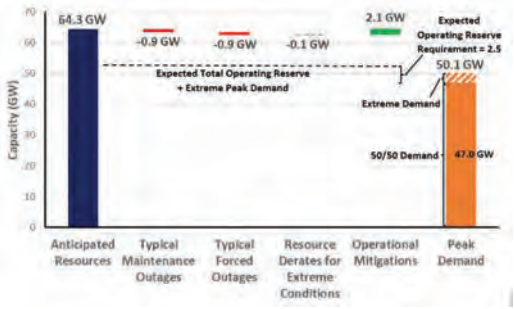
Risk Scenario Summary

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.



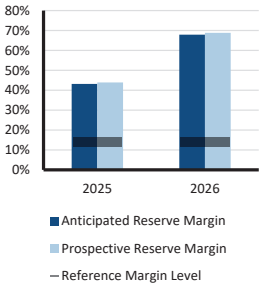
Texas RE-ERCOT

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.

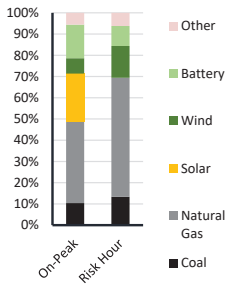
On-Peak Reserve Margin



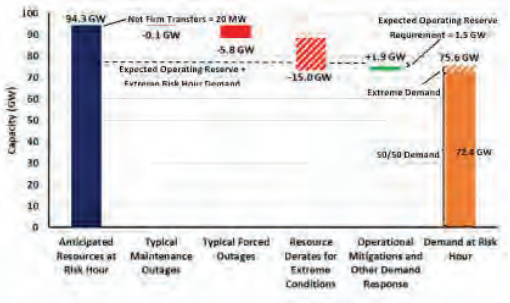
Risk Scenario Summary

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.



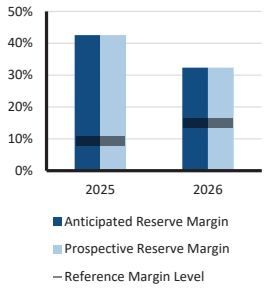
WECC-Alberta

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.

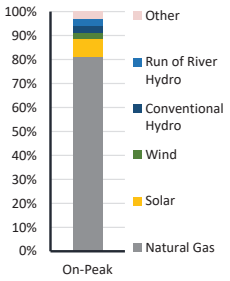
On-Peak Reserve Margin



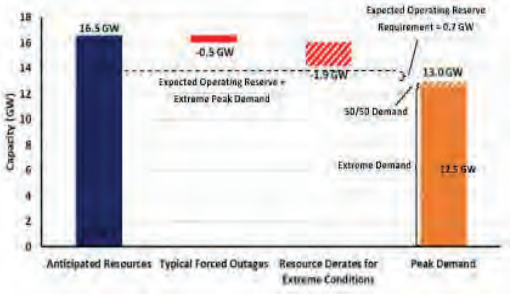
Risk Scenario Summary

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.



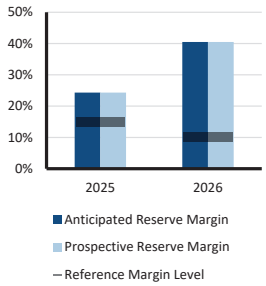
WECC-Basin

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%

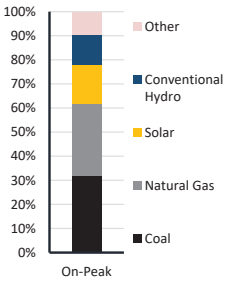
On-Peak Reserve Margin



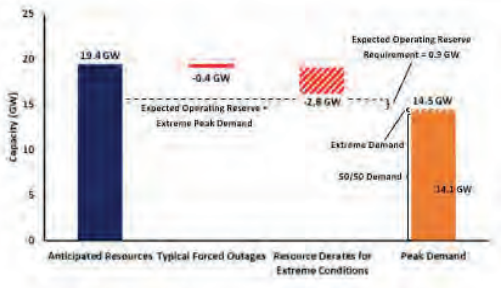
Risk Scenario Summary

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.



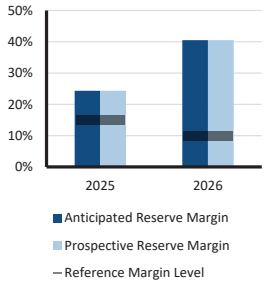
WECC-British Columbia

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.

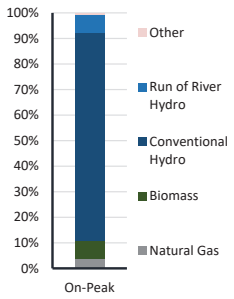
On-Peak Reserve Margin



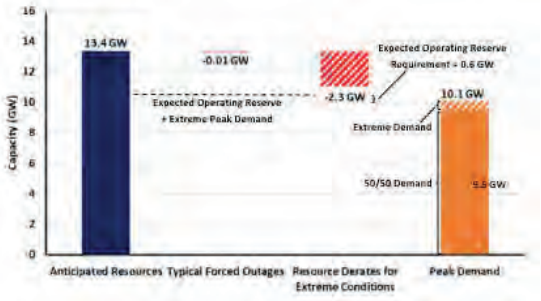
Risk Scenario Summary

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.



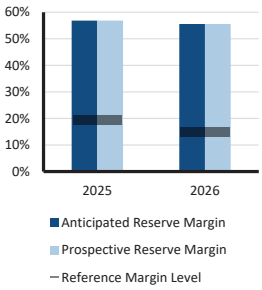
WECC-California

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.

