BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) | ) | |
| Emergency Order: Tri-State | ) | Order No. 202-25-14 |
| Generation and Transmission | ) | |
| Association, Platte River Power | ) | |
| Authority, Salt River Project, | ) | |
| PacifiCorp, and Xcel Energy | ) | |

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

Filed January 28, 2026

Exhibit 1-31:
PJM Elliott Report

# Winter Storm Elliott

## Event Analysis and Recommendation Report

July 17, 2023

For Public Use

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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.<br><br>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:<br>• Existing actions in Cold Weather Advisory and Cold Weather Alert regarding winterization and staffing procedures<br>• Criteria, sequencing, and communication of alerts, warnings and actions<br>• 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:<br>1. Different levels of fuel security, including dual-fuel capability, firm gas and non-firm gas<br>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:<br>• Review the Capacity Performance construct, with consideration of financial risks.<br>• Strengthen capacity accreditation and qualification criteria (e.g., winterization/fuel assurance).<br>• 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.<br>• 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](https://www.pjm.com) 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.

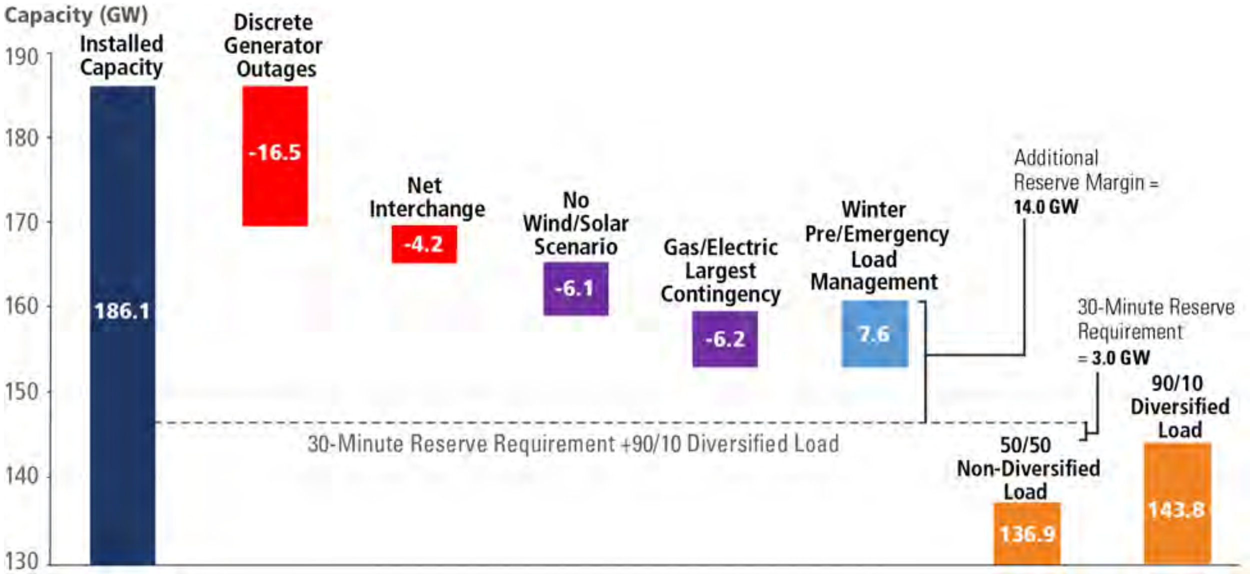
The study conditions include forecasted demand based on forecast weather and estimated outages, as well as a series of more extreme scenarios, including, but not limited to:

- 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

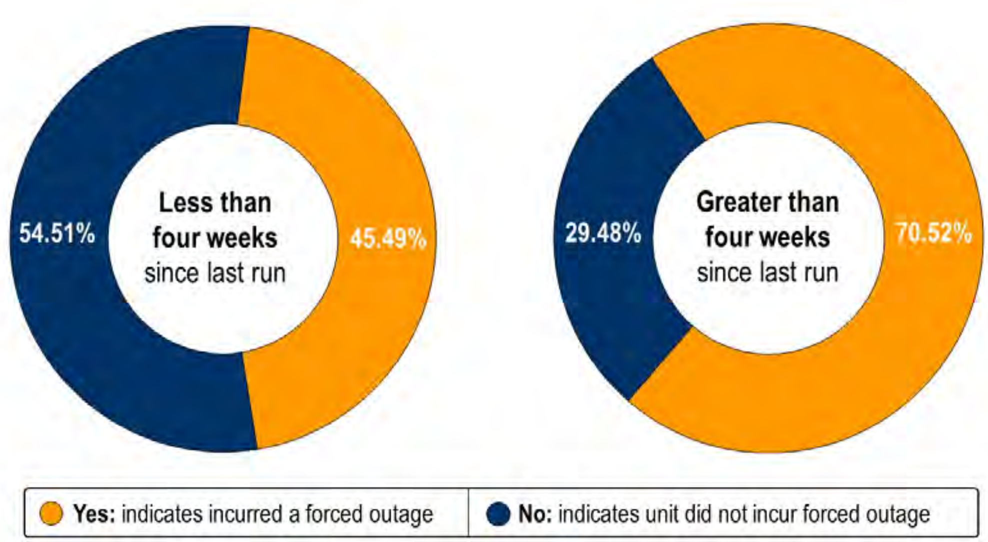
Following the 2014 Polar Vortex, PJM made several changes to its Cold Weather Operating Procedures, including establishing a Generation Resource Operational Exercise Program and a Generation Resource Cold Weather Checklist. The Generation Resource Operations Exercise Program is intended to enhance unit 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.

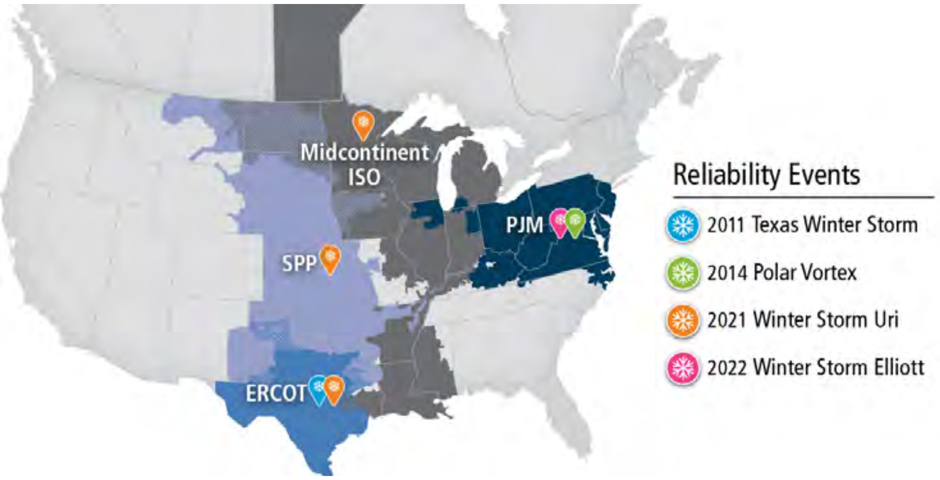
## Reliability Analysis Used in the Capacity Market

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

2023

HOUR ENDING

Friday, Feb. 2, 2023

| Area | 07 | 08 | 09 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| COMED | -2 | -1 | 0 | 1 | 3 | 5 | 7 | 8 | 9 | 9 | 8 | 7 | 6 | 7 | 7 | 8 | 8 |
| | 10 | 10 | 10 | 10 | 9 | 8 | 8 | 7 | 7 | 6 | 5 | 5 | 4 | 4 | 5 | 6 | 7 |
| AEP | 18 | 16 | 17 | 17 | 18 | 19 | 20 | 20 | 21 | 21 | 20 | 18 | 18 | 17 | 16 | 16 | 15 |
| | 12 | 12 | 12 | 12 | 12 | 12 | 13 | 13 | 12 | 12 | 11 | 10 | 9 | 7 | 6 | 5 | 4 |
| FE | 14 | 12 | 12 | 13 | 13 | 14 | 14 | 14 | 15 | 15 | 14 | 14 | 13 | 12 | 13 | 12 | 12 |
| | 13 | 13 | 13 | 13 | 14 | 14 | 15 | 14 | 14 | 13 | 12 | 11 | 10 | 8 | 8 | 7 | 6 |
| DPL | 17 | 17 | 16 | 17 | 18 | 19 | 20 | 21 | 21 | 21 | 20 | 19 | 18 | 18 | 17 | 16 | 16 |
| | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 10 | 9 | 7 | 6 | 5 | 5 | 4 |
| EKPC | 23 | 22 | 23 | 25 | 26 | 28 | 29 | 30 | 31 | 31 | 29 | 28 | 26 | 24 | 23 | 23 | 22 |
| | 10 | 9 | 9 | 10 | 9 | 9 | 9 | 9 | 9 | 9 | 8 | 7 | 5 | 5 | 5 | 5 | 4 |
| DEOK | 20 | 19 | 18 | 20 | 21 | 22 | 24 | 24 | 24 | 24 | 23 | 22 | 21 | 20 | 19 | 18 | 17 |
| | 10 | 10 | 10 | 11 | 11 | 11 | 11 | 11 | 11 | 10 | 10 | 7 | 6 | 6 | 5 | 4 | 4 |
| AP | 20 | 19 | 18 | 18 | 19 | 19 | 20 | 19 | 20 | 19 | 18 | 16 | 15 | 15 | 14 | 14 | 14 |
| | 14 | 14 | 14 | 15 | 15 | 16 | 16 | 16 | 16 | 15 | 14 | 13 | 12 | 11 | 10 | 9 | 8 |
| DUQ | 15 | 13 | 12 | 13 | 14 | 14 | 15 | 15 | 15 | 15 | 14 | 12 | 11 | 11 | 11 | 10 | 10 |
| | 13 | 13 | 14 | 14 | 15 | 15 | 15 | 15 | 15 | 14 | 13 | 12 | 10 | 9 | 9 | 8 | 7 |
| PJM | 30 | 28 | 27 | 27 | 27 | 26 | 25 | 25 | 25 | 24 | 22 | 21 | 20 | 19 | 19 | 18 | 17 |
| | 16 | 16 | 16 | 17 | 18 | 18 | 19 | 19 | 19 | 19 | 18 | 16 | 16 | 15 | 15 | 15 | 14 |
| DOM | 37 | 36 | 36 | 36 | 36 | 36 | 35 | 35 | 35 | 34 | 33 | 30 | 29 | 27 | 25 | 24 | 23 |
| | 11 | 13 | 14 | 15 | 16 | 16 | 16 | 16 | 16 | 15 | 15 | 14 | 13 | 12 | 12 | 12 | 12 |
| NY | 29 | 28 | 27 | 26 | 26 | 26 | 26 | 24 | 23 | 22 | 20 | 19 | 18 | 17 | 16 | 15 | 13 |
| | 19 | 19 | 20 | 20 | 21 | 21 | 21 | 21 | 21 | 21 | 20 | 20 | 20 | 20 | 19 | 19 | 19 |

Saturday, Feb. 3, 2023

| Area | 00 | 01 | 02 | 03 | 04 | 05 | 06 | 07 | 08 | 09 | 10 | 11 | 12 | 13 | 14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| COMED | 9 | 9 | 9 | 10 | 11 | 11 | 13 | 14 | 16 | 19 | 22 | 25 | 28 | 31 | 33 |
| | 7 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 14 | 15 | 16 | 16 | 17 | 17 |
| AEP | 15 | 14 | 14 | 14 | 13 | 14 | 15 | 15 | 16 | 18 | 22 | 25 | 28 | 31 | 33 |
| | 4 | 4 | 5 | 5 | 6 | 6 | 7 | 8 | 8 | 10 | 11 | 12 | 12 | 13 | 13 |
| FE | 11 | 11 | 11 | 11 | 10 | 10 | 11 | 12 | 13 | 15 | 18 | 21 | 24 | 26 | 29 |
| | 5 | 5 | 5 | 6 | 6 | 7 | 8 | 9 | 9 | 11 | 12 | 13 | 13 | 14 | 14 |
| DPL | 15 | 15 | 15 | 15 | 15 | 15 | 16 | 16 | 17 | 20 | 23 | 26 | 30 | 33 | 35 |
| | 4 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 12 | 13 | 14 | 15 | 16 | 16 | 16 |
| EKPC | 22 | 22 | 21 | 21 | 21 | 21 | 21 | 21 | 23 | 27 | 31 | 35 | 40 | 43 | 45 |
| | 4 | 4 | 4 | 5 | 5 | 5 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 12 |
| DEOK | 17 | 17 | 16 | 16 | 16 | 16 | 16 | 17 | 18 | 21 | 25 | 30 | 34 | 38 | 41 |
| | 4 | 4 | 5 | 5 | 6 | 6 | 7 | 7 | 8 | 9 | 10 | 11 | 12 | 12 | 13 |
| AP | 13 | 13 | 12 | 11 | 11 | 11 | 11 | 11 | 12 | 15 | 18 | 21 | 24 | 26 | 29 |
| | 7 | 7 | 7 | 6 | 6 | 5 | 5 | 5 | 5 | 6 | 6 | 8 | 8 | 9 | 9 |
| DUQ | 9 | 9 | 8 | 8 | 8 | 8 | 8 | 8 | 10 | 12 | 15 | 18 | 21 | 23 | 27 |
| | 6 | 6 | 5 | 5 | 5 | 5 | 5 | 6 | 6 | 7 | 8 | 9 | 9 | 10 | 10 |
| PJM | 16 | 15 | 15 | 14 | 13 | 14 | 13 | 14 | 16 | 18 | 20 | 22 | 24 | 25 | 27 |
| | 13 | 14 | 13 | 12 | 11 | 10 | 9 | 8 | 8 | 7 | 7 | 7 | 8 | 8 | 8 |
| DOM | 22 | 22 | 21 | 21 | 20 | 19 | 19 | 19 | 21 | 24 | 26 | 28 | 31 | 32 | 33 |
| | 11 | 11 | 10 | 9 | 9 | 8 | 7 | 6 | 6 | 5 | 5 | 6 | 6 | 6 | 7 |
| NY | 13 | 13 | 12 | 11 | 10 | 10 | 9 | 10 | 12 | 13 | 16 | 18 | 21 | 23 | 24 |
| | 19 | 19 | 18 | 17 | 17 | 16 | 15 | 14 | 13 | 12 | 12 | 11 | 11 | 12 | 12 |

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<br>• 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 |

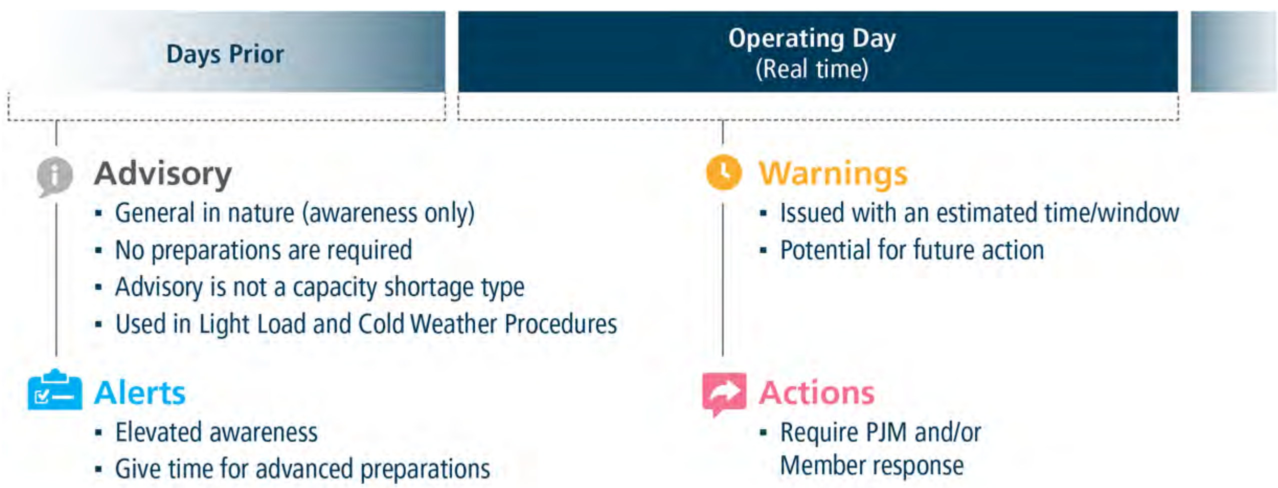
| Date | PJM Team | Activity |
|---|---|---|
| | Forecast | • At the time of the forecast's creation, the actual load on Dec. 23 was coming in lower than the forecast. When the team began assessing the forecast for Dec. 24, they observed that the actual load was coming in lower than the previous day's 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.<br>• 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.

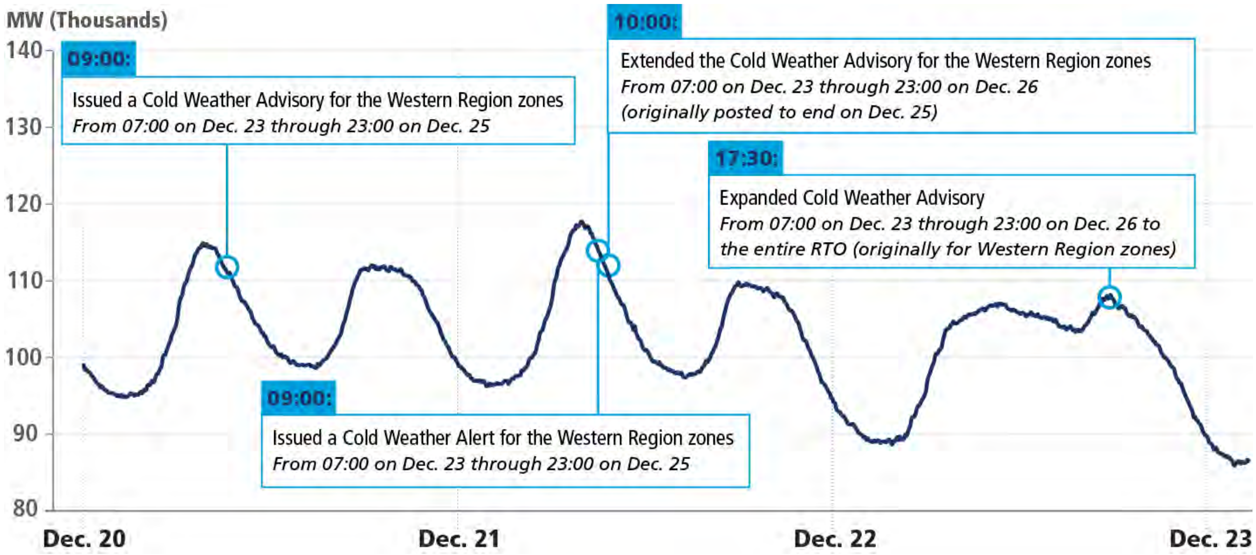
As described in PJM Manual 13, Section 2.3, PJM has established three emergency procedure levels for capacity shortages, as well as an advisory level.

**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*

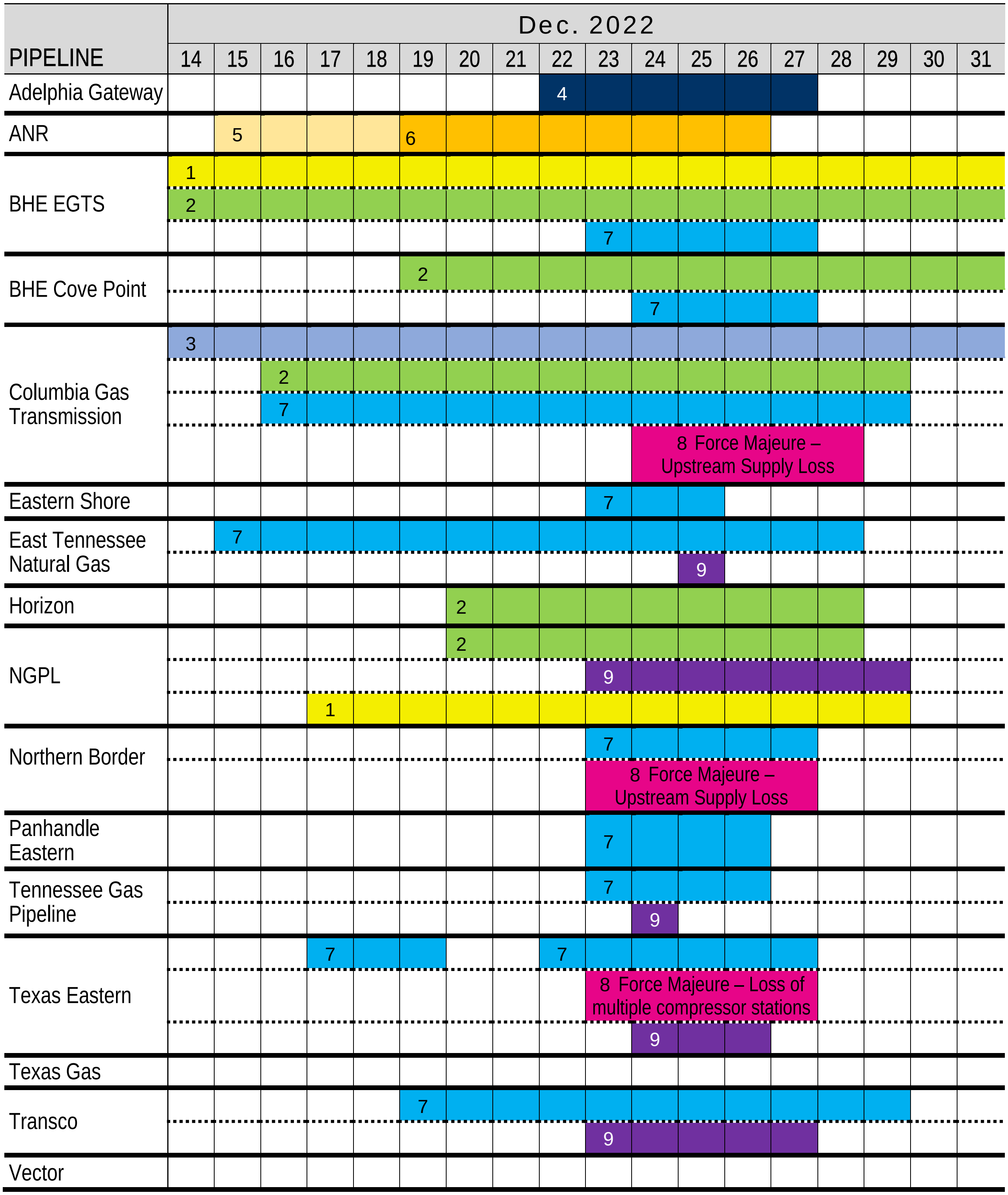
Prior to each winter season, PJM, along with fellow members of the ISO/RTO Council Electric Gas Coordination Task Force, meet with the pipeline industry to review the upcoming winter and discuss mutual preparedness activities.

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<br>Customers with interruptible transportation contracts at higher risk of not being able to schedule adequate pipeline capacity |
| 2 | Ratable Take Requirement<br>Pipeline requiring customers to supply and burn gas at uniform hourly rates to avoid excessive pressure fluctuations |
| 3 | Critical Day (Transport Deliveries/Storage Withdrawals)<br>Pipeline requiring customers to stay within their transportation and storage contractual requirements |
| 4 | Action Alert (Daily Balancing)<br>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<br>Alerting customers of pending cold temperatures and tightening system conditions |
| 6 | Phase 2 Cold Weather Extreme Conditions<br>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<br>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<br>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<br>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.

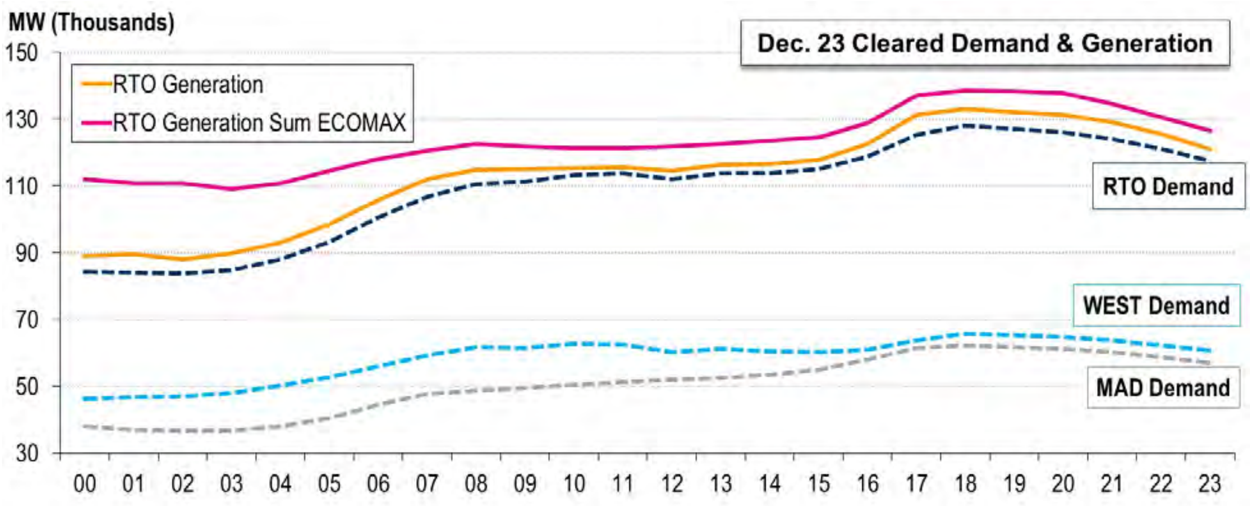
PJM also performs additional reliability analysis to confirm transmission facilities are operated within their equipment limits when committing generation. During severe winter weather events, PJM communicates extensively with both Generation Owners and gas pipeline operators to adequately understand 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.

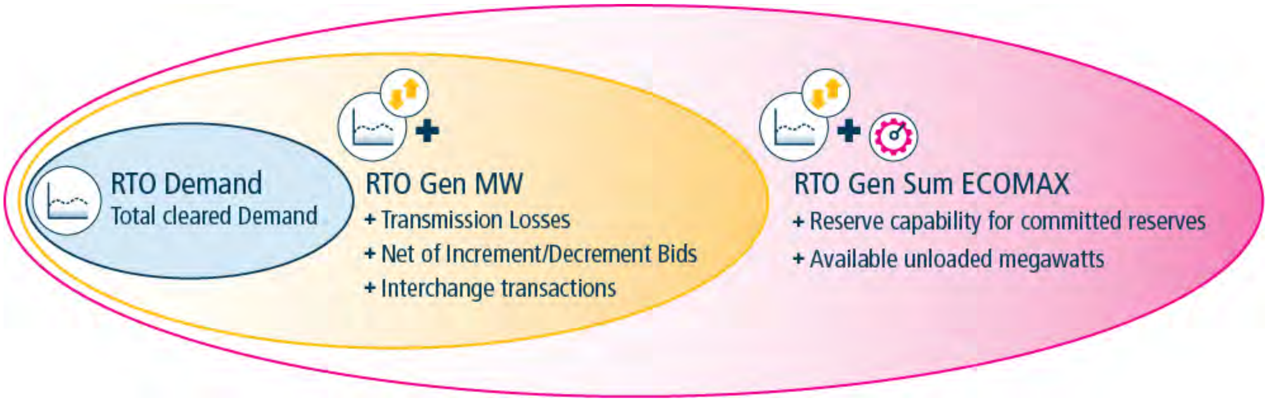
**Figure 9.** Dec. 23 Cleared Demand and Generation from Day-Ahead Market




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.

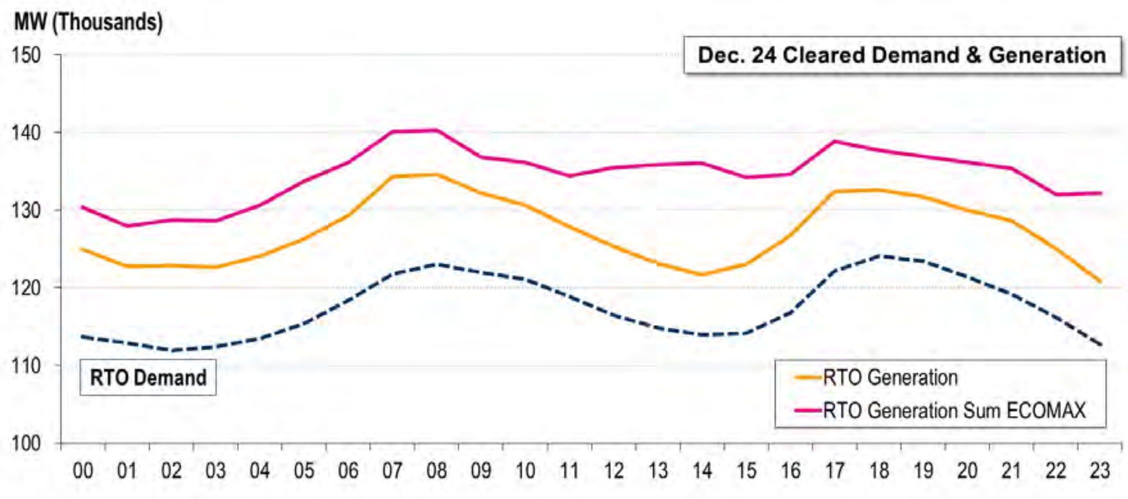
As early as Dec. 20, generation resource operating limitations and minimum operating, design or performance temperature were submitted to PJM in advance of the cold weather event after PJM declared a Cold Weather Advisory. All of the generator-submitted data was taken into consideration, with PJM forecasting 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

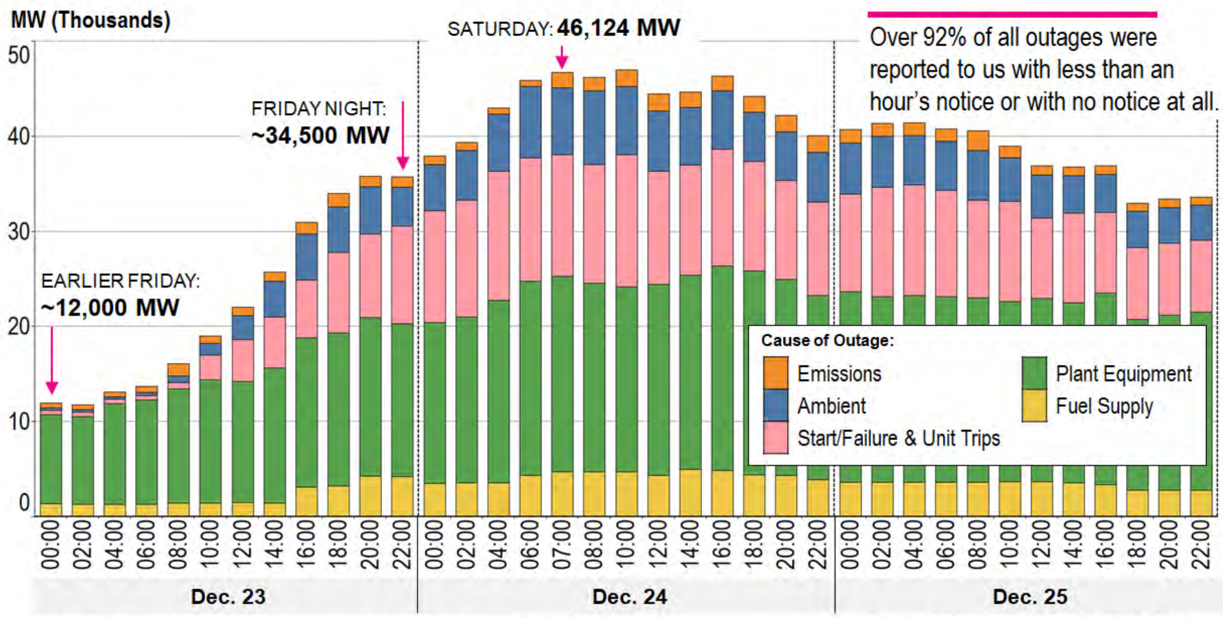
Dec. 23 and Dec. 24 by employing several emergency procedures and utilizing market signals to incent response from the supply and demand side resources. Although the 136,010[3] MW peak load on the evening of Dec. 23 was not one of PJM's top 10 peak winter load days, it essentially matched the forecasted 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

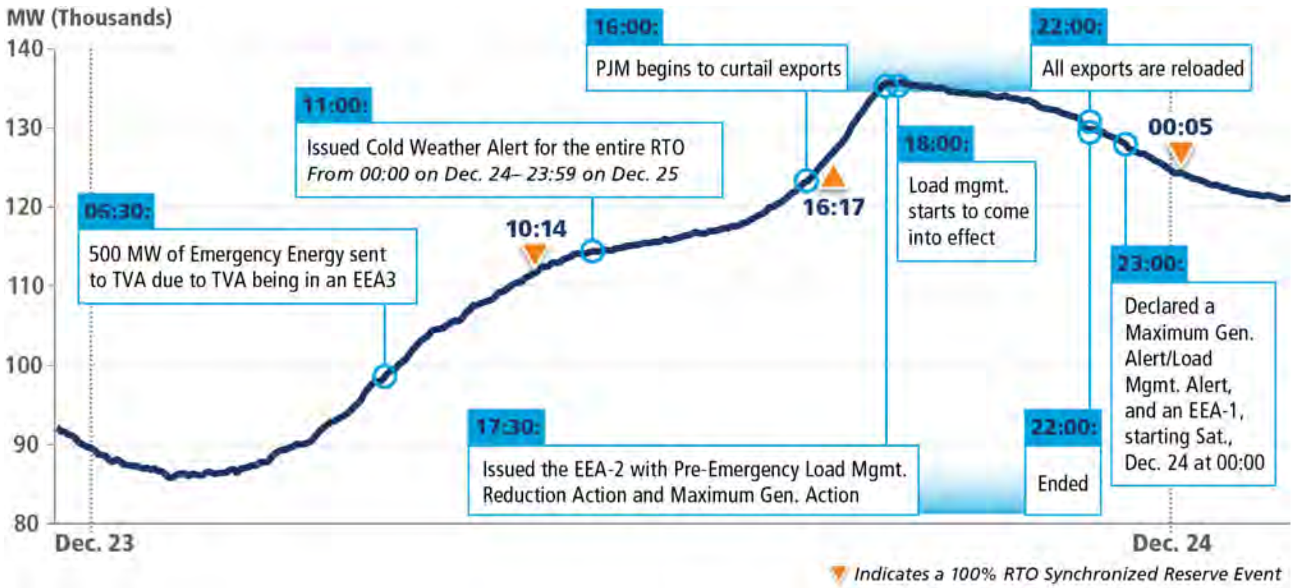
[3] The Dec. 23 peak of 136,010 MW incorporates Demand Response as part of the total.

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.

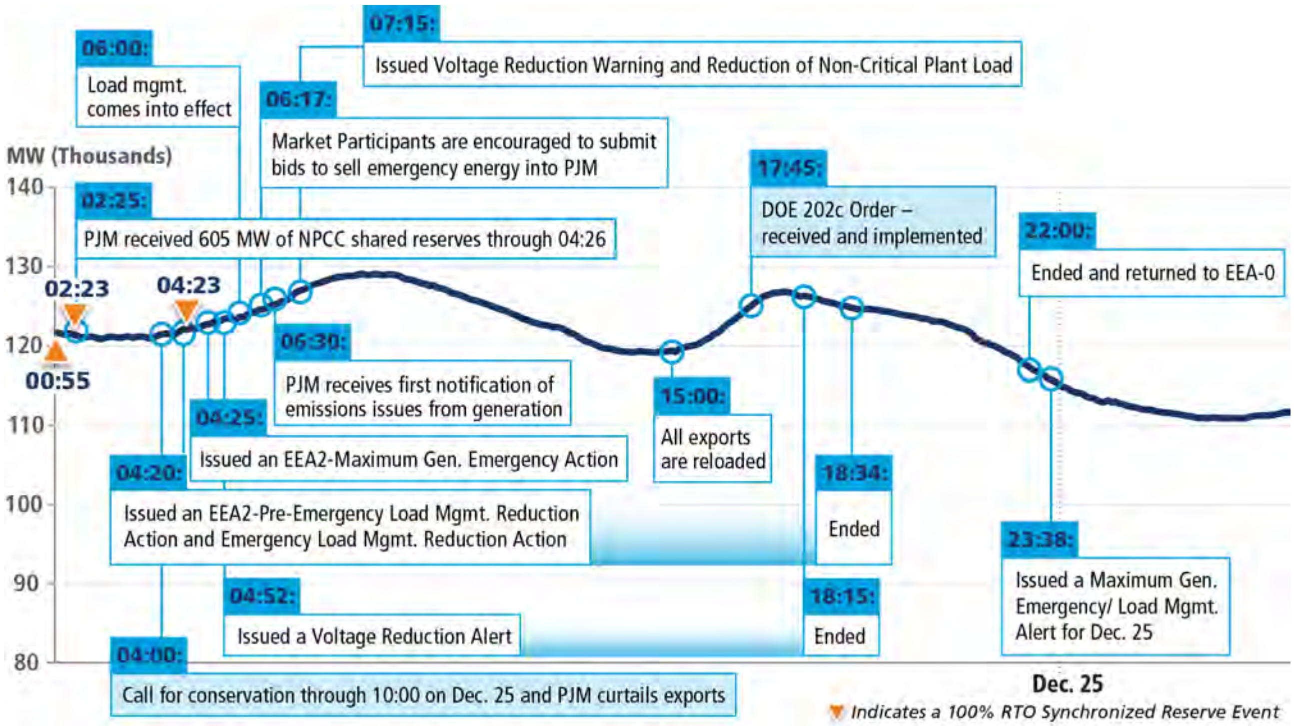
### *Dec. 24*

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 |

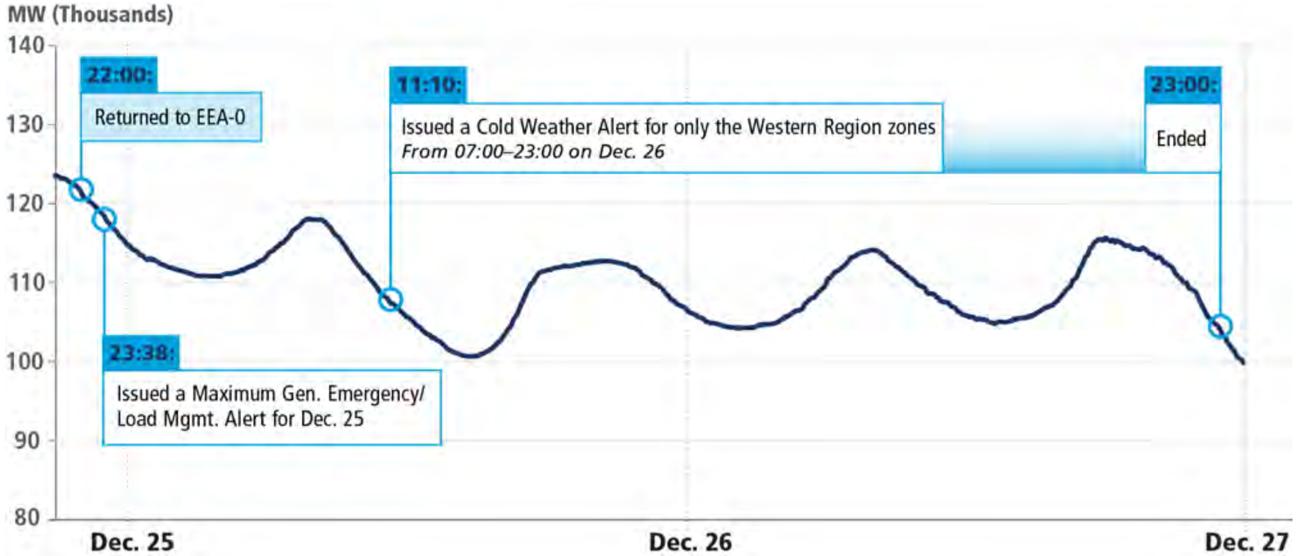
At 22:00 on Dec. 24, PJM canceled the Max Emergency Generation Action. This ended the Dec. 24 PAI. Around 22:00, the Demand Response ended, and PJM backed out of the EEA-2, indicating PJM was able to meet its load and Operating Reserve requirements. PJM's Call for Conservation also ended at this time.

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.

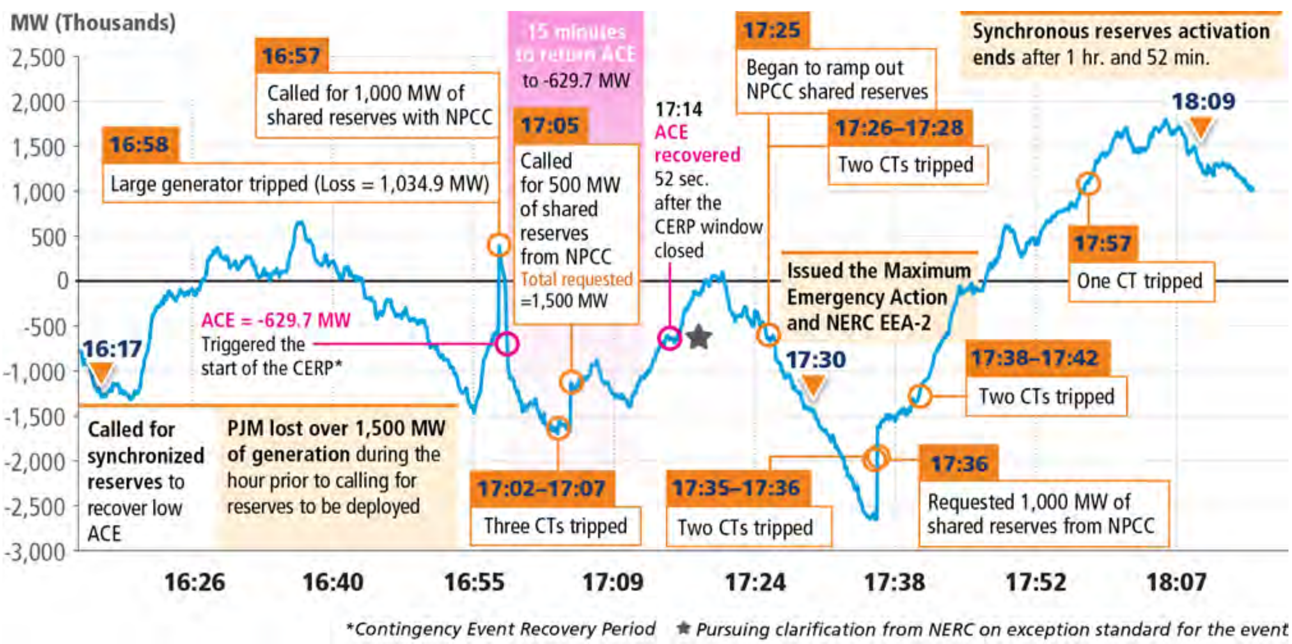
## Disturbance Control Standard Event

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.

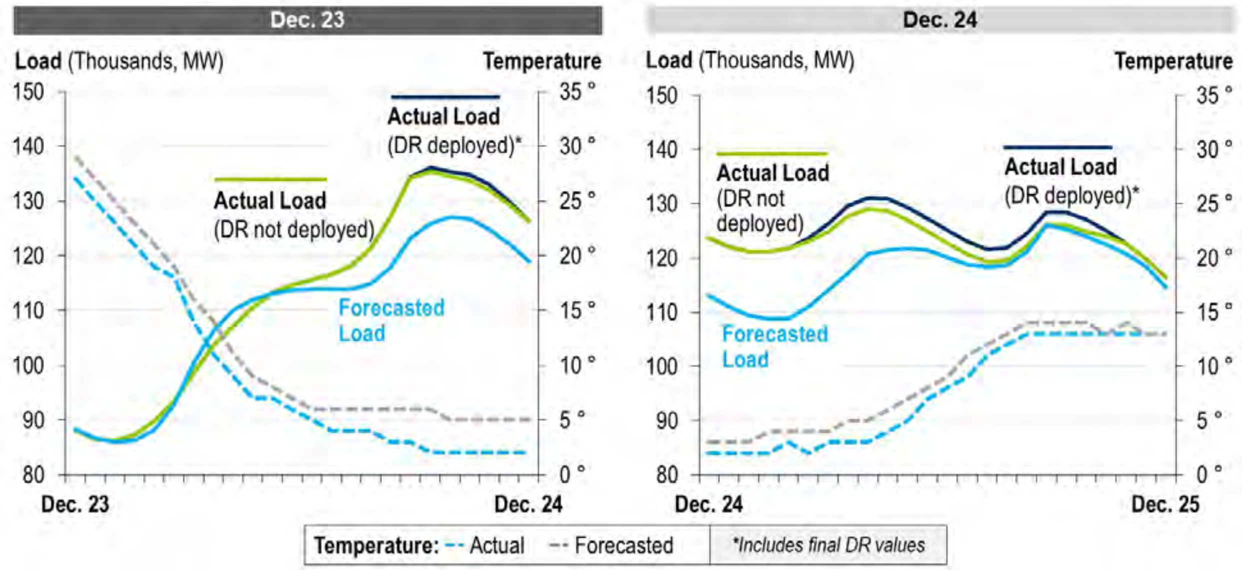
## Load Forecast Versus Actual Load

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

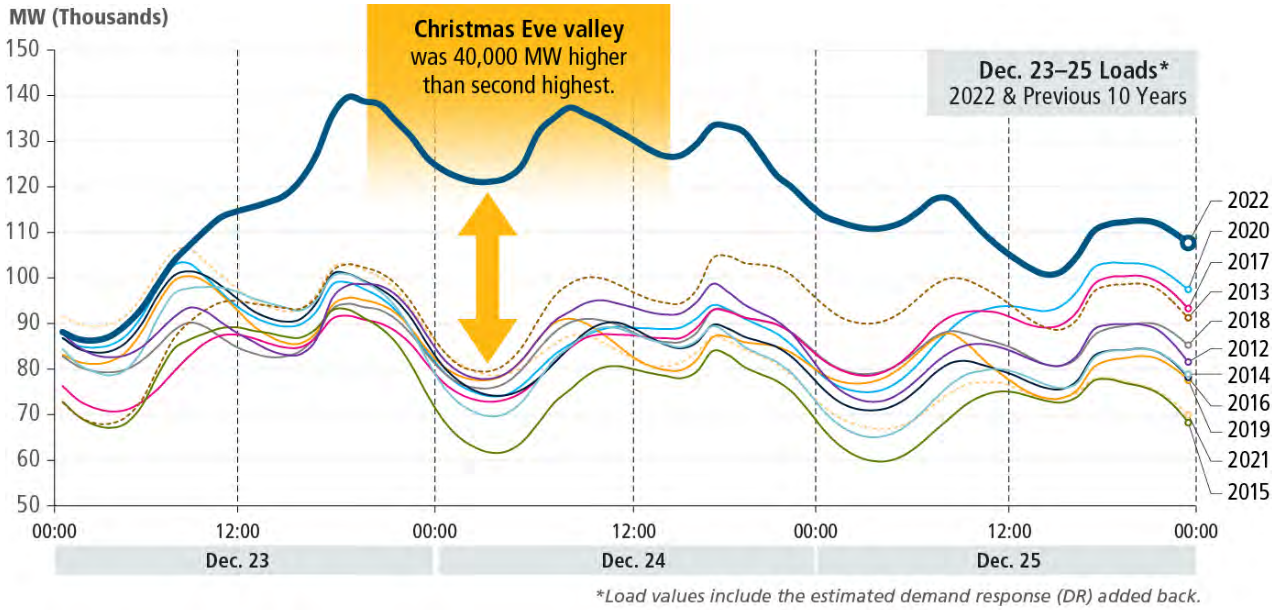
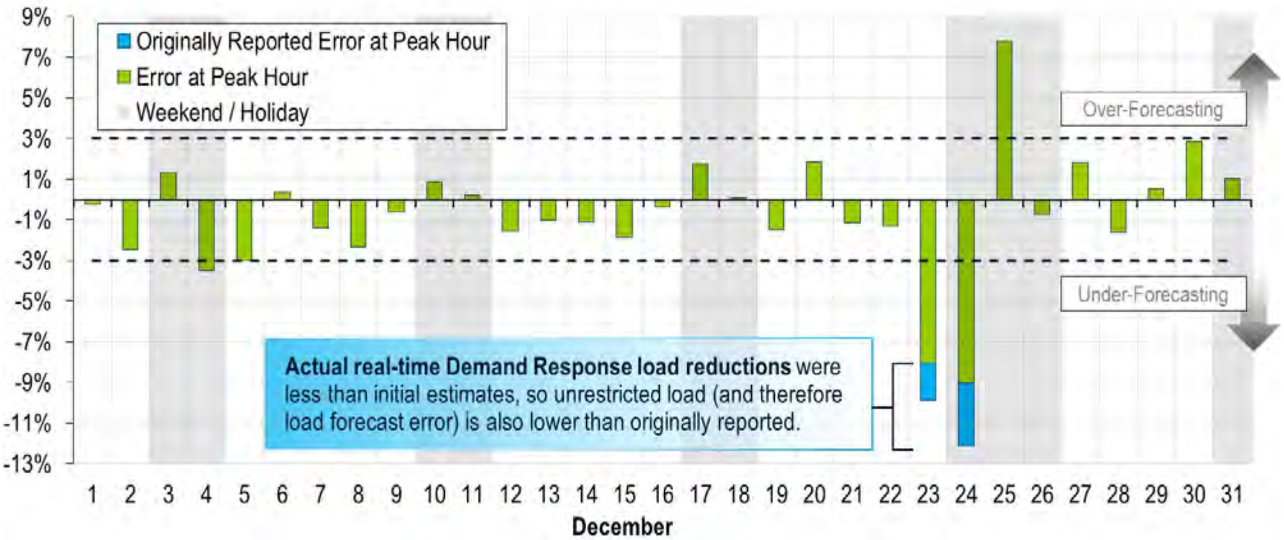


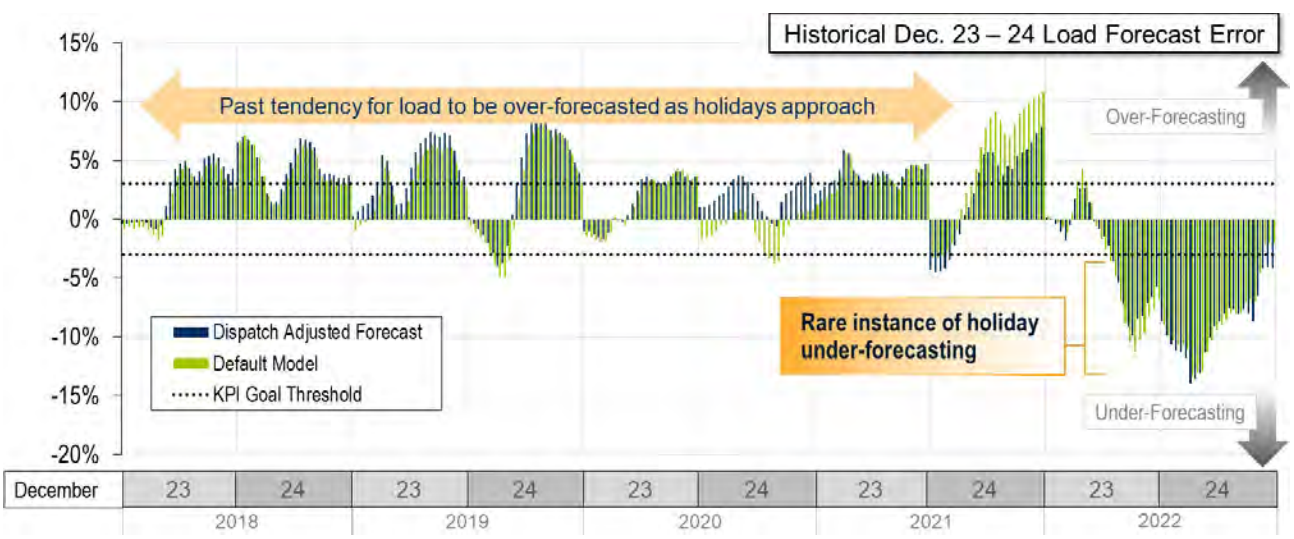
Figure 20 presents graphic presents the daily peak forecast error for December.

**Figure 20.** December Daily Peak Load Forecast Error



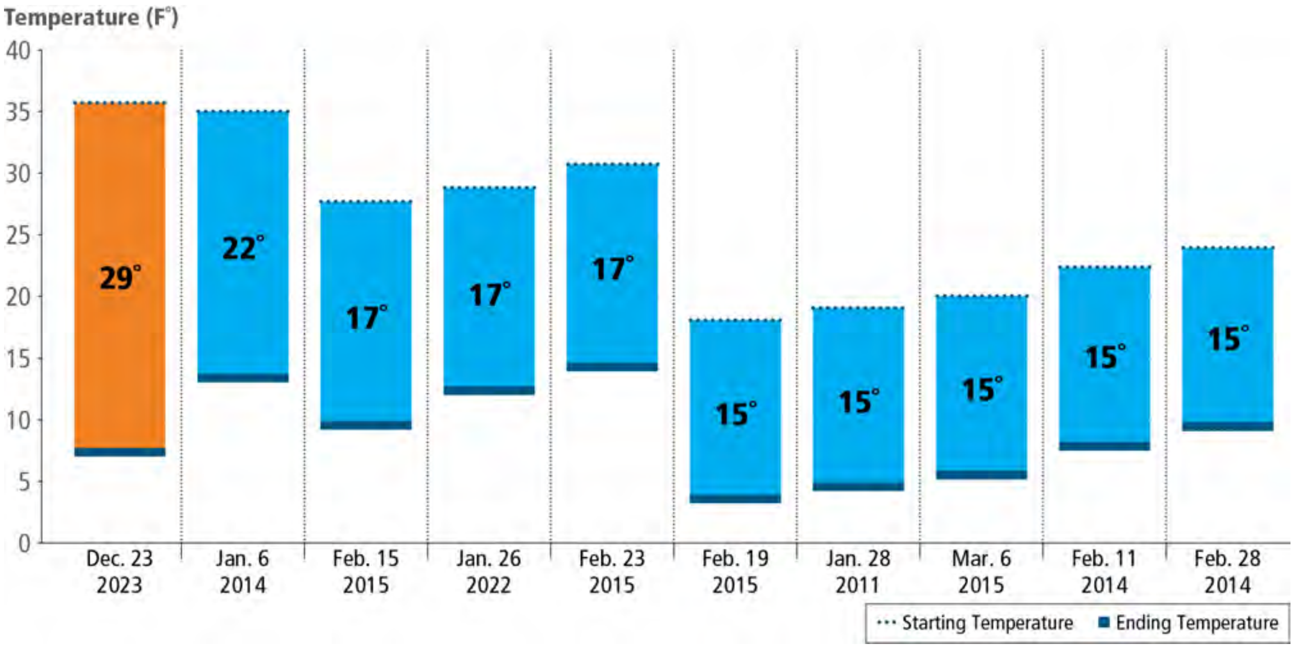

The extreme weather not only included bitter cold temperatures that were outside of the data sample used to train the load forecast models (mid-2019 to mid-2022), but also a rapid temperature drop, strong winds, heavy icing and snowfall, all of which occurred unusually early in this winter. Figure 21 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.

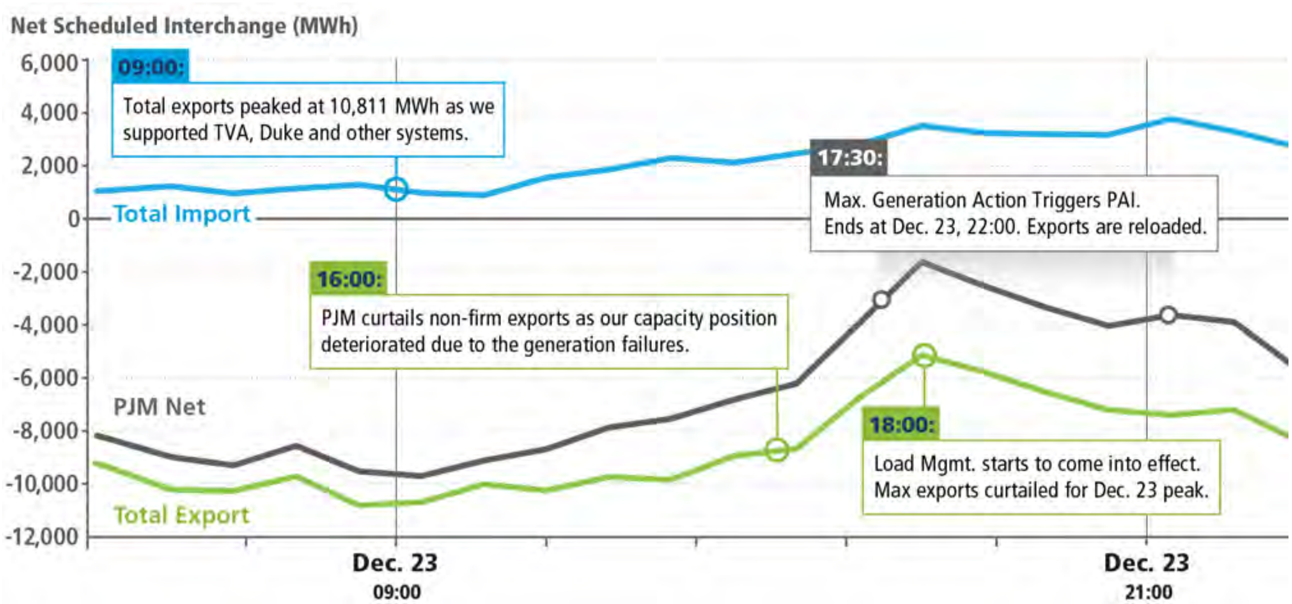
As PJM made the decision to issue Cold Weather Advisories and Alerts for these operating days, the bitter cold temperatures traveled across the country from the north and west to the south and east. Early in the day on Dec. 23, areas to PJM's west and south were already experiencing bitter cold temperatures. 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

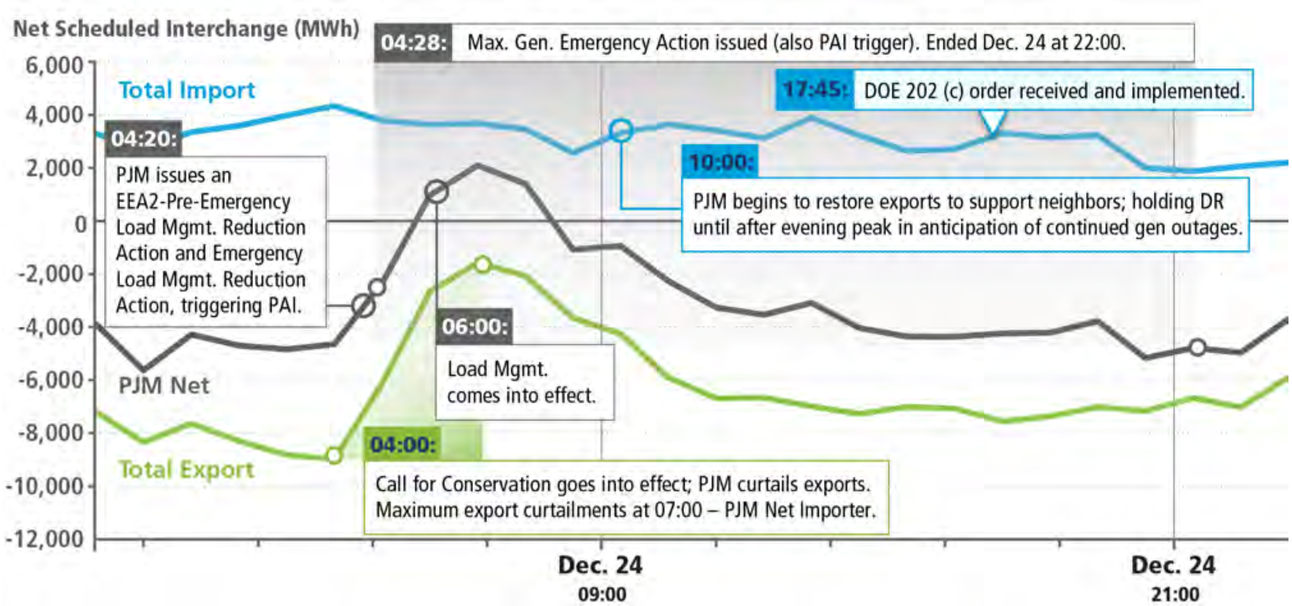
[5] Interconnection Reliability Operating Limit (IROL) is a system operating limit that, if exceeded, could lead to system instability, uncontrolled separation, or cascading that adversely impact the reliability of the bulk electric system.
[6] A tag is information describing a physical Interchange Transaction 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

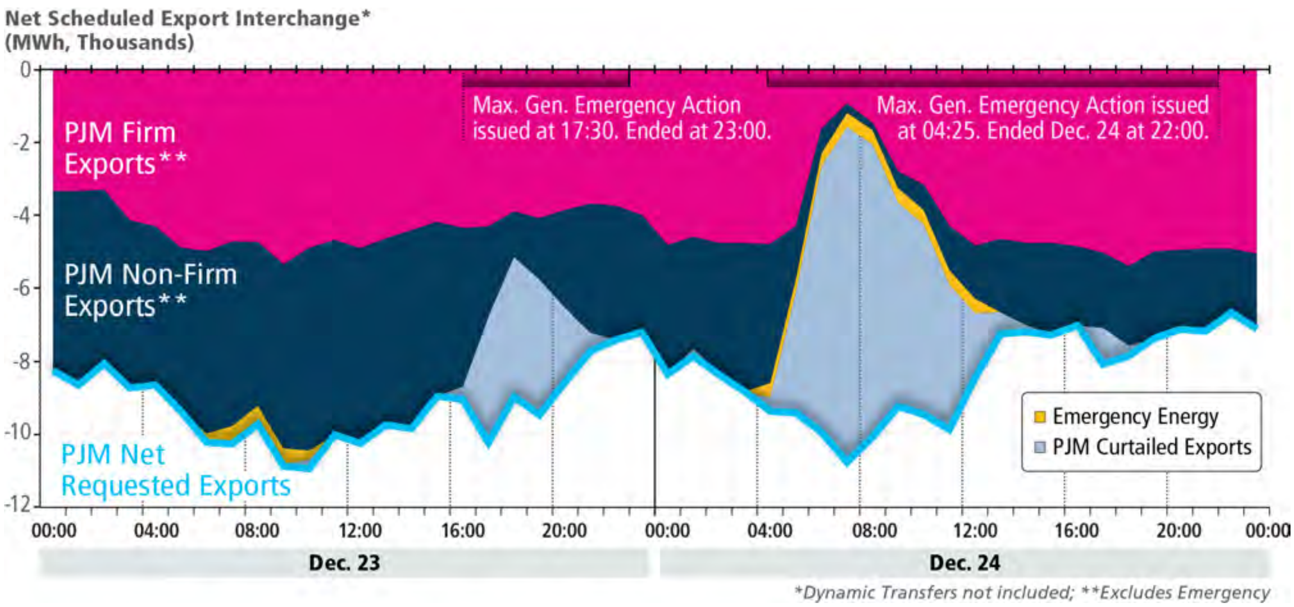



## *Coordination With Neighbors*

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



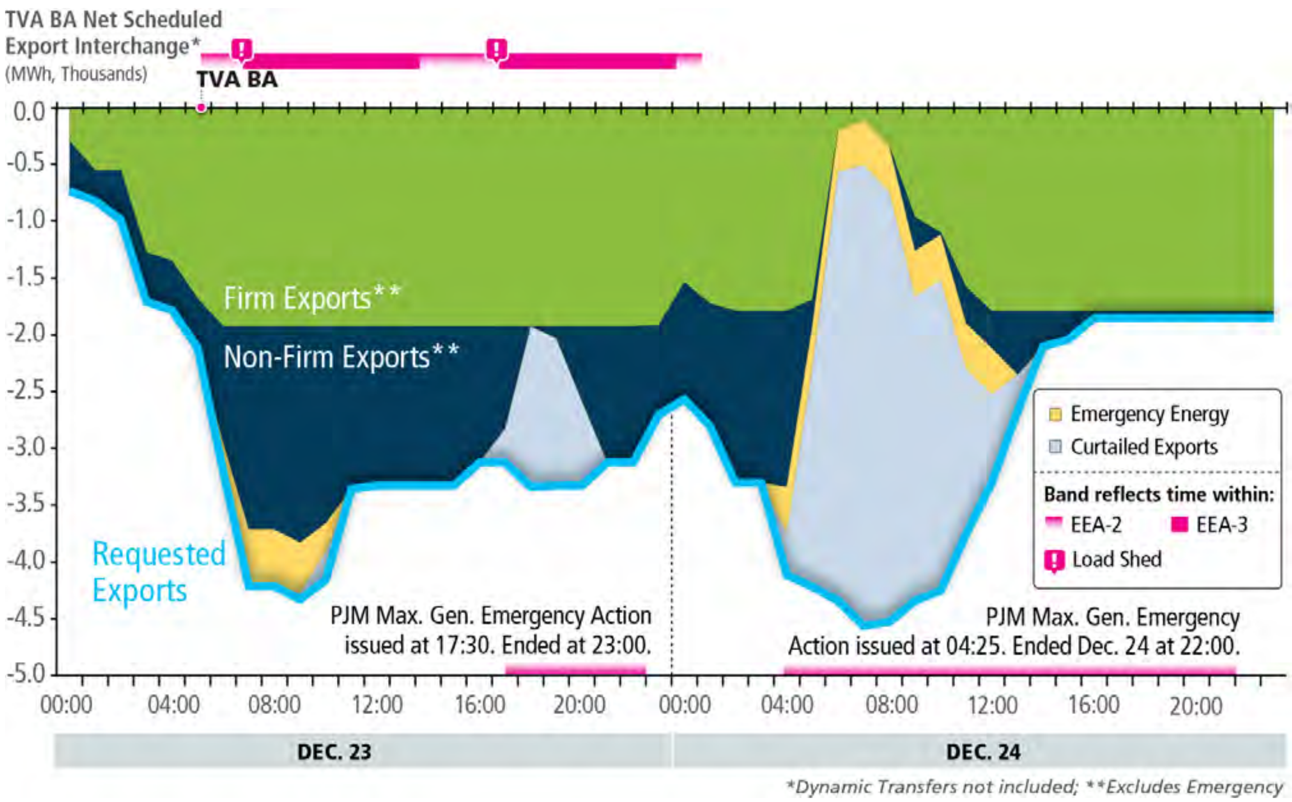

Comparing the values in **Figure 25** to the supply/demand conditions that PJM actually experienced confirms that PJM could not have met system demand only by cutting non-firm exports. On Dec. 23, 2022, at 17:30, PJM issued a Pre-Emergency Load Management Reduction Action for the 30-minute and 60-minute 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.

