BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 44
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. Evaluate reasons why the information provided by Curtailment Service Providers regarding their ability to curtail load was not accurate. Incorporate lessons learned as necessary to include validation procedures.		Under internal PJM review
2	Emergency Procedures	Reinforce PJM and member steps and expectations in Manual 13 for operation during emergency procedures through additional training and manual clarifications. Specific focus on: • Existing actions in Cold Weather Advisory and Cold Weather Alert regarding winterization and staffing procedures • Criteria, sequencing, and communication of alerts, warnings and actions • Consideration of potential opportunities to clarify member expectations in M-13		New
3	Operating Reserves	Evaluate triggers for increasing the Operating Reserve Requirements in advance of the operating day based on risks imposed by projected extreme temperatures, unusual temperature changes, load uncertainty, solar/wind uncertainty, generator performance uncertainty, OFOs, etc.		Pending internal process change
4	Load Forecast	Evaluate opportunities for improvements to the extreme weather load forecast processes and methodology with independent and peer analysis.		Under internal PJM review
5	Unit Parameters	PJM will provide additional training relating to the use of Parameter Limited Schedules (PLS) and price schedules. The focus of the training will include the time to start parameters for the various schedule types and the use of PLS parameters. The intended training audience is for anyone managing and updating the PLS and price schedules.		New

ID	Category	Recommendation	Type	Status
6	Unit Status	Evaluate the Temporary Exception and Real-Time Value processes that require gas-fired generators to either update their operating parameters, or confirm that no updates are needed, when Cold Weather Advisories, Alerts, Conservative Operations, or pipeline OFOs are issued that may impact their ability to procure gas outside of standard nomination timelines. Make improvements to ensure accurate offer information from generation resources.		Under discussion at the Electric Gas Coordination Senior Task Force (EGCSTF)
7	Gas Electric Coordination	Develop solutions to address near-term gas generator unavailability resulting from gas and electric market timing issues, particularly during periods of cold temperatures and high winter demand.		Under discussion at the EGCSTF
8	Gas Electric Coordination	Explore opportunities to increase alignment between the scheduling of natural gas-fired resources with nomination cycles.		Under discussion at the EGCSTF
9	Gas Electric Coordination	Evaluate the current multi-day commitment process for use during expected critical high demand periods so as to analyze the costs and benefits of providing greater certainty of fuel supply procurement through the critical period, with a focus on weekends when the gas commodity market can be less liquid.		Under discussion at the EGCSTF
10	Gas Electric Coordination	Provide recommendations to FERC to investigate weekend gas supply liquidity to facilitate increased gas procurement ability during weekend/holiday periods.		Under discussion at the EGCSTF
11	Gas Electric Coordination	Work with states to discuss opportunities to increase prioritization of natural gas for usage in electricity production for resources behind LDCs.		Under discussion at the EGCSTF
12	Gas Electric Coordination	Explore opportunities to better align submitted offer data to true availability of natural gas resources.		Under discussion at the EGCSTF
13	Gas Electric Coordination	Evaluate the ability to include fuel-specific information in the capacity accreditation model. Consider including items such as: 1. Different levels of fuel security, including dual-fuel capability, firm gas and non-firm gas 2. Minimum requirements for onsite fuel		Under discussion in the CIFP process
14	Unit Status	Evaluate options for requiring generators to provide procurement information to PJM in real time and day ahead to provide greater situational awareness to PJM regarding the ability and timeliness of procuring fuel.		Under discussion at the EGCSTF
15	Voltage Reduction	Review and update, as necessary, the expected load reduction achieved during a Voltage Reduction Action due to changing composition of load. This recommendation specifically focuses on the Voltage Reduction Summary table in Manual 13.		New

ID	Category	Recommendation	Type	Status
16	Reserve Performance	Evaluate opportunities to increase the performance of Synchronized Reserves to achieve the desired response. This may include levels procured, procurement practices, compensation or other aspects of the Reserve Market design.		Stakeholders notified that PJM's reserve requirement will be increased to 1.3 times the largest contingency MW effective May 19 until further notice
17	Reserve Pricing and Penalties	Evaluate the current Reserve Market design to ensure reserve products, estimated reserve capabilities on resources, procurement practices and timelines, quantities procured, performance incentives, etc., align with operational needs and that prices and performance incentives are similarly aligned.		Issue charge planned for August
18	Cost Offer Verification	Distribute training on the Cost Offer Verification process to members (standard email or similar notification) before cold weather events and send alerts to update MIRA ahead of time.		New
19	CIFP	Evaluate how risk modeling in the reliability analysis used in the capacity market can be improved to better account for the drivers of reliability risk experienced in the winter.		Under review at the CIFP
20	CIFP	Evaluate reforms to capacity market rules and incentives to improve the performance of resources, including: • Review the Capacity Performance construct, with consideration of financial risks. • Strengthen capacity accreditation and qualification criteria (e.g., winterization/fuel assurance). • Evaluate opportunities to improve testing rules to complement assessments during actual reliability events, including frequency of the tests, defined guidelines for test success/failure, and penalties for test failure. • Evaluate current practices in other ISO/RTOs for requiring generator inspections and implement any best practices.		Under review at the CIFP
21	CIFP	Evaluate opportunities to align the incentives from the capacity market via PAIs with real-time operating conditions, particularly with regard to PAI triggers.		PJM filed changes to the PAI triggers on May 30. Discussions will continue as part of the larger reforms in the CIFP process.
22	CIFP	Evaluate if and how exports should be accounted for in the balancing ratio.		Under review at the CIFP
23	CIFP	Reevaluate what happens in the scenario that a resource has not submitted a valid offer.		Under review at the CIFP
24	CIFP	Explore opportunities to refine and simplify excusal rules to reduce manual and case-by-case review processes.		Under review at the CIFP

ID	Category	Recommendation	Type	Status
25	CIFP	Review the M&V calculations of Energy Efficiency and Demand Resources for PAIs to assess if the determination of actual performance and bonus accurately reflects the reliability benefit provided.		Under review at the CIFP
26	CIFP	Evaluate the performance issues regarding NRBTMG, and provide recommendations on enhancing its performance or altering its participation in the capacity market.		Reviewed at the May 8 DISRS Stakeholder group
27	CIFP	Explore opportunities for further education on PAIs, such as providing periodic training sessions.		In Progress
28	Call for Conservation	Evaluate opportunities to enhance Public Notification Language in Attachment A of Manual 13 regarding Call for Conservation to better direct the appeal to all customers, not just residential. Establish a process for annual review of state alert contacts, and explore additional opportunities to further amplify PJM's message through state communication channels, up to and including Emergency Alert Systems.		In Progress
29	Outreach	Operations, Corporate Communications and SGP will seek ways to enhance communications, specifically looking at timeliness, relevance and clarity of information provided along with curating and updating of appropriate contacts for each audience and channel for messaging.		In Progress
30	Drills & Exercises	Operations, Corporate Communications and SGP will also strengthen their periodic drilling with states, Transmission Owners and other members by: 1) Finding opportunities to include states in PJM crisis exercises; 2) Providing education on PJM emergency procedures and Call for Conservation during summer and winter operations drills; 3) Following up with parties not represented at drills to make sure they are aware and contacts are up to date.		In Progress

Legend for Type

- Operational Change
- Market Construct Process Change or Addition
- Process Improvement
- Training and awareness improvement

About This Report

Purpose

The purpose of this analysis and subsequent report is to review the events up to and during Winter Storm Elliott, assess the actions of PJM and its members during those times, and look for lessons learned and associated recommendations to help improve grid reliability.

Analysis Process

The review process performed for this report was driven by the Human Performance and Operating Experience (HP&OE) program at PJM. The HP&OE program promotes excellence in human performance through behaviors that support reliable grid operations, fair and efficient energy markets, and infrastructure planning. The goals of this program are to:

- Reduce the frequency and impact of human error
- Share and learn from internal and external events
- Analyze events to identify corrective actions to prevent and reduce impacts of adverse events
- Ensure that processes and procedures are executed correctly to achieve the desired results

The fundamental aspects of the HP&OE program are:

- Prevention: Reduce errors that lead to events
- Detection: Identify potential issues across the organization
- Correction: Learn from events through event analysis and completion of remedial actions

To conduct this review and event analysis, PJM employed the Learning Teams analysis tool. Learning Teams are utilized in the industry as a collaborative event analysis best practice because it focuses on bringing people together to better understand an event with the basis on learning and identifying successes and improvements.

PJM conducted multiple different focused area Learning Team sessions with subject matter experts and independent participants across various areas of PJM to allow for open and collaborative discussions. The Facilitation Team followed a structured and consistent methodology with a focus on the event itself, and additionally on the timeline and decisions leading into the event, which allowed all members of the team to share their perspective. From the Learning Team sessions, successes and opportunities for improvement were identified that lead to recommendations for future analysis of enhancements to rules and procedures. The recommendations from PJM's Learning Team's sessions on Winter Storm Elliott are contained in this report. The recommendations are then tracked through the HP&OE program until they are resolved.

Organization of This Report

This report outlines the operational preparations that PJM takes in advance of winter generally, and took for Winter Storm Elliott during the Dec. 23–25 holiday weekend specifically, including emergency procedures, communications with members and forecasting. It documents the operating conditions PJM operators faced and the actions they took, and it details the working of the PJM markets just before and during the storm. The Conclusion summarizes the processes and forums that will be used to act on the set of recommendations. For definitions of industry terms, consult the PJM Glossary on PJM.com.

Advance Preparations

Each year, PJM performs winter readiness assessments and exercises in advance of the cold weather months. These assessments include power flow analyses that simulate potential conditions on the power system for expected and extreme winter conditions, as well as a capacity "waterfall chart" to determine if adequate capacity is expected to be available based on various stress cases. This analysis is known as the Winter Operations Assessment Task Force Study.

In 2021, in light of the severe cold weather issues experienced in Texas during February 2021, PJM initiated an analysis that resulted in numerous additional improvements to its winter preparedness efforts. Those improvements included approving rules to assist Transmission Owners (TOs) in identifying and prioritizing service to critical facilities in emergencies, prohibiting Load Management programs from including any critical gas infrastructure, further improving information sharing with the natural gas industry, and confirming that TOs were prepared to rotate outages if load shedding was required.

PJM also collects data on generating resource fuel inventory, supply and delivery characteristics, emissions limitations, and minimum operating temperatures via the Seasonal Fuel Inventory and Emissions Data Request (PJM Manual 14D, Section 7.35) and also via Periodic Fuel and Emissions Data Requests issued as needed throughout the season. Furthermore, PJM validates that Generation Owners have adequately prepared for winter by requiring that they confirm they have completed the Cold Weather Preparation Guideline and Checklist.

Also, as a result of increasing supply chain risks to fuel deliveries, PJM initiated a weekly fuel and non-fuel consumables data request for all generators that utilize coal or oil as their primary or backup fuel. Capturing this data more frequently allows PJM to better understand any fuel supply, supply chain or transportation issues that could impact generators. Due to the continued concern with supply chain issues, the practice was extended through all of 2022, including the winter of 2022. Current system conditions do not necessitate this weekly data request but will be re-initiated, if necessary. These rule changes provided better visibility into generators' supply of fuels and other material critical to their operation and enhance the flexibility those generators need to rebuild their supplies when facing shortfalls beyond their control. The data requests did not identify any issues.

As described above, PJM prepares extensively for the peak winter season, including the following key annual activities:

- PJM Winter Operations Assessment Task Force Study
- Generation Resource Cold Weather Preparation Guideline and Checklist
- Cold Weather Resource Operational Exercise
- Pre-Winter Emergency Procedures Drill
- PJM Winter Readiness Meeting

This section details PJM's processes leading up to the storm, including regular winter preparations, issuing Cold Weather Advisories and Cold Weather Alerts, and other activities taken during the week of Dec. 18 in advance of Dec. 23 and Dec. 24.

PJM Winter Operations Seasonal Study

The PJM Operations Assessment Task Force (OATF) consists of representatives from PJM and PJM Transmission Owners. This team, under the direction of PJM, conducts seasonal studies for the summer and winter periods. Each

study analyzes the PJM system with the transmission and generation configuration approximating the expected conditions for that study period.

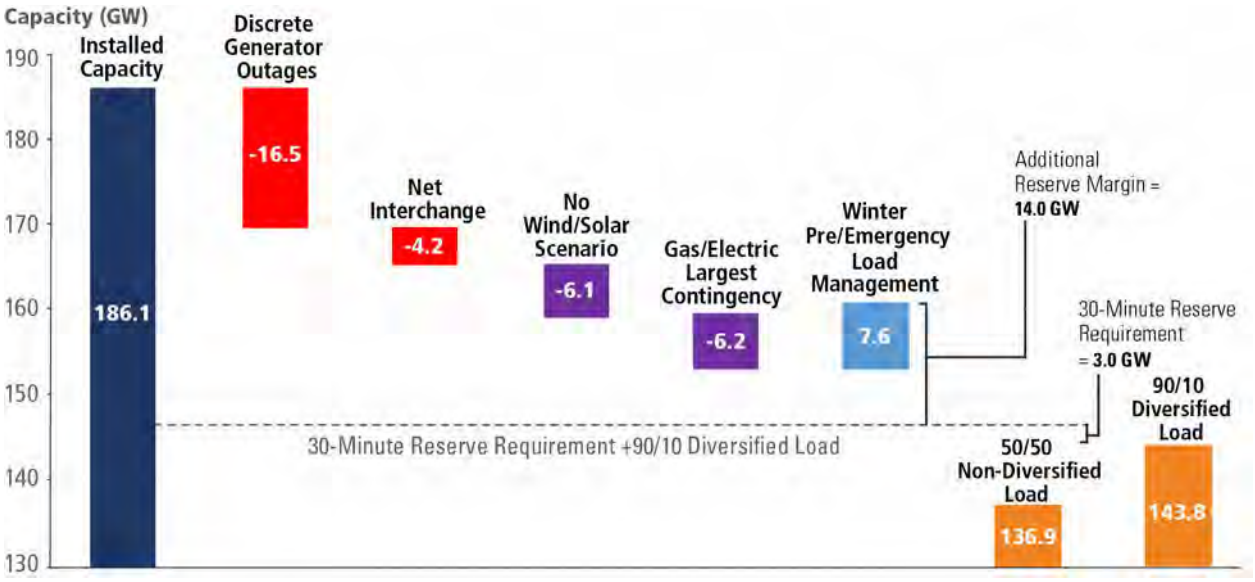
The study conditions include forecasted demand based on forecast weather and estimated outages, as well as a series of more extreme scenarios, including, but not limited to:

- External contingencies that could impact PJM reliability
- The loss of more than one bulk electric system (BES) element (N-1-1 relay trip conditions)
- A Maximum-Credible Contingency Analysis (e.g., loss of a substation, loss of multiple lines in a common right of way)
- An import capability analysis
- An extreme (90/10) load forecast study
- A solar and wind generation sensitivity study
- A gas pipeline disruption study

The results of this analysis indicated that there was sufficient generation for the 2022/2023 winter period to meet the demand under all studied conditions. The process for conducting the OATF study is documented in PJM Manual 38, Operations Planning, Attachment A.

As shown in Figure 1, PJM projected that more than adequate capacity should have been available for the 2022/2023 winter period.

Figure 1. Projected Capacity for 2022/2023 Winter Period



The OATF study is reviewed at the System Operations Subcommittee (SOS) and the Operating Committee (OC).

Generation Resource Operational Exercise

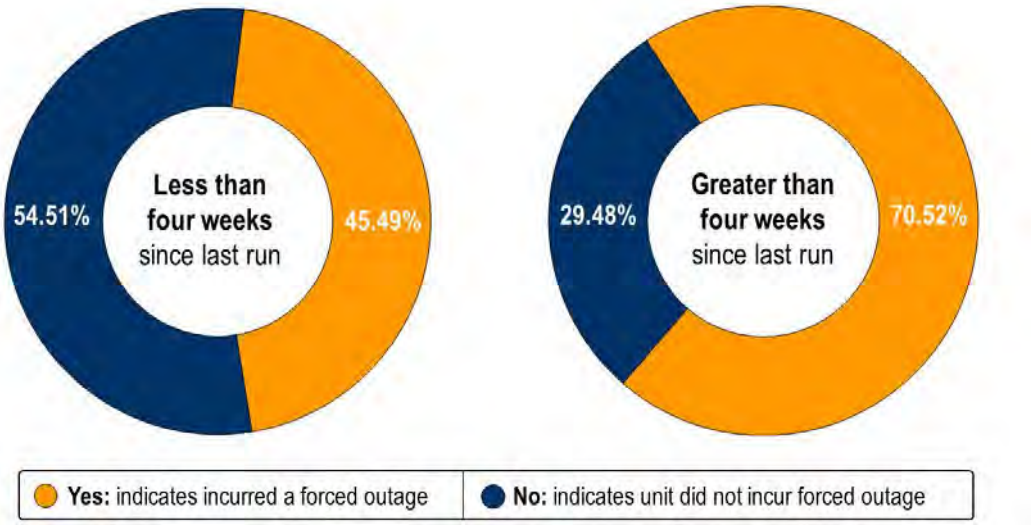
Following the 2014 Polar Vortex, PJM made several changes to its Cold Weather Operating Procedures, including establishing a Generation Resource Operational Exercise Program and a Generation Resource Cold Weather Checklist. The Generation Resource Operations Exercise Program is intended to enhance unit performance during cold weather operations and encourage generating units to be prepared for extreme cold weather and can start and run on alternate fuels, if necessary. The exercise assists in the identification and correction of start-up and fuel-switching problems (PJM Manual 14D, Section 7.5).

PJM also recommends that Generation Owners conduct an operational exercise prior to the onset of cold weather to validate a unit's cold weather operations. Specifically, PJM recommends that Generation Owners self-schedule any of their resources that have not operated in the eight weeks leading up to Dec. 1 to determine whether they are capable of reliably operating on both primary and alternate fuel and responding to PJM's dispatch instructions. Generation Owners are requested to submit an informational eDART ticket with a cause of "Cold Weather Preparation Exercise" to document that the generation resource has been scheduled to operate under the cold weather operational exercise.

The charts in Figure 2 present the forced outage rates during Elliott for units that had not run in the weeks leading up to the event. A four-week time period was used as the cutoff for the performance analysis. Those units that had not run in more than four weeks had higher forced outage rates. This data demonstrates that generators that had run in the few weeks prior to Winter Storm Elliott performed better than those that did not. As a result, PJM believes consideration should be given to making this currently recommended exercise a requirement.

When reviewing generator performance for units that did not operate for four weeks prior to Winter Storm Elliott, 70.5% of units incurred a forced outage during the event. This data supports continuing or expanding the Generation Resource Operational Exercise described in PJM Manual 14D, Section 7.5.1, which is currently recommended, but not required for Generation Owners to perform.

Figure 2. Forced Outages Versus Last Run Time



Generation Resource Cold Weather Preparation Checklist

Similarly, the Generation Resource Cold Weather Checklist (presented in PJM Manual 14D, Section 7.5 and Attachment N), or a similar one developed and maintained by the Generation Owner, should be used annually prior to the local

National Oceanic and Atmospheric Administration (NOAA) first frost date to prepare its generation resources for extreme cold weather event operations.

This checklist includes verification by Generation Owners that they have performed everything from increasing staffing for weather emergencies to performing required maintenance activities to prepare equipment for winter conditions. This checklist was first developed and issued to Generation Owners in 2014 and is updated annually as new industry lessons learned are published by NERC and others. For this winter, the checklist was updated to require information about a generating unit's cold weather operating limits. This was added as a result of the lessons learned from Winter Storm Uri.

The checklist identifies and prioritizes components, systems and other areas of vulnerability that may experience freezing problems or other cold weather operational issues such as safety staffing, equipment preparation, fuel preparation and environmental preparation; as well notes the actions to be taken when cold weather is forecast and actions during cold weather. Between Nov. 1 and Dec. 15 of each year, the Generation Owner is required to verify via eDART that the represented generation resources have completed the items on the checklist, or a substantially equivalent one developed by the Generation Owner. Ahead of Winter Storm Elliott, 99% of the generation resource owners in the PJM region verified that they completed the items on the Generation Resource Cold Weather Preparation Checklist or equivalent.

Table 1 summarizes the Cold Weather Checklist responses:

Table 1. Cold Weather Checklist Response Summary 2022

	Unit Count	Installed Capacity (MW)
Yes – Using Generation Owner Equivalent Guideline and Checklist	1,043	179,332
Yes – Using PJM Guideline and Checklist	270	16,974
No	52	1,262
No Response	37	238

The Cold Weather Checklist is discussed in the System Operations Subcommittee (SOS), Operating Committee (OC) and Market Reliability Committee (MRC). Additional information on generation performance is presented in the Operating Day section of this report.

Transmission Outage Deferrals

Transmission outage deferrals are an approved measure to promote the ability to transfer power across the RTO and promote an abundance of caution to be as prepared as possible. When PJM issues a Cold Weather Alert, PJM recalls/cancels non-critical transmission maintenance outages. Specifically, the following transmission outages were deferred or returned to service early:

- BLACKOAK-HATFIELD (eDART # 1053409 12/19 – 12/22) outage request was denied due to a conflict and cold weather.
- Two major outages returned to service early on Dec. 23. PJM was in close coordination with the TOs for the return of Mt. Storm-Valley 500 kV and the Malizewski-Marysville 765 kV lines.

Due to emergency procedures and multiple day-ahead outage approval processes, these lines were requested to be in service for Dec. 23.

Cold Weather Advisory

In advance of the mandatory North American Electric Reliability Corporation (NERC)[1] Winterization Standard becoming effective on April 1, 2023, PJM established the Cold Weather Advisory. A Cold Weather Advisory provides an early notice that forecast temperatures may call for a Cold Weather Alert. The early notification of an Advisory is intended to provide PJM members ample time to gather information required by NERC standards EOP-011, Emergency Preparedness and Operations, IRO-010 RC Data Specification and Collection, and TOP-003 Operational Reliability Data. Members are to take any necessary precautions to prepare generating facilities for cold weather operations. PJM attempts to issue the advisory as far in advance as possible, typically within three to five days, but given fluctuating and changing weather forecasts, advisories could be issued up to 24 hours in advance.

Members are expected to perform the following actions upon the issuance of a Cold Weather Advisory:

- Prepare to take freeze protection actions, such as erecting temporary windbreaks or shelters, positioning heaters, verifying heat trace systems, or draining equipment prone to freezing.
- Review weather forecasts to determine any forecasted operational changes and notify PJM of any changes.
- Update Markets Gateway by entering unit-specific operation limitations associated with cold weather preparedness, including the following limitations:
  - Generator capability and availability
  - Fuel supply and inventory concerns
  - Fuel switching capabilities
  - Environmental constraints
  - Generating unit minimums (design temperature, historical operating temperature or current cold weather performance temperature as determined by an engineering analysis)

PJM conducted a Cold Weather Advisory drill on Dec. 16, 2022. In advance of the drill at the December OC and the SOS meetings, PJM reviewed the objective of the upcoming drill and the expected member actions to be performed during the drill.[2]

Pre-Winter Emergency Procedures Drill

Pursuant to PJM Manual 13, PJM conducts emergency procedure drills prior to every summer and winter that include PJM, Generation Owners and Transmission Owners, and are focused on capacity shortage events. The drill encourages all entities to be familiar with the required actions and communications required for each emergency procedure, up to and including load shed action, as specified in PJM Manual 13, Emergency Operations.

On Nov. 3, 2022, PJM conducted the 2022 Winter Emergency Procedures Drill, testing established procedures for capacity shortages in accordance with conservative operations. Participants included PJM Operations, Dispatch staff and personnel from PJM Corporate Communications/State Government Policy, Local Control Centers and Market Operations Centers.

[1] NERC is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. NERC develops and enforces NERC Reliability Standards, which define the reliability requirements for planning and operating the North American bulk power system.
[2] Cold Weather Advisory Process, PJM System Operations Subcommittee, Dec. 2, 2022.

The following emergency procedures were implemented in the simulation stage of the drill: Cold Weather Alert, Low Voltage Alert, Maximum Generation Emergency Alert, Unit Startup Notification Alert, Primary Reserve Alert, and a Voltage Reduction Alert. All emergency procedure warnings and actions were issued as part of the drill to encourage participants to properly notify government agencies and to exercise internal communications for each member company.

Information about the drill scenario is contained in a packet sent to external participants and in a script for PJM staff. PJM also offers an eLearning module each year in support of the drill. This online training course, available via the PJM Learning Management System on the PJM website, provides an overview of the emergency procedures that participants may encounter during the drill exercise.

The plans for the drill are reviewed at the Dispatcher Training Subcommittee (DTS), the SOS and the OC.

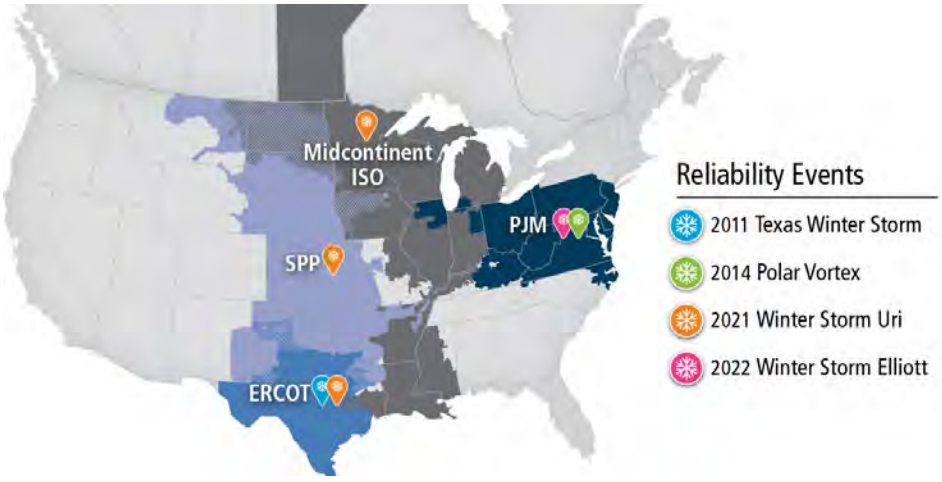
Reliability Analysis Used in the Capacity Market

PJM performs several reliability studies that inform the clearing of the capacity market.

- Installed Reserve Margin (IRM) Study – Study run by PJM that determines the amount of reserves beyond the peak load necessary to maintain a Loss of Load Expectation (LOLE) of one event in 10 years
- Capacity Emergency Transfer Objective (CETO)/Capacity Emergency Transfer Limit (CETL) Studies – Studies run by PJM to determine if the transmission system is capable of delivering enough energy to Locational Deliverability Areas (LDA) to meet reliability targets
- Accreditation – Calculation performed by PJM to determine how much capacity a resource can sell as a percentage of its nameplate capacity

These studies all assume that the reliability risk PJM may face aligns with peak loads, which typically occur in the summer. The assumption behind coinciding reliability risk with peak loads is that if enough capacity is scheduled for the expected peak load, it will also be sufficient for all other hours in the year. However, recent history in PJM and other RTO/ISOs indicates that reliability risk also occurs outside of the peak load and may be trending away from the peak to something else. Figure 3 presents the recent reliability events outside the peak load periods.

Figure 3. Recent Reliability Events



Finding the causes behind these events is important to determine how PJM's reliability risk modeling may need to be adjusted to better capture the likelihood, severity and patterns of risk. PJM and stakeholders are already working on identifying and modeling these new risks.

PJM Winter Readiness Meeting

PJM also conducts an internal, cross-divisional meeting each fall to review each PJM department's preparedness for winter operations. It includes discussions and presentations by PJM's Operations, Markets and Planning divisions. The following topics are addressed in these cross-divisional meetings:

- Weather and load forecast outlook
- Review of winter OATF study (including base case parameters, peak load study results and sensitivity studies)
- Potential gas/electric concerns for upcoming peak period
- Interconnection projects update (including key project upgrades and delays, generation additions and retirements, review of additional reactive resources coming online, generation preparation, outage and performance updates)
- Review of NERC Standard FAC-014, Requirement 6, list of multiple facility contingencies (if any) that result in stability limitations
- Review of any specific concerns or questions from PJM's Dispatch, Reliability Engineering and Markets personnel

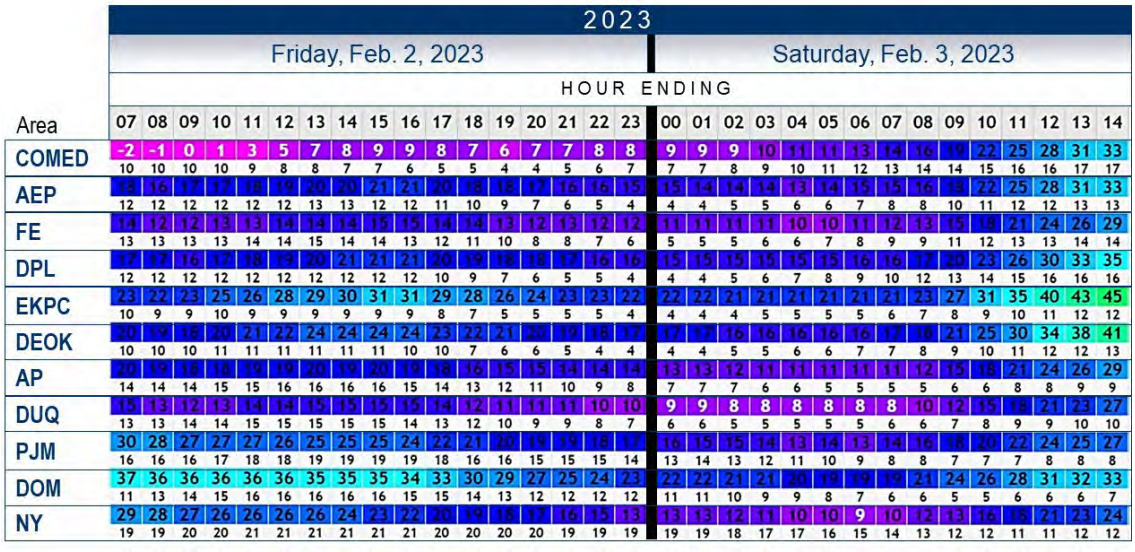
Preparations Ahead of Winter Storm Elliott

In preparation for Winter Storm Elliott, PJM performed the established load forecast planning process, issued Advisories and Alerts, and coordinated activities with both the adjacent systems and the natural gas industry. PJM also planned for the commitment of resources needed to meet the Dec. 23 and Dec. 24 operating days' demand and reserve requirements.