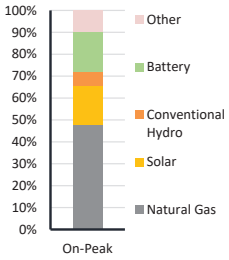
On-Peak Reserve Margin



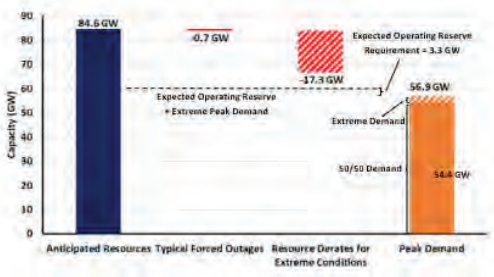
Risk Scenario Summary

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 SERVM 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.



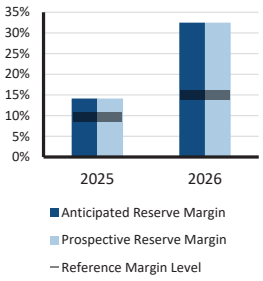
WECC-Mexico

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.

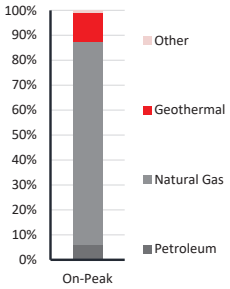
On-Peak Reserve Margin



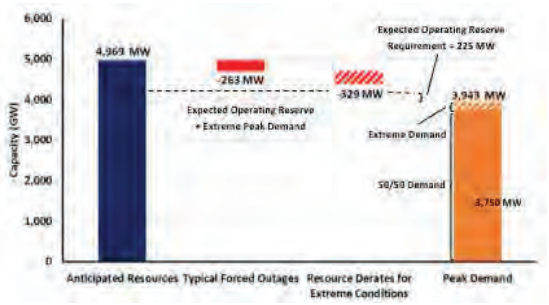
Risk Scenario Summary

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.

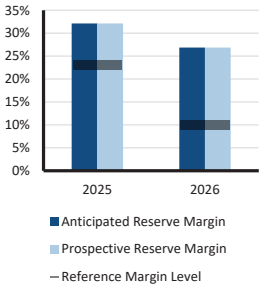
Highlights

- 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.

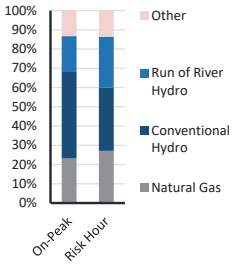
Risk Scenario Summary

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.

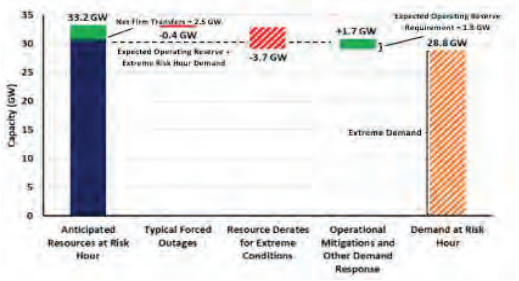
On-Peak Reserve Margin



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.



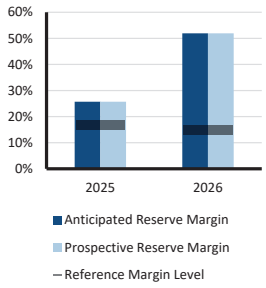
WECC-Rocky Mountain

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.

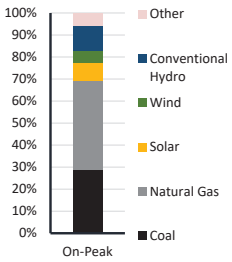
On-Peak Reserve Margin



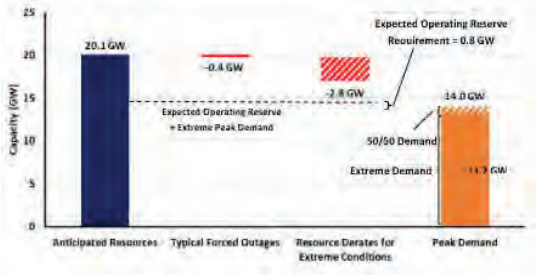
Risk Scenario Summary

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.



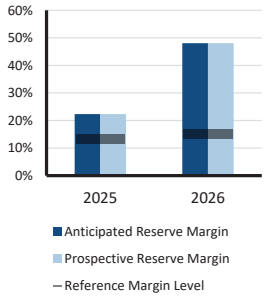
WECC-Southwest

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.

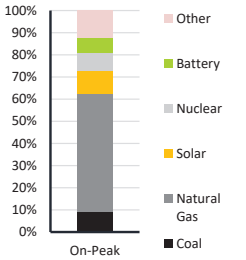
On-Peak Reserve Margin



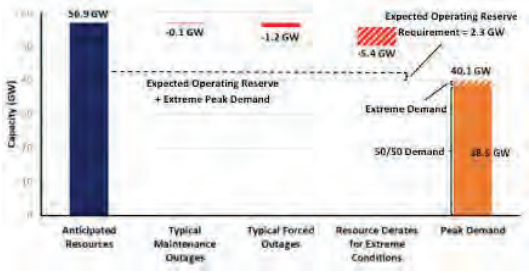
Risk Scenario Summary

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 load[17] 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 coincident[20] 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**.