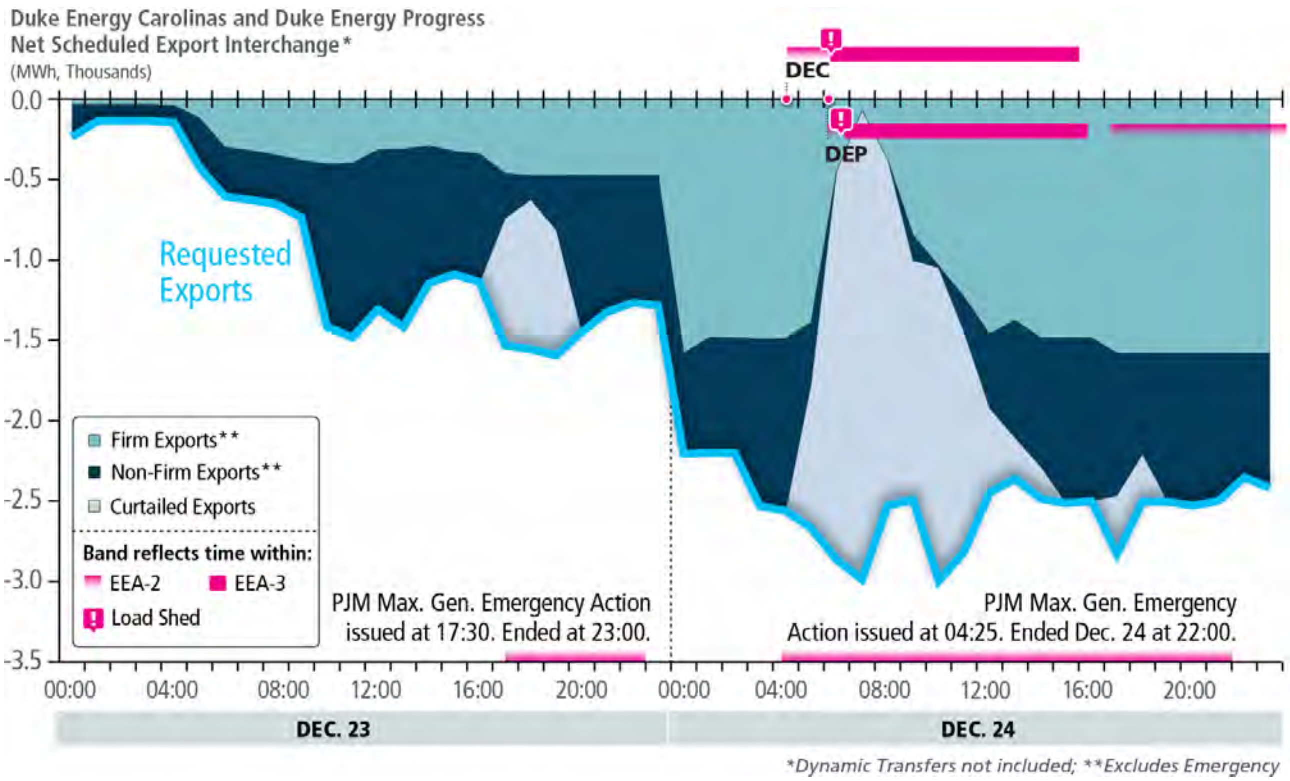
**Figure 26.** TVA BA Net Scheduled Export Exchange




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.

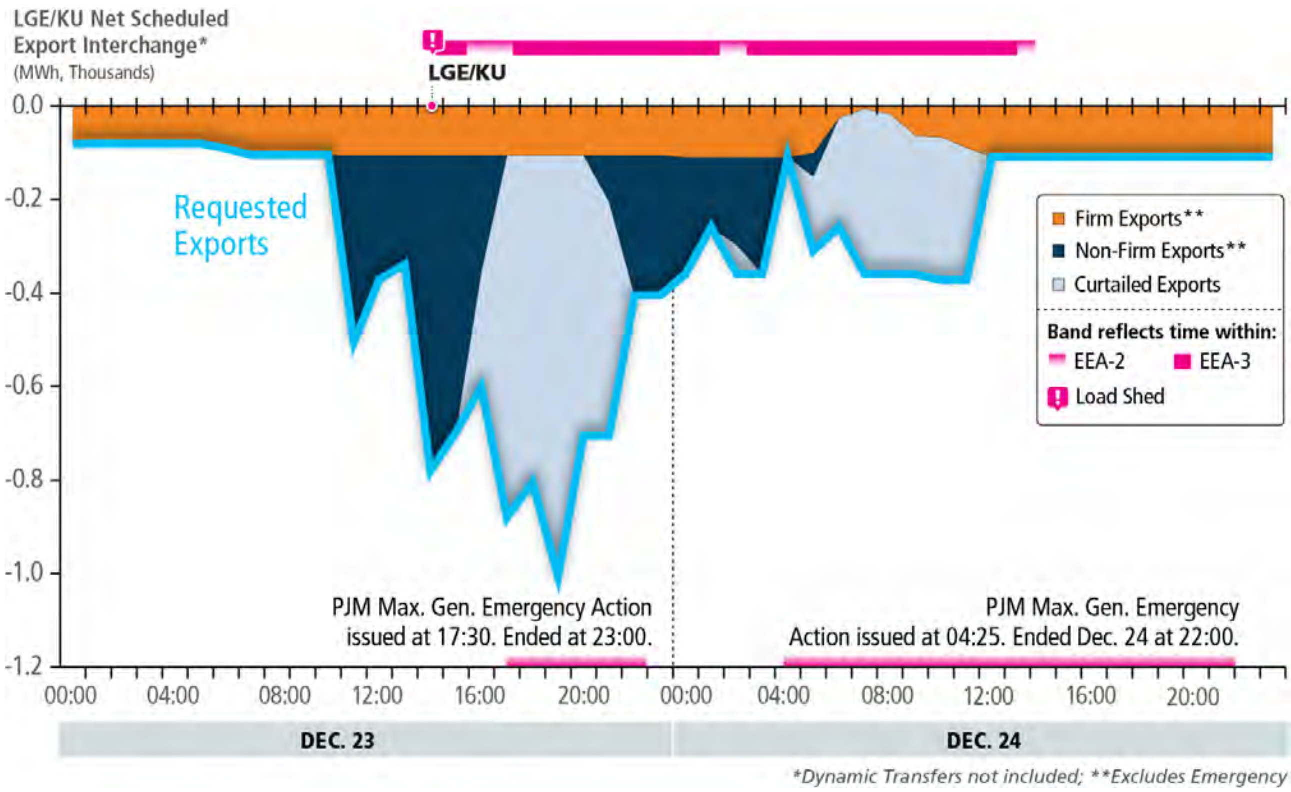
**Figure 27.** Duke Energy Carolinas & Duke Energy Progress Net Scheduled Export Interchange




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

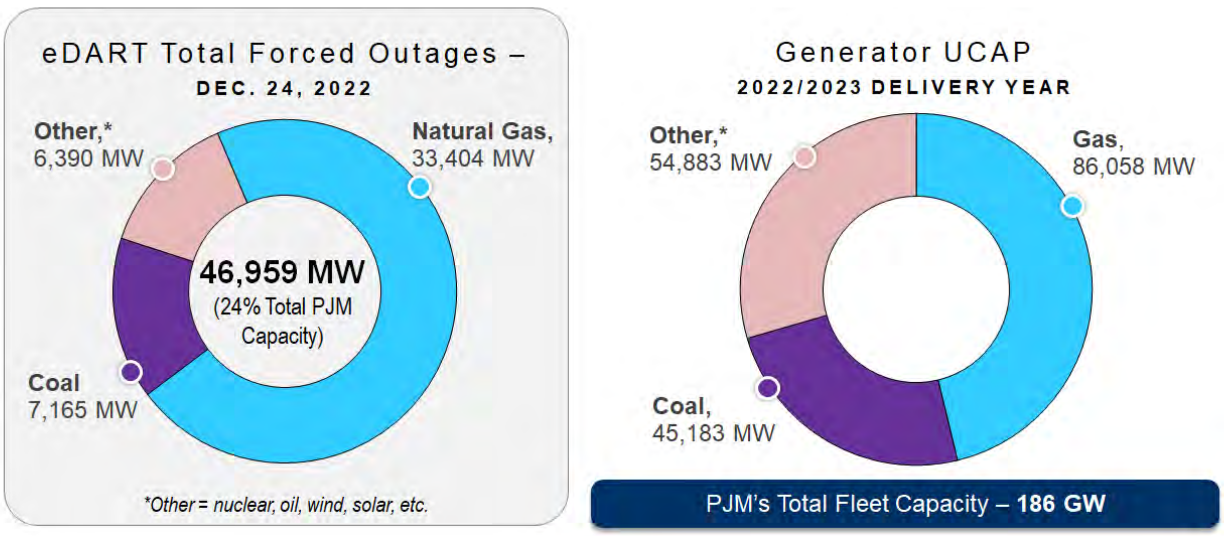
Elliott and did expect additional unplanned generation outages. For reference, the historic forced outage rate for winter is ~4.7%. The peak outage rate for the 2020/2021 winter period was 7.9%[7] and was 7.6%[8] for the 2021/2022 winter period.

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.

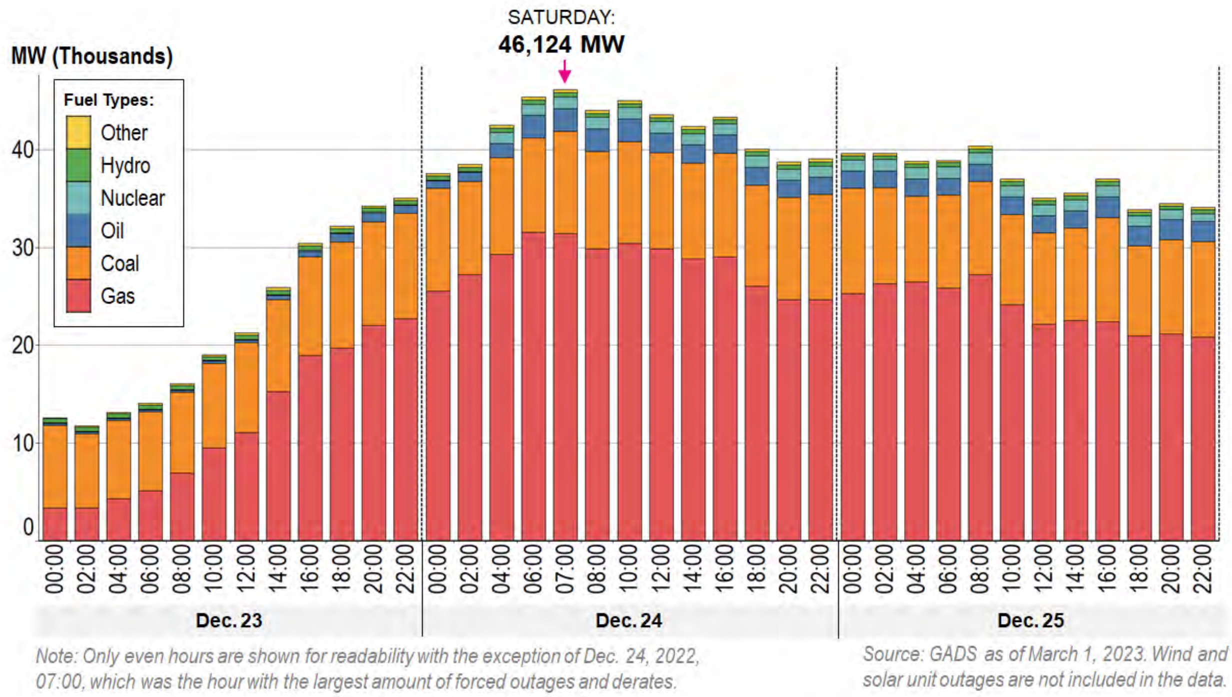
**Figure 29.** Forced Outages




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.

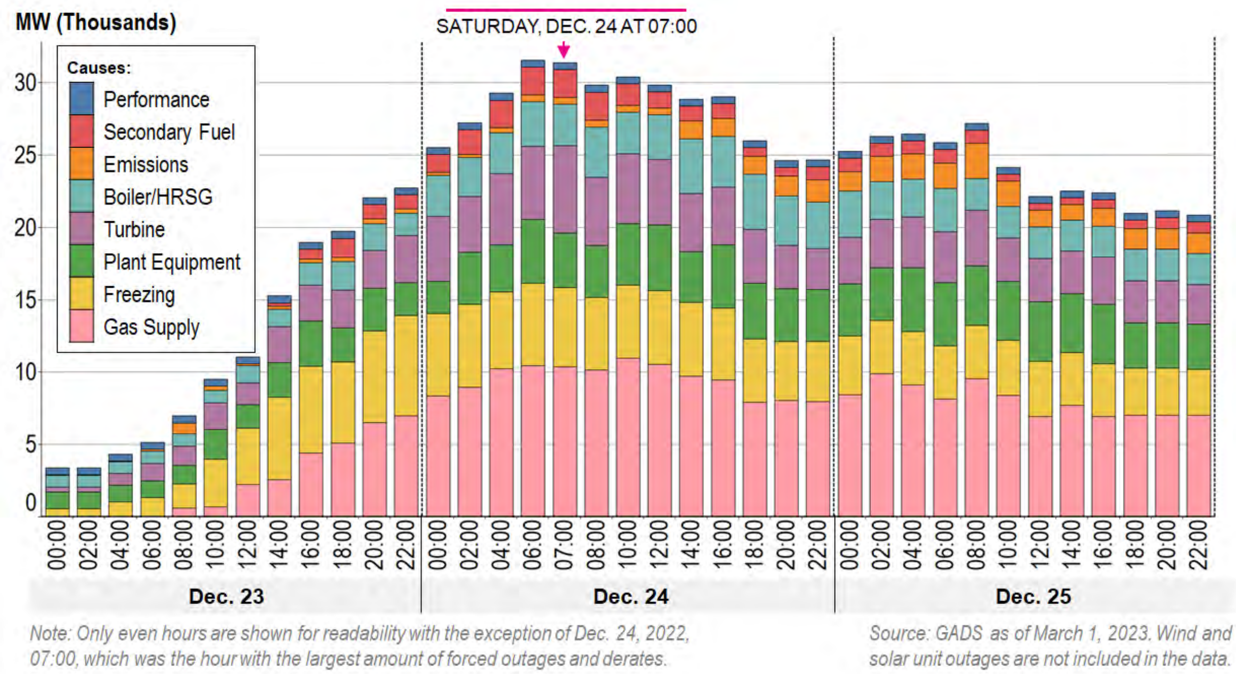
[7] Winter Operations of the PJM Grid: Dec. 1, 2020 – Feb. 28, 2021, PJM Operating Committee, April 8, 2021
[8] Winter Operations of the PJM Grid: Dec. 1, 2021 – Feb. 28, 2022, PJM Operating Committee, April 14, 2022

**Figure 30.** Dec. 23 and Dec. 24 Forced Outages



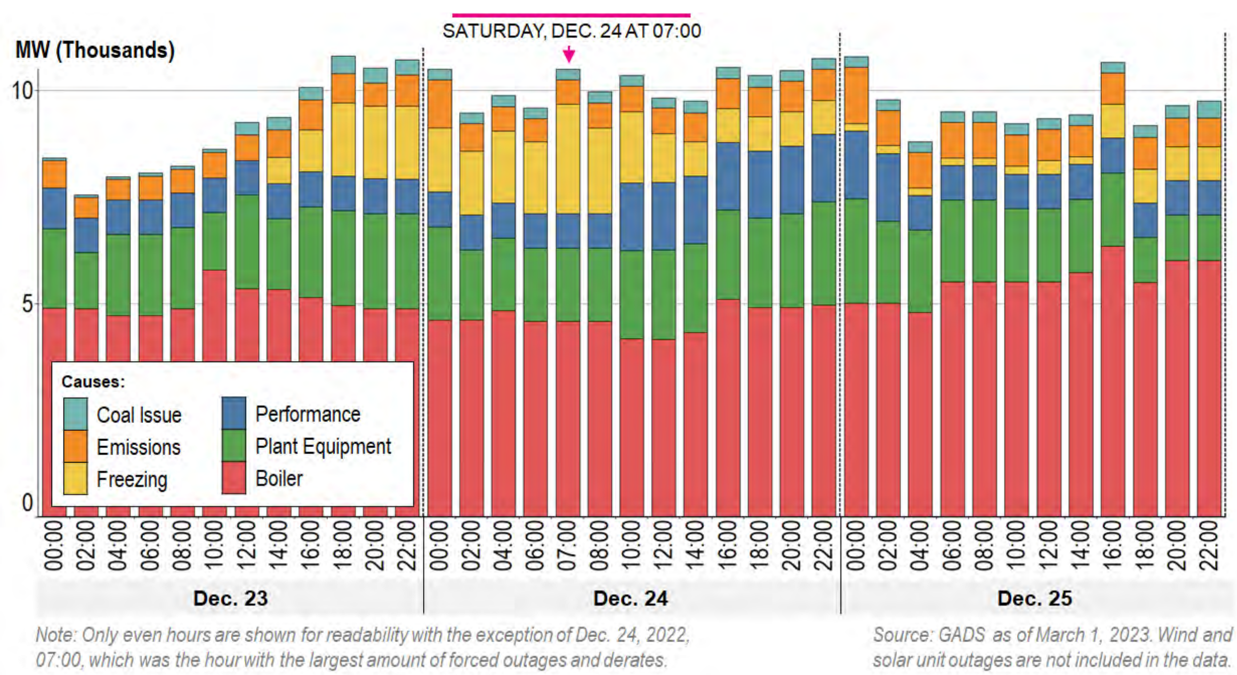

Looking more closely at the causes for the generation outages by fuel type indicates that various plant and mechanical failures, including freeze-related issues, were the major reasons units were unavailable. **Figure 31** presents the gas unit forced outages. As with other resource types, outages on 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



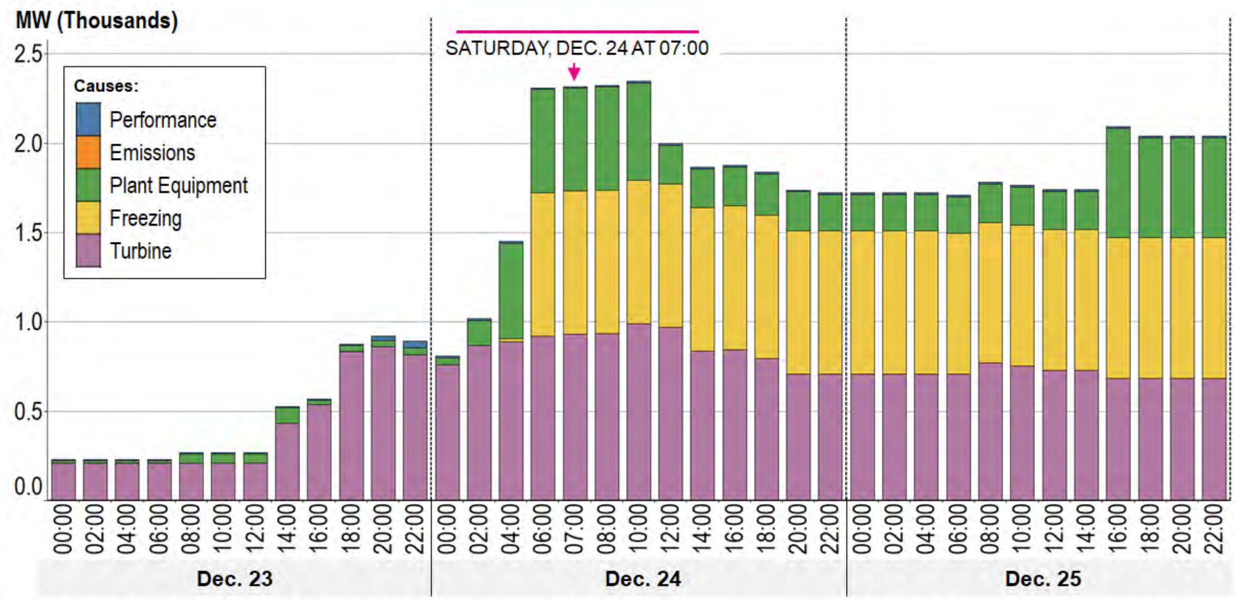

As presented in **Figure 32**, for coal units, boiler problems and tube leaks were the primary cause of outages and derates followed by other plant equipment issues. Freezing issues increased starting around 14:00 on Dec. 23 and peaked at approximately 07:00 on Dec. 24.

**Figure 32.** Dec. 23, 24 and 25 Coal Forced Outages/Derates by Cause



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

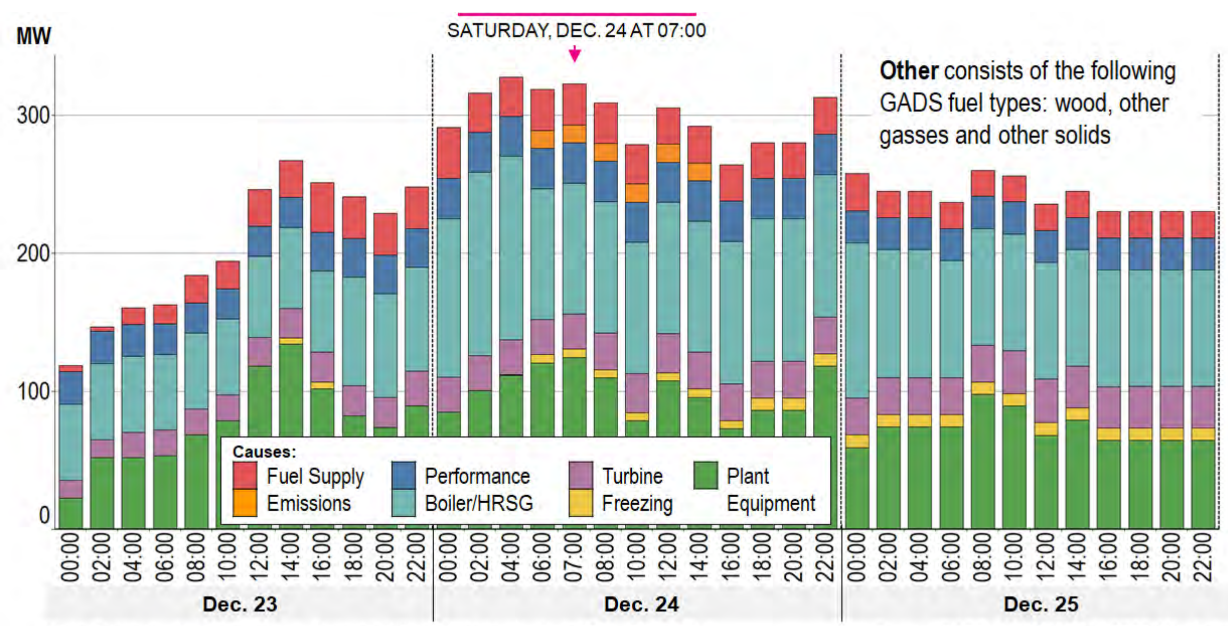



*Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.*

*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

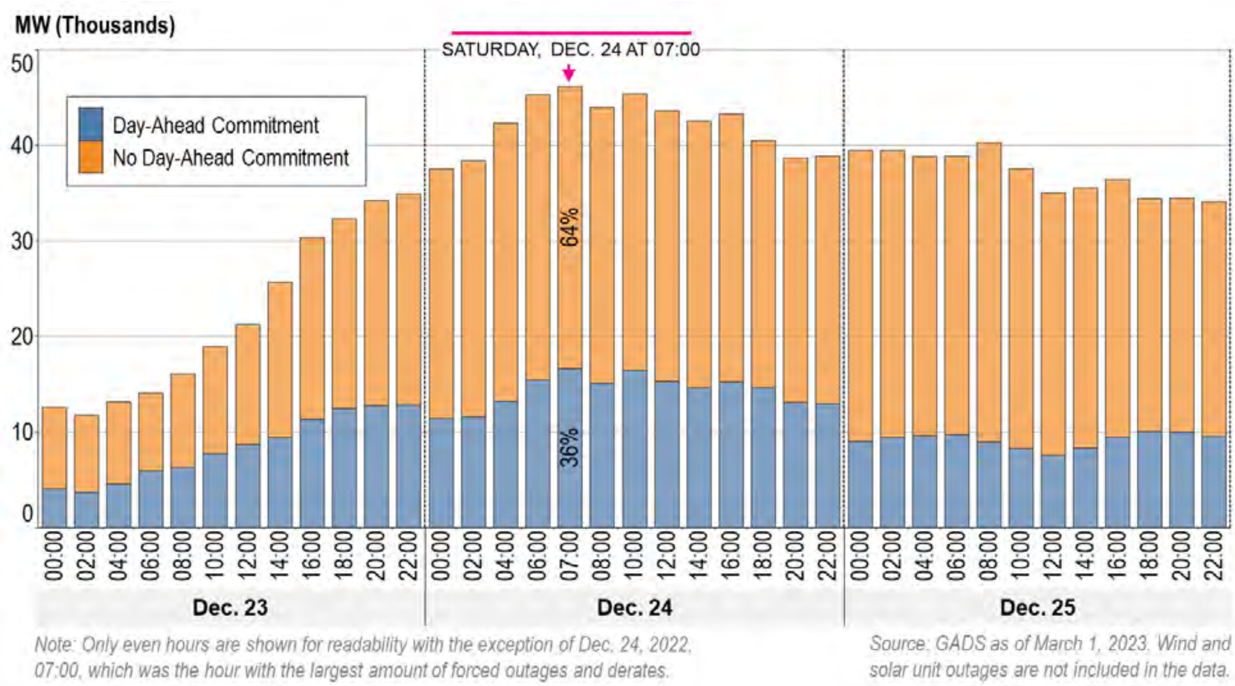



*Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.*

*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.

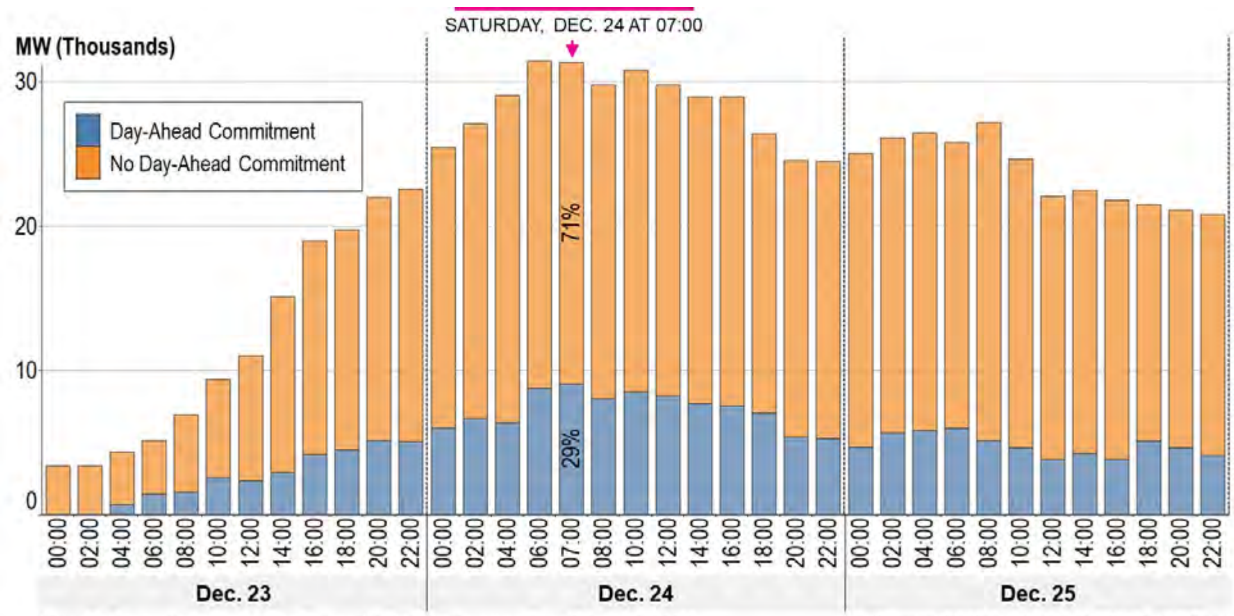
**Figure 35.** Dec. 23, 24 and 25 Forced Outages With and Without Day-Ahead Market Commitment




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




*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.*

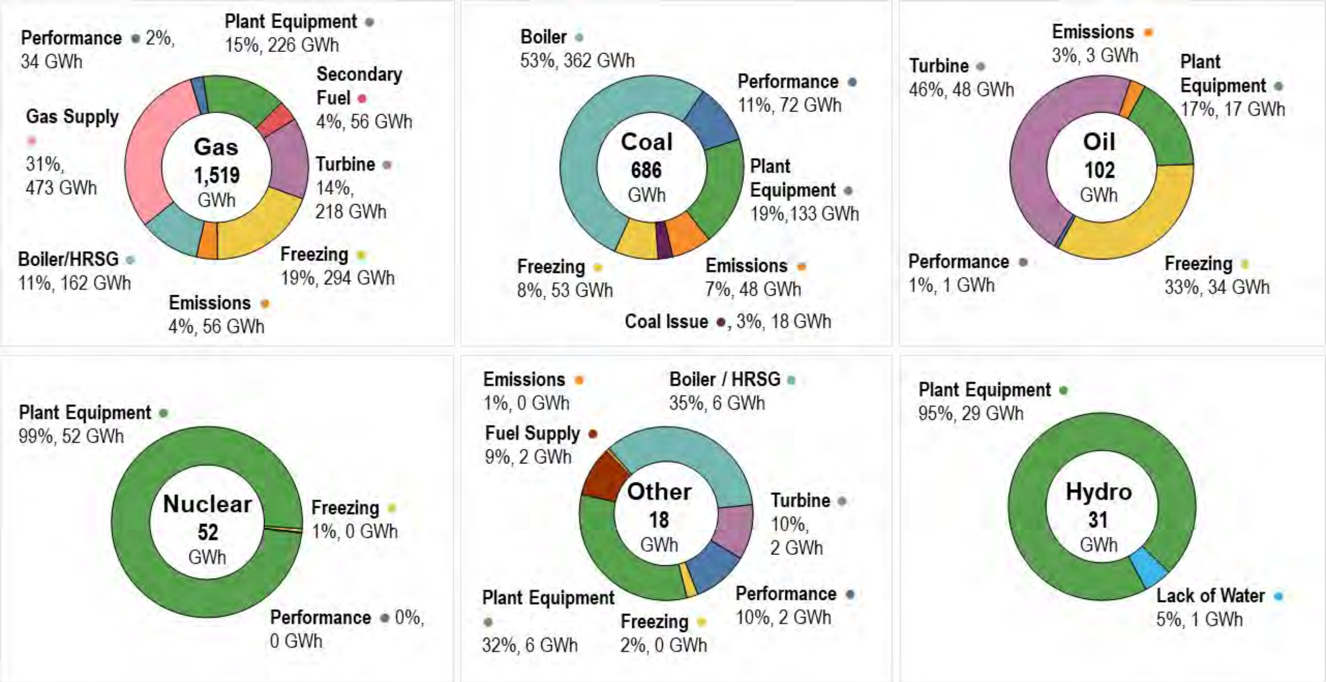
In addition to forced outages, approximately 6,000 MW of steam generation was called but was not online as expected per their time to start for the morning peak on Dec. 24. The vast majority of these resources were gas-fired resources.

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

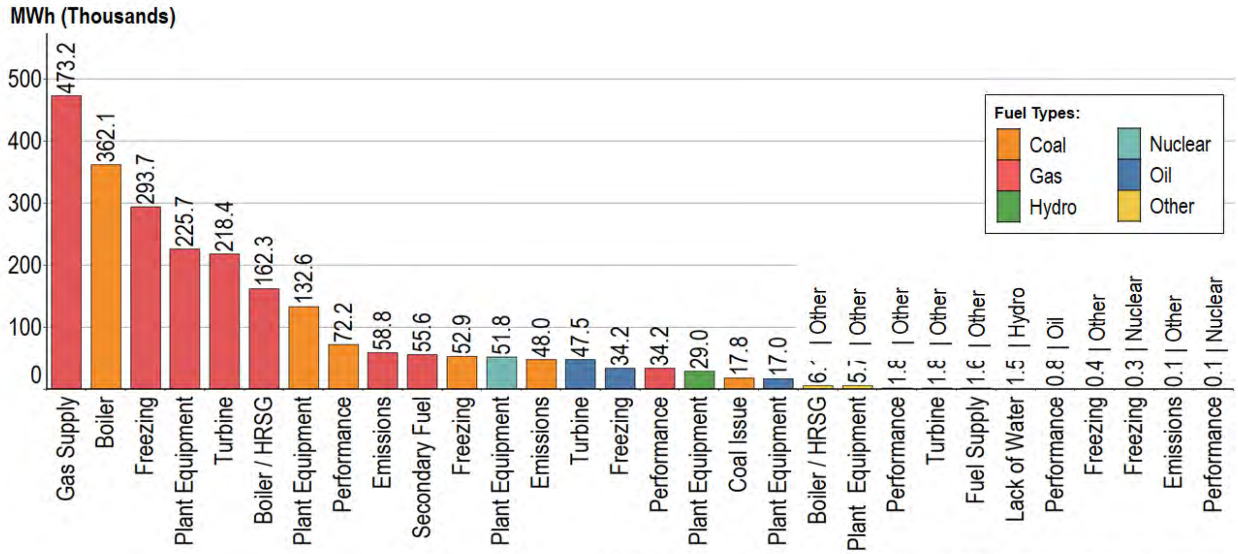



In **Figure 38**, total available MWh for the period of Dec. 23 to Dec. 25 was calculated by multiplying GADS Net Dependable Capacity by 72 hours. The MWh outage rates shown in **Figure 38** were then overlaid to show availability by fuel type.

**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




*Source: GADS as of March 1, 2023. Wind and solar unit outages are not included in the data.*

## *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

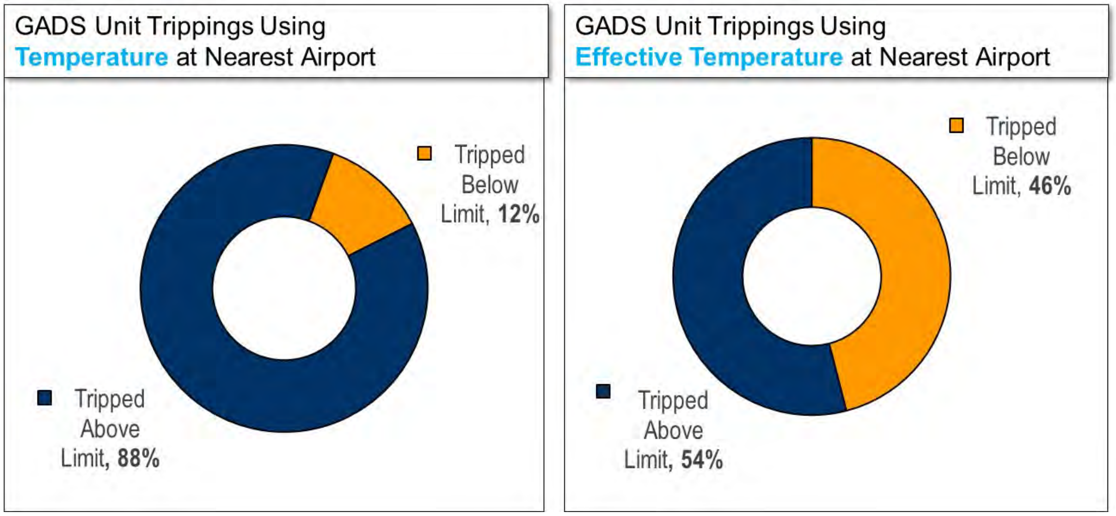
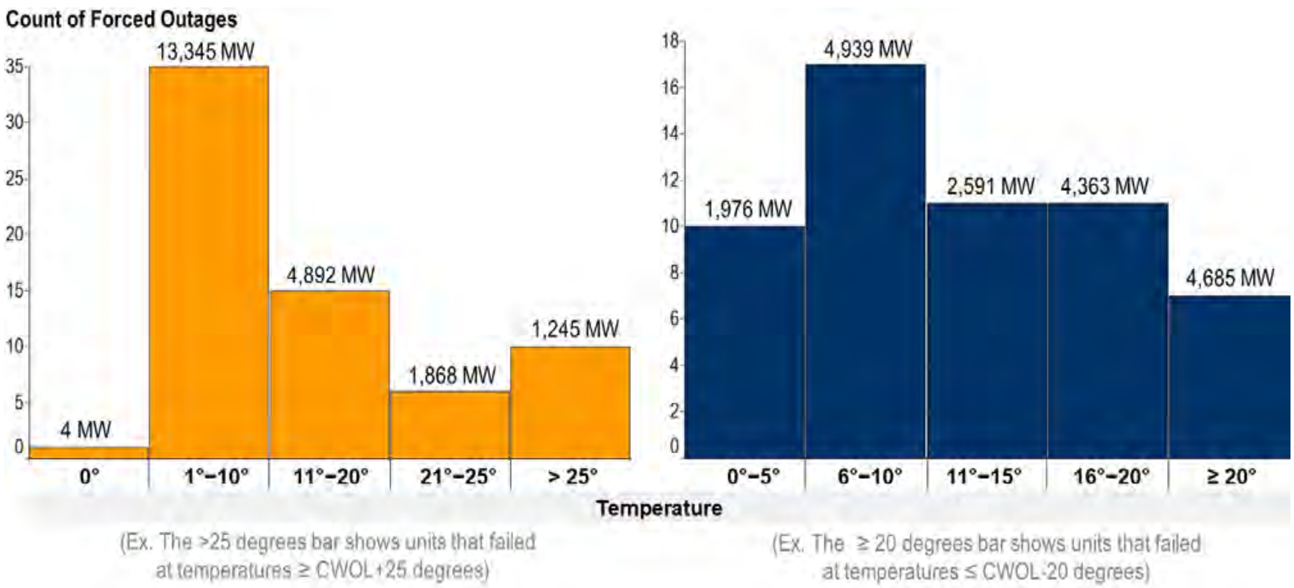



Figure 41 presents a comparison of the effective temperatures experienced by units at the time of a cold weather-related forced outage with their submitted CWOL temperature. The chart to the left presents the MW quantity of the units that failed at different temperatures ranges prior to reaching their 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

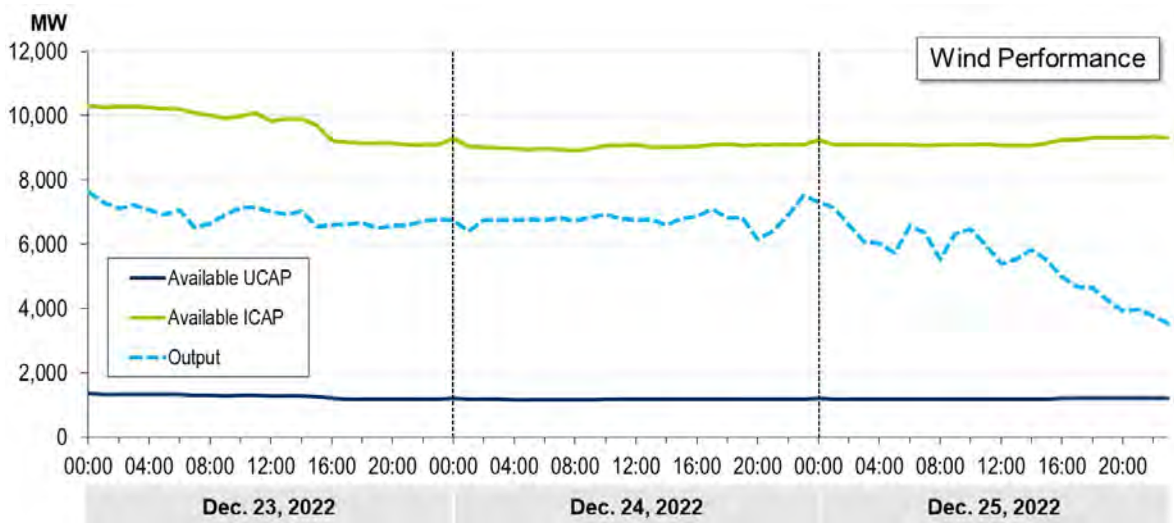
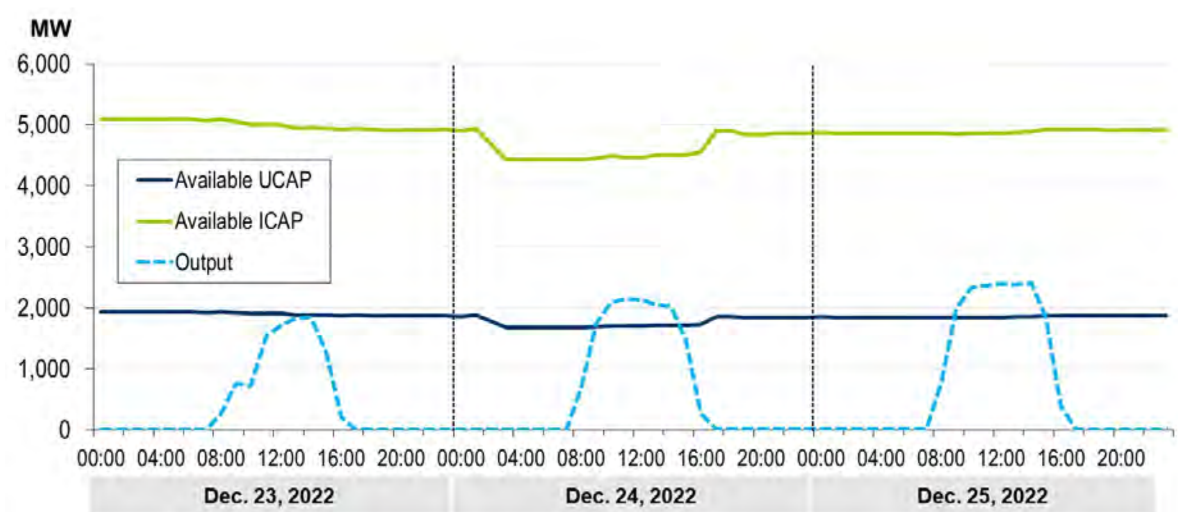



**Figure 43.** Solar Resource Performance

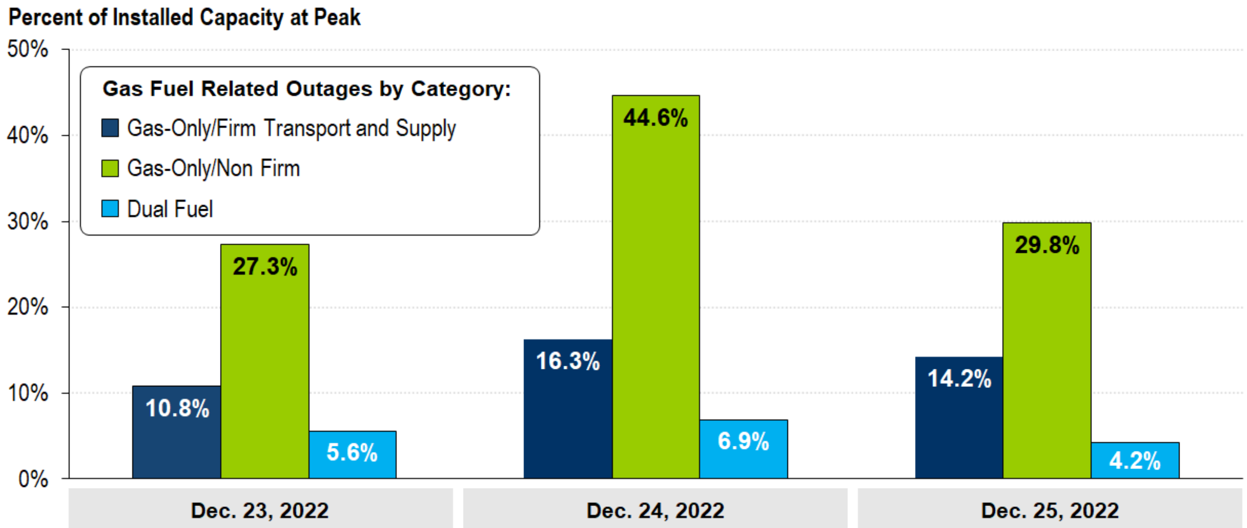



## *Fuel Security Observations*

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.

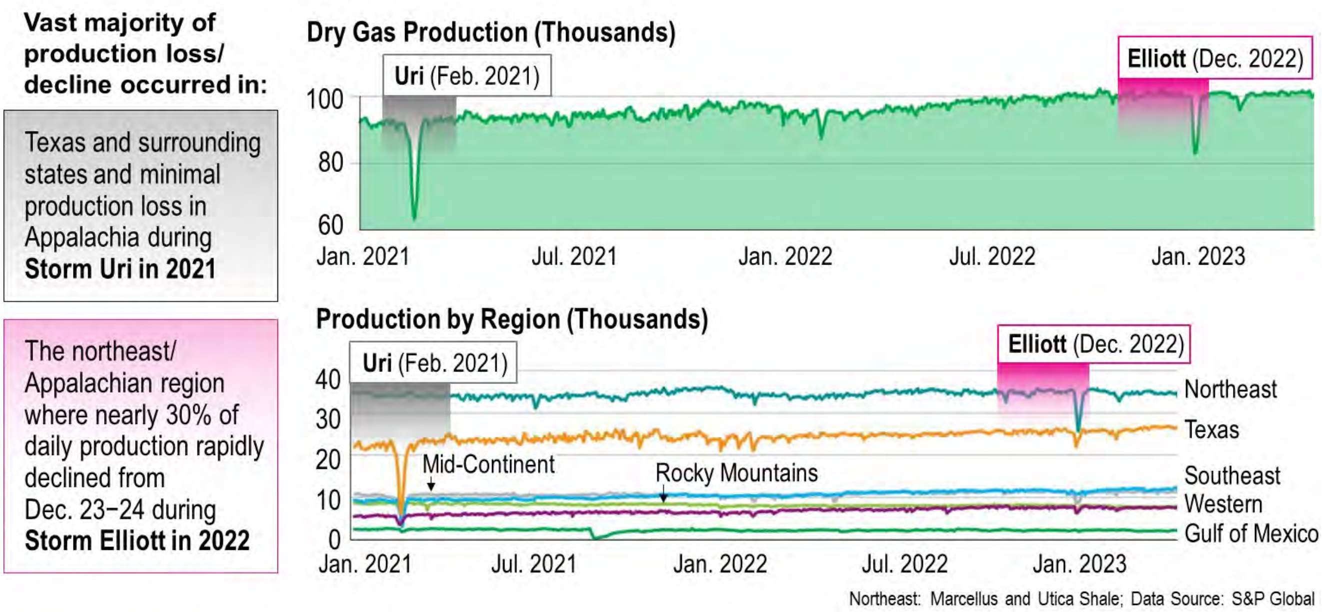
In addition, during this time, several local gas distribution companies (LDCs) began to issue interruption notices for a small number of generators behind their citygates. This is not unexpected during very cold temperatures as LDCs, by nature of their service tariffs, can interrupt gas generation customers 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

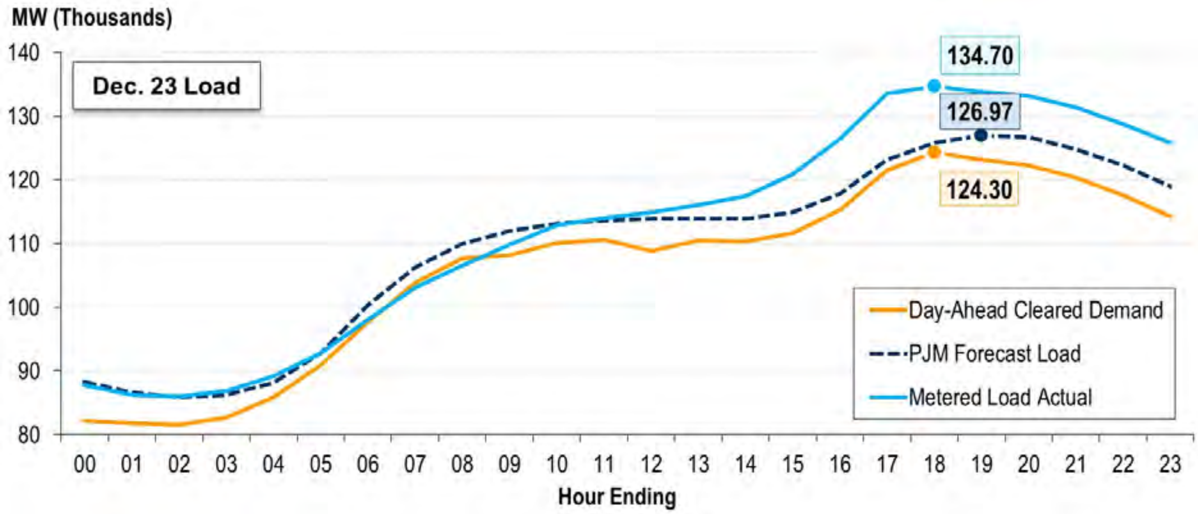
The Day-Ahead Energy Market is a forward market in which hourly clearing prices are calculated for each hour of the next operating day, based on generation offers, demand bids, increment offers, decrement bids, up-to-congestion bids and bilateral transaction schedules submitted into the Day-Ahead Energy 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.

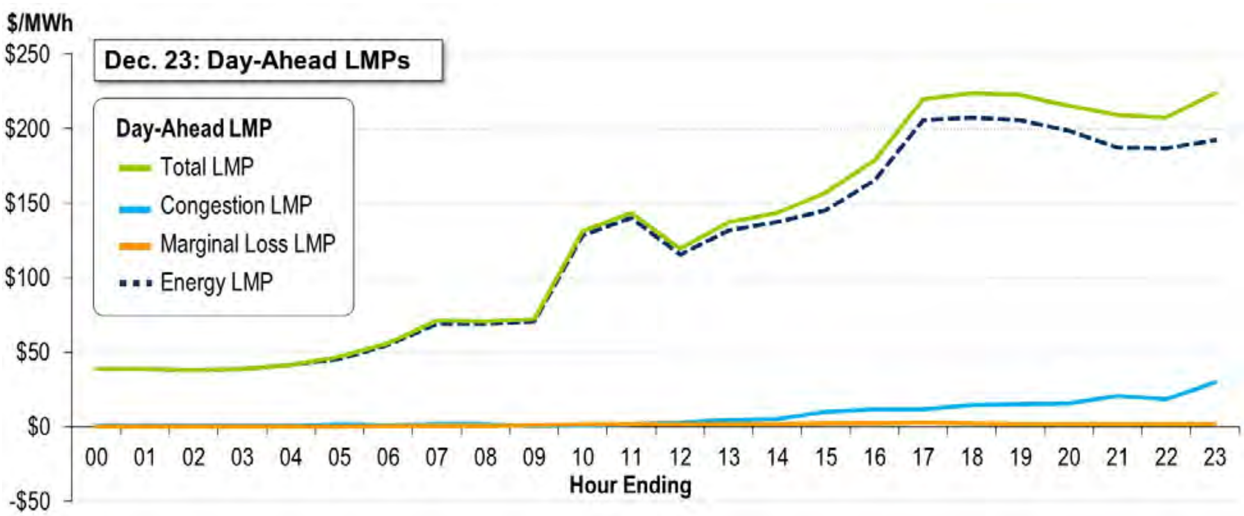
**Figure 46.** Dec. 23 Day-Ahead Cleared Demand, Forecast Load and Metered Load




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

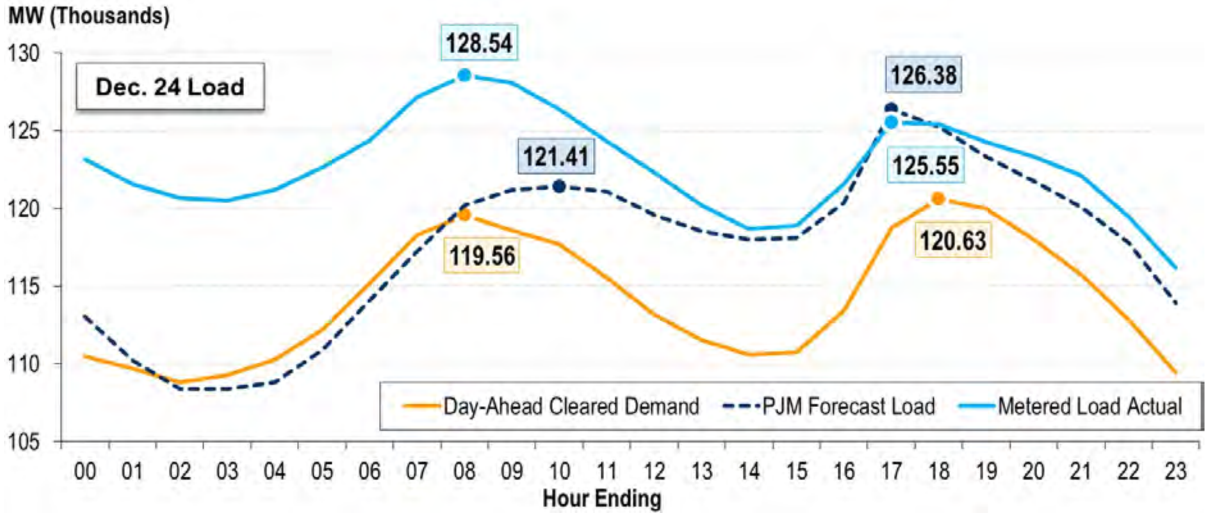



The Day-Ahead LMPs for Dec. 23 were higher than a typical Day-Ahead price, with a peak hourly LMP of $224/MWh. For example, the monthly load-weighted LMP for December 2022 was $93.39/MWh[10]. In the Day-Ahead Market, energy shortage conditions did not occur. LMPs increased in the Day-Ahead Market through 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.

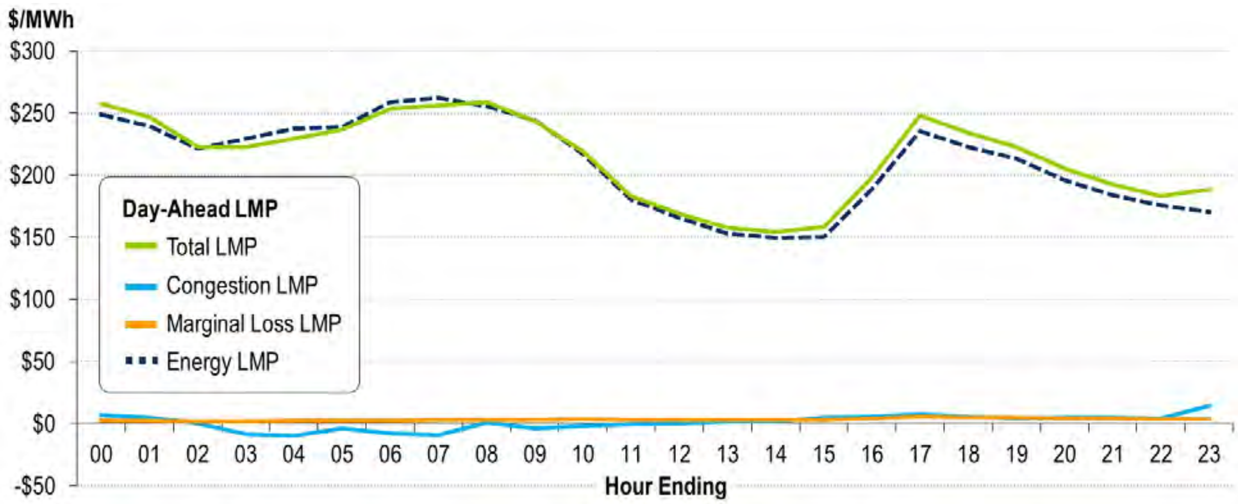
**Figure 48.** Dec. 24 Day-Ahead Cleared Demand, Forecast Load and Metered Load




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% |

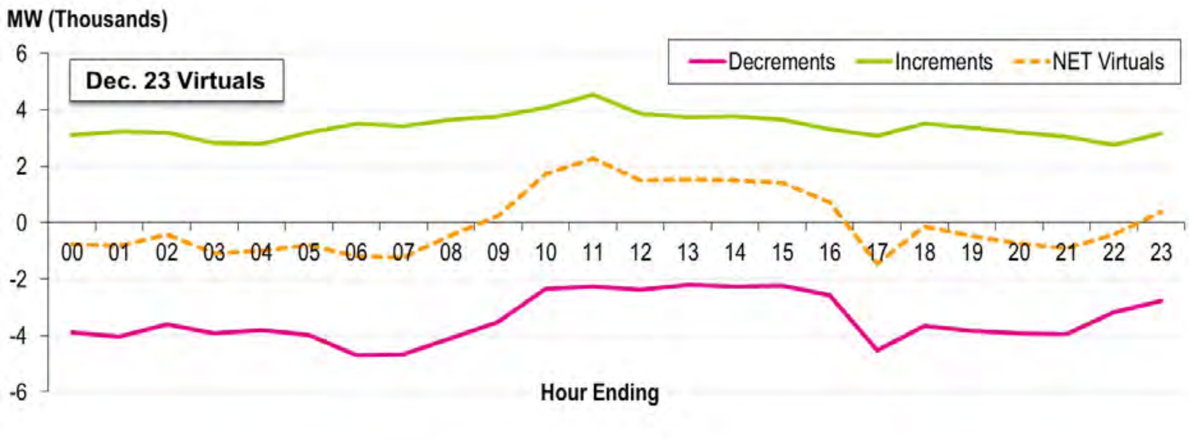
## *Virtual Transactions*

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.