Load Forecast Planning Process

PJM uses a vendor tool to view forecast weather conditions up to 14 days out. At six days out, PJM begins to receive hourly weather forecast data from three separate vendors for 28 weather stations dispersed throughout the PJM region. This data is visualized in a heat map tool used by PJM system operators and engineers. Figure 4 presents a sample of the heat map tool for Feb. 2 and Feb. 3, 2023. This is an example of a wintertime heat map and does not present the actual temperatures from Winter Storm Elliott.

Figure 4. PJM Heat Map Tool Example



PJM's forecast team and Dispatch leadership also receive detailed weather forecast reports from vendors at various time horizons warning of extreme weather conditions. The PJM forecast team reviews and synthesizes data from all of these sources and delivers daily verbal reports on upcoming weather at the daily Dispatch morning meeting. The PJM forecast team supplements this communication with email summaries and dialogue with PJM system operators.

The load forecast is first performed six days out using a performance-weighted average of the three weather vendor forecasts as inputs. A suite of models trained on three years of historical data generate separate load forecasts that are then combined into one ensemble forecast using another weighted average system. Both the ensemble forecast and individual model forecasts are updated each hour as load actuals and updated weather forecast data is received.

To create the next-day load forecast, PJM Operations support staff reviews weather conditions and recent load forecast performance each day, then integrates this information with known strengths, weaknesses and biases of each model to identify adjustments to the forecast. The support staff then communicates the recommended adjustments to Dispatch, and the two groups collaborate to finalize the forecast. Extra attention is given to holidays, where the models have increased forecast error due to closures of schools and businesses and altered human behavior. Starting at least two days out, the team analyzes model error and weather conditions from that holiday in previous years, then calculates adjustments to counter repeated model biases.

The relationship between load and temperature can change with time, as behind-the-meter solar, data centers, and new types of appliances are connected to the system. PJM monitors these changes, continually evaluates load patterns to assess impacts, and retrains and enhances the models, as needed. Staff analyzed electric heating statistics from the Energy Information Administration and determined that there does not appear to be a significant transition to electric heating in the PJM footprint that would have caused under-forecasting of winter load.

The PJM Operations staff conducted the following load forecasting activities in advance of the Winter Storm Elliott event:

Date	PJM Team	Activity
Mon. **Dec. 19:**	Forecast	• Alerted PJM Dispatch of upcoming blizzard conditions and extreme cold via email • Met to discuss holiday forecasts (with extra support from other staff)
Tues.–Fri. **Dec. 20–23**	Forecast	• Delivered verbal updates on approaching storm risks at the daily Dispatch morning meeting
Wed.–Fri. **Dec. 21–23**	Forecast	• Provided on-site support, meeting daily with dispatchers to support adjusting the forecast
Thurs. **Dec. 22**	Dispatch + Forecast	• Collaborated on the load forecast for Dec. 23, increasing the peak forecast to 127,000 MW from the original forecast of 124,600 MW
	Forecast	• Created the preliminary forecast for Dec. 24 with a maximum peak of 124,000 MW
Fri. **Dec. 23**	Dispatch + Forecast	• Collaborated on load forecast for Dec. 24

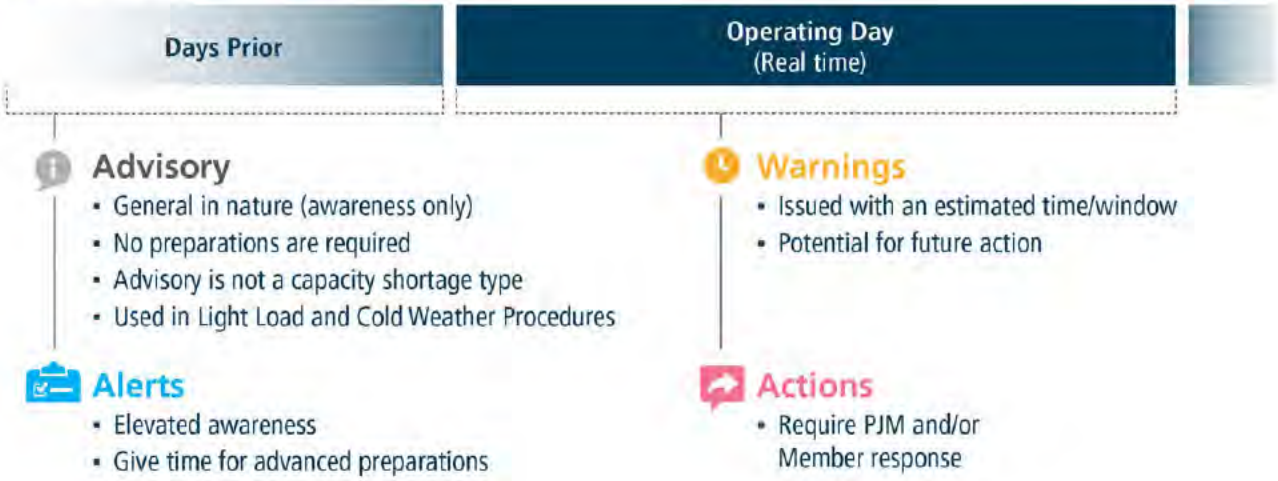
Date	PJM Team	Activity
	Forecast	• At the time of the forecast's creation, the actual load on Dec. 23 was coming in lower than the forecast. When the team began assessing the forecast for Dec. 24, they observed that the actual load was coming in lower than the previous day's forecast. This led the team to determine that holiday impacts were causing the load to come in low and that effect would persist into Dec. 24. • The PJM forecast team created the preliminary load forecast for Dec. 26.
Sat.–Mon. Dec. 24–26	Forecast	• Continued to provide load forecasting guidance and support to Dispatch

Emergency Procedures Issued and Actions Taken in Advance of Operating Day

PJM is responsible for determining and declaring that an emergency is expected to exist, exists or has ceased to exist in any part of the PJM RTO or in any other Control Area that is interconnected directly or indirectly with the PJM RTO. PJM directs the operations of the PJM members, as necessary, to manage, allocate or alleviate an emergency. PJM also is responsible for transferring energy on the PJM members' behalf to resolve an emergency, as well as executing agreements with other Control Areas interconnected with the PJM RTO for the mutual provision of service to meet an emergency.

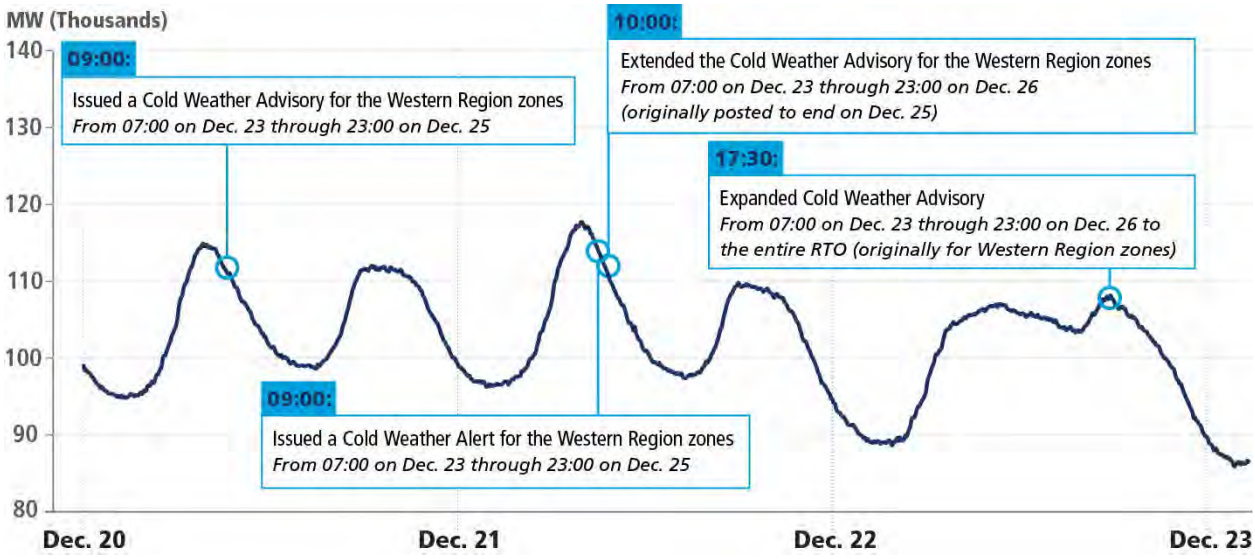
As described in PJM Manual 13, Section 2.3, PJM has established three emergency procedure levels for capacity shortages, as well as an advisory level.

Figure 5. Emergency Procedure Levels



To maximize PJM's ability to operate reliably during periods of extreme and/or prolonged severe weather conditions, procedures are necessary to keep all affected system personnel aware of the forecast and/or actual status of the system and to promote the maximum levels of resource availability are attained. PJM issued both advisories and alerts in the days leading up to Dec. 23 and Dec. 24, as presented in Figure 6:

Figure 6. Cold Weather Alerts and Advisories for Dec. 23 and 24



PJM initiated the following steps in advance of the Dec. 23 and Dec. 24 operating days:

- At 09:00 on Dec. 20, PJM issued a Cold Weather Advisory for the Western Region zones from 07:00 on Dec. 23 through 23:00 on Dec. 25. Members are to take any necessary precautions to prepare generating facilities for cold weather operations, including the following actions:
- Erecting temporary windbreaks or shelters, positioning heaters, verifying heat trace systems, or draining equipment prone to freezing
- Updating Markets Gateway by entering unit-specific operating limitations associated with cold weather preparedness (i.e., generator capability and availability, fuel supply and inventory concerns, environmental constraints)
- At 09:00 on Dec. 21, PJM issued a Cold Weather Alert for the Western Region zones from 07:00 on Dec. 23 through 23:00 on Dec. 25. At 10:00 on Dec. 21, PJM also extended the Cold Weather Advisory for the Western Region zones from 07:00 on Dec. 23 through 23:00 on Dec. 26. The purpose of a Cold Weather Alert is to prepare personnel and facilities for expected extreme cold weather conditions. PJM generally issues a Cold Weather Alert when the forecast weather conditions approach minimum or actual temperatures of 10 degrees Fahrenheit or below. PJM can initiate a Cold Weather Alert at higher temperatures if PJM anticipates increased winds or if PJM projects a portion of gas-fired capacity is unable to obtain spot market gas during load pick-up periods. When a Cold Weather Alert is issued, members are to perform the following actions:
- Update their unit parameters, including the Start-up and Notification, Min Run Time, Max Run Time, Eco Min, Eco Max, etc., in Markets Gateway.

- Report to PJM Dispatch any resource limited facilities, as they occur, via Markets Gateway.
- Determine whether alternate fuel will be made available to PJM for dispatch. If made available, any known alternate fuel resource limitations will be communicated via Markets.
- Based on direction received from PJM, call in or schedule personnel in sufficient time to ensure that all combustion turbines and diesel generators that are expected to operate are started and available for loading when needed for the morning pick up.
- At 17:30 on Dec. 22, PJM expanded its Cold Weather Advisory from 07:00 on Dec. 24 through 23:00 on Dec. 26 for the entire RTO. Given the expected weather, PJM was very prudent in developing the operating plans for Dec. 23, as presented throughout this section.

Figure 7 presents the expected member actions for the Advisories and Alerts that were issued in advance of the Dec. 23 and Dec. 24 operating days:

Figure 7. Expected Member Actions for Advisories and Alerts for Dec. 23 and Dec. 24

Dec. 20, 2022

Cold Weather Advisory for Western Region From Dec. 23–26 (Later Expanded to Entire RTO)

- Prepare to take freeze-protection actions, such as erecting temporary windbreaks or shelters, positioning heaters, verifying heat trace systems, or draining equipment prone to freezing.
- Review weather forecasts, determine any forecasted operational changes, and notify PJM of any changes.
- Members are to update PJM with operation limitations associated with cold weather preparedness. Operating limitations include: generator capability and availability, fuel supply and inventory concerns, fuel switching capabilities, environmental constraints, generating unit minimums.

Dec. 21, 2022

Cold Weather Alert Issued for the Western Region for Dec. 23–26 (Later Expanded to Entire RTO)

- Generation dispatchers review fuel supply/delivery schedules in anticipation of greater-than-normal operation of units.
- Generation dispatchers monitor and report projected fuel limitations to PJM dispatcher and update the unit Max Run field in Markets Gateway if less than 24 hours of run time remaining.
- Generation dispatchers contact PJM Dispatch if it is anticipated that spot market gas is unavailable, resulting in unavailability of bid-in generation.

Coordination With Adjacent Systems

In addition to its internal preparations for peak conditions, PJM also coordinates with adjacent systems prior to possible emergency conditions. This coordination can occur through the regional reliability entity responsible for compliance with NERC standards in that region or with the neighboring entity itself.

PJM participates in a daily morning conference call with adjacent systems at 03:30 during which peak load estimates, reserve requirements and estimated loads are discussed. Participants on the call include Tennessee Valley Authority (TVA), Virginia-Carolina (VACAR), Midcontinent Independent System Operator (MISO), PJM and Florida Reliability Coordinating Council (FRCC). There is also a call at 05:00 that PJM conducts with NYISO and a daily call at 08:00 with MISO. Load projections, reserves and anticipated daily challenges are discussed on these calls as well.

During the aforementioned calls, expected conditions were reviewed, and load projections and expected reserve quantities were shared. Members of the Northeast Power Coordinating Council (NPCC), the regional reliability entity for New York ISO (NYISO), ISO New England (ISO-NE), Independent Electricity System Operator (IESO), the Canadian Maritimes, and New Brunswick Power, were anticipating large temperature drops from the incoming arctic air mass and temperatures to be in the single digits. Council members coordinated anticipated operating conditions from multiple transmission facilities that tripped from previous ice storms that had impacted Canadian entities. These transmission facilities limited the entities' ability to export energy to adjacent areas. Members of the NPCC were anticipating tight operating conditions from the reduction of imports and anticipated higher loads from the incoming arctic air mass and agreed to conduct further calls and coordination throughout the duration of the storm.

PJM also met with SERC Reliability Corporation members to review expected conditions and share information to prepare for the event. SERC members were in close coordination throughout the event as well. The FRCC issued conservative operations on Friday, Dec. 23. TVA was managing capacity concerns as they lost units over the midnight period from extreme cold conditions. TVA declared conservative operations on Dec. 23 and EEAs up to an EEA 3 at 05:12 on Dec. 23. Southwest Power Pool (SPP) issued a cold weather advisory along with a resource advisory. On Dec. 23, SPP set a new winter peak of 47, 214 MW. Its previous winter peak was 43,661 MW.

PJM met with MISO to prepare for the event. MISO was monitoring the Arctic air mass forecasted to move into the footprint beginning Dec. 21 and Dec. 22 that was pushing temperatures below normal. MISO was not anticipating any capacity or reliability concerns.

MISO's Outage Coordination Team was evaluating all planned transmission outages, in the event some may need to be delayed due to the cold temperatures. MISO continued to closely monitor the numerous gas pipelines' cold weather notices, and Operational Flow Orders (OFOs) for any potential impact to generation. MISO declared a maximum generation warning for its southern region on Dec. 23 from 09:15 until 13:00 as well as for its entire footprint from 17:30 to 22:00 EST on Dec. 23. PJM had two coordination calls with MISO on each day of the event to exchange information, one at 03:30 and one at 08:00.

The Southern Company Balancing Authority declared an EEA 1 at 01:09 and EEA 2 at 05:33 due to lower-than-optimal generation reserves. The Southern Company Balancing Authority received 1,000 MW of emergency energy from Florida Power & Light and 100 MW of emergency energy from MISO.

As described later in this report, PJM coordinated extensively with TVA throughout the event to coordinate interchange transactions and system conditions. PJM ran studies to simulate additional interchange being exported to its neighbors. PJM will continue to participate in seasonal assessments and preparedness with its neighbors and seek opportunities to enhance coordination with neighbors.

Coordination With Natural Gas Industry

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

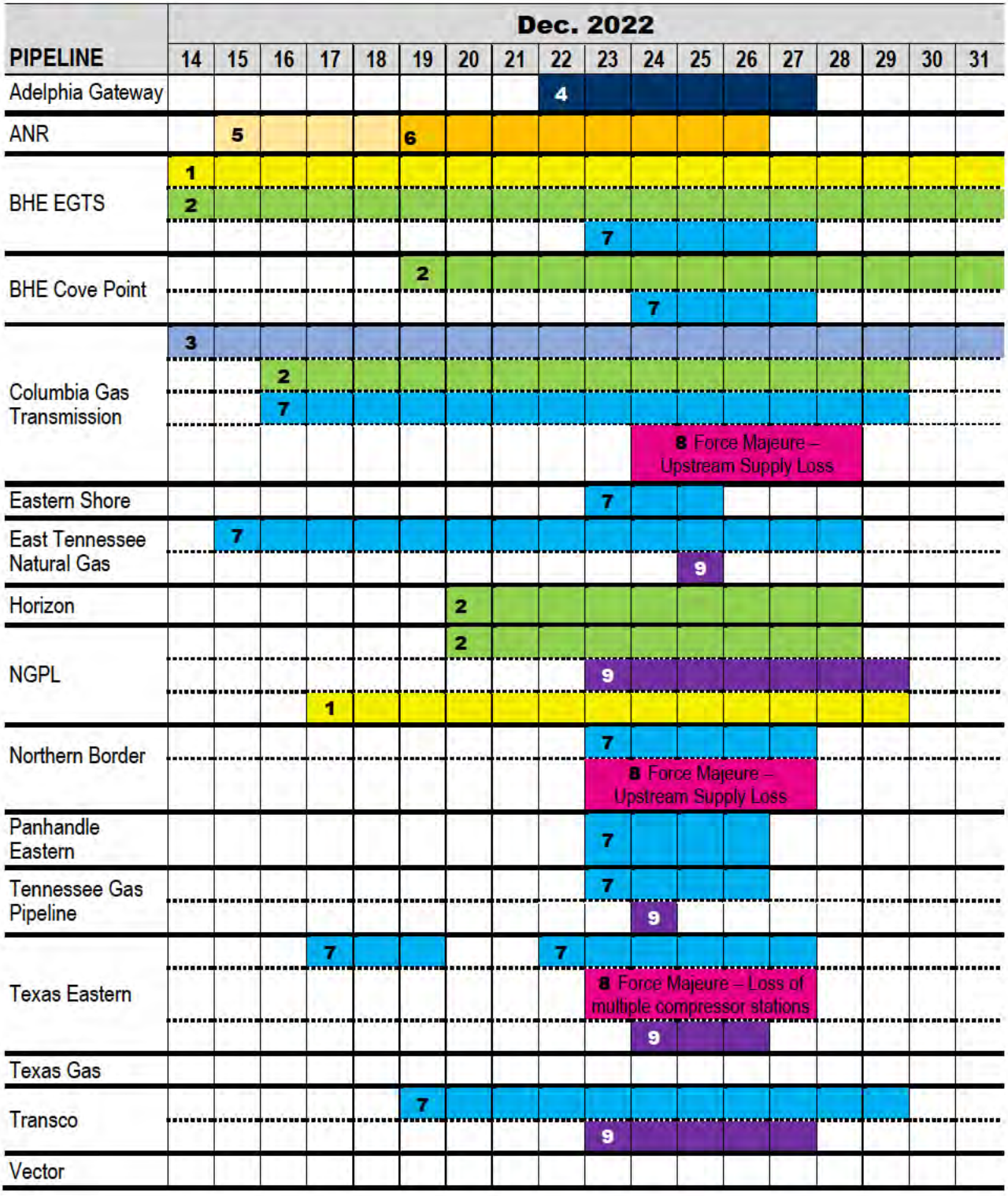
In addition to daily team meetings to review pipeline conditions and operational impacts, the PJM Gas-Electric Coordination Team conducts weekly operational calls during the winter months (November through March) with all of the major interstate natural gas pipelines within the PJM service territory. These interstate pipelines serve generation resources directly and also serve local gas distribution companies (LDCs), which in turn serve a smaller subset of PJM generators behind the LDC citygates. The purpose of these calls is to assess mutual system conditions. This includes reviewing load forecasts for both the electric and gas systems, any system outages that might impact service to

generators, active and pending pipeline capacity restrictions, and any gas generation pipeline nomination anomalies. As a result of FERC's issuance of Order 787, PJM established a Memorandum of Understanding (MOU) with nine of the major pipelines in 2015 and has individual agreements in place with the majority of pipelines and multiple LDCs. During critical gas pipeline capacity-constrained periods, LDCs have the ability to interrupt gas supply to certain gas-fired generators that are served behind the LDC citygates as generators are served at a lower priority level than core residential customers that are considered human needs customers. As such, it is important for PJM to understand when those generators may be interrupted, and for those generators subject to interruption to effectively communicate that information to PJM in a timely manner.

With respect to gas-electric coordination activities leading up to Winter Storm Elliott, these calls with the pipelines began early in the week immediately preceding the impacts of Elliott, and at that point, most of the pipelines had provided notification on their electronic bulletin boards announcing various cold weather alerts and system restrictions. This was in the form of OFOs and Ratable Take Requirements. OFOs are issued to enforce daily balancing rules requiring customer imbalances (difference between nominated gas volume and burned gas volume) to stay within a certain tolerance percentage. Ratable Take Requirements mandate that customers deliver and burn their gas at uniform hourly rates. Pipelines take these actions to mitigate large swings in system pressures. These restrictions gradually increased throughout the week, and by Friday morning, all pipelines had active notices of varying degrees. Operationally, all pipelines appeared to be well prepared for the cold, and even on the morning of Friday, Dec. 23, reports from the pipelines indicated that line pack was high, systems were ready and that load had not yet begun to pick up significantly, particularly in eastern zones.

Figure 8 provides a summary of the pipeline restrictions that were in place from Dec. 14 through Dec. 31.

Figure 8. Interstate/Infrastructure Pipeline Restrictions



	Pipeline Notice
1	**Restrictions on Non-Firm Contracts** Customers with interruptible transportation contracts at higher risk of not being able to schedule adequate pipeline capacity
2	**Ratable Take Requirement** Pipeline requiring customers to supply and burn gas at uniform hourly rates to avoid excessive pressure fluctuations
3	**Critical Day** (Transport Deliveries/Storage Withdrawals) Pipeline requiring customers to stay within their transportation and storage contractual requirements
4	**Action Alert** (Daily Balancing) Requires customers to ensure that their supply and demand is balanced at the end of each 24-hour gas day within the tolerances provided by the pipeline Tariff provisions
5	**Phase 1 Cold Weather Advisory** Alerting customers of pending cold temperatures and tightening system conditions
6	**Phase 2 Cold Weather Extreme Conditions** Requires customers to abide by their specific contract and rate provisions and to burn gas on a uniform hourly basis as their contracts direct; interruptible contracts at greater risk of having service cut
7	**Daily Balancing OFO** Requires customers to ensure that their supply and demand is balanced at the end of each 24-hour gas day within the tolerances provided by the pipeline Tariff provisions
8	**Force Majeure** Declared when there an event outside of the pipeline's control occurs that may render service unavailable to certain customers regardless of contractual arrangements (e.g., loss of compressor station)
9	**Loss of Upstream Supply** As a result of less gas coming into the pipeline due to upstream supply failures, pipelines provide notice that risk of downstream pressure loss and customer nomination cuts are increasing.

On the gas commodity supply side, nearly all of the natural gas consumed by generation in PJM originates in the Marcellus and Utica shale in the Appalachian region. Historically, loss of supply due to gas production well freeze-offs during cold snaps has not been as severe as compared to gas basins in the south central and southwestern United States. This was confirmed during outreach with a sample of producers after Winter Storm Uri in February 2021. While Uri did not have a major direct impact on PJM, there was a desire to get out ahead of the issues to determine if the supply losses experienced during Uri could occur in the Appalachian region. The feedback from those producers indicated that gas production and midstream processing and transport were much more hardened against cold temperatures compared to the same facilities in the south and southwest. Typical losses due to well freeze-off conditions range from around 2 to 3 Bcf (billion cubic feet) per day in the Appalachian region and this was the general assumption going into Elliott. In the end, the actual supply loss was closer to 10 Bcf, which significantly challenged the ability for natural gas-fired resources to procure fuel, likely leading to a portion of the outages on these resources.

It is important to note that while PJM coordinates with the natural gas industry prior to and during events such as Winter Storm Elliott, the tools used by PJM system operators to commit and dispatch resources relies on the availability and

offer data submitted for each generator. If the generator availability and offer data is not consistent with the resource's true capability, PJM operators are left with an inaccurate view of the true capability of the fleet.

Day-Ahead Market and Reliability Assessment Commitment Results

The PJM Energy Market consists of two markets: a Day-Ahead Market and a Real-Time Market. Two days prior to an operating day, PJM begins to set up the conditions, such as the expected outages and conditions for the operating day, in the model for the Day-Ahead Energy Market. (The two-settlement market mechanism is described in more detail in Appendix A.)

The Day-Ahead Market is cleared so that the cost to serve demand (physical and virtual) is minimized, while respecting the physical operating limits of the transmission system. Commitments in the Day-Ahead Market are financially binding on participants. Any differences between day-ahead commitments and what occurs in the operating day is addressed in the Real-Time Market. The PJM Day-Ahead Market utilizes the bid-in load from the Load Serving Entities, as well as virtual bids from Market Participants.

Capacity resources are required to offer into the Day-Ahead and Real-Time markets with accurate reporting of their availability and unit parameters, which include but are not limited to, start time, ramp rate, and minimum output and maximum output. In addition, resources can and do update their offers in both of these markets to reflect their actual fuel and operating costs.

For each operating day, PJM performs reliability analysis and develops an operating plan. PJM performs two reliability analyses a day ahead of the operating day. The first analysis, performed by the PJM reliability engineers, is an input into the PJM Day-Ahead Market performed prior to closing at 11:00. The second reliability analysis, called Reliability Assessment Commitment (RAC), is performed after the Day-Ahead Market clears and includes the commitments made in the Day-Ahead Market. After 16:15, PJM begins the RAC run, which commits adequate generation to meet the PJM forecasted demand plus reserves, while minimizing start-up and no-load cost. The focus of this commitment is reliability, and the objective is to minimize start-up and no-load costs for any additional resources that are committed. Using the most up-to-date weather forecast, load forecast, transmission facility and generator availability, and other information, PJM commits additional generation, if necessary, to satisfy both expected loads and the needed reserves for the operating day. This includes scheduling additional resources during the operating day that did not have a Day-Ahead Market commitment. PJM scheduled 4,411 MW of combustion turbines (CTs) between Dec. 23 and Dec. 24.

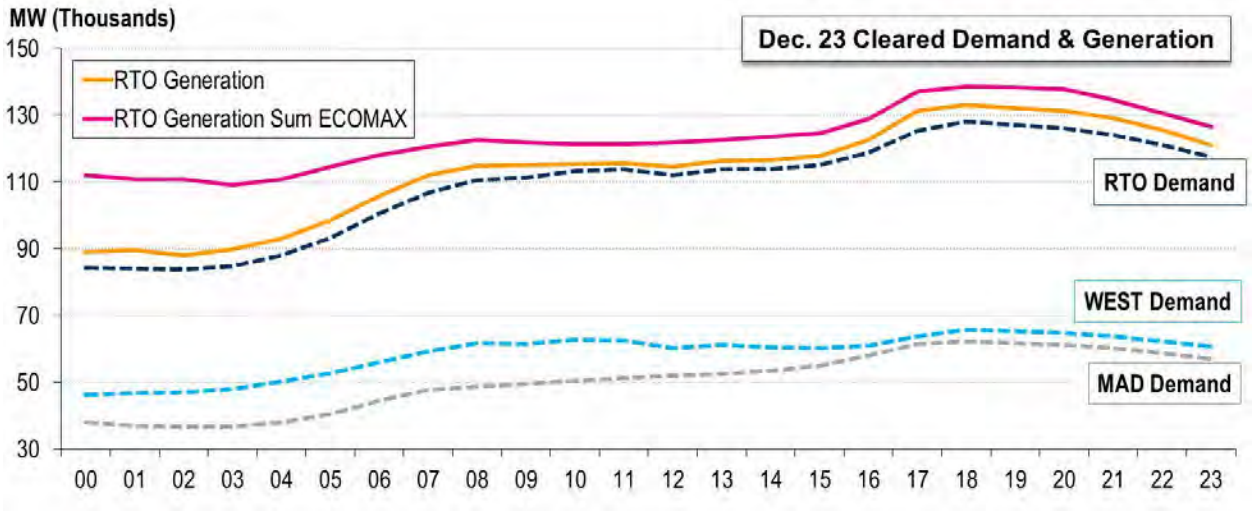
PJM also performs additional reliability analysis to confirm transmission facilities are operated within their equipment limits when committing generation. During severe winter weather events, PJM communicates extensively with both Generation Owners and gas pipeline operators to adequately understand the likelihood that natural gas-fueled generators are able to procure the gas needed to operate. PJM may perform additional resource commitment runs, as necessary, based on updated PJM load forecasts and updated resource availability information. It is important to note that these resource commitment runs use available offer data submitted into Markets Gateway by Generation Owner/operators. If the offer information is not accurate, the commitment results and operating plan PJM develops may be inadequate. Following these commitment runs, PJM sends out individual generation commitment updates to specific Generation Owners only.