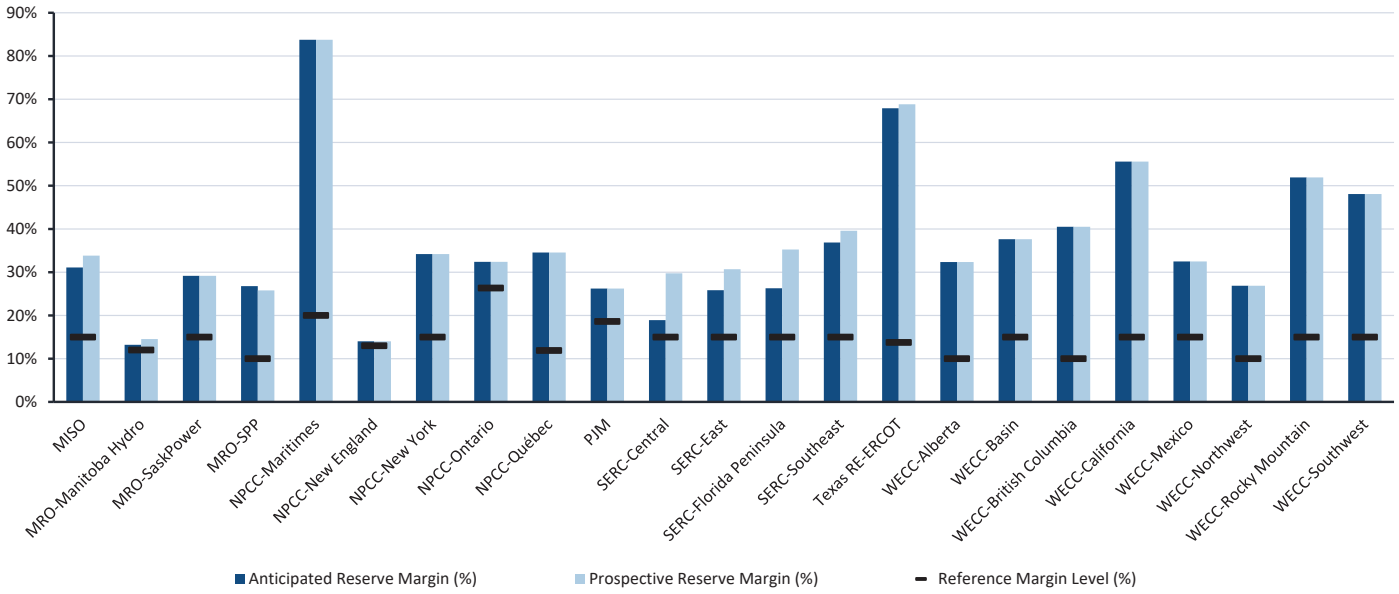


Figure 5: Summer 2026 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[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.

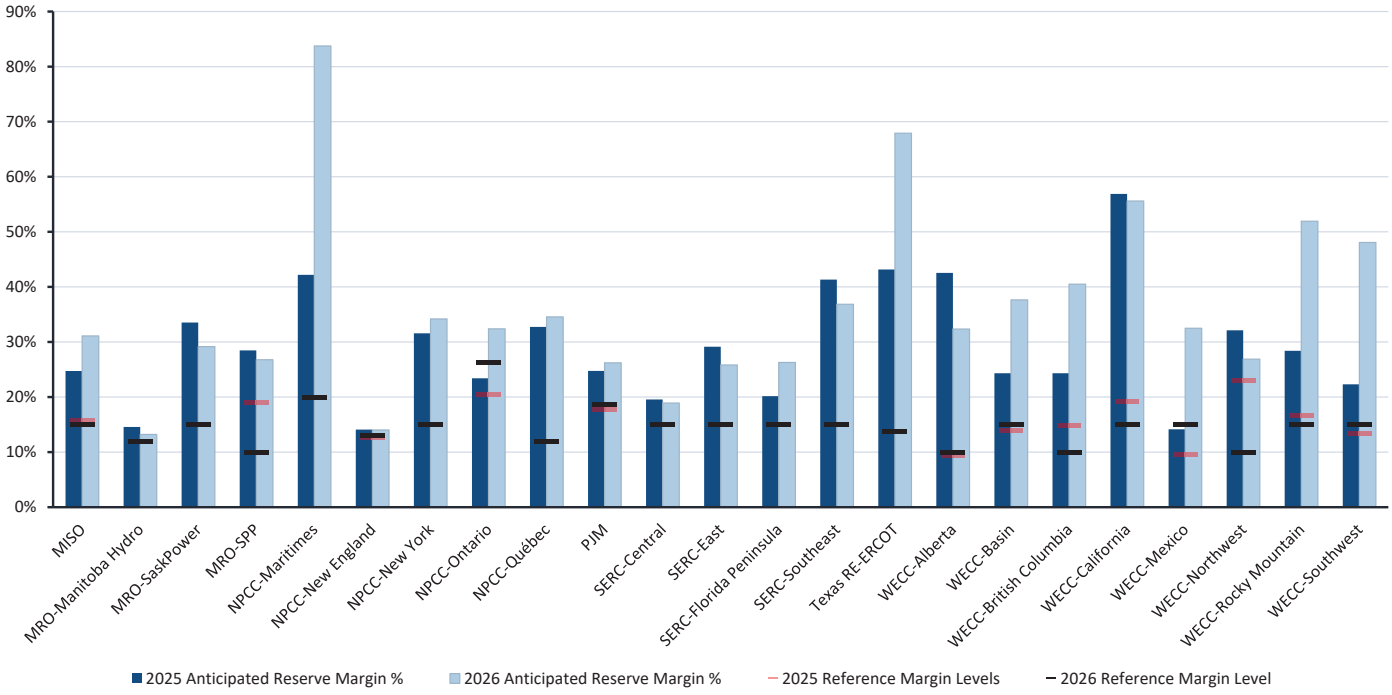


Figure 6: Summer 2025 and Summer 2026 Anticipated Reserve Margins Year-to-Year Change

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.