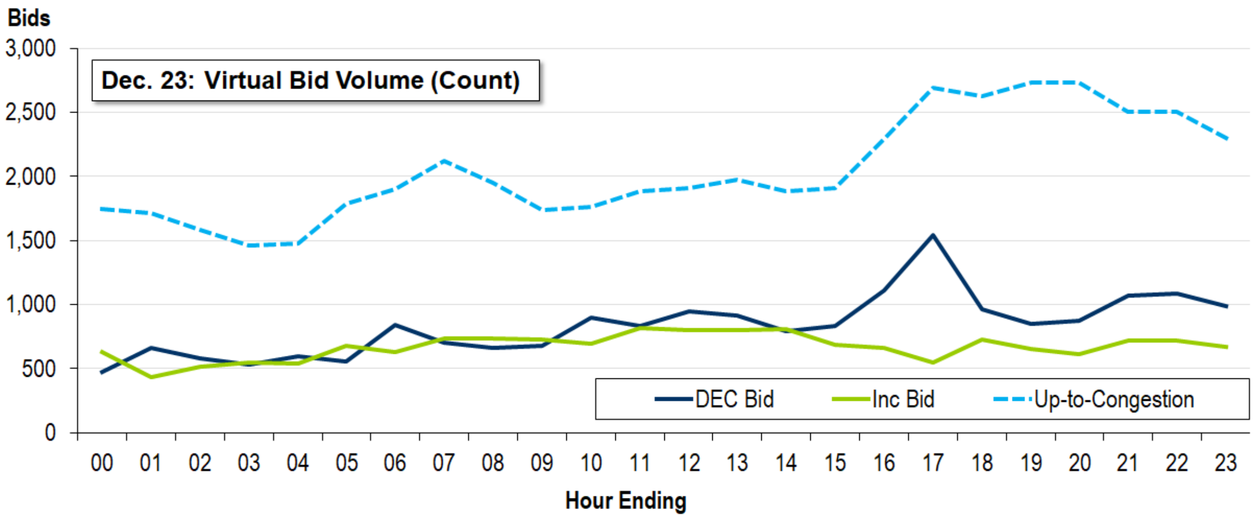
**Figure 50.** Dec. 23 Cleared Virtual Transactions




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.

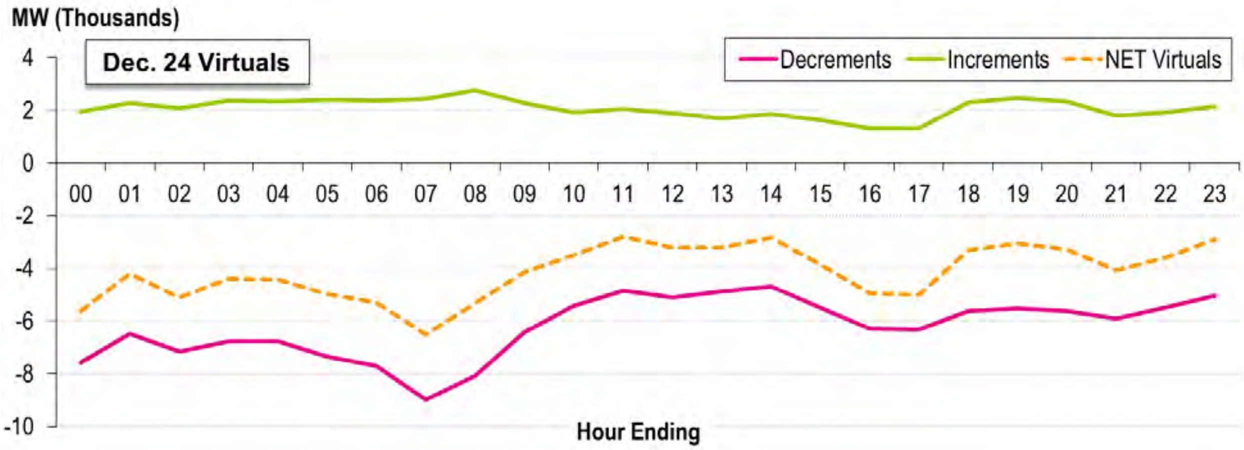
**Figure 51.** Dec. 23 Virtual Transaction Bid Volume




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.

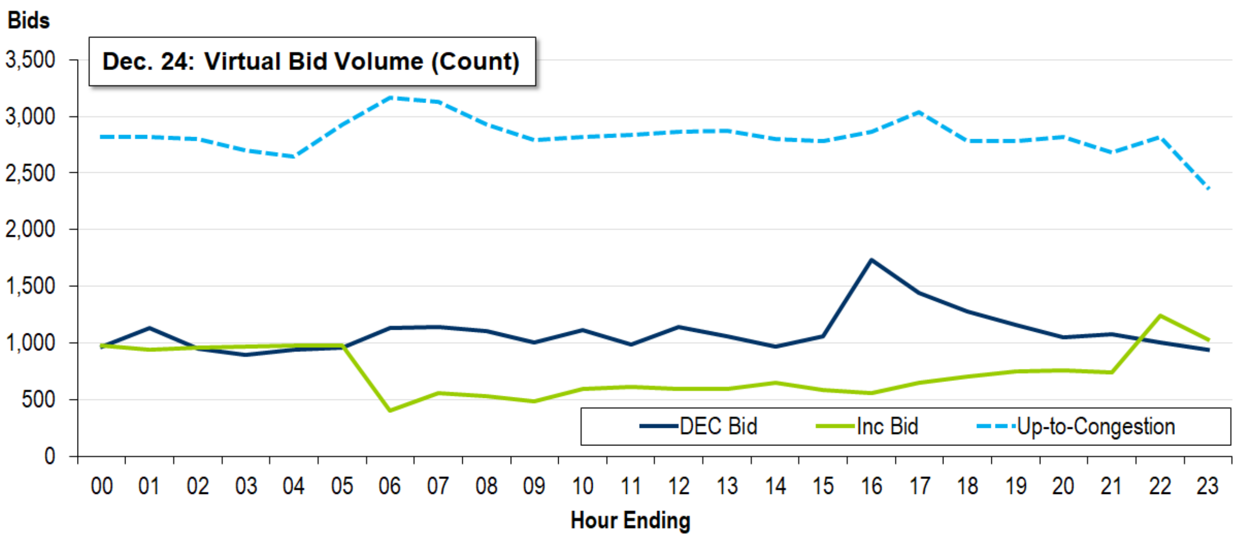
**Figure 52.** Dec. 24 Cleared Virtual Transactions




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

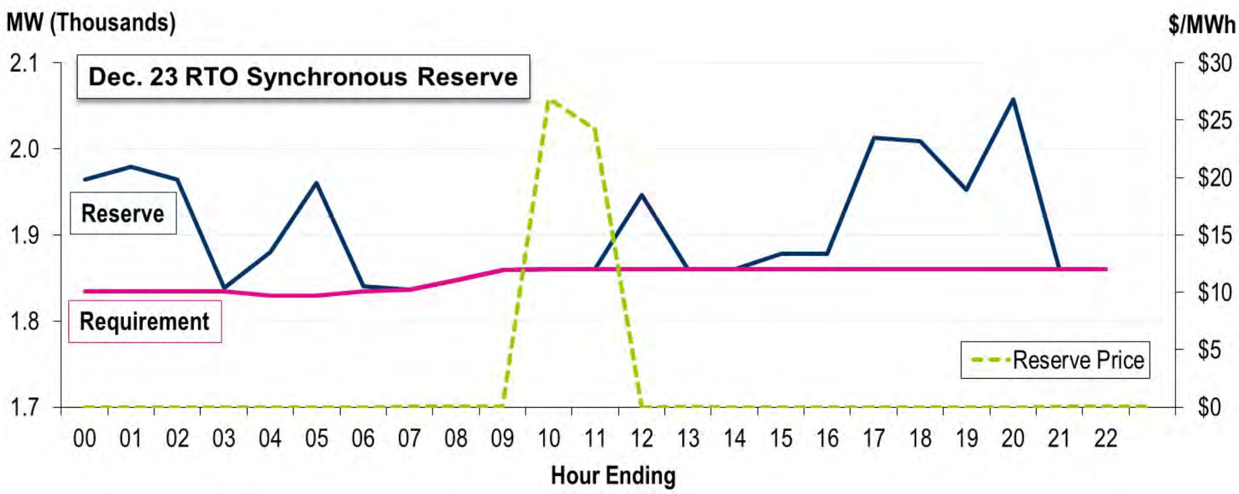
PJM procures resources to meet its reserve requirements, as described earlier in this section, in the Day-Ahead Markets. The clearing of the Day-Ahead Reserve Market results in an hourly price for Synchronized Reserves, Non-Synchronized Reserves and Secondary Reserves for the next day. These prices are 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

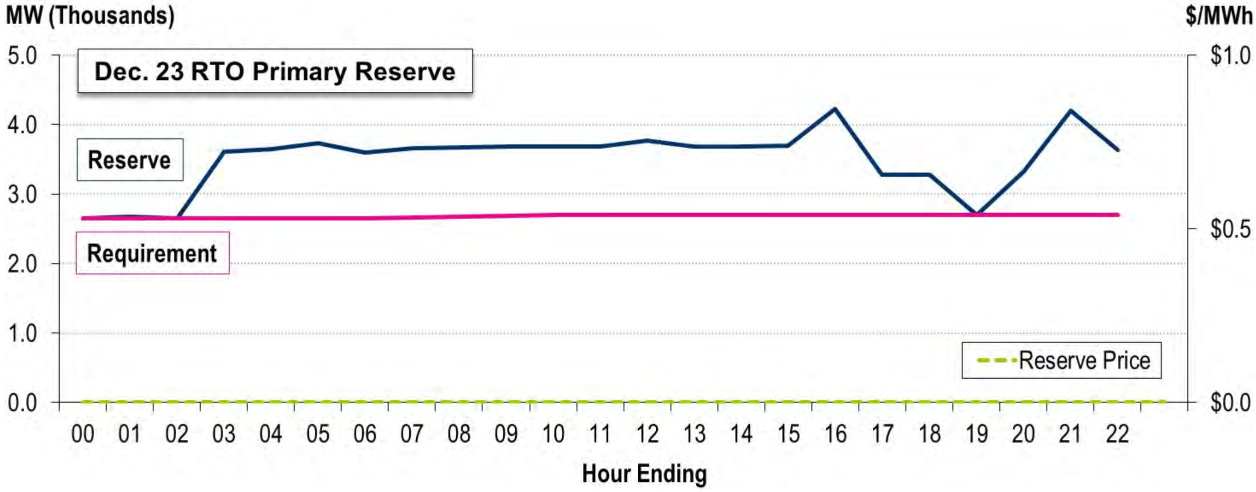
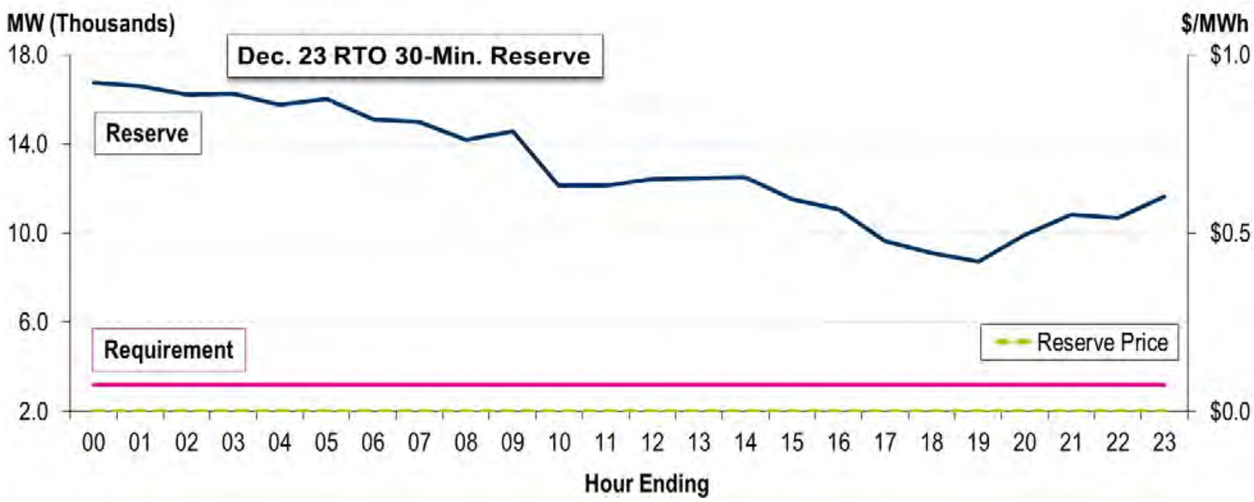



**Figure 56.** Dec. 23 30-Minute Reserve and Prices




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

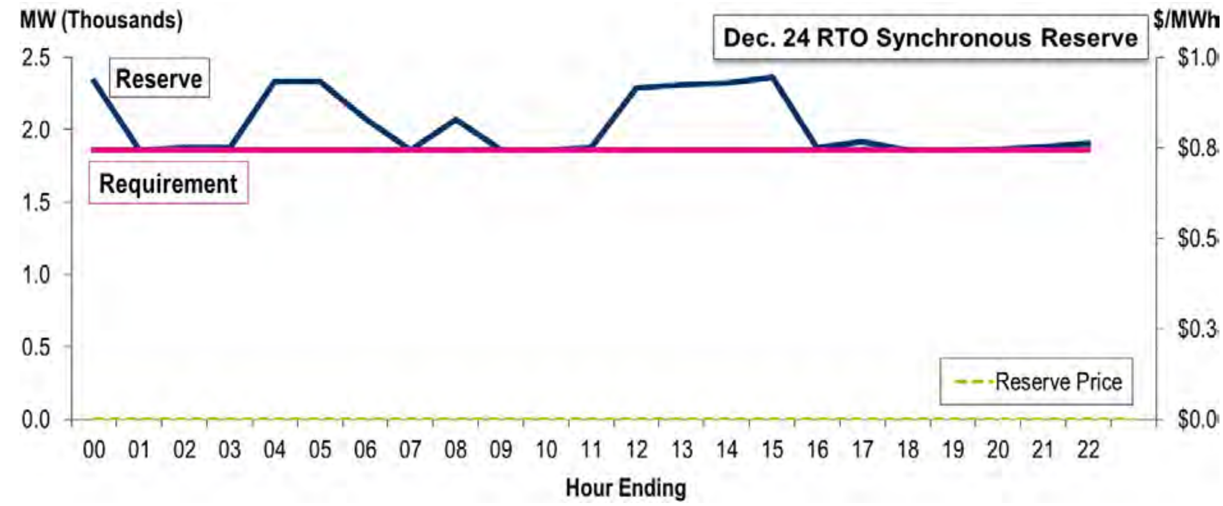



**Figure 58.** Dec. 24 Day-Ahead Primary Reserve

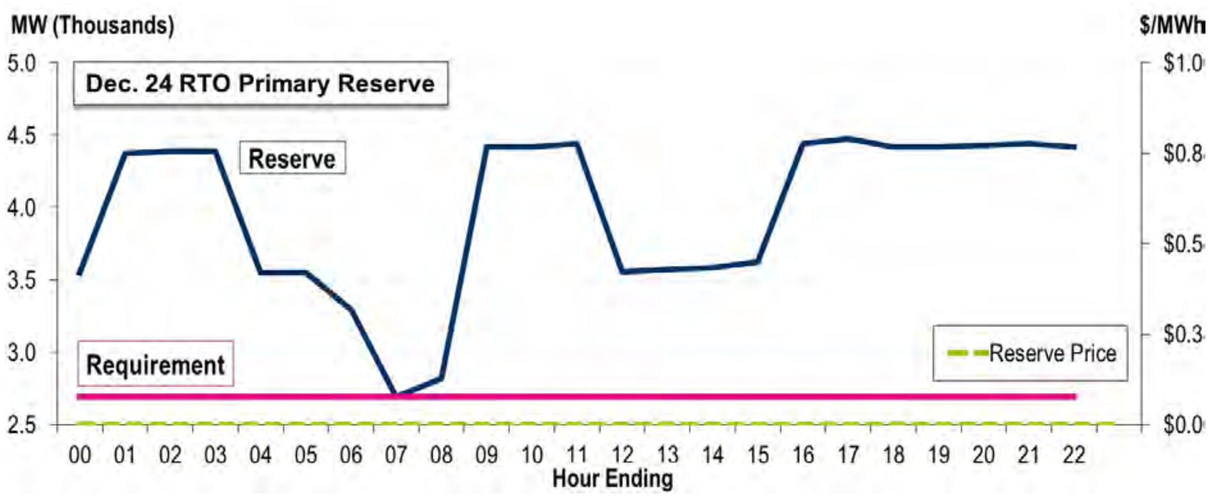
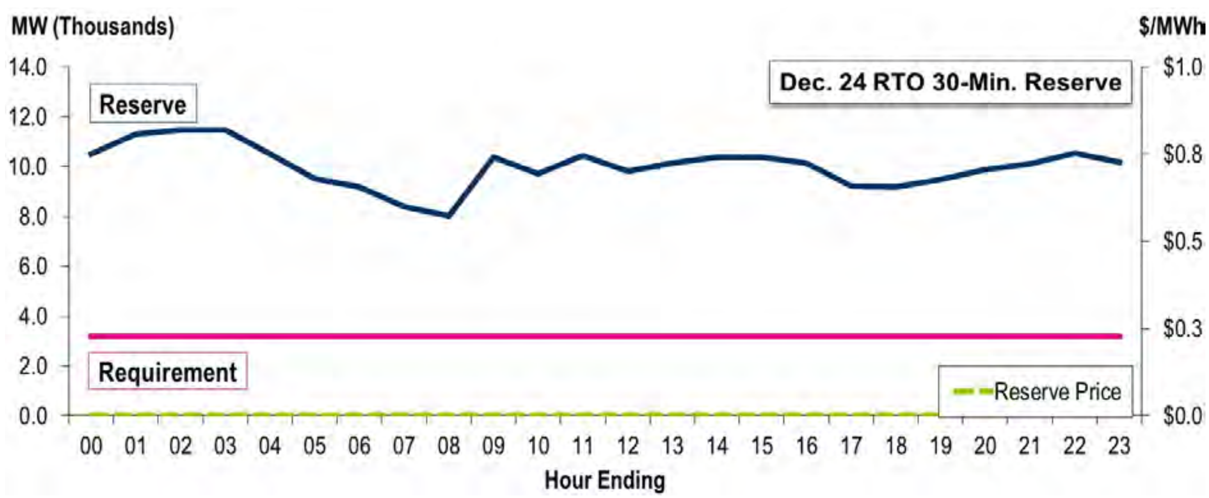



**Figure 59.** Dec. 24 30-Minute Reserve & Prices



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.

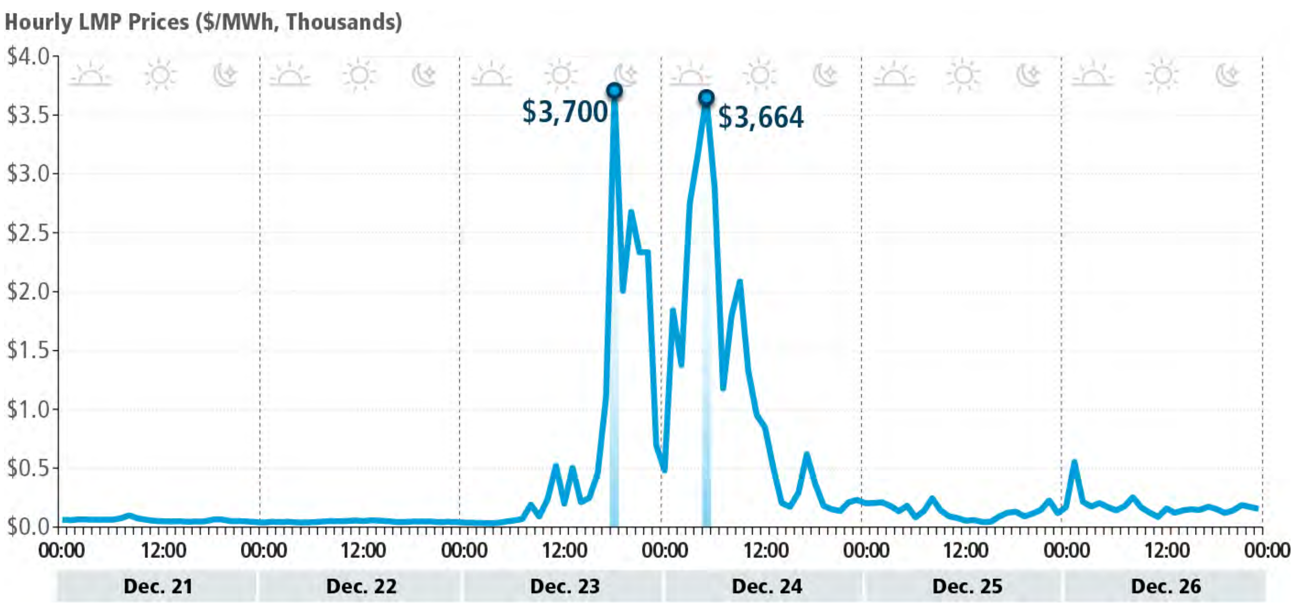
## Real-Time Market Results

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.

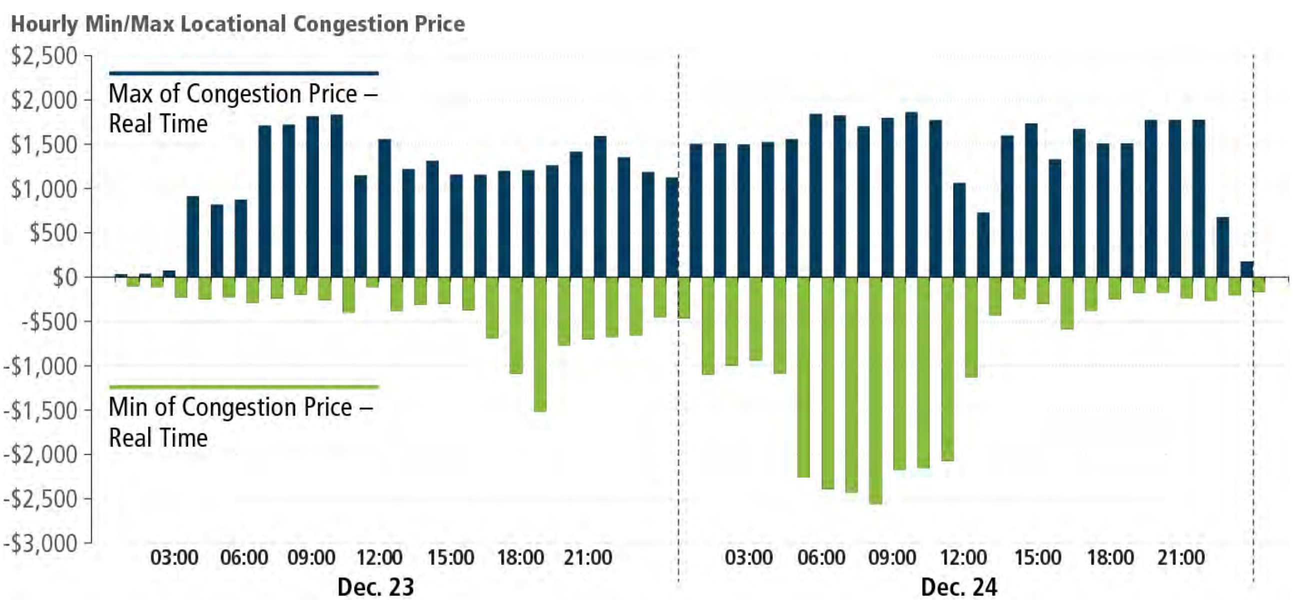
The underlying goal and intent of reflecting the TCPF in LMPs is to provide market signals that incentivize supply and/or load response to help relieve a constraint in the short term, while also incentivizing the development of additional supply, load response and/or transmission upgrades through long-term 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.

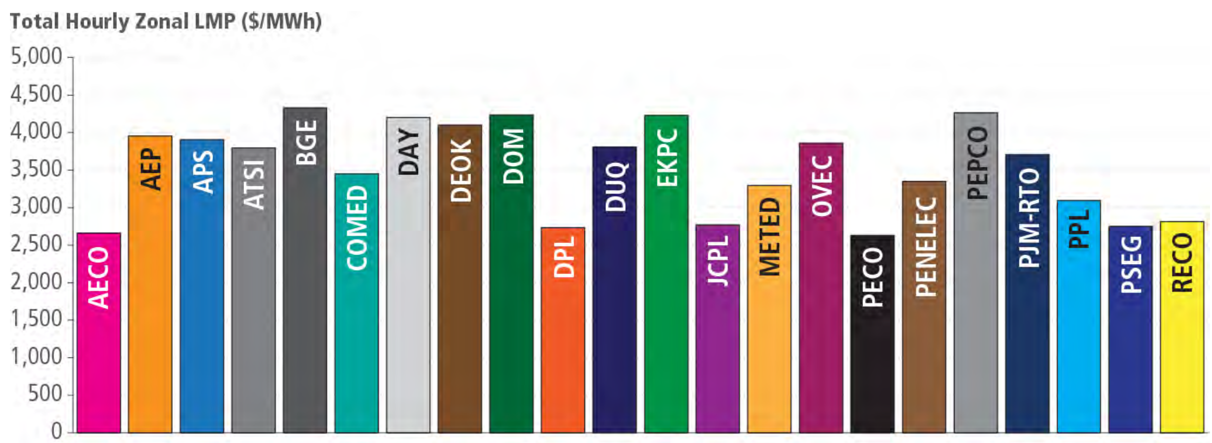
**Table 4.** Dec. 23 and Dec. 24 Binding Constraints on High-Voltage Equipment

| 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<br>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<br>12:30–12:45<br>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.

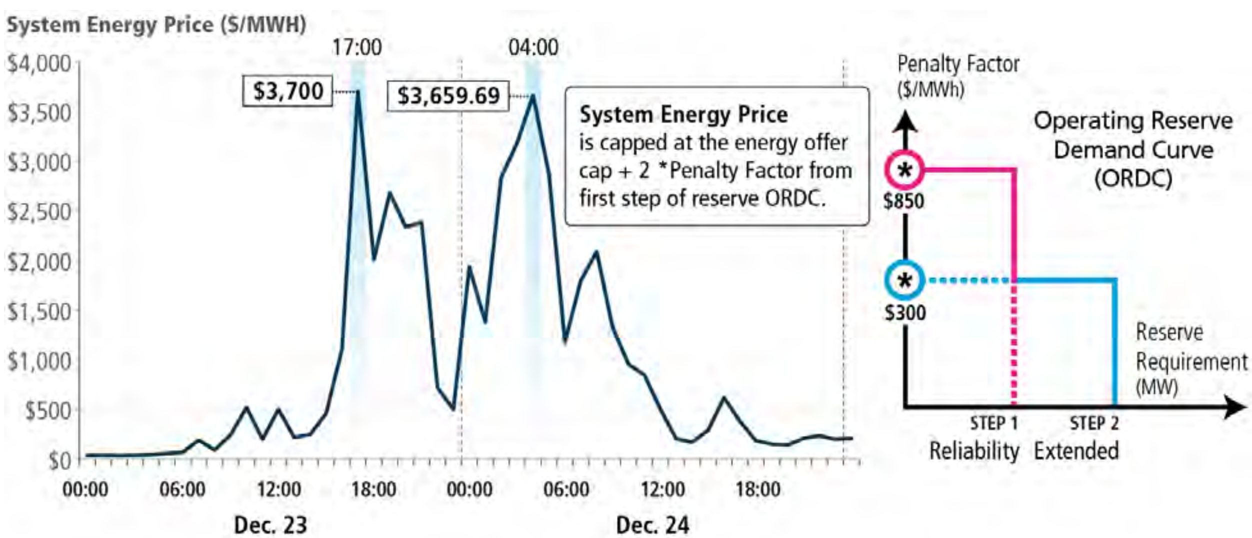
PJM uses Operating Reserve Demand Curves (ORDCs) to set the demand and willingness to pay for each of its reserve products. Like the TCPF, the ORDCs contain Reserve Penalty Factors that function as a cap on the $/MWh cost willing to be incurred to maintain a specific reserve requirement in a specific 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



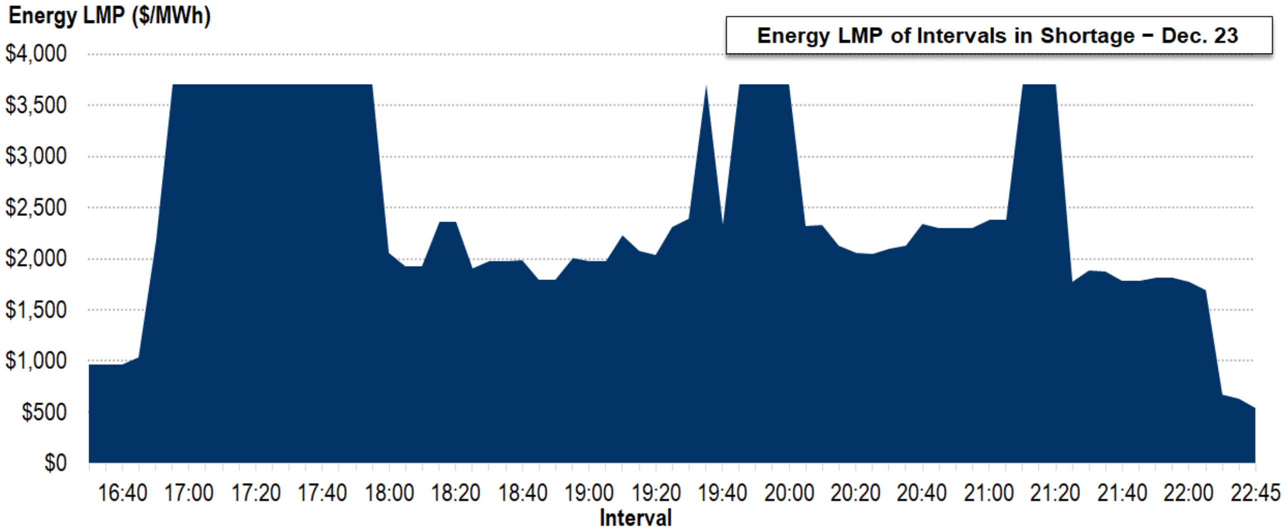

There were 71 shortage intervals approved by PJM Dispatch between 16:30 and 22:45 on Dec. 23. Table 5 reflects the breakdown by Reserve Sub-Zones.

**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.

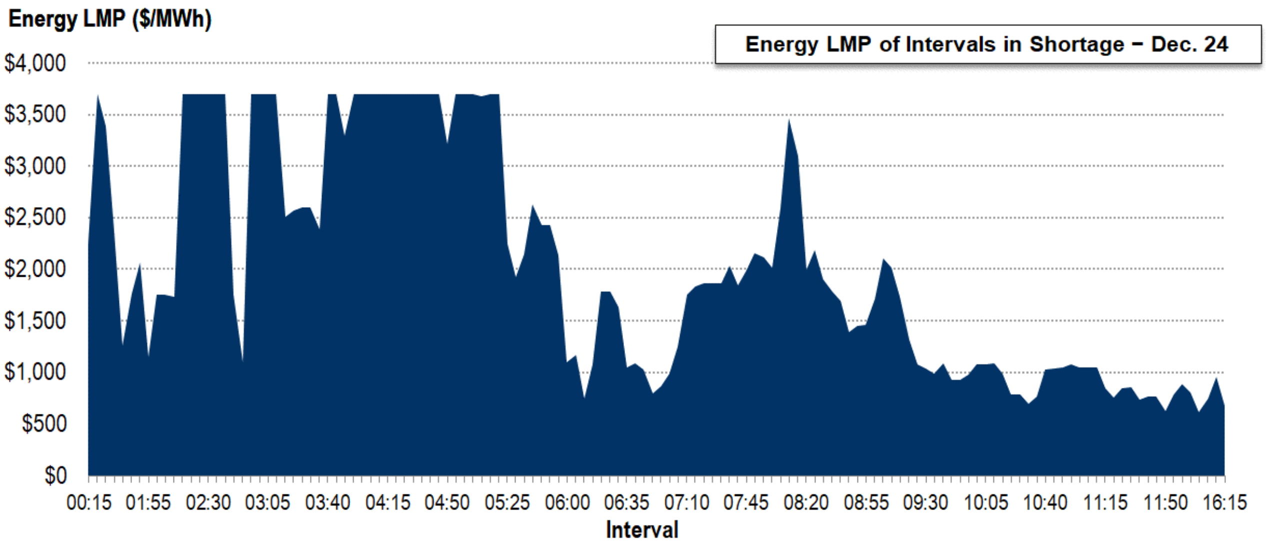
There were 134 shortage intervals approved by PJM Dispatch between 00:15 and 16:15 on Dec. 24. Table 6 presents the breakdown of the shortage intervals by Reserve Sub-Zones.

**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.

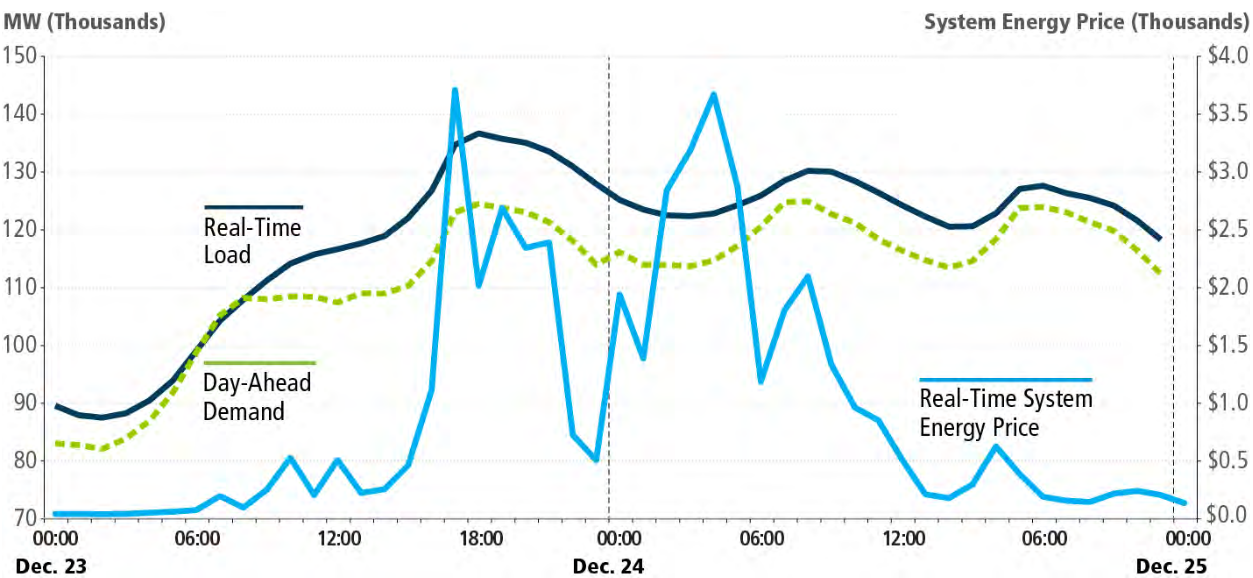
**Figure 67.** Dec. 24 LMPs During Shortage Intervals




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

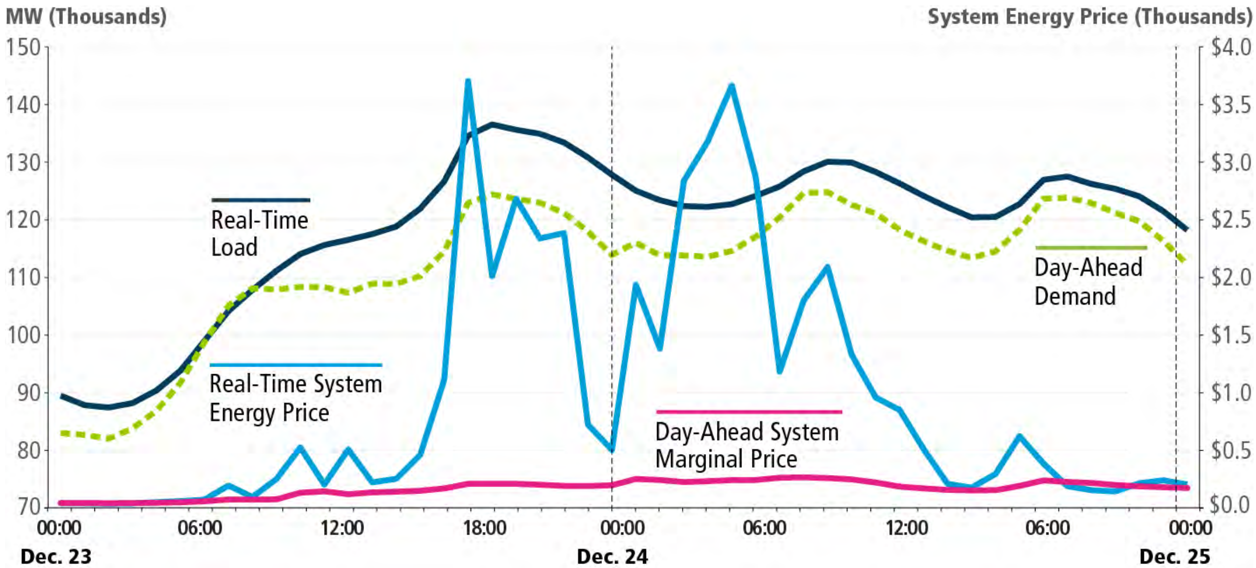


Real-Time LMPs are calculated based on five-minute intervals. Both generation and emergency Demand Response resources can and did set the price.

## *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.

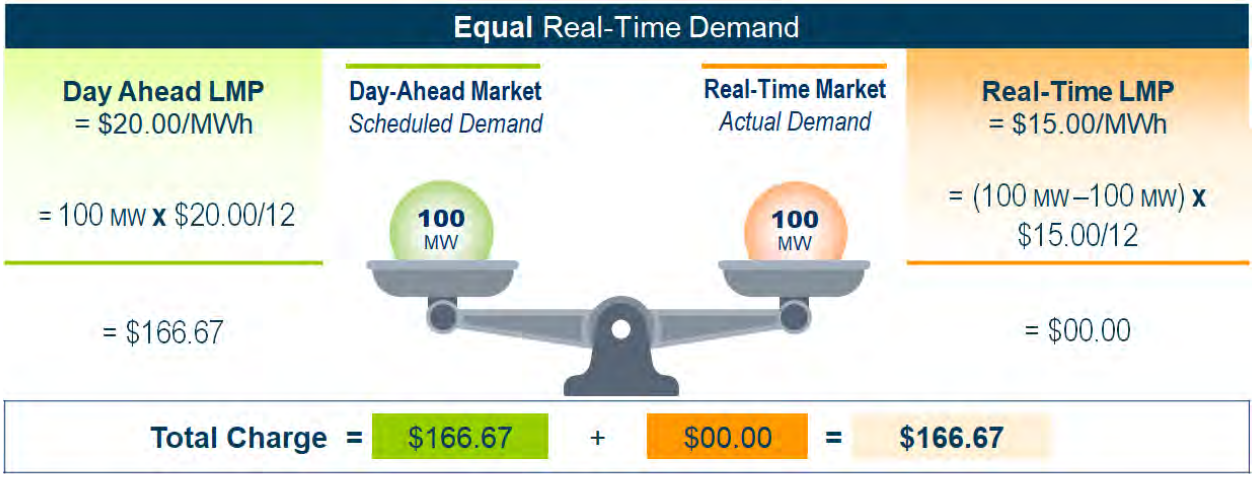
**Figure 69.** Day-Ahead and Real-Time Load and Day-Ahead and Real-Time Hourly System Energy Price




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



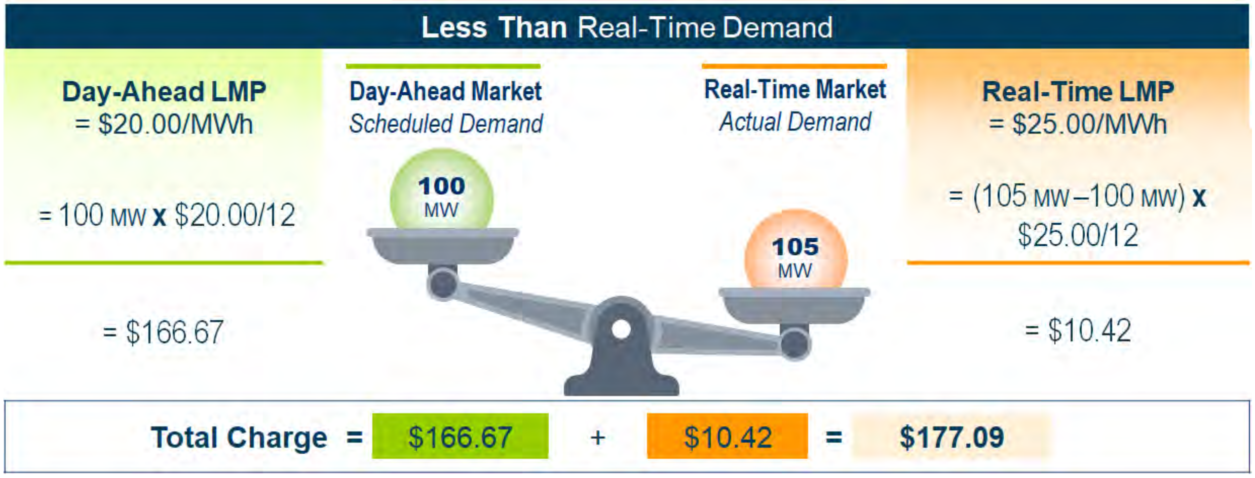

In Figure 70, the LSE submitted a 100 MW bid in the Day-Ahead Market. The Day-Ahead Market cleared at $20.00/MWh. The Day-Ahead Market settlement for this five-minute interval is the day-ahead scheduled demand multiplied by the Day-Ahead LMP divided by 12 (there are 12 five-minute intervals in an hour), 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



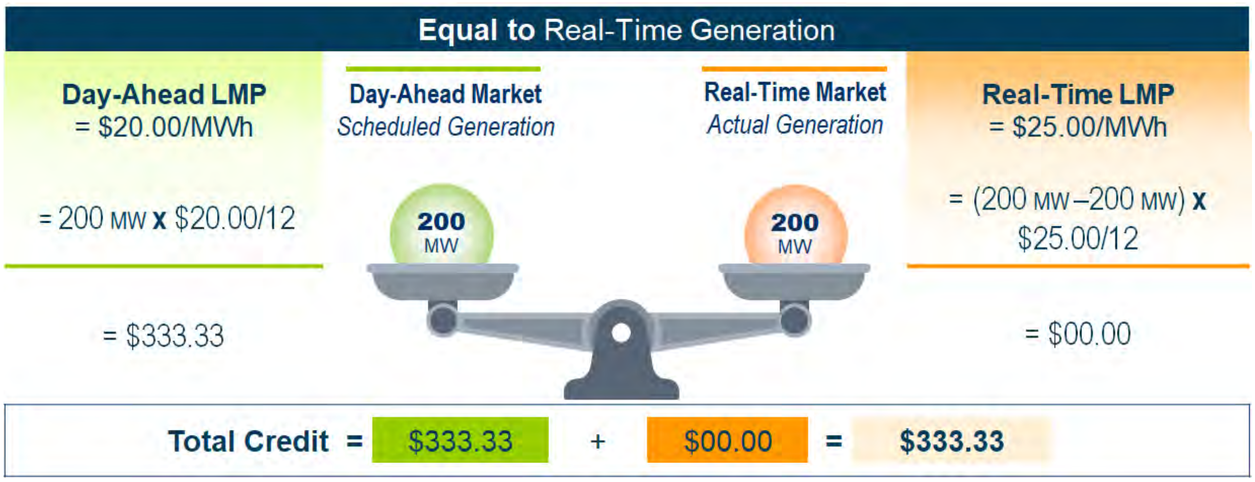
In Figure 71, the LSE submitted a 100 MW bid in the Day-Ahead Market. The Day-Ahead Market cleared at $20.00/MWh. The resulting Day-Ahead Market settlement for this sample five-minute interval is the Day-Ahead scheduled demand multiplied by the Day-Ahead Market LMP, in this case the Day-Ahead Market 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



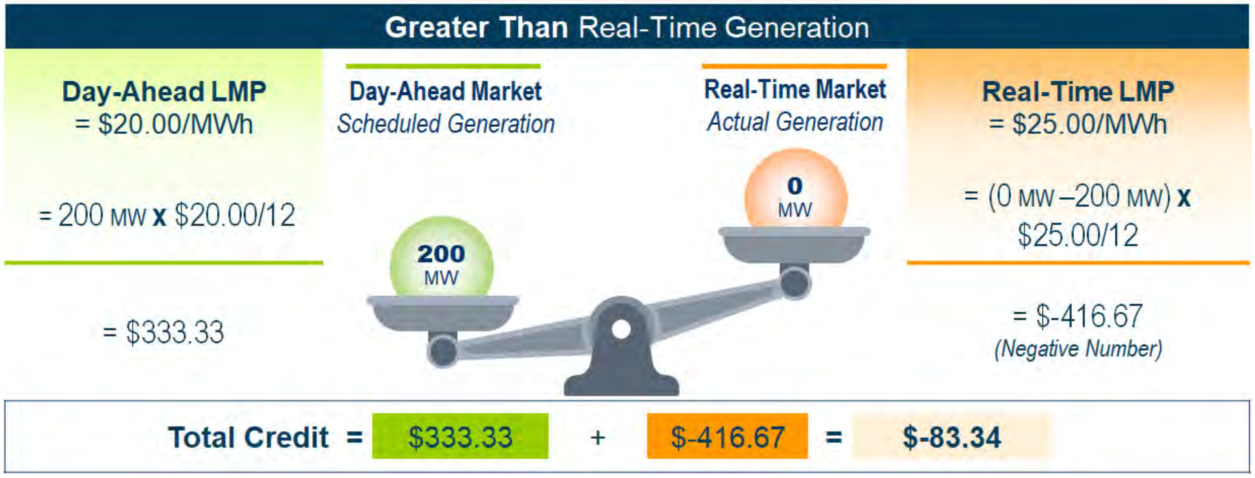

In Figure 72, the Generator submitted a 200 MW offer in the Day-Ahead Market. The Day-Ahead Market cleared at $20.00/MWh. The Day-Ahead Market settlement for the generator is the Day-Ahead Market scheduled generation multiplied by the Day-Ahead Market price, or 200 MW multiplied by $20.00 MW/h, divided 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

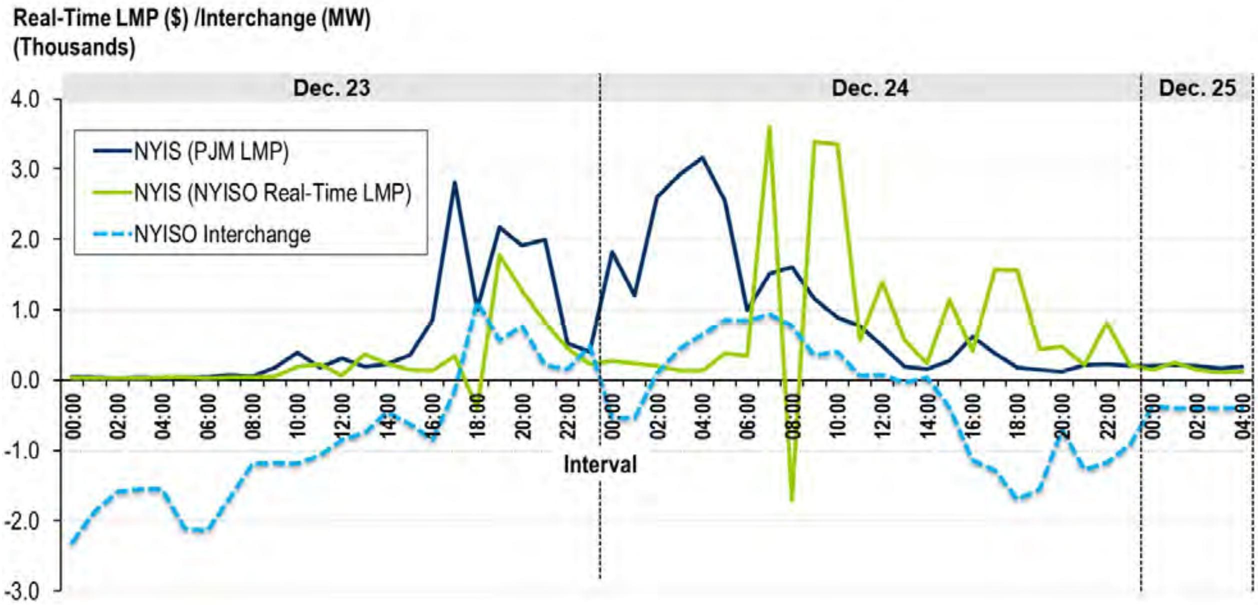



**Figure 75.** MISO Net Interchange

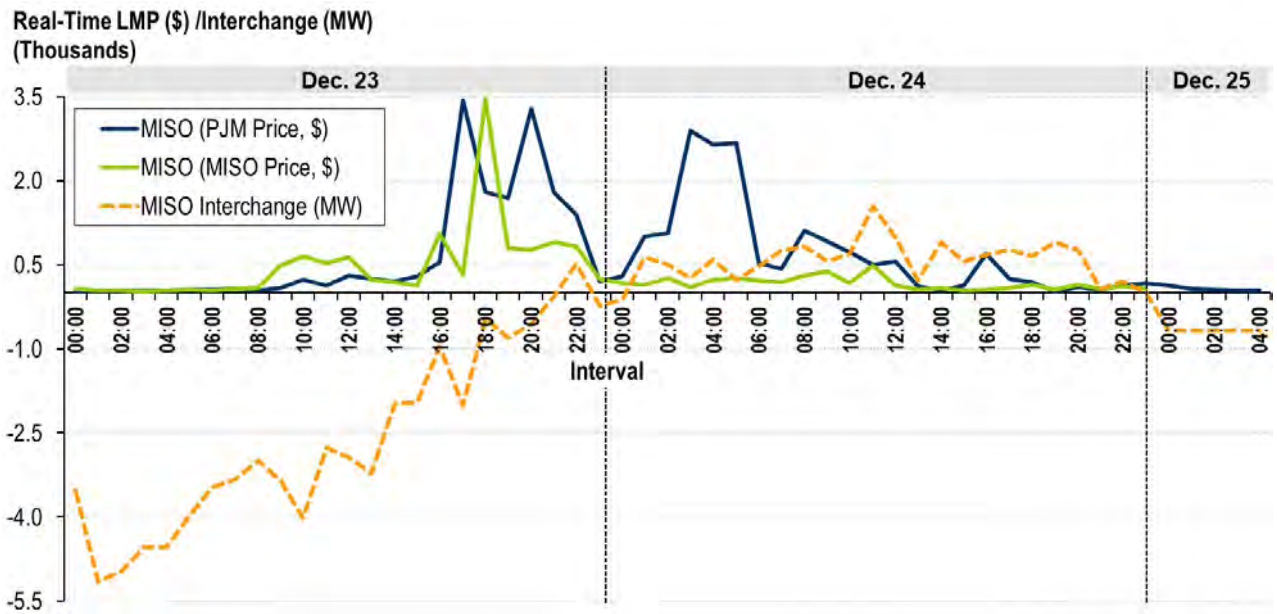


Figure 76 provides hourly net interchange values between PJM and the aggregate net interchange for LG&E-KU, TVA, Duke, DEP-East, and DEP-West, along with interface price values for PJM.

**Figure 76.** South Net Interchange

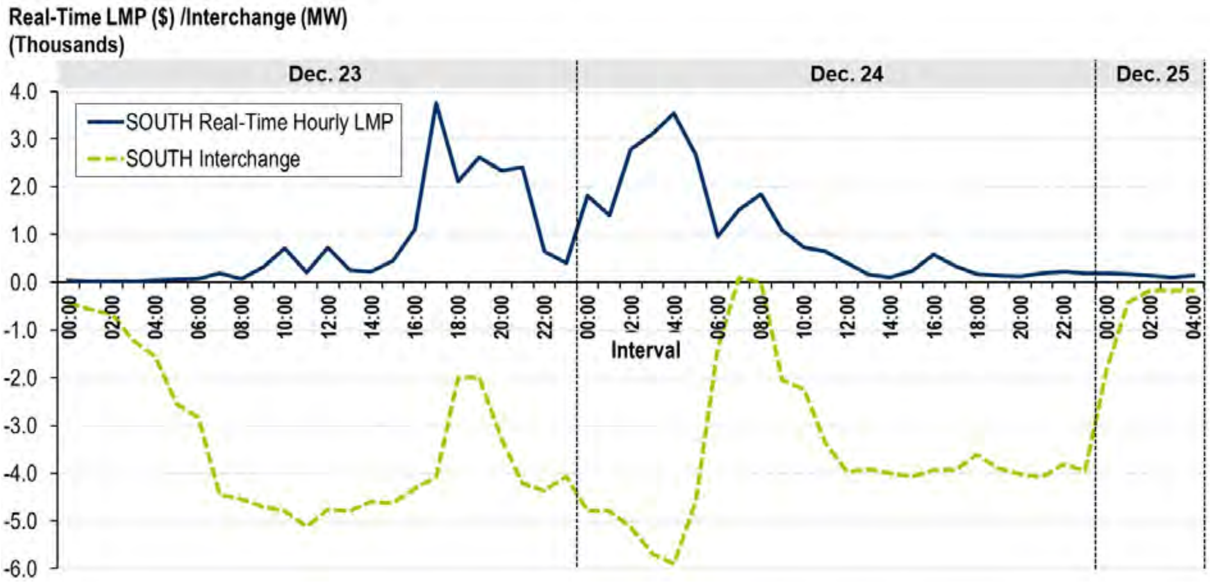
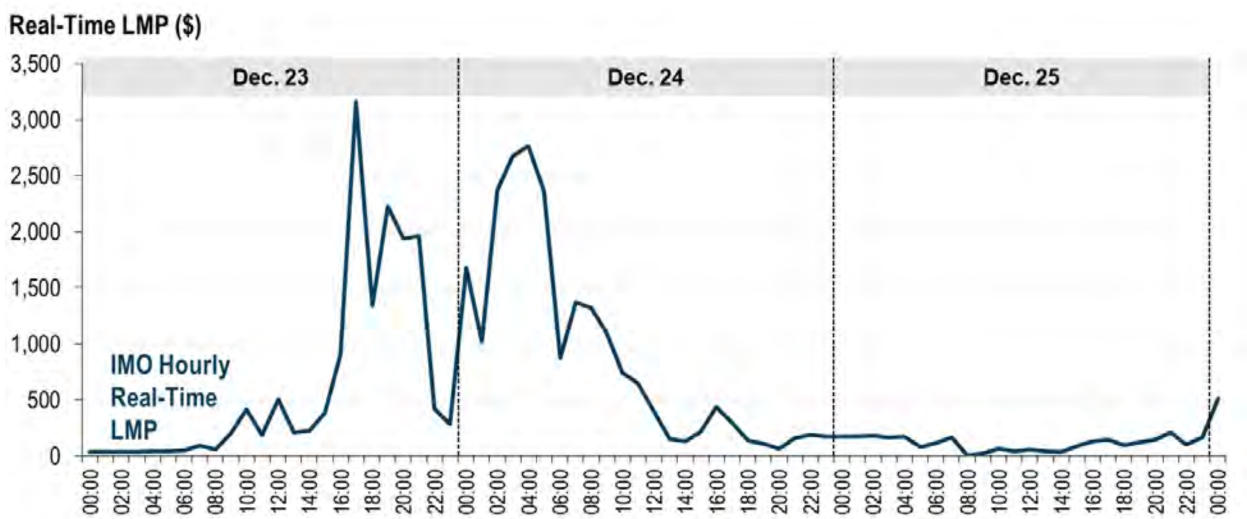



Figure 77 provides hourly pricing for the IMO interface. This information can be used by Market Participants during real time to make energy transfer decisions.