The outcome of all of these processes is a set of resource commitments expected to be able to maintain reliability during the operating day.

Dec. 23

PJM's Dec. 23 operating day plan was prudent, given the expected. PJM scheduled the system such that almost 29,000 MW of reserve capacity was available to meet load and generation contingencies, and to support neighboring systems, according to the information submitted by Market Participants. Figure 9 presents the cleared day-ahead demand, and the generation committed to meet that demand, plus reserves for Dec. 23 operating day.

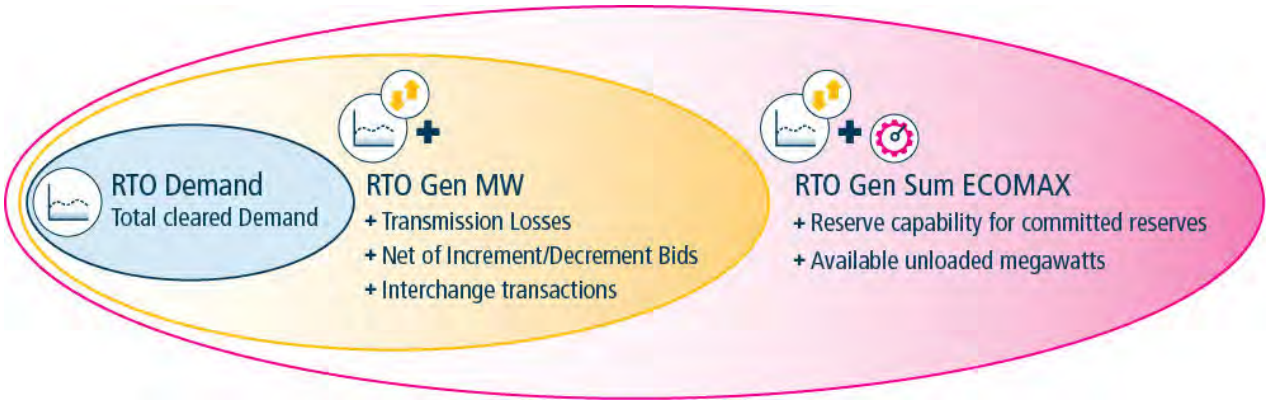
Figure 9. Dec. 23 Cleared Demand and Generation from Day-Ahead Market



In Figure 9:

- RTO Demand is the total cleared demand in the Day-Ahead Market, which includes fixed demand and cleared price-sensitive demand. The RTO Demand is not the same as the PJM Load Forecast.
- RTO Gen MW is the total generation megawatts loaded (or cleared) in the Day-Ahead Market. It includes all cleared generation. This value is greater than the RTO Demand because it accounts for transmission losses, the net of increment and decrement bids, and interchange transactions in or out of the PJM Balancing Authority.
- RTO Gen Sum ECOMAX is the total sum of all online generation resource's economic maximums committed in the Day-Ahead Market. This value is larger than the RTO Gen MW because it includes reserve capability for committed reserves and unloaded megawatts not explicitly needed in the clearing process but are available due to the mix of resources committed in the Day-Ahead Market.

Figure 10. Cleared Demand & Generation Representation



For the Dec. 23 operating day, the Day-Ahead Market committed 133,165 MW of generation for energy (yellow line in Figure 9), with 5,474 MW of unloaded generation (magenta line in Figure 9), including approximately 11,000 MW of combustion turbines (CTs) scheduled economically and 1,270 MW committed for reliability purposes to control constraints. PJM also scheduled an additional 3,168 MW in the RAC runs. In addition, there was another approximately 16,000 MW in CTs available for dispatch in real time that were not committed in the Day-Ahead Market.

Entering the operating day on Dec. 23, PJM had approximately 158,000 MW of operating capacity with a projected peak load of around 127,000 MW. Based on the Day-Ahead Market results, PJM did not anticipate the need to run a significant amount of additional CTs on Dec. 23 or Dec. 24. However, as more and more generating resources started to report their unavailability to PJM during the evening peak on Dec. 23 and through the early morning hours of Dec. 24, PJM Dispatch began scheduling additional CTs to come online.

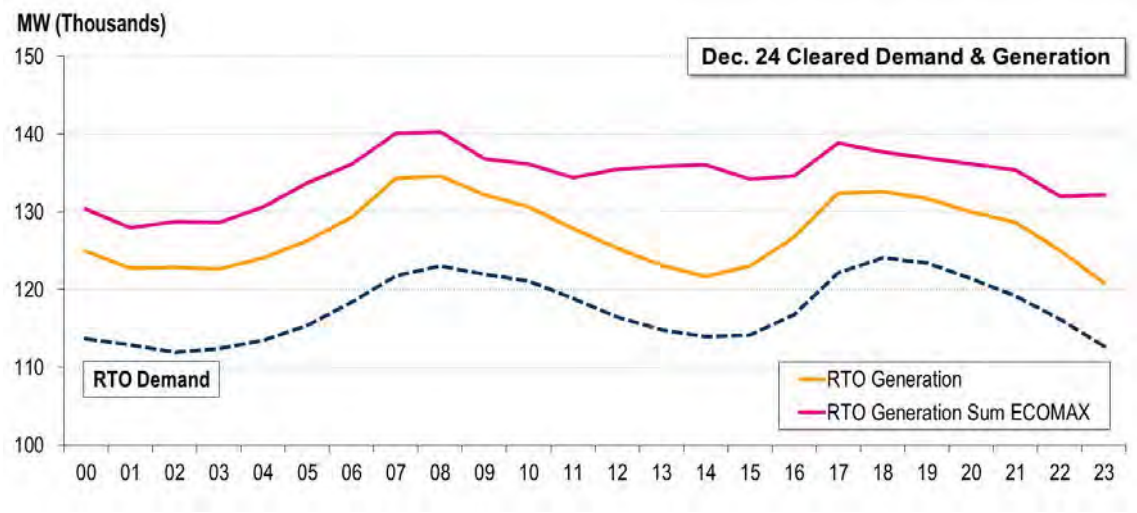
As early as Dec. 20, generation resource operating limitations and minimum operating, design or performance temperature were submitted to PJM in advance of the cold weather event after PJM declared a Cold Weather Advisory. All of the generator-submitted data was taken into consideration, with PJM forecasting a significant surplus of generation leading into the Dec. 23 operating day. This included accounting for a historical average of generator forced outages through cold weather events. As such, PJM did not declare a Unit Startup Notification Alert or commit any long lead generation or recall maintenance outages to meet capacity forecasts. As described in the Operating Day section of this report, in 92% of cases where generators failed to perform, PJM either had little or no notice, and very few resources provided updated parameters to reflect fuel supply constraints or other unit issues.

Dec. 24

Prior to the operating day of Dec. 24, PJM issued a Cold Weather Advisory on Dec. 20 for the period of Dec. 23 to 26. PJM then issued a Cold Weather Alert for the entire RTO on Dec. 23, effective for Dec. 24. The operating plan for Dec. 24 was updated based on operating conditions experienced on Dec. 23. Load forecasts were updated, and unit commitments' needs were updated based on generating resources that experienced forced outages throughout the day on Dec. 23.

Figure 11 presents the cleared day-ahead demand and committed generation to meet that demand, plus reserves for the Dec. 24 operating day.

Figure 11. Dec. 24 Cleared Demand & Generation from Day-Ahead Market



For Dec. 24, the Day-Ahead Market committed 134,615 MW of generation for energy (yellow line in Figure 11), with an additional 5,672 MW of unloaded generation (magenta line in Figure 11). PJM committed resources based on the RAC runs and for reliability. PJM also committed additional resources, based on unit availability and other parameters in Markets Gateway. In total, approximately 6,000 MW of additional capacity for Dec. 24 was committed, beyond what was committed in the Day-Ahead Market, to support the anticipated loads and reserve requirements. In addition, there were another 9,500 MW in CTs available for dispatch in real time, as communicated by generators to PJM. This results in a total of approximately 155,700 MW in operating capacity for Dec. 24.

PJM system operators knew that there was going to be uncertainty in the load forecast as a result of the extreme weather. In addition to accounting for weather and load uncertainty, PJM scheduled additional reserve resources in anticipation of generator failures. Generation failures often increase somewhat during bitter-cold conditions – recent history indicates on the order of 5% to 10%. On Dec. 24, several generating resources were committed in the Day-Ahead Market but were not available in the operating day due to forced outages. The decision was therefore made to operate prudently by scheduling additional reserves. Generation performance, including generation resources that were committed in the Day-Ahead Market but were not available in the operating day, is presented in the Operating Day section of the report.

Utilizing these commitments, as well as the generator parameters of units that did not have Day-Ahead Market commitments, but were reporting to PJM as available with short notice, PJM anticipated that approximately 155,700 MW of generation would be available for Dec. 24.

Operating Day

The Operating Day section of the report details the events and actions PJM initiated during the operating days of Dec. 23 and Dec. 24 to maintain reliability and not shed load. It describes the emergency procedures issued and actions taken, the public Call for Conservation, the Disturbance Control Standard event, as well as the generation and Demand Response performance, real-time interchange, and gas availability issues.

On Dec. 23 and Dec. 24, PJM remained reliable, was able to serve its customers, and was able to support neighboring areas to the south and minimize the amount of load shed in these external areas. PJM reliably met the demand on both

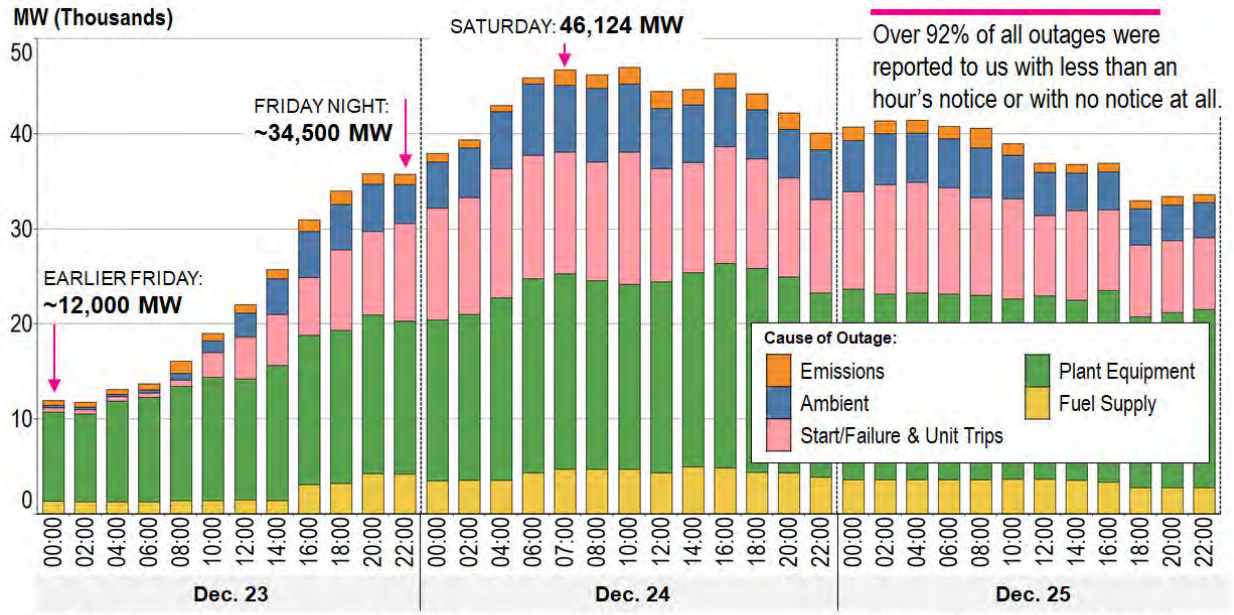
Dec. 23 and Dec. 24 by employing several emergency procedures and utilizing market signals to incent response from the supply and demand side resources. Although the 136,010[3] MW peak load on the evening of Dec. 23 was not one of PJM's top 10 peak winter load days, it essentially matched the forecasted 50/50 peak load for the 2022/2023 winter season (approximately 25,000 MW above an average winter day).

As described in the Advanced Planning section, going into the Dec. 23 operating day, PJM had over 158,000 MW of operating capacity with a projected peak load of around 127,000 MW, resulting in over 30,000 MW of reserves. Based on the Day-Ahead Market results, PJM did not anticipate the need to run a significant amount of additional generation on Dec. 23 or Dec. 24. However, as more and more generating resources started to report their unavailability to PJM during the evening peak on Dec. 23 and through the early morning hours of Dec. 24, PJM Dispatch began scheduling additional generators to come online.

Emergency Procedures Issued and Actions Taken During Dec. 23 and Dec. 24

As the extreme cold front moved into the PJM region throughout Dec. 23, the load shape looked more like a summer day, with a lower morning valley that ramped up throughout the day. Coincident with the increasing demand, PJM began experiencing rapidly increasing levels of forced generation outages, as shown in Figure 12. Additional information on generation performance is presented in later in this section.

Figure 12. Forced Outages by Cause



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

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

The conditions of Winter Storm Elliott led to PJM requesting the loading of Synchronized Reserve generation on five separate occasions during Dec. 23 and Dec. 24. Four of these events were called in response to a low Area Control Error (ACE) caused by increasing load and generation tripping and start failures. One of the events was called in direct response to the loss a generating unit. Five Synchronized Reserve Events over a two-day period is extremely unusual. All five of the events on Dec. 23 and Dec. 24 exceeded 10 minutes in duration, which is again extraordinary. Since the start of 2021, there have been 47 Synchronized Reserve Events, of which only 17 (36%) were more than 10 minutes in

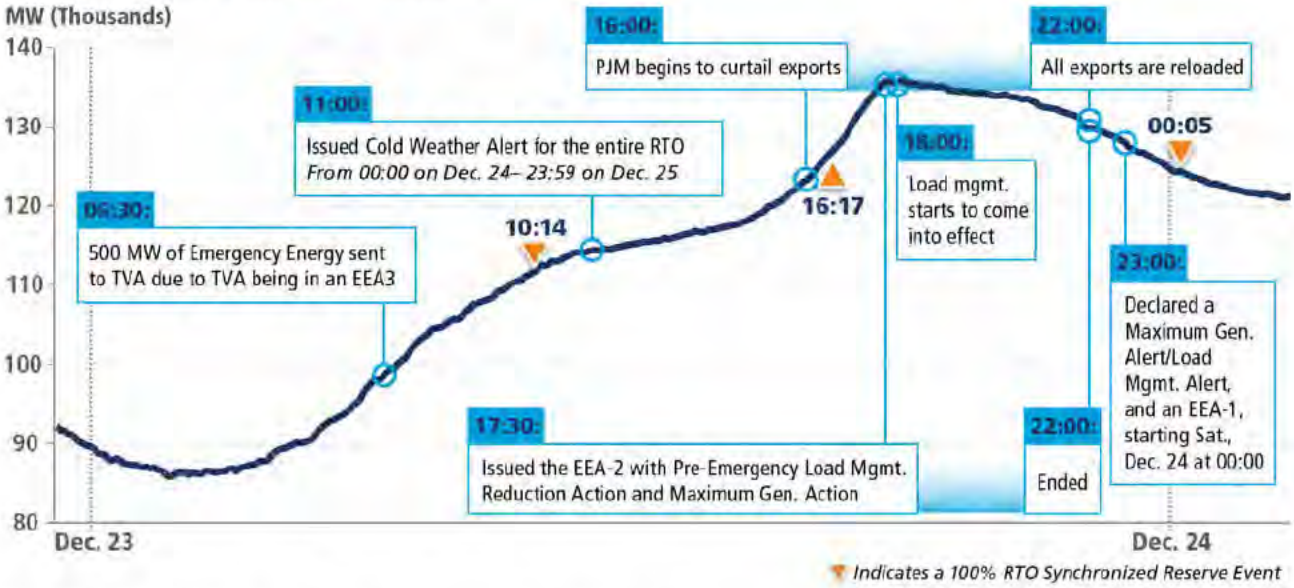
[3] The Dec. 23 peak of 136,010 MW incorporates Demand Response as part of the total.

duration, and five of these 17 occurred during Winter Storm Elliott. Additional information on Synchronized Reserve Events and Reserve performance is presented in the Markets Outcomes section of this report.

Dec. 23

PJM system operators initiated several actions on Dec. 23 as load continued to increase. **Figure 13** presents the PJM emergency procedures initiated, as well as the PJM load and the Synchronized Reserve Events, for Dec. 23.

Figure 13. Dec. 23 Emergency Procedures



Early in the morning on Dec. 23, PJM was exporting energy to adjacent areas and tracking under the load forecast. At 06:30, PJM provided 500 MW of emergency energy to TVA, who had issued a NERC Energy Emergency Alert Level 3 (EEA3), which is issued when the Balancing Authority, in this case TVA, is unable to meet the minimum contingency reserves requirements. At 10:00 on Dec. 23, PJM conducted an SOS-Transmission call to inform Transmission Owners of anticipated system conditions and the operating plan for the day.

	Dec. 23 HE 05
Outages	13,449 MW
Interchange	7,517 MW
Load	88,237 MW

At 10:14 on Dec. 23, PJM deployed Synchronized Reserves to recover low ACE caused by increasing load combined with generation resources tripping offline and failing to start. At this time, total PJM reserves were approximately 1,500 MW. At 11:00 on Dec. 23, PJM issued a Cold Weather Alert for the entire RTO from 00:00 on Dec. 24 through 23:59 on Dec. 26.

Beginning around 14:00 on Dec. 23, generation continued to trip or fail to start at a rate of approximately 1,800 MW per hour. This posed a challenge for PJM's ability to deliver exports to neighbors. During this period, the operational situation was strained for a number of reasons:

	Dec. 23 HE 13
Outages	24,032 MW
Interchange	8,283 MW
Load	115,048 MW

- PJM's ACE was dropping and trending significantly below zero, indicating insufficient generation to support load due to generator outages and failures. PJM found that it was unexpectedly and rapidly exhausting its operating and Primary Reserves because of the unexpected generator outages.
- PJM had put generation resources on notice, through Advisories and Alerts, of PJM's need for them to be prepared to run. PJM relied on Generator Owner/operator-submitted data and believed these reserves were available. In

many cases, this data did not reflect the actual capability of the generator and PJM would only learn of the generation resource failures at the time PJM was expecting these resources to begin to run.

- A Disturbance Control Standard (DCS) event, discussed later in this report, was also unfolding during this same time period.

Late in the afternoon of Dec. 23, temperatures continued to drop rapidly, and load continued to increase very quickly. During this period of operational uncertainty and deteriorating system conditions, PJM took additional emergency steps it determined were necessary to preserve the reliability of the system. Despite margins being incredibly tight, no load was shed.

Shortly after 16:00, PJM began cutting non-firm exports, consistent with PJM Manual 13. Export transactions had been decreasing throughout the afternoon, but by 16:00, it was evident PJM could no longer support non-firm exports. Given the trends in ACE, the high outage rates being observed in real time, and the time it would take for the impacts of the capacity recalls to be known, PJM Dispatch believed capacity recalls alone were insufficient to stabilize the system.

	Dec. 23 HE 15
Outages	26,672 MW
Interchange	6,732 MW
Load	117,143 MW

While the export transactions were being curtailed, at 16:17, PJM entered into another Synchronized Reserve Event due to low ACE caused by increasing load and generation resources tripping and failing to start. PJM deployed Synchronized Reserves for almost two hours, before canceling at 18:09. Load was continuing to increase, and PJM had several additional generation resource trips throughout the Synchronized Reserve Event period. The PJM ACE did not recover until after Demand Response was implemented at 18:00.

Available Synchronized Reserves continued to drop as PJM began calling upon these resources for energy, with many failing to perform at expected levels. At times during this period, PJM was within 1,000 MW of its required Synchronized Reserve level of 1,667 MW. PJM dipped below this required Synchronized Reserve threshold for a portion of the hour ending 18:00 because it was deploying Synchronized Reserves but not getting the expected response.

At 17:30, ACE was very low at nearly -3,000 MW, and the load was continuing to grow. In response, PJM issued a NERC Energy Emergency Alert Level 2 (EEA-2[4]) with Pre-Emergency Load Management Reduction Action and Maximum Generation Action, directing generation resources to operate above their normal maximum output levels. An EEA-2 is issued to ensure all NERC Reliability Authorities understand the potential and actual PJM system emergencies and is typically issued when the following events have occurred: public appeals to reduce demand; voltage reduction; and interruption of non-firm load in accordance with applicable contracts, demand-side management, or utility load conservation measures (NERC Standard EOP-11).

	Dec. 23 HE 16
Outages	28,351 MW
Interchange	6,032 MW
Load	119,375 MW

Certain emergency warnings and actions trigger a Capacity Performance Assessment Interval (PAI). The issuance of the EEA-2 with Pre-Emergency Load Management Reduction Action and Maximum Generation Action triggered the first performance assessment event, requiring PJM to evaluate the performance of all resources located in the Emergency

[4] EOP-011 NERC Energy Emergency Alerts (EEAs):
EEA0 – No Energy Deficiencies
EEA1 – All Available Resources in Use or Anticipated to be In Use; triggered when PJM issues Maximum Generation Emergency Alert)
EEA2 – Load Management Procedures in effect; triggered when PJM issues Emergency Mandatory Load Management Reduction, Voltage Reduction Action, or Deploy All Resources Action (whichever is issued first)
EEA3 – Firm Load Interruption Imminent or in Progress; triggered when PJM issues Manual Load Dump Action

Action area for each applicable five-minute interval. The performance assessment events are described in more detail in the Markets Outcomes section of the report.

PJM also called for 30-minute and 60-minute Emergency Demand Response to be activated. The 30-minute Emergency Demand Response came into effect by 18:00, and the 60-minute Demand Response came into effect by 18:30. PJM did not call for the two-hour Demand Response resources, as these resources would not have been implemented until after the evening peak. Demand Response performance can be difficult to determine in real time due to the lack of visibility of the performance to the system operator. More information on the performance of Demand Response is described later in this section.

	Dec. 23 HE 18
Outages	33,040 MW
Interchange	1,527 MW
Load	130,856 MW

Generation resources continued to trip offline and fail to start, resulting in ACE trending low during the hour ending 18:00. Starting at 17:05, PJM called Northeast Power Coordinating Council (NPCC) for 1,500 MW of shared reserves. NPCC is made up of New York and the six New England states, as well as the Canadian provinces of Ontario, Québec and the Maritime provinces of New Brunswick and Nova Scotia. Shared Reserve Activation is a procedure between the NPCC and the PJM Mid-Atlantic Control Zone to jointly activate a portion of their 10-minute reserve following any of the following situations:

- Generation or energy purchase contingencies equal to or greater than 500 MW (300 MW for the Maritimes) occur under conditions where activation assists in reducing a sustained load/generation mismatch.
- Two or more resource losses below 500 MW (300 MW for the Maritimes) within one hour of each other
- Periods of significant mismatch of load and generation

The objective of Shared Reserve Activation is to provide faster relief of the initial stress on the interconnected transmission system.

Over the evening peak on Dec. 23, PJM attempted to commit additional generating units that reported to PJM as being available to schedule. PJM system operators also considered long-lead-time resources that were beyond the window to be requested to start, which totaled about 3,000 MW. Generator maintenance outages that were recallable totaled about 1,692 MW; however, these are only recallable with 72-hours' notice. (Note: if PJM determines that it must rescind its approval of a Generator Maintenance Outage of a Generation Capacity Resource that is already underway in order to preserve the reliable operation of the PJM region, PJM must provide the member at least 72-hours' advance notice.)

Following the peak at approximately 18:10, PJM began lifting export transaction curtailments. By 22:00, PJM exports had returned to full flow. (Additional information on the real-time interchange is presented later in this section.)

	Dec. 23 HE 22
Outages	36,054 MW
Interchange	3,274 MW
Load	133,096 MW

At 23:00, load began to slowly ramp down, leading PJM to cancel the EEA-2 and the Pre-Emergency Load Management Reduction action at 23:00, ending the first performance assessment event. In addition, at 23:00 on Dec. 23, PJM declared a Maximum Generation Alert/Load Management Alert for Dec. 24, which provides an early alert that system conditions may require the use of the PJM emergency procedures. This is implemented when Maximum Emergency generation is called into the operating capacity or if Demand Response is projected to be implemented. When PJM declares a Maximum Generation Alert/Load Management Alert:

- Member transmission and generation dispatchers are expected to review plans to determine if any maintenance or testing, scheduled or being performed, on any monitoring, control, transmission, or generating equipment can be

deferred or canceled. Transmission and generation dispatchers are expected to suspend any high-risk testing of generating or transmission equipment.

- Member generation dispatchers are expected to report to PJM Dispatch any and all resource-limited facilities as they occur via Markets Gateway and update PJM Dispatch. Member generation dispatchers are also expected to update the "early return time" for any planned generator outages as indicated in PJM Manual 10, Section 2.

PJM also issued a NERC Energy Emergency Alert Level 1 (EEA-1) starting Saturday, Dec. 24, at 00:00, indicating PJM foresees or is experiencing conditions where all available resources are scheduled to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves.

Shortly before midnight on Dec. 23, PJM issued a Call for Conservation for the entire PJM footprint, asking consumers to scale back their energy use, where possible, between the hours of 04:00 on Dec. 24 and 10:00 on Dec. 25.

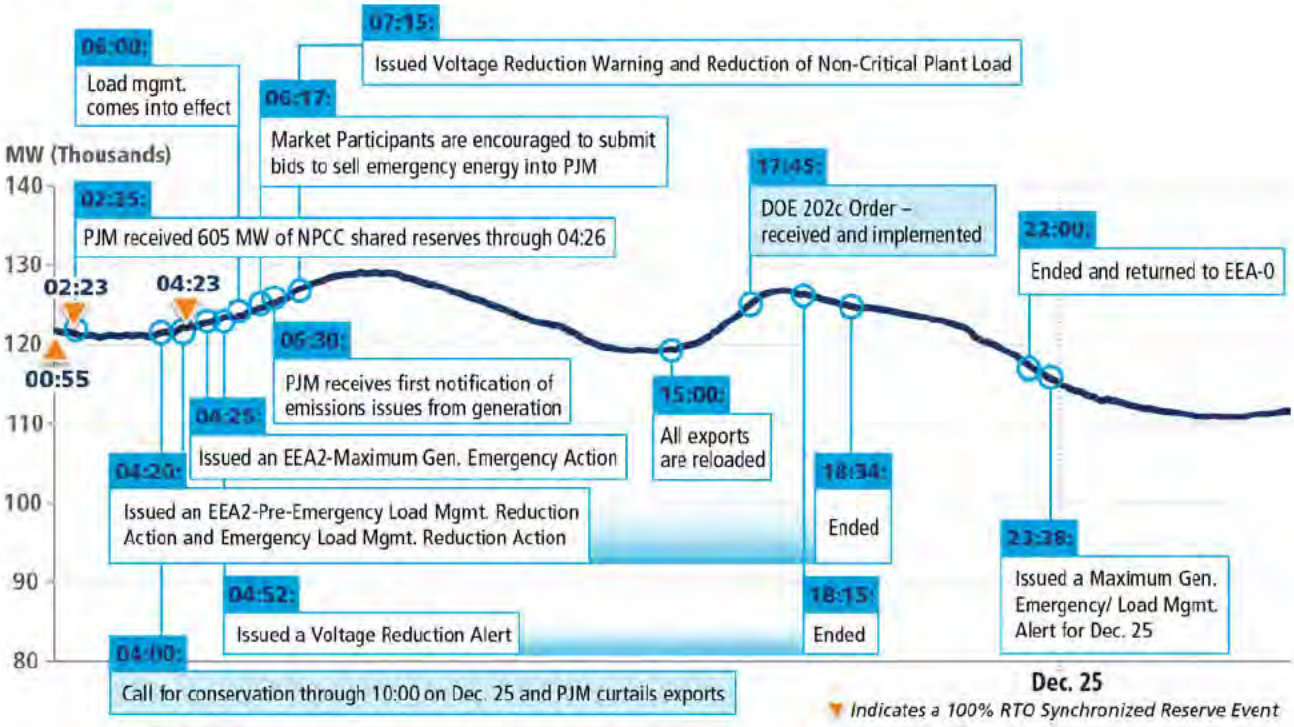
Dec. 24

The high demand for electricity continued after the peak on Dec. 23 and into the overnight period of Dec. 24. In addition to forced outages, approximately 6,000 MW of generators were called but were not online for their expected start time for the Dec. 24 morning peak, with the vast majority of these being gas-fired resources.

The high rates of generator outages also limited PJM's ability to replenish pond levels for pumped storage hydro prior to the morning peak on Dec. 24, leaving PJM with extremely limited run hours for pumped storage generation. Between forced outages, derates, generators not starting on time, and the inability to fill pumped storage hydro ponds, approximately 47,000 MW of the generation fleet in the PJM region was unavailable for the Dec. 24 morning peak. Additionally, the valley load during the early morning hours on Dec. 24 was atypically high. It was approximately 40,000 MW higher than the next-highest valley over the last decade.