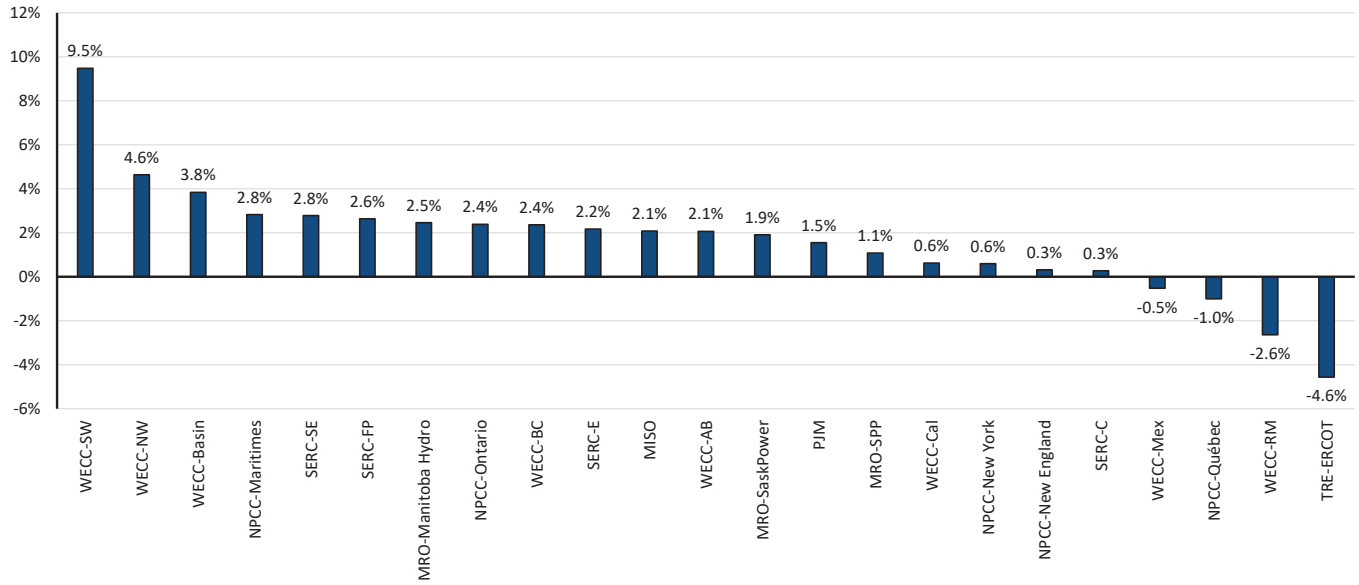


Figure 7: Changes in Net Internal Demand—Summer 2025 Forecast Compared to Summer 2026 Forecast

[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-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-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-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

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

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

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

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

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

	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate 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 States[24] 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 States[26] and Canada[27]), U.S. electricity generation reached a record high for the assessment summer period (June – September) at 1,628 TWh[28], 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 TWh[29]. 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 heatwave[30] 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 record[31] (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 peak[38] 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 1[39] 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 unavailable[40] 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 4.1	2.5	50	296	227	**
WECC-NW	29.8	29.1 32.7	1,054	3,107	1,398	666	1,825
WECC-RM	13.4	13.8 15.0	2,313	1,359	1,571	1,669	1,954
WECC-Basin	13.8	13.6 15.0	931	911	2,660	2,231	0
WECC-SW	36.9	35.1 39.0	1,230	1,091	4,472	4,293	2,323
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.

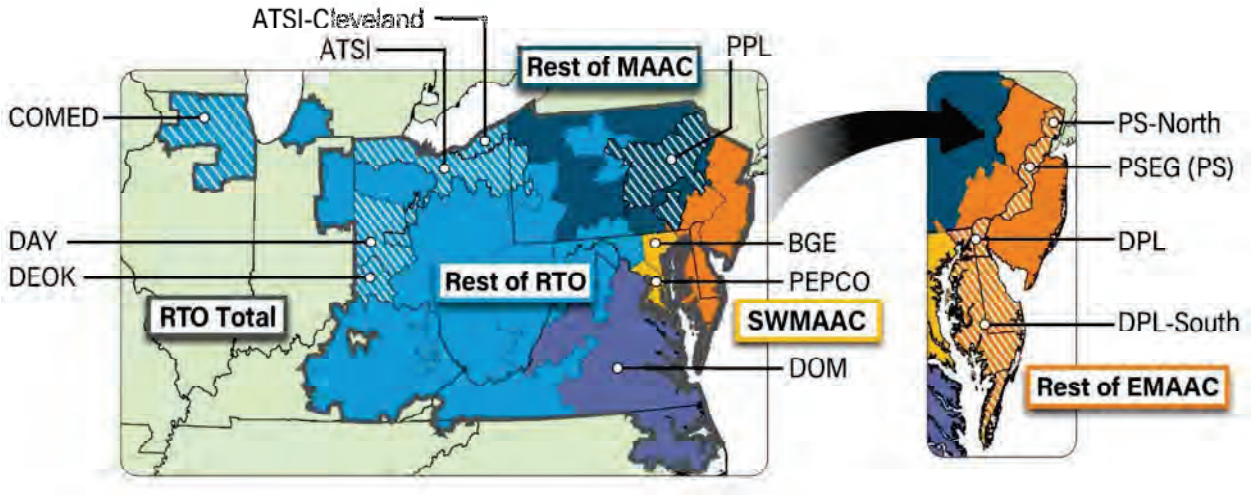
An LDA was modeled in the BRA and had a separate VRR Curve if (1) the LDA has a CETO/CETL margin that is less than 115%; or (2) the LDA had a locational price adder in any of the three immediately preceding BRAs; or (3) the LDA is EMAAC, SWMAAC and MAAC. An LDA not otherwise qualifying under the above 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.**

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

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

	Auction Results				
Delivery Year	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