**Figure 77.** IMO Net Interchange




## *Ancillary Services: Regulation and Reserves*

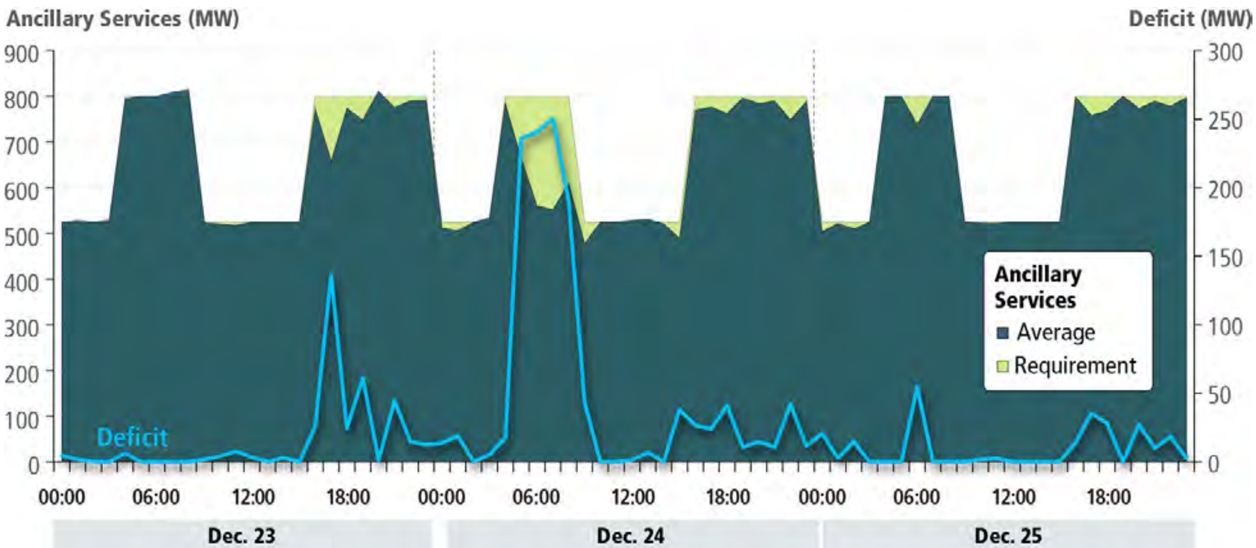
During Winter Storm Elliott, high prices for regulation, synchronized reserve, and Non-Synchronized Reserves occurred at the same time as high Real-Time Energy LMPs. During these stressed conditions, ancillary service prices increased as the reserve margin decreased, and system capacity competed to meet 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

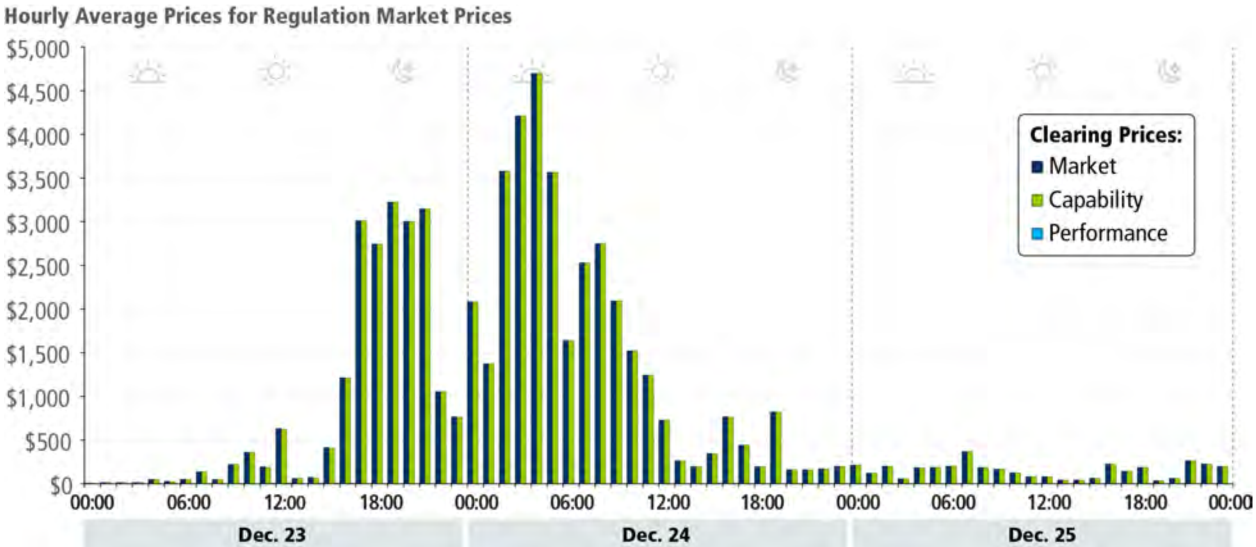



The regulation deficit is caused by the generator availability issues detailed in this report that resulted in a lack of available regulation-capable resources to commit. The regulation price spikes seen on Dec. 23 and Dec. 24 can be attributed to the low performance factor of the marginal unit for regulation 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

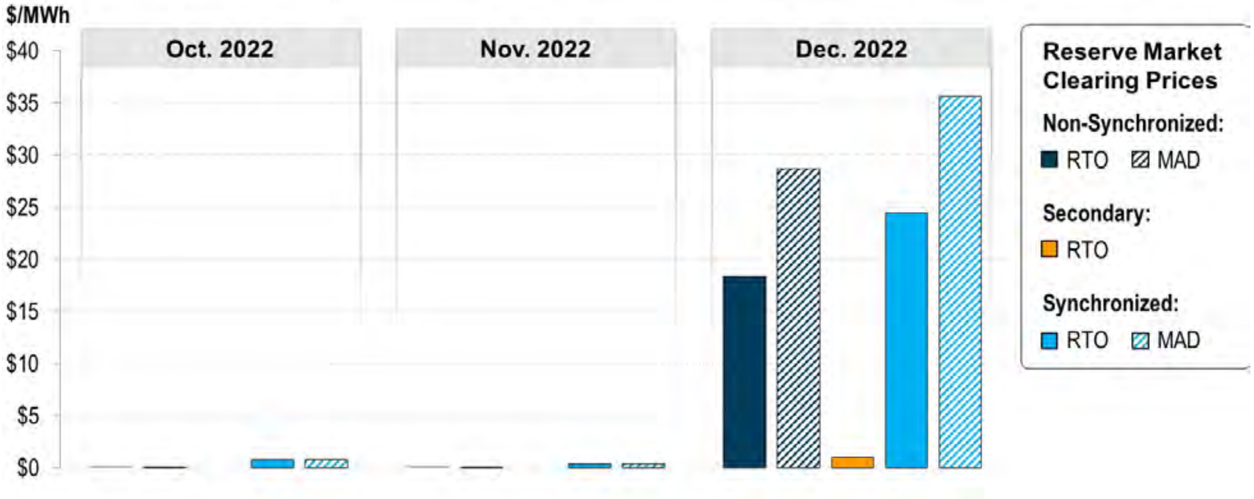



Figure 81 presents daily max and daily average SRMCPs since Oct. 1, 2022. This figure shows that the drivers of the high monthly averages SRMCPs observed in Dec. 2022 and displayed in Figure 80 are driven almost entirely by the operational events and market outcomes related to Winter Storm Elliott.

**Figure 81.** Shortage Pricing Impacts on SRMCP

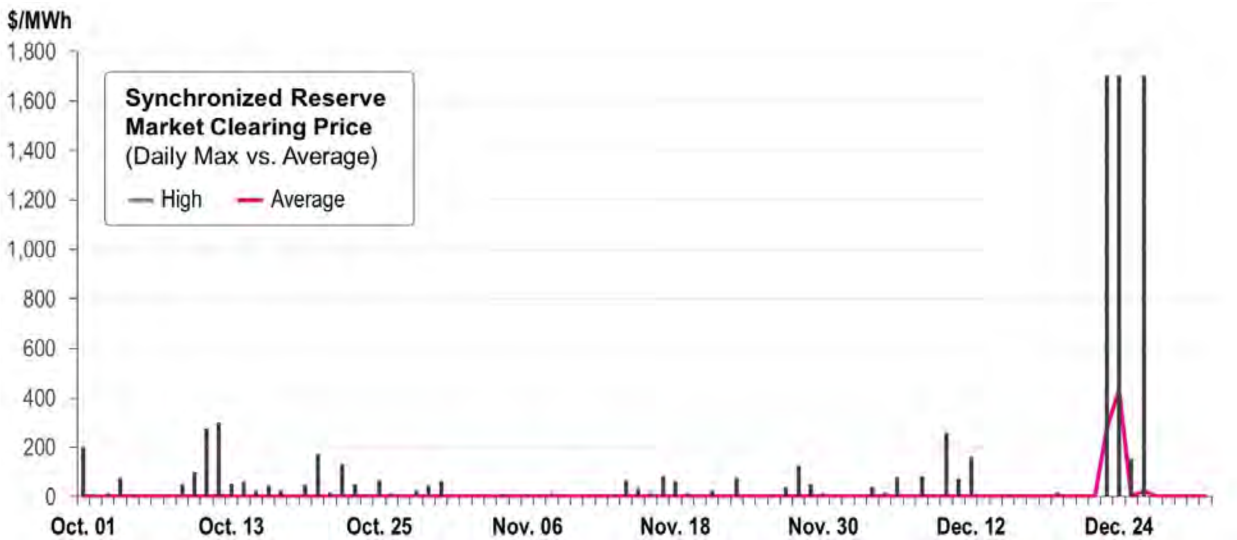
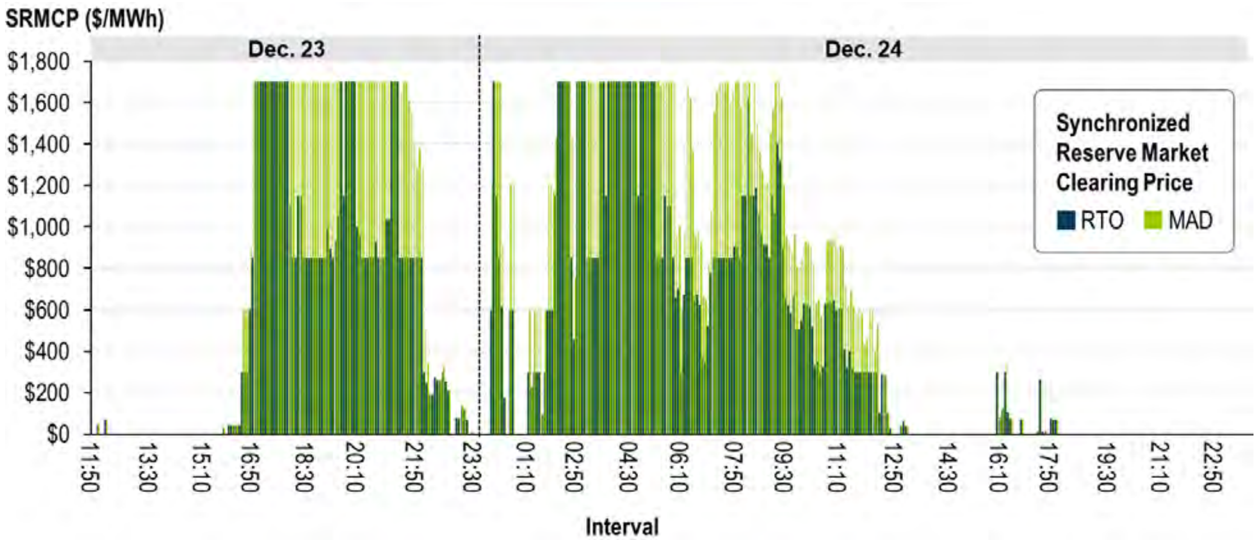



Figure 82 presents the Real-Time SRMCPs for Dec. 23 and Dec. 24.

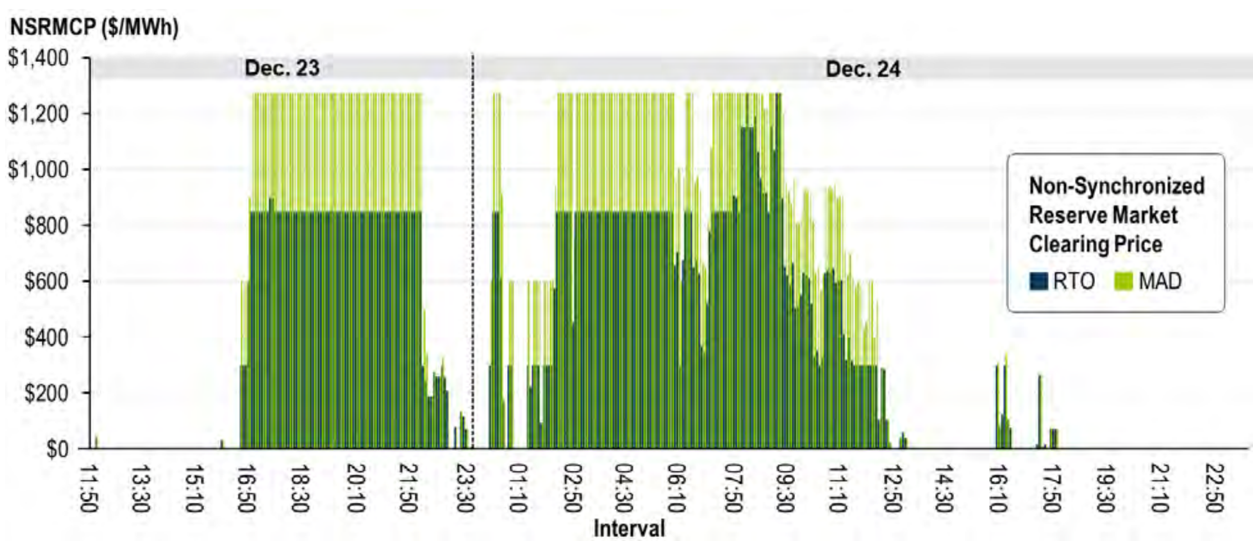
**Figure 82.** Dec. 23 and 24 Real-Time SRMCPs




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.

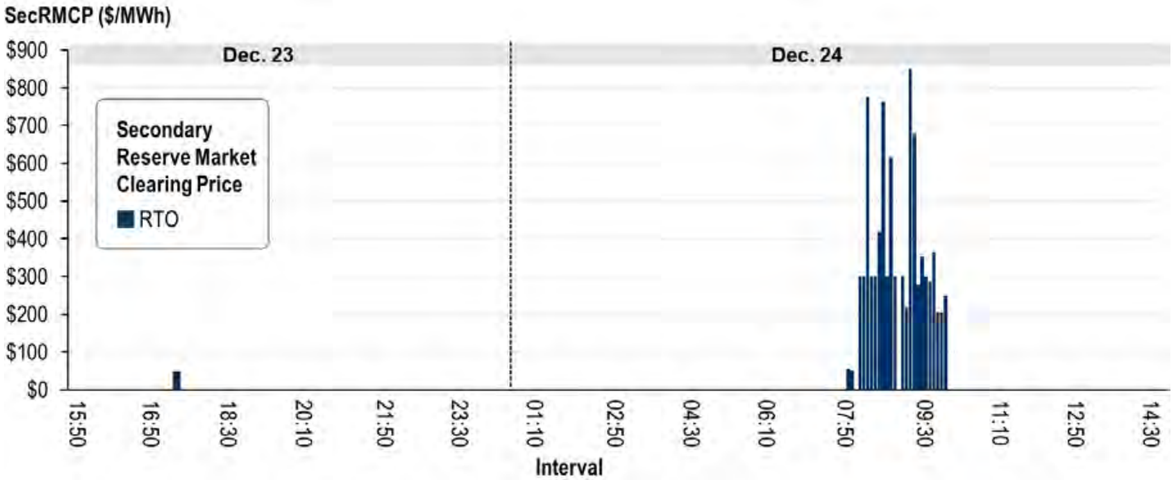
**Figure 83.** Dec. 23 and Dec. 24 Real-Time NSRMCPs




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

| Event Date | | | Synch Reserve Assignment (MW) | Synch Reserve Unit Response (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.

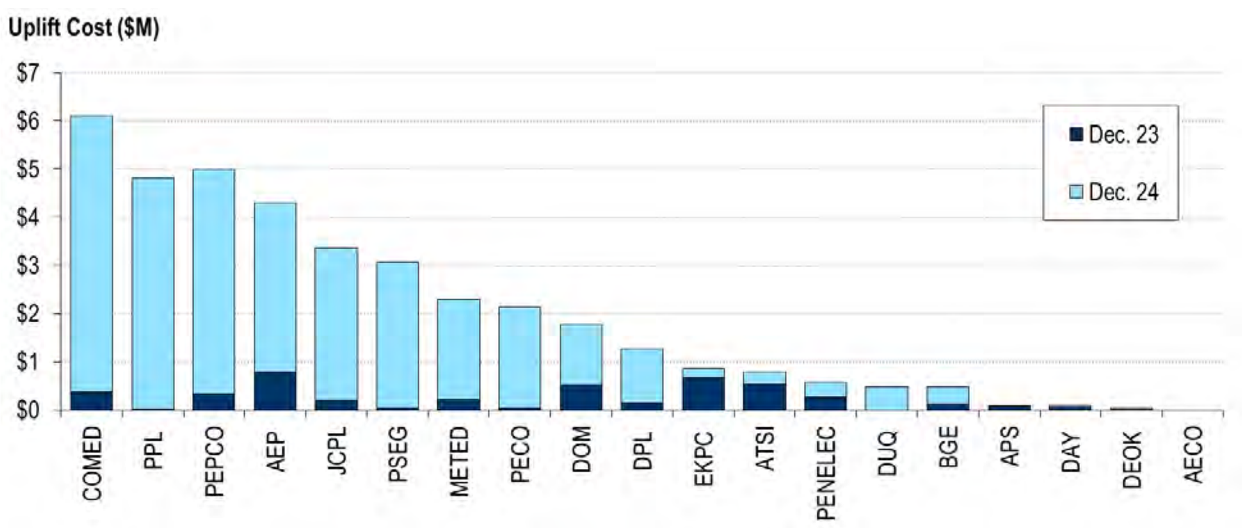
There are two reasons for out-of-market costs:

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

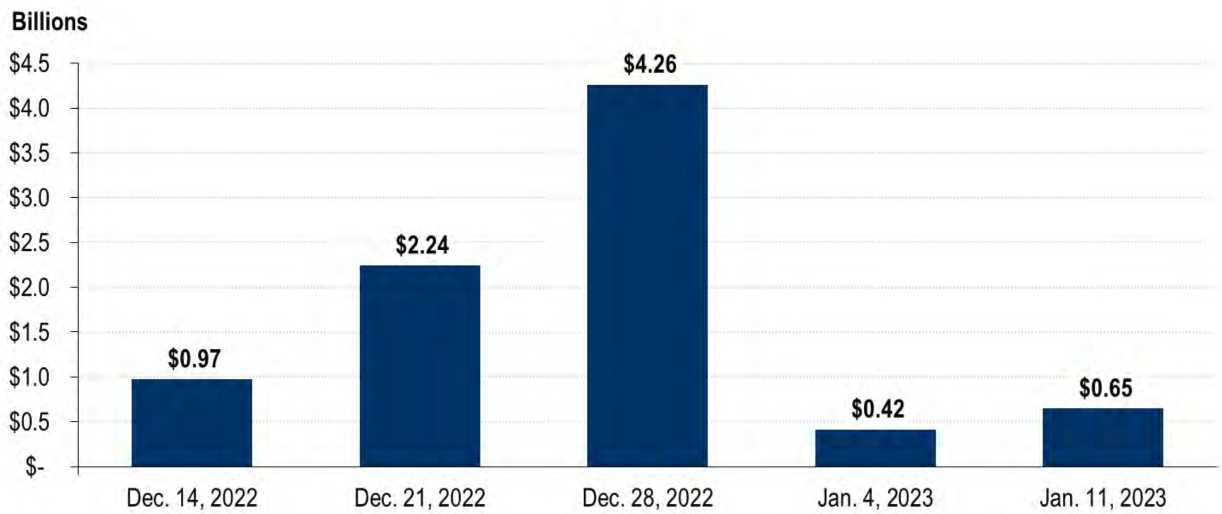
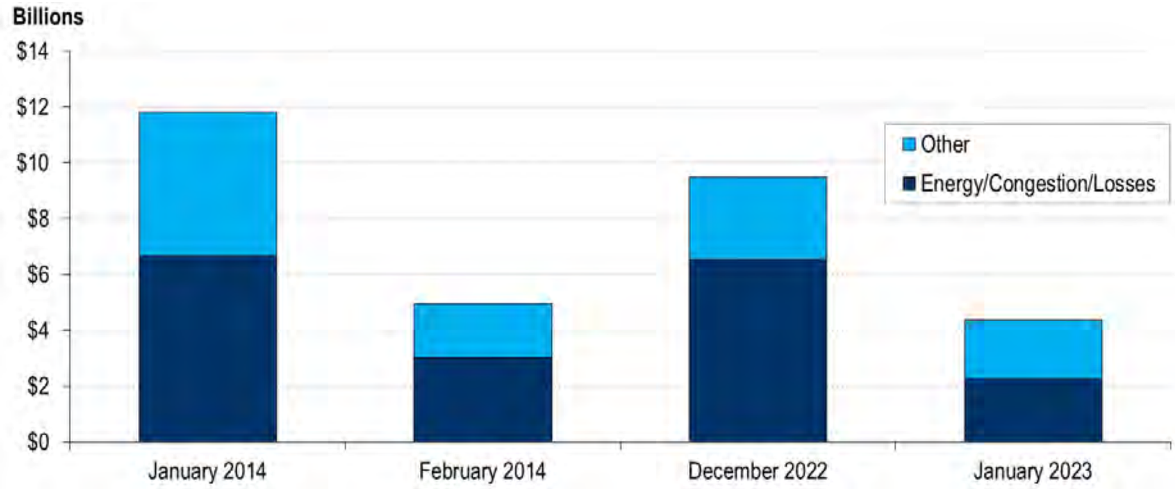



Figure 37 displays gross billing for Dec. 23 and Dec. 24, embedded in the bar chart for the week of Dec. 28. A significant increase in gross billing is observed when comparing the prior two weeks and successive two weeks to the week of Dec. 28. System conditions and operator actions reflecting the status 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 | RTO | 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]

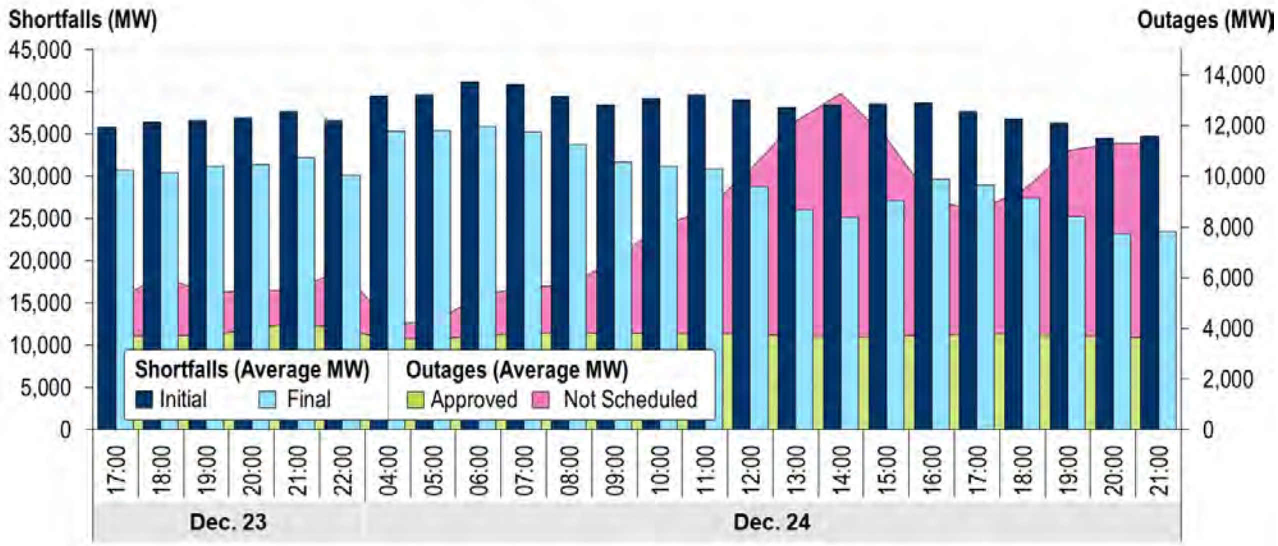
[17] The average DR and PRD shortfall megawatts offset by over-performance by other resources is 230 MW per interval.

**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.

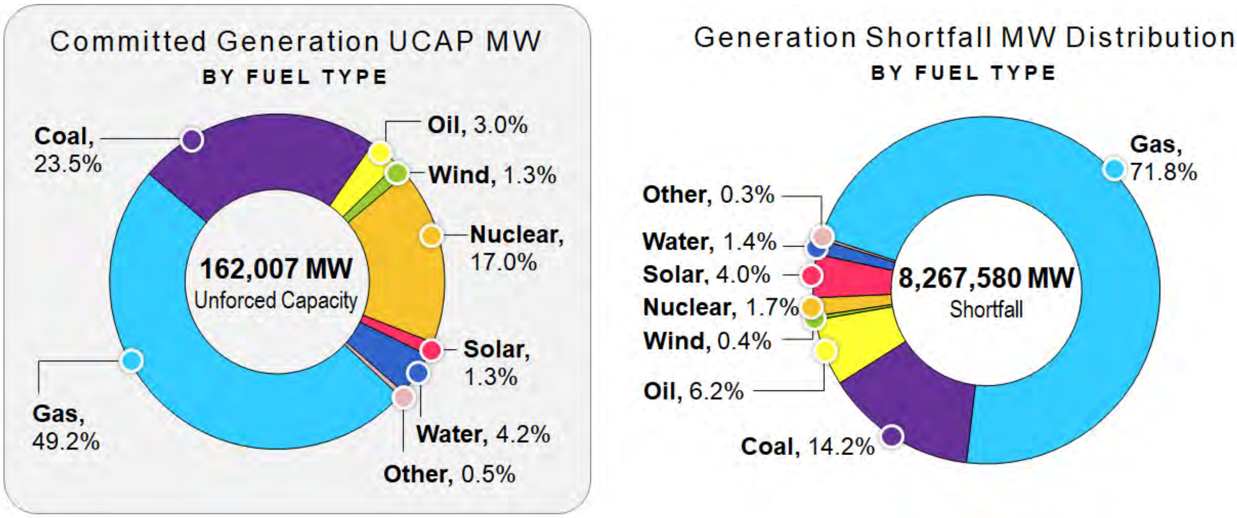
**Figure 88.** Excusal Megawatts and Final Shortfall MW (hourly average of five-minute interval values)




## 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: CP Resources | Average Bonus MW: Energy Resources | Average Total Bonus MW |
|---|---|---|---|---|
| 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.

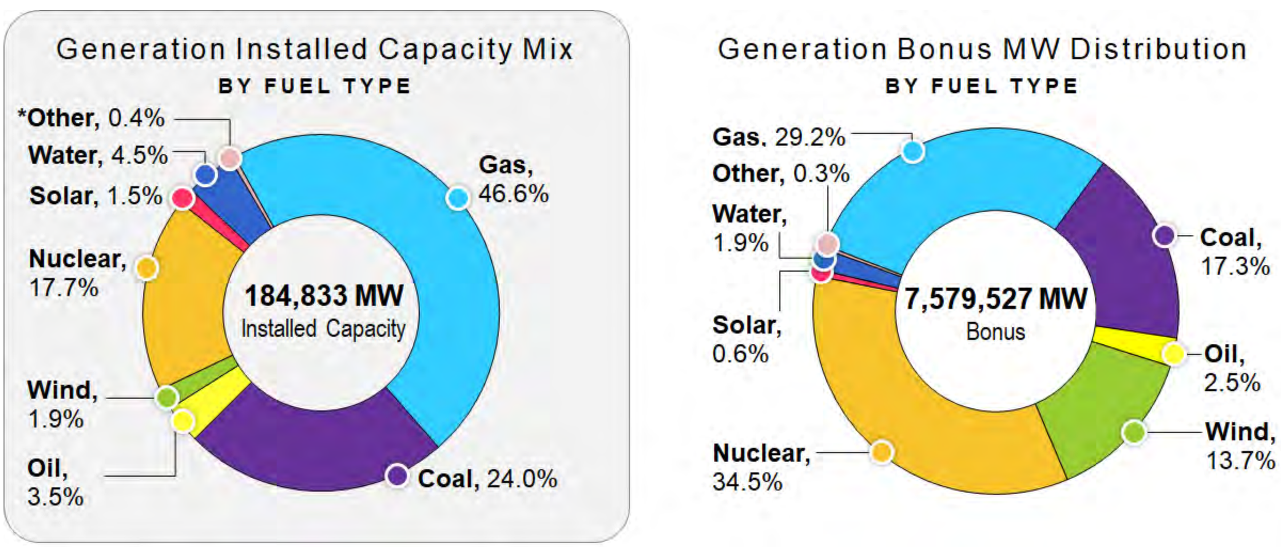
| Hour (EPT Hour Beginning) | | Average Bonus MW | | | |
|---|---|---|---|---|---|
| | | Generation | Net Imports | EE | DR & PRD |
| | 18:00 | 24,265.0 | 3,670.7 | 1,720.9 | 2,120.80 |
| | 19:00 | 23,588.6 | 3,549.7 | 1,720.9 | 2,835.90 |
| | 20:00 | 23,533.7 | 3,461.0 | 1,720.9 | 849.90 |
| | 21:00 | 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

| | | Average Capacity | | |
|---|---|---|---|---|
| Date | Product | 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) | Average Capacity 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 | Dec. 24 | Dec. 25 |
|---|---|---|---|---|---|
| Maximum Generation Emergency Action Email | Stakeholders | Notifying the beginning of a Performance Assessment Interval | 19:01 | | |
| Email Notification | Transmission Owner communications departments | A winter operation update conference call to be held with PJM Corporate Communications at 08:30, Dec. 24. | 21:54 | | |
| Email Notification | Stakeholders | The Maximum Emergency Generation Action has ended at 23:00, Dec. 23, along with the corresponding Performance Assessment Interval. | 23:32 | | |
| Email Notification | Stakeholders | The issuance of a public call for electricity conservation shortly before midnight | | 00:31 | |
| Maximum Generation Emergency Action Email | Stakeholders | General email notification to stakeholders, notifying the beginning of a Performance Assessment Interval | | 05:19 | |
| PJM New Release Distribution List | PJM news release distribution list | On public Call for Conservation sent to PJM news release distribution lists | | 05:40 | |
| Generation Owner Request | 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 | |
| Email Notification | 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 | |
| Email Notification | 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 | |
| Email Notification | Stakeholders | The Maximum Emergency Generation Action has ended at 20:00, Dec. 24, along with the corresponding Performance Assessment Interval. | | 22:14 | |
| Email Notification | Stakeholders | Announcing the end of the public call for electricity conservation | | | 11:54 |
| Technical Communication | 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

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) | ) | |
| Emergency Order: Tri-State | ) | Order No. 202-25-14 |
| Generation and Transmission | ) | |
| Association, Platte River Power | ) | |
| Authority, Salt River Project, | ) | |
| PacifiCorp, and Xcel Energy | ) | |

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

Filed January 28, 2026

Exhibit 1-32:
NARUC Coal Report

# Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices

National Association of Regulatory Utility Commissioners | January 2020


*Phillip Graeter, Energy Ventures Analysis, Inc.*

*Seth Schwartz, Energy Ventures Analysis, Inc.*

**EXHIBIT 15: TYPICAL STARTUP AND CYCLING COSTS FOR A MEDIUM-SIZED COAL-FIRED POWER PLANT ($2019)[19]**

| Type of Start | Cost category | Cost estimates ($/MW) Expected | Low | High |
|---|---|---|---|---|
| Hot Start (1–23 h offline) | Maintenance and capital | $ 128 | $ 102 | $ 162 |
| | Forced outage | $ 60 | $ 48 | $ 76 |
| | Start-up fuel | $ 20 | $ 14 | $ 30 |
| | Auxiliary power | $ 11 | $ 8 | $ 13 |
| | Efficiency loss from low and variable load operation | $ 5 | $ 4 | $ 8 |
| | Water chemistry cost and support | $ 1 | $ 1 | $ 2 |
| | **Total cycling cost** | **$ 225** | **$ 178** | **$ 291** |
| Warm Start (24 - 120 h offline) | Maintenance and capital | $ 137 | $ 109 | $ 170 |
| | Forced outage | $ 65 | $ 51 | $ 80 |
| | Start-up fuel | $ 43 | $ 30 | $ 57 |
| | Auxiliary power | $ 23 | $ 18 | $ 28 |
| | Efficiency loss from low and variable load operation | $ 6 | $ 5 | $ 9 |
| | Water chemistry cost and support | $ 6 | $ 4 | $ 9 |
| | **Total cycling cost** | **$ 277** | **$ 217** | **$ 351** |
| Cold Start (> 120 h offline) | Maintenance and capital | $ 205 | $ 162 | $ 255 |
| | Forced outage | $ 96 | $ 76 | $ 120 |
| | Start-up fuel | $ 64 | $ 45 | $ 24 |
| | Auxiliary power | $ 29 | $ 23 | $ 36 |
| | Efficiency loss from low and variable load operation | $ 6 | $ 5 | $ 10 |
| | Water chemistry cost and support | $ 17 | $ 13 | $ 21 |
| | **Total cycling cost** | **$ 417** | **$ 325** | **$ 465** |
| Load follow down to 36% of Capacity | Maintenance and capital | $ 20 | $ 12 | $ 31 |
| | Forced outage | $ 9 | $ 6 | $ 15 |
| | Efficiency loss from low and variable load operation | $ 1 | $ 1 | $ 2 |
| | Mill cycle gas | $ 2 | $ 19 | $ 50 |
| | **Total cycling cost** | **$ 32** | **$ 19** | **$ 50** |

As shown in **Exhibit 15,** expected costs for cold starts can be almost double the startup cost for a hot start when the remaining temperature in the boiler and turbine system are still significantly higher. However, even hot starts can range from $89,000 to $145,500 per start for a 500 MW coal-fired EGU. These costs can also vary significantly between coal units based on differences in boiler size and design (subcritical vs. supercritical). The highest cost

19 Source: Lefton S A, Hilleman D (2011). *Make your plant ready for cycling operations.* http://www.powermag.com/make-your-plant-ready-for-cycling-operations/

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| | | |
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| Federal Power Act Section 202(c) | ) | |
| Emergency Order: Tri-State | ) | Order No. 202-25-14 |
| Generation and Transmission | ) | |
| Association, Platte River Power | ) | |
| Authority, Salt River Project, | ) | |
| PacifiCorp, and Xcel Energy | ) | |

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

Filed January 28, 2026

Exhibit 1-33:
IEA Flexibility Report

# Increasing the flexibility of coal-fired power plants

Colin Henderson

September 2014

# 4 Increasing flexibility – turbine and water-steam systems

There is much that can be done to make these areas of a plant more durable, able to respond faster and suffer less efficiency losses. Examples are given in this chapter.

## 4.1 Reducing stresses during start-up

Start-up, especially from cold, places particularly large stresses on many parts of a coal-fired plant. The turbine is no exception in this regard. Very rapid temperature changes need to be kept to the minimum, while component designs can be adapted to suit. Lindsay and Dragoon (2010) have collected together data from published sources on start-up times for different plant conditions. They found that, generally, coal plants required approximately 12 hours to cold start, 4 hours to warm start, and 1 hour to hot start. There was considerable variation, and this was believed to stem from how hot, warm, and cold starts were defined, and whether those times were actually equipment-limited or not.

One of the requirements for flexibility in the turbine is that the very small clearances between stationary and moving components remain almost constant during output changes. This requires careful design, advanced sealing (*see also* Henderson, 2013) and measures for ensuring uniform thermal loading and applies especially during cold start-up operations (Quinkertz and others, 2008).

Turbine bypass systems are a necessity in plants designed for two-shift (on/off) and other flexible forms of operation. They allow all or part of the steam to bypass the HP turbine or LP turbine so that the rate of steam temperature change in the turbine can be managed as the boiler is starting up and shutting down. This allows thermal stresses in the turbine to be reduced (Lindsay and Dragoon, 2010). This is not to be confused with another type of bypass (HP stage bypass), that can be installed for frequency control in new plants and is described later.

The very high temperature and pressure conditions of USC systems necessitate use of thick-walled components so that they possess adequate strength. Unfortunately, this can limit the rate of temperature change consistent with reducing thermal fatigue to acceptable levels. In the turbine, one means used to counter this is steam cooling of the outer casing to keep its temperature 30–40°C lower than that of the inner casing at the corresponding position along the turbine during load changes. The steam for this is bled radially from points along the inner casing. The steam reduces temperature extremes in the outer casing and allows its thickness to be reduced. The result is that cold start-up time is reduced by almost 50% (Almstedt and others, 2007).

## 4.2 Load following using sliding pressure operation

While, traditionally, throttling has been used to vary output from a turbine while keeping the pressure constant (Lindsay and Dragoon, 2010), sliding pressure operation has become a commonly applied system in modern supercritical once-through systems (Henderson, 2004). A critical constraint on ramping operation is matching steam and turbine metal temperatures, and more rapid output changes can be achieved using sliding pressure. Sliding pressure also offers advantages over throttle control

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| Emergency Order: Tri-State | ) | Order No. 202-25-14 |
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| Association, Platte River Power | ) | |
| Authority, Salt River Project, | ) | |
| PacifiCorp, and Xcel Energy | ) | |

Exhibit to
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Filed January 28, 2026

Exhibit 1-34:
Secretary Wright's West Virginia Remarks

https://www.wvnews.com/news/wvnews/energy-secretary-chris-wright-future-of-u-s-coal-is-long-and-bright/article_948eb88e-2509-42a3-b985-07c47f1ee151.html

TOP STORY

# Energy Secretary Chris Wright: Future of U.S. coal Is 'long and bright'

by Charles Young SENIOR STAFF WRITER
Jul 5, 2025

1 of 2




Some coal-fired facilities have been closed before the end of their useful lives, said U.S. Energy Secretary Chris Wright Morgantown.

Staff photo by Charles Young

MORGANTOWN (WV News) — “The future for coal is long and bright,” said U.S. Energy Secretary

Wright, while visiting the National Energy Technology Laboratory facility, said the Trump administration wants to work to reverse the industry's decades of decline by encouraging greater production and use of coal, along with preventing the premature closure of still-viable coal-fired power plants.

The administration views coal as a valuable asset needed to gain an economic edge over China, especially when it comes to AI, Wright said.

"We're going to need 50 to maybe 150 gigawatts of new capacity, and if you're going to add a lot of new capacity, the first thing you should do is stop shrinking the capacity you have," he said.

Wright calls the need to increase the nation's electrical capacity the "second Manhattan Project," in reference to the program that created the first atomic weapons.

"AI is the second parallel — a huge innovation where we can't get second," he said. "China put on about 90 new coal plants last year, and about a similar amount of new plants will come on this year. They've rapidly grown their electricity for industrial processes, also for AI."

Recommissioning a retired coal-fired facility is a difficult process, but his team plans to look into the possibility of bringing some closed plants back online, Wright said.

"We're looking at that, and I think you will see some coal plants reopened," he said.

Meanwhile, his department will work to prevent the imminent closure of facilities throughout the country, Wright said.

"I think our biggest impact by far is going to be — there are like 40 coal plants that are supposed to close this year — and our biggest impact is going to be to stop the closure of most of those," he said.

As U.S. energy secretary, he has the authority to prevent the planned closure of some power plants, Wright said.

"It's been very politically fashionable to close, really for the last 15 or 20 years, coal power

West Virginia has a long history of energy production, dating back more than a century, Wright said.

“West Virginia has been an energy industrial powerhouse since it has been a state,” he said. “I think the outlook in energy and industry is quite bright.”

In April, Trump signed a series of executive orders to reinvigorate the “Beautiful Clean Coal Industry,” prevent regulatory overreach by state governments, and strengthen the reliability of the national electric grid.

“These executive orders are a direct investment in America’s energy future and in the communities that have long powered our nation,” Trump said during the event.

The orders mark a major shift for the industry, according to Coal Association President Chris Hamilton.

“We are deeply grateful to President Trump, Energy Secretary Wright, Secretary [Doug] Burgum, and EPA Administrator Lee Zeldin for their leadership in rolling back these anti-coal regulations,” he said. “For years, our industry has faced undue pressure from excessive regulatory measures that have led to job loss and stifled industry growth and innovation.”

Hamilton

Sen. Shelley Moore Capito, R-W.Va., recently said the administration’s efforts to support the coal industry will “keep our coal miners working and our coal facilities open, I think will increase employment just because of increased production but also the increased use of coal.”

However, it’s unlikely any new coal-fired power plants will be built any time soon, Capito said.

“You and I both know that’s a pretty steep hill to climb,” she said. “There have been no new coal

The Longview Power Plant in Monongalia County, near Maidsville, went into operation in 2011.

Capito

The Longview Power Plant in Monongalia County, near Maidsville, went into operation in 2011.
Staff file photo by Charles Young

The president's plan instead calls for the industry to "modernize what we have," Capito said.

"So that we can run them through their entire life and then keep that employment very robust," she said.

There are nine coal-fired electrical generation facilities in West Virginia: Pleasants Power Station, Harrison Power Station, Mountaineer Power, John Amos, Mount Storm, Morgantown Energy Associates, Longview Power, Fort Martin Power Station and Mitchell Power.

West Virginia is the second largest coal producer in the nation, after Wyoming, and accounts

West Virginia has 16% of U.S. recoverable coal reserves, the third-largest state reserves after Wyoming and Illinois.

In 2023, coal-fired power plants accounted for 86% of West Virginia's total electricity net generation. Renewable energy resources, primarily wind energy and hydroelectric power, contributed 7%, and natural gas also provided about 7%.

Senior Staff Writer Charles Young can be reached at 304-626-1447 or cyoung@theet.com

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| Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy | ) ) ) ) ) ) | Order No. 202-25-14 |

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

Filed January 28, 2026

Exhibit 1-35:
July Resource Adequacy Report

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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*Additional figures and tables in appendices*

# List of Acronyms

| | |
|---|---|
| AI | Artificial Intelligence |
| CAISO | California Independent System Operator |
| DOE | U.S. Department of Energy |
| EIA | Energy Information Administration |
| EO | Executive Order |
| EPRI | Electric Power Research Institute |
| ERCOT | Electric Reliability Council of Texas |
| EUE | Expected Unserved Energy |
| FERC | Federal Energy Regulatory Commission |
| GADS | Generating Availability Data System |
| ISO | Independent System Operator |
| ISO-NE | ISO New England Inc. |
| ITCS | Interregional Transfer Capability Study |
| LBNL | Lawrence Berkeley National Laboratory |
| LOLE | Loss of Load Expectation |
| LOLH | Loss of Load Hours |
| LTRA | Long-Term Reliability Assessment |
| MISO | Midcontinent Independent System Operator |
| NERC | North American Electric Reliability Corporation |
| NREL | National Renewable Energy Laboratory |
| NYISO | New York Independent System Operator |
| PJM | PJM Interconnection, LLC |
| PNNL | Pacific Northwest National Laboratory |
| ReEDS | Regional Energy Deployment System |
| RTO | Regional Transmission Organization |
| SERC | SERC Reliability Corporation |
| TPR | Transmission Planning Region |
| USE | Unserved Energy |

# Background to this Report

On April 8, 2025, President Trump issued Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid." EO 14262 builds on EO 14156, “Declaring a National Emergency (Jan. 20, 2025),” which declared that the previous administration had driven the Nation into a national energy emergency where a precariously inadequate and intermittent energy supply and increasingly unreliable grid require swift action. The United States’ ability to remain at the forefront of technological innovation depends on a reliable supply of energy and the integrity of our Nation’s electrical grid.

EO 14262 mandates the development of a uniform methodology for analyzing current and anticipated reserve margins across regions of the bulk power system regulated by the Federal Energy Regulatory Commission (FERC). Among other things, EO 14262 requires that such methodology accredit generation resources based on the historical performance of each generation resource type. This report serves as DOE’s response to Section 3(b) of EO 14262 by delivering the required uniform methodology to identify at-risk region(s) and guide reliability interventions. The methodology described herein and any analysis it produces will be assessed on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States.

# Executive Summary

Our Nation possesses abundant energy resources and capabilities such as oil and gas, coal, and nuclear. The current administration has made great strides—such as deregulation, permitting reform, and other measures—to enable addition of more energy infrastructure crucial to the utilization of these resources. However, even with these foundational strengths, the accelerated retirement of existing generation capacity and the insufficient pace of firm, dispatchable generation additions (partly due to a recent focus on intermittent rather than dispatchable sources of energy) undermine this energy outlook.

Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation. A failure to power the data centers needed to win the AI arms race or to build the grid infrastructure that ensures our energy independence could result in adversary nations shaping digital norms and controlling digital infrastructure, thereby jeopardizing U.S. economic and national security.

Despite current advancements in the U.S. energy mix, this analysis underscores the urgent necessity of robust and rapid reforms. Such reforms are crucial to powering enough data centers while safeguarding grid reliability and a low cost of living for all Americans.

## Key Takeaways

- **Status Quo is Unsustainable**. The status quo of more generation retirements and less dependable replacement generation is neither consistent with winning the AI race and ensuring affordable energy for all Americans, nor with continued grid reliability (ensuring "resource adequacy"). Absent intervention, it is impossible for the nation's bulk power system to meet the AI growth requirements while maintaining a reliable power grid and keeping energy costs low for our citizens.

- **Grid Growth Must Match Pace of AI Innovation**. The magnitude and speed of projected load growth cannot be met with existing approaches to load addition and grid management. The situation necessitates a radical change to unleash the transformative potential of innovation.

- **Retirements Plus Load Growth Increase Risk of Power Outages by 100x in 2030**. The retirement of firm power capacity is exacerbating the resource adequacy problem. 104 GW of firm capacity are set for retirement by 2030. This capacity is not being replaced on a one-to-one basis and losing this generation could lead to significant outages when weather conditions do not accommodate wind and solar generation. In the "plant closures" scenario of this analysis, annual loss of load hours (LOLH) increased by a factor of a hundred.

- **Planned Supply Falls Short, Reliability is at Risk**. The 104 GW of retirements are projected to be replaced by 209 GW of new generation by 2030; however, only 22 GW would come from firm baseload generation sources. Even assuming no retirements, the model found increased risk of outages in 2030 by a factor of 34.

- **Old Tools Won't Solve New Problems.** Antiquated approaches to evaluating resource adequacy do not sufficiently account for the realities of planning and operating modern power grids. At a minimum, modern methods of evaluating resource adequacy need to incorporate frequency, magnitude, and duration of power outages; move beyond exclusively analyzing peak load time periods; and develop integrated models to enable proper analysis of increasing reliance on neighboring grids.

*This report clearly demonstrates the need for rapid and robust reform to address resource adequacy issues across the Nation. Inadequate resource adequacy will hinder the development of new manufacturing in America, slow the re-industrialization of the U.S. economy, drive up the cost of living for all Americans, and eliminate the potential to sustain enough data centers to win the AI arms race.*

## Developing a Uniform Methodology

DOE's resource adequacy methodology assesses the U.S. electric grid's ability to meet future demand through 2030. It provides a forward-looking snapshot of resource adequacy that is tied to electricity supply and new load growth, systematically exploring a range of dimensions that can be compared across regions. As detailed in the methodology section of this report, the model is derived from the North American Electric Reliability Corporation (NERC) Interregional Transfer Capability Study (ITCS) which leverages time-correlated generation and outages based on actual historic data.[1] A deterministic approach[2] simulates system stress in all hours of the year and incorporates varied grid conditions and operating scenarios based on historical events:

- **Demand for Electricity – Assumed Load Growth:** The methodology accounts for the significant impact of data centers, particularly those supporting AI workloads, on electricity demand. Various organizations' projections for incremental data center electricity use by 2030 range widely (35 GW to 108 GW). DOE adopted a national midpoint assumption of 50 GW by 2030, aligning with central projections from Electric Power Research Institute (EPRI)[3] and Lawrence Berkeley National Laboratory (LBNL).[4] This 50 GW was allocated regionally using state-level growth ratios from S&P's forecast,[5] reflecting infrastructure characteristics, siting trends, and market activity; and, mapped to NERC Transmission Planning Regions (TPRs).

1. This model differs from traditional peak hour reliability assessments in that it explicitly simulates grid performance hour-by-hour across multiple weather years with finer geographic detail and optimized inter-regional transfers, and explores various retirement and build-out scenarios. Furthermore, the DOE approach integrates weather-synchronized outage data.
2. Deterministic approaches evaluate resource adequacy using relatively stable or fixed assumptions about the representation of the power system. Probabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty that require more computing power. Deterministic was chosen for this analysis for transparency and to model detailed historic system conditions.
3. EPRI, "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption," March 2024, https://www.epri.com/research/products/3002028905.
4. Shehabi, A., et al., "2024 United States Data Center Energy Usage Report," https://escholarship.org/uc/item/32d6m0d1.
5. S&P Global – Market Intelligence, "US Datacenters and Energy Report," 2024.

An additional 51 GW of non-data center load was modeled using NERC data, historical loads (2019-2023), and simulated weather years (2007-2013), adjusted by the Energy Information Administration's (EIA) 2022 energy forecast, with interpolation between 2024 and 2033 to estimate 2030 demand.

- **Supply of Electricity – Assumed Generation Retirements and Additions:** Between the current system and the projected 2030 system, the model considers three scenarios for generator retirements and additions. These scenarios were selected to describe the metrics of interest and how they change during certain assumptions of generation growth and retirements.

The resource adequacy standard (or criterion) is the measure that defines the desired level of adequacy needed for a given system. Conceptually, a resource adequacy criterion has two components—metrics and target levels—that determine whether a system is considered adequate. Comprehensive resource adequacy metrics[6] are incorporated in this analysis to capture the magnitude and duration of system stress events:

- **Magnitude of Outages – Normalized Unserved Energy (NUSE):** Measures the amount of unmet electrical energy demand because of insufficient generation or transmission, typically measured in megawatt hours (MWh).

  While USE describes the absolute amount of energy not delivered, it is less useful when comparing systems of different size or across different periods. Normalizing, by dividing by total load over a whole period (for example, a year) allows comparison of these metrics across different system sizes, demand levels, and periods of analysis. For example, 100 MWh of USE in a small, isolated microgrid can be more impactful than 100 MWh of USE in a larger regional grid that serves millions of people. USE is normalized by dividing by total load:

$$\frac{100\ MWh\ (of\ unserved\ energy)}{10{,}000{,}000\ MWh\ (of\ total\ energy\ delivered\ in\ a\ year)} x100 = 0.001\ percent$$

Although the use of NUSE is not standardized in the U.S. today,[7] several system operators domestically and across the world have begun using NUSE as a useful metric.

- **Duration of Outages – Loss of Load Hours (LOLH):** Measures the expected duration of power outages when a system's load exceeds its available generation capacity. At the core, LOLH helps assess how frequently and for how long the power system is likely to experience insufficient supply, providing a picture of reliability in terms of time. LOLH is calculated as both a total and average value per year, in addition to the maximum percentage of load lost in any given hour per year.

6. In the interest of technical accuracy, and separate from their contextualization in the main text, NUSE is more precisely a measure of volume that is expressed as a percentage. Similarly, 2.4 hours of LOLH represents the cumulative sum of distinct periods of load loss, not a singular, continuous duration.
7. There is no common planning criterion for this metric in North America. NERC's Long-Term Reliability Assessment employs a normalized expected unserved energy (NEUE) metric to define target risk levels for each region. Grid operators, such as ISO-NE, have also considered NUSE in energy adequacy studies. For example, see ISO-NE, "Regional Energy Shortfall Threshold (REST): ISO's Current Thinking Regarding Tail Selection," April 2025, https://www.iso-ne.com/static-assets/documents/100022/a09_rest_april_2025.pdf.

## Reliability Standard

DOE's methodology recognizes that the traditional 1-in-10 loss of load expectation (LOLE) criterion is insufficient for a complete assessment of resource adequacy and risk profile. This antiquated criterion is not calculated uniformly and fails to adequately account for crucial factors such as the duration and magnitude of potential outages.[8] To provide a comprehensive understanding of system reliability and, specifically, to complement current resource adequacy standards while informing the creation of new criteria, the methodology uses the following reliability standard:

- **Duration of Outages:** No more than 2.4 hours of lost load in an individual year.[9] This translates into one day of lost load in ten years to meet the 1-in-10 criteria.

- **Magnitude of Outages:** No more than an NUSE of 0.002%.[10] This means that the total amount of energy that cannot be supplied to customers is 0.002% of the total energy demanded in a given year.

## Achieving Reliability Standard

- **Perfect Capacity Surplus/Deficit:** Defined as the amount of generation capacity (in MW) a region would need to achieve specified threshold conditions. Based on these thresholds, this standard helps answer the hypothetical question of how much more (or less) power plant capacity is needed for a power system to be considered "perfectly reliable" according to pre-defined standards. This methodology employs this perfect capacity metric to identify the amount of capacity needed to remedy potential shortfalls (or excesses) in generation.

## Key Results Summary

This analysis developed three separate cases for 2030. The "**Plant Closures"** case assumes all announced retirements occur plus mature generation additions based on NERC's Tier 1 resources category,[11] which encompasses completed and under-construction power generation projects, as well as those with firm-signed and approved interconnection service or power purchase agreements. The "**No Plant Closures"** case assumes no retirements plus mature additions. A "**Required Build**" case further compares the impacts of retirements on perfect capacity additions needed to return 2030 to the current system level of reliability.

---

8. While 1-in-10 analyses have evolved, industry experts have raised concerns about its effectiveness to address future system risks. Concerns include energy constraints that arise from intermittent resources, increasing battery storage, limited fuel supplies, and the shifting away of peak load periods from times of supply shortfalls.
9. The "1-in-10 year" reliability standard for electricity grids means that, on average, there should be no more than one day (24 hours) of lost load over a ten-year period. This translates to a maximum of 2.4 hours of lost load per year.
10. This analysis targets NUSE below 0.002% for each region because this is the target NERC uses to represent high risk in resource adequacy analyses. Estimates used in industry and analyzed recently range from 0.0001% to 0.003%.
10. Mature generation additions are based on NERC's 2024 LTRA Tier 1 resources, which assume that only projects considered very mature in the development pipeline will be built. For example, Tier 1 additions are those with signed interconnection agreements or power purchase agreements, or included in an integrated resource plan, indicating a high degree of certainty in their addition to the grid. Full details of the retirement and addition assumptions can be found in the methodology section of this report.

DOE ran simulations using 12 different years of historical weather. Every hour was based on actual data for wind, solar, load, and thermal availability to stress test the grid under a range of realistic weather conditions. The benefit of this approach is that it allows for transparent review of how actual conditions manifest themselves in capacity shortfalls. For all scenarios, LOLH and NUSE are calculated and used to compare how they change based on generation growth, retirements, and potential weather conditions.

- **Current System:** Supply of power (generation) and demand for power (load) consistent with 2024 NERC Long-Term Reliability Assessment (LTRA), including 2023 actual generation plus Tier 1 additions for 2024.

- **Plant Closures:** This case assumes 104 GW of announced retirements based on NERC estimates including approximately 71 GW of coal and 25 GW of natural gas, which closely align with retirement numbers in EIA's 2025 Annual Energy Outlook. In addition, this case assumes 100% of 2024 NERC LTRA Tier 1 additions totaling 209 GW are constructed by 2030. This includes 20 GW of new natural gas, 31 GW of additional 4-hour batteries, 124 GW of new solar and 32 GW of incremental wind. Details of the breakdown can be found in Appendix A.

- **No Plant Closures:** This case adds all the Tier 1 NERC additions but assumes no retirements.

- **Required Build:** To understand how much capacity may need to be added to reach reliability targets, the analysis adds hypothetical perfect capacity (which is idealized capacity that has no outages or profile) until a NUSE target of 0.002% is realized in each region. This scenario includes the same assumptions about retirements as our Plant Closures scenario described above.

As shown in the figures and tables below, the model shows a significant decline in all reliability metrics between the current system scenario and the 2030 Plant Closures scenario. Most notably, there is a hundredfold increase in annual LOLH from 8.1 hours per year in the current case to 817 hours per year in the 2030 Plant Closures. In the worst weather year assessed, the total lost load hours increase from 50 hours to 1,316 hours.

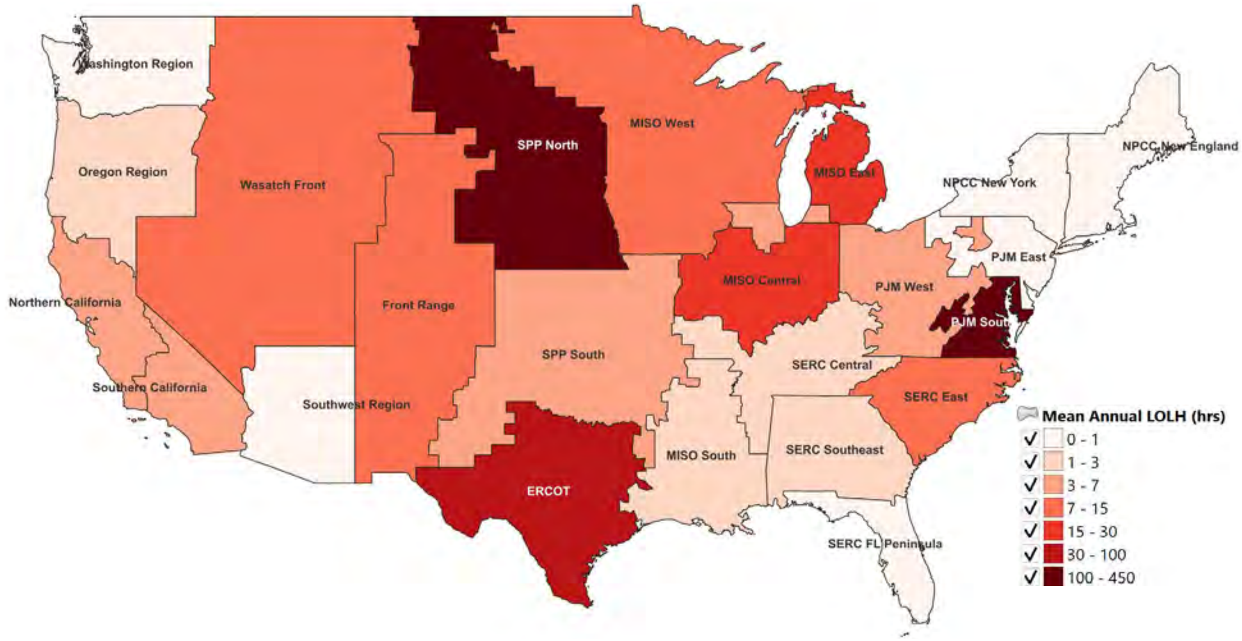



Figure 1. Mean Annual LOLH by Region (2030) – Plant Closures

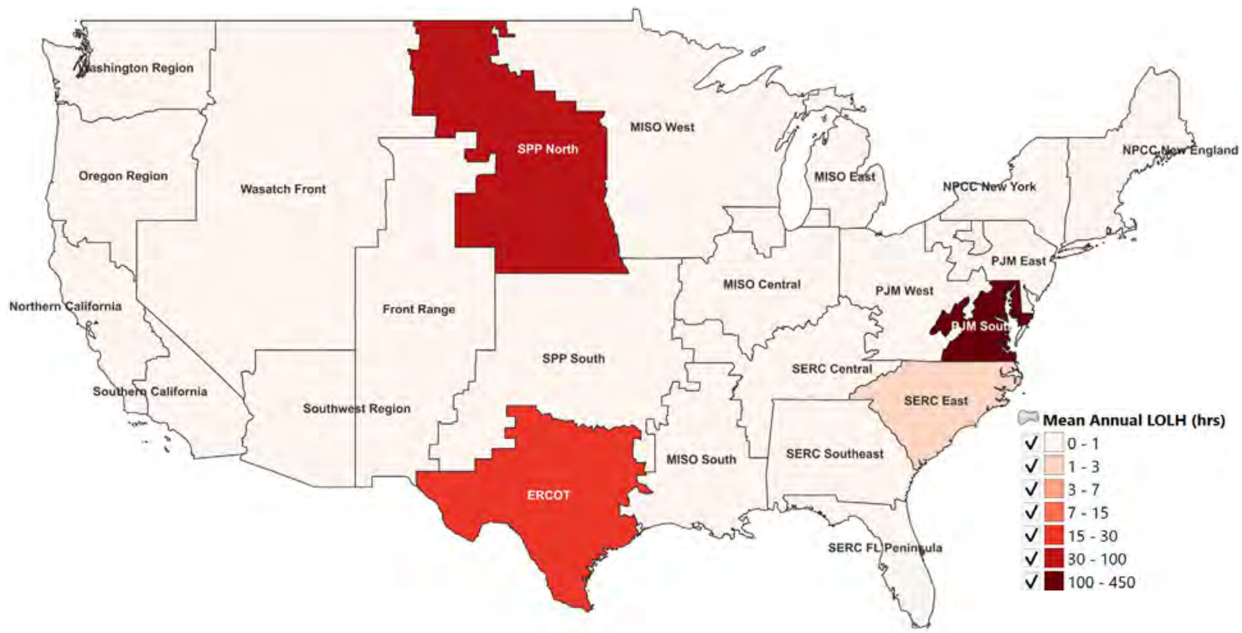



Figure 2. Mean Annual LOLH by Region (2030) – No Plant Closures

Table 1. Summary Metrics Across Cases

| Reliability Metric | | 2030 Projection | | |
|---|---|---|---|---|
| | Current System | Plant Closures | No Plant Closures | Required Build |
| AVERAGE OVER 12 WEATHER YEARS | | | | |
| Average Loss of Load Hours | 8.1 | 817.7 | 269.9 | 13.3 |
| Normalized Unserved Energy (%) | 0.0005 | 0.0465 | 0.0164 | 0.00048 |
| WORST WEATHER YEAR | | | | |
| Annual Loss of Load Hours | 50 | 1316 | 658 | 53 |
| Normalized Unserved Load (%) | 0.0033 | 0.1119 | 0.0552 | 0.002 |

## Current System Analysis

Analysis of the current system shows all regions except ERCOT have less than 2.4 hours of average loss of load per year and less than 0.002% NUSE. This indicates relative reliability for most regions based on the average indicators of risk used in this study. In the current system case, ERCOT would be expected to experience on average 3.8 LOLH annually going forward and a NUSE of 0.0032%. When looking at metrics in the worst weather years, regions meet or exceed additional criteria. All regions experienced less than 20% of lost load in any hour.

However, PJM, ERCOT,[12] and SPP experienced significant loss of load events during 2021 and 2022 winter storms Uri and Elliot which translated into more than 20 hours of lost load. This results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load. It is worth noting that in the case of PJM and SPP, the current system model shortfalls occurred within subregions rather than for the entire ISO footprint.