PJM system operators took the several actions on Dec. 24 to maintain system reliability and serve load. Figure 14 presents the PJM emergency procedures issued, as well as the PJM load, for Dec. 24.

Figure 14. Dec. 24 Emergency Procedures



At 00:05 on Dec. 24, PJM deployed Synchronized Reserves due to low ACE caused by increasing load and generator trip and start failures. At 02:23, PJM deployed Synchronized Reserves again for approximately one hour to recover from another generation resource trip. At 02:25, PJM received 605 MW of NPCC shared reserves from 02:25 through 04:26. More information on the Synchronized Reserve Events is presented in the Markets Outcomes section of this report.

	Dec. 24 HE 01
Outages	38,368 MW
Interchange	4,604 MW
Load	124,757 MW

During a typical midnight period, load reduces, and PJM would operate pumped storage resources as pumps to fill their ponds so that they have the ability to generate for the upcoming peak. Operating a pumped storage resource in pumping mode increasing load on the system because electricity is consumed to operate the resource as a pump. Given the tight conditions, PJM was not able to pump at any of the pumped storage facilities prior to the morning peak. This left PJM with extremely limited run hours for pumped storage generation. As previously stated, going into the morning peak on Dec. 24, resource unavailability was approximately 47,000 MW, including the unavailability of pumped storage hydro generation.

At 04:20 on Dec. 24, PJM issued an EEA-2 – Pre-Emergency Load Management Reduction Action and Emergency Load Management Reduction Action. In this case, PJM dispatched all Load Management, starting with long lead (120 minute) at 04:20, short lead (60 minute) at 05:00, and quick lead (30 minute) at 05:30. Demand Response performance is described later in this section.

At 04:23, PJM deployed Synchronized Reserves again due to low ACE caused by increasing load and generation resources tripping and start failures. And then at 04:25, PJM issued an EEA-2 – Maximum Generation Emergency Action and began to load Maximum Emergency generation. This triggered the Dec. 24 PAI event. When PJM issues a Maximum Generation Emergency Action:

	Dec. 24 HE 03
Outages	40,243 MW
Interchange	3,322 MW
Load	121,487MW

- Member generation dispatchers are expected to report to PJM all resource-limited facilities as they occur in Markets Gateway and update PJM Dispatch. Generation dispatchers also suspend regulation and load all units to the Maximum Emergency generation level and then notify PJM Dispatch of any Maximum Emergency generation load prior to PJM requested Maximum Emergency generation is loaded.
- Non-Retail Behind-the-Meter Generation (NRBMG) is also loaded. NRBMG performance is described later in this section.

At 04:52, PJM issued a Voltage Reduction Alert. A Voltage Reduction Alert notifies members that a voltage reduction may be required during a future critical period. This alert is issued when the estimated Operating Reserve capacity is less than the forecasted Synchronized Reserve requirement. When PJM issues a Voltage Reduction Alert:

- Member generation dispatchers are expected to order all generating stations to curtail non-critical station light and power.
- Member transmission dispatchers and distribution providers (DPs) are expected to prepare to reduce voltage, if requested.
- Member transmission dispatchers/DPs and curtailment service providers (CSPs) are expected to notify appropriate personnel that there is a potential need to implement load management programs, in addition to interrupting their interruptible/curtailable customers in the manner prescribed by each policy, if it has not already been implemented previously.
- Market Participants are expected to remain on heightened awareness regarding PJM system conditions and the potential need for Emergency Energy Purchases.

At 06:17, PJM requested bids for emergency energy and PJM also repeated a public appeal to conserve energy. Note: PJM did not load emergency imports on Dec. 24.

	Dec. 24 HE 06
Outages	46,036 MW
Interchange	1,437 MW
Load	122,172 MW

At 07:15, PJM issued a Voltage Reduction Warning and Reduction of Non-Critical Plant Load, warning members that the available Synchronized Reserve is less than the Synchronized Reserve Requirement and that present operations have deteriorated such that a voltage reduction may be required.

At 07:30, PJM conducted an SOS-Transmission conference call with the PJM Transmission Owners to update their leadership on the situation and indicated PJM was in a very critical operating period, with the potential that PJM may need to shed load. Another SOS-Transmission conference call took place at 10:00.

As PJM approached the morning peak, PJM was a net importer of energy. TVA and Duke were both in an EEA-3 and shedding load. PJM was unable to provide assistance to TVA and Duke, and PJM was receiving assistance primarily from NYISO.

Forced outages of generation continued to increase through the morning peak on Dec. 24, with an estimated level of 41,000 MW of outages and 200 unit trips. Factoring in a number of reserve generators (units that are offline and available – that are called if needed) that missed scheduled start times Saturday morning or operated at less than capacity, combined with PJM's inability to replenish pumped storage based on the lack of availability of generators overnight, PJM was missing approximately 47,000 MW of the generation fleet by the morning peak of Dec. 24, the coldest day of the holiday weekend.

The morning peak for Dec. 24 was approximately 130,000 MW, occurring at 08:30.

As the morning peak was occurring, it was reported to PJM that several generators may need to come offline at or around the evening peak due to emissions restrictions. At this point, PJM contacted the U.S. Department of Energy (DOE) and held several calls to discuss the concerns and options available to ensure the units could remain online if needed. PJM also began outreach to state utility commissions and environmental agencies in states where there was a potential to operate units under a DOE Emergency Order.

Heading into Saturday evening, there was still uncertainty about resource performance. To mitigate the risk of generators coming offline due to emissions limitations, PJM submitted a petition to the DOE Saturday afternoon. At 17:30, the DOE issued an emergency order under Section 202(c) of the Federal Power Act, determining that an electric reliability emergency existed within the PJM region that required intervention by the United States Secretary of Energy to keep the power flowing.

The emergency order was effective Dec. 24 through 12:00 on Dec. 26. The order authorized all electric generating units serving the PJM footprint to operate up to their maximum generation output levels under limited, prescribed circumstances, even if doing so exceeded their air quality or other permit limitations.

Two generating units that fell under the order ran at levels that exceeded a condition in their operating permit. The Department of Energy requires PJM to identify those generators, which were Bethlehem Energy in Bethlehem, Northampton County, Pennsylvania, and York Energy 1 in Peach Bottom Township, York County, Pennsylvania. On Dec. 24, PJM communicated the need to operate these units under the DOE emergency order to the Pennsylvania Department of Environmental Protection. In accordance with the DOE's requests, PJM followed up with communications to the local communities where the plants are located through local media outlets.

The evening peak for Dec. 24 was approximately 136,000 MW. Following the evening peak, PJM started to cancel emergency procedures. At 18:15, PJM canceled the Voltage Reduction Warning and the Reduction of Non-Critical Plant Load. At 18:34, PJM canceled the Voltage Reduction Alert.

	Dec. 24 HE 17
Outages	47,310 MW
Interchange	3,607 MW
Load	120,183 MW

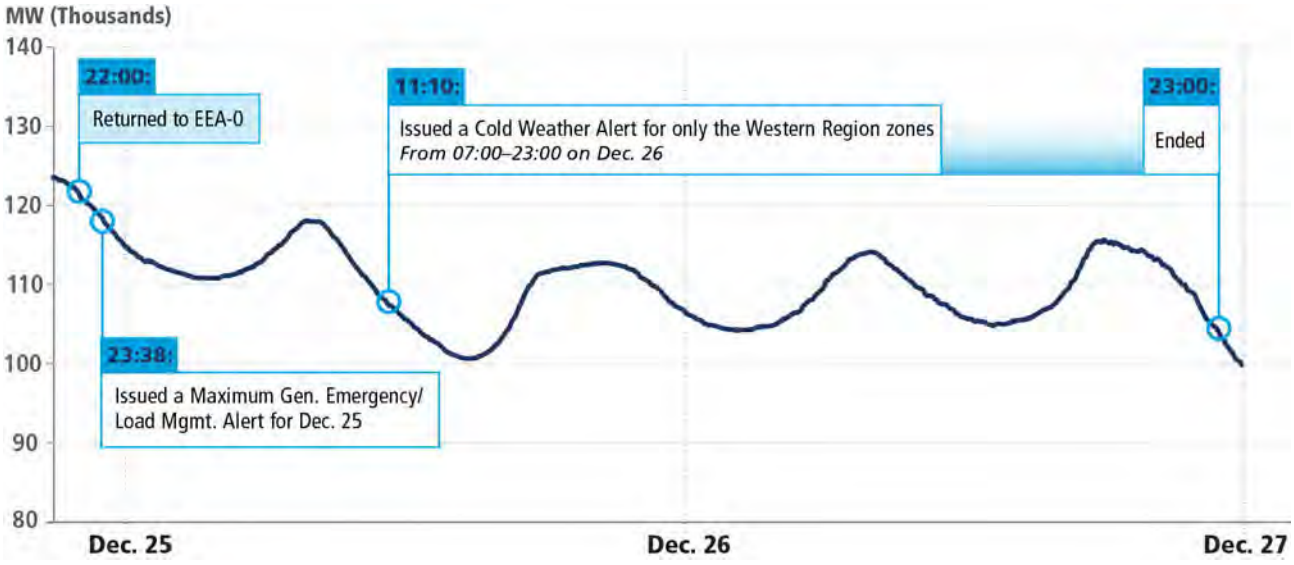
At 22:00 on Dec. 24, PJM canceled the Max Emergency Generation Action. This ended the Dec. 24 PAI. Around 22:00, the Demand Response ended, and PJM backed out of the EEA-2, indicating PJM was able to meet its load and Operating Reserve requirements. PJM's Call for Conservation also ended at this time.

At 22:38 on Dec. 24, PJM issued a Max Emergency Generation Alert for Dec. 25, resulting in PJM going into Dec. 25 in an EEA-1.

Dec. 25 and Dec. 26

On Dec. 25, a Sunday, PJM still had very high loads for a Christmas operating day. The morning peak was approximately 117,000 MW. There was sufficient capacity available to meet this morning peak as well as the evening peak, and PJM returned to EEA-0 at 22:00. **Figure 15** presents the PJM emergency procedures, as well as the load for Dec. 24 at 22:00 to Dec. 26 at 23:00.

Figure 15. Dec. 25 and Dec. 26 Emergency Procedures



At 11:10 on Dec. 25, PJM issued a Cold Weather Alert for the Western Region zones only from 07:00 Dec. 25 to 23:00 Dec. 26. At 23:00 on Dec. 26, the Cold Weather Alert ended.

Figure 16 summarizes the emergency alerts, warnings and actions PJM implemented from Dec. 23 through Dec. 26.

Figure 16. Summary of Alerts, Warnings, and Actions Issued on Dec. 23, Dec. 24 and Dec. 25

Action Warning Alert Advisory

MESSAGE TYPE	DEC. 20	DEC. 21	DEC. 22	DEC. 23	DEC. 24	DEC. 25
Cold Weather Advisory			1	1	1	1
Cold Weather Alert				1	1	1
Emergency Load Mgmt Reduction Action				2	3	
Maximum Generation Emergency Action				1	1	
Maximum Generation Emergency/Load Management Alert				1	2	1
Non-Market Post Contingency Local Load Relief Warning	1	1		2	2	1
Post Contingency Local Load Relief Warning	3	3	1	25	26	6
Pre-Emergency Load Mgmt Reduction Action				2	3	
Synchronized Reserve Event				2	3	
Maximum Generation Emergency/Load Management Alert					1	
Voltage Reduction Warning and Reduction of NCPL					1	

As outlined in PJM Manual 13, Section 2.3: Capacity Shortages, "PJM dispatchers have the flexibility of implementing the emergency procedures in whatever order is required to ensure overall system reliability. PJM dispatchers have the flexibility to exit the emergency procedures in a different order than they are implemented when conditions necessitate." As such, PJM Operations evaluated the usage and combination of any and all emergency procedures during Winter Storm Elliott in order to best maintain overall system reliability. While many emergency procedures were issues by PJM throughout the event, some were considered and ultimately not issued.

- Cold Weather Alert – While a Cold Weather Advisory was issued for the entire PJM RTO on Dec. 20 for the operating period of Dec. 23–26, PJM Operations did not declare a Cold Weather Alert for the entire RTO until the Dec. 24 operating day, opting only to declare a Cold Weather Alert for the Western PJM zones for the Dec. 23 operating day. PJM Operations forecasted the potential for cold weather starting on Dec. 23 and, as such, issued the appropriate advisory, while continuing to monitor forecasted temperatures leading up to the operating day. Per PJM Manual 13, Section 3.3.2 Cold Weather Alert, "as a general guide, PJM can initiate a Cold Weather Alert across the RTO or on a Control Zone basis when the forecasted weather conditions approach minimum or actual temperatures of 10 degrees Fahrenheit or below." Outside of the Western zones, temperatures were never forecasted to reach near a minimum of 10 degrees and instead were expected to be several degrees higher at their minimum. As such, it was not appropriate to issue a Cold Weather Alert for the zones outside of the PJM Western footprint until Dec. 24 when the trigger temperatures were forecasted.
- Deploy All Resources Action – The Deploy All Resources Action is a unique emergency procedure with a unique application. Its purpose is to immediately load all available generation and Demand Response following a severe system disturbance to attempt to halt frequency decay. This could lead to unintended loss of system control with regard to energy balance. It is only expected to be used as a means of last resort. This specific emergency procedure was discussed by PJM Operations and decided against implementing for several reasons, as implementing a Deploy All Resource Action could have aggravated some of the thermal and voltage constraints that were being managed. In addition, PJM Operations was manually controlling the output of all pumped hydro facilities during the event. Issuance of this emergency procedure would have removed PJM's controlling ability of these resources and instead would have immediately depleted the pond levels, which were needed to be precisely managed through the event.
- Manual Load Dump Warning, Voltage Reduction Action & Manual Load Dump Action – These three steps constitute the most severe emergency procedures that can be utilized to maintain reliability. While PJM Operations has these steps in the queue to issue, as necessary, system conditions never dictated a need to utilize them. During a conference call held with PJM Transmission Owners at 07:30 on Dec. 24, prior to the most challenging system conditions of the event, which was the Saturday, Dec. 24, morning peak, PJM management made a clear statement for the Transmission Owners to be prepared to respond as quickly as possible to any or all of these emergency procedures as there was the possibility that they could be issued imminently. PJM Operations kept the Voltage Reduction Action in reserve to deploy, if additional generation tripped offline. Per PJM Manual 13, this would have been approximately 1.3% of the RTO load at the time. If a Voltage Reduction Action were issued, it would have been immediately followed with a Manual Load Dump Warning and EEA-3 declaration, as a Manual Load Dump would have been the only remaining emergency procedure to maintain reliability. Then, if required, PJM would have been prepared to issue a Manual Load Dump Action. PJM was ultimately able to maintain reliability through the event without issuance of these three emergency procedures.

Disturbance Control Standard Event

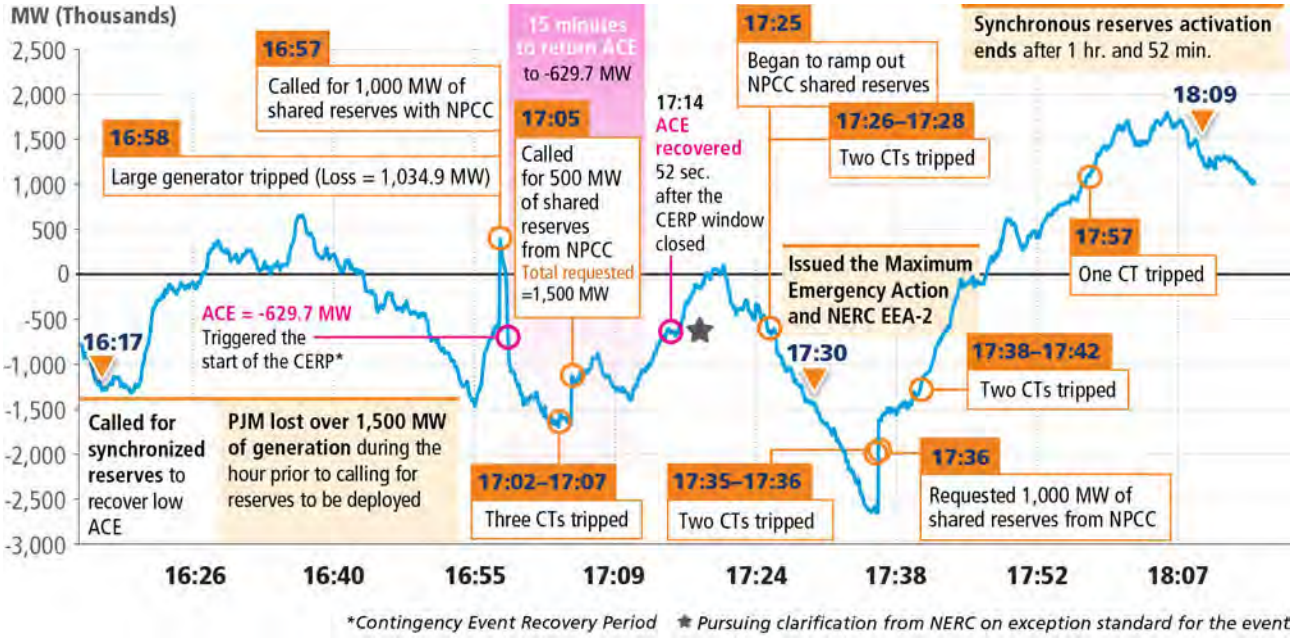
The purpose of the NERC Standard BAL-002, Disturbance Control Performance, is to ensure that PJM, a NERC Balancing Authority, is able to utilize its contingency reserve to balance resources and demand, and to return interconnection frequency to within defined limits following a Reportable Disturbance. NERC defines a Reportable Disturbance as any event that causes an Area Control Error (ACE) change greater than or equal to 80% of a Balancing Authority's or reserve sharing group's most severe contingency. ACE is a measure of how well the Balancing Authority is matching generation to the load. If load and generation are perfectly balanced, the ACE is zero. When a generator within

a Balancing Authority trips offline, the ACE goes down, and can go negative if it was already not above zero by a quantity at least as great as the output of the generator when it tripped. Because generator failures are far more common than significant losses of load and because contingency reserve activation does not typically apply to the loss of load, the application of Disturbance Control Standard (DCS) is limited to the loss of supply and does not apply to the loss of load.

PJM is required to have access to or operate with resource reserves to respond to disturbances. These reserves may be supplied from generation, controllable load, or coordinated adjustments to interchange schedules. The DCS Standard requires PJM to satisfy disturbance recovery criterion within a certain disturbance recovery period for 100% of Reportable Disturbances. The criterion requires PJM to return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the disturbance, a return of ACE is made to its pre-disturbance value. In either case, the disturbance recovery period is 15 minutes after the start of a Reportable Disturbance. Subsequently, PJM must fully restore the Synchronized Reserve within 90 minutes. All contingency losses (i.e., disturbances) with the lesser of 900 MW in the Eastern Interconnection or 80% of the Most Severe Single Contingency must be calculated and reported.

As described below, PJM was not able to recover the ACE within the prescribed 15 minutes. Figure 17 presents PJM's ACE on the evening of Dec. 23 during the DCS event:

Figure 17. ACE During DCS



Heading into the evening peak on Dec. 23, load was increasing rapidly and PJM was ramping the generation fleet to keep up with the increasing load. Load was increasing quicker than PJM was able to ramp generation, and, as a result, the PJM ACE started to go negative. By 16:17 on Dec. 23, ACE was trending at around negative 1,000 MW, indicating low capacity. In response, PJM called for Synchronized Reserves to be loaded to recover from the low ACE. After approximately ten minutes, the ACE partially recovered but, by 16:40, went negative again. By 16:55, the ACE was approximately negative 1,500 MW. At 16:57, PJM called for 1,000 MW of shared reserves from NPCC. At that point, PJM's ACE was 429 MW as a result of PJM deploying reserves for approximately 40 minutes.

Approximately one minute following PJM's call for shared reserves from NPCC, a large generator in PJM tripped, losing approximately 1,035 MW. The Generation Owner reported that the generator was loaded at 850 MW at the time the unit tripped. The loss of this large generation resource was the initiating event with respect to the BAL-002 standard reporting event. Prior to the unit tripping, PJM's ACE was negative 630 MW. After the unit tripped, PJM's ACE dropped below negative 1,500 MW. Per the BAL-002 standard, PJM is required to recover ACE to negative 630 MW within15 minutes.

PJM had been deploying reserves since 16:17. Load on the system was continuing to increase. Between 17:02 and 17:07, additional generation tripped, and, as a result, the ACE continued to decline to approximately negative 1,600 MW. At 17:05, PJM called for an additional 500 MW of shared reserves from NPCC, bringing the total shared reserves from NPCC to 1,500 MW.

By 17:14, the PJM ACE had recovered back to negative 630 MW, ending the DCS event 15 minutes and 52 seconds after the large generator tripped. Although the DCS event had technically ended, controlling the ACE continued to be a challenge. As reflected in Figure 17, the PJM ACE climbed back to around zero about five minutes later but then went negative again. Throughout all of this, PJM continued to deploy reserves and was ramping whatever resources were online and available.

At 17:25, PJM started to ramp out the shared reserves from NPCC, which can only be relied upon for 30 minutes (recall PJM called for shared reserves at 16:57). As load continued to increase and additional generation was lost, the PJM ACE was approaching negative 3,000 MW by 17:34.

At 17:36, PJM requested 1,000 MW of shared reserves from NPCC again, which helped the ACE to begin to recover. The ACE continued to recover until 18:09, at which time PJM ended the call for Synchronized Reserves to be loaded, 1 hour and 52 minutes after PJM began deploying them.

During this period, PJM was ramping generation as quickly as possible and deploying Synchronized Reserves for almost two hours. By 18:00, the rate that the load was increasing slowed as PJM was beginning to see the impact of the Demand Response that was called at 17:30.

PJM evaluated compliance with the BAL-002 standard, and engaged in communications with ReliabilityFirst regarding the matter. This evaluation included the consideration that BAL-002-3 R1.3 provides scenarios in which Responsible Entities are not subject to compliance with BAL-002-3 R1.1, provided certain thresholds are met.

In response to the low response rate and lack of available reserves, PJM will be reviewing procedures to identify triggering conditions that will further increase the amount of reserves that are scheduled leading into the operating day. This will include triggers to potential increase the amount of the Synchronized, Primary and/or Operating Reserves scheduled in the Day-Ahead, RAC and Real-Time market clearing.

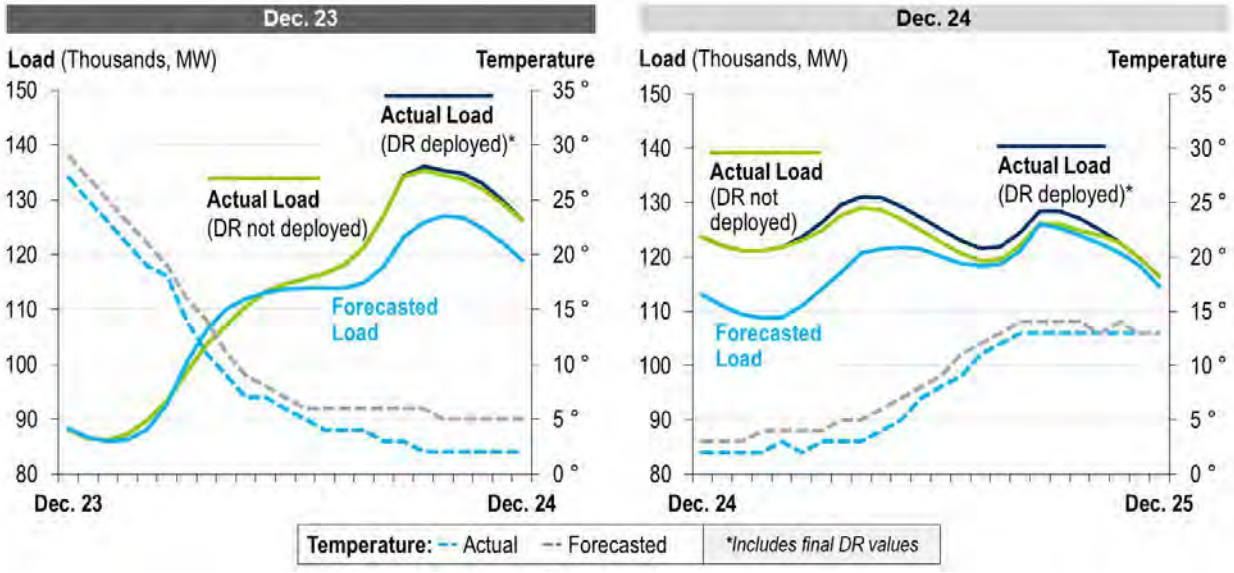
Load Forecast Versus Actual Load

The load forecasts for Dec. 23 and Dec. 24 presented a unique set of challenges. The winter holiday period has historically been a challenging time to forecast due to school vacations, business closures and atypical human behavior patterns, as presented in Figure 19. In the past, over-forecasting was more of an issue than under-forecasting, resulting in the PJM forecast team enhancing processes in recent years to correct for this over-forecasting trend. The winter 2022 holidays were further complicated by the extreme weather and Christmas Eve occurring on a Saturday, which had not occurred since 2016.

On Dec. 23, the forecasted peak load was 126,968 MW, and the actual peak was 136,010 MW, which included Demand Response added back into the load. On Dec. 24, the forecasted peak load was 121,723 MW, and the actual peak was

131,113 MW, which included Demand Response added back into load. On both Dec. 23 and Dec. 24, the actual load came in well higher than forecast, as presented in Figure 18.

Figure 18. Dec. 23 and Dec. 24 Actual Load



The high demand for electricity continued after the peak on Dec. 23 and into Dec. 24. The actual valley load, or low point of demand, on Dec. 24 was significantly greater than originally forecasted as well. The Dec. 24 valley load was higher than any other peak, or high point of demand, for that date over the previous decade, as shown in Figure 19, which presents the holiday load for 2022 and the previous 10 years.