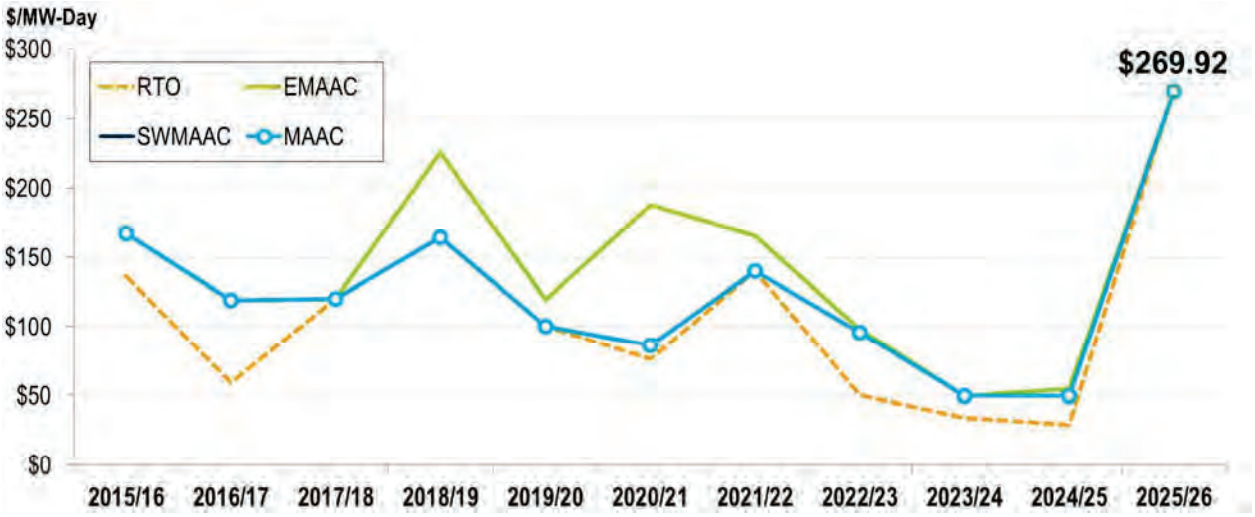


Table 3 provides the total offered and cleared MWs and associated prices by LDA. This table provides an indication of how much supply did not clear for each LDA. Since BGE and DOM were constrained LDAs, they cleared at a higher price than the rest of RTO or $466.35 and $444.26, respectively.

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 Resources[1] 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

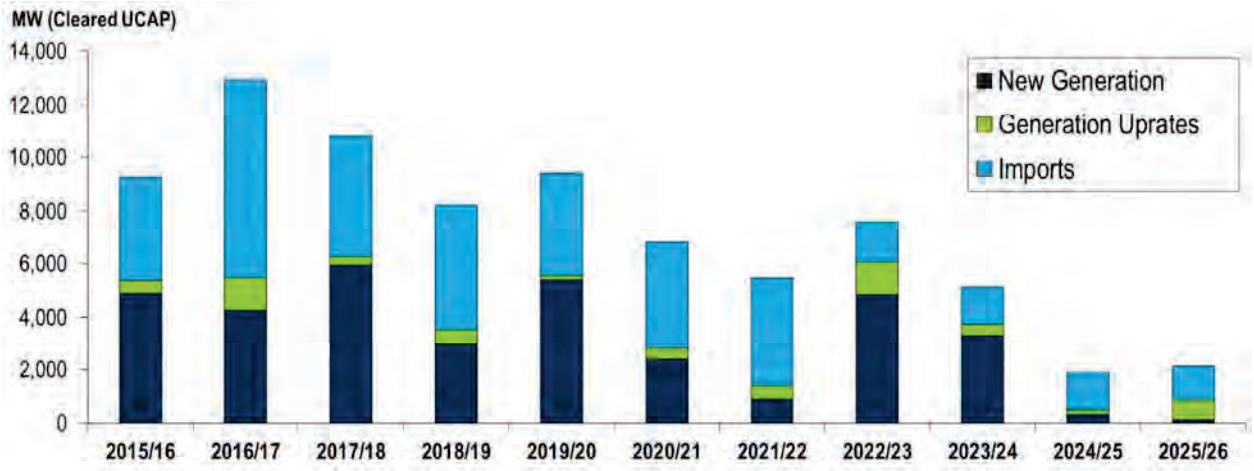


Table 4 contains a summary of the RTO resources for each cleared BRA from 2015/2016 through the 2025/2026 Delivery Years in terms of ICAP. The summary includes all resources located in the RTO (including FRR Capacity Plans).

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 CIFP 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

	Delivery Year *(All values in ICAP)*										
Auction Supply	**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	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
Eligible 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

	Offered and Cleared UCAP							
	2022/23		2023/24		2024/25		2025/26 (Reflects ELCC Accreditation)	
Type	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					
	NORTH	WEST 1	WEST 2	SOUTH 1	SOUTH 2	Total
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

	Capacity Performance					
	Offered MW (UCAP)			Cleared MW (UCAP)		
Resource Type	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