12. ERCOT has since winterized its generation fleet and did not suffer any outages during Winter Storm Elliot.

## 2030 Model Results

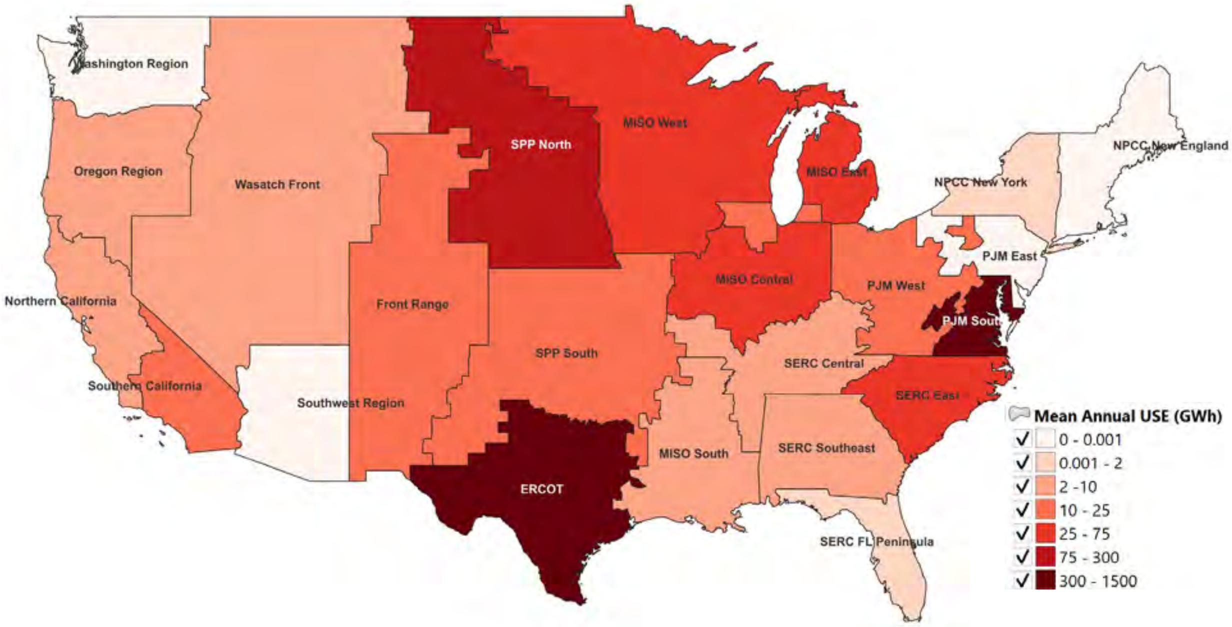



Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures

**Key Findings – Plant Closures Case:**

- **Systemwide Failures**: All regions except ISO-NE and NYISO failed reliability thresholds. These two regions did not have additional AI/data center (AI/DC) load growth modeled.
- **Loss of Load Hours (LOLH)**: Ranged from 7 hours/year in CAISO to 430 hours/year in PJM.
- **Load Shortfall Severity**: Max shortfall reached as high as 43% of hourly load in PJM; 31% in CAISO.
- **Normalized Unserved Energy**: Normalized values ranged from 0.0032% (non-CAISO West) to 0.1473% (PJM), far exceeding thresholds of 0.002%.
- **Extreme Events**: Most regions experienced ≥3 hours of unserved load in at least one year. PJM had 1,052 hours in its worst year.
- **Spatial Takeaways**: Subregions in PJM, MISO, and SERC met thresholds—indicating possible benefits from transmission—but SPP and CAISO failed in all subregions.

**Key Findings – No Plant Closures Case:**

- **Improved System Performance**: Most regions avoided loss of load events. PJM, SPP, and SERC still experienced shortfalls.
- **Regional Failures**:

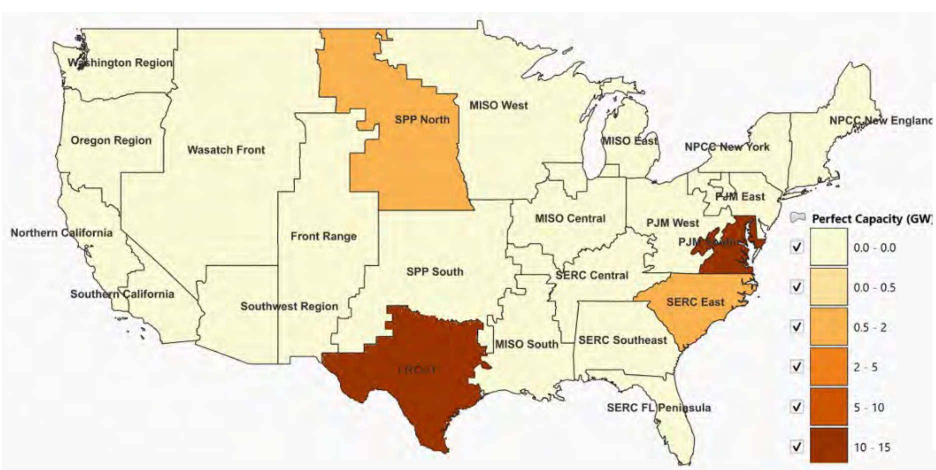
- **PJM**: 214 hours/year average, 0.066% normalized unserved energy, 644 hours in worst year, max 36% of load lost.
- **SPP**: 48 hours/year average, 0.008% normalized unserved energy, max 19% load lost.
- **ERCOT**: 20 average hours, 0.028% normalized unserved energy, 101 max hours/year, peak shortfall of 27%.
- **SERC-East**: Generally adequate (avg. 1 hour/year, 0.0003% NUSE), but Elliot storm in 2022 caused 42 hours of shortfall.

The overall takeaway is that avoiding announced retirements improves grid reliability, but shortfalls persist in PJM, SPP, ERCOT, and SERC, particularly in winter.

## Required Build

This required build analysis quantifies "hypothetical capacity," defined as power that is 100% reliable and available that is needed to resolve the shortfalls. Known in industry as “perfect capacity,” this metric is utilized to avoid the complex decision of selecting specific generation technologies, as that is ultimately an optimization of reliability against cost considerations. Nevertheless, it serves as a valuable indicator, illustrating either the magnitude of a resource gap or the scale of large load that will be unable to interconnect. For the Required Build case, this hypothetical capacity was calculated by adding new generating resources to each region until a target of 0.002% of NUSE is reached.

The table below shows the tuned perfect capacity results. For the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM, which experiences shortfalls due to the winter storm Elliot historical weather year. By 2030, without considering any generation retirements, an additional 12.5 GW of generating capacity is needed across PJM, SPP, and SERC to reduce shortfalls.




| | 2024-Current System (MW) | 2030-No Plant Closures (MW) |
|---|---|---|
| PJM | 2400 | 10,500 |
| SERC-E | | 500 |
| SPP-N | | 1,500 |
| ERCOT | 1600 | 10500 |
| Total | 4000 | 23000 |

**Perfect Capacity/Additions**

Figure 4. Tuned Perfect Capacity (MW) By Region

# 1 Modeling Methodology

The methodology uses a zonal PLEXOS[13] model with hourly time-synchronous datasets for load, generation, and interregional transfer for the 23 U.S. subregions (referred to as TPRs in this study)[14] including ERCOT (see Figure 5 below). While ERCOT operates outside of FERC's general jurisdiction,[15] it provides a valuable case for understanding broader reliability and resource adequacy challenges in the U.S. electric grid, and FPA Section 202(c) allows DOE to issue emergency orders to ERCOT.

We base this analysis on actual weather and power plant outage data from 2007 to 2023 using NERC's ITCS[16] base dataset. DOE specifically decided to start this analysis with the ITCS dataset since it is a complete representation of the interconnected electrical system for the lower 48 and it has been thoroughly reviewed by industry experts in a public and transparent process. DOE has in turn made modifications to the dataset to fit the needs of this study. The contents of this section focus on those modifications which DOE implemented for purposes of this study.

PLEXOS is an industry-trusted simulation tool used for energy optimization, resource adequacy, and production cost modeling. This study leverages PLEXOS' ability to exercise an hourly production cost model to determine the balance between loads, generation, and imports for each region. Modeling was carried out using a deterministic approach that evaluates whether a power system has sufficient resources to meet projected demand under a pre-defined set of conditions which correspond to the past few years of real-world events. The model ultimately determines the amount of unmet load if generation resources and imports are not sufficient for meeting the load in each discrete time period.

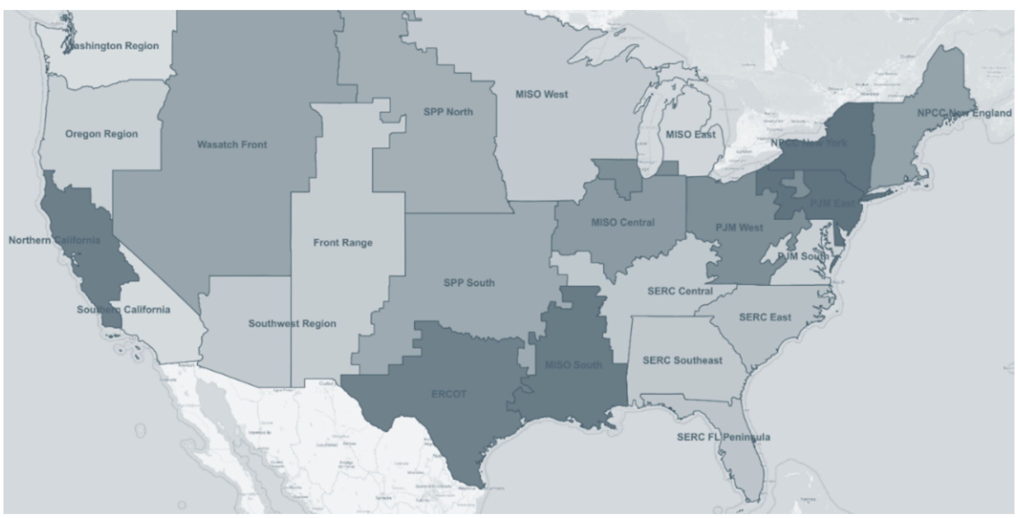



Figure 5. TPRs used in NERC ITCS

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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.

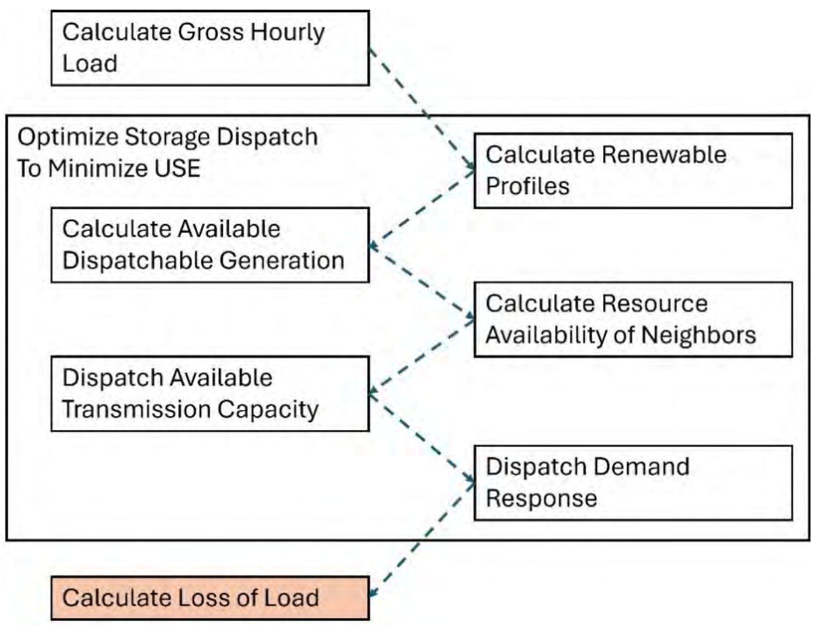


Figure 6. Simplified Overview of Model

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.

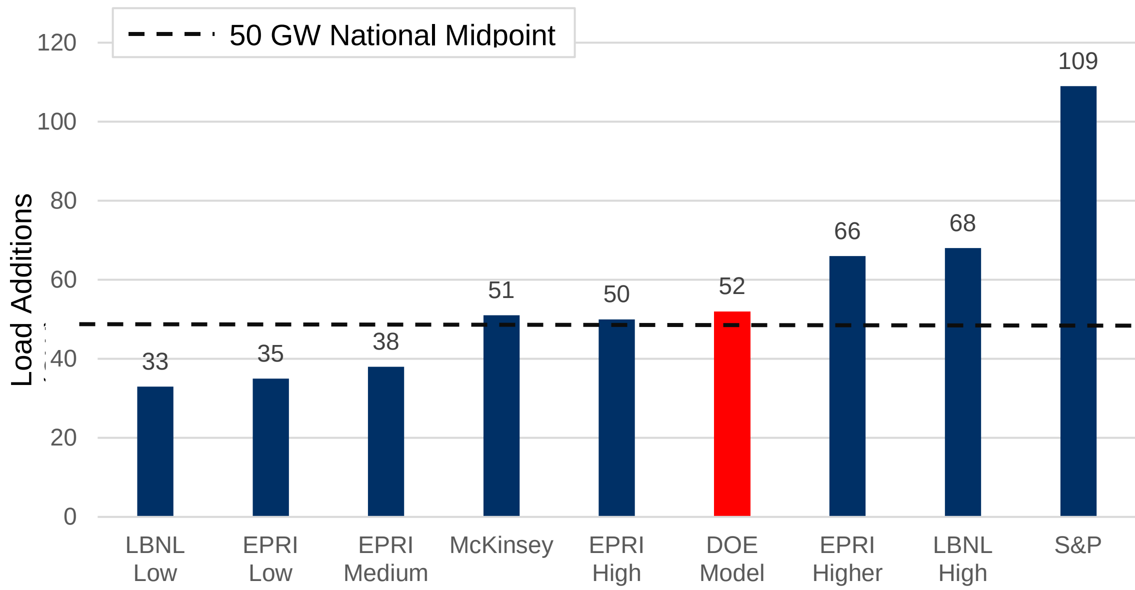


Figure 7. 2024 to 2030 Projected Data Center Load Additions

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.

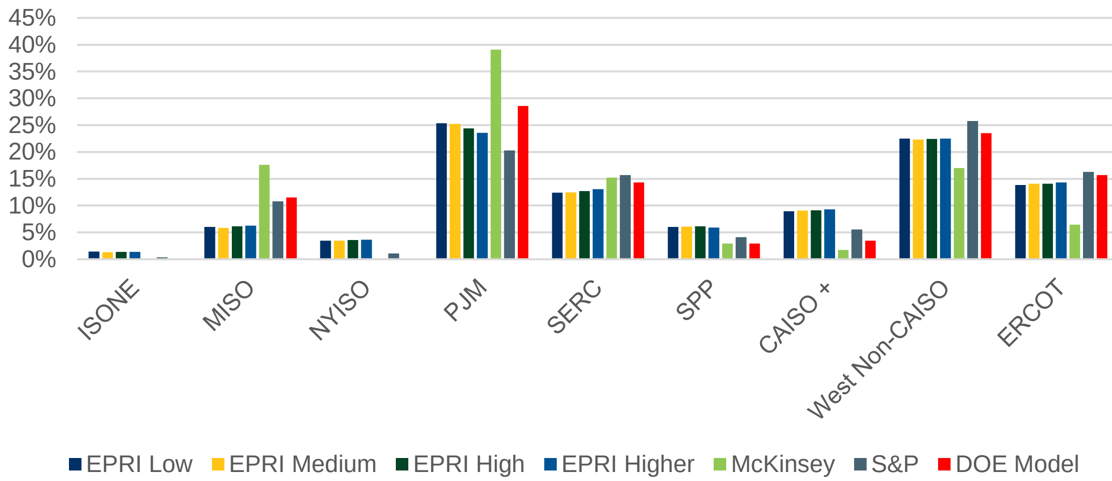


Figure 8. New Data Center Build (% Split by ISO/RTO) (2030 Estimated)

## 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.

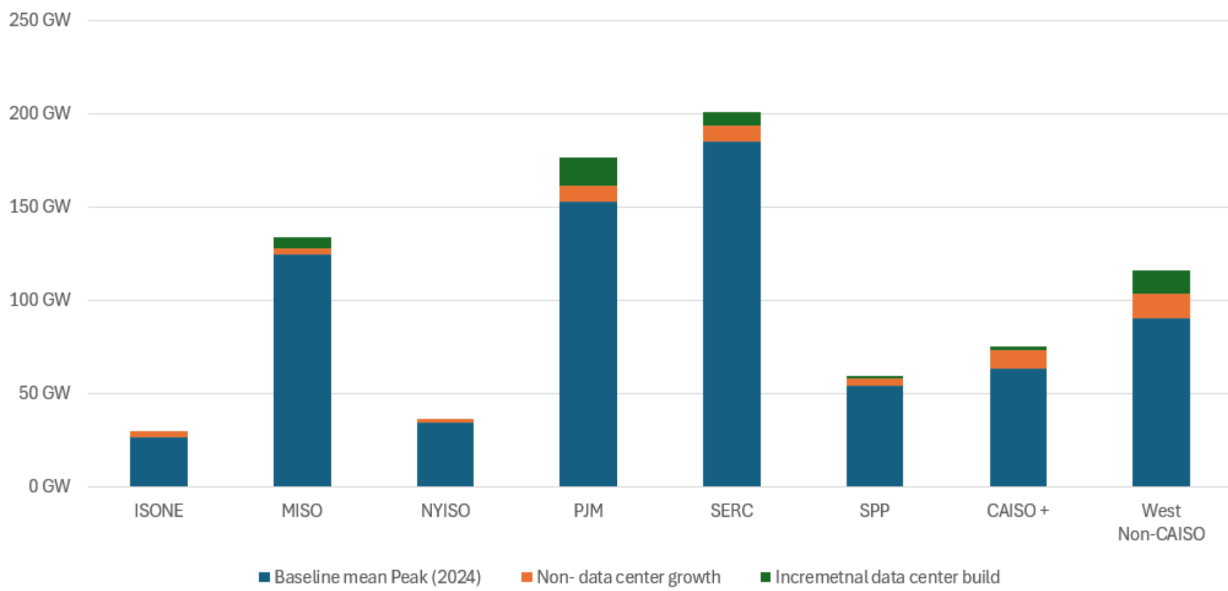


Figure 9. Mean Peak Load by RTO (Current Case vs 2030 Case)

## 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.

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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.

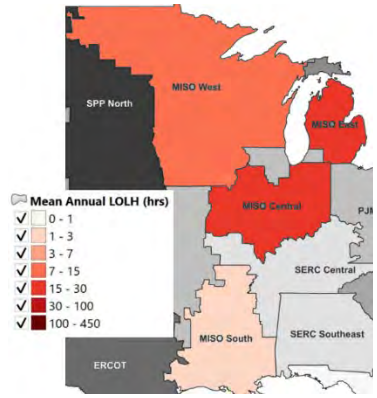


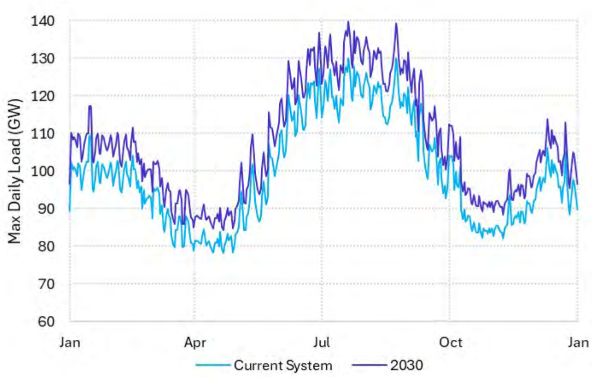

Table 2. Summary of MISO Reliability Metrics

| 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 |

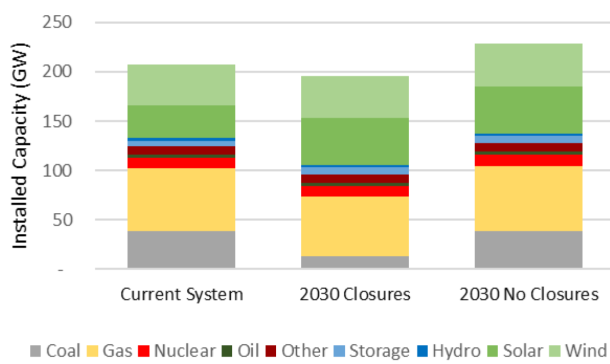



Figure 11. MISO Generation Capacity by Technology and Scenario

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.

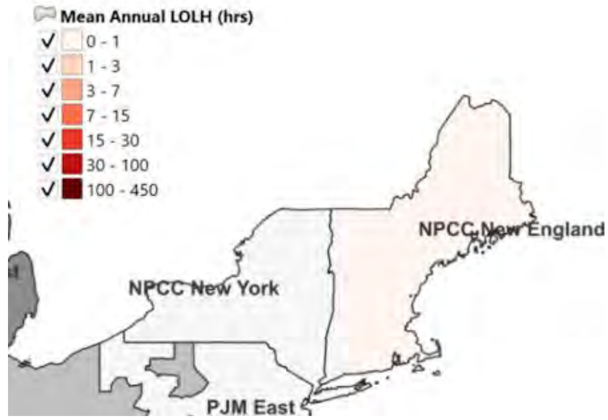
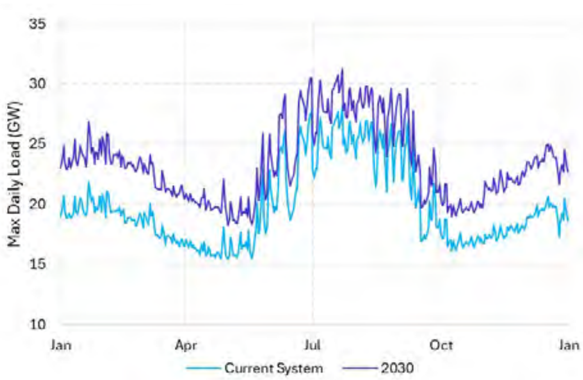



Table 4. Summary of ISO-NE Reliability Metrics

| 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** |

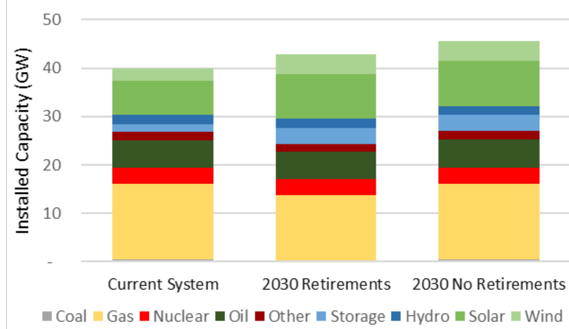



Figure 13. ISO-NE Generation Capacity by Technology and Scenario

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.

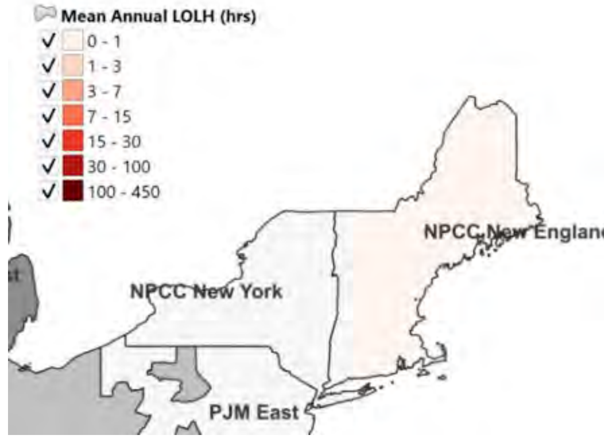
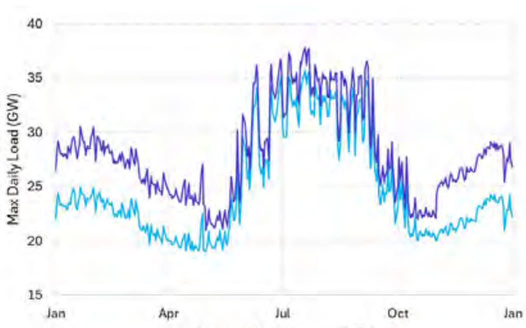



Table 6. Summary of NYISO Reliability Metrics

| Reliability Metric | Current System | 2030 Projection: Plant Closures | 2030 Projection: No Plant Closures | 2030 Projection: 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** |

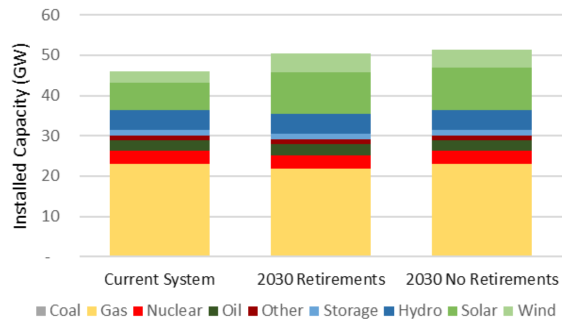


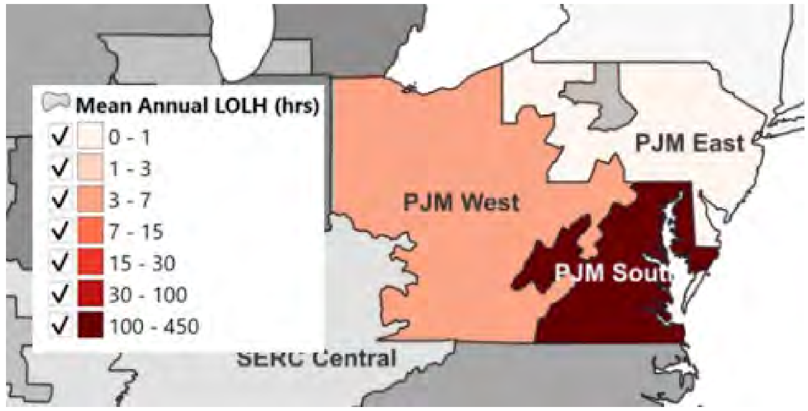

Figure 15. NYISO Generation Capacity by Technology and Scenario

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



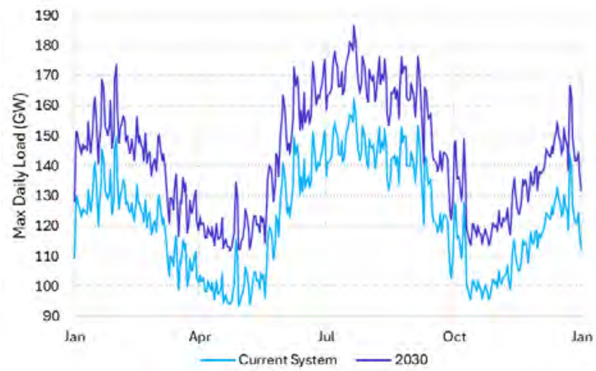

In the current system model, PJM experienced shortfalls, but they were below the required threshold. In the No Plant Closures case, shortfalls increased dramatically, with 214 average annual LOLH and peak unserved load reaching 17,620 MW, indicating growing strain even without retirements. In the Plant 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 |

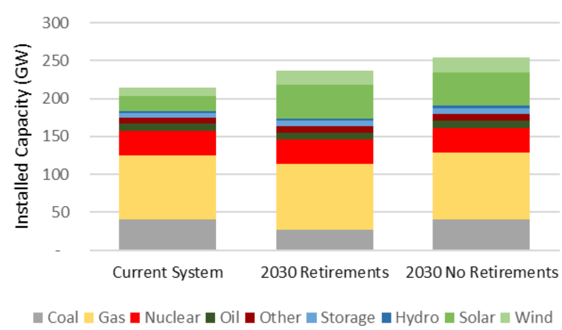


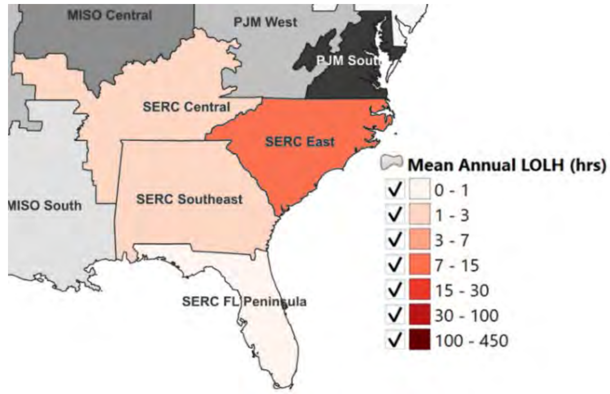

Figure 17. PJM Generation Capacity by Technology and Scenario

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



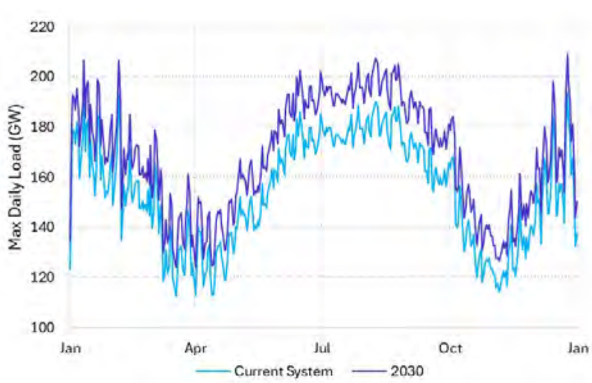

In the current system model and the No Plant Closures case, SERC maintained overall adequacy, though some subregions—particularly SERC-East—faced emerging winter reliability risks. In the Plant Closures case, shortfalls became more severe, with SERC-East experiencing increased unserved energy and loss 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 | Current System | 2030 Projection: Plant Closures | 2030 Projection: No Plant Closures | 2030 Projection: 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** |

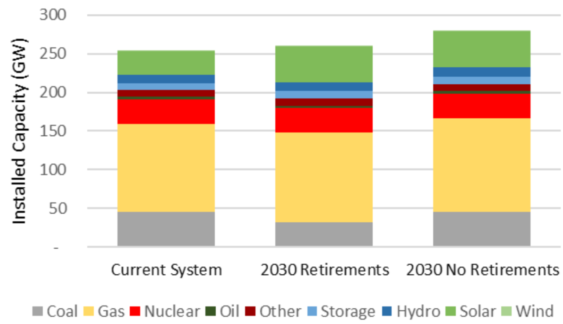



Figure 19. SERC Generation Capacity by Technology and Scenario

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.

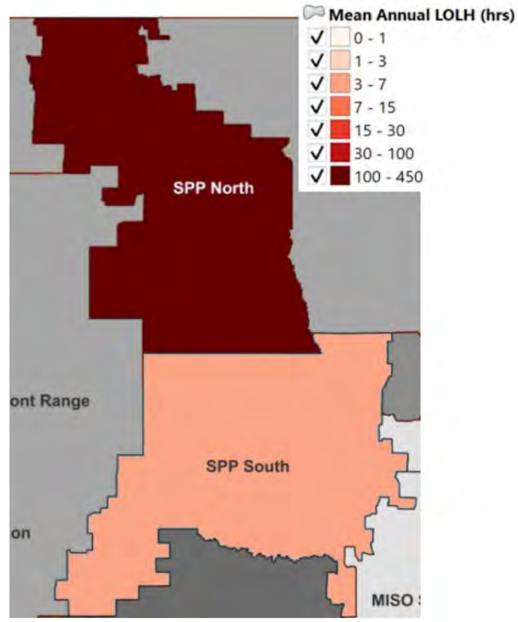
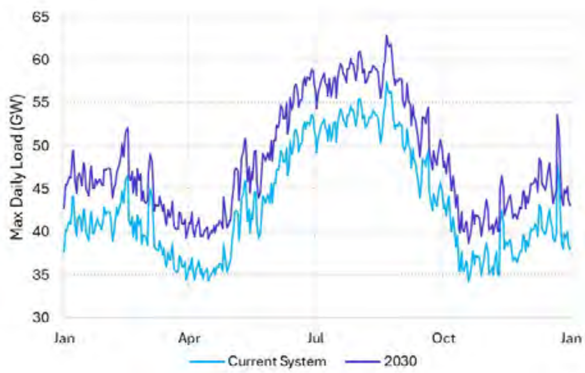



Table 12. Summary of SPP Reliability Metrics

| Reliability Metric | Current System | 2030 Projection | | |
|---|---|---|---|---|
| | | Plant Closures | No Plant Closures | Required Build |
| AVERAGE OVER 12 WEATHER YEARS | | | | |
| Average Loss of Load Hours | 1.7 | 379.6 | 47.8 | 2.4 |
| Normalized Unserved Energy (%) | 0.0002 | 0.0911 | 0.0081 | 0.0002 |
| Unserved Load (MWh) | 541 | 313,797 | 27,697 | 803 |
| WORST WEATHER YEAR | | | | |
| Max Loss of Load Hours in Single Year | 20 | 556 | 186 | 26 |
| Normalized Unserved Load (%) | 0.0022 | 0.2629 | 0.0475 | 0.0027 |
| Unserved Load (MWh) | 6,492 | 907,518 | 163,775 | 9,433 |
| Max Unserved Load (MW) | 606 | 13,263 | 2,432 | 762 |

### Load Assumptions

SPP's peak load was roughly 57 GW in the current system model and projected to increase to roughly 63 GW by 2030. Approximately 1.5 GW of this relates to new AI/DCs being installed (3% of U.S. total).




| Subregion | 2024 | 2030 |
|---|---|---|
| SPP-N | 12,668 | 14,676 |
| SPP-S | 44,898 | 48,337 |
| Total | 57,449 | 62,891 |

Figure 20. SPP Max Daily Load in the Current System versus 2030

### Generation Stack

Total installed generating capacity for 2024 was 95 GW. In 2030, 15 GW of new capacity was added leading to 110 GW of capacity in the No Plant Closures case. In the Plant Closures case, 7 GW of capacity was retired such that net generation change in the 2030 Plant Closures case was +8 GW, or 103 GW of overall installed capacity on the system.

| Subregion | Current System | 2030 Plant Closures | 2030 No Plant Closures |
|---|---|---|---|
| SPP-N | 20,065 | 20,679 | 22,385 |
| SPP-S | 75,078 | 82,451 | 88,064 |
| Total | 95,142 | 103,130 | 110,449 |

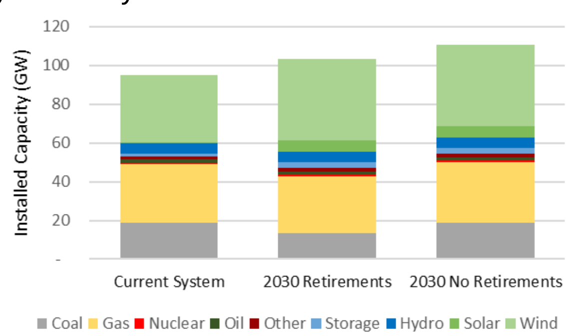


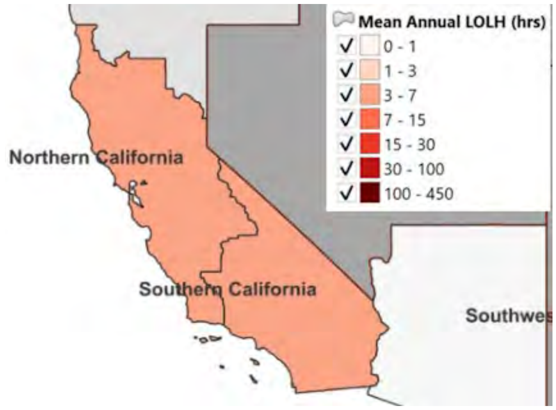

Figure 21. SPP Generation Capacity by Technology and Scenario

SPP's generation mix was comprised primarily of wind, natural gas, and coal. In 2024, wind comprised 36% of nameplate, natural gas comprised 32%, and coal 20%. In the 2030 case, most retirements come from coal and natural gas while additions occur for wind, solar, storage, and natural gas. The model assumed almost no rooftop solar and 1.3 GW of demand response.

Table 13. Nameplate Capacity by SPP Subregion and Technology (MW)

| | Coal | Gas | Nuclear | Oil | Other | Storage | Hydro | Solar | Wind | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| **2024** | **18,919** | **30,003** | **769** | **1,626** | **1,718** | **1,522** | **5,123** | **774** | **34,689** | **95,142** |
| SPP-N | 5,089 | 3,467 | 304 | 504 | 519 | 8 | 3,041 | 91 | 7,041 | **20,065** |
| SPP-S | 13,829 | 26,536 | 465 | 1,121 | 1,199 | 1,514 | 2,082 | 683 | 27,649 | **75,078** |
| **Additions** | **0** | **1,094** | **0** | **7** | **462** | **1,390** | **0** | **5,288** | **7,066** | **15,306** |
| SPP-N | 0 | 126 | 0 | 2 | 114 | 11 | 0 | 633 | 1,434 | **2,320** |
| SPP-S | 0 | 968 | 0 | 5 | 348 | 1,379 | 0 | 4,655 | 5,632 | **12,987** |
| **Closures** | **(5,530)** | **(1,732)** | **0** | **(56)** | **0** | **0** | **0** | **0** | **0** | **(7,318)** |
| SPP-N | (1,488) | (200) | 0 | (17) | 0 | 0 | 0 | 0 | 0 | **(1,705)** |
| SPP-S | (4,042) | (1,532) | 0 | (39) | 0 | 0 | 0 | 0 | 0 | **(5,613)** |

## 2.7 CAISO+



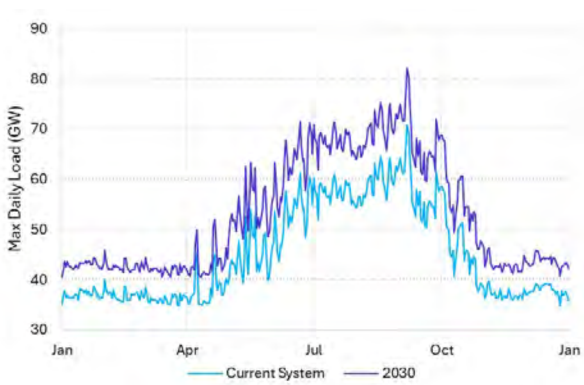

In the current system and No Plant Closures cases, CAISO+ did not experience major reliability issues, though adequacy was often maintained through significant imports during tight conditions. In the Plant Closures case, however, the region faced substantial shortfalls, particularly during summer evening hours when solar output declines. Average LOLH reached 7 hours per year, and the worst-case year showed load shed events affecting up to 31% of demand. The NUSE exceeded reliability thresholds, signaling the system's vulnerability to high load and low renewable output periods.

Table 14. Summary of CAISO+ Reliability Metrics

| Reliability Metric | | 2030 Projection | | |
|---|---|---|---|---|
| | Current System | Plant Closures | No Plant Closures | Required Build |
| AVERAGE OVER 12 WEATHER YEARS | | | | |
| Average Loss of Load Hours | - | 6.8 | - | - |
| Normalized Unserved Energy (%) | - | 0.0062 | - | - |
| Unserved Load (MWh) | - | 23,488 | - | - |
| WORST WEATHER YEAR | | | | |
| Max Loss of Load Hours in Single Year | - | 21 | - | - |
| Normalized Unserved Load (%) | - | 0.0195 | - | - |
| Unserved Load (MWh) | - | 73,462 | - | - |
| Max Unserved Load (MW) | - | 12,391 | - | - |

### Load Assumptions

CAISO+'s peak load was roughly 79 GW in the current system model and projected to increase to roughly 82 GW by 2030. Approximately 2 GW of this relates to new AI/DCs being installed (4% of U.S. total).




| Subregion | 2024 | 2030 |
|---|---|---|
| CALI-N | 29,366 | 34,066 |
| CALI-S | 41,986 | 48,666 |
| **Total** | **70,815** | **82,146** |

Figure 22. CAISO+ Max Daily Load in the Current System versus 2030

## Generation Stack

Total installed generating capacity for 2024 was approximately 117 GW. In 2030, 14 GW of new capacity was added leading to 131 GW of capacity in the No Plant Closures case. In the Plant Closures case, 8 GW of capacity was retired such that net closures in the Plant Closures case were +6 GW, or 123 GW of overall installed capacity on the system.

| Subregion | Current System | 2030 Plant Closures | 2030 No Plant Closures |
|---|---|---|---|
| CALI-N | 47,059 | 48,897 | 52,501 |
| CALI-S | 69,866 | 74,041 | 78,308 |
| **Total** | **116,925** | **122,938** | **130,809** |

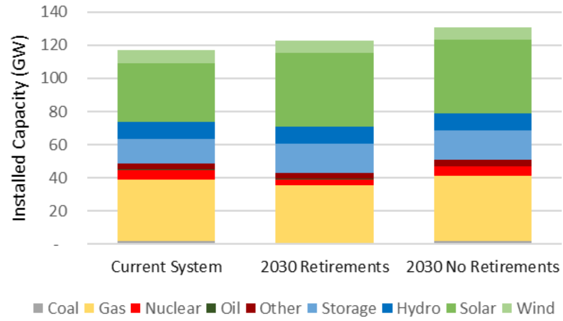



Figure 23. CAISO+ Generation Capacity by Technology and Scenario

CAISO+'s generation mix was comprised primarily of natural gas, solar, storage, and hydro. In 2024, natural gas comprised 32% of nameplate, solar comprised 31%, storage 13%, and hydro 9%. In 2030, most retirements come from coal, natural gas, and nuclear while additions occur for solar and storage. The model assumed 10 GW of rooftop solar and less than 1 GW of demand response.

Table 15. Nameplate Capacity by CAISO+ Subregion and Technology (MW)

| | Coal | Gas | Nuclear | Oil | Other | Storage | Hydro | Solar | Wind | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| **2024** | **1,816** | **37,434** | **5,582** | **185** | **3,594** | **14,670** | **10,211** | **35,661** | **7,773** | **116,925** |
| CALI-N | 0 | 12,942 | 5,582 | 165 | 1,872 | 4,639 | 8,727 | 11,759 | 1,373 | **47,059** |
| CALI-S | 1,816 | 24,492 | 0 | 20 | 1,722 | 10,031 | 1,483 | 23,902 | 6,400 | **69,866** |
| **Additions** | **0** | **2,126** | **0** | **0** | **92** | **3,161** | **0** | **8,507** | **0** | **13,885** |
| CALI-N | 0 | 735 | 0 | 0 | 44 | 757 | 0 | 3,906 | 0 | **5,442** |
| CALI-S | 0 | 1,391 | 0 | 0 | 48 | 2,404 | 0 | 4,600 | 0 | **8,442** |
| **Closures** | **(1,800)** | **(3,771)** | **(2,300)** | **0** | **0** | **0** | **0** | **0** | **0** | **(7,871)** |
| CALI-N | 0 | (1,304) | (2,300) | 0 | 0 | 0 | 0 | 0 | 0 | **(3,604)** |
| CALI-S | (1,800) | (2,467) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **(4,267)** |

## 2.8 West Non-CAISO

In both the current system and No Plant Closures cases, the West Non-CAISO region maintained adequacy on average. In the Plant Closures case, the region's reliability declined, with annual LOLH increasing and peak shortfalls in the worst year affecting up to 20% of hourly load in some subregions. While overall NUSE normalized unserved energy remained just above the 0.002% threshold, specific areas, especially those with limited local resources and constrained transmission, exceeded acceptable risk levels. These reliability gaps were primarily driven by increasing reliance on variable energy resources without sufficient firm generation.

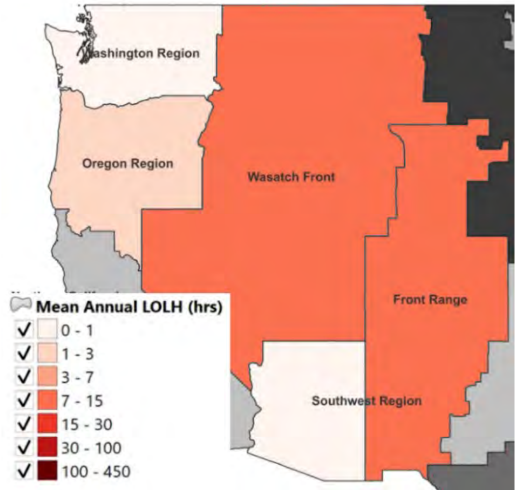
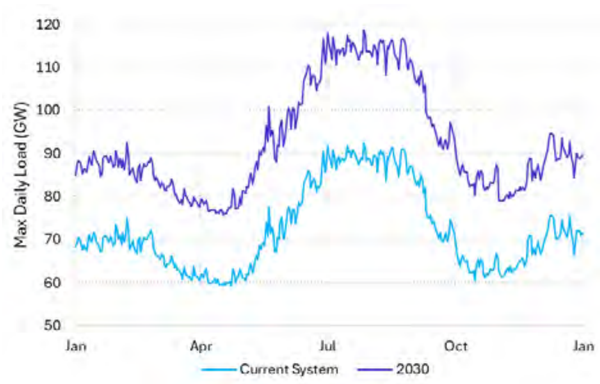



Table 16. Summary of West Non-CAISO Reliability Metrics

| Reliability Metric | | 2030 Projection | | |
|---|---|---|---|---|
| | Current System | Plant Closures | No Plant Closures | Required Build |
| AVERAGE OVER 12 WEATHER YEARS | | | | |
| Average Loss of Load Hours | - | 17.8 | - | - |
| Normalized Unserved Energy (%) | - | 0.0032 | - | - |
| Unserved Load (MWh) | - | 21,785 | - | - |
| WORST WEATHER YEAR | | | | |
| Max Loss of Load Hours in Single Year | - | 47 | - | - |
| Normalized Unserved Load (%) | - | 0.0098 | - | - |
| Unserved Load (MWh) | - | 66,248 | - | - |
| Max Unserved Load (MW) | - | 5,071 | - | - |

## Load Assumptions

West Non-CAISO's peak load was roughly 92 GW in the current system model and projected to increase to roughly 119 GW by 2030. Approximately 12 GW of this relates to new AI/DCs being installed (24% of U.S. total).




| Subregion | 2024 | 2030 |
|---|---|---|
| WASHINGTON | 20,756 | 23,187 |
| OREGON | 11,337 | 16,080 |
| SOUTHWEST | 23,388 | 30,169 |
| WASATCH | 27,161 | 35,440 |
| FRONT R | 20,119 | 24,996 |
| **Total** | **92,448** | **118,657** |

Figure 24. West Non-CAISO Max Daily Load in the Current System versus 2030

## Generation Stack

Total installed generating capacity for 2024 was 178 GW. In 2030, 29 GW of new capacity was added leading to 207 GW of capacity in the No Plant Closures case. In the Plant Closures case, 13 GW of capacity was retired such that net generation change in the Plant Closures case was 16 GW, or 193 GW of overall installed capacity on the system.

| Subregion | Current System | 2030 Plant Closures | 2030 No Plant Closures |
|---|---|---|---|
| WASHINGTON | 35,207 | 36,588 | 37,573 |
| OREGON | 19,068 | 21,689 | 22,081 |
| SOUTHWEST | 42,335 | 47,022 | 49,158 |
| WASATCH | 42,746 | 45,175 | 50,251 |
| FRONT R | 38,572 | 43,011 | 47,844 |
| **Total** | **177,929** | **193,485** | **206,908** |

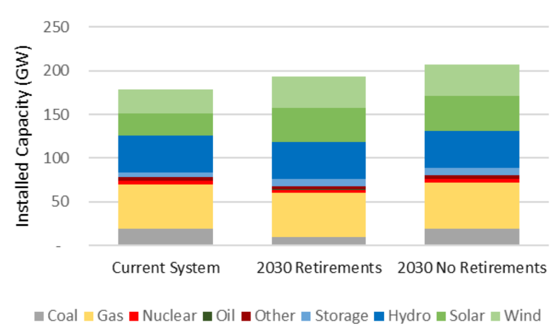



Figure 25. West Non-CAISO Generation Capacity by Technology and Scenario

West Non-CAISO's generation mix was comprised primarily of natural gas, hydro, wind, solar, and coal. In 2024, natural gas comprised 28% of nameplate, hydro comprised 24%, wind 15%, solar 13%, and coal 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar, wind, storage, and natural gas. The model assumed 6 GW of rooftop solar and over 1 GW of demand response.

Table 17. Nameplate Capacity by West Non-CAISO Subregion and Technology (MW)

| | Coal | Gas | Nuclear | Oil | Other | Storage | Hydro | Solar | Wind | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| **2024** | **19,850** | **49,969** | **3,820** | **644** | **4,114** | **5,104** | **42,476** | **24,652** | **27,298** | **177,929** |
| WASHINGTON | 560 | 3,919 | 1,096 | 17 | 595 | 489 | 24,402 | 1,438 | 2,690 | **35,207** |
| OREGON | 0 | 3,915 | 0 | 6 | 456 | 482 | 8,253 | 2,517 | 3,440 | **19,068** |
| SOUTHWEST | 4,842 | 17,985 | 2,724 | 323 | 1,316 | 2,349 | 1,019 | 8,093 | 3,685 | **42,335** |
| WASATCH | 7,033 | 14,061 | 0 | 87 | 1,433 | 1,194 | 7,587 | 7,299 | 4,052 | **42,746** |
| FRONT R | 7,415 | 10,089 | 0 | 211 | 314 | 590 | 1,215 | 5,306 | 13,432 | **38,572** |
| **Additions** | **0** | **2,320** | **0** | **1** | **8** | **2,932** | **0** | **14,759** | **8,959** | **28,979** |
| WASHINGTON | 0 | 246 | 0 | 0 | 0 | 109 | 0 | 1,059 | 952 | **2,366** |
| OREGON | 0 | 246 | 0 | 0 | 0 | 150 | 0 | 1,399 | 1,218 | **3,013** |
| SOUTHWEST | 0 | 309 | 0 | 0 | 0 | 2,338 | 0 | 3,578 | 599 | **6,823** |
| WASATCH | 0 | 884 | 0 | 0 | 7 | 233 | 0 | 4,946 | 1,435 | **7,505** |
| FRONT R | 0 | 634 | 0 | 0 | 0 | 102 | 0 | 3,779 | 4,756 | **9,271** |
| **Closures** | **(9,673)** | **(2,540)** | **0** | **(6)** | **(311)** | **(170)** | **(627)** | **0** | **(95)** | **(13,422)** |
| WASHINGTON | (317) | (195) | 0 | (0) | (66) | (28) | (369) | 0 | (11) | **(986)** |
| OREGON | 0 | (195) | 0 | (0) | (58) | 0 | (125) | 0 | (14) | **(392)** |
| SOUTHWEST | (1,185) | (951) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **(2,136)** |
| WASATCH | (3,978) | (699) | 0 | (2) | (178) | (89) | (115) | 0 | (16) | **(5,077)** |
| FRONT R | (4,194) | (501) | 0 | (4) | (8) | (53) | (18) | 0 | (54) | **(4,832)** |

## 2.9 ERCOT

In the current system model, ERCOT exceeded reliability thresholds, with 3.8 annual Loss of Load Hours and a NUSE of 0.0032%, indicating stress even before future retirements and load growth. In the No Plant Closures case, conditions worsened as average LOLH rose to 20 hours per year and the worst-case year reached 101 hours, driven by data center growth and limited dispatchable additions. The Plant Closures case intensified these risks, with average annual LOLH rising to 45 hours per year and unserved load reaching 0.066%. Peak shortfalls reached 27% of demand, with outages concentrated in winter when generation is most vulnerable. To meet reliability targets, ERCOT would require 10,500 MW of additional perfect capacity by 2030.

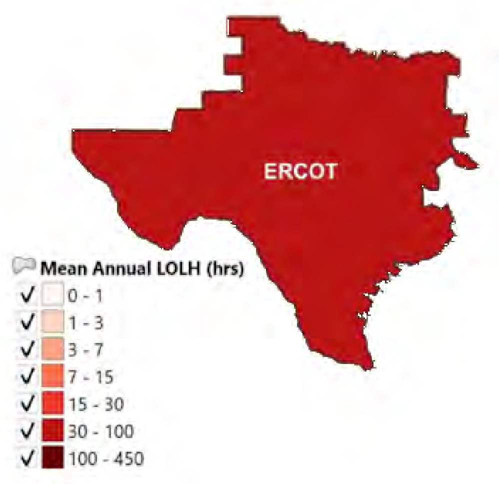
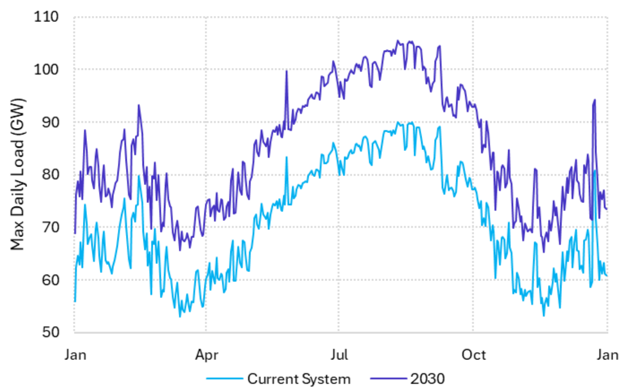



Table 18. Summary of ERCOT Reliability Metrics

| Reliability Metric | | 2030 Projection | | |
|---|---|---|---|---|
| | Current System | Plant Closures | No Plant Closures | Required Build |
| AVERAGE OVER 12 WEATHER YEARS | | | | |
| Average Loss of Load Hours | 3.8 | 45.0 | 20.3 | 1.0 |
| Normalized Unserved Energy (%) | 0.0032 | 0.0658 | 0.0284 | 0.0008 |
| Unserved Load (MWh) | 15,378 | 397,352 | 171,493 | 4,899 |
| WORST WEATHER YEAR | | | | |
| Max Loss of Load Hours in Single Year | 30 | 149 | 101 | 12 |
| Normalized Unserved Load (%) | 0.0286 | 0.02895 | 0.01820 | 0.0098 |
| Unserved Load (MWh) | 136,309 | 1,741,003 | 1,093,560 | 58,787 |
| Max Unserved Load (MW) | 10,115 | 27,156 | 23,105 | 8,202 |

### Load Assumptions

ERCOT's peak load was roughly 90 GW in the current system model and projected to increase to roughly 105 GW by 2030. Approximately 8 GW of this relates to new data centers being installed (62% of U.S. total).




| Subregion | 2024 | 2030 |
|---|---|---|
| ERCOT | 90,075 | 105,485 |
| Total | 90,075 | 105,485 |

Figure 26. ERCOT Max Daily Load in the Current System versus 2030

## Generation Stack

Total installed generating capacity for 2024 was 157 GW. In 2030, 55 GW of new capacity was added leading to 213 GW of capacity in the No Plant Closures case. In the Plant Closures case, 4 GW of capacity was retired such that net generation change in the Plant Closures case was +51 GW, or 208 GW of overall nameplate capacity on the system.

| Subregion | Current System | 2030 Plant Closures | 2030 No Plant Closures |
|---|---|---|---|
| ERCOT | 157,490 | 208,894 | 212,916 |
| Total | 157,490 | 208,894 | 212,916 |

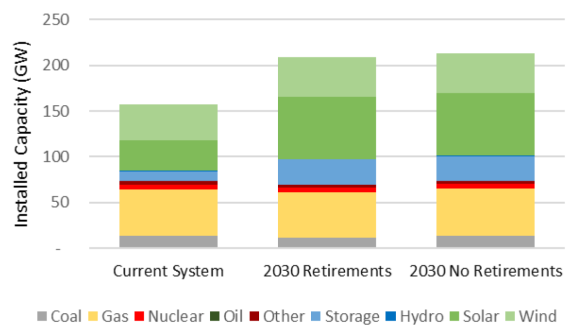



Figure 27. ERCOT Generation Capacity by Technology and Scenario

ERCOT's generation mix was comprised primarily of natural gas, wind, and solar. In 2024, natural gas comprised 32% of nameplate, wind comprised 25%, and solar 22%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed 2.5 GW of rooftop solar and 3.5 GW of demand response.

Table 19. Nameplate Capacity for ERCOT and by Technology (MW)

| | Coal | Gas | Nuclear | Oil | Other | Storage | Hydro | Solar | Wind | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| **2024** | **13,568** | **50,889** | **4,973** | **10** | **3,627** | **10,720** | **583** | **33,589** | **39,532** | **157,490** |
| ERCOT | 13,568 | 50,889 | 4,973 | 10 | 3,627 | 10,720 | 583 | 33,589 | 39,532 | **157,490** |
| **Additions** | **0** | **569** | **0** | **0** | **0** | **16,538** | **0** | **34,681** | **3,638** | **55,426** |
| ERCOT | 0 | 569 | 0 | 0 | 0 | 16,538 | 0 | 34,681 | 3,638 | **55,426** |
| **Closures** | **(2,000)** | **(2,022)** | **0** | **0** | **0** | **0** | **0** | **0** | **0** | **(4,022)** |
| ERCOT | (2,000) | (2,022) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | **(4,022)** |

# Appendix A - Generation Calibration and Forecast

The study team started with the grid model from the NERC ITCS, which was published in 2024 with reference to NERC 2023 LTRA capacity.[27] This zonal ITCS model serves as the starting point for the network topology (covering 23 U.S regions), transmission capacity between zones, and general modeling assumptions. The resource mix and retirements in the ITCS model were updated for this study to reflect the various 2030 scenarios discussed previously. Prior to developing the 2030 scenarios, the study team also updated the 2024 ITCS model to ensure consistency in the current model assumptions.

## 2024 Resource Mix

Because there were noted changes in assumed capacity additions between the 2023 and 2024 LTRAs[28], the ITCS model was updated with the 2024 LTRA data, provided directly by NERC to the study team. The 2024 LTRA dataset, reported at the NERC assessment area level—which is more aggregated in some areas than the ITCS regional structure (covering 13 U.S. regions; see Figure A.1)—includes both existing resource capacities[29] and Tier 1, 2, and 3 planned additions for each year from 2024 to 2033. As explained below, to incorporate this data into the ITCS model, a mapping process was developed to disaggregate generation capacities from the NERC assessment areas to the more granular ITCS regions by technology type. To preserve the daily or monthly adjustments to generator availability for certain categories (wind, solar, hybrid, hydropower, batteries, and other) by using the ITCS methods, the nameplate LTRA capacity was used. For all other categories (mostly thermal generators), summer and winter on-peak capacity contributions were used.

27. NERC, "Interregional Transfer Capability Study (ITCS)." https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf.

28. NERC, "2024 Long-Term Reliability Assessment," December, 2024, 24. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

29. Capacities are reported for both winter and summer seasonal ratings, along with nameplate values.

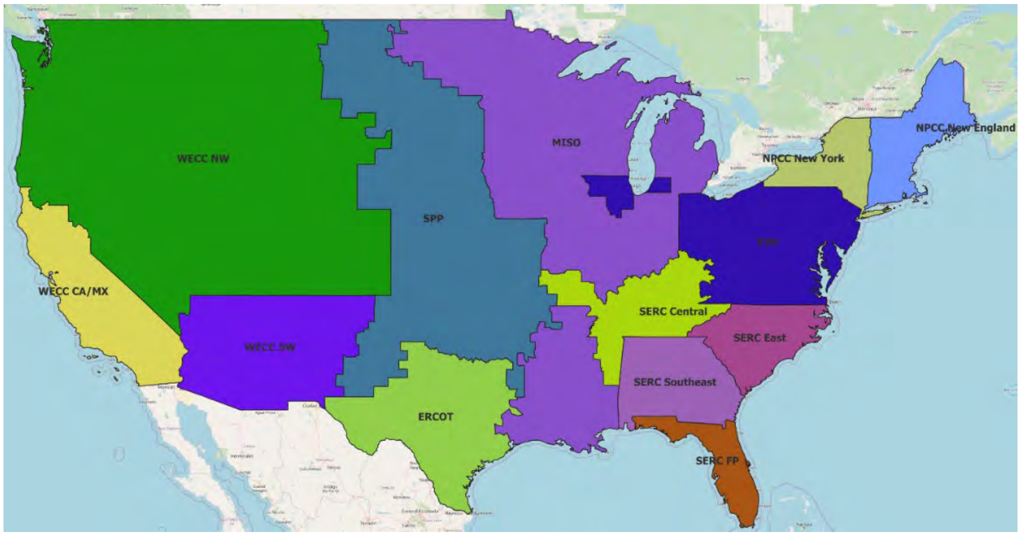



Figure A.1. NERC assessment areas.

To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant-level data were used to tabulate the generation capacity for each ITCS region and NERC assessment area. The geographical boundaries for the NERC assessment areas and the ITCS regions were constructed based on ReEDS zones.[30] Disaggregation fractions were then calculated by technology type using the combined existing capacity and planned additions through 2030 from EIA 860 data as of December 2024. Specifically, to compute each fraction, an ITCS region's total (existing plus planned) capacity was divided by the corresponding total capacity across all ITCS regions within the same mapped NERC assessment area and fuel type group:

$$Fraction_{rf} = \frac{Capacity_{rf}}{\sum_{r' \in ITCS(R)} Capacity_{r'f}} \qquad \text{(Equation.1)}$$

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 |

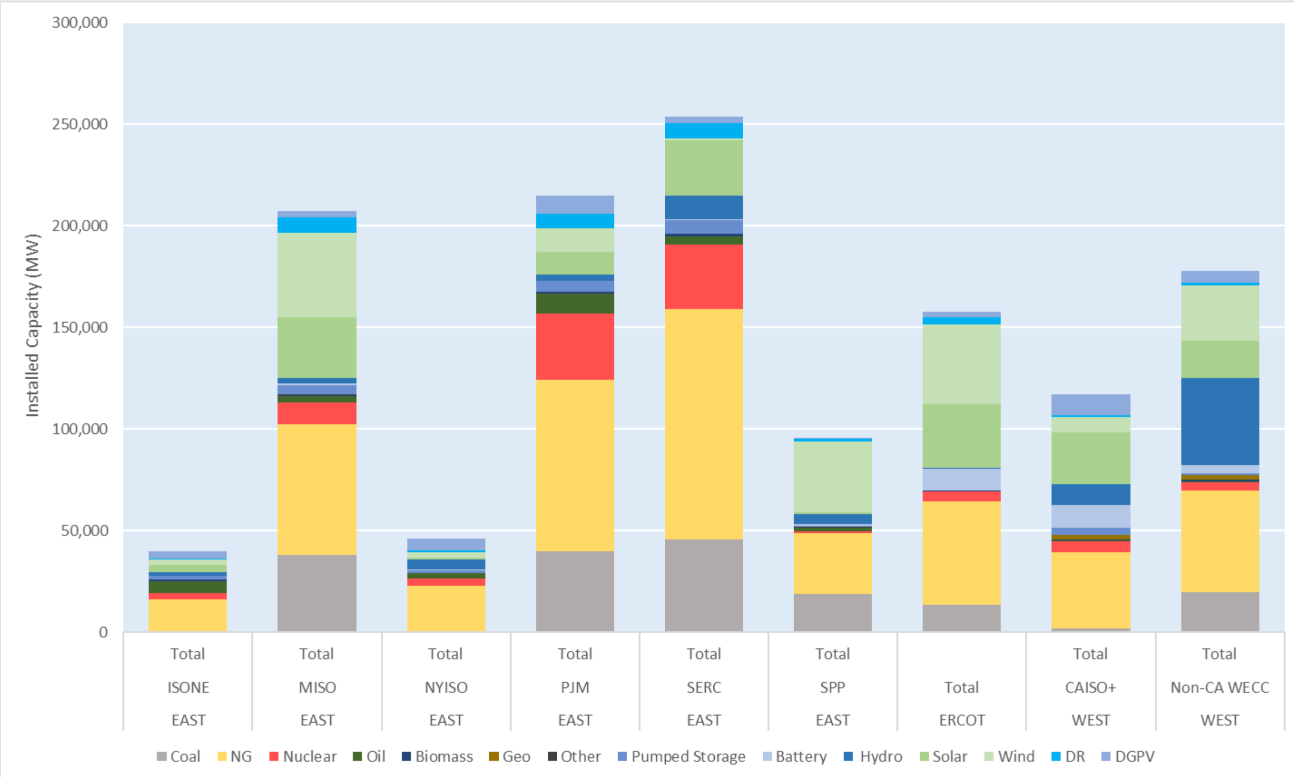



Figure A.2. Existing and Tier 1 capacities by NERC assessment area in 2024.