Figure 19. Holiday Load for Previous 10 Years

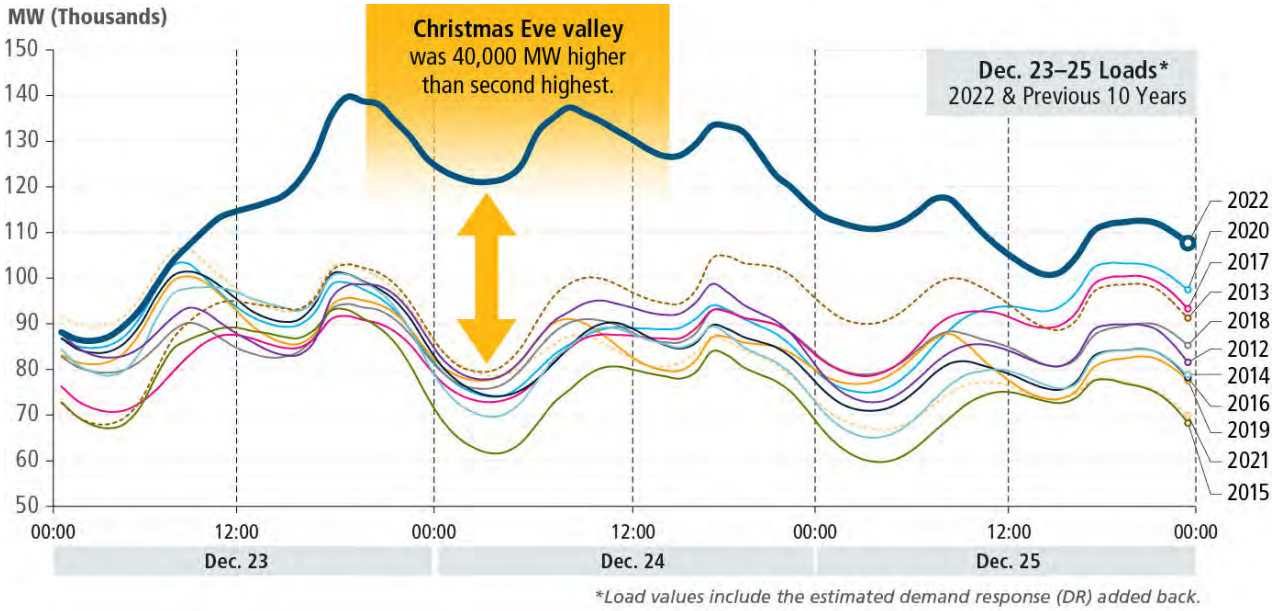
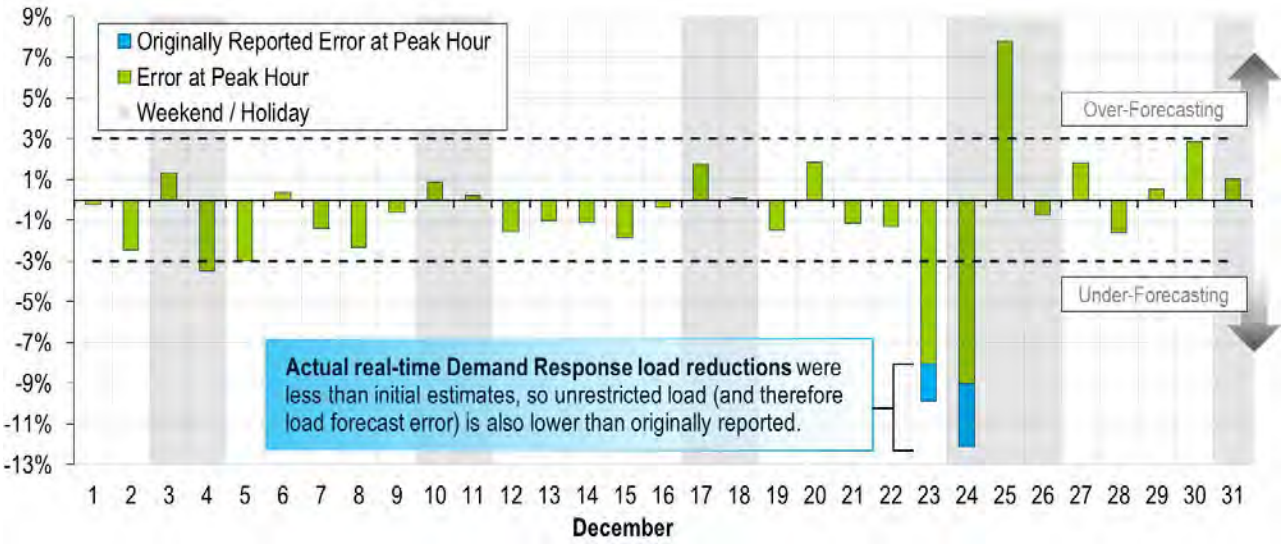


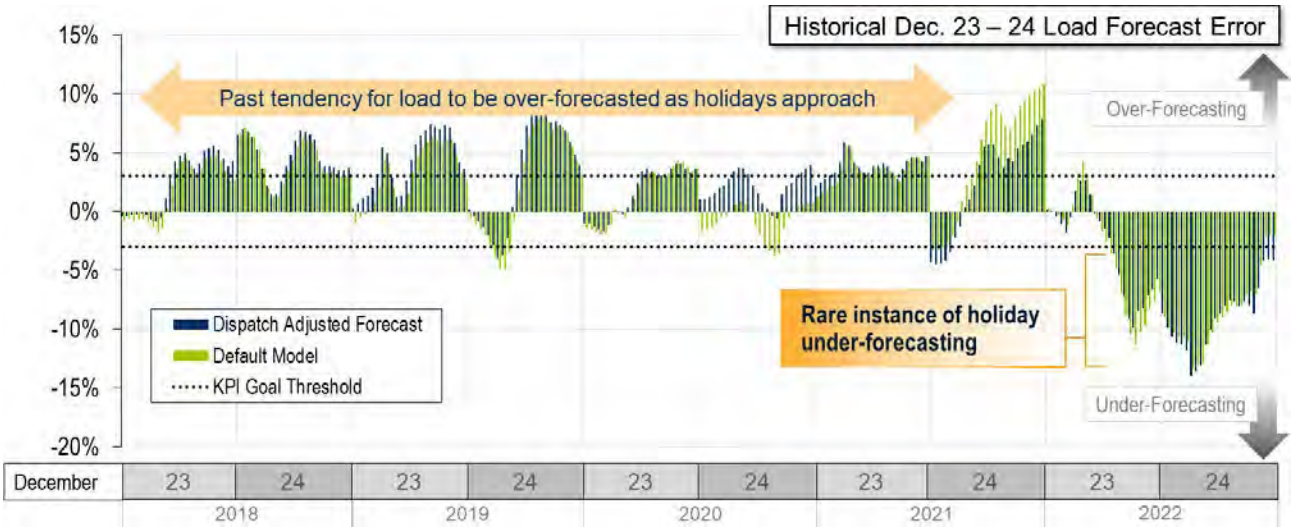
Figure 20 presents graphic presents the daily peak forecast error for December.

Figure 20. December Daily Peak Load Forecast Error



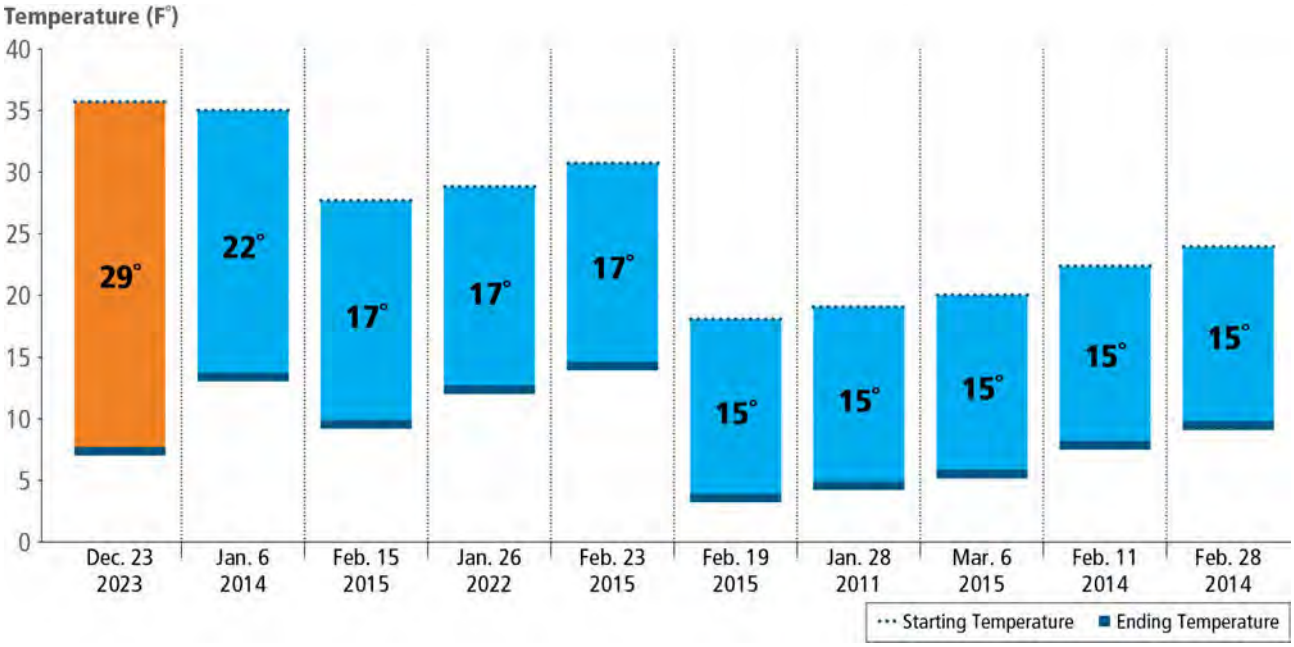
The extreme weather not only included bitter cold temperatures that were outside of the data sample used to train the load forecast models (mid-2019 to mid-2022), but also a rapid temperature drop, strong winds, heavy icing and snowfall, all of which occurred unusually early in this winter. Figure 21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

Figure 21. Historical Dec. 23–24 Load Forecast Error



The load forecast is determined by an algorithm that considers expected weather conditions, day of the week and holidays. The model had not been exposed to the conditions that occurred on Dec. 23, with the confluence of unprecedented cold temperature drops, the holiday and the weekend. Within the PJM footprint, the difference between the high and low temperatures on Dec. 23 was one of the greatest in recorded history, as shown in the Figure 22.

Figure 22. Dec. 23 High and Low Temperatures



In Figure 22, the top and bottom of each bar represent the starting and ending temperature for each day, respectively.

The following primary drivers contributed to the load forecast error observed on Dec. 23 and 24:

- Extreme weather – severe cold and blizzard conditions, the most drastic temperature drop in at least 10 years, and early occurrence of cold weather
- Holiday impacts, which usually result in lower demand levels than normal

While PJM uses a sophisticated set of load forecasting tools and processes, we believe the Dec. 23 and 24 load forecasts highlight a case where two simultaneous conditions, a holiday and extreme weather with very limited analogous history, occurred together to produce atypically large forecast errors. PJM is already engaged with an independent party to further investigate enhancements to the load forecasting process, in general, and related to these specific events.

Emergency Generation and Demand Response Performance

Altogether, a Maximum Generation Action, Demand Response and public Call for Conservation helped address challenging operating conditions on Dec. 23 and 24. This section discusses information regarding the use of emergency resources. Information regarding the Call for Conservation is presented in the Government, Member & Media Outreach section.

PJM issued a Max Generation Action on Dec. 23 between 17:30 and 22:00 and observed a total increase of approximately 2,300 MW as a result of generation resources operating between their economic maximum and emergency maximum limits. Similarly on Dec. 24, PJM issued a Max Generation Action between 04:30 and 22:00 and observed a total increase of approximately 2,800 MW as a result of generation resources operating between their economic maximum and emergency maximum limits.

Demand Response was used to reduce peak loads in the entire PJM region during the winter storm. PJM called on Demand Response two times to address operational challenges with capacity shortages.

As described previously, PJM called for Demand Response on Dec. 23, which was to be implemented by 18:00. Demand Response with a capacity commitment is referred to as Load Management, which is comprised of Pre-Emergency and Emergency Demand Response. Load Management is required to reduce or maintain load at or below the committed value based on PJM dispatch within 30 minutes (quick lead time), 60 minutes (short lead time), or 120 minutes (long lead time). Based on the expected peak for the day, PJM dispatched both the 30-minute and the 60-minute lead resources on the evening of Dec. 23.

In total, PJM dispatched what it anticipated to be 4,336 MW of Load Management on Dec. 23 with 4,007 MW of 30-minute lead resources by 18:00 and another 329 MW of 60-minute lead resources by 18:30. In real-time, Curtailment Service Providers (CSPs) are required to provide estimates of their load reduction capability to PJM since customer load may already be low for other reasons (public appeal to reduce load, normal operating conditions, etc.). These estimates are intended to give PJM operators a quantity of load that will reduce if they deploy a specific category of Load Management. CSPs estimated, and therefore PJM expected, that 4,336 MW of load would be reduced based on the deployment on Dec. 23. PJM estimates, based on after-the-fact customer load data, that actual load reductions were approximately 1,100 MW. In total on Dec. 23, approximately 74% of the Demand Response that PJM operators dispatched and expected to reduce load did not.

As PJM was approaching the morning peak on Dec. 24, given the critical capacity condition, PJM system operators dispatched all Load Management with a total capacity commitment of 7,522 MW at 04:20.

4,007 MW of 30-minute Demand Response was expected to respond at 06:00.	329 MW of 60-minute Demand Response was expected to respond by 06:00.	3,186 MW of 120-minute Demand Response was expected to respond by 06:20.

CSPs estimated, and therefore PJM expected, that approximately 7,400 MW of load would be reduced. Based on after-the-fact customer load data, PJM estimates that actual load reductions from PJM dispatch was approximately 2,400 MW. This corresponds to approximately 68% of the Demand Response PJM operators dispatched and expected to reduce load not performing.

The significant difference between the data provided to PJM about load curtailment capability and the actual performance clearly identify an opportunity and need to improve the rules and processes regarding Load Management capability estimates.

Real-Time Interchange

Interchange transactions take the form of an import, meaning market participants purchase power from a neighboring area and sell into PJM, an export, where power is purchased from PJM and sold to an external area, or a wheel, where power is simultaneously purchased from a neighboring area, scheduled across PJM, and then sold to an external area. PJM is typically a net exporter of energy to neighboring systems, and that remained true in the days preceding Winter Storm Elliott. With this information in mind, PJM operators took a conservative stance in preparing for the Dec. 23 and Dec. 24 operating day and planned for sufficient reserves to meet both forecast internal load and the needs of neighboring systems who rely on support from PJM in the form of interchange transactions and emergency purchases.

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

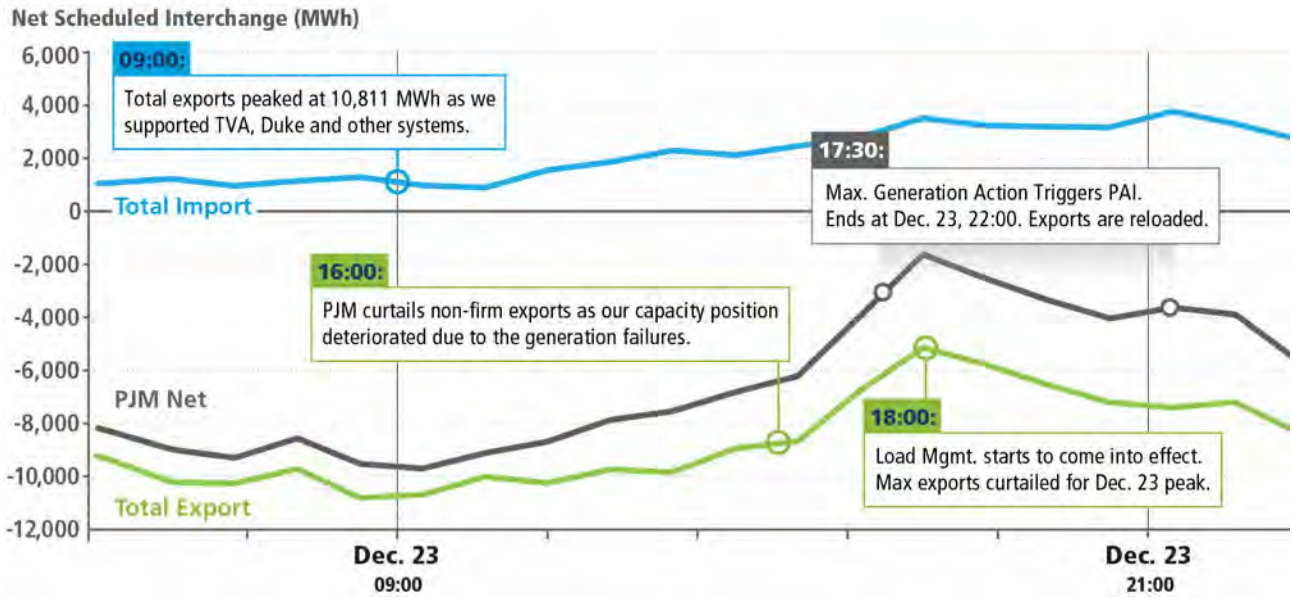
areas to PJM's west and south were already experiencing bitter cold temperatures. PJM was exporting energy throughout the morning and early afternoon on that day. Throughout the Dec. 23 to 24 period, PJM was balancing the extremely tight capacity situation due to the unprecedented amount of generator trippings and forced outages, controlling flows on the AEP-Dominion IROL[5] interface, as well as the extreme system conditions faced by our neighbors to the south.

Dec. 23

At the start of Dec. 23, PJM exported over 8,000 MWh for the hour ending 01:00 and increased that amount over the morning hours to reach almost 11,000 MWh for the hour ending 10:00 (Figure 23). These exports included the supply of emergency energy to TVA during the hours ending 07:00 through 11:00. During hour-ending 13:00, exports started a slight downward trend, and as PJM's capacity position continued to deteriorate, non-firm exports to adjacent areas were ultimately curtailed via a Maximum Generation Emergency Action. PJM system operators initiated the curtailment of non-firm export transactions at hour ending 17:00 by limiting roughly 400 MWh of exports, and quickly jumped to limiting well over 3,000 MWh of transactions each hour from hours ending 18:00 through 20:00. At that point, PJM system operators began a transition out from the heaviest Maximum Generation curtailments, with most transactions resuming full flow by hour-ending 22:00. In anticipation of, and in response to the Minimum Generation Action on Dec. 23, PJM curtailed in total almost 14,000 MWh of exports.

Figure 23 presents the Net Scheduled Interchange on Dec. 23.

Figure 23. Dec. 23 Net Scheduled Interchange



Dec. 24

When current and forecast system conditions indicated reduced availability to support exports on Dec. 24, the Transmission Load Relief (TLR) mechanism was considered as an option to provide relief for the AEP-Dominion IROL interface; however, the resulting analysis showed the need for an excessive volume of tag[6] curtailments on neighboring

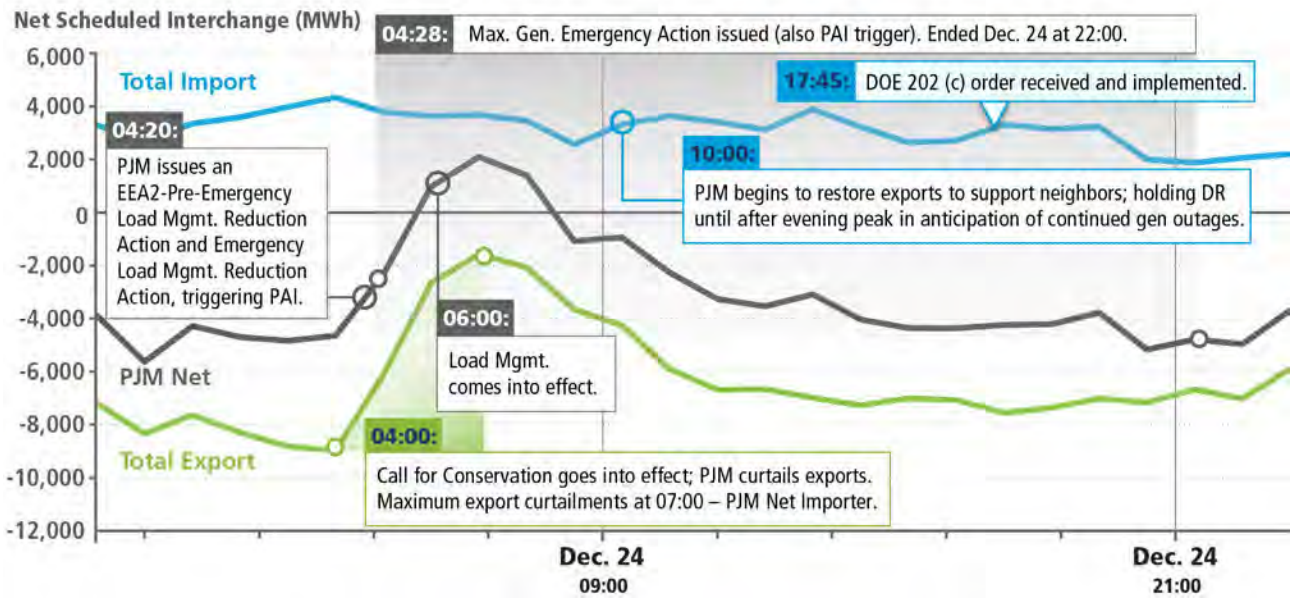
[5] Interconnection Reliability Operating Limit (IROL) is a system operating limit that, if exceeded, could lead to system instability, uncontrolled separation, or cascading that adversely impact the reliability of the bulk electric system.
[6] A tag is information describing a physical Interchange Transaction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

systems that were already experiencing significant issues of their own. PJM system operators concluded that issuing a TLR would create far-reaching impacts across the Eastern Interconnection and likely make system conditions and emergencies worse for our neighbors. PJM also elected to limit curtailment of exports over the midnight period knowing the severe system conditions of our neighbors to the south. This limited PJM's ability to pump hydro stations.

Facing both a capacity emergency and lack of controlling options for AEP-DOM, PJM made the decision to take a more surgical approach and initiated curtailments in anticipation of a Maximum Generation Emergency Action, which was ultimately declared at 04:25. PJM system operators began limiting non-firm exports in hour ending 05:00 and increased the magnitude of curtailments by hour ending 06:00 when they had also begun limit firm exports. The most significant curtailments occurred in hour ending 08:00 with over 4,000 MWh of firm transactions limited and over 5,000 MWh of non-firm exports limited. Both PJM and its capacity deficient neighbors were experiencing peak loads at the same time, and PJM did not have excess capacity to support export requests regardless of the supporting transmission service priority. After the morning peak load, PJM slowly started to lift the limits on exports; however, the duration of this event was much longer than that seen on Dec. 23, with firm curtailments persisting until 12:00 and non-firm curtailments persisting until 15:00. For the event on Dec. 24, PJM curtailed over 45,000 MWh of export transactions. Conversely, PJM observed over 40,000 MWh of import transaction curtailments on Dec. 24, primarily resulting from TLRs issued by neighboring Reliability Coordinators (RCs). At the peak of the curtailments, PJM briefly transitioned to an overall net-importer of energy for several hours on the Dec. 24, with a net schedule of approximately 2,800 MWh into the footprint for hour ending 08:00.

Figure 24 presents the Net Scheduled Interchange on Dec. 24.

Figure 24. Dec. 24 Net Scheduled Interchange

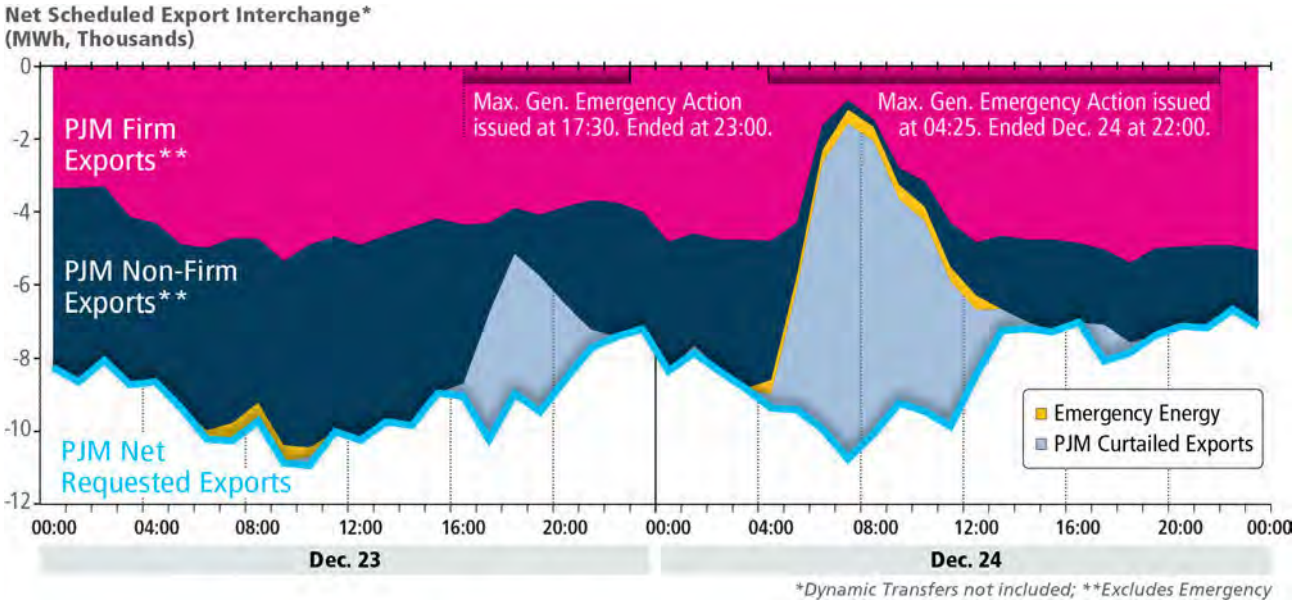


Coordination With Neighbors

As the extreme cold temperatures moved through areas to the southwest of the PJM footprint, neighboring systems began to experience strains. On both Dec. 23 and Dec. 24, PJM coordinated closely with its neighbors to maximize transfers. PJM provided emergency energy to adjacent systems as system conditions allowed on both Dec. 23 and Dec. 24 (Figure 25) before eventually having to reduce exports in order to serve consumers within the PJM footprint.

Transmission constraints also limited PJM's ability to support export transactions across the southern interfaces. These constraints included the pre-contingency emergency thermal limit of the Broadford 765/138 kV transformer and post-contingency transfer limit of the AEP-Dominion IROL interface. Figure 25 presents the Net Scheduled Exports for Dec. 23 through Dec. 24.

Figure 25. Dec. 23 and Dec. 24 Net Scheduled Exports



Comparing the values in Figure 25 to the supply/demand conditions that PJM actually experienced confirms that PJM could not have met system demand only by cutting non-firm exports. On Dec. 23, 2022, at 17:30, PJM issued a Pre-Emergency Load Management Reduction Action for the 30-minute and 60-minute Demand Resources that resulted in load reductions of about 1,100 MW. At the same time, PJM system operators also issued a Maximum Generation Emergency Action that resulted in an average of 2,372 MW of additional generation. In total, these actions had about 3,472 MW of impact. In comparison, non-firm exports were 1,241 MW for hour 18:00 and were 1,683 MWs for hour 19:00. Accordingly, even if the operators had cut all non-firm exports, there would have been a deficit of at least 1,789 MW needed to satisfy PJM load and firm exports. Pre-Emergency and Emergency Actions thus would have been necessary to satisfy capacity needs even if all non-firm exports had been cut.

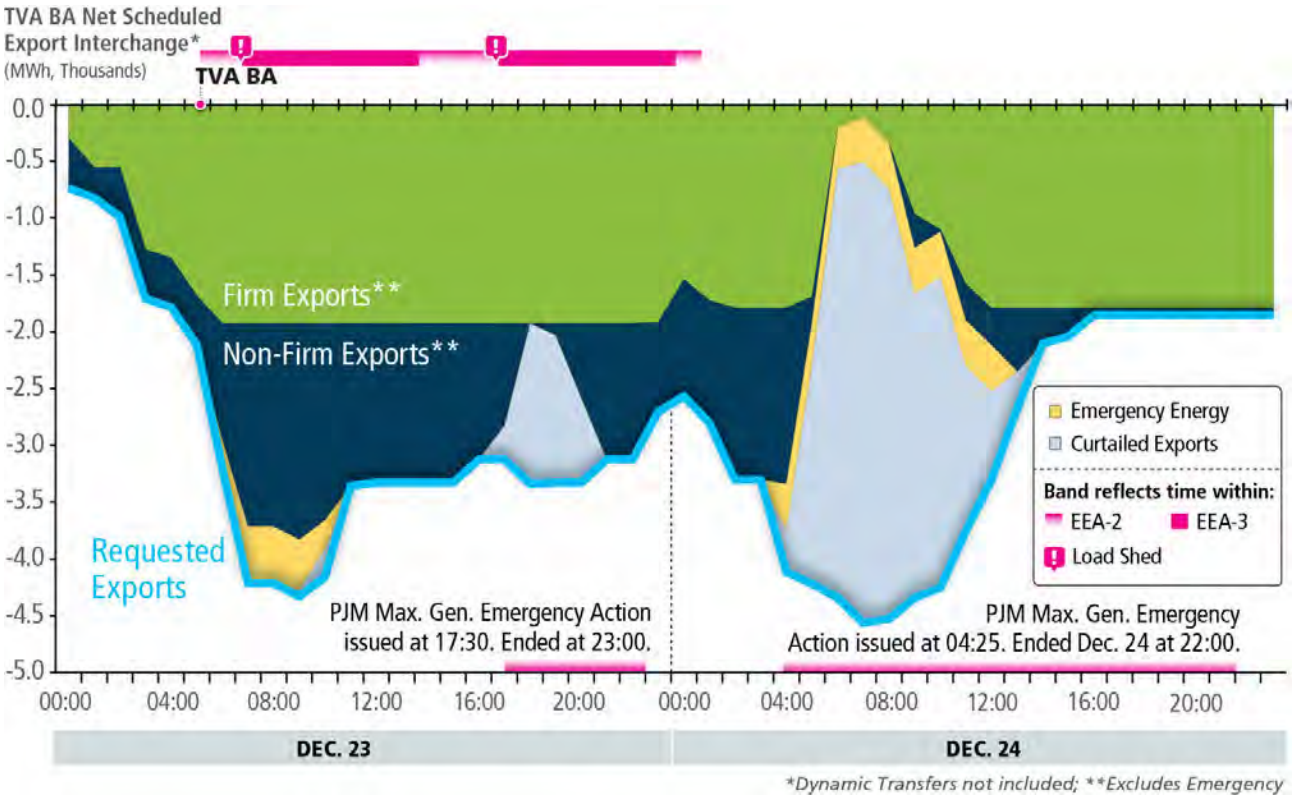
The situation for Dec. 24 is similar. At 04:20, PJM issued a Pre-Emergency Load Management Reduction Action and an Emergency Load Management Reduction Action that covered all Demand Resources and resulted in about 2,400 MW of load reduction. And at 04:28, PJM issued a Maximum Generation Emergency Action that it resulted in an average of about 2,879 MW in additional generation. In total, these actions had 5,279 MW of impact. In comparison, for hour 05:00, non-firm exports were 1,820 MW, falling to a low of 591 MW in hour 8:00 and increasing to a maximum level of 2,359 MW in hour 19:00 before the PAIs ended at 22:00. Accordingly, even if the PJM system operators had cut all non-firm exports there would have been a deficit between about 4,688 MW and 2,920 MW during this period needed to satisfy PJM load and firm exports. Pre-Emergency and Emergency Actions thus would have been necessary even if all non-firm exports had been cut.

Figure 25 also shows that PJM prioritized meeting its own load by cutting exports – both firm and non-firm – when necessary. The graph shows a significant number of hours in which the assistance requested by other regions was not

supplied. This correlates to the periods when PJM needed most of its generation for internal loads notwithstanding that, during some of these times, other regions were seeking emergency supplies.

As presented in Figure 26, PJM was able to assist TVA by providing non-firm exports during times that the TVA system was shedding load, which is represented by the fuchsia bars indicating when TVA was in an EEA-2 or EEA-3. Had PJM not done so, it is likely that TVA would have been required to engage in additional load shedding beyond what actually occurred.