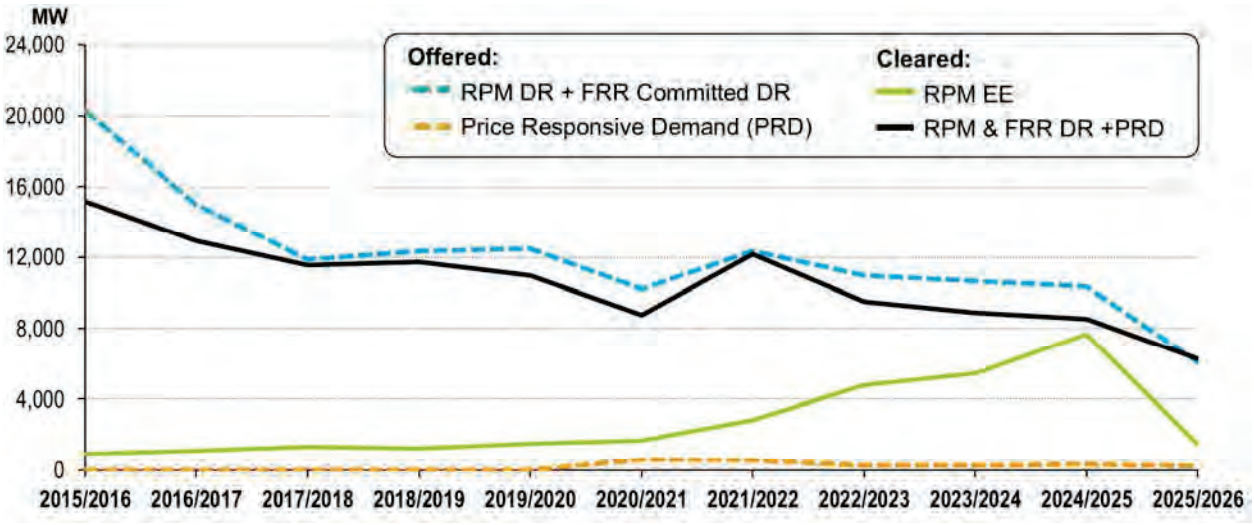


Table 9 provides a breakdown of offered and cleared DR and EE by LDA. COMED cleared the most DR and EE (1,424.5 MW), followed by AEP (1,055.7 MW) and then DOM (827.7 MW).

Table 9. DR and EE Offered and Cleared by LDA

		Offered MW (UCAP)*			Cleared MW (UCAP)*		
LDA	**Zone**	**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

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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.

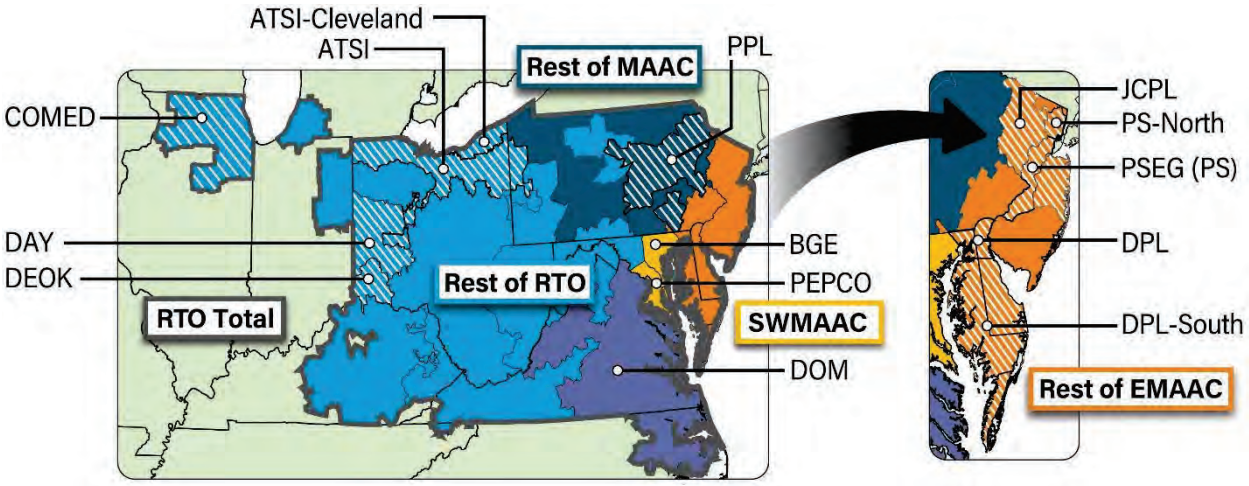
An LDA was modeled in the BRA and had a separate VRR Curve if (1) the LDA has a CETO/CETL margin that is less than 115%; or (2) the LDA had a locational price adder in any of the three immediately preceding BRAs; or (3) the LDA is EMAAC, SWMAAC and MAAC. An LDA not otherwise qualifying under the above 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

		BRA Resource Clearing Prices ($/MW-day)*		
Capacity Type	BRA	Rest of RTO	BGE	DOM
Capacity Performance	2026/27**	*$329.17*	*$329.17*	*$329.17*
	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

	Auction Results				
Delivery Year	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