## 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.

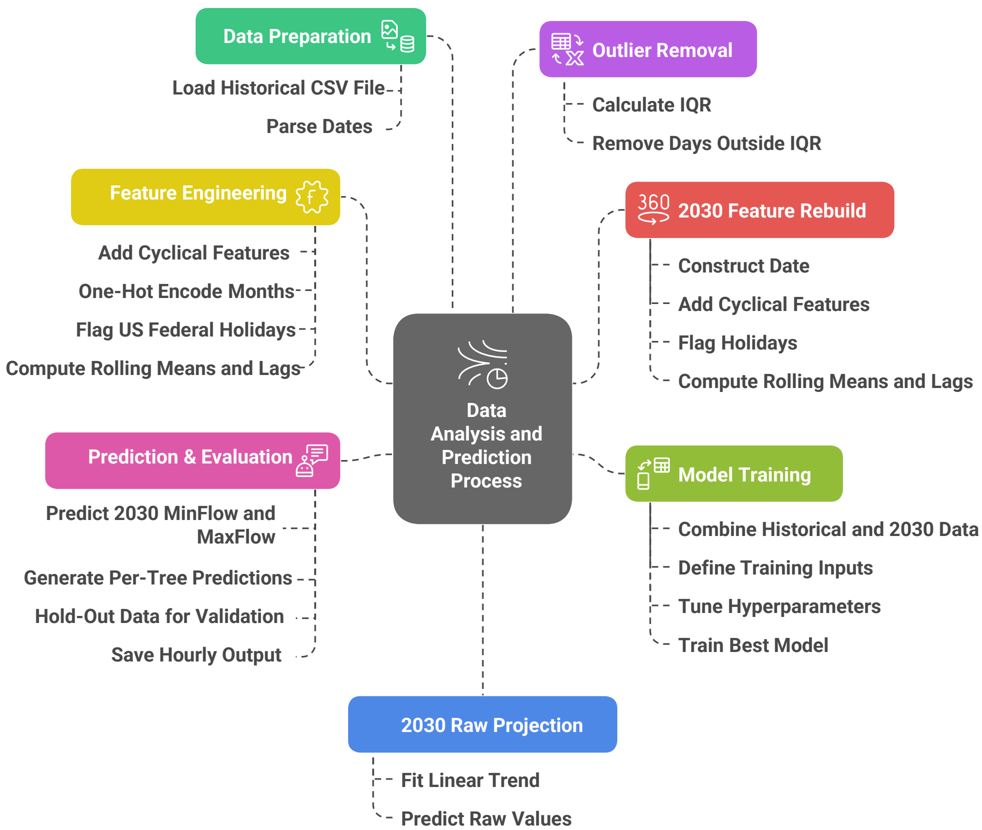



Figure B.1. Data analysis and prediction process.

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.

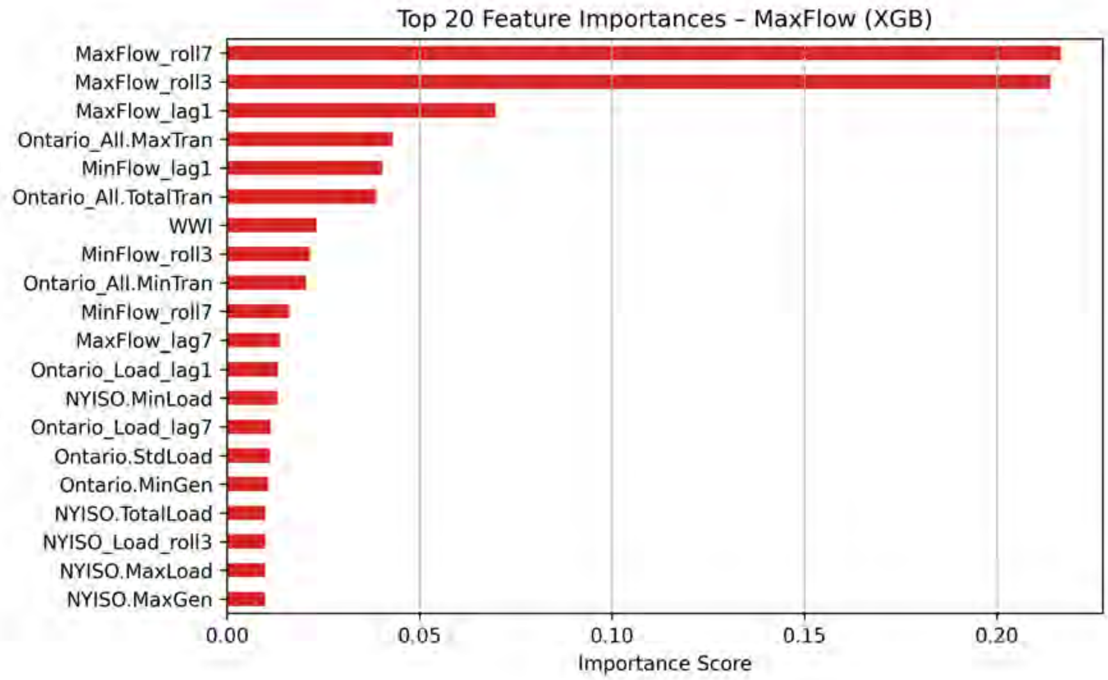



Figure B.2. Feature importance for predicting the hourly maximum energy transfer (MaxFlow) between NYISO and Ontario. XGB = eXtreme Gradient Boosting.

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.

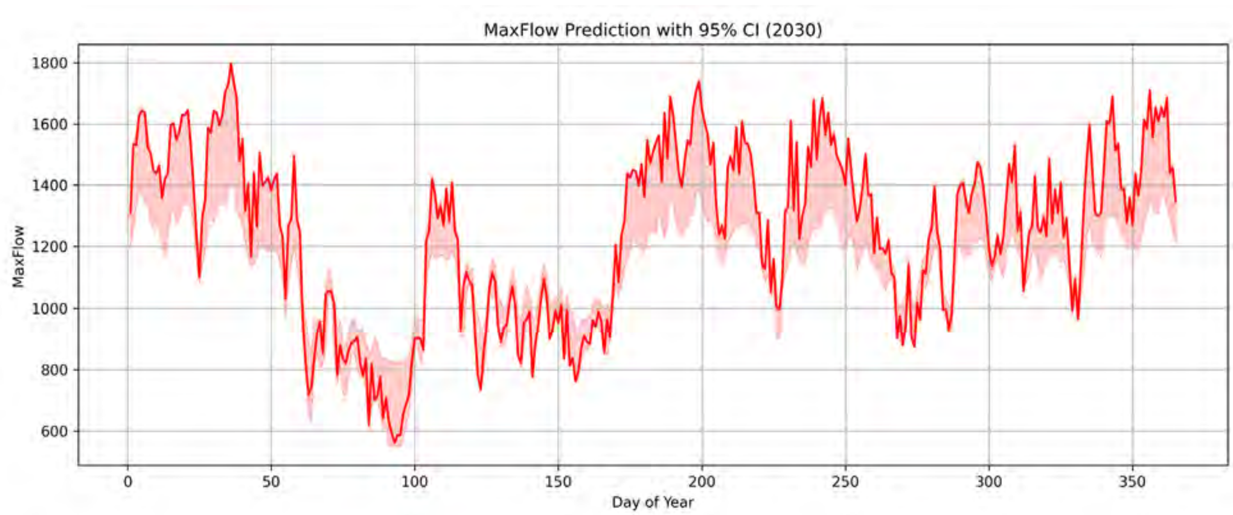



Figure B.3. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI).

### 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.

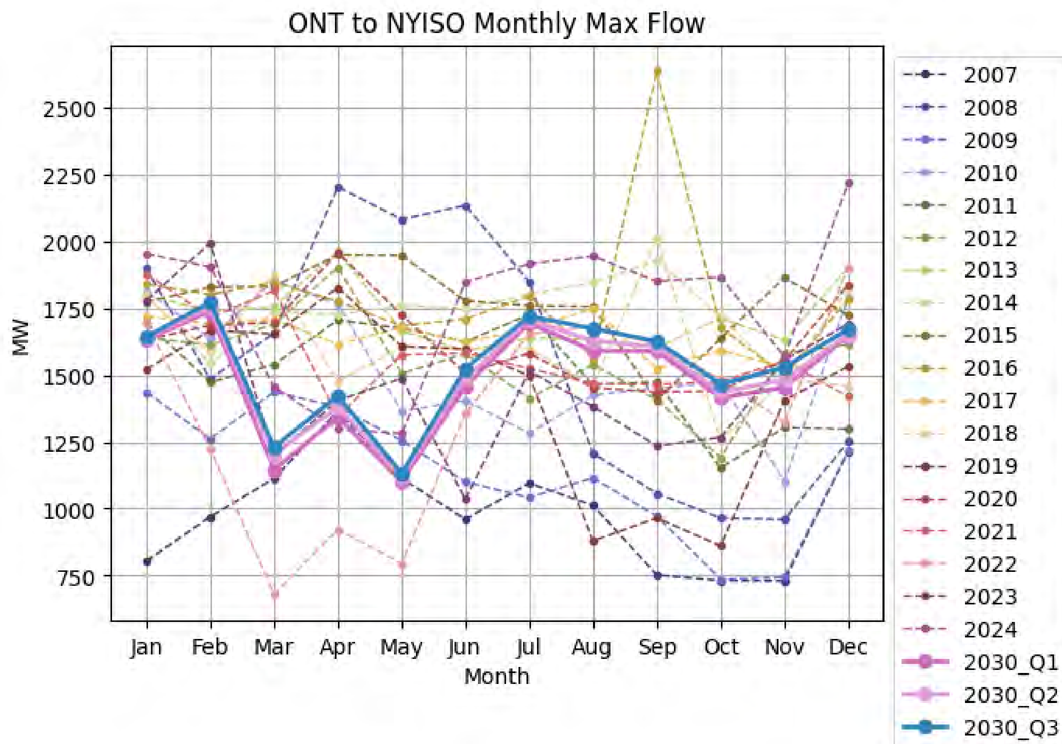



Figure B.4. Monthly maximum energy transfer between Ontario (ONT) and New York (NYISO).

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.

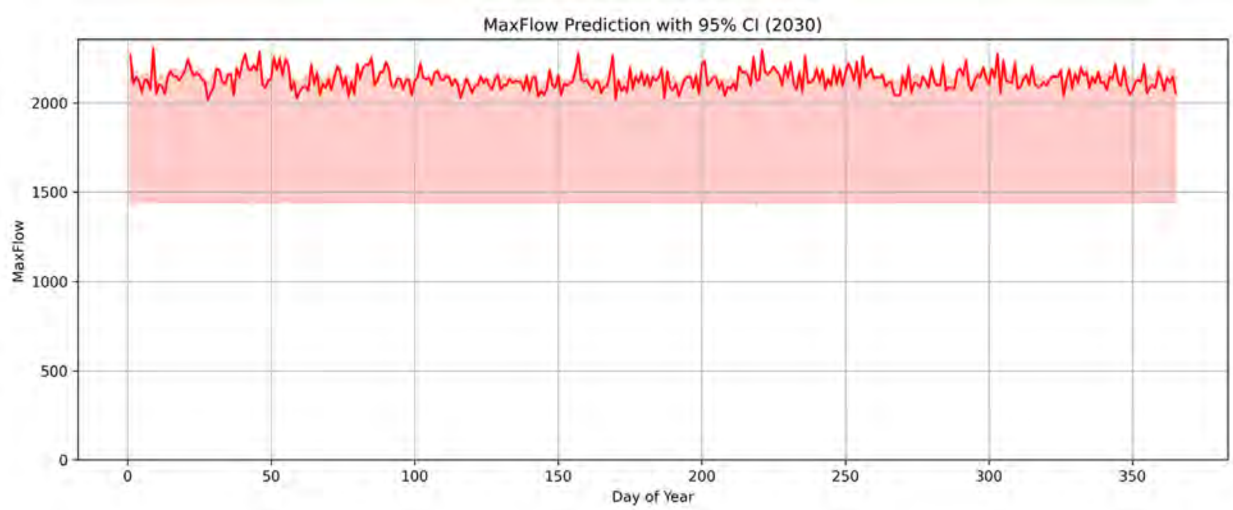



Figure B.5. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between British Columbia and the Pacific Northwest.

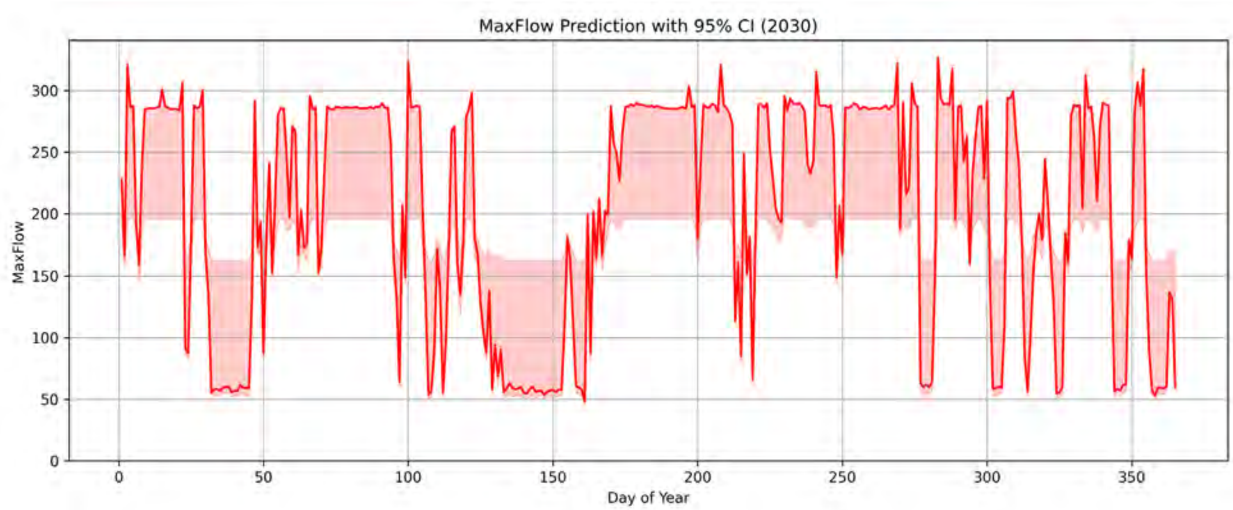



Figure B.6. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between AESO and Montana.

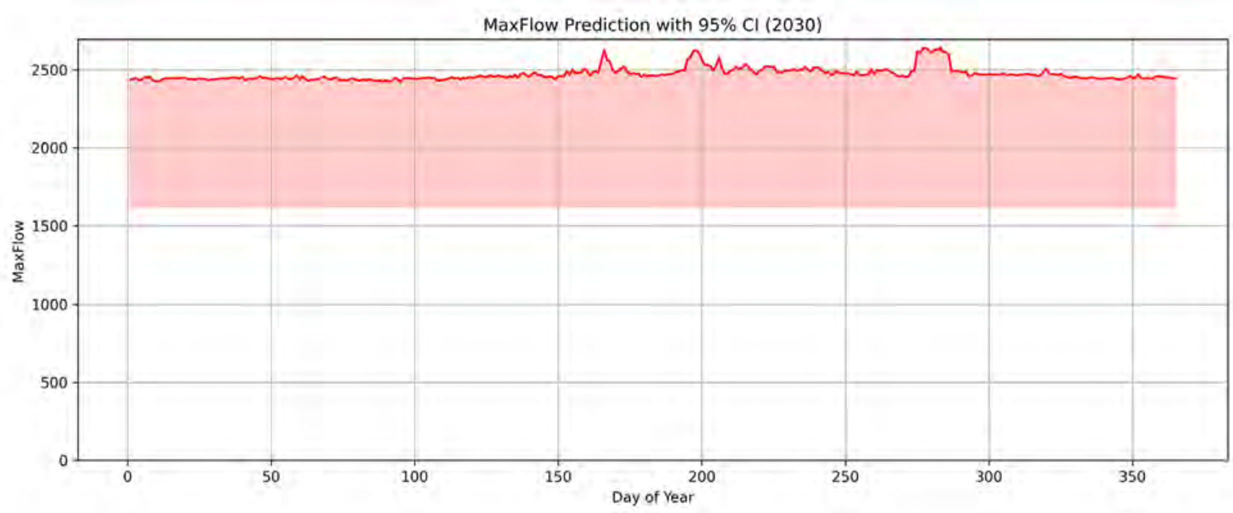



Figure B.7. Projected 2030 maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Manitoba and MISO.

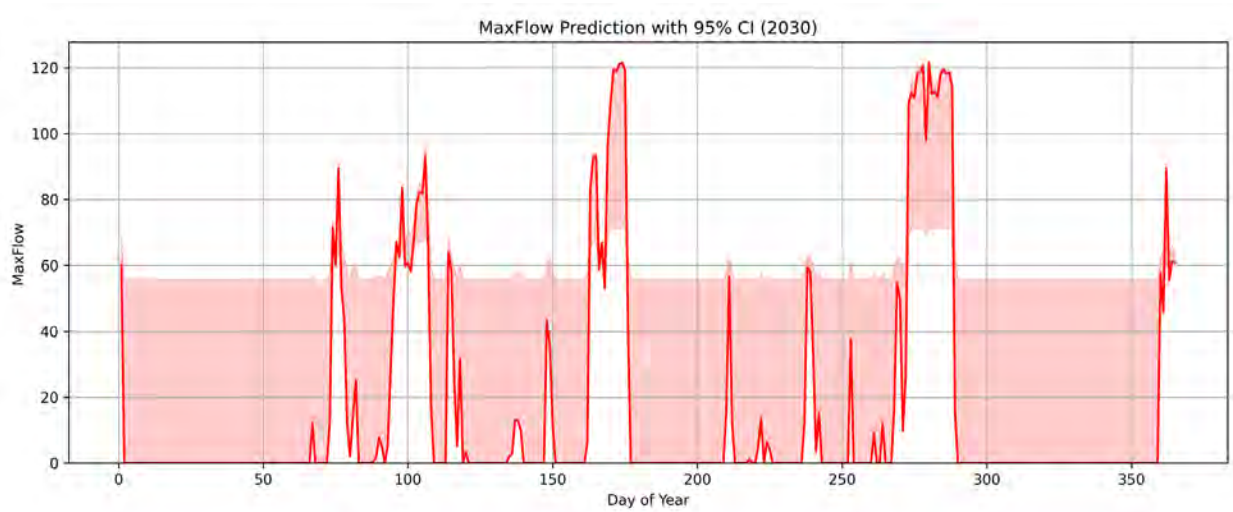



Figure B.8. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO West.

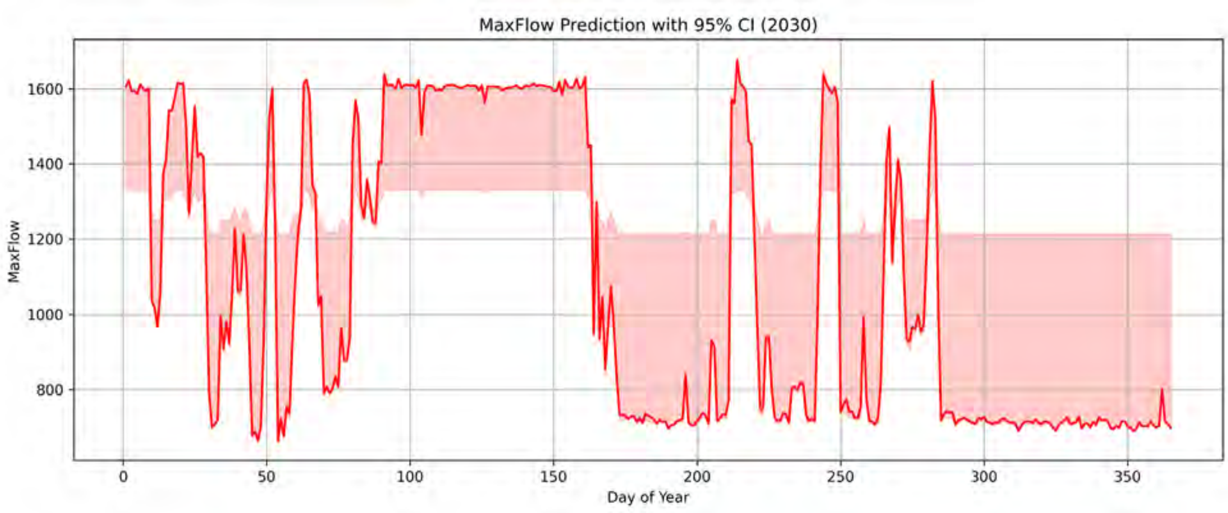



Figure B.9. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO East.

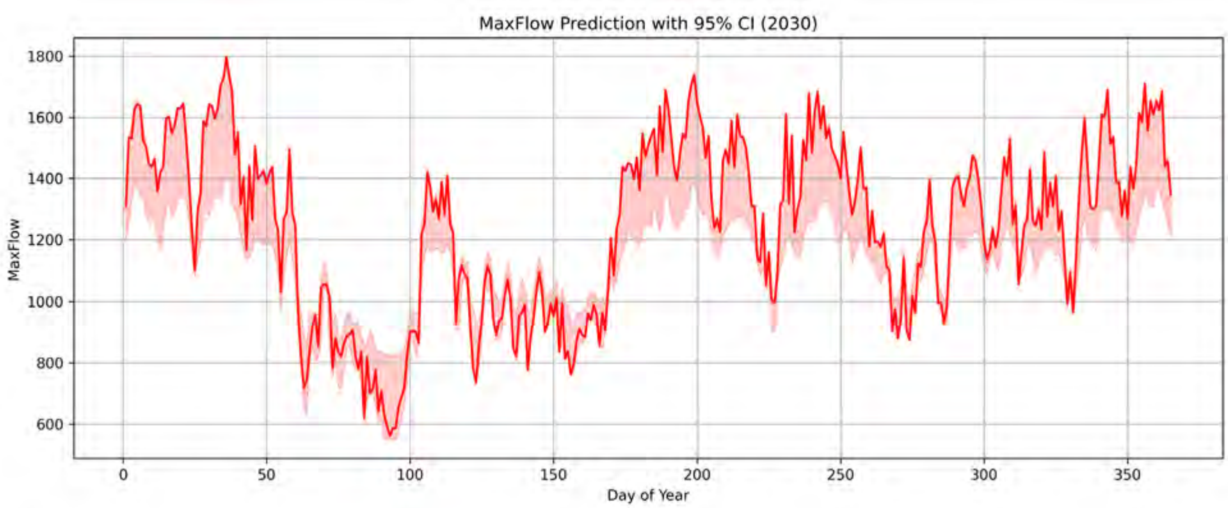



Figure B.10. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and New York.

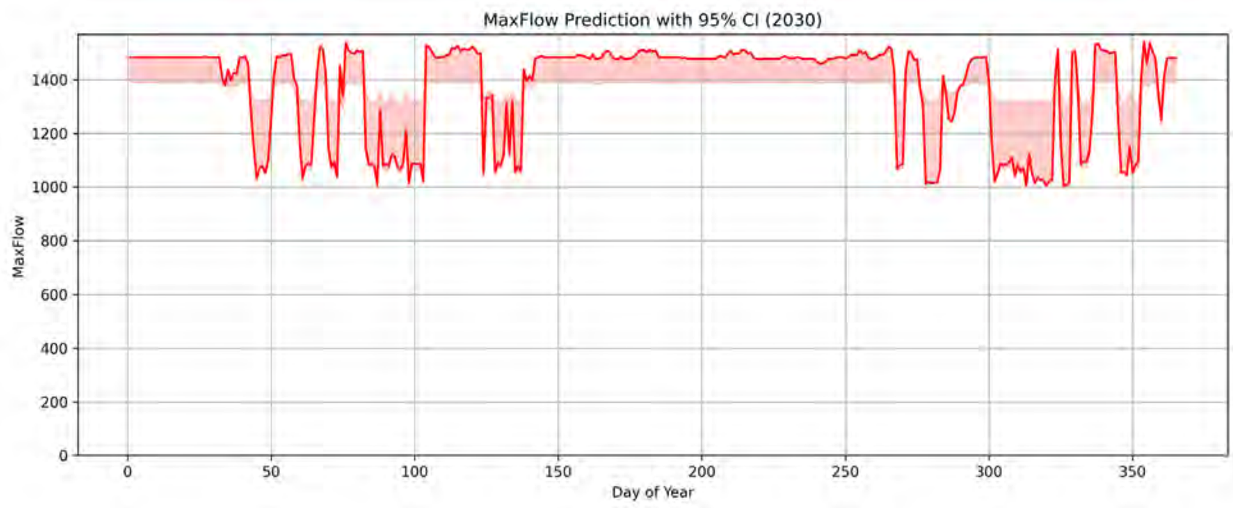



Figure B.11. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New York.

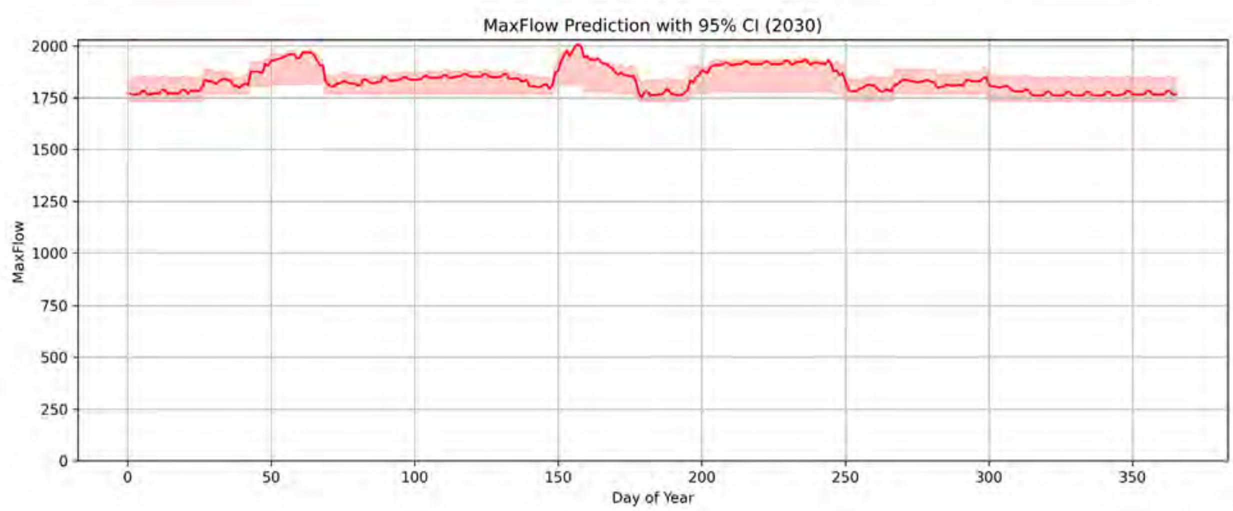



Figure B.12. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New England.

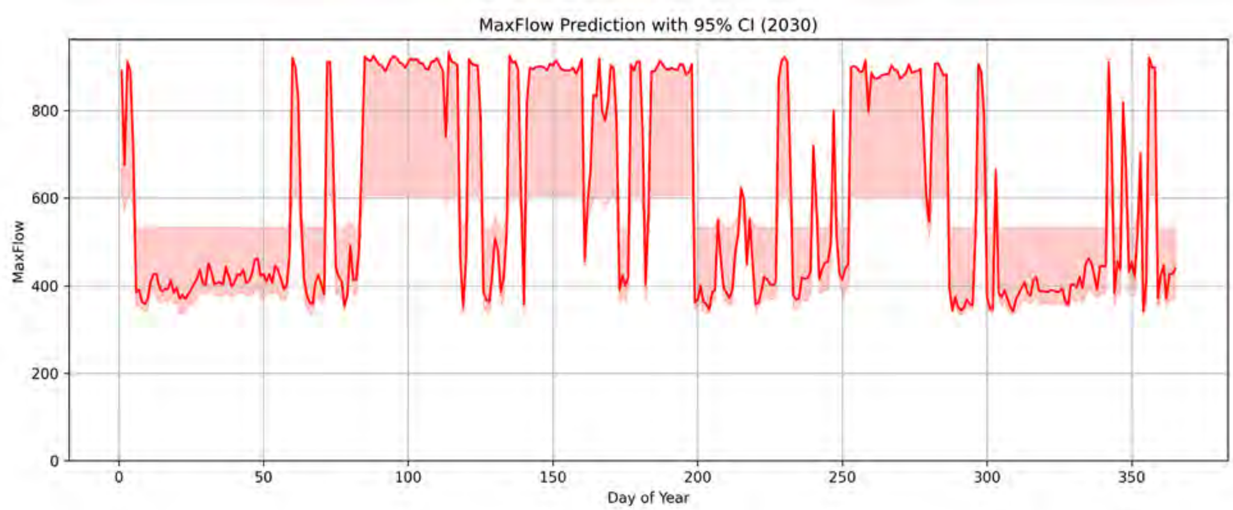



Figure B.13. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between New Brunswick and New England.

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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.

**15522** **Federal Register** / Vol. 90, No. 70 / Monday, April 14, 2025 / Presidential Documents

(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

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy | ) ) ) ) ) ) | Order No. 202-25-14 |

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

Filed January 28, 2026

Exhibit 1-36:
Energy Emergency EO

Federal Register
Vol. 90, No. 18
Wednesday, January 29, 2025

# Presidential Documents

Title 3—

The President

**Executive Order 14156 of January 20, 2025**

## Declaring a National Energy Emergency

By the authority vested in me as President by the Constitution and the laws of the United States of America, including the National Emergencies Act (50 U.S.C. 1601 *et seq.*) (''NEA''), and section 301 of title 3, United States Code, it is hereby ordered:

**Section 1**. *Purpose.* The energy and critical minerals (''energy'') identification, leasing, development, production, transportation, refining, and generation capacity of the United States are all far too inadequate to meet our Nation's needs. We need a reliable, diversified, and affordable supply of energy to drive our Nation's manufacturing, transportation, agriculture, and defense industries, and to sustain the basics of modern life and military preparedness. Caused by the harmful and shortsighted policies of the previous administration, our Nation's inadequate energy supply and infrastructure causes and makes worse the high energy prices that devastate Americans, particularly those living on low- and fixed-incomes.

This active threat to the American people from high energy prices is exacerbated by our Nation's diminished capacity to insulate itself from hostile foreign actors. Energy security is an increasingly crucial theater of global competition. In an effort to harm the American people, 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. An affordable and reliable domestic supply of energy is a fundamental requirement for the national and economic security of any nation.

The integrity and expansion of our Nation's energy infrastructure—from coast to coast—is an immediate and pressing priority for the protection of the United States' national and economic security. It is imperative that the Federal government puts the physical and economic wellbeing of the American people first.

Moreover, the United States has the potential to use its unrealized energy resources domestically, and to sell to international allies and partners a reliable, diversified, and affordable supply of energy. This would create jobs and economic prosperity for Americans forgotten in the present economy, improve the United States' trade balance, help our country compete with hostile foreign powers, strengthen relations with allies and partners, and support international peace and security. Accordingly, our Nation's dangerous energy situation inflicts unnecessary and perilous constraints on our foreign policy.

The policies of the previous administration have driven our Nation into a national emergency, where a precariously inadequate and intermittent energy supply, and an increasingly unreliable grid, require swift and decisive action. Without immediate remedy, this situation will dramatically deteriorate in the near future due to a high demand for energy and natural resources to power the next generation of technology. 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. Our Nation's current inadequate development of domestic energy resources leaves us vulnerable to hostile foreign actors and poses an imminent and growing threat to the United States' prosperity and national security.

These numerous problems are most pronounced in our Nation's Northeast and West Coast, where dangerous State and local policies jeopardize our Nation's core national defense and security needs, and devastate the prosperity of not only local residents but the entire United States population. 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. In light of these findings, I hereby declare a national emergency.

**Sec. 2**. *Emergency Approvals.* (a) The heads of executive departments and agencies (''agencies'') shall identify and exercise any lawful emergency authorities available to them, as well as all other lawful authorities they may possess, to facilitate the identification, leasing, siting, production, transportation, refining, and generation of domestic energy resources, including, but not limited to, on Federal lands. If an agency assesses that use of either Federal eminent domain authorities or authorities afforded under the Defense Production Act (Public Law 81–774, 50 U.S.C. 4501 *et seq.*) are necessary to achieve this objective, the agency shall submit recommendations for a course of action to the President, through the Assistant to the President for National Security Affairs.

(b) Consistent with 42 U.S.C. 7545(c)(4)(C)(ii)(III), the Administrator of the Environmental Protection Agency, after consultation with, and concurrence by, the Secretary of Energy, shall consider issuing emergency fuel waivers to allow the year-round sale of E15 gasoline to meet any projected temporary shortfalls in the supply of gasoline across the Nation.

**Sec. 3**. *Expediting the Delivery of Energy Infrastructure.* (a) To facilitate the Nation's energy supply, agencies shall identify and use all relevant lawful emergency and other authorities available to them to expedite the completion of all authorized and appropriated infrastructure, energy, environmental, and natural resources projects that are within the identified authority of each of the Secretaries to perform or to advance.

(b) To protect the collective national and economic security of the United States, agencies shall identify and use all lawful emergency or other authorities available to them to facilitate the supply, refining, and transportation of energy in and through the West Coast of the United States, Northeast of the United States, and Alaska.

(c) The Secretaries shall provide such reports regarding activities under this section as may be requested by the Assistant to the President for Economic Policy.

**Sec. 4**. *Emergency Regulations and Nationwide Permits Under the Clean Water Act (CWA) and Other Statutes Administered by the Army Corps of Engineers.* (a) Within 30 days from the date of this order, the heads of all agencies, as well as the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works shall:

(i) identify planned or potential actions to facilitate the Nation's energy supply that may be subject to emergency treatment pursuant to the regulations and nationwide permits promulgated by the Corps, or jointly by the Corps and EPA, pursuant to section 404 of the Clean Water Act, 33 U.S.C. 1344, section 10 of the Rivers and Harbors Act of March 3, 1899, 33 U.S.C. 403, and section 103 of the Marine Protection Research and Sanctuaries Act of 1972, 33 U.S.C. 1413 (collectively, the ''emergency Army Corps permitting provisions''); and

(ii) shall provide a summary report, listing such actions, to the Director of the Office of Management and Budget (''OMB''); the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works; the Assistant to the President for Economic Policy; and the Chairman of the Council on Environmental Quality (CEQ). Such report may be combined, as appropriate, with any other reports required by this order.

(b) Agencies are directed to use, to the fullest extent possible and consistent with applicable law, the emergency Army Corps permitting provisions to facilitate the Nation's energy supply.

(c) Within 30 days following the submission of the initial summary report described in subsection (a)(ii) of this section, each department and agency shall provide a status report to the OMB Director; the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works; the Director of the National Economic Council; and the Chairman of the CEQ. Each such report shall list actions taken within subsection (a)(i) of this section, shall list the status of any previously reported planned or potential actions, and shall list any new planned or potential actions that fall within subsection (a)(i). Such status reports shall thereafter be provided to these officials at least every 30 days for the duration of the national emergency and may be combined, as appropriate, with any other reports required by this order.

(d) The Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works, shall be available to consult promptly with agencies and to take other prompt and appropriate action concerning the application of the emergency Army Corps permitting provisions. The Administrator of the EPA shall provide prompt cooperation to the Secretary of the Army and to agencies in connection with the discharge of the responsibilities described in this section.

**Sec. 5**. *Endangered Species Act (ESA) Emergency Consultation Regulations.* (a) No later than 30 days from the date of this order, the heads of all agencies tasked in this order shall:

(i) identify planned or potential actions to facilitate the Nation's energy supply that may be subject to the regulation on consultations in emergencies, 50 CFR 402.05, promulgated by the Secretary of the Interior and the Secretary of Commerce pursuant to the Endangered Species Act (''ESA''), 16 U.S.C. 1531 *et seq.;* and

(ii) provide a summary report, listing such actions, to the Secretary of the Interior, the Secretary of Commerce, the OMB Director, the Director of the National Economic Council, and the Chairman of CEQ. Such report may be combined, as appropriate, with any other reports required by this order.

(b) Agencies are directed to use, to the maximum extent permissible under applicable law, the ESA regulation on consultations in emergencies, to facilitate the Nation's energy supply.

(c) Within 30 days following the submission of the initial summary report described in subsection (a)(ii) of this section, the head of each agency shall provide a status report to the Secretary of the Interior, the Secretary of Commerce, the OMB Director, the Director of the National Economic Council, and the Chairman of CEQ. Each such report shall list actions taken within the categories described in subsection (a)(i) of this section, the status of any previously reported planned or potential actions, and any new planned or potential actions within these categories. Such status reports shall thereafter be provided to these officials at least every 30 days for the duration of the national emergency and may be combined, as appropriate, with any other reports required by this order. The OMB Director may grant discretionary exemptions from this reporting requirement.

(d) The Secretary of the Interior shall ensure that the Director of the Fish and Wildlife Service, or the Director's authorized representative, is available to consult promptly with agencies and to take other prompt and appropriate action concerning the application of the ESA's emergency regulations. The Secretary of Commerce shall ensure that the Assistant Administrator for Fisheries for the National Marine Fisheries Service, or the Assistant Administrator's authorized representative, is available for such consultation and to take such other action.

**Sec. 6**. *Convening the Endangered Species Act Committee.* (a) In acting as Chairman of the Endangered Species Act Committee, the Secretary of the Interior shall convene the Endangered Species Act Committee not less than quarterly, unless otherwise required by law, to review and consider any lawful applications submitted by an agency, the Governor of a State, or any applicant for a permit or license who submits for exemption from obligations imposed by Section 7 of the ESA.

(b) To the extent practicable under the law, the Secretary of the Interior shall ensure a prompt and efficient review of all submissions described in subsection (a) of this section, to include identification of any legal deficiencies, in order to ensure an initial determination within 20 days of receipt and the ability to convene the Endangered Species Act Committee to resolve the submission within 140 days of such initial determination of eligibility.

(c) In the event that the committee has no pending applications for review, the committee or its designees shall nonetheless convene to identify obstacles to domestic energy infrastructure specifically deriving from implementation of the ESA or the Marine Mammal Protection Act, to include regulatory reform efforts, species listings, and other related matters with the aim of developing procedural, regulatory, and interagency improvements.

**Sec. 7**. *Coordinated Infrastructure Assistance.* (a) In collaboration with the Secretaries of Interior and Energy, the Secretary of Defense shall conduct an assessment of the Department of Defense's ability to acquire and transport the energy, electricity, or fuels needed to protect the homeland and to conduct operations abroad, and, within 60 days, shall submit this assessment to the Assistant to the President for National Security Affairs. This assessment shall identify specific vulnerabilities, including, but not limited to, potentially insufficient transportation and refining infrastructure across the Nation, with a focus on such vulnerabilities within the Northeast and West Coast regions of the United States. The assessment shall also identify and recommend the requisite authorities and resources to remedy such vulnerabilities, consistent with applicable law.

(b) In accordance with section 301 of the National Emergencies Act (50 U.S.C. 1631), the construction authority provided in section 2808 of title 10, United States Code, is invoked and made available, according to its terms, to the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works, to address any vulnerabilities identified in the assessment mandated by subsection (a). Any such recommended actions shall be submitted to the President for review, through the Assistant to the President for National Security Affairs and the Assistant to the President for Economic Policy.

**Sec. 8**. *Definitions.* For purposes of this order, the following definitions shall apply:

(a) The term "energy" or "energy resources" means crude oil, natural gas, lease condensates, natural gas liquids, refined petroleum products, uranium, coal, biofuels, geothermal heat, the kinetic movement of flowing water, and critical minerals, as defined by 30 U.S.C. 1606 (a)(3).

(b) The term "production" means the extraction or creation of energy.

(c) The term "transportation" means the physical movement of energy, including through, but not limited to, pipelines.

(d) The term "refining" means the physical or chemical change of energy into a form that can be used by consumers or users, including, but not limited to, the creation of gasoline, diesel, ethanol, aviation fuel, or the beneficiation, enrichment, or purification of minerals.

(e) The term "generation" means the use of energy to produce electricity or thermal power and the transmission of electricity from its site of generation.

(f) The term "energy supply" means the production, transportation, refining, and generation of energy.

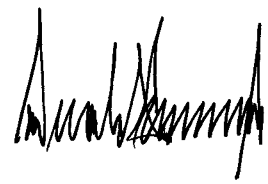
**Sec. 9**. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of OMB 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,
*January 20, 2025.*

[FR Doc. 2025–02003
Filed 1–28–25; 11:15 am]
Billing code 3395–F4–P

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) | ) | |
| Emergency Order: Tri-State | ) | Order No. 202-25-14 |
| Generation and Transmission | ) | |
| Association, Platte River Power | ) | |
| Authority, Salt River Project, | ) | |
| PacifiCorp, and Xcel Energy | ) | |

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

Filed January 28, 2026

Exhibit 1-37:
Grid EO

# 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.

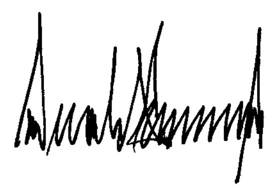
**Sec. 4**. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

(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

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy | ) | Order No. 202-25-14 |

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

Filed January 28, 2026

Exhibit 1-38:
NY Times Coal Article

# *Trump Signs Orders Aimed at Reviving a Struggling Coal Industry*

The moves include loosening environmental rules, but it is unclear how much they can help reverse the sharp decline in coal power over the last two decades.

**Listen to this article · 7:58 min** Learn more


**By Brad Plumer and Mira Rojanasakul**
Reporting from Washington

April 8, 2025

President Trump signed a flurry of executive orders Tuesday aimed at expanding the mining and burning of coal in the United States, in an effort to revive the struggling industry.

One order directs federal agencies to repeal any regulations that “discriminate” against coal production, to open new federal lands for coal mining and to explore whether coal-burning power plants could serve new A.I. data centers. Mr. Trump also said he would waive certain air-pollution restrictions adopted by the Biden administration for dozens of coal plants that were at risk of closing down.

In a move that could face legal challenges, Mr. Trump directed the Energy Department to develop a process for using emergency powers to prevent unprofitable coal plants from shutting down in order to avert power outages. Mr. Trump proposed a similar action in his first term but eventually abandoned the idea after widespread opposition.

Flanked by dozens of miners in white hard hats at the White House, Mr. Trump said he was also instructing the Justice Department to identify and fight state and local climate policies that were “putting our coal miners out of business.” He added that he would issue “guarantees” that future administrations could not adopt policies harmful to coal, but did not provide details.

“This is a very important day to me because we’re bringing back an industry that was abandoned despite the fact that it was the best, certainly the best in terms of power, real power,” Mr. Trump said.

In recent weeks, Mr. Trump, Chris Wright, the energy secretary, and Doug Burgum, the interior secretary, have all spoken about the importance of coal. The two cabinet members sat in the front row at the White House ceremony, which was attended by members of Congress from Wyoming, Kentucky, West Virginia and other coal-producing states.

“Beautiful clean coal,” Mr. Trump told the gathering. “Never use the word ‘coal’ unless you put ‘beautiful, clean’ before it.”

Coal is the most polluting of all fossil fuels when burned, and accounts for roughly 40 percent of the world’s industrial carbon dioxide emissions, the main driver of global warming. It releases other pollutants, including mercury and sulfur dioxide, that are linked to heart disease, respiratory problems and premature deaths. Coal mining and the resulting coal ash from power plants can also present environmental problems.

Over the past two decades, the use of coal has fallen precipitously in the United States, as utilities have switched to cheaper and cleaner electricity sources like natural gas, wind and solar power. That transition has been the biggest reason for the drop in U.S. emissions since 2005.

**Coal power has declined sharply — and more retirements are coming.**

**Coal capacity retired each year**

Capacity (megawatts)
300,000

More capacity retired under Trump's first term than under Biden.

200,000

**Operating coal plants**

**Planned retirements**

About half of remaining coal capacity is set to retire.

100,000

**Projections**

2000 2025 2050

**G.W. BUSH** **OBAMA** **TRUMP** **BIDEN** **TRUMP**

Source: Global Energy Monitor and New York Times reporting. • Note: Includes coal capacity added. • By Mira Rojanasakul/The New York times

It is unclear how much Mr. Trump could reverse that decline. In 2011, the nation generated nearly half of its electricity from coal; last year, that fell to just 15 percent. Utilities have already closed hundreds of aging coal-burning units and have announced retirement dates for roughly half of the remaining plants.

In recent years, growing interest in artificial intelligence and data centers has fueled a surge in electricity demand, and utilities have decided to keep more than 50 coal-burning units open past their scheduled closure dates, according to America's Power, an industry trade group. And as the Trump administration moves to loosen pollution limits on coal power — including regulations applied to carbon dioxide and mercury — more plants could stay open longer, or run more frequently.

"You know, we need to do the A.I., all of this new technology that's coming on line," Mr. Trump said on Tuesday. "We need more than double the energy, the electricity, that we currently have."

Yet a major coal revival is unlikely, some analysts said.

“The main issue is that most of our coal plants are older and getting more expensive to run, and no one’s thinking about building new plants,” said Seth Feaster, a data analyst who focuses on coal at the Institute for Energy Economics and Financial Analysis, a research firm. “It’s very hard to change that trajectory.”

During his first term, Mr. Trump sought to prevent unprofitable coal plants from closing, using emergency authority that is normally reserved for fleeting crises like natural disasters. But that idea brought a fierce blowback from oil and gas companies, grid operators and consumer groups, who said it would drive up electricity bills, and the administration eventually backed away from the idea.

If the idea was tried again today, it would be likely to lead to lawsuits, said Ari Peskoe, director of the Electricity Law Initiative at Harvard Law School. “But there’s not a lot of litigation history here,” he said. “Typically these emergency orders last for no longer than 90 days.”

Ultimately, Mr. Trump struggled to fulfill his first-term pledge of rescuing the coal industry. Despite the fact that his administration repealed numerous climate regulations and appointed a coal lobbyist to lead the Environmental Protection Agency, 75 coal-fired power plants closed, and the industry shed about 13,000 jobs during his presidency.

Coal’s decline continued under President Joseph R. Biden Jr., who sought to move the country away from the fossil fuel altogether in an effort to fight climate change. Last year, his administration issued a sweeping E.P.A. rule that would have forced all of the nation’s coal plants to either install expensive equipment to capture and bury their carbon dioxide emissions or shut down by 2039.

This year, upon returning to office, Mr. Trump ordered the E.P.A. to repeal that rule. And Trump administration officials have repeatedly warned that shutting down coal plants would harm power supplies. Unlike wind and solar energy, coal plants can run at any hour of the day, making them useful when electricity demand spikes.

Some industry executives who run the nation’s electric grids have also warned that the country could face a greater risk of blackouts if too many coal plants retire too quickly, especially since power companies have faced delays in bringing new gas, wind and solar plants online, as well as in adding battery storage and transmission lines.

"For decades, most people have taken electricity and coal for granted," said Michelle Bloodworth, chief executive of America's Power. "This complacency has led to damaging federal and state policies that have caused the premature retirement of coal plants, thus weakening our electric grid and threatening our national security."

Yet coal opponents say that keeping aging plants online can worsen deadly air pollution and increase energy costs. Earlier this year, PJM Interconnection, which oversees a large grid in the Mid-Atlantic, ordered a power plant that burns coal and another that burns oil to stay open until 2029, four years past their planned retirement date, to reduce the risk of power outages. The move could ultimately cost utility customers in the area of more than $720 million.

"Coal plants are old and dirty, uncompetitive and unreliable," said Kit Kennedy, managing director for power at the Natural Resources Defense Council, an environmental group. "The Trump administration is stuck in the past, trying to make utility customers pay more for yesterday's energy. Instead, it should be doing all it can to build the electricity grid of the future."

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

**Mira Rojanasakul** is a Times reporter who uses data and graphics to cover climate and the environment.

A version of this article appears in print on , Section A, Page 15 of the New York edition with the headline: Trump Signs Orders Aimed At Reviving Coal Industry

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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| Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy | ) ) ) ) ) ) | Order No. 202-25-14 |

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

Filed January 28, 2026

Exhibit 1-39:
DOE July 7 Press Release

# Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security

The Department of Energy warns that blackouts could increase by 100 times in 2030 if the U.S. continues to shutter reliable power sources and fails to add additional firm capacity.

Energy.gov

July 7, 2025

4 min

***The Department of Energy warns that blackouts could increase by 100 times in 2030 if the U.S. continues to shutter reliable power sources and fails to add additional firm capacity.***

**WASHINGTON—** The U.S. Department of Energy (DOE) today released its Report on Evaluating U.S. Grid Reliability and Security. The report fulfills Section 3(b) of President Trump's Executive Order, *Strengthening The Reliability And Security Of The United States Electric Grid*, by delivering a uniform methodology to identify at-risk regions and guide Federal reliability interventions.

The analysis reveals that existing generation retirements and delays in adding new firm capacity, driven by the radical green agenda of past administrations, will lead to a surge in power outages and a growing mismatch between electricity demand and supply, particularly from artificial intelligence (AI)-driven data center growth, threatening America's energy security.

"This report affirms what we already know: The United States cannot afford to continue down the unstable and dangerous path of energy subtraction previous leaders pursued, forcing the closure of baseload power sources like coal and natural gas," Secretary Wright said. "In the coming years, America's reindustrialization and the AI race will require a significantly larger supply of around-the-clock, reliable, and uninterrupted power. President Trump's administration is committed to advancing a strategy of energy addition, and supporting all forms of energy that are affordable, reliable, and secure. If we are going to keep the lights on, win the AI race, and keep electricity prices from skyrocketing, the United States must unleash American energy."

**Highlights of the Report:**

- **The status quo is unsustainable.** DOE's analysis shows that, if current retirement schedules and incremental additions remain unchanged, most regions will face unacceptable reliability risks within five years and the Nation's electrical power grid will be unable to meet expected demand for AI, data centers, manufacturing and industrialization while keeping the cost of living low for all Americans. Staying on the present course would undermine U.S. economic growth, national security, and leadership in emerging technologies.

- **Grid growth must match the pace of AI innovation.** Electricity demand from AI-driven data centers and advanced manufacturing is rising at a record pace. The magnitude and speed of projected load growth cannot be met with existing approaches to load addition and grid management. Radical change is needed to unleash the transformative potential of innovation.
- **With projected load growth, retirements increase the risk of power outages by 100 times in 2030.** Allowing 104 GW of firm generation to retire by 2030—without timely replacement—could lead to significant outages when weather conditions do not accommodate wind and solar generation. Modeling shows annual outage hours could increase from single digits today to more than 800 hours per year. Such a surge would leave millions of households and businesses vulnerable. We must renew a focus on firm generation and continue to reverse radical green ideology in order to address this risk.
- **Planned supply falls short, reliability at risk.** The 104 GW of plant retirements are replaced by 209 GW of new generation by 2030; however, only 22 GW comes from firm baseload generation sources. Even assuming no retirements, the model found outage risk in several regions rises more than 30-fold, proving the queue alone cannot close the dependable-capacity deficit.
- **Old tools won't solve new problems.** Traditional peak-hour tests to evaluate resource adequacy do not sufficiently account for growing dependence on neighboring 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.

DOE's report identifies regions most vulnerable to outages under various weather and retirement scenarios and offers capacity targets needed to restore acceptable reliability. The methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act.

Click here for a fact sheet on the report.

###

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Energy Department Issues Final Rule Delaying Compliance Deadline for Manufactured Housing Standards

July 1, 2025

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Energy Department Expands Commitment to Collaboration with Norway on Water Power Research and Development

July 7, 2025

**Tags:**

STRENGTHEN GRID RELIABILITY AND SECURITY

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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| Federal Power Act Section 202(c) | ) | |
| Emergency Order: Tri-State | ) | Order No. 202-25-14 |
| Generation and Transmission | ) | |
| Association, Platte River Power | ) | |
| Authority, Salt River Project, | ) | |
| PacifiCorp, and Xcel Energy | ) | |

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

Filed January 28, 2026

Exhibit 1-40:
PIOs' RFR of July Resource Adequacy Report

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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| | ) |
| *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

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[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

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[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.

[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

[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

[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]

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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

[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

[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.

Dated: August 8, 2025

Respectfully submitted,

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

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

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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| Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy | ) ) ) ) ) ) | Order No. 202-25-14 |

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

Filed January 28, 2026

Exhibit 1-40a:
Department's Response to PIOs' RFR of July Resource Adequacy Report

Department of Energy
Washington, DC 20585

September 5, 2025

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**RE: August 8, 2025 Submission**

To Whom It May Concern:

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

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

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

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[1] Submission at 1.

[2] 16 U.S.C. § 825*l*(a).

[3] *Id.*

Sincerely,

Tina Francone

Tina Francone
Director of the Grid Deployment Office, Acting

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy | ) ) ) ) ) ) | Order No. 202-25-14 |

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

Filed January 28, 2026

Exhibit 1-41:
Inst. Pol'y Integrity Report

# Enough Energy

## A Review of DOE's Resource Adequacy Methodology

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**July 2025**

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

# Table of Contents

# 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.

[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]

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

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

[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]

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

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

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

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

206 16 U.S.C. § 824a(c)(1).

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

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

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

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

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

The DOE study itself cautions, "the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[214] Despite DOE's press statement asserting that the study's methodology can help guide "guide Federal reliability interventions,"[215] presumably to address the EO's mandate that DOE find a way to routinize further 202(c) emergency orders,[216] the study reports a fundamental limitation for doing so: It does not find any near-term reliability risk from current levels of resource adequacy.

The study itself states that, "one of the key takeaways from this study process is the underscored 'call to action' for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our

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

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

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

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

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

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

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

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

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

# Conclusion

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

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) | ) | |
| Emergency Order: Tri-State | ) | Order No. 202-25-14 |
| Generation and Transmission | ) | |
| Association, Platte River Power | ) | |
| Authority, Salt River Project, | ) | |
| PacifiCorp, and Xcel Energy | ) | |

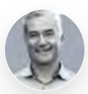
Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-42:
GridLab Report

1

# GridLab Analysis: Department of Energy Resource Adequacy Report



Ric OConnell

Rethinking Reliability

July 11, 2025

# Overview:

This memo provides a high-level overview of the recently released Department of Energy (DOE) Resource Adequacy Report, released on July 7, 2025. This report is a result of the Executive Order from the Trump Administration on Strengthening the Reliability and Security of the Grid, which directed the agency to develop and publish a methodology for "analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy."

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

# Bottomline of the DOE report:

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

# Bottomline of GridLab analysis:

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

## DOE Report Analysis – Key Takeaways:

- The report is based on three key assumptions: (1) the amount of load that will be added to the grid over the next five years, (2) the number of plants assumed to retire, and (3) the amount of new capacity added to the grid. The study used aggressive assumptions regarding load growth and retirements, but conservative assumptions about how much new generation capacity will be added, even assuming no new resources after 2026.
  - Load Growth: The report assumes 50 GW of data center load and allocates it regionally. It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact. The DOE report then adds 51 GW of non-data center load, which means overall load growth by 2030 is 101 GW or 15%. For comparison, EIA assumed 6% growth in their Annual Energy Outlook 2025 high growth case. This is very aggressive load growth, although not necessarily unreasonable, as it is collected from each of the RTOs and utilities.
  - Retirements: The report assumed 104 GW of retirements by 2030, with 3/4 of this coal and 1/4 gas. But the most recent data from the U.S. Energy Information Administration released in June (the EIA 860) has just **half** of this capacity retiring. In the report, the DOE assumed these 50 GW of likely retirements, but included another 50 GW of *announced* retirements, inconsistent with their assumption around capacity additions. Most likely many plants will choose

    not to retire due to the changing regulatory and economic landscape, driven by the administration's policies.
  - Capacity Additions: The report assumes just 22 GW of new "firm" capacity (narrowly defined as gas) is added which is based on NERC LTRA "Tier 1" – projects with a very high likelihood of success. The report assumes no projects are built post 2026, which is not realistic for a report forecasting to 2030. A more reasonable assumption for capacity additions is the EIA 860 released in June, which has 35 GW of gas additions, and another 53 GW of batteries – **88 GW of firm additions by 2030.**
- The study ignores both utility plans for meeting increased load growth and how markets will respond. In fact, markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that will likely add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.
- This national report attempts to address what is primarily a regional issue with regional solutions. A handful of regions face pressure due to rising load growth, and those regions have already enacted plans to address this growth. For example, MISO, SPP and PJM have all instituted "fast track" processes to get firm generation online (gas and batteries), which is expected to install 43 GW of new resources by 2030. The DOE report, however, shows just 13.5 GW of new firm resources in those three regions.