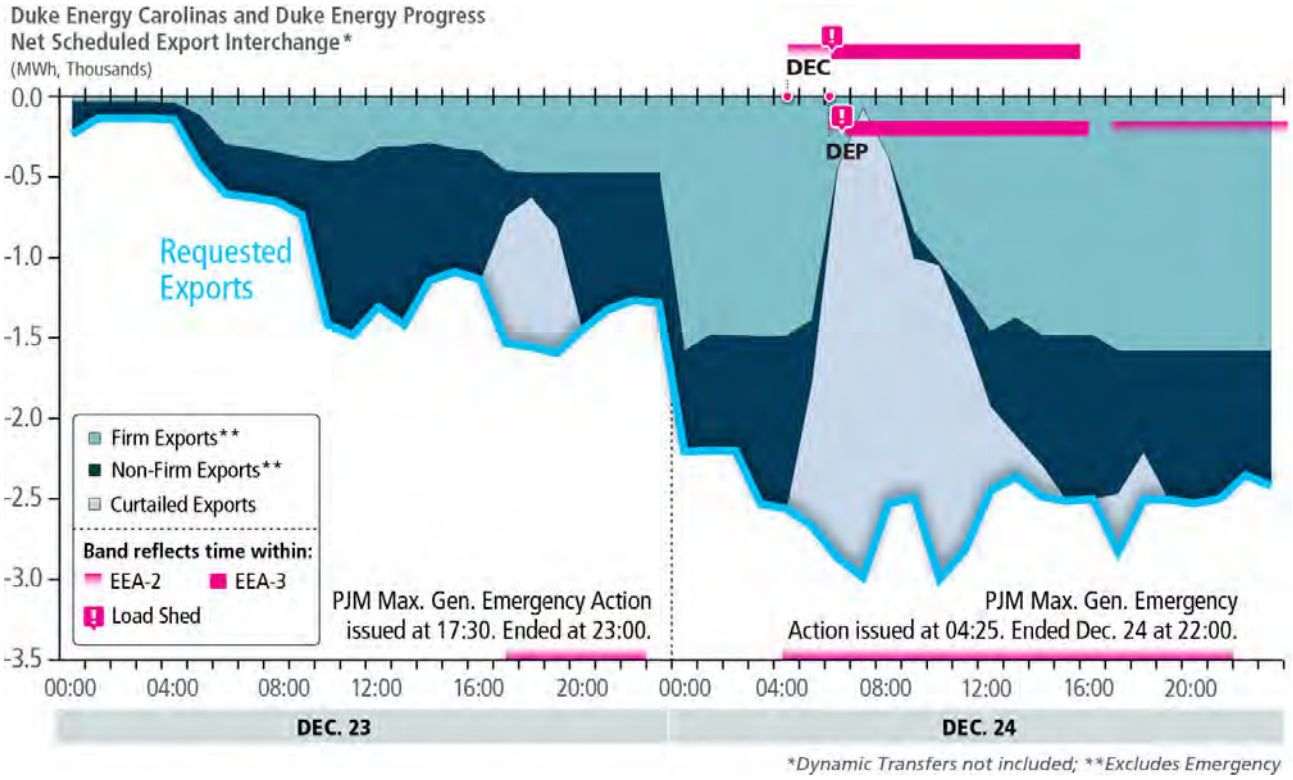
Figure 26. TVA BA Net Scheduled Export Exchange



The non-firm exports supplied to TVA provided assistance during periods when TVA was in a capacity deficient condition.

Similarly, the non-firm exports supplied to Duke Carolinas and Duke Energy Progress provided assistance to those systems when they were experiencing capacity deficient conditions as shown in the Figure 27.

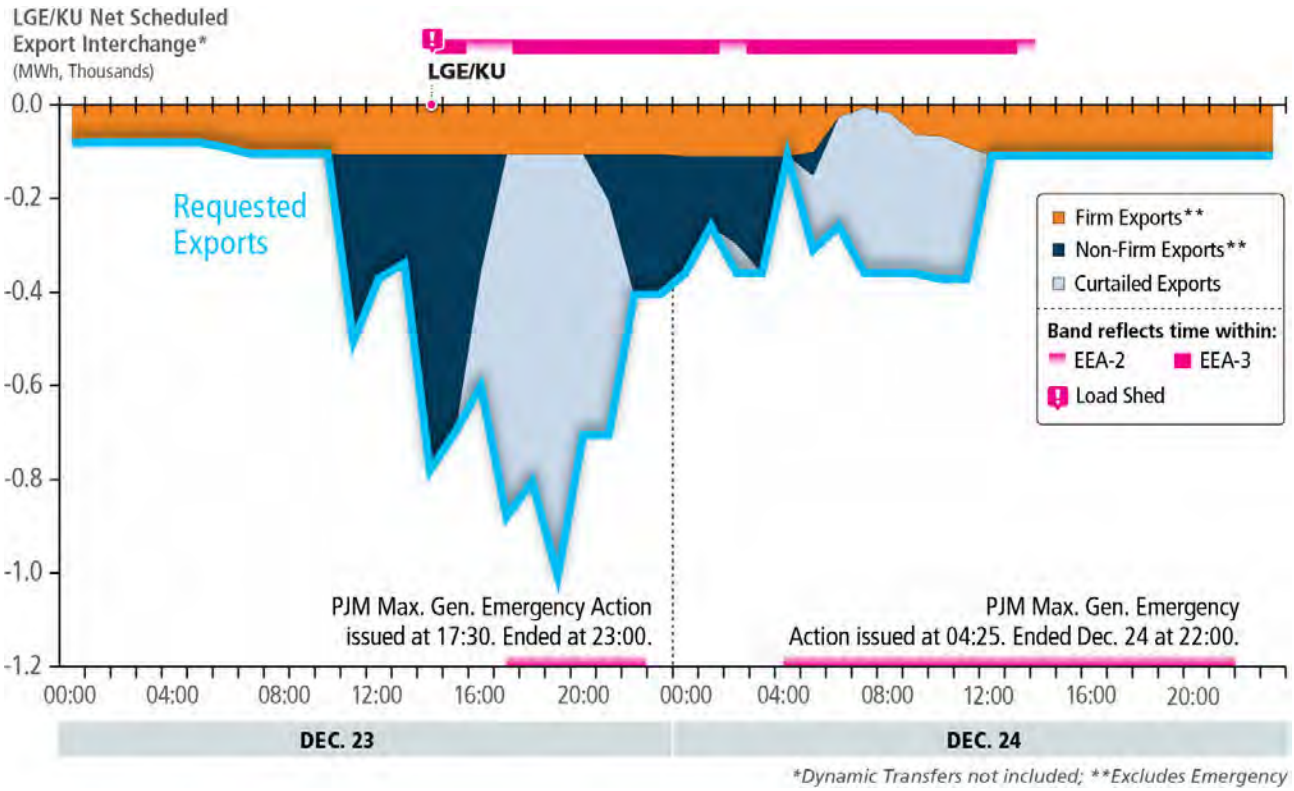
Figure 27. Duke Energy Carolinas & Duke Energy Progress Net Scheduled Export Interchange



As presented in Figure 27, PJM was also able to provide assistance by supplying non-firm exports to Duke Carolinas and Duke Energy Progress when they were shedding load. Again, if PJM had not provided this assistance, it is likely that Duke Carolinas and Duke Energy Progress would also have had to engage in more load shedding.

Lastly, Louisville Gas and Electric Company and Kentucky Utilities Company (LGE/KU) also received non-firm exports when they were experiencing capacity deficit conditions as shown in Figure 28.

Figure 28. LGE/KU Net Scheduled Export Interchange



PJM made non-firm deliveries to LGE/KU when the region was shedding load. Had PJM not made these exports, additional load shedding would likely have been needed.

Generation Performance

Prior to the operating day and Winter Storm Elliott, PJM had issued both Cold Weather Advisories and Cold Weather Alerts. Both procedures notify Generation Owners, Transmission Owners, and all PJM members of impending cold temperatures and to take action. Specifically, Generation Owners must take freeze protection actions, notify PJM of any operational changes or limitations as a result of the imminent cold weather, and update the operational parameters of generation units in Markets Gateway. These unit parameters include the Start-up and Notification Time, Min Run Time, Max Run Time, Eco Min, Eco Max, etc. Having accurate information about these unit parameters, in particular any changes to the start-up and notification times, are critical to PJM's decision making with respect to when a unit is given a commitment to run (i.e., when it is scheduled by PJM). PJM Dispatchers and their tools rely heavily on offer data information submitted by resource owner/operators. Given that 92% of forced outages that occurred were reported to PJM either after they occurred or with less than 60-minutes notice, it suggests that this information was not maintained throughout the event.

PJM started the operating day of Dec. 23 with 12,000 MW of unplanned outages, 4,293 MW of planned outages and 1,692 MW of maintenance outages at the evening peak on Dec. 23. These outages were primarily due to various equipment problems at generation facilities. PJM was tracking the cold temperatures arriving as a result of Winter Storm

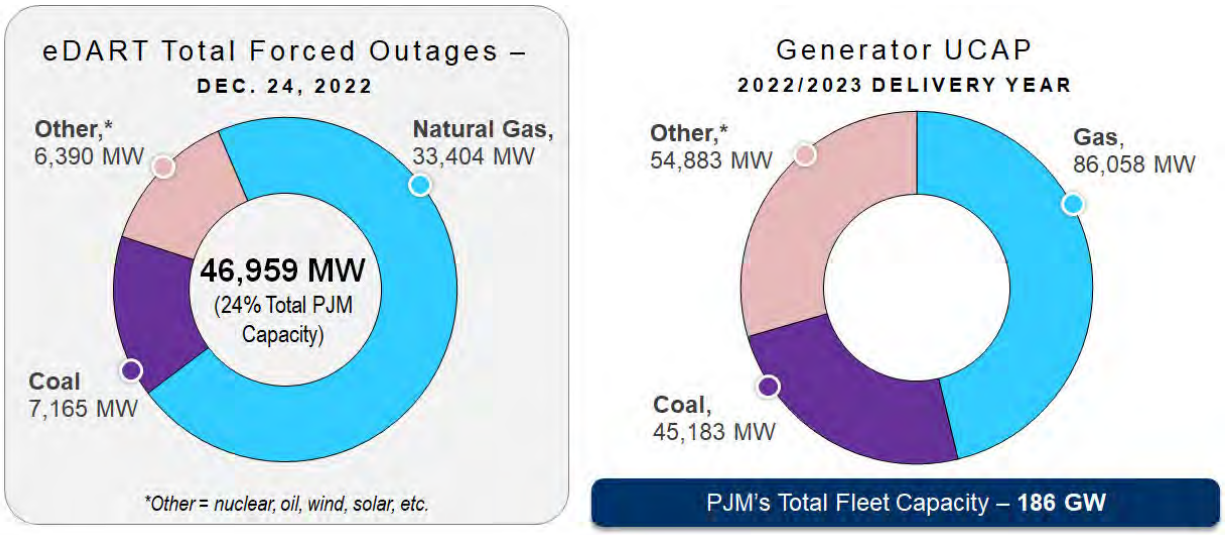
Elliott and did expect additional unplanned generation outages. For reference, the historic forced outage rate for winter is ~4.7%. The peak outage rate for the 2020/2021 winter period was 7.9%[7] and was 7.6%[8] for the 2021/2022 winter period.

While many generators performed well, the overall outage rate was unacceptably high. PJM had approximately 47,000 MW of units on forced outages during the hours when they were most needed. This correlates to a 24% forced outage rate. For comparison, the forced outage rate during the 2013 Polar Vortex was 22%. While a cross section of generation was impacted by the cold weather, gas plants and dual-fuel gas plants made up the majority of outages primarily due to mechanical issues likely resulting from the extreme cold.

Forced Outage Analysis

As presented in Figure 29, the majority of forced outage MW were from natural gas facilities. Approximately 70% of all outages were natural gas, about 16% coal, and the remainder were oil, nuclear, hydro, wind and solar.

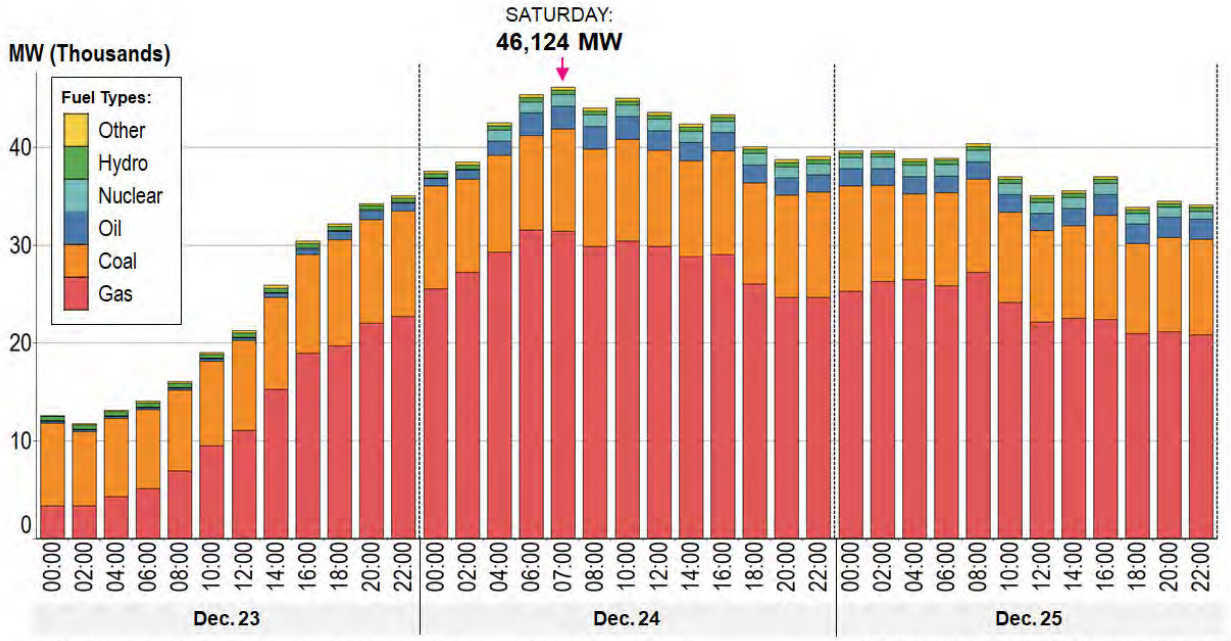
Figure 29. Forced Outages



As shown in the Figure 30, forced outages increased significantly and quickly throughout the day on Dec. 23 and peaked at over 46,000 MW at 07:00 on Dec. 24. Even as forced outage rates declined from the peak, they remained at an unacceptably high level through Dec. 25.

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

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

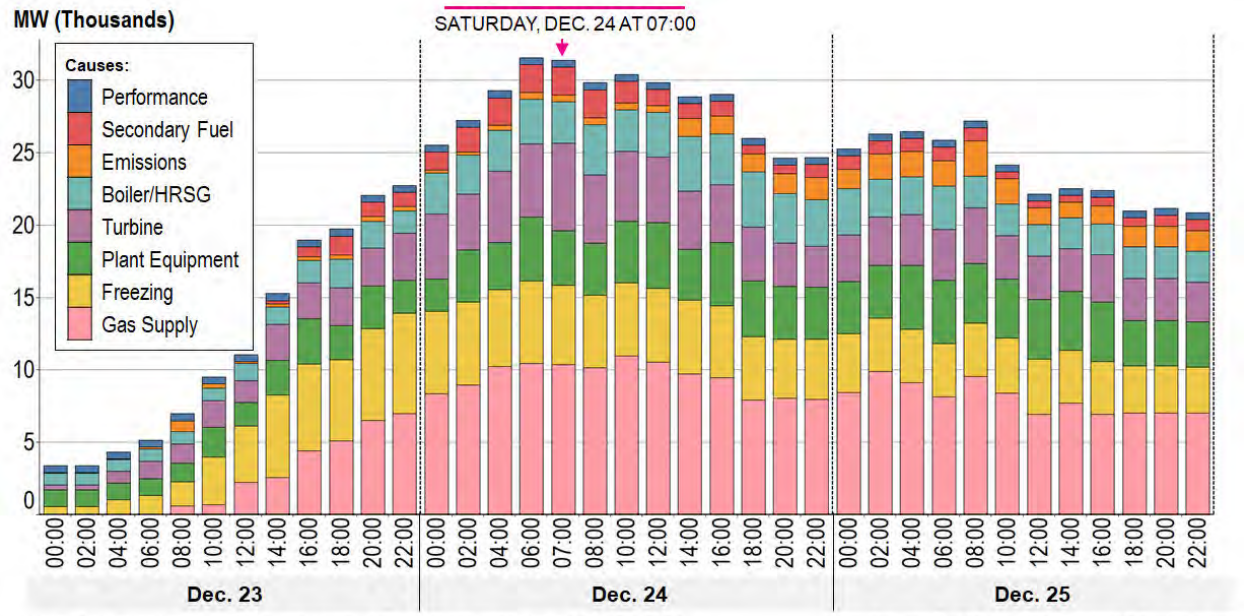


Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

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

Looking more closely at the causes for the generation outages by fuel type indicates that various plant and mechanical failures, including freeze-related issues, were the major reasons units were unavailable. Figure 31 presents the gas unit forced outages. As with other resource types, outages on gas units were primarily attributed to physical plant issues (freezing and plant equipment issues), but gas generators also experienced a significant level of gas supply issues. The gas supply-related outages accounted for just over 11,000 MW (approximately 13% of total gas generation capacity) at the peak hour on Dec. 24. By contrast, during the 2014 Polar Vortex, the total gas resources that were unavailable on peak due to gas supply issues was 9,300 MW (approximately 19% of total gas generation capacity).

Figure 31. Dec. 23, 24 and 25 Gas – Forced Outages/Derates by Cause

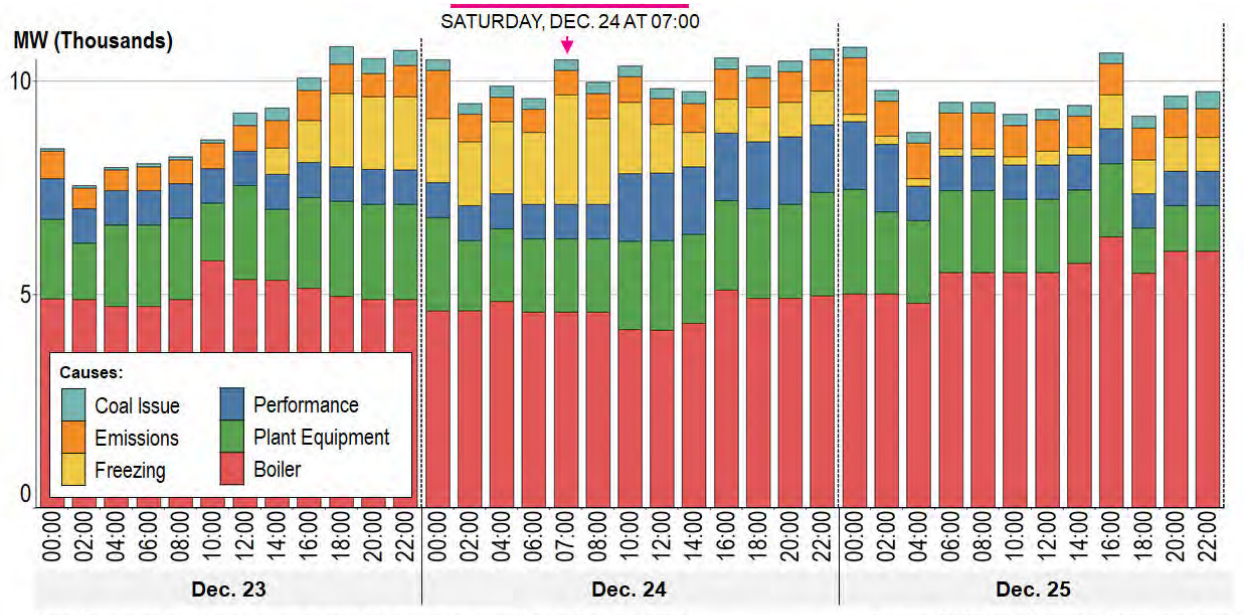


Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

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

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

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

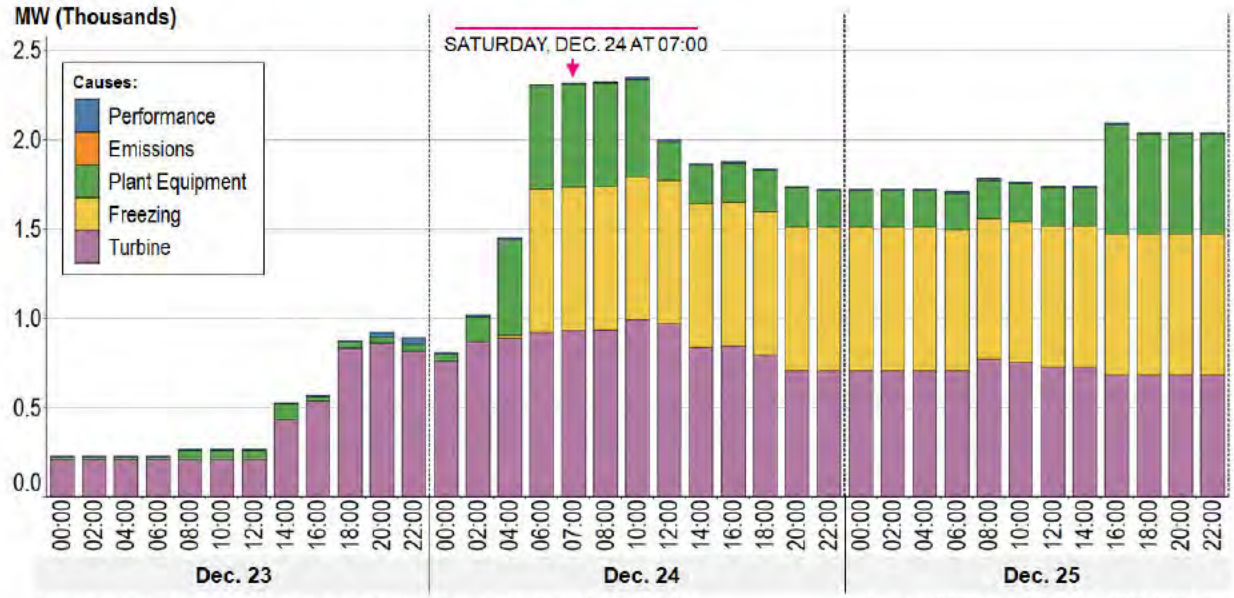


Note: Only even hours are shown for readability with the exception of Dec. 24, 2022, 07:00, which was the hour with the largest amount of forced outages and derates.

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

As shown in **Figure 33**, for oil units, turbine issues accounted for a large majority of the outages. A significant amount of freeze-related outages and derates were experienced from 06:00 on Dec. 24, and continued throughout the day on Dec. 25.

Figure 33. Dec. 23, 24 and 25 Oil Forced Outages/Derates by Cause

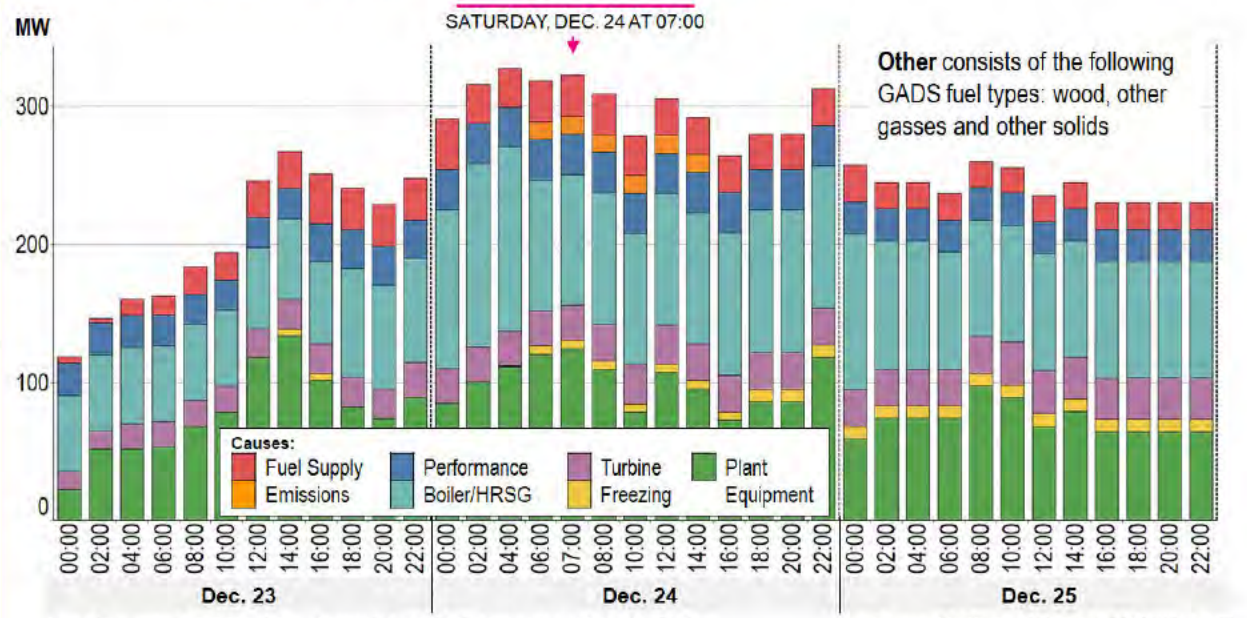


Note: Only even hours are shown for readability with the exception of Dec. 24, 2022. 07:00, which was the hour with the largest amount of forced outages and derates.

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

As presented in **Figure 34**, for generators fueled by wood, other gases or other solids, most outages/derates were attributed boiler, HRSG and other plant equipment problems.

Figure 34. Dec. 23, 24 and 25 Other – Forced Outages/Derates by Cause

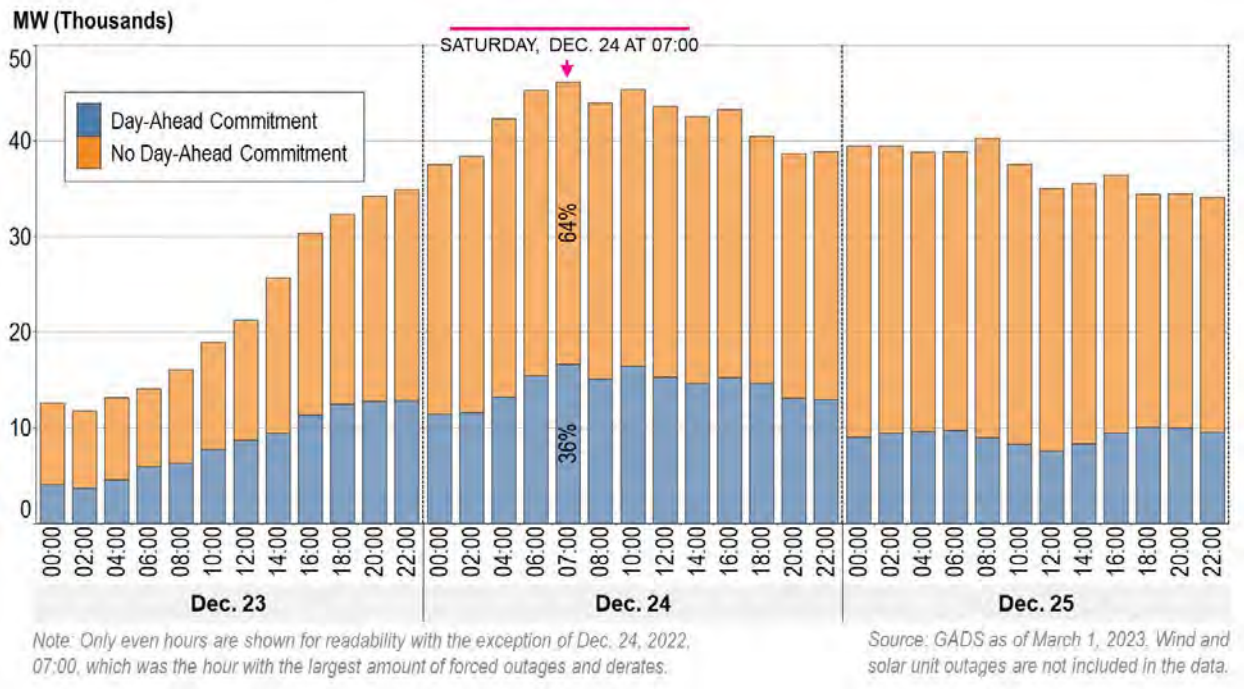


Note. Only even hours are shown for readability with the exception of Dec. 24, 2022. 07:00, which was the hour with the largest amount of forced outages and derates.

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

In addition to the causes of the forced outages and the outages by fuel type, Figure 35 presents the outages for units based on day-ahead commitments. This is an important piece of the puzzle to understand with respect to PJM's planning for the operating day. PJM always expects some resources will fail. On cold weather days in particular, this is considered and noted in PJM Manual 13. However, as Figure 35 shows, over 16,000 MW of generation that was committed in the Day-Ahead Market failed to perform.