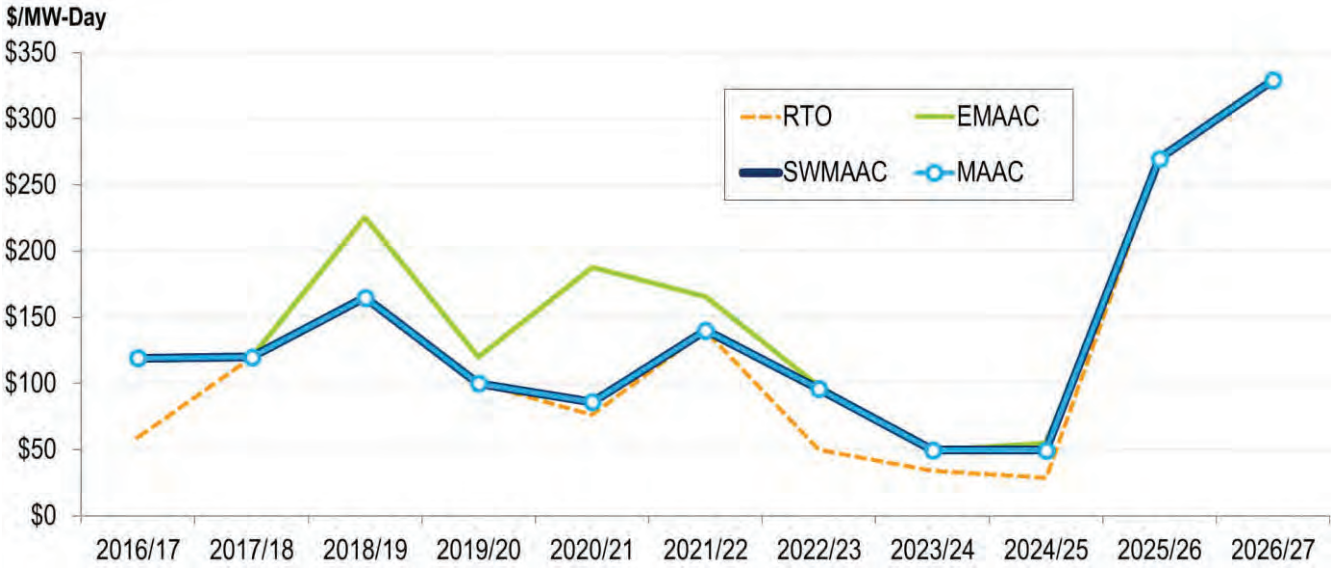


Table 3 provides the total offered and cleared megawatts and associated prices by LDA. This table provides an indication of how much supply did not clear for each LDA.

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 Resources[2] 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

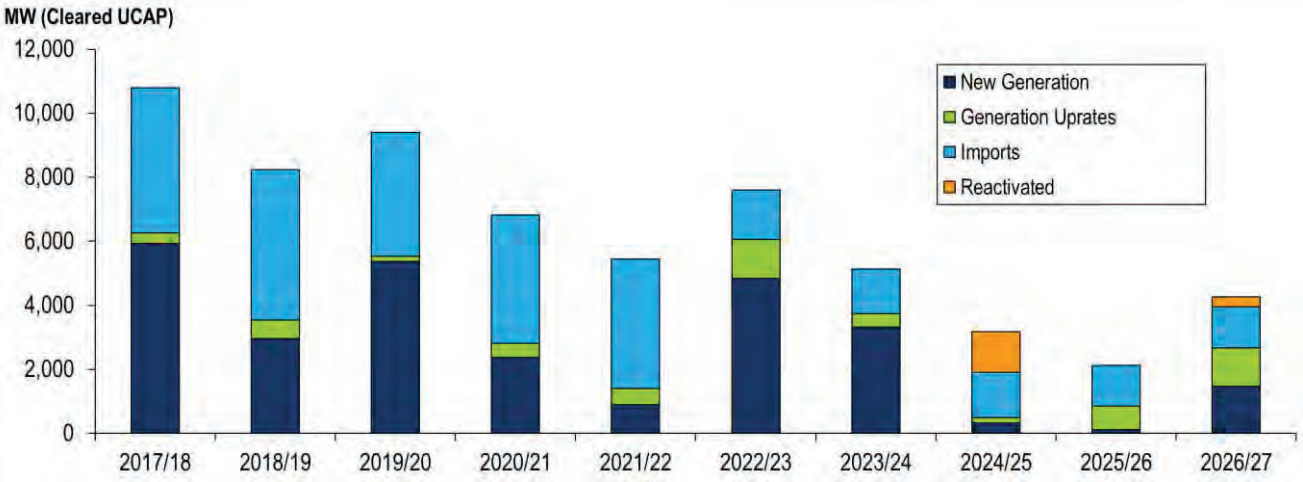


Table 4 contains a summary of the RTO resources for each cleared BRA from 2016/2017 through the 2026/2027 Delivery Years in terms of ICAP. The summary includes all resources located in the RTO (including FRR Capacity Plans).

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

	Delivery Year *(All values in ICAP)*										
Auction Supply	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

	Offered and Cleared UCAP									
	2023/24		2024/25		2025/26 (Reflects ELCC Accreditation)		2026/27 (Reflects ELCC Accreditation)		2026/27 - 2025/26 Change	
Type	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					
	NORTH	WEST 1	WEST 2	SOUTH 1	SOUTH 2	Total
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

Capacity Performance

	Offered MW (UCAP)			Cleared MW (UCAP)		
Resource Type	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