## DOE Report Assumptions vs. U.S.

## Energy Information Administration Data:

| | DOE Report | EIA 860 |
|---|---|---|
| Load growth: | 101 GW | N/A |
| Capacity Additions | 209 GW | 200 GW |
| Gas Capacity Additions | 22 GW | 35 GW |
| Battery Capacity Additions | 31 GW | 53 GW |
| Retirements | 104 GW | 52 GW |

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

## Conclusion:

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

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

Filed January 28, 2026

Exhibit 1-43:
Duke University Rethinking Load Growth Study

Duke NICHOLAS INSTITUTE *for* ENERGY, ENVIRONMENT & SUSTAINABILITY

# Rethinking Load Growth

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

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

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## Citation

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

## Nicholas Institute for Energy, Environment & Sustainability

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

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# CONTENTS

# INTRODUCTION

## A New Era of Electricity Demand

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

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

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

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

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

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

## Summary of Analysis and Findings

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

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

Key results include (see Figure 1):

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

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

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

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

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

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

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

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

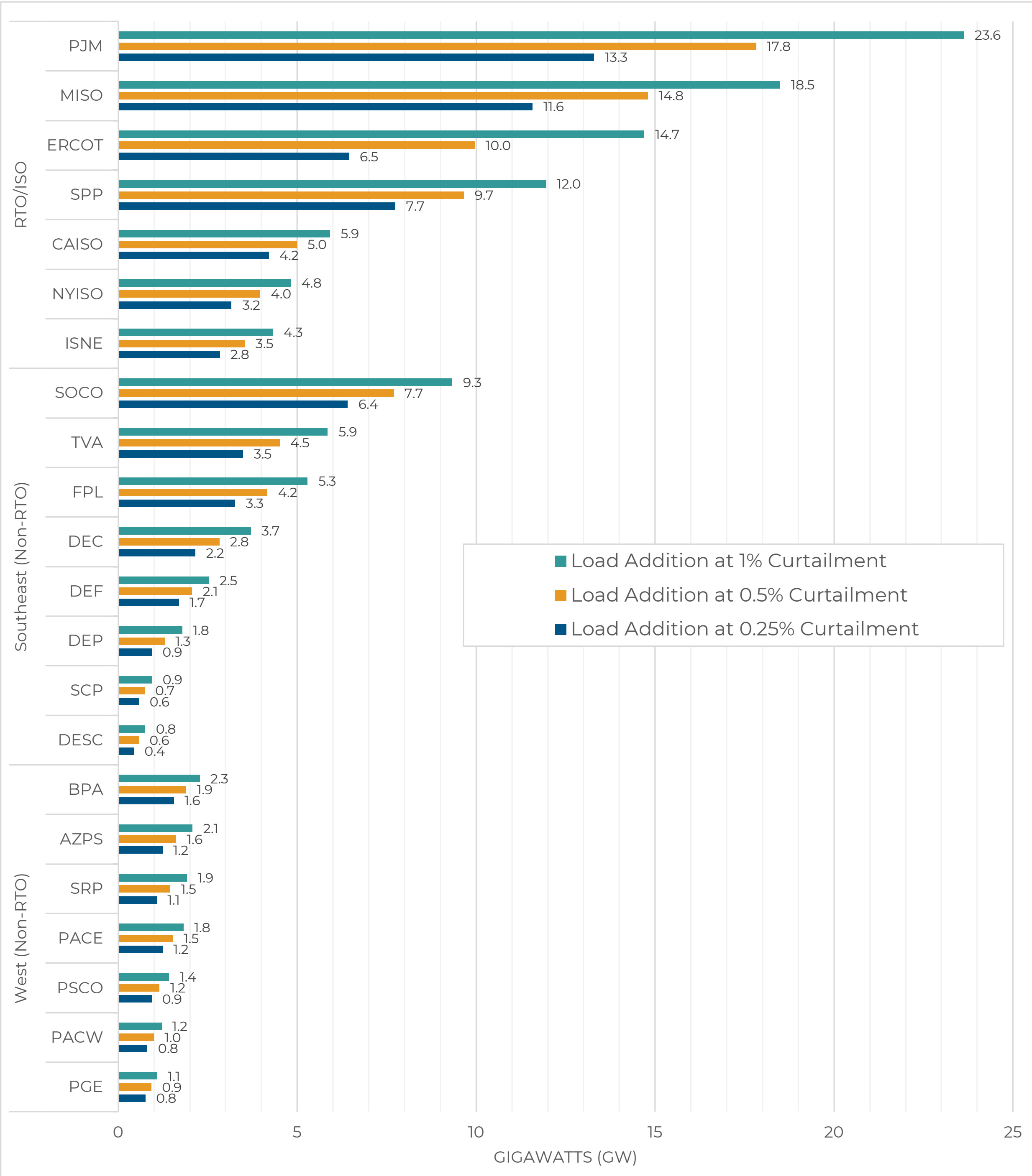
This paper proceeds as follows: the following section provides background on the opportunities and challenges to integrating large new data centers onto the grid. It explores how load flexibility can accelerate interconnection, reduce ratepayer costs through higher system utilization, and expand the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

## BACKGROUND

### Load Flexibility Can Accelerate Grid Interconnection

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

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




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

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

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

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

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

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

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

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

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

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

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

## Ratepayers Benefit from Higher System Utilization

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

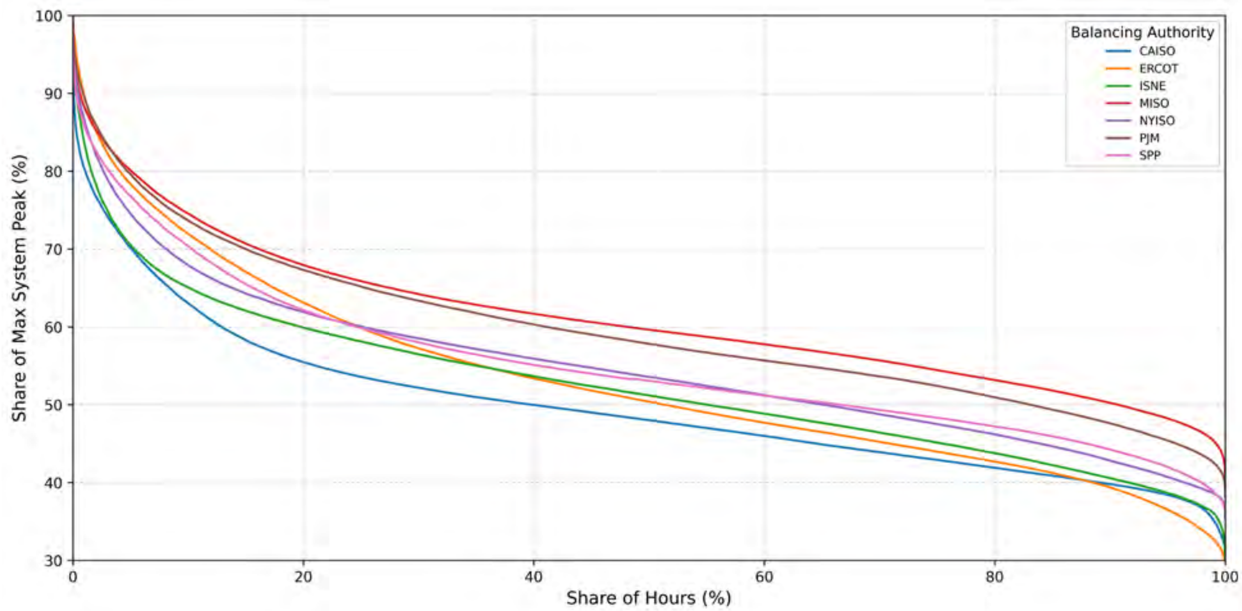
The power system is designed to handle the highest demand peaks, which in some cases may occur less than once per year, on average, due to extreme weather events. As a result, the bulk of the year sees demand levels well below that peak, leaving substantial headroom in installed capacity. Seasonal shifts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

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

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

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

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




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

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

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

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

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

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

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

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

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

## Demand Response and Data Centers

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

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

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

9 RTO/ISO and retail data may overlap.

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

## The Participation Gap: Data Centers and Demand Response

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

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

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

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

Existing demand response program designs may inadvertently discourage participation. Many programs were originally created with traditional industrial consumers in mind, with different incentives and operational specifications. Price-based programs may require high price variability to elicit meaningful responses, while direct control programs without sufficient guardrails may introduce unacceptable risks related to uptime and performance. The complexity of active participation in demand response markets, including bidding processes and navigating market mechanisms, adds another layer of difficulty. Without streamlined participation structures, tailored incentives, and metrics that reflect the scale and responsiveness of data centers, many existing demand response programs may be ill-suited to the operational realities of modern data centers.

### Table 1. Key Data Center Terms

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

## Rethinking Data Centers with AI-Driven Flexibility

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

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

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

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

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

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

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

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

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

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

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

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

## Table 2. Trends Enabling Data Center Load Flexibility

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

## Table 3. Implementations of Computational Load Flexibility

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

## ANALYSIS OF CURTAILMENT-ENABLED HEADROOM

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

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

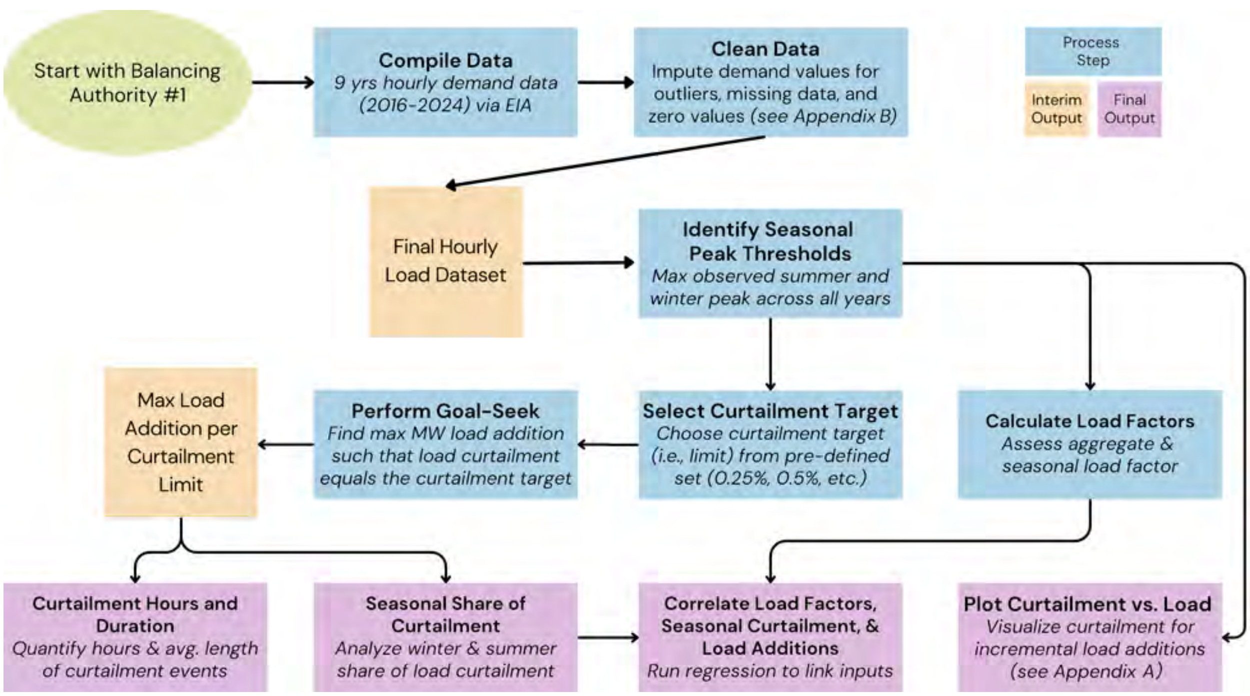
ceptable new load curtailment rates. In this context, *curtailment* refers to instances where the new load temporarily reduces its electricity draw—such as by using on-site generation resources, shifting load temporally or spatially, or otherwise reducing operations—to ensure system demand does not exceed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

## Data and Method

### Data

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

### Figure 3. Steps for Calculating Headroom and Related Metrics




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

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

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

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

### Determining Load Additions for Curtailment Limits

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

### Load Curtailment Definition and Calculation

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

### Peak Thresholds and Seasonal Differentiation

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

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

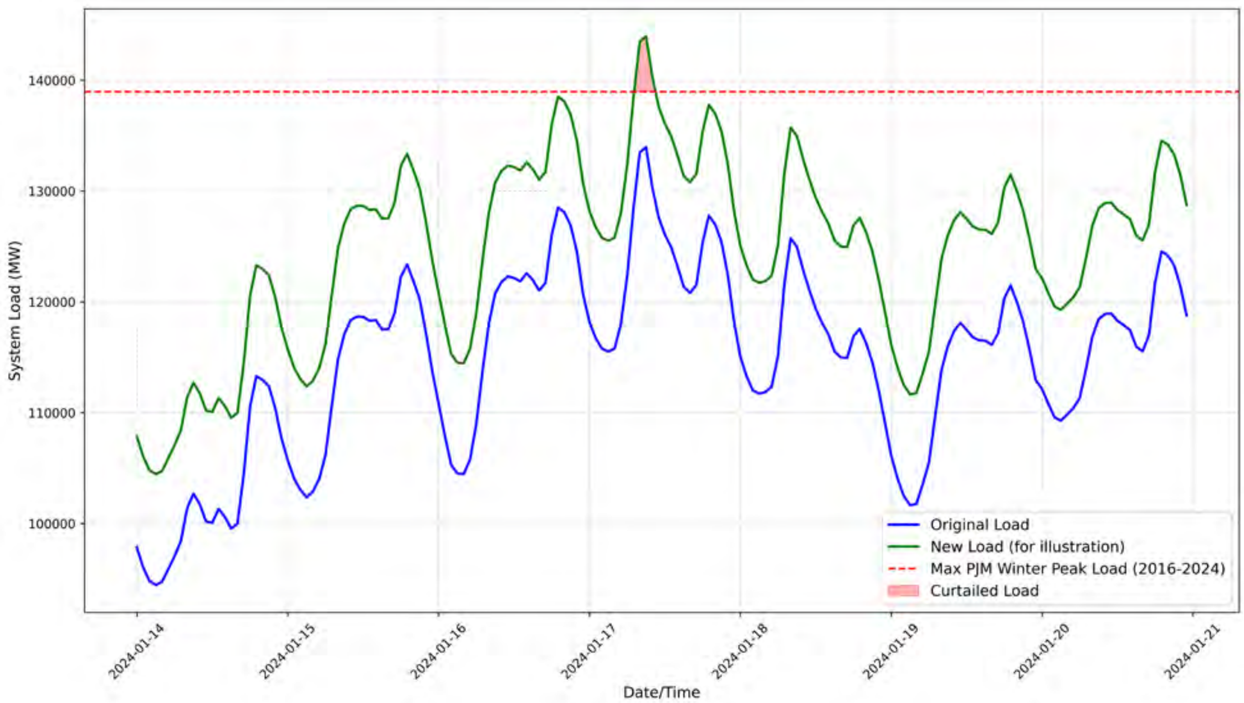
17 Fewer than half of the year's load hours were available, making the data unsuitable for inclusion.

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

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

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

## Figure 4. Illustrative Load Flexibility in PJM



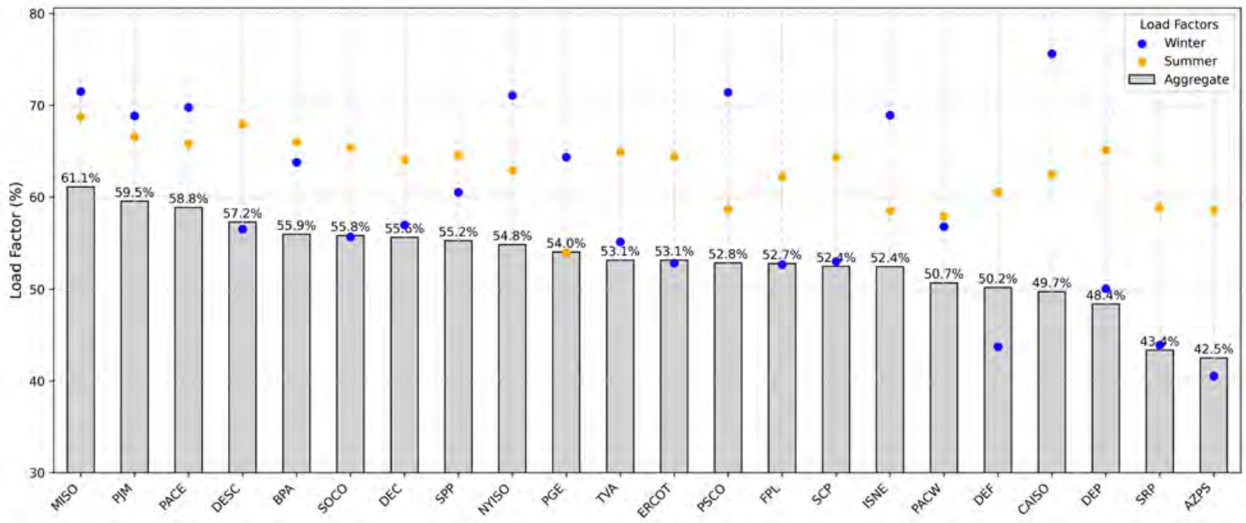

megawatt-hours that exceeded these thresholds was counted as curtailed energy. This seasonal differentiation captures the distinct demand characteristics of regions dominated by cooling loads (summer peaks) versus heating loads (winter peaks).

### Year-by-Year Curtailment Analysis

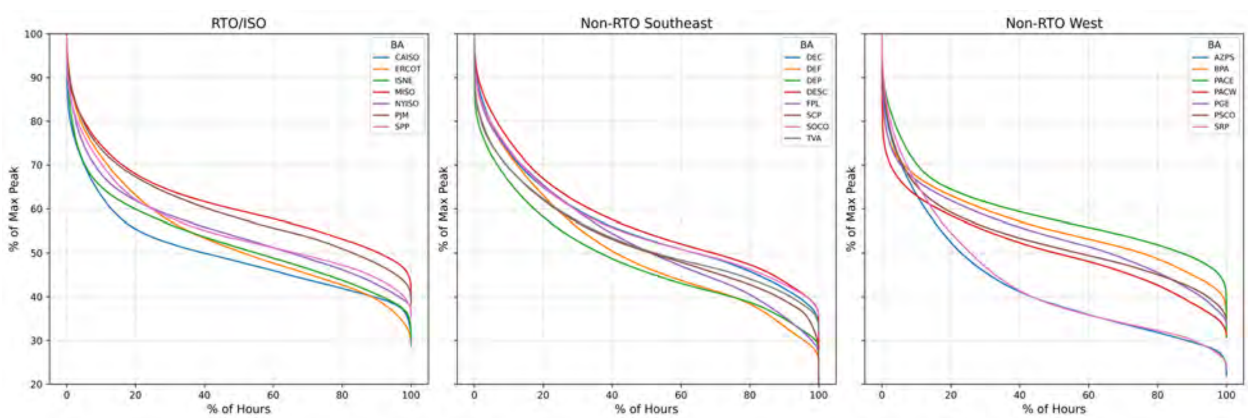
Curtailment was analyzed independently for each year from 2016 to 2024. This year-by-year approach captures temporal variability in demand patterns, including the effects of extreme weather events and economic conditions. For each year, curtailment volumes were calculated across all load addition increments,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

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

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




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




# Results

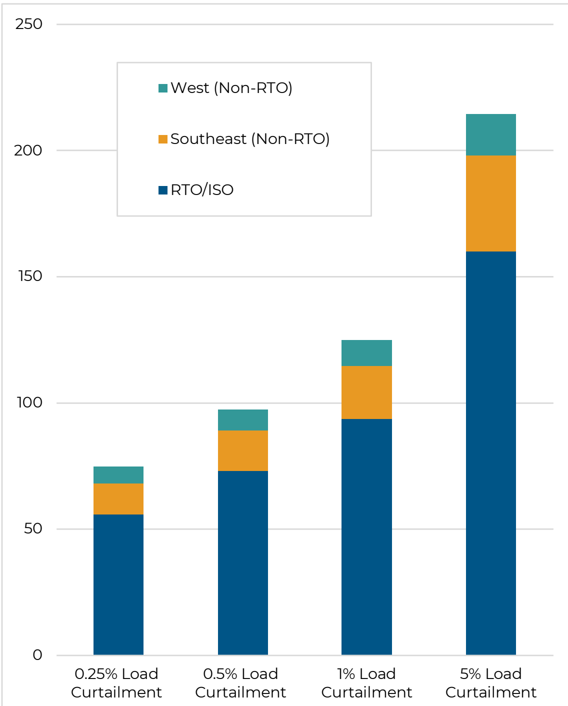
## Load Factor

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

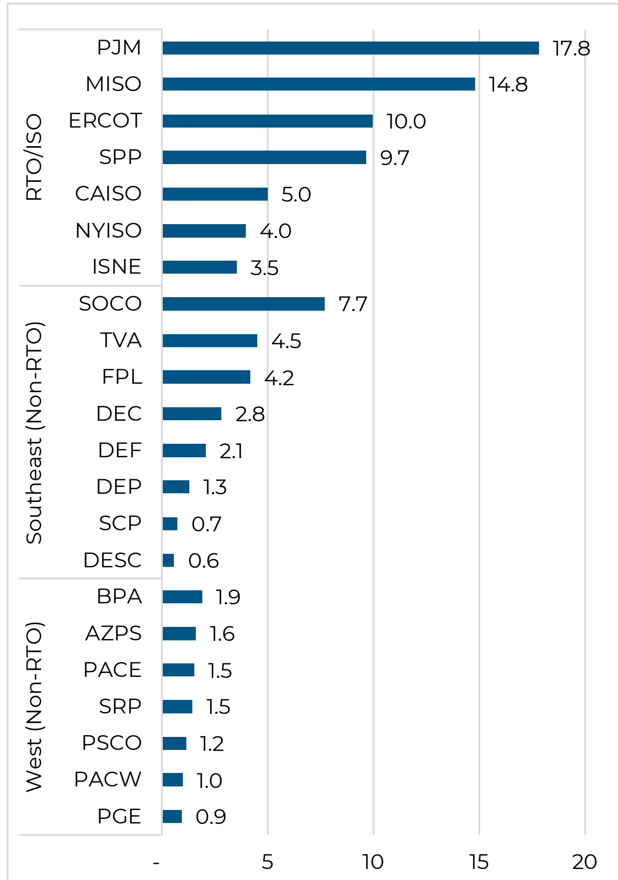
## Headroom Volume

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

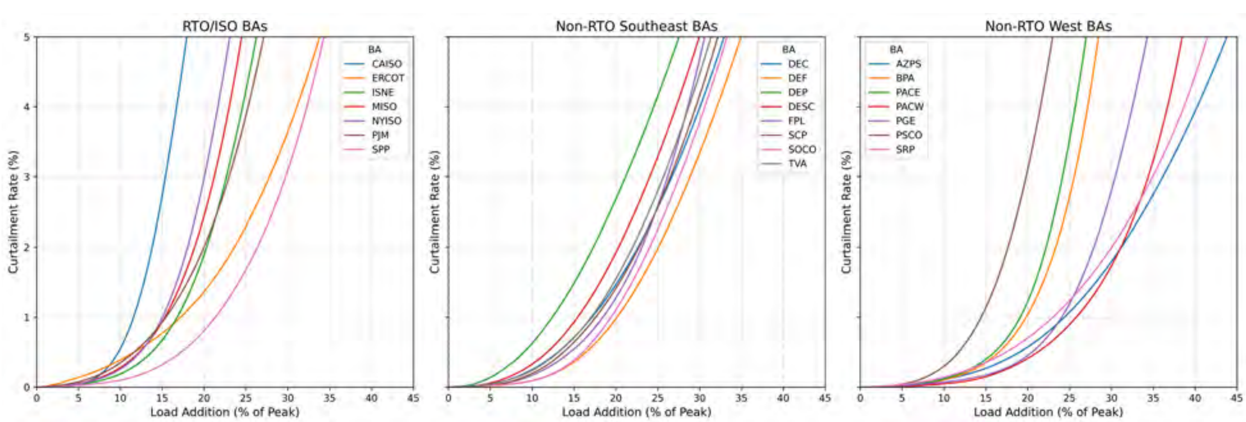
## Figure 7. Headroom Enabled by Load Curtailment Thresholds, GW




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




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



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

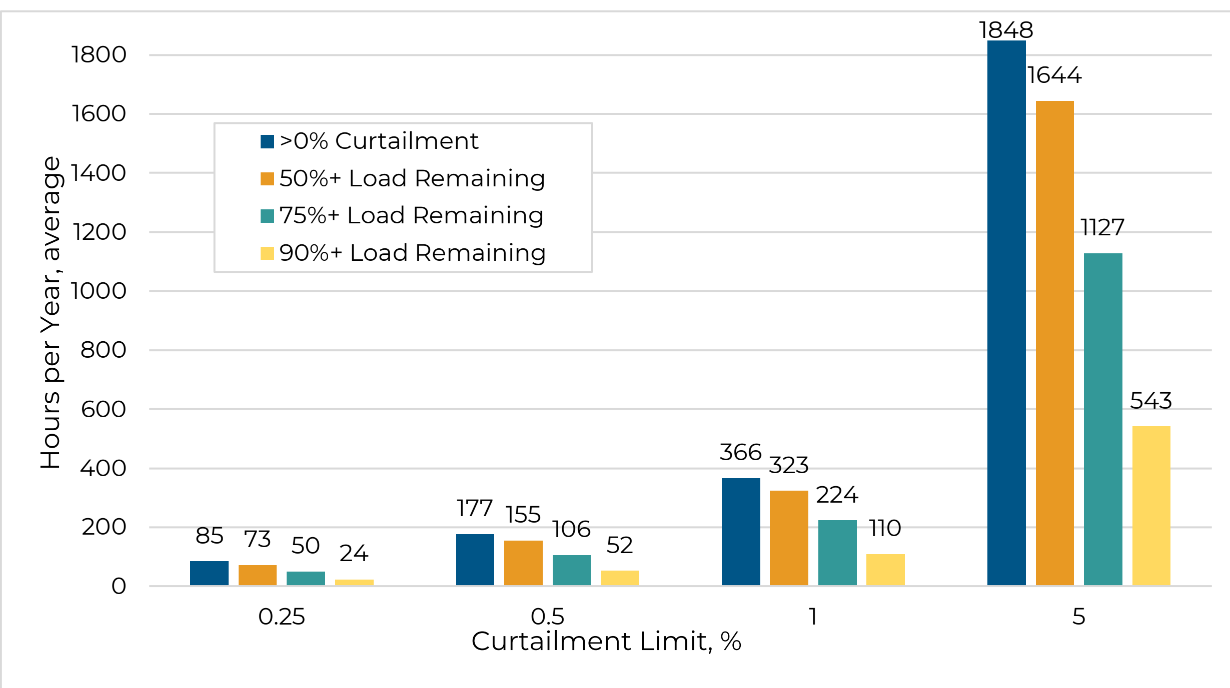
### Curtailment Hours

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

### Curtailment Duration

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

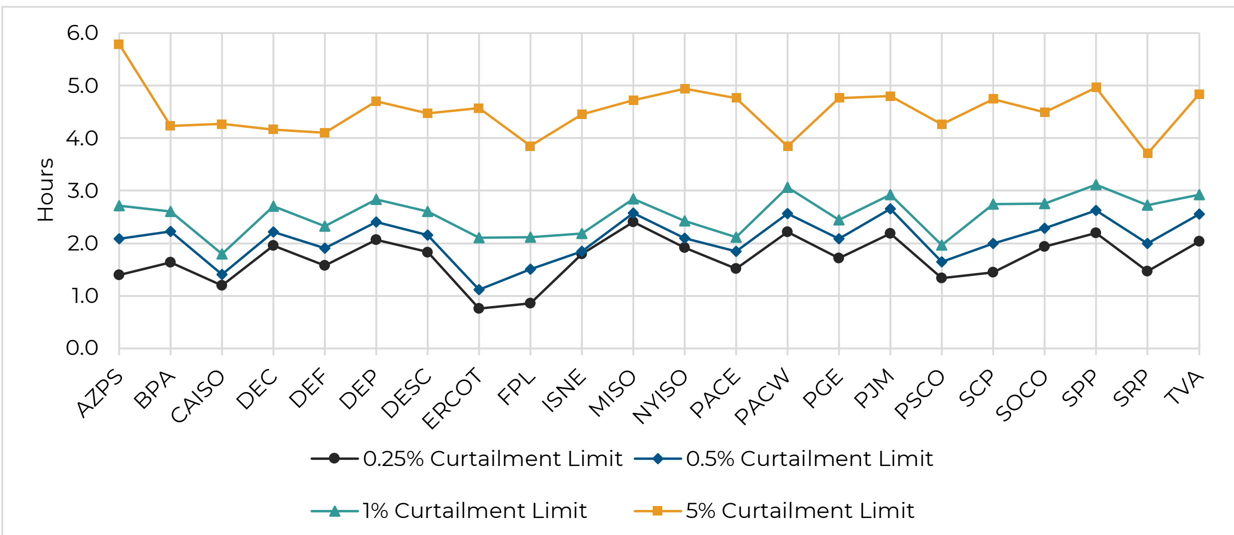
### Figure 10. Hours of Curtailment by Load Curtailment Limit



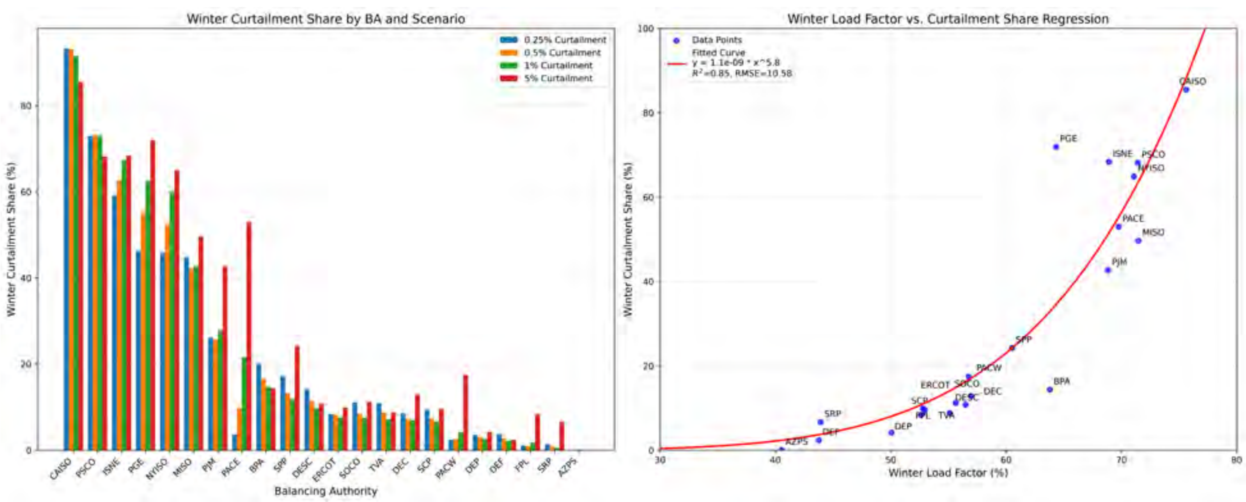
## Seasonal Concentration of Curtailment

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

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




### Figure 12. Seasonal Curtailment Analysis




(a) (b)

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

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

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

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

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

## Discussion

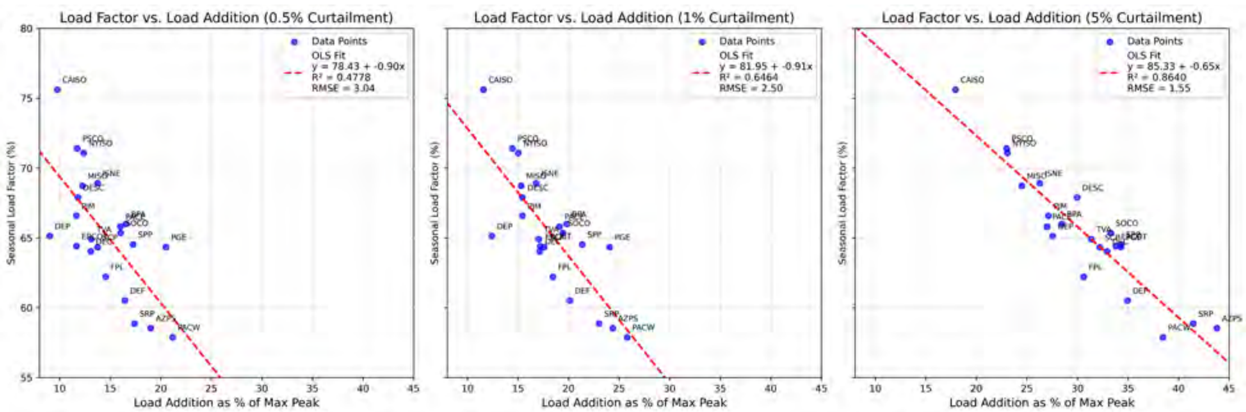
The results highlight that the significant headroom in US power systems—stemming from their by-design low load factors—could be tapped to enable the integration of substantial load additions with relatively low rates of load curtailment. They also underscore substantial variation in flexibility across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

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

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

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

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




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

## Limitations

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

On the other hand, some aspects of this study may have contributed to an underestimation of available headroom. First, the analysis assumes that each BA's maximum servable load in the winter and summer is equivalent to the BA's highest realized seasonal peak demand based on the available historical data. However, the available generation capacity in each balancing authority should materially exceed this volume when accounting for the installed reserve margin. In other words, system operators have already planned their systems to accommodate load volume that exceeds their highest realized peak. Second, the analysis removed outlier demand values in some BAs to avoid using unreasonably high maximum peak thresholds, which would understate the curtailment rates. However, if some of the removed outliers properly represent a level of system load that the system is prepared to serve reliably, this analysis may have understated the curtailment-enabled headroom. Third, the analysis assumed all new load is constant and hence increases the total system load by the same gigawatt hour-by-hour, which would tend to overstate the absolute level of required gigawatt hour curtailment for a load that is not constant.

## Future Analysis

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

### Network Constraints

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

### Intertemporal Constraints

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

### Loss of Load Expectation

Peak load is a widely used proxy for resource adequacy and offers a reasonable indicative metric for high-level planning analyses. However, a more granular assessment would incorporate periods with the highest loss of load expectation (LOLE), which represent the times when the system is most likely to experience supply shortfalls. Historically, LOLE periods have aligned closely with peak load periods, making peak load a convenient and broadly applicable metric. However, in markets with increasing renewable energy penetration, LOLE periods are beginning to shift away from traditional peak load periods. This shift is driven by the variability and timing of renewable generation, particularly solar and wind, which can alter the temporal distribution of system stress. As a result, analyses focused solely on peak load may understate or misrepresent the operational challenges associated with integrating large new loads into these evolving systems.

## CONCLUSION

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

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

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

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

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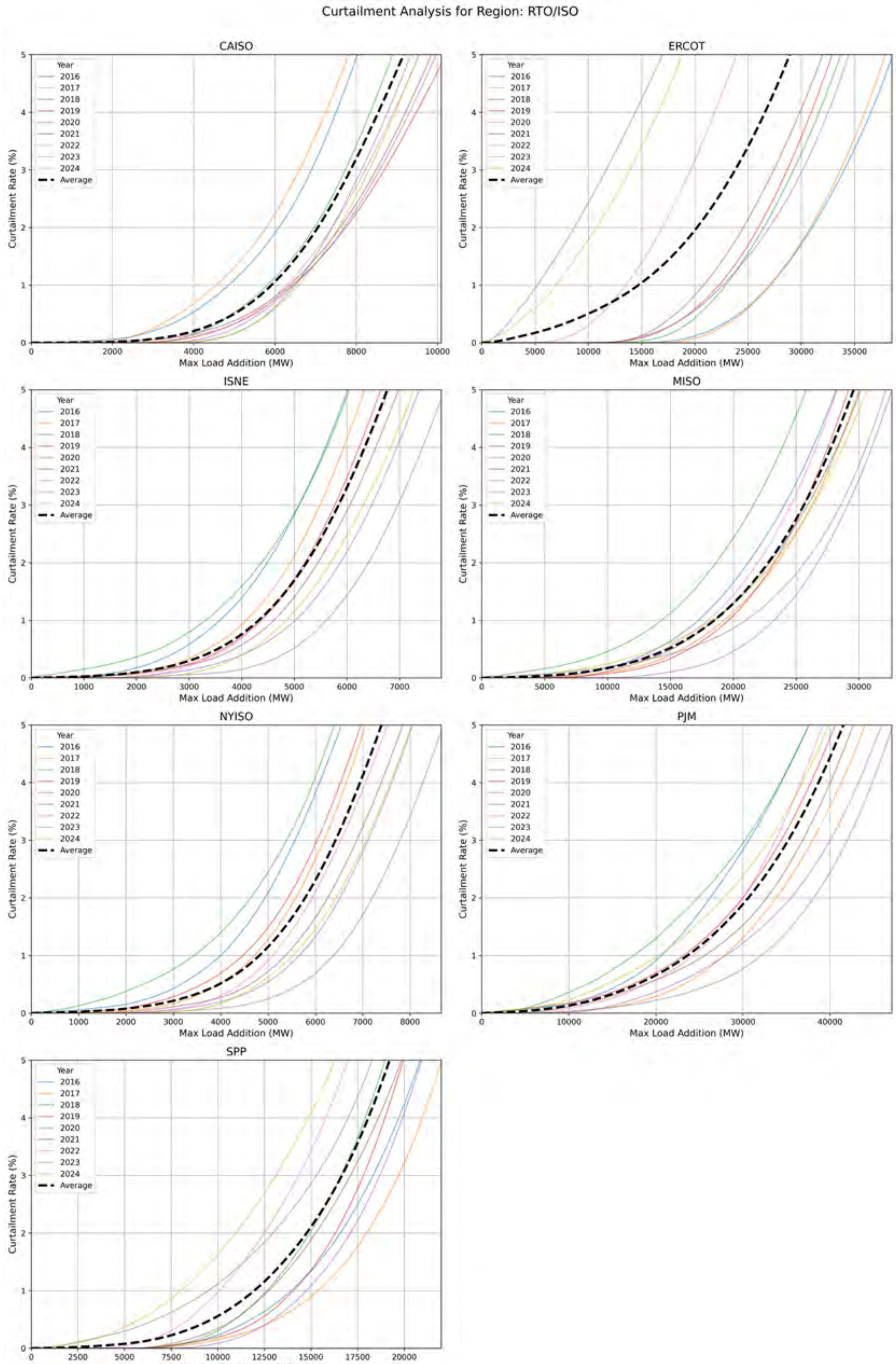
## ABBREVIATIONS

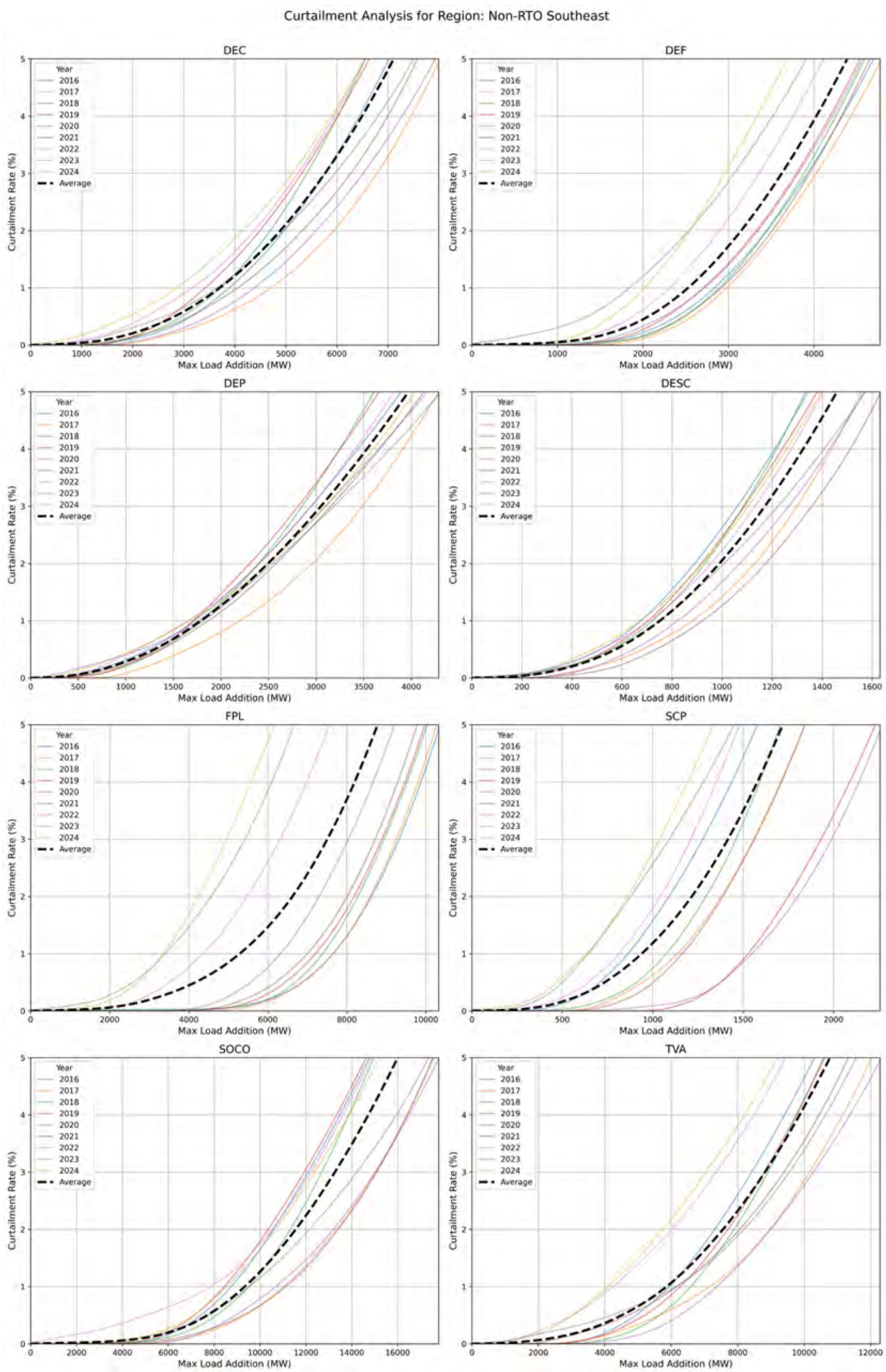
| | |
|---|---|
| AI | Artificial intelligence |
| AZPS | Arizona Public Service Company |
| BA | balancing authority |
| BPA | Bonneville Power Administration |
| CAGR | compound annual growth rate |
| CAISO | California Independent System Operator |
| CLRs | controllable load resources |
| CPUs | central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

# APPENDIX A: CURTAILMENT-ENABLED HEADROOM PER BALANCING AUTHORITY

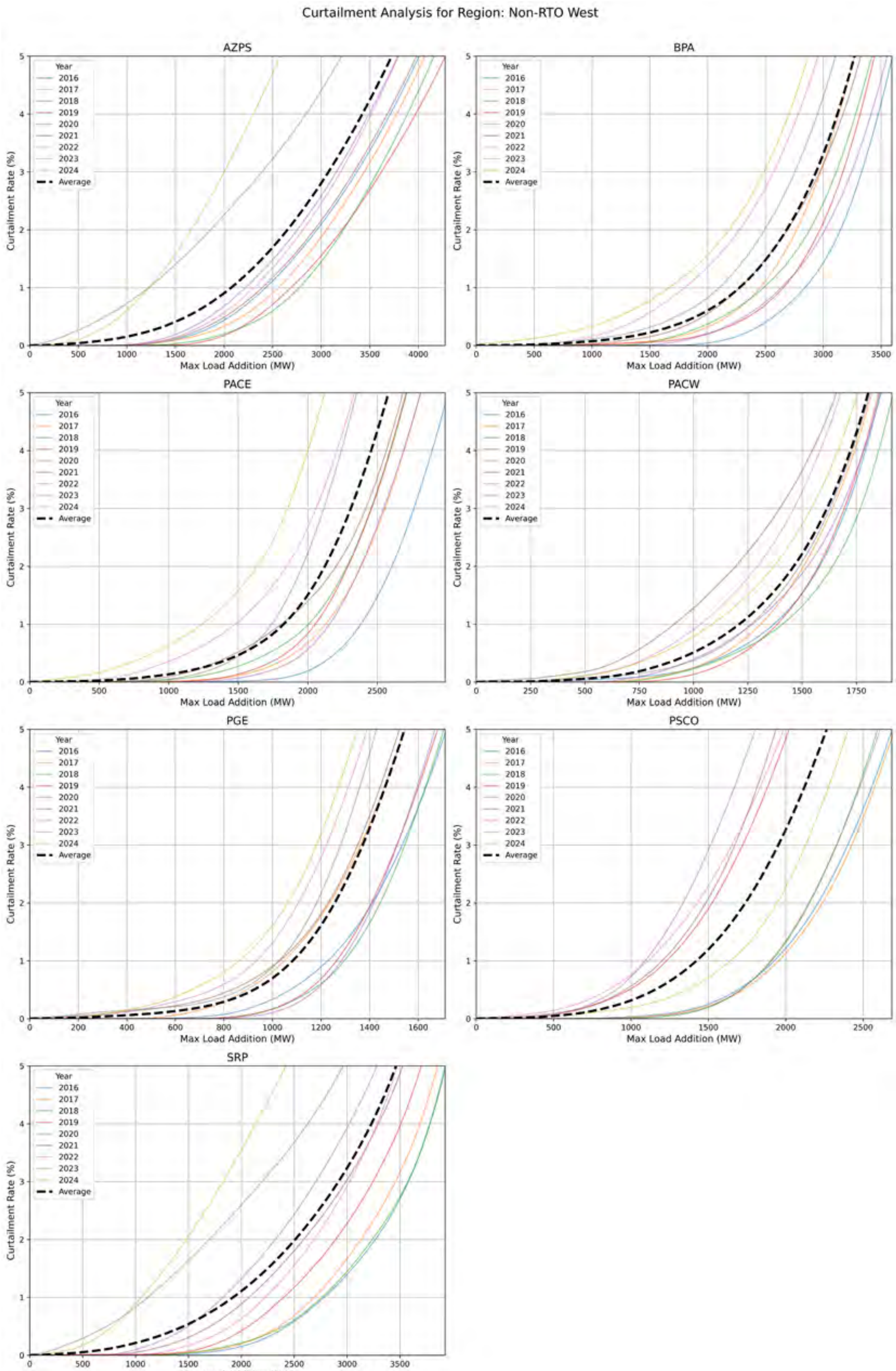
## Figure A.1. Curtailment Rate Versus Load Addition by RTO/ISO, MW



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



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



## APPENDIX B: DATA CLEANING SUMMARY

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

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

## APPENDIX C: CURTAILMENT GOAL-SEEK FUNCTION

Mathematically, the function can be expressed as

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

where

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

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

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

where

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

These hourly curtailments are aggregated to find the total annual curtailment

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

where

| | | |
|---|---|---|
| $T_y$ | = | all hours in year $y$. |

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

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

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| | | |
|---|---|---|
| Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy | ) ) ) ) ) ) | Order No. 202-25-14 |

Exhibit to
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Filed January 28, 2026

Exhibit 1-44:
RMI Analysis of Coal Plants' Threats to Reliability



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

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

**August 12, 2025**

**By Gabriella Tosado, Ashtin Massie, Joe Daniel**

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

## The myth

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

> Coal-fired power plants, far from being a reliable backbone for this new era of electricity demand, are a brittle, outmoded technology that threatens to undermine the very grid resilience they're being proposed to protect.

Tweet

## Reality #1: Aging coal plants are failing to consistently deliver under stress

Coal plants face a fundamental constraint: they are aging and increasingly unreliable. Most of the coal fleet was built in the 1970s and 1980s, and years of wear and tear have led to a rise in unplanned outages. In many cases the sheer cost to maintain and modernize these plants did not make sense with the availability of more reliable and affordable alternatives — and that's still the case.

According to the Energy Systems Integration Group (ESIG) *Ensuring Efficient Reliability* report, a coal plant's capacity accreditation, or the amount of time it can contribute to peak demand, is only 83 percent when adjusted for real-world performance. PJM also has capacity accreditation of coal plants at 83 percent and some plants fare even worse. Gridlab's reliability study found Colstrip, a large regional coal plant in Montana, operating with a capacity accreditation of only 54 percent — meaning it's effectively unavailable nearly half the time it's needed.

Extreme weather exacerbates these vulnerabilities. Cold snaps, heat waves, and storms have all exposed coal's fragility during grid stress events. Reliability is not just about being dispatchable, it's about delivering performance under stress. Coal plants struggle to do that consistently. For coal plants to truly meet the constant demands of data centers, they would need to run at high-capacity factors and avoid major outages, all of which fly in the face of current performance trends. If a large coal plant trips offline while supporting a cluster of data centers,

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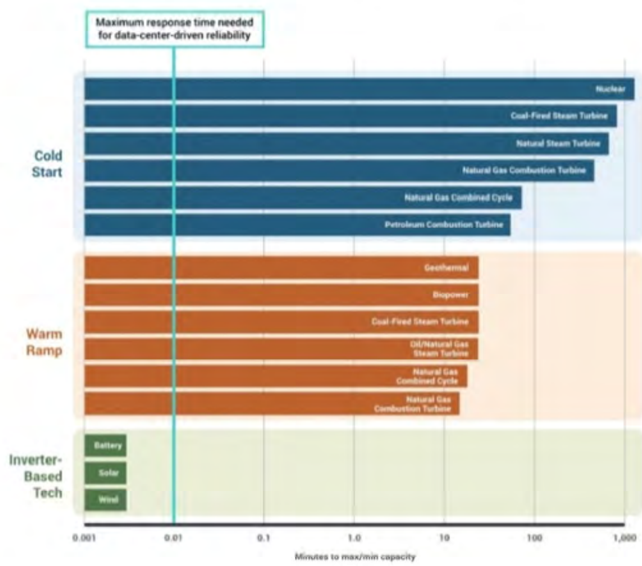
the sudden loss of supply could lead to cascading failures across the grid. This is because generation must equal load at all times, datacenter or no datacenter. As a result, relying on coal plants to support these high-density digital loads doesn't enhance reliability, it endangers it. And it's not a matter of *if* the coal plant will fail, but *when*.

### Reality #2: The inflexibility of coal plants risks grid stability

Coal boosters often point to the "always-on" nature of coal plants as evidence of their reliability. But that characteristic is a liability, not a strength, when it comes to supporting large, fast-changing loads like data centers. Coal units are inherently inflexible: they ramp slowly, respond poorly to sudden load shifts, and are difficult to turn on or off quickly. This rigidity is a poor match for the dynamic and often unpredictable nature of data center demand. Further, inflexible coal plants can worsen grid congestion; by occupying limited transmission capacity with inflexible generation, they prevent cheaper or cleaner resources from being delivered. This issue has already been flagged by **independent market monitors** in regions like MISO – which covers 15 US states and a Canadian province – where congestion-related market distortions have cost **over $1 billion a year**. Coal plants displace faster-responding resources that are better suited to follow load. And the stakes are high.

As noted by the North American Electric Reliability Corporation (NERC), large, voltage-sensitive loads like data centers require flexible, responsive grid solutions, not slow-ramping generators that can take 12 or more hours to come online. NERC's recent ***Incident Review and Guidance on Voltage-Sensitive Large Load Integration*** describes an event in 2024 where a transmission fault triggered a sudden disconnection of 1,500 megawatts of voltage-sensitive data center load, leading to sharp frequency and voltage spikes that required operator intervention. The incident exposes the system's vulnerability to instability when inflexible generation cannot respond to large load fluctuations.

**Minutes needed for a power plant to reach max/min capacity**




If a data center either loses access to load or goes offline rapidly, a grid's generation needs to respond at sub-second speeds. The average coal plant ramp rate is **4 percent per minute** which translates to spending over 20 minutes to respond to a large load event. From a cold start, the average coal plant would take over **12 hours** to reach max capacity. Coal plants simply can't respond fast enough to support the reliability needs of modern data centers. Whether it's the hours-long startup time from a cold state or sluggish ramp rates to turn off, these plants are too slow to provide the real-time flexibility required during sudden load changes or outages.

### Reality #3: Clean resources are available now that can better respond to and support data centers for less



The good news is that we don't need to rely on brittle coal plants to meet the needs of a digital economy. A range of cleaner, more resilient solutions is already available – and scalable. For example, we recently found that **more than 95 percent** of future demand can be met with fast, scalable, and clean solutions:

### Alternative near-term solutions to meet load growth

| Technology | Opportunity |
|---|---|
| Energy Efficiency | Over 50 GW of energy efficiency can be deployed – by both creating programs for new loads and expanding existing programs aligned with system needs. Energy efficiency can unlock benefits beyond system cost savings, improving comfort and resilience in homes. |

| | |
|---|---|
| Virtual Power Plants | 60 GW of virtual power plants can be deployed by 2030, with programs stood up and enrolled in under 6 months. Policymakers in Virginia recently passed a bill that requires 450 MW of VPPs deployed rapidly to meet growing demand. |
| Advanced Transmission Technologies | Grid enhancing technologies and reconductoring can unlock over 80 GW of incremental peak capacity by reducing transmission and interconnection constraints. Lawmakers in New Mexico passed a bill requiring utilities to assess the use these technologies in plans to get more out of the existing grid. |
| Clean Repowering | There is 14 GW of fossil-fuel generation expected to retire, that could serve as sites for quick addition of new renewable energy and storage while reducing system costs. Market operators like PJM are enabling clean repowering by updating rules to allow for surplus interconnection. |
| Power Couples | New load can be co-located with renewable energy at the site of existing, underutilized generators with approved interconnections—a strategy which we call "Power Couples." There is over 30 GW of opportunity to deploy Power Couples under $100/MWh, and over 50 GW of opportunity under $200/MWh. |

Coal plants are a legacy technology, not a solution for the future. Coal plants' operational characteristics make them less suited to meet the scale and speed of these new challenges. The path forward is not about discarding the past, but about building on it with cleaner, more adaptable resources that can reliably serve evolving grid needs.

Technologies like battery storage, demand flexibility, and clean energy portfolios offer practical, cost-effective options that align with modern load dynamics. As we noted in a recent **article**, by running coal plants only when it is economical to do so and using the extra transmission headroom that creates to reinvest with clean energy upgrades, our grid can support the next wave of economic growth with the flexibility it demands. There are reasons to manage the shift to new, clean resources **thoughtfully and intentionally**, but propping up coal plants that are not suited for the job is a step in the wrong direction.

## RECOMMENDED READING

### Gas Turbine Supply Constraints Threaten Grid Reliability; More Affordable Near-Term Solutions Can Help

June 18, 2025

Read More

### Reinvesting at Coal Plant Sites with Clean Energy Upgrades Supports both Reliability and Affordability

July 16, 2025

Read More

**Solutions Can Help**

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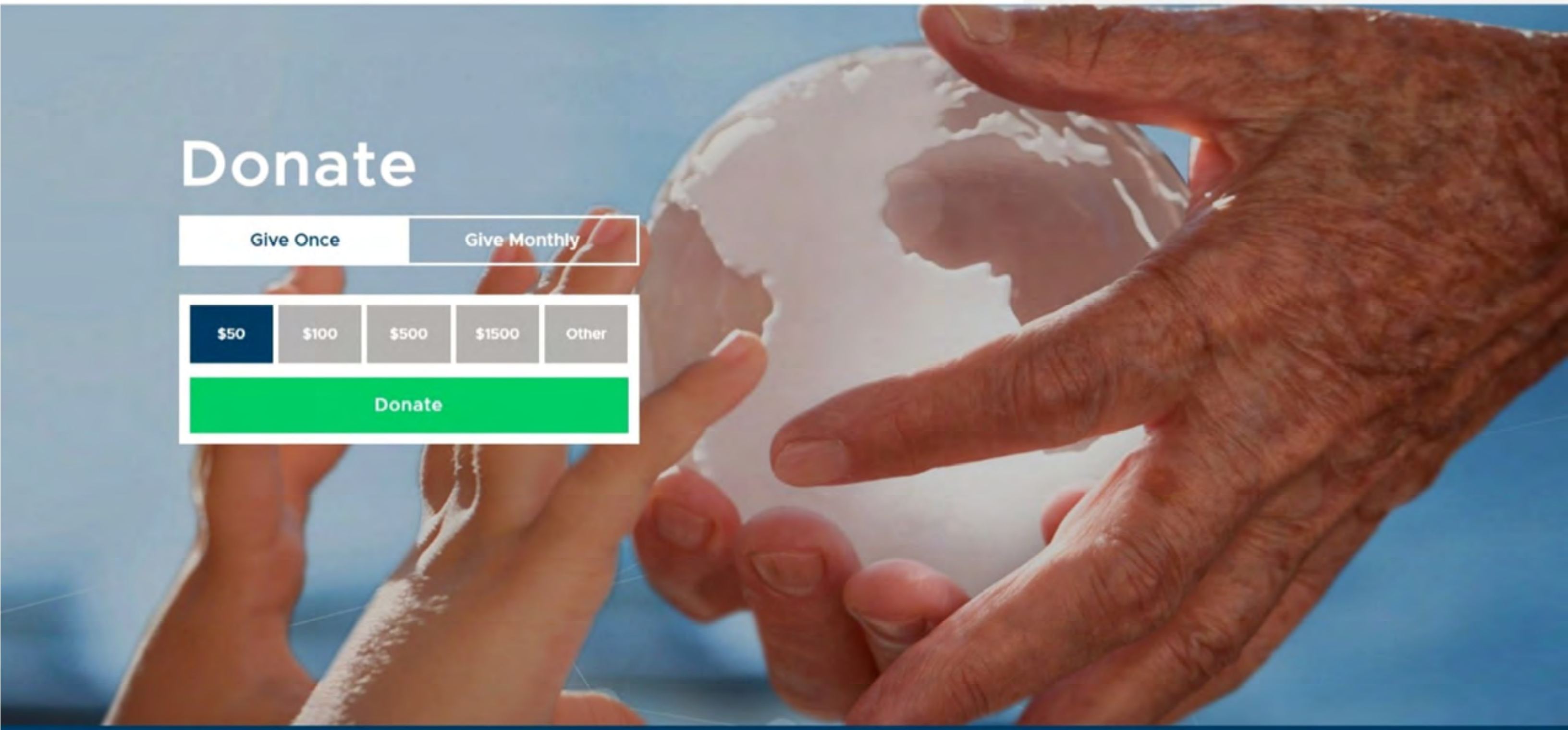

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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-45:
Energy Innovation Report

# DODGING THE FIRM FIXATION FOR DATA CENTERS AND THE GRID

**Eric G. Gimon**

**Senior Fellow, Energy Innovation**

**November 2025**

# ACKNOWLEDGEMENTS:

I would like to thank my Energy Innovation colleagues for their patient review and feedback on various drafts of this report. I would also like to acknowledge the Energy Systems Integration Group for their conferences, taskforce meetings, and webinars which helped me get started on my research.


# TABLE OF CONTENTS

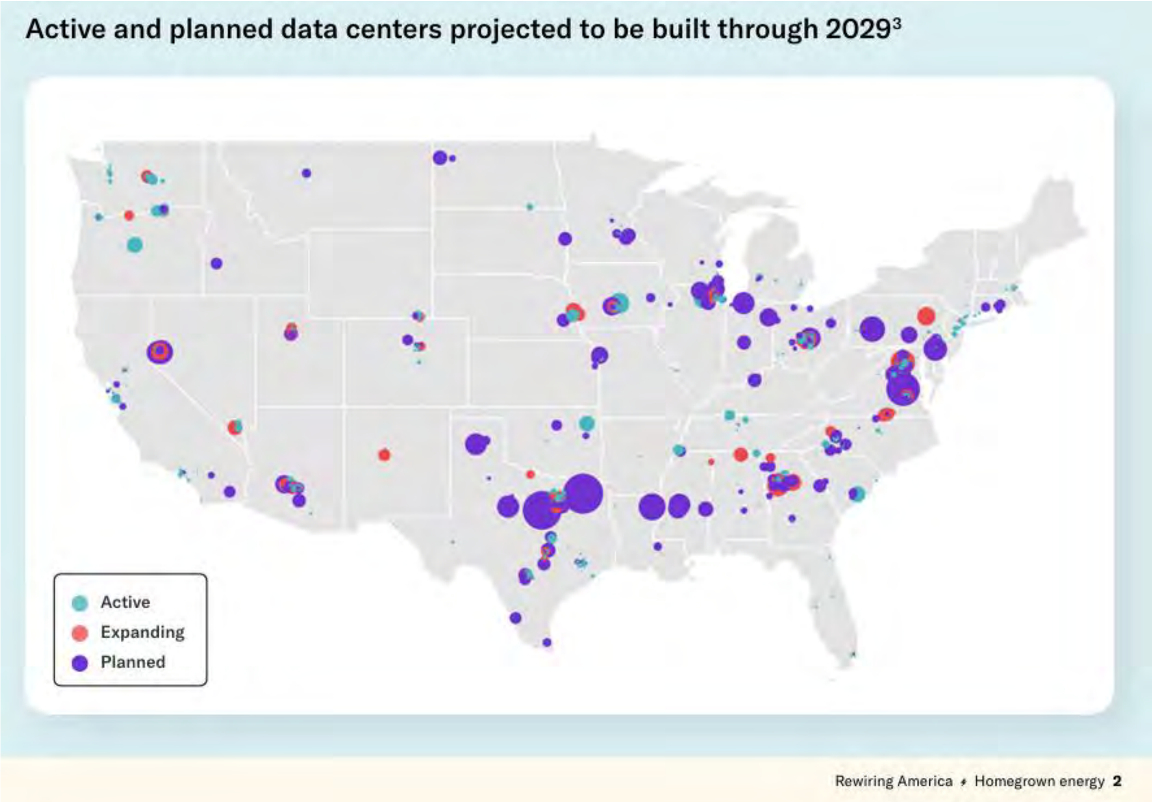


# EXECUTIVE SUMMARY

In multiple states[1,2] (see Figure 1) massive new data center campuses and a coterie of smaller ones have reversed years of flat or declining electricity demand, leaving utilities and policymakers scrambling for solutions.

*Figure 1 Existing and Projected data centers from Rewiring America's "Homegrown Energy" report[3].*




Faced with this onslaught of new demand, many utilities and developers are depending on old habits by adding new gas plants, refurbishing coal units, or turning to nuclear partnerships along with extensive grid upgrades near new load centers – the "firm fixation."

It reflects a belief that only firm resources and major transmission upgrades can handle data centers' needs. Yet this approach overlooks two essential truths: (1) power plants and data centers are both parts of a larger, interconnected system, and (2) data center loads, especially those driven by artificial intelligence (AI), are far more dynamic than the flat, baseload profiles they are often assumed to be. Firm fixation leads utilities and regulators to default to outdated firm-generation solutions instead of modern, modular approaches that consider the full complexities of today's power grid. At the scale of even the most compact new data centers, connecting to the grid is no small matter.

Regardless of approach, three features of recent growth are well known to the electricity industry and policy community, and to some extent the wider public. First, new data center load is being amplified by extreme investment interest in AI. Second, incremental load tends to be highly concentrated due to the nature of the growing individual server need for power and the geographic concentration of data centers. Third, the data center industry's appetite for new growth is so large, and other facility capital costs so high that new project owners are willing to pay more for power than average existing electricity consumers.

In a 2024 brief, Energy Innovation proposed instead that a portfolio of solutions – clean energy portfolios, advanced transmission technologies, demand-side flexibility, and efficiency – could work together to obviate the need to rush to meet demand with new fossil generation.[4] Reality so far has deviated significantly from this vision, setting up the power sector for failure: Either new demand will not be met or the negative cost and performance impacts of doing so on other grid users will challenge electricity markets and other long-standing arrangements in a dangerous manner.

The mad scramble to meet data center demand using traditional but crude resource investment methods can create potential missed opportunities to manage load growth that come from a deeper understanding of data centers. Of course, their electricity demand is problematic because it is concentrated, growing fast, and willing to outspend other users. However, it is also far more complex than the flat, 24/7 block it is often assumed to be. This primer identifies six defining features that provide a more nuanced version picture of data centers:

- **Agency and Split Incentives** – Multiple actors (developers, operators, and tenants) and ownership or usage types of data centers create a divided responsibility over grid interaction and access to energy-saving incentives that complicates energy decisions.
- **Clustering** – Facilities tend to concentrate geographically, amplifying local grid stress and transmission costs while creating systemic planning challenges.
- **Consumption Profiles** – Loads are not 24/7 blocks. Instead, they are choppy, with swings of hundreds of megawatts over short intervals, undermining assumptions of steady baseload behavior and potentially affecting the stability of the grid if safeguards are not put in place.
- **Flexibility** – While some AI-driven workloads can be scheduled for off-peak hours, this flexibility is uneven across facility types and even within users in the same data center campuses. While modest levels of curtailment or load-shifting based demand response during peak hours could ease interconnection bottlenecks and peak demand requirements, these may work best in combination with battery energy storage to overcome split incentives and other complexities.