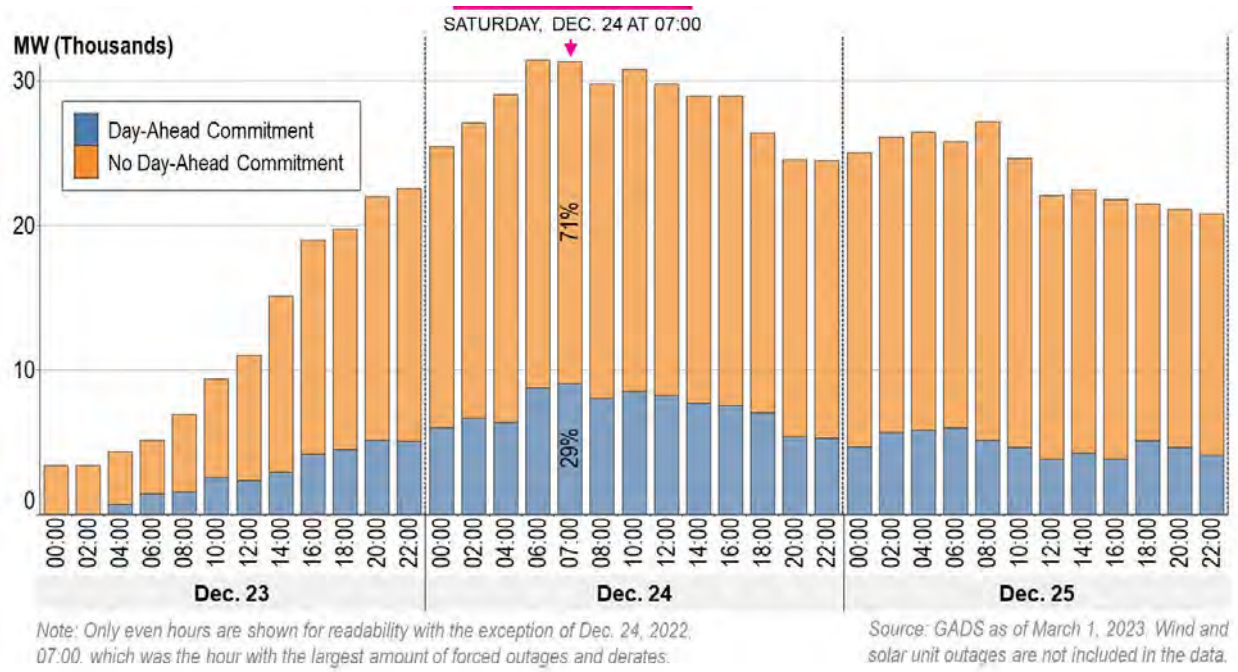
Figure 35. Dec. 23, 24 and 25 Forced Outages With and Without Day-Ahead Market Commitment



When scheduling replacement energy to account for the missing 16,000 MW, PJM was relying on the unit information submitted by Generation Owners to evaluate the amount of available reserves and the timelines needed to schedule those units if/when needed (15-minute notice, 30-minute notice, one-hour notice, etc.) As noted previously, PJM requires Generation Owners to update their parameters to reflect any changes from normal operating condition so that the reserve calculations are accurate. However, in the case of Winter Storm Elliott, these parameters were not updated for many generators. More specifically, the following information was not updated to align with actual operating conditions including longer notification times, extended minimum run times, inflexibility in dispatch range, etc. This was predominately related to gas-fired generators where pipeline restrictions, nomination deadlines and the unavailability of gas supply were not accurately reflected in generator operating parameters, despite having the ability to utilize Temporary Exceptions or Real-Time Values (PJM Manual 11, Sections 2.3.4.3 and 2.3.4.4) to convey this information accurately to PJM.

For the Dec. 23 operating day, only 6% (37 out of 578) of the gas-fired generators in the PJM system submitted increased notification time requirements. All others were reported as available to operate, with their normal operating parameters in place. This lack of timely and accurate information led to extremely challenging conditions for the PJM system operators that continued through the end of the day on Dec. 25. As presented in Figure 36, the failure of so many Day-Ahead Market committed units, coupled with the lack of generator parameter updates, led to a high volume of natural gas generators having no Day-Ahead Market commitment and then becoming forced outages due to lack of fuel.

Figure 36. Dec. 23, 24 and 25 Forced Outages With and Without Day-Ahead Market Commitment



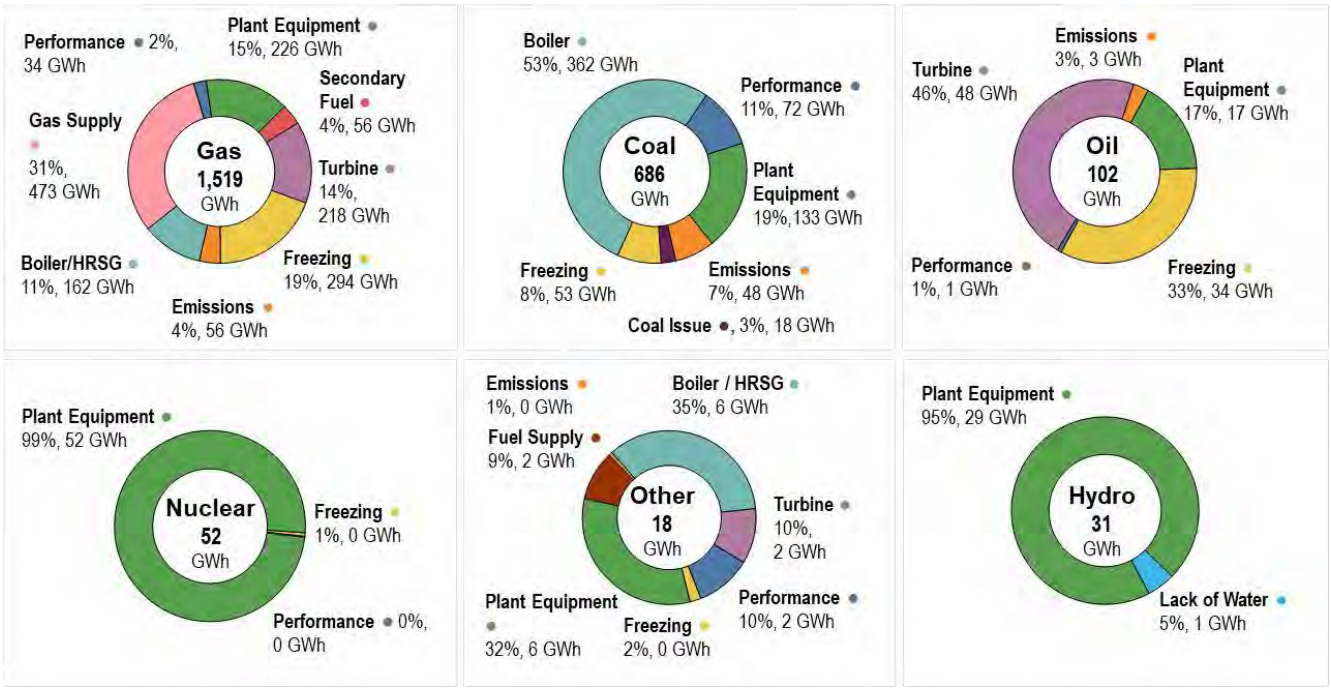
In addition to forced outages, approximately 6,000 MW of steam generation was called but was not online as expected per their time to start for the morning peak on Dec. 24. The vast majority of these resources were gas-fired resources.

The high rates of generator outages also limited PJM's ability to replenish pond levels for pumped storage hydro prior to the morning peak on Dec. 24. That left PJM with extremely limited run hours for pumped storage generation. Between forced outages, derates, generators that did not start on time, and the inability to fill pumped storage hydro ponds, PJM was operating with approximately 47,000 MW of generator unavailability for the Dec. 24 morning peak, including the unavailability of pumped storage resources to generate.

The highest forced outage rate during Winter Storm Elliott was over 24%, which is higher than PJM experienced during the Polar Vortex in 2014. This level of generation outages was unprecedented and not anticipated. PJM, along with the Independent Market Monitor, has undertaken efforts to determine what happened with these generators to understand both why these failures occurred and how to reduce them in the future. This is further discussed later in the report.

To effectively compare resource unavailability by fuel type and by cause during the Winter Storm Elliott event, both the reduction quantity and duration must be considered. While a 1,000 MW forced outage is much larger than a 100 MW forced outage, if the 1,000 MW forced outage only lasts one hour but the 100 MW forced outage lasts one day, then the 100 MW forced outage is a more significant unavailability event. Using MWh as the comparison metric incorporates both the magnitude and duration of the outage to give a more complete picture of the impact. Figure 37 presents the MWh analysis for a duration of Dec. 23 00:00 to Dec. 25 23:59.

Figure 37. Dec. 23, 24 and 25 Forced MWh by Fuel Type and Cause



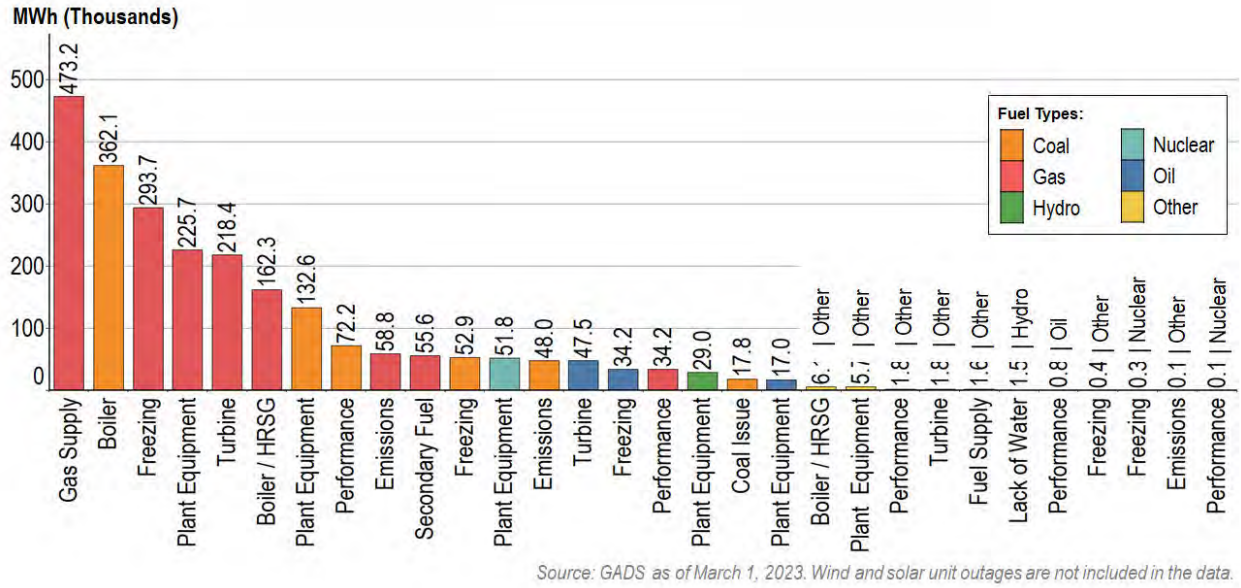
In Figure 38, total available MWh for the period of Dec. 23 to Dec. 25 was calculated by multiplying GADS Net Dependable Capacity by 72 hours. The MWh outage rates shown in Figure 38 were then overlaid to show availability by fuel type.

Figure 38. Dec. 23, 24 and 25 Availability by Fuel Type



Figure 39 breaks down the outage causes further, considering both fuel type and outage cause. Overall, freezing, plant equipment issues – including boiler, heat recovery steam generator (HRSG) and turbine problems, and emissions make up the majority of outages.

Figure 39. Dec 23, 24 and 25 Forced MWh by Fuel Type and Cause



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

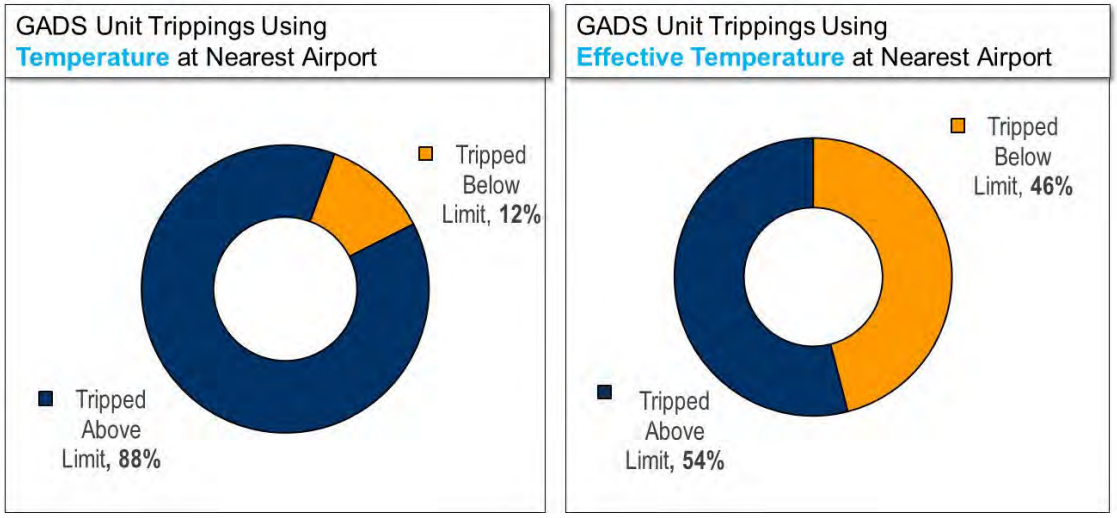
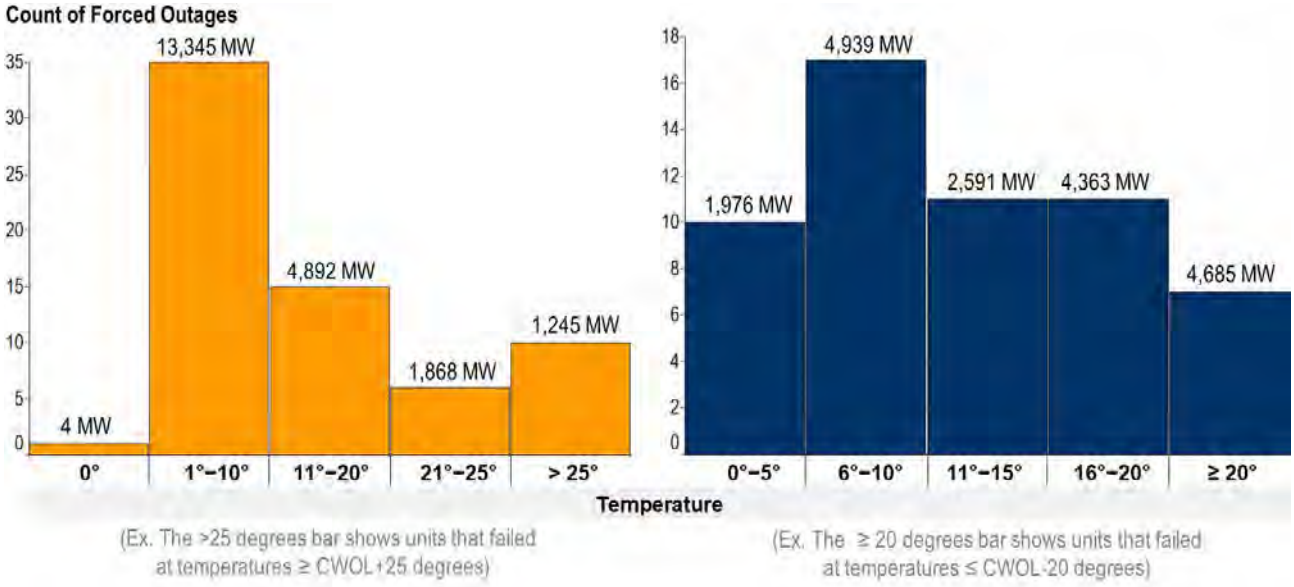


Figure 41 presents a comparison of the effective temperatures experienced by units at the time of a cold weather-related forced outage with their submitted CWOL temperature. The chart to the left presents the MW quantity of the units that failed at different temperatures ranges prior to reaching their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

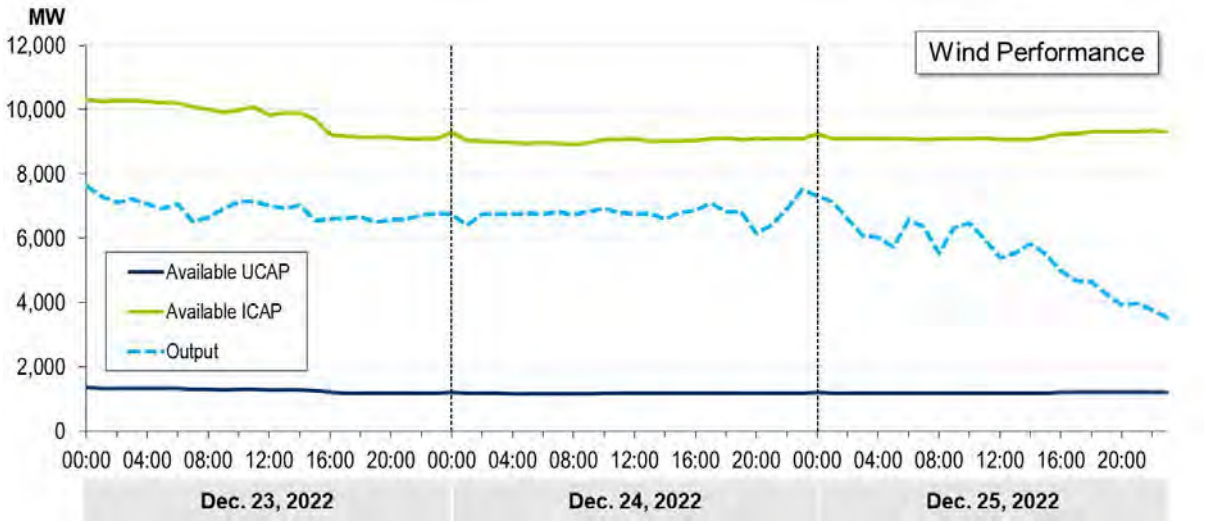
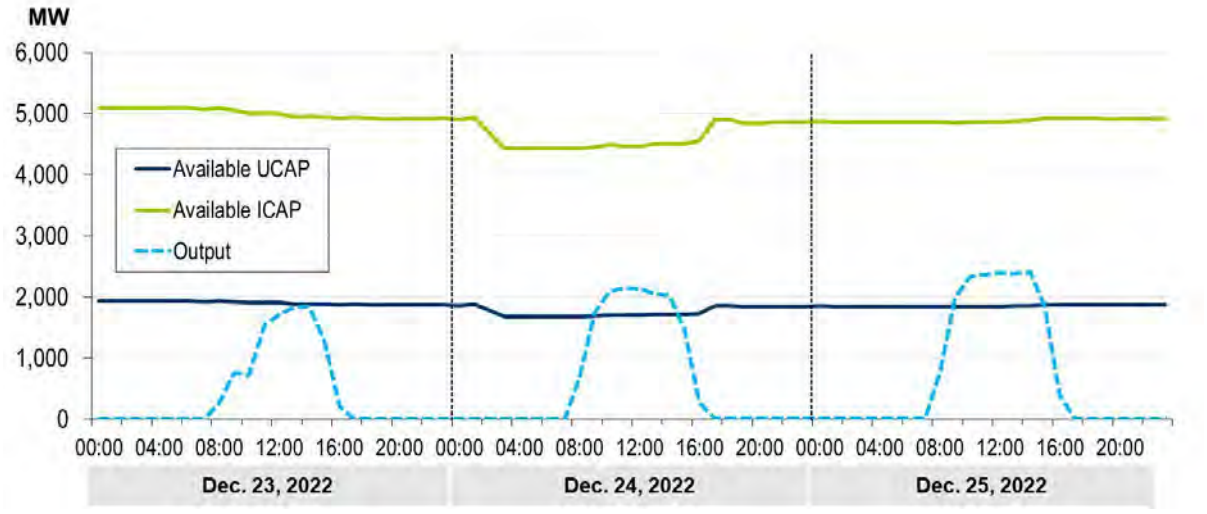


Figure 43. Solar Resource Performance

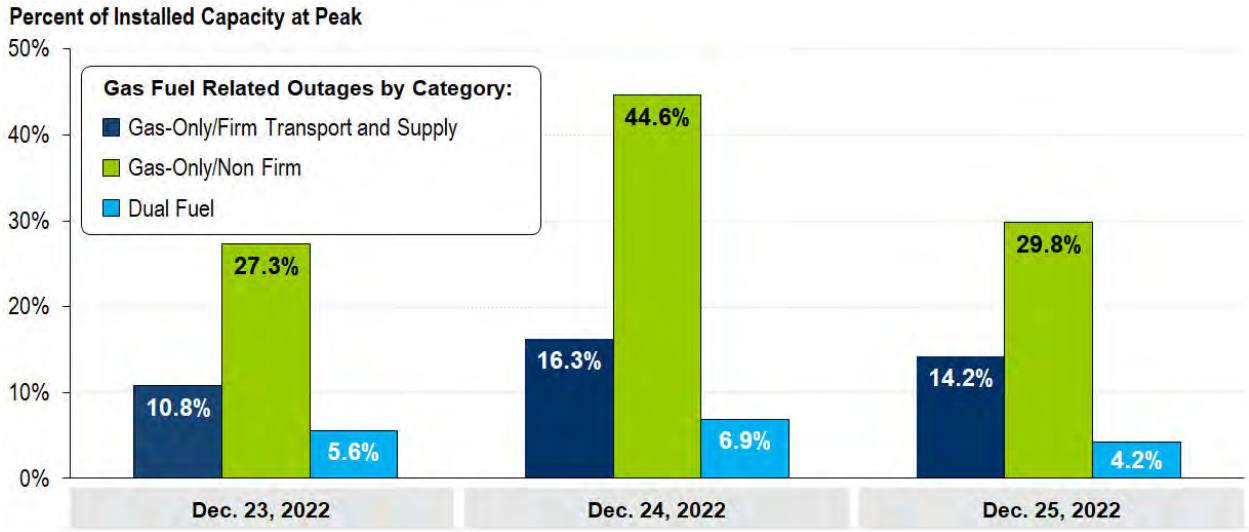


Fuel Security Observations

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.

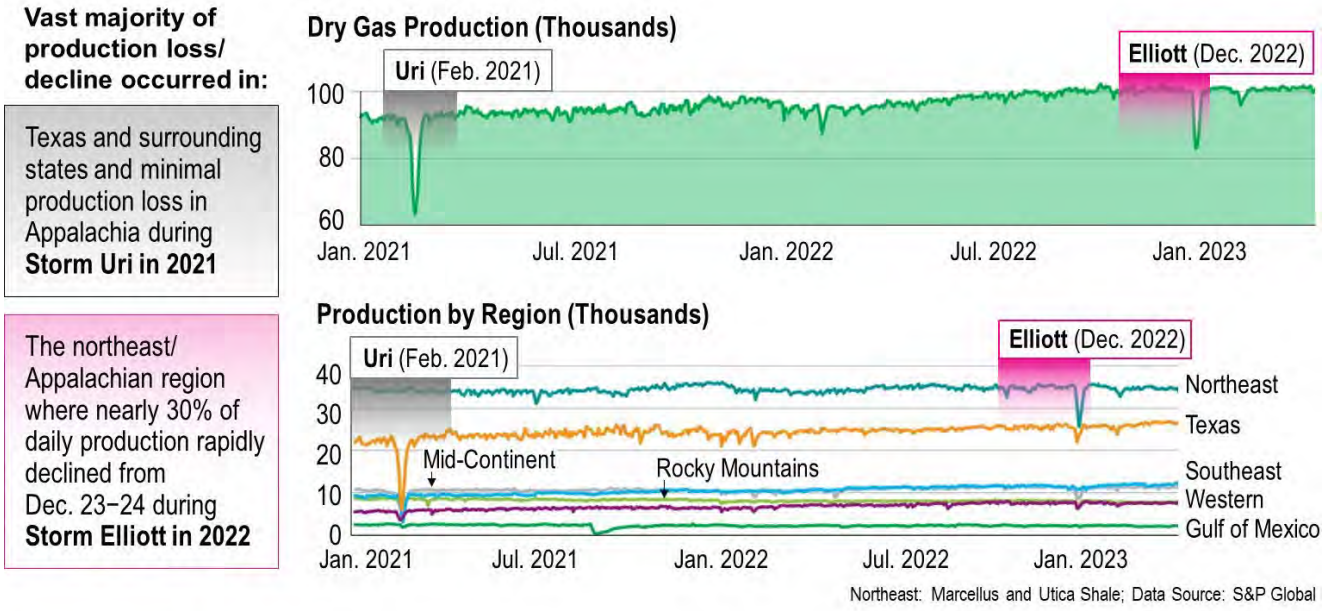
In addition, during this time, several local gas distribution companies (LDCs) began to issue interruption notices for a small number of generators behind their citygates. This is not unexpected during very cold temperatures as LDCs, by nature of their service tariffs, can interrupt gas generation customers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

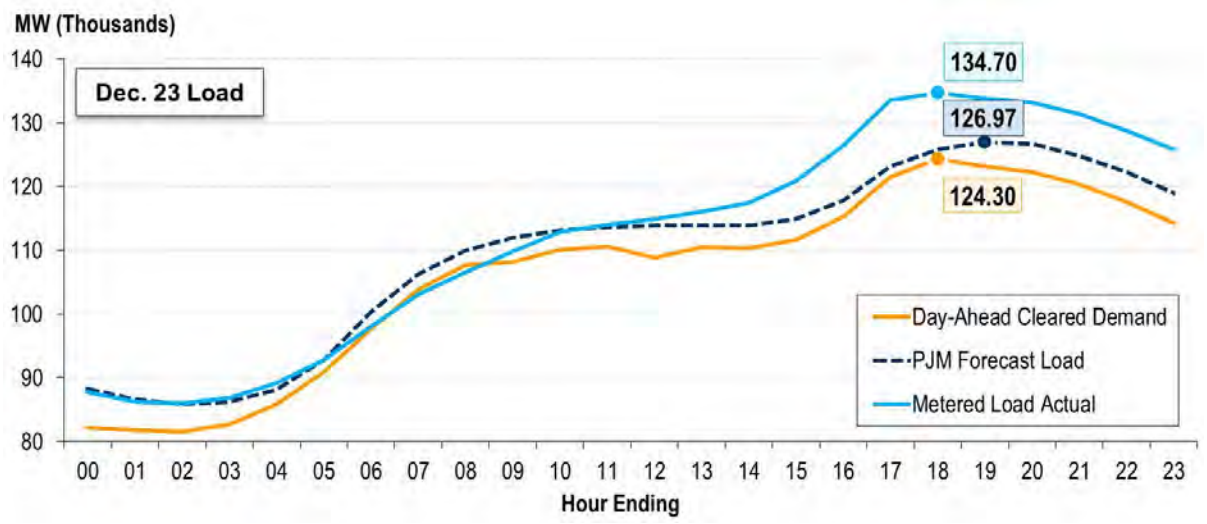
The Day-Ahead Energy Market is a forward market in which hourly clearing prices are calculated for each hour of the next operating day, based on generation offers, demand bids, increment offers, decrement bids, up-to-congestion bids and bilateral transaction schedules submitted into the Day-Ahead Energy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

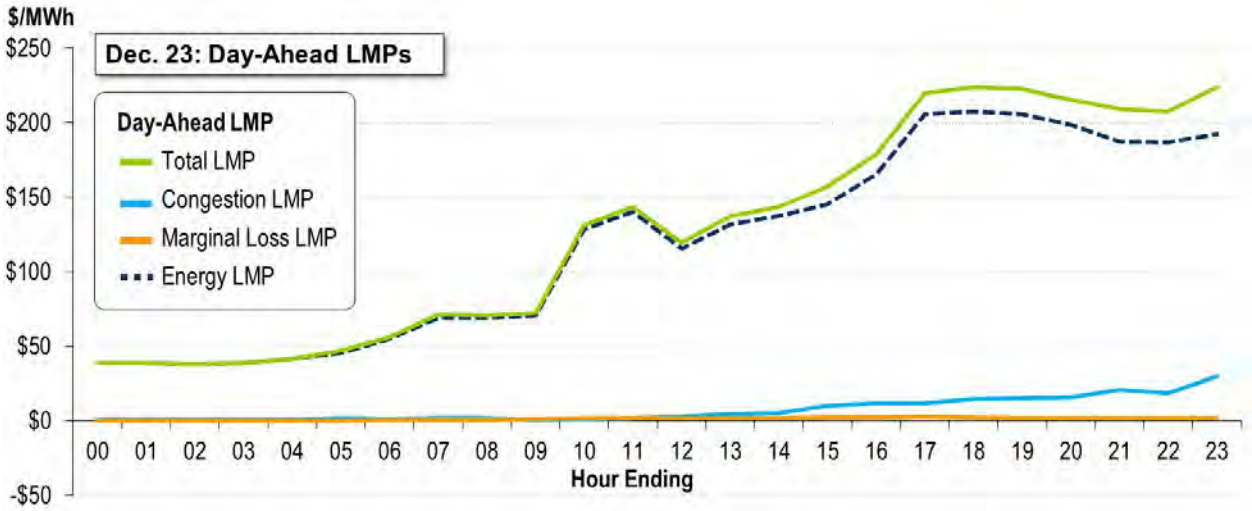
Figure 46. Dec. 23 Day-Ahead Cleared Demand, Forecast Load and Metered Load