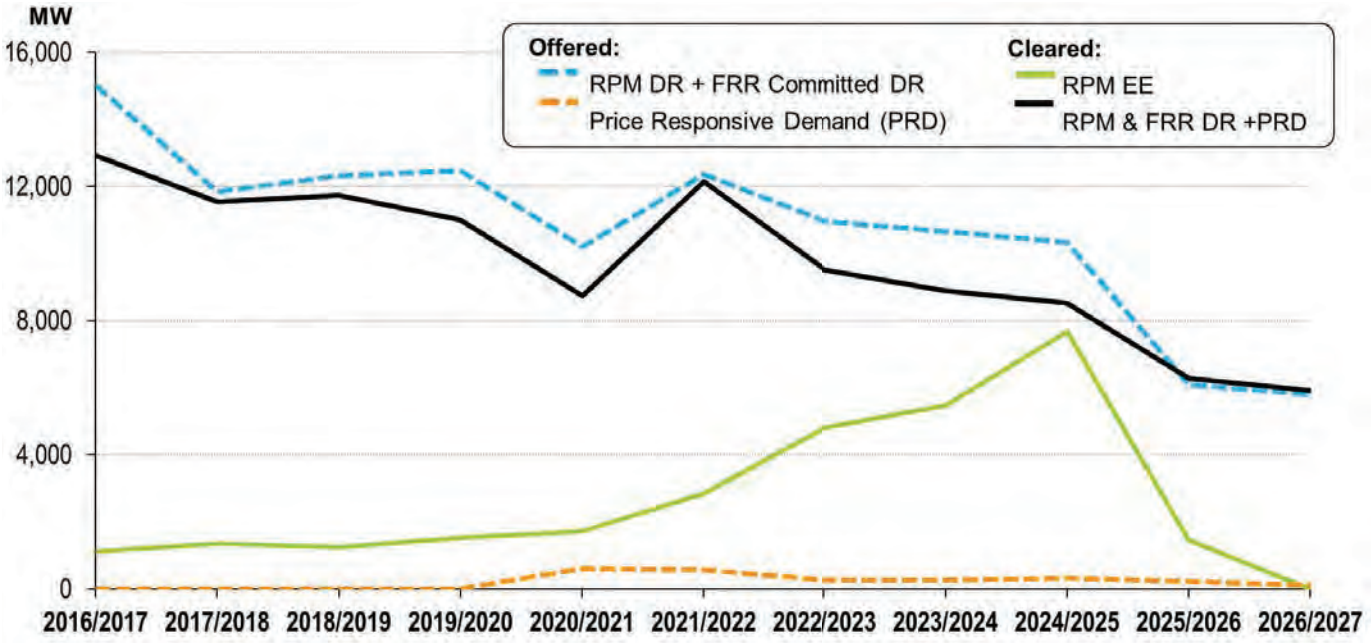


Table 9 provides a breakdown of offered and cleared DR by LDA. COMED cleared the most DR (969.9 MW), followed by AEP (941.1MW) and then DOM (555.1 MW).

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

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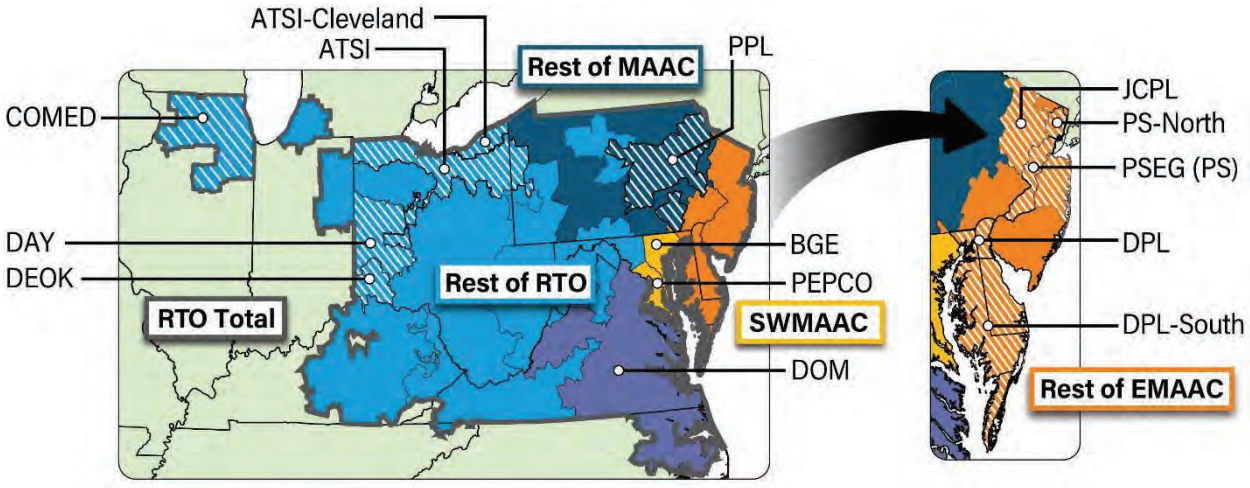
Introduction

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.

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
ATSI (rest of)	296.4	266.2
ATSI-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

	Offered MW (UCAP)			Cleared MW (UCAP)		
Resource Type	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							
		Point 1		Point 2		Point 3		Point 4	
LDA	PJM Buy Bid [1] (MW)	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)
RTO (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

	PJM Bids/Offers (UCAP MW)		PJM Cleared Bids/Offers (UCAP MW)		
LDA	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
ATSI (rest of)	25.9	0.0	25.9	0.0	25.9
ATSI-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

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[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 Proce*ss § 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

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[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

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[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

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[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

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[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

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[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

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[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

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[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

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[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

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[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

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[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

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[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 205[87] 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

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[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

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[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 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

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[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]

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[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-____**

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:

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[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.

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[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

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[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]

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[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]

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[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

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[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

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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

Respectfully submitted,

/s/ Zachary B. Cohen

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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-____**

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.

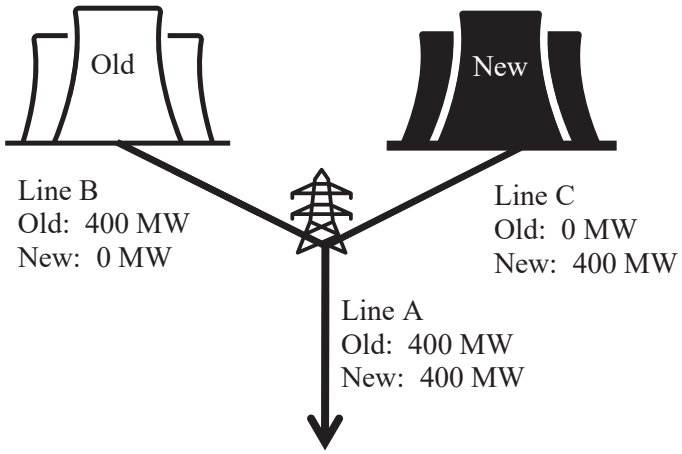
20. Eddystone Generating Station Units 3 and 4 are roughly 50-year-old oil and gas units in Pennsylvania, each with a generating capacity of 380 MW. On December 1, 2023, Constellation announced it would retire Eddystone Units 3 and 4, and submitted deactivation requests to PJM and the Market Monitor 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