- **Backup Requirements** – Current reliance on diesel for backup generation is unsustainable. Batteries and longer-duration storage are cleaner, more scalable options that provide knock-on benefits for the grid if allowed to participate as both backup and demand response.
- **Modularity** – Data centers grow in phases just as demand grows in phases rather than all at once, aligning poorly with "lumpy" firm large one-time investments in dispatchable power plants and infrastructure upgrades, while fitting well with modular renewables and battery deployments.

When examined as a whole, these features undermine the firm fixation logic. One-to-one matching of data centers with dedicated or "captive" firm power plants is particularly unwise for both the power generator and the new data centers, even given their willingness to pay for speed-to-power. Relying on captive plants for all supply such as pairing a nuclear plant with a large data center exposes them to outages, inflexibility, and stranded-asset risks, while hybrid co-location deals still rely heavily on the broader grid.

Most new demand will need to be served fully or in-part through the bulk power system, requiring upgrades in three key areas: **connection infrastructure, grid services (especially peak capacity), and bulk electricity supply.**

Once this is established, it's clear that data centers can tap the grid's advantages as a "system of systems" that pools variable demand and generation resources solutions together and ensures supply and demand match in real-time. As peak demand rises, this crucial service must be met, but not necessarily by firm generation. A deeper understanding of data center demand attributes yields a more complete solution set which includes data center flexibility, onsite storage, portfolios of clean energy, and others.

The challenges data centers pose include lengthy interconnection queues, peak stress, price impacts, and rising emissions – but these are not insurmountable. Three core lessons emerge for policymakers and stakeholders:

- The process of connecting any new **large load is a key leverage point.** It is the moment to ensure consumption tariffs reflect cost causation, encourage flexibility, and align incentives without imposing unworkable burdens later. Interconnection is the moment of maximum leverage: not to extract unreasonable concessions, but to ensure new entrants cover the full costs of the infrastructure they trigger, and to nudge data center developers towards solutions such as flexible demand or local storage that relieves local bottlenecks and supports the broader grid. Likewise, developers and customers should lean toward local fixes that speed access to the grid, improve power quality, and ease broader impacts—reducing the likelihood of being saddled with extraordinary requirements later.

- **Demand side is a resource hiding in plain sight**. Household electrification and distributed resources can free up tens of gigawatts (GW) at costs comparable to new gas plants and on a faster timetable, offering a more pragmatic and equitable path to integration. Yet at the state and regional level, policy innovation still lags behind. However, several widespread mechanisms exist to channel data center owners and operators' willingness to pay into new solutions that help other existing customers accommodate rapid data center load growth in a fair, fast and equitable way. Because grid connection bottlenecks can be managed by multiple possible combinations of diverse resources, data centers don't need to do all the work of mitigating their grid impacts onsite or through a single counterparty. Once a data center has invested in flexibility and equipment to resolve local connection issues, additional constraints such as upstream transmission and grid services bottlenecks as well as large incremental amounts of annual electricity delivery can be addressed with demand-side solutions from other grid users. A recent report from Rewiring America proposes that many of the resources needed to meet data center load growth could come from sponsoring household upgrades instead of new generation.[5]
- **Storage and flexibility deliver a two-for-one win.** Batteries and managed demand not only ease all manner of data center impacts but can also accelerate renewable integration, providing cleaner, faster, and cheaper capacity than firm fossil solutions. Because batteries are increasingly essential for buffering, backup, and power quality, they also provide a built-in solution for integrating variable renewables—a two-for-one advantage. Furthermore, these renewable-plus-battery solutions can capitalize upon existing surplus interconnection to more quickly connect data centers to the grid in co-located arrangements.

This report challenges the electricity and data center industries to move beyond a firm fixation and adopt solutions that leverage the full capabilities of modern power systems.

The next section describes six defining features of data centers: agency, clustering, consumption profile, flexibility, backup needs, and modularity. We then pivot to explaining why traditional firm responses fall short within the broader context of how the modern grid supplies power to consumers, especially large, new consumers. We will look at how new, modular solutions can meet digital demand more effectively. These steps will depend on a more nuanced understanding of data centers, as opposed to how they are often imagined.

Our hope is that this information will empower policymakers to make wiser decisions when faced with AI growth and proposed public investments, avoiding a firm fixation on simplistic approaches and reaching for more realistic answers that embrace the full complexities of the challenge that rapid data center load growth presents today. By moving beyond simplistic assumptions, policymakers can avoid overcommitting to outdated firm resources and instead adopt strategies that embrace modularity, flexibility, and clean energy. We want to leave policymakers with three key takeaways to avoid falling into a firm power matching fallacy and to instead embrace the ability to mix and match resources to meet data center needs.

What began as a major strain on the grid can become the catalyst for building a smarter one, supporting both the digital economy's explosive growth and the clean energy transition.

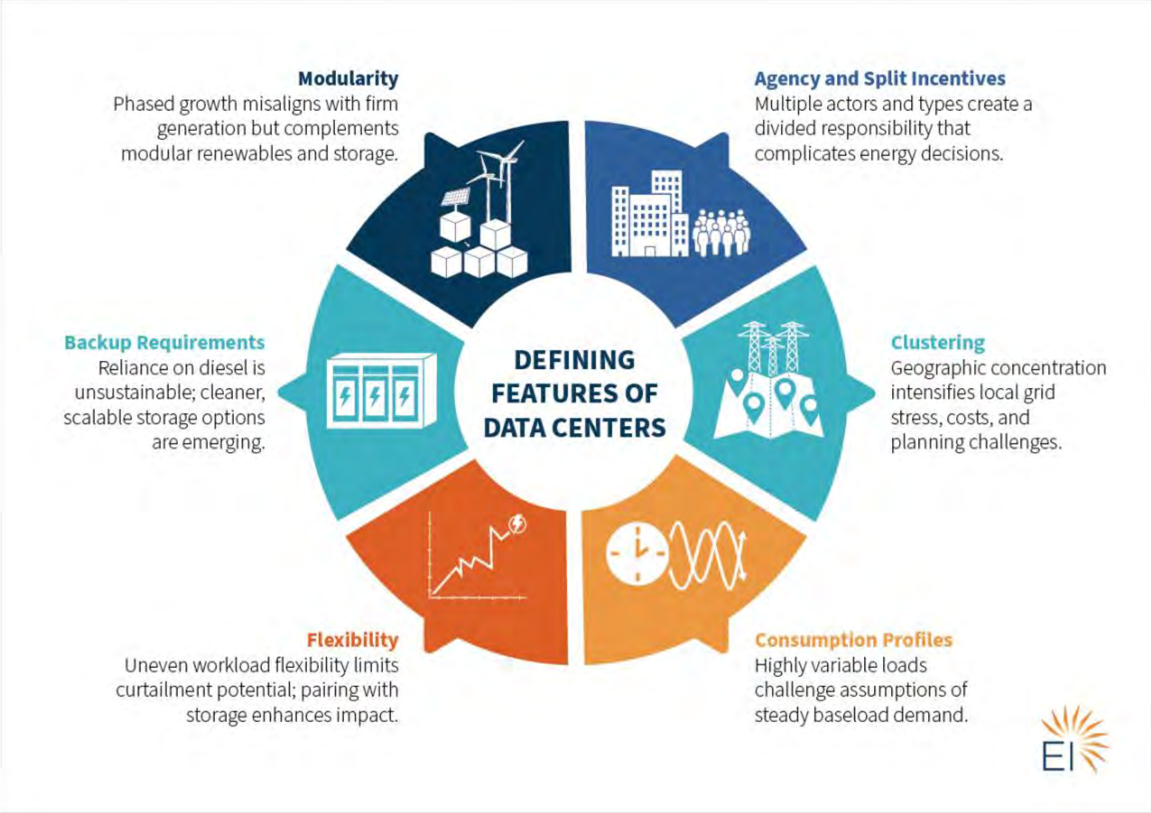
## COMMERCIAL AND INDUSTRIAL REALITIES THAT APPLY TO DATA CENTERS

**Actual data centers are not the simple "flat 24/7 block of demand" people imagine.**

Six different demand features of data centers explain the diversity of data center types (agency, clustering, and profile) and their internal workings (flexibility, backup, and modularity).

*Figure 2 Actual data centers are not the simple "flat 24/7 block of demand" people imagine.*

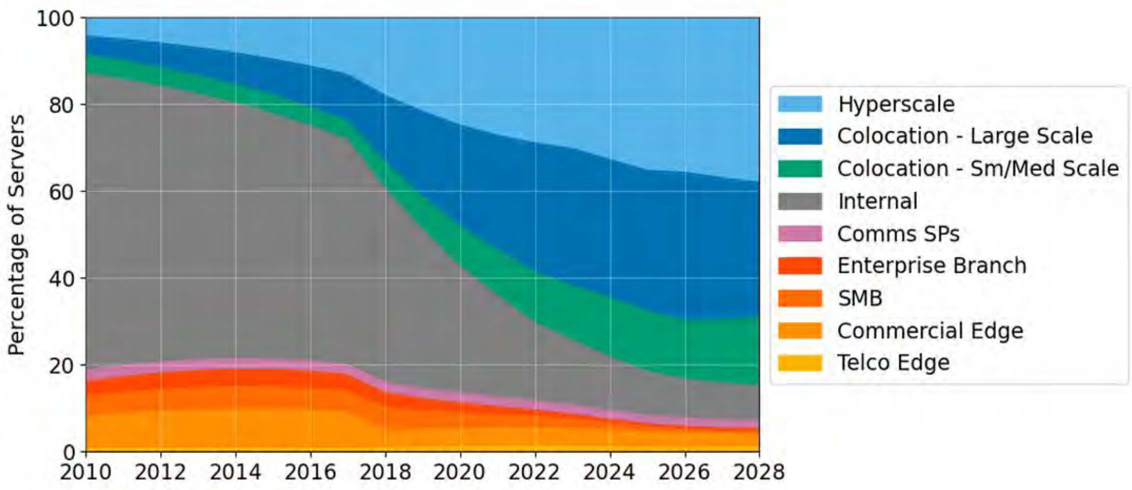



## Data Center Feature 1: Agency and the split-incentive problem

Planning *and* operating *a data center* involves many decision-makers. *Some data centers (often called co-locations or "colos") are facilities where customers can rent space to house their servers and equipment or just run their software on provided equipment. This means the facility is developed and owned by a different company* from those *that rent rack space, buy* computing *capacity, and ultimately consume electricity. Multiple actors force complicated decisions around electricity supply.*

If we want new data centers to adapt their development approach to better integrate with the grid and increase their "speed-to-power," policymakers must understand the planning, construction, and operation of modern data centers. Many different actors are involved, creating a classic split-incentive problem. Loosely speaking, apart from the users or clients, three groups of actors dictate the energy and resource impacts of data centers: developers, facility operators, and service providers. These tend to be separate entities. Overlap sometimes occurs, but usually not enough to prevent split-incentive issues. More than half (and an even larger fraction of the current pipeline)[6] of data centers are categorized as co-location facilities—large facilities that rent out space to multiple separate entities.

*Figure 3 Distribution of server types by data center type. 2024 United States Data Center Energy Usage Report[7]*




We illustrate the split incentives by cataloguing some of the key concerns for each of the three types of decision-makers in the life of a data center. In early stages, data center development is mostly a real estate bet: developers acquire land, water, and electric connection rights and then these rights pass on to the projects they sell. The natural incentive for developers is to keep the range of future owners they could sell to as wide as possible. Hence, they are unlikely to want to enter contracts or agreements (or support legislation) that might prematurely impair any of the land, water, and power consumption rights for their projects. For example, they may not want to agree to be a flexible consumer in return for faster interconnection (load interconnection currently takes three to 11 years) because that might scare off some prospective buyers.

Similarly, owner/operators that lease capacity to data centers customers do not necessarily have much insight into how flexible these customers are or how their customers' usage pattern might change over time. They are conservative about aspects such as whether the tenant-user would be interested in avoiding on-peak usage, participating in time-varying rates, accessing clean energy tariffs, or participating in a demand-response program. Obviously, renters must abide by some rules (via master service agreements or service-level agreements[i]) about behavior that impacts power quality (voltage, frequency, harmonics, transients, etc.) or broader

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[i] A master service agreement is an umbrella standardized contractual framework between a utility and the "customer of record" (which could be a data center owner/operator, a tenant/end-customer, or a special purpose entity created to hold the contract) across multiple facilities in the utility's territory. A load serving agreement is more specific to power delivery at a given site.

 

electrical concerns (like grounding, interference, and surge protection), but that still leaves a lot of uncertainty for the data center owner/operator. Violations may also pass undetected until a severe problem occurs.

Because data centers are also large electricity consumers, utilities will want to know if contracts are backed by the ultimate users (e.g., hyperscalers[ii]) or an intermediate company that could go bankrupt or disappear. Grid investments involve assets with multi-decadal lifetimes, while the service life of cutting-edge chips can be two to three years. Utilities and their regulators have a strong interest in recovering any incremental costs of investments needed to serve data centers and will look for contractual arrangements to make this happen.

### Data Center Feature 2: Clustering, data centers are attracted by similar conditions or to each other

*Data center locations tend to be concentrated in a few regions rather than evenly distributed. This clustering amplifies stress on already energy-dense grids. The main drivers are favorable conditions—reliable power, dense fiber, skilled workforce, tax regimes, and land—but anchor investments by hyperscalers or AI campuses could also accelerate the process. Policymakers should avoid treating projects as one-offs and consider the likelihood of a single facility snowballing into a larger cluster.*

“Clustering” describes how data centers in the U.S. tend to collect in a handful of regions rather than being evenly distributed. Clustering creates stress for the bulk power system because it takes already energy-dense loads and adds even more load nearby. The easiest explanation for clustering is that it derives from favorable existing conditions: reliable electricity, dense fiber connectivity, neighboring trained workforce, supportive tax regimes, and land availability.

Large anchor projects also draw in more data center development: Once a hyperscaler or AI training facility establishes itself, it signals viability, brings new infrastructure, and lowers costs for additional entrants. Policymakers wanting to provide support for a big project by promises of jobs and tax revenue, risk underestimating the impacts of this attractive force as welcoming one project may quickly lead to a cascade of follow-on facilities, with both outsized benefits and mounting strains.[8]

Recent history reveals a pattern whereby anchor investments amplify favorable local conditions into enduring centers of digital infrastructure. Northern Virginia’s “Data Center Alley” grew from early fiber and internet exchange into the world’s largest concentration of data centers. Amazon Web Services (AWS) was an early and steady

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[ii] A hyperscaler is a cloud service provider or operator that builds and manages massive data center networks supporting millions of virtual servers and petabytes of data, operating globally and designed to scale seamlessly across regions. Examples might include Amazon Web Services (AWS), Microsoft Azure, Google Cloud Platform (GCP), Meta (Facebook), Apple, Alibaba Cloud, and Tencent Cloud.

 

investor in this cluster.[iii] Today, Data Center Alley reportedly handles roughly ~70 percent of the world's internet traffic, contains over 12 million square feet of commissioned data center space, and sustains hundreds of megawatts of power load.[9]. Reno's Tahoe-Reno Industrial Center became a global hub after Switch and Apple established major campuses, followed by Google and others[10]. Central Ohio offers a newer case: Google and AWS each invested in major builds, quickly attracting colocation providers.[11]. Atlanta and Phoenix look to be on similar paths[12].

In theory, diverse types of data centers should reinforce these patterns. Colocation facilities are drawn to network-dense hubs where they can maximize interconnection to other facilities. For example, enterprise servers might want to easily connect to multiple cloud providers—providers of cornerstone internet services stand to benefit from the reduced latency proximity affords, especially for content delivery like streaming video and games and so on. Hyperscalers could function as anchors, just like a department store in a shopping mall, investing billions into single campuses that create the vendor ecosystems others rely on. However, AI-focused facilities, with their unprecedented power needs, can also reshape the landscape by displacing other data centers competing for the same power network and generation resources.[13]

Electric power infrastructure both attracts and is stressed by clustering. Access to transmission lines and substations is a prerequisite, but as clusters grow, demand can overwhelm grids. Northern Virginia now faces multi-year waits for new hookups[14]. Reno's growth has raised water concerns and left Nevada utilities facing a potential doubling in necessary electrical infrastructure (also spurring them toward large renewable additions)[15]. Ohio illustrates the stakes most vividly: By March 2023, the utility AEP Ohio imposed a moratorium on new data center service agreements in Central Ohio, pending further study citing grid strain. Eventually regulators approved a new tariff[16] requiring data centers to pay for 85 percent of subscribed capacity whether it is used or not, with penalties for cancellation or under-performance and a four-year on-ramp[iv]. Clustering behavior can easily outrun planning and force regulators into reactive steps, introducing delays before more pro-active policies and tariffs can be put in place.

The policy lesson is not to avoid clusters—after all, they bring new jobs, tax revenue, and digital infrastructure—but to keep a skeptical eye on benefits claimed by developers and focus on smart planning. This should consider the multiple interests of stakeholders affected by a data center cluster and work in advance to align land use,

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[iii] AWS is certainly not the only part of this story but has been called out as a major player. Dan Swinhoe, "The Amazon Factor in Virginia," Data Center Dynamics, November 6, 2024, https://www.datacenterdynamics.com/en/analysis/the-amazon-factor-in-virginia/. Amazon also touts its $51.9 billion investment in Virginia between 2011 and 2021 (capital + operations) in its data center infrastructure in Fairfax, Loudoun, and Prince William counties. Roger Wehner, "Learn About AWS's Long-Term Commitment to Virginia," Amazon, June 7, 2023, https://www.aboutamazon.com/news/aws/aws-commitment-to-virginia.

[iv] Under the decision, new data centers can access up to 50 percent capacity in the first year, 65 percent in the second, 80 percent in the third, and 90 percent in the fourth before getting full access to the grid.

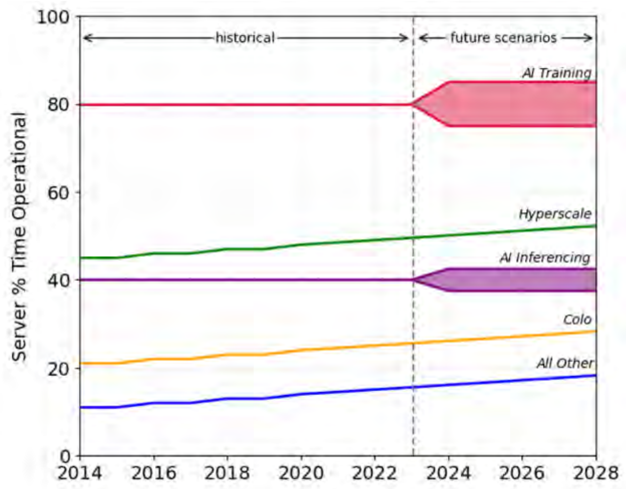
 

grid upgrades, generation, flexible loads, and permitting frameworks, ensuring that benefits can be captured without bottlenecks or backlash once clusters grow.

### Data Center Feature 3: Consumption profile

*Data center electricity usage is not steady or 24/7*. Up *close*, *it can be quite choppy and challenging. Batteries could act as a buffer—a keystone solution to managing power quality.*

*Figure 4 Server utilization by data center type. 2024 United States Data Center Energy Usage Report (LBNL).*

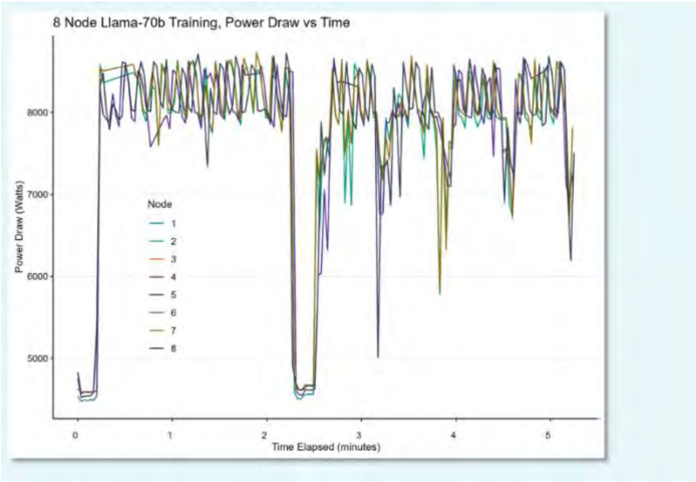



Data centers exhibit considerable variability, especially going between operational and idle states. In Lawrence Berkeley National Laboratory's (LBNL) 2024 United States Data Center Energy Usage Report, the authors explain that in 2014 colos reported 21 percent utilization rates, hyperscalers 45 percent – rising to an estimated 35 percent and 50 percent respectively in 2027. The same report models AI learning centers and AI inferencing at 80 percent and 40 percent utilization rates, respectively. These don't directly translate into electricity consumption load factors because some electricity is used for other purposes like cooling that don't follow a 1:1 relationship with computing load.

Even looking at the whole power consumption profile of a data center, it's important to differentiate between actual load factor (the percentage of possible 24/7 full power use that a data center in fact uses) and availability (the percentage of maximum power a data center expects to have if it wants it, i.e., the *option* to use power). Whether power comes from on-site generation or from the grid, it needs to be prepared to provide power when the data center wants it, and back off when the data center doesn't.

*Figure 5 8 Node trace of power consumption in an AI learning cluster. 2024 United States Data Center Energy Usage Report (LBNL).*




Big swings in data center demand will clearly be a challenge, even for the most flexible on-site generation. Given the scale at which many data centers operate, these swings can still create problems for large regional grids [v]. The CEO of Hitachi Energy reportedly commented "there can be swings of 200, 300 MW within a ten-minute period as data centers move from learn vs stop learn mode, and that these types of swings would not be acceptable from other grid customers."

At smaller time scales, large numbers of similar chips in one place switch on and off and can create an aggregate resonance effect [vi]. Existing electrical standards are inadequate for screening out these behaviors, and utilities may not have sufficient sensors to properly trace back issues to a particular data center. In aggregate, the evidence points to data centers deteriorating power quality metrics in their environs.[17]

More research needs to be done that focuses on new large digital loads, including variable generation resources with inverters that center around things like low-voltage ride through or fault clearing. For more information, context, and solutions on some of the challenges with interconnecting these large loads, see GridLab's recent Practical Guidance and Considerations for Large Load Interconnections.

Data centers are not a "perfect baseload" fit to directly couple with large mechanical generators or even the grid, and they will need significant electrical equipment to buffer this connection and prevent extra wear and tear on co-located generation or nearby grid users. Even if some data centers can learn to be flexible, incorporating battery energy storage, especially as the hardware cost decreases, will likely become a key element in managing data center impacts on the grid. When good wind and solar resources are available nearby, batteries can play a dual role in managing both load and generation variability at multiple time scales. Consider the Lancium Clean Campus in under construction in Abilene, Texas: "In addition to the 1.2 GW grid interconnection,

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[v] See the GridLab report *Practical Guidance and Considerations for Large Load Interconnections*, with special attention to July 2024 Northern Virginia Data Center Event called out in Figure 1.2.
[vi] Some of these resonance issues can potentially be solved by on-chip energy management and storage. Rouslan Dimitrov et al., "How New GB300 NVL72 Features Provide Steady Power for AI," Nvidia, July 28, 2025, https://developer.nvidia.com/blog/how-new-gb300-nvl72-features-provide-steady-power-for-ai/?utm.

 

Lancium's power plan for the site includes large-scale behind-the-meter battery storage and solar resources, which serve to ensure grid reliability, and economic and carbon optimization."[18]

### Data Center Feature 4: Flexibility, or the lack thereof

*Flexibility could be key to quickly connecting new data centers, especially those involved with AI learning. Managed demand is possible, but on-site batteries may be a better solution where split incentives or onsite needs make demand control too rigid or complex.*

Data centers can be flexible, but different functions involve different levels of flexibility. This is probably hardest to achieve for co-location data centers because the third-party owner which interfaces with the grid and with utilities is not the one deciding what servers inside its facility are doing. Additionally, data centers are tasked with fluctuating sets of applications, creating uncertainty about how reliable or persistent demand management can be as a means of providing flexibility.

Data centers fully owned by large hyperscalers provide a higher degree of control over the whole facility. But the diversity of services being provided, often with low latency (response times) needs, may create constraints on what the hyperscaler can do. Hyperscale data centers provide both regular services—like AWS' cloud computing—and AI workloads such as inference, which involves answering client queries using pre-processed AI models.

For AI learning data centers, which create these large learning models, the goal is to cram as many chips as possible into the same square mile with the fastest internal connectivity so that the collection can operate as one big parallel machine[19]. Much of the possible flexibility here comes from adjusting the timing of computing batches, yet matching these adjustments to power supply flexibility needs is not a given, especially when considering that data center operators will want to prioritize computation over flexibility. This is a consequence of the relatively larger size of the capital investment in computing hardware versus energy generation and distribution for most applications.

Flexibility is a particularly important quality for data centers because they are such a large component of load growth, and just a little flexibility would reduce the need for new peaking resources and speed up interconnection[20]. A 2025 analysis[21] by the Nicholas Institute for Energy, Environment & Sustainability at Duke University finds that just 0.5 percent to 1 percent flexibility opens significant space on the grid: 98 GW of new load could be integrated at an average annual load curtailment rate of 0.5 percent, and 126 GW at a rate of one percent. This level of flexibility is similar to what is provided by demand-response programs that exist today for other loads, but as far as speeding up interconnection, it may be the AI-driven hyperscalers and learning centers, acting more directly under their owners' control and schedules, that can achieve more.

 

AI loads are fundamentally more flexible than generic data center loads because they can be processed in batches, easily scheduled, and often internally orchestrated. For example, in a presentation[22] to the Texas grid operator Electric Reliability Council of Texas (ERCOT), the company Emerald AI demonstrated how it could implement flexibility at a data center. The company argued there is enormous potential to control AI data center load, and that "major hyperscalers are amenable to curtailing up to 25 percent for up to 200 hours in return for priority interconnection of 1 GW."

No one knows if any particular data center's operations will remain stable enough to guarantee a given level of flexibility or willingness to curtail over the lifetime of matching local grid upgrades. In some cases, the data center load can be flexible (willing to forgo some batches of work) but not exactly in the way that best serves the local grid. Some amount of local battery energy storage (providing multiple value streams like integrating local on-site variable energy, backup, and power quality services) could also help data centers be more flexible at their grid interface, especially those with less direct control over internal processes.

### Data Center Feature 5: Backup needed for disturbances and outages

*Most data centers require backup. Demand flexibility and short-duration batteries can either eliminate or lighten the load for traditional backup solutions.*

Many data center customers aspire to high availability—as much as 99.999 percent uptime—hence the need for backup power to take over in case of any grid failure. The Uptime Institute, a widely followed source for industry tier certification in data center design, build, and operations,[23] defines four reliability tiers (I through IV) with increasing expectations for performance under challenging conditions, with an eye towards worst-case scenario planning. Many data centers serving enterprise needs require at least a Tier III level of reliability, either because of a direct need, like maintaining accessibility to data under adverse conditions, or as a proxy for operational trustworthiness. For mission-critical operations—major banks, stock exchanges, the military, or hyperscalers serving global customers—a Tier IV level of availability may be required.

Because Tier III and Tier IV facilities require 72 and 96 hours of on-site power capacity, respectively, simple economics dictate that backup is usually in the form of diesel generators with fuel storage on-site. Batteries can also be used to help ride-through disturbances in power supply,[vii] providing faster response times and reducing fuel and maintenance expenses on diesel. However, with today's technology, battery energy storage systems (BESS) that can cover critical needs for three to four days are not

[vii] In current facilities, this ride-through comes via the uninterrupted power system (UPS) usually provided by old-school lead-acid batteries, but modern lithium-ion battery energy systems can provide these services along-side the bulk of backup power needs.

 

economically feasible, especially without some form of on-site generation to sustain their state of charge.[viii]

However, diesel does not scale well: As data centers get much larger, massive tank farms for the generators' on-site fuel require complex fire protection, spill containment, and environmental risk mitigation. Furthermore, many air districts (e.g., Virginia, California, or Oregon) place strict caps on generator run time and cumulative emissions in a site or region. Placing more than a hundred diesel generators on one site creates a cumulative permitting challenge and may well face serious local resistance along with the prospect of delays or outright rejection from regulators. Somewhat cleaner gas generators (turbines[ix] or reciprocating engines) are usually connected to a pipeline and require large propane or liquefied natural gas storage facilities to satisfy on-site capacity requirements.

Some large hyperscalers are opting to target better up-time based on statistical estimates rather than explicit proxies for reliability. For example, Microsoft has publicly committed to reducing the use of diesel generators by 2030. To that end, it contracted with Saft, a subsidiary of TotalEnergies, to install four battery energy storage systems, each in groups of four megawatt hours (MWh) and capable of 80 minutes of on-site power, to replace diesel backup.[24] In the U.S., Microsoft's newest Azure region in San Jose, California is also being built diesel-free, but is using natural gas turbines for backup (plus batteries for ride-through). In general, the U.S. grid is quite reliable, with the one-in-ten reliability standard[x] mostly achieved at the transmission service level.[xi] Most outages that do occur are less than one or two hours, so a battery can carry enough of the backup burden to get the facility to a high level of reliability while hardly, if ever, using on-site generation.

As longer-duration storage solutions like Form's 100-hour battery[25] or thermal batteries[26] connected to local renewables and steam turbines in local energy parks[27] emerge, data centers will be able to free themselves from fossil fuel backups while taking advantage of integrated design to combine multiple uses of batteries for flexibility, power quality, and backup.

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[viii] To see how this is done in detail, see the NREL Vulcan platform demonstration in collaboration with Verrus. Deepthi Vaidhynathan et al., "Vulcan Test Platform: Demonstrating the Data Center as a Flexible Grid Asset" (National Renewable Energy Laboratory, June 2025), https://www.nrel.gov/docs/fy25osti/94844.pdf.

[ix] Although gas turbines face significant supply chain cost and delivery challenges currently. GridLab, *Gas Turbine Cost Report*, https://gridlab.org/gas-turbine-cost-report/.

[x] The one-in-ten reliability standard is a standard that applies for the bulk power system (i.e. transmission level) requiring transmission planners, system operators and reliability planners to aim for nor more than one "event" of involuntary load-shedding in ten years. If one "event" was 24 hours, that is already 99.97 percent up-time.

[xi] Actual recent figures for grid performance are quite good (see table 1.1). North American Electric Reliability Corporation, *2024 State of Reliability*, June 2024, https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2024_Technical_Assessment.pdf.

 

### Data Center Feature 6: Modularity—data centers are built in phases

*Data centers expand in discrete phases, from racks to halls to entire campuses, with uncertain demand and rapidly rising power density. This modular growth pattern matches well with the modularity of renewables-plus-batteries deployment, which can be built in parallel to meet incremental load without the risks of lumpy firm power investments.*

For utilities and data center developers, timing capital investments can be challenging. Matching these investments with energy supply for their increasingly electric power sub-components compounds the challenge. Building a new data center means committing to constructing a large building and grid capacity without knowing if consumers will come, how quickly they will deploy, or how their consumption will evolve over time. Tenants in a co-location situation, hyperscalers, and AI data centers may not immediately have all the chips available (or face some other bottleneck) so may want to deploy in phases: slowly building up electrical demand over time until reaching full capacity, if all the anticipated demand materializes. With a chip service life of around two to three years, the balance between increased efficiency and increased computing power may mean newer chips could either increase or decrease electricity demand in each physical asset footprint.[xii]

The digital world's infrastructure is itself modular—built from discrete, substitutable units. Data centers are not just abstract systems of bytes and tokens; they are also collections of tangible components: chips, servers, and, above all, racks. The rack is the main unit of reference: a cabinet holding multiple slender servers or "rack units." Racks are grouped into "pods" of 20–30, and an enterprise client might deploy a couple of pods at a time in either a dedicated or co-location facility. Some tenants lease only a handful of racks in a shared space, while hyperscalers may build entire halls of 200–400 racks, with multiple halls forming a single phase of expansion on a large campus[28].

The modular nature of data centers lets developers manage financial risk by building in phases, with the option to add new capacity quickly but in a planned way. Each phase, however, carries high stakes not only in capital cost but also in power demand. A 2024 Uptime Institute report[29], states finds that four- to six-kilowatt (kW) racks remain common, with a trend towards higher consumption today. Meanwhile, AI applications and high- performance computing are pushing the development of liquid-cooled racks with incredible increases in power density. Vertiv, an Ohio-based company that designs, manufactures, and services critical infrastructure for data centers, reported in its 2024 Investor Event Presentation[30] that extreme rack densities already reach 250 kW

[xii] This is certainly a question in flux. Google has reported that over a recent 12-month period, the energy footprint of the Median Gemini Apps text prompt dropped by 33x! At a given facility this can be achieved by increased throughput or reduced energy use, or both. Amin Vahdat and Jeff Dean, "Measuring the Environmental Impact of AI Inference," Google Cloud, August 21, 2025, https://cloud.google.com/blog/products/infrastructure/measuring-the-environmental-impact-of-ai-inference.

 

per rack today and could exceed one MW within five years. That means a space the size of a bedroom closet could consume more power than a thousand average homes. As a result, a single phase of development for a data center might range from on the low end at 250 kW (two-dozen at 10–12 kW per rack) on the low end to 250 MW at the high end (a 1,000 liquid-cooled 250 kW racks) at the high end, with extra overhead for cooling.

The extreme end of data center development is exemplified by data center developer Vantage's recently announced plans [31] to build its $25 billion Frontier campus situated on 1,200 acres in Shackleford County, Texas, with an eventual total consumption of 1.4 GWs—close to average total consumptions of the states of either Rhode Island or Delaware. And this project is not alone: a September 2025 ERCOT staff report [32] to ERCOT's board details 130 GW of non-crypto data center load in the interconnection queue through 2030.[33] In the last few years, Texas has met new additional load with new, mostly clean generation. Of the 428 GWs of generation requests as of August 31, 2025, 204 GWs are for wind and solar and 180 GWs are for energy storage (together 90 percent of all requests).

Data center development may come in all levels of power consumption. However, because developers rarely build, install, and commission data centers in a single phase, projects of all sizes need a power supply that can grow and expand with them. When covering the incremental energy demand from a new data center, a large new single firm resource is an unwieldy indivisible capital investment. A modular approach with renewables plus batteries reduces risk and provides better economics: You're not committing to a single lump-sum investment in a 500 MW gas turbine; you can phase investments, optimize based on real usage, and spread spending—and risk—over time.

With computing loads that grow unevenly, modular investments let operators respond dynamically—deploy more solar, wind, or storage as AI racks come online. As a bonus, you can avoid supply chain bottlenecks because incremental installation bypasses the big lead times and equipment backlogs associated with large generator orders, enabling continuous expansion without project delays. Just as data centers grow in discrete steps, modular renewables and batteries let the grid grow in parallel.

These six features highlight why data center demand is complex, not just a flat, 24/7 block of constant load. We now turn to how supply options can, and cannot, match this demand.

## THE BEST WAY TO MEET DATA CENTER DEMAND IS DIVERSE RESOURCE PORTFOLIOS

 

When thinking about how to supply new demand from the rapidly growing data center industry, the key point to remember is **one-to-one matching with "firm" resources will not "solve" the load growth needs from data** centers.

In this section, we explain why single, stand-alone generation resource matching for any given industrial load has rarely been the historical course, and how and why that might change. We then describe the three resource buckets that new data center projects need to acquire to use the existing bulk power system. Finally, we discuss how the data center demand features described in the preceding section create further challenges and barriers in acquiring these resources.

## Debunking the one-to-one matching myth

If you imagine data centers as large capital assets running power through expensive electronics 24/7, it seems natural to imagine a dedicated "captive" 24/7 power plant built to match this demand, with historical precedent for this one-to-one matching. For example, in the post-war era aluminum producer Alcoa built smelters near cheap grid sources of hydropower in New York and the Pacific Northwest along with captive coal plants in Indiana and Texas to feed the company's aluminum smelters and mills. Today, industrial facilities use on-site combined-heat-and-power (CHP) plants to consume both the electricity and waste heat from fuel-driven power plants to operate industrial facilities with high end-use efficiency, and thus lower energy costs. According to the U.S. Energy Information Administration's (EIA) latest Manufacturing Energy Consumption Survey from 2022, U.S. manufacturers produce around 17 percent of their electricity needs on-site (Table 11.1) and that on-site generation is 97 percent co-generation (Table 11.3).[xiii]

### Single plants may not "play nice" with data centers

The demand characteristics of data centers described in the prior section raise immediate concerns regarding matching a captive plant with a data center. For example, while a data center may want 24/7 availability, its actual consumption will ramp up and down significantly with a profile that a large, single on-site generator might struggle to meet. Many fossil generators have a minimum dispatch level they cannot fall below, and "ramp rates" limits dictate how quickly they can adjust up and down. Furthermore, a modular, phased build-out does not lend itself to a single matching resource because in order to provide sufficient power for the full buildout,

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[xiii] This survey defines co-generation as "the production of electrical energy and another form of useful energy, such as heat or steam, through the sequential use of energy. Cogeneration includes electricity generated from fossil fuels, such as natural gas, fuel oils, and coal; wood; and other biomass." In practice, the steam/heat is the main other energy output, so co-generation is often used as synonymous with CHP.

 

the single resource would have to operate at lower, inefficient, dispatch levels during earlier phases of data center construction and operation.

Beyond a mismatch with the demand characteristics of data centers described in the prior section, there are additional reasons to question using a captive plant as a 1-1 match for a data center.

### Captive power plants are not highly reliable alone

Table 4 from the North American Electric Reliability Corporation (NERC) 2024 State of Reliability Overview [34], shows the recent weighted forced outage rate (rate of unexpected failure) was 11.7 percent for coal, 7.7 percent for gas, 6.4 percent for hydro, and 2 percent for nuclear. Another relevant consideration is planned maintenance, like cleaning out coal boilers, maintaining and inspecting gas turbines, or refueling nuclear plants every 18-24 months. [xiv] This means a single supposedly "firm" plant will be unavailable for a double-digit percentage of time—not what data centers are looking for.

If an industry is set on self-supply, one strategy is to over-supply generation. Alcoa's Warrick, Indiana aluminum smelter and mill built three captive 144 MW coal plants alongside a 300 MW coal unit shared 50/50 with the local utility Vectren. With a total capacity of 732 MW but serving a local load of 550 MW,[35] the facility was clearly resilient to losing one unit and still running. But this effectively meant carrying 25 percent more capacity than necessary, without a guarantee of full reliability. Alcoa mitigated this extra cost by selling excess power to the grid and importing power from Unit 4 or the broader grid when necessary. This illustrates the general case that a grid connection remains both a sink for surplus and an important backup option; most on-site power is not fully independent and large loads will still want interconnection to the bulk power system. In fact, payment for grid backup (usually called "standby rates") is a common feature of CHP tariffs.[36].

### What happens when the power plant is no longer needed?

An interesting postscript to the Alcoa Warrick plant story is that Alcoa announced it would shut down its aluminum smelter in 2016 (although it had partial restarts post 2018) because of poor market conditions [37] and transferred major rolling mill and finishing operations to Kaiser Aluminum in 2021.[38] It is now left with an unattractive coal generation asset, whose generation capacity now exceeds Alcoa's local demand and

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[xiv] This is on average a 32-day process. Aaron Larson, "Planning Is Key to Successful Nuclear Refueling Outages," POWER Magazine, September 1, 2023, https://www.powermag.com/planning-is-key-to-successful-nuclear-refueling-outages/.

 

will likely struggle to sell surplus capacity in the broader power market along with most coal assets,[39] which comes with significant environmental remediation liabilities.[xv]

This is always the risk with a captive power plant: One day the load will vanish because of changing economics. Investors will want to know if Plan B exists and that the captive plant is in and of itself an attractive asset with a bright future.

### Co-location of prime power generation assets with data centers today

Grid bottlenecks create considerable talk about co-locating "prime power" generation[xvi] with new data centers. This might include leveraging existing nearby assets (for example, the Talen-Susquehanna deal which co-locates a data center next to a nuclear plant[40]), restarting mothballed generators, or building new on-site resources (such as gas plants). But these arrangements are not true one-to-one matches of generation with load, since they still depend heavily on a grid connection for full functionality, sometimes at the expense of other consumers.

For example, in the Talen-Susquehanna deal, the data center is physically adjacent to a pair of nuclear units. It is unlikely the units' output will ramp precisely in step with data center consumption. Therefore, matching local supply with demand creates net output—nuclear output minus on-site data center consumption—variability which must be managed by the grid operator. During the refueling of one nuclear unit, the other must pick up the data center load, thereby reducing exports to the grid. In effect, the grid acts as backup.

Hybrid arrangements using on-site power together with the grid can address bottlenecks. They combine physical and financial hedges. The Talen-Susquehanna deal, for instance, was eventually reshaped into a power purchase agreement after regulatory push-back.[41]. These hybrid deals share many of the properties—and many of the drawbacks—of other on-site generation deals discussed above.

If land is available, the best way to provide on-site prime power is not with a single firm resource but by using an energy park[42] with renewables and batteries, with backup from longer- duration storage and/or gas generators.[43] Then most of the generation is

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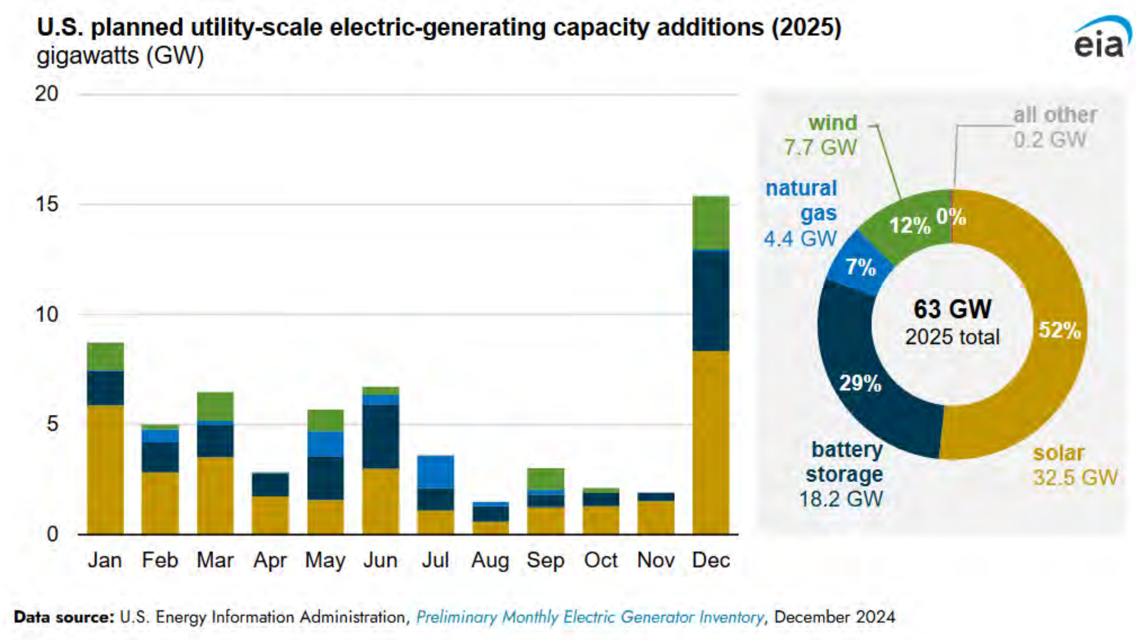
In 2024, Sierra Club and Environmental Integrity Project intervened in a case against Alcoa Warrick for "100+ permit violations" in 2022 and 2023, including releases of mercury, aluminum, chlorine, copper, fluoride, nickel, and zinc into the Ohio River. Environmental Integrity Project, "Groups Intervene in State Action to Stop Aluminum Smelting Plant's Illegal Dumping of Heavy Metals in Ohio River," February 21, 2024, https://environmentalintegrity.org/news/groups-intervene-in-state-action-to-stop-aluminum-smelting-plants-illegal-dumping-of-heavy-metals-in-ohio-river. There are also lingering questions regarding compliance for Warrick's "ash ponds" under the Environmental Protection Agency's Coal Combustion Residuals rules. Hoosier Environmental Council, "Today's EPA Action Means More Coal Ash Cleanup for Indiana" (press release), April 25, 2024, https://www.hecweb.org/wp-content/uploads/2024/04/PRESS-RELEASE-Todays-EPA-Action-Means-More-Coal-Ash-Cleanup-for-Indiana.pdf.

[xvi] Prime power is the continuous everyday power that powers the data center, as opposed to backup power There is also "bridge power" which is local generation which acts as prime power until a grid connection is put in place, and then becomes either backup or just a part of the supply portfolio.

clean, faster, and cheaper to deploy than other generation and helpful for hyperscaler emissions commitments. In addition, the combined resource is more reliable, with fewer large points of failure than a handful of fossil units – a good Plan B if load never fully materializes or decreases. Included energy park resources would reflect a microcosm of trends in the wider U.S. market where the large majority of generation coming online[44] and waiting in interconnection queues are renewables and batteries.[45]

*Figure 6 Solar, battery storage to lead new U.S. generating capacity additions in 2025. US EIA.*




## Providing new electricity supply for data centers from the bulk power grid

Given that most data centers will need to get some, if not all, of their power from the bulk power system, it is helpful to review how large commercial or industrial loads do this. The power grid is a system of systems including physical transmission and distribution poles and wires, the generation and loads they connect, operations and dispatch, power markets, and power purchase agreements.

As soon as a large new load decides to connect to the bulk power system, its needs can be disaggregated and met in many ways.

The grid resources a new data center project must collect to successfully draw from the bulk power system fall into three broad buckets: connection, grid services, and bulk electricity.

### New large data centers will require connection and network upgrades

How data centers connect to the grid depends on their size: scale matters. Smaller enterprise and co-location data centers (tens of MW or less) will often connect to a distribution system's high-end network (i.e., somewhere between 13.8 and 69 kilovolts) and may tie into an existing distribution substation with a new feeder. The utility typically owns and operates the primary substation equipment, while the data center customer owns the step-down transformer to its facility. The local utility conducts the impact studies and plans local upgrades to ensure compliance with NERC standards. Too many connections in the same area may trigger transmission upgrades and inclusion in transmission planning studies. In some geographies, like Virginia, this may involve an independent system operator (ISO) such as PJM [xvii] in planning and approving upgrades.

Larger data center campuses will have their own complex internal grid that connects directly to a bulk power system transmission substation. The data center must file a large load interconnection request with the local transmission owner or ISO. Tariffs and agreements will include matters like covering study costs, equipment ownership, and who pays for upgrades. The state may also require approvals for siting, environmental review, and cost recovery. The connection process can become long and painstaking once local capacity on the grid becomes tight. In Virginia's Dominion utility territory, data centers larger than 100 MW face up to a seven- year wait for power hookups.[46]

One important feature of new connection costs is that they are usually covered by the new load because cost causality is clear. Unfortunately, this may not hold true for more upstream transmission impacts where transmission upgrade costs are traditionally socialized more widely. A recent Natural Resources Defense Council (NRDC) report[47] tells the story in PJM: "Tight supply conditions led PJM to approve a $5 billion transmission expansion project to meet new data center demand in Virginia, where data centers already account for around a quarter of the state's electricity demand. The costs for this project were distributed by the Federal Energy Regulatory Commission (FERC), PJM, and utilities using varying cost allocation methods. Maryland residential customers were left with a bill of approximately $330 million, and Virginia residents had to foot $1.25 billion for transmission designed largely for a handful of data center customers in only a small region of the state."

### Data centers create new stresses on a bulk power system planned around peak demand; they also consume other grid services

The main grid service data centers require regardless of size is peak capacity: the ability to serve up to their maximum interconnection rating during periods of system peak.

[xvii] Also referred to as a regional transmission operator, PJM covers 13 states in the mid-Atlantic and is one of the largest power markets in the world.

Going back to PJM (often a source of current examples because it already serves so many data centers), the ISO's board chair communicated about future reliability concerns because: "PJM's 2025 long-term load forecast shows a peak load growth of 32 GW from 2024 to 2030. Of this, approximately 30 GW is projected to be from data centers."[48]

PJM's conundrum is how to keep the grid reliable as data center demand grows faster than new generation. Its "non-capacity-backed load" proposal would classify very large new loads (less than 50 MW) as customers outside the capacity market.[49]. The idea is to avoid shifting costs to others, but critics say that the 50 MW cutoff is arbitrary, curtailment rules could distort market signals, and contract and siting decisions may be disrupted.[50]. PJM is still debating whether the non-capacity-backed load should be voluntary or mandatory in shortage zones before filing at FERC for the 2028/29 delivery year.[51]

One challenge with resources like peak capacity is that once a project has been approved for interconnection, been built, and paid its share of costs, it becomes a load like any other. At that point, it is very difficult for the market to discriminate against it without creating efficiency concerns or legal risks. Data centers do more than strain peak supply; like all large loads with some variation, they also draw on ancillary services and other grid management resources.

### If incremental demand is not met with increased supply, prices and emissions will rise

As the recent Nicholas Institute report[52] points out, some amount of flexibility from data centers could significantly reduce costs and delays associated with connection and peak demand constraints from new data centers. The report estimates peak load bottlenecks could be avoided for around 100 GW of so-called "curtailment-enabled headroom" on the U.S. grid. However, even if data centers avoid consumption during the most problematic hours, they still need power the rest of the time. Absent new supply on those same grids, the extra generation available off-peak will be from more expensive, and typically dirtier, marginal generation units.

Data centers' need to draw most of their power from existing units is thus a problem for other electricity customers because absent new matching supply, it will drive up their wholesale electricity costs. It is also problematic for the data centers themselves, which frequently are tied to corporations that have carbon reduction goals which are incompatible with increased emissions from existing fossil power plants. Conversely, new supply (especially cheap and clean supply) arriving quickly enough to offset data center consumption without requiring a large amount of new grid infrastructure creates potential for "beneficial electrification[53]" where more power over the same wires reduces other consumers' costs[54].

### Further consequences: Challenges and barriers specific to data centers

Connecting large new data center loads through the lens of three resource buckets faces three broad challenges required by all such loads. But these resource buckets also interact with the six more specific data center demand characteristics outlined in the preceding section.

#### Connection challenges specific to data centers

Because the source of many connection issues—or at least more expensive upgrades—come down to a limited set of hours and circumstances, flexibility is often cited as a master key for easing or speeding up connection. But flexibility is not always as simple to implement as first imagined, and other connection challenges specific to data centers are not necessarily circumvented with a touch of flexibility.

- **Agency:** Especially for co-location data centers, the operator is stuck between wanting to be more flexible to satisfy grid constraints and the imperative to be as generic as possible in contracts with tenants to accommodate as broad a class of customers as possible. Typical quality of service and service-level agreements also act as a barrier for to tapping flexibility.[55] Intervenors in public utility cases also question whether policies for ensuring new data centers cover all their incremental costs are effective[56].
- **Clustering:** Clustering leads to many data centers on the same part of the grid, necessitating more upstream transmission upgrades, as in the Virginia case mentioned cited by NRDC, mentioned above.
- **Consumption profile:** Big swings in power demand and power quality impacts on other consumers make data centers trickier for utilities and transmission providers to study and interconnect than simple 24/7 constant loads. Standard protection schemes and the collective behavior of 60 data centers recently caused a large reliability problem in Virginia in July 2024 when these data centers all dropped off the grid at once and caused a sudden surge in excess electricity that strained grid resources.[57]
- **Flexibility:** Some data centers are not flexible at all; others could be flexible but not in a manner consistent or predictable enough to satisfy the engineers running interconnection studies. These engineers are only likely to be satisfied after adding sophisticated energy management systems and large batteries, along with the promise of judicious backup power.
- **Backup:** As mentioned, backup power could be leveraged to facilitate connection or provide so-called "bridge power"[58] for data centers that cannot wait for interconnection. Unfortunately, backup power (used either for

flexibility or bridge power) tends to be dirty, leading to siting and local community environmental concerns.[59][60]

- **Modularity:** With a modular or phased build-out, a data center may ask up front for a large enough connection to accommodate all future phases, leading to stranded asset risk if all phases do not materialize.

### Grid services challenges specific to data centers

Just as for solving connection issues, flexibility can help tamper the impact of new data centers on system-wide needs like peak capacity issues. A large overlap exists between local grid and larger grid issues with peak planning. However, as described in the prior section, flexibility is not always easy to implement or deploy in a manner which solves all challenges. Furthermore, the specific features of data centers tend to create additional challenges beyond help from simple load flexibility measures.

- **Agency:** Utilities often see new fossil resources like gas peakers as the easiest way to resolve new peak demand issues from data centers.[61] Because gas turbines are increasingly expensive, this may not be a good deal for other utility customers and may also entrench future emissions, working against many data center providers' and host states' clean power goals. Because eventual data center owner/operators tend to build where developers have prepared the ground, the fact that these developers may perceive emissions goals as secondary to "speed-to-power," and that utilities choose their own procurement path creates an agency mismatch.
- **Clustering:** The clustering of data centers tends to amplify their effects on the regional grid, with sharper surges in demand for grid services that cannot be accommodated fast enough through new resources builds.
- **Consumption profile:** While data centers don't run all the time, they plan their infrastructure for peak computing demand. This creates a knock-on effect for the bulk power system, which plans for peak power demand.
- **Flexibility:** Flexibility is not always a simple feature to implement or deploy.
- **Backup:** On-site backup power is a poor substitute for system resources because of expense as well as siting and local environmental concerns.
- **Modularity:** While the broader grid is in a good position to adjust to a phased build out of data center demand, this requires either coordination with the local utility or strong forward signals in the market to avoid disruptive demand shocks for grid services.

### Bulk electricity challenges specific to data centers

Certain subcategories here (consumption profile, flexibility, modularity) concern time domains that do not apply when considering total annual consumption.

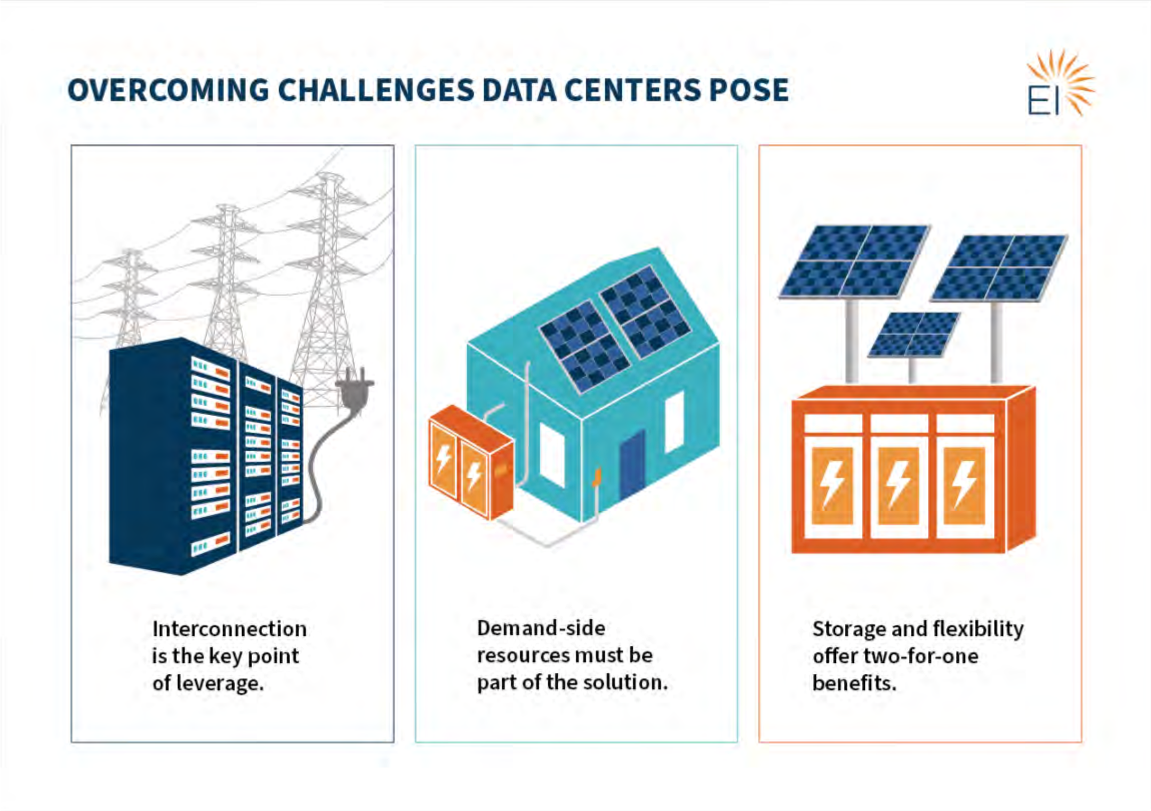
 

- **Agency:** As with grid connection and services, intermediate entities between electricity provisioners and data center owner/operators with emissions goals may not consider the environmental impacts of reliance on using spare capacity from existing marginal resources.
- **Clustering:** Clustering means more annual electricity drawn from the same grid. This creates a greater need for new supply, amplifying the problems of price and emissions increases.
- **Consumption profile:** A variable but not necessarily predictable profile for large data center loads could create new challenges for grid operators, even at off-peak times.
- **Flexibility:** Data center demand flexibility could potentially alleviate emission concerns by targeting off-peak consumption more towards time periods with lower marginal emissions. This requires an extra layer of control on top of whatever that data center might have already committed to ease grid connection and mitigate impacts on grid operational resources.
- **Backup:** Supplying too much of the actual annual electricity use from backup power creates problematic environmental impacts.

# TAKEAWAYS FOR POLICYMAKERS AND OTHER STAKEHOLDERS

*Figure 7 Three key takeaways*




Many organizations (Clean Air Task Force/Brattle,[62] GridLab,[63] NRDC,[64] the Bipartisan Policy Center,[65] and the Regulatory Assistance Project[66]) have provided detailed and useful guides for coping with the challenges of meeting new data center loads.

This section distills the key lessons from the features and challenges discussed above.

## Interconnection is the key point of leverage to influence when and how data centers join the grid

Accommodating large, dense new loads affects every grid participant, and the challenges show up at multiple scales. Geographically, they range from the substation where the data center connects to the entire interconnected system. In time, they span from sub-second transients to hours of local and bulk stress to the accumulation of annual demand.

When issues are tied directly to a data center's load or its immediate connection, cost-causation principles are easier to apply. But at larger scales, like meeting new annual demand or rising peaks across a region, the problem is less about the nature of data centers than the pace and size of their growth. At that point, they can reasonably argue for being treated like any other customer buying power "at the pump," without special obligations.

This tension is what policymakers need to keep in mind. Interconnection is the moment of maximum leverage: not to extract unreasonable concessions, but to ensure new entrants cover the infrastructure costs they trigger, and to nudge them toward implementing solutions like flexible demand or local storage that relieve local bottlenecks and support the broader grid. Likewise, developers and customers should lean toward local fixes that speed access to the grid, improve power quality, and ease broader impacts—reducing the likelihood of being saddled with extraordinary requirements later.

### Using other demand-side resources

In one of our earlier reports on meeting the load growth challenge,[67] we pointed out the importance of using demand-side resources to meet this challenge most efficiently. Often the discussion of demand-side solutions focuses on direct measures at a data center, especially in the wake of the efficiencies revealed in the DeepSeek announcement.[68] However, data centers can meet their resource needs with other demand-side resources elsewhere on the grid. Recently, Voltus, an aggregator of distributed energy resources (DERs), announced a deal with Cloverleaf Infrastructure—a data center developer—to meet new capacity needs from data centers with market-accredited capacity from DERs.[69] This kind of transaction compensates other existing customers and thus helps accommodate the rapid rise of data center loads fairly, speedily, and equitably. Since connecting to the grid can involve mixing and matching resources to relieve bottlenecks, once a data center has invested in the flexibility and extra equipment needed to resolve local connection issues, there is no reason why more upstream connection issues, grid services bottlenecks, and the need for a large amount of annual electricity delivery cannot be resolved with demand-side solutions from other grid users.

A recent Rewiring America report proposes many of the resources to meet data center load growth could come from sponsoring household upgrades.[70] The report finds that if hyperscalers paid 50 percent of the up-front cost of installing heat pumps in the tens of millions of U.S. households that currently use inefficient electric heating, cooling, and water heating, they could free up a total 30 GW of capacity on the grid. In addition, if hyperscalers paid 30 percent of the up-front cost of rooftop solar and storage in every single-family household in the U.S., they could add 109 GW of capacity on the grid. The cost of these upgrades would be comparable to the report's estimate of $315/kW-year to build and operate a new gas power plant.

### Storage and flexibility relieve data center challenges; they can also ease interconnection of new variable renewables

On-site prime generation solutions built around renewables and flexibility (modulating demand and using batteries) may provide cheaper, cleaner, and faster means for meeting new and existing data center demand. Because batteries are increasingly essential for buffering, backup, and power quality, they also provide a built-in solution for integrating variable renewables—offering a two-for-one advantage.

Furthermore, these renewable-plus-battery solutions can take advantage of existing surplus interconnection[71] to more quickly connect data centers to the grid in "power couples."[72]

By exploring the nuanced solutions, policymakers can avoid overcommitting to outdated firm resources and instead adopt strategies that embrace modularity, flexibility, and clean energy. Doing so will support both the digital economy's explosive growth and the clean energy transition.

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