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

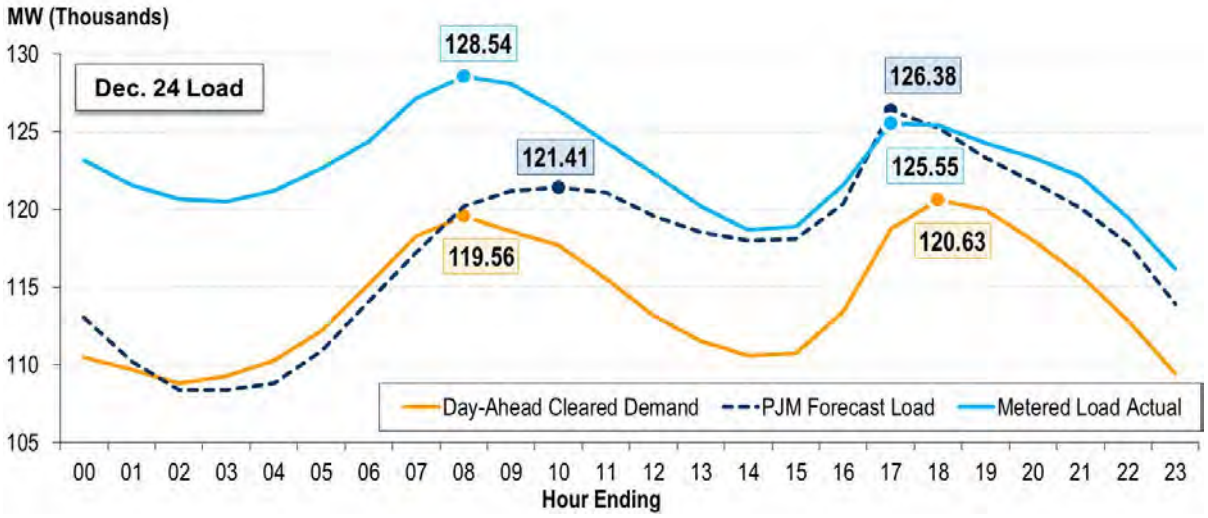


The Day-Ahead LMPs for Dec. 23 were higher than a typical Day-Ahead price, with a peak hourly LMP of $224/MWh. For example, the monthly load-weighted LMP for December 2022 was $93.39/MWh[10]. In the Day-Ahead Market, energy shortage conditions did not occur. LMPs increased in the Day-Ahead Market through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

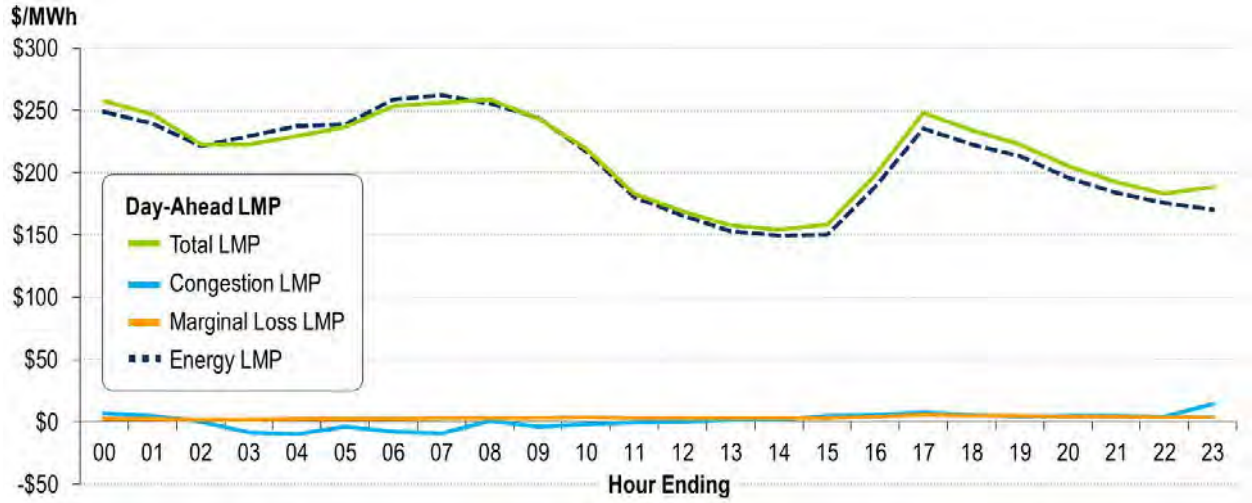
Figure 48. Dec. 24 Day-Ahead Cleared Demand, Forecast Load and Metered Load



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%

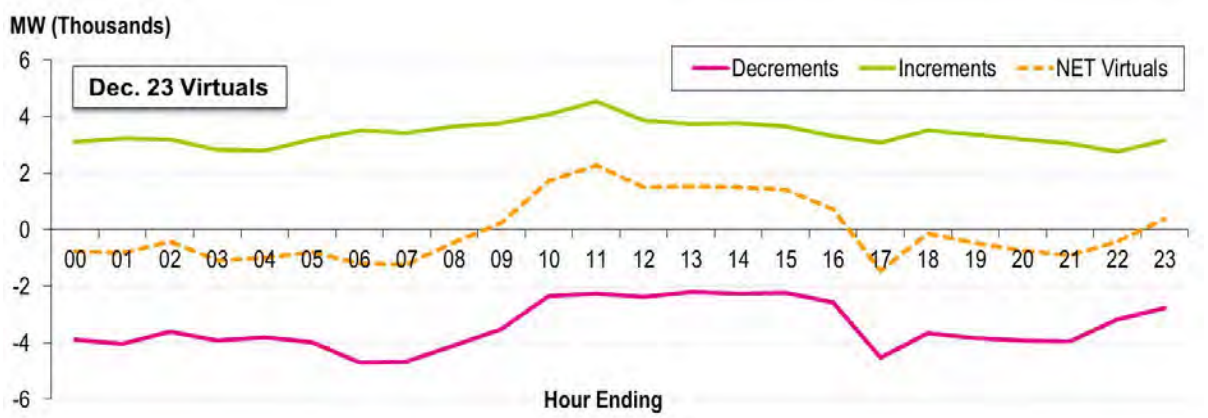
Virtual Transactions

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.

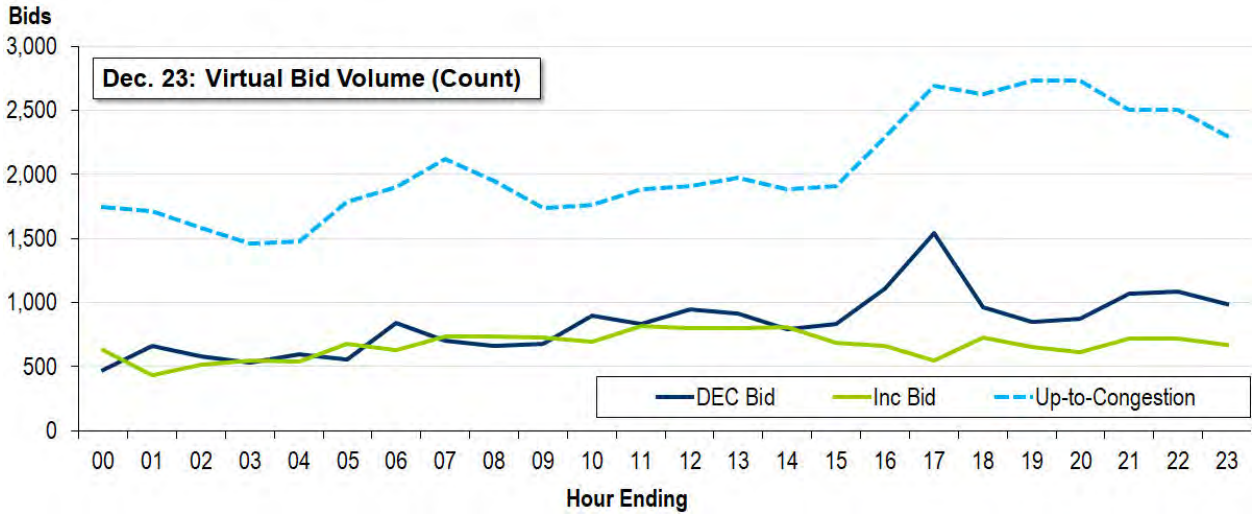
Figure 50. Dec. 23 Cleared Virtual Transactions



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.

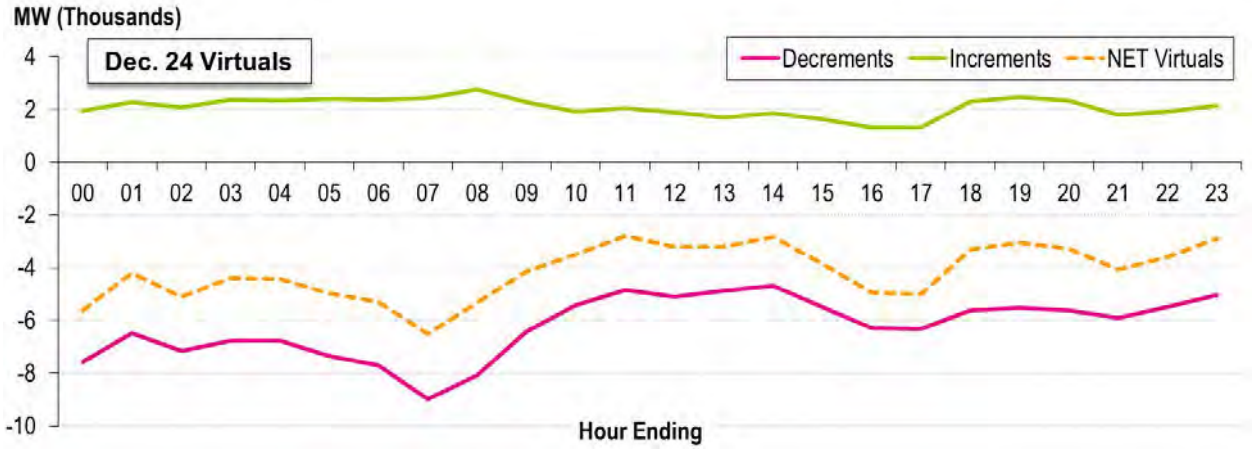
Figure 51. Dec. 23 Virtual Transaction Bid Volume



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.

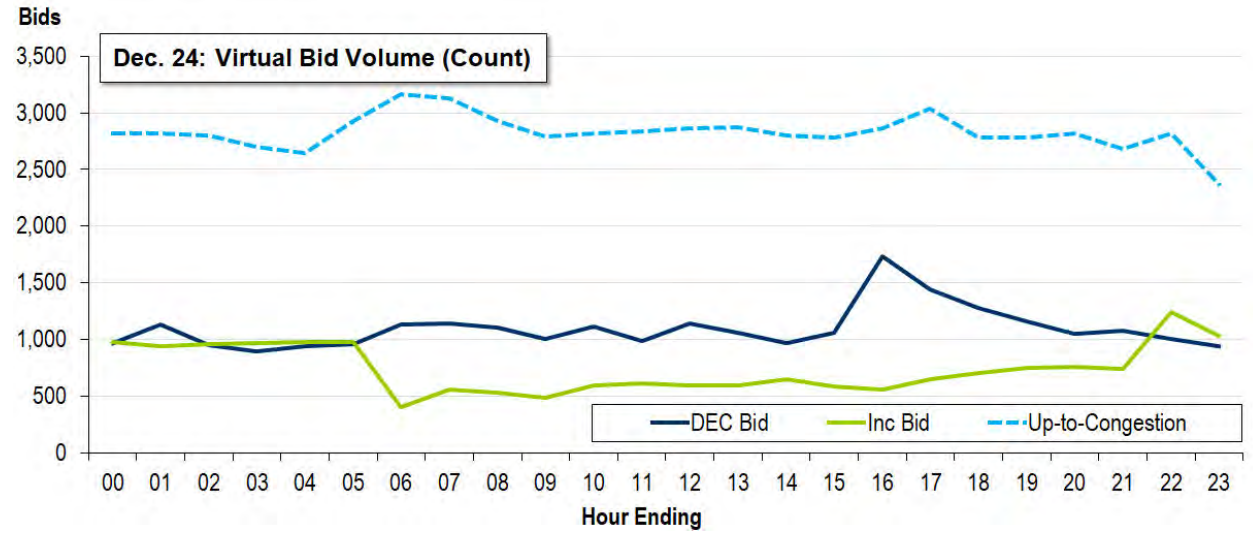
Figure 52. Dec. 24 Cleared Virtual Transactions



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

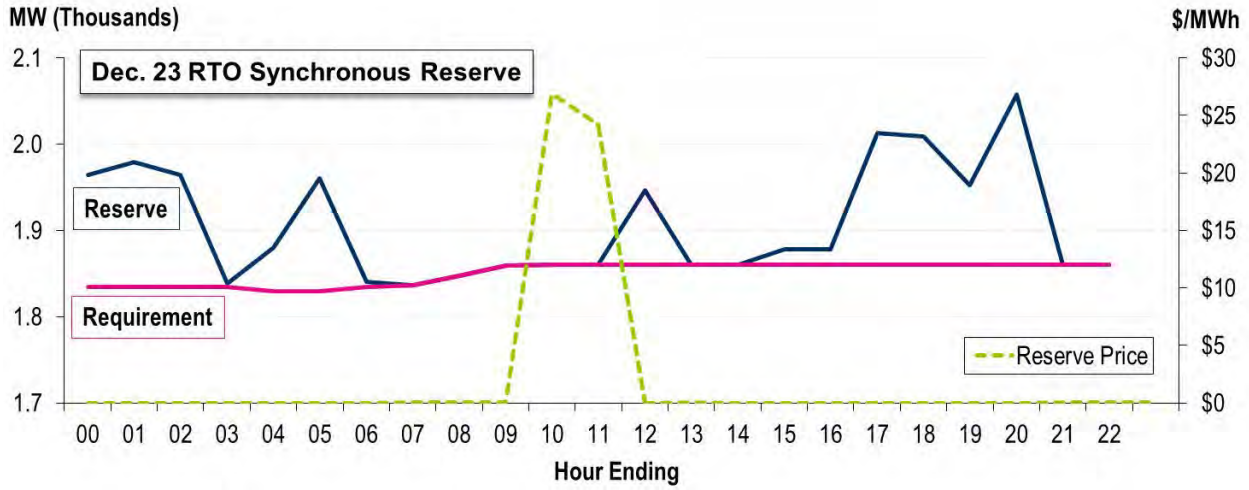
PJM procures resources to meet its reserve requirements, as described earlier in this section, in the Day-Ahead Markets. The clearing of the Day-Ahead Reserve Market results in an hourly price for Synchronized Reserves, Non-Synchronized Reserves and Secondary Reserves for the next day. These prices are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

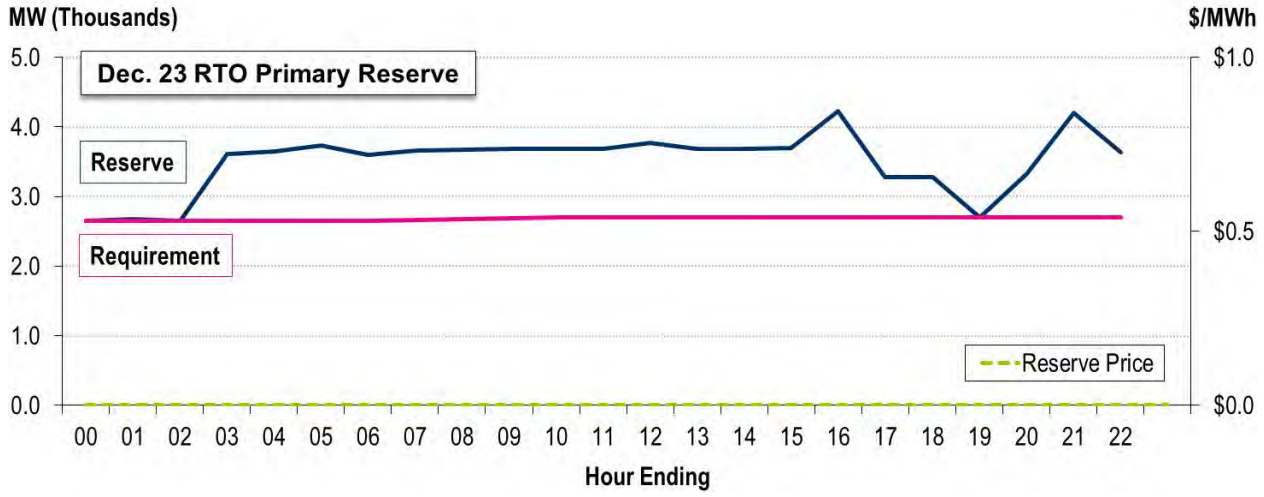
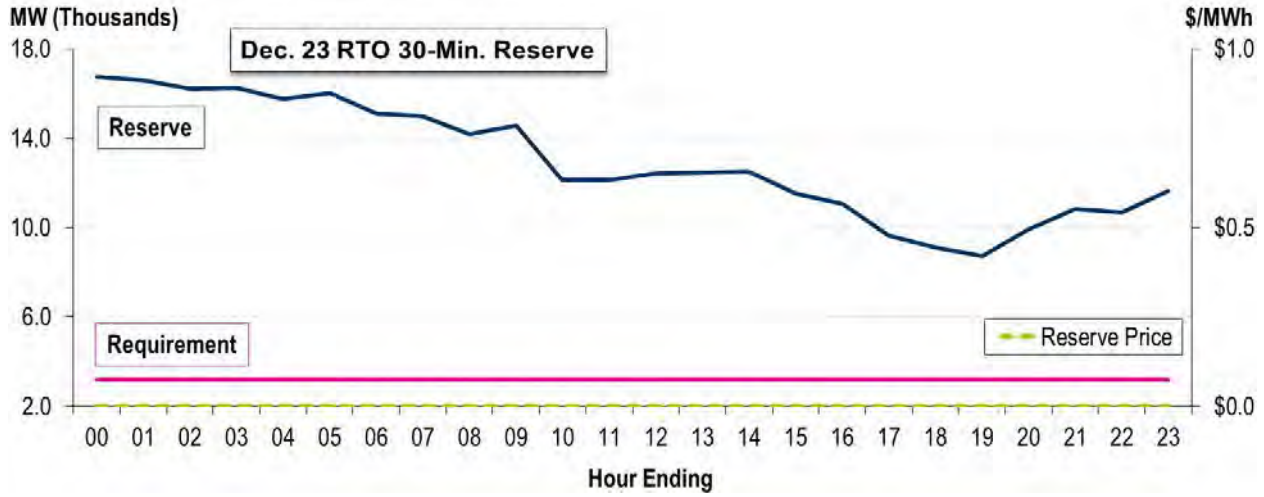


Figure 56. Dec. 23 30-Minute Reserve and Prices



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

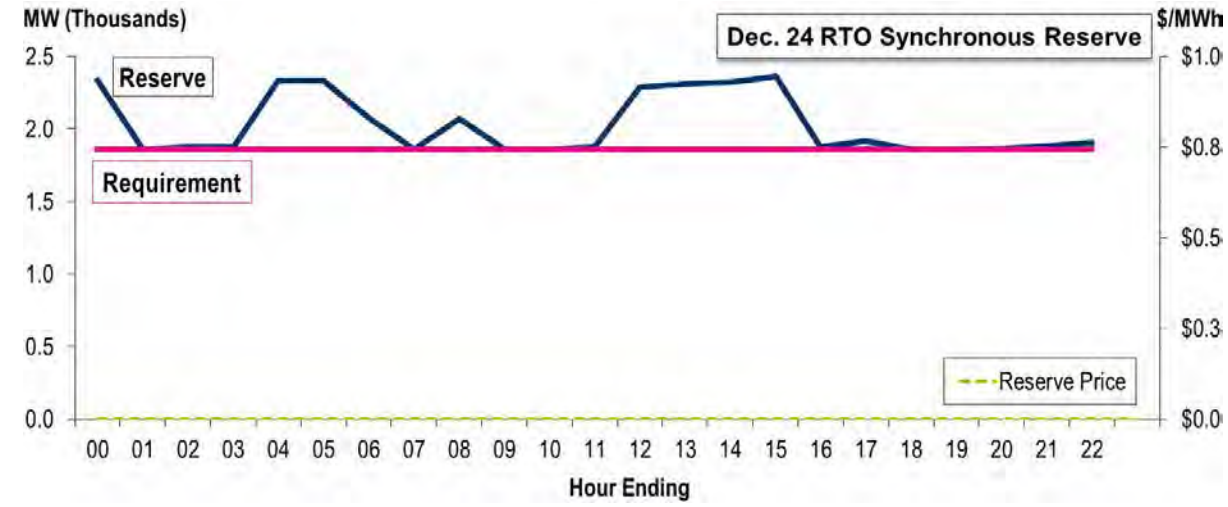


Figure 58. Dec. 24 Day-Ahead Primary Reserve

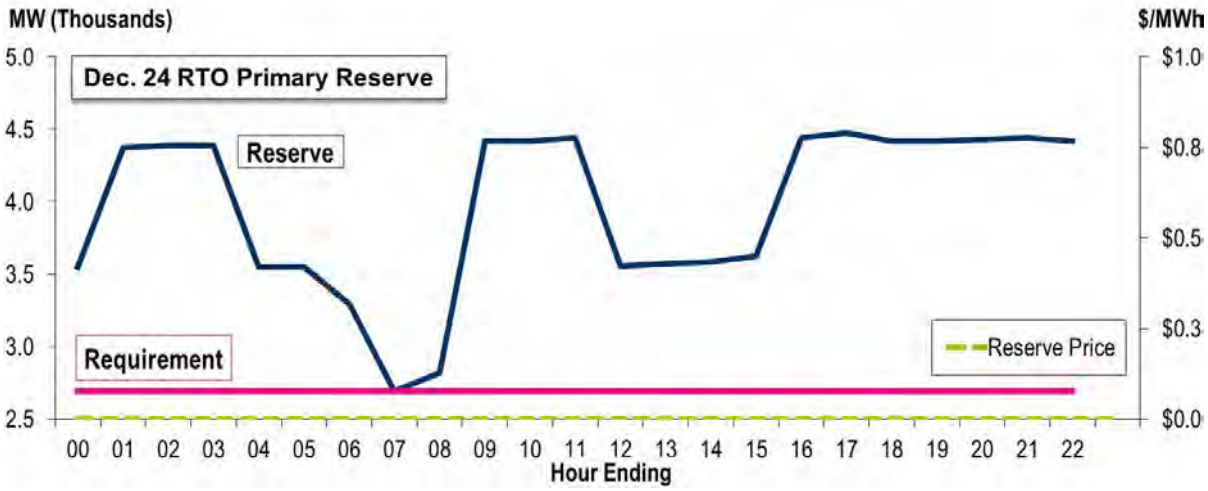
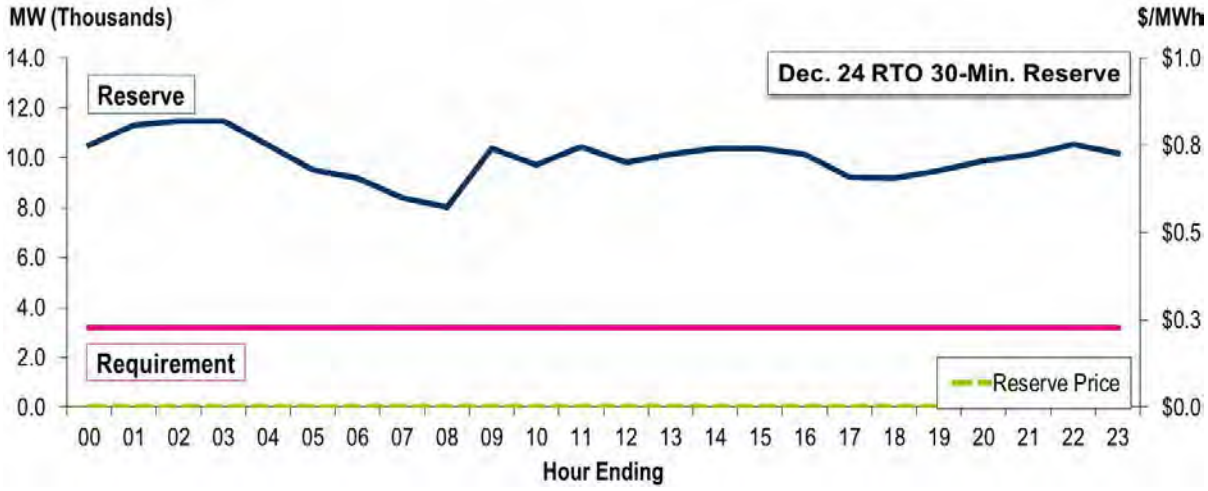


Figure 59. Dec. 24 30-Minute Reserve & Prices



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.

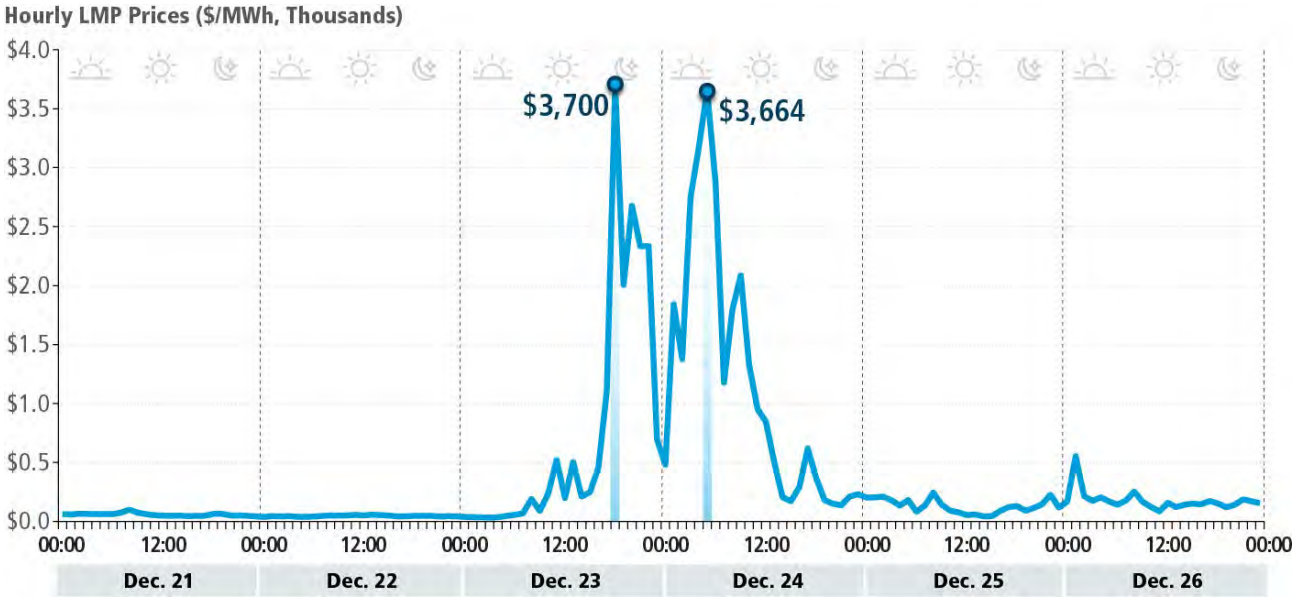
Real-Time Market Results

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.

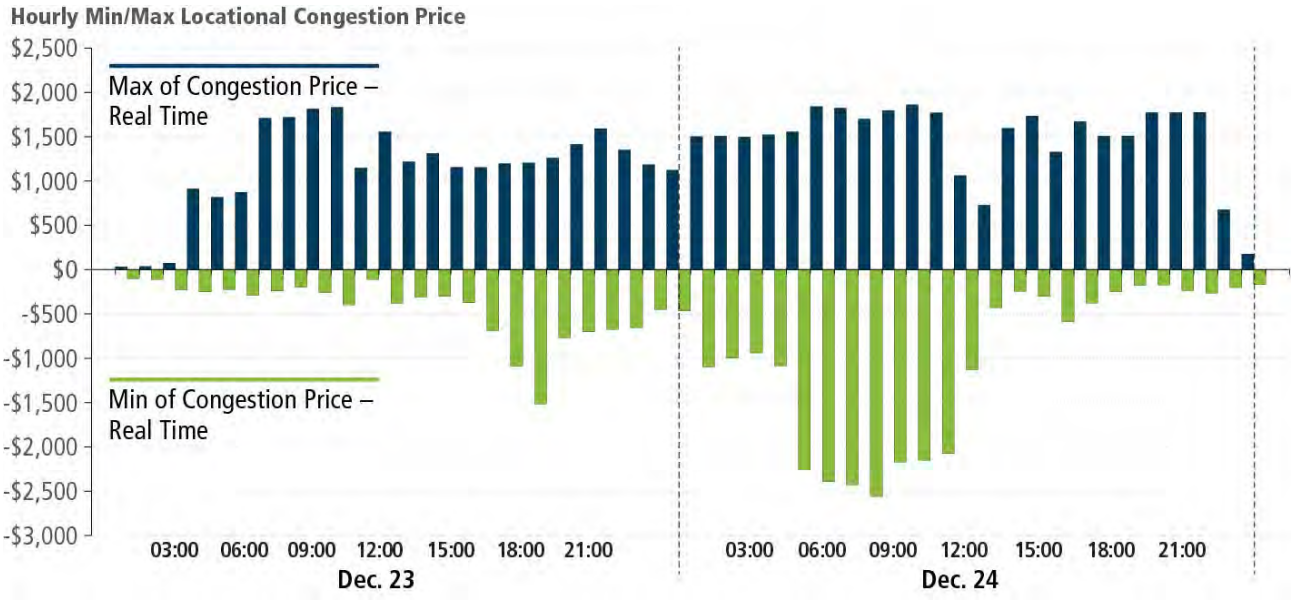
The underlying goal and intent of reflecting the TCPF in LMPs is to provide market signals that incentivize supply and/or load response to help relieve a constraint in the short term, while also incentivizing the development of additional supply, load response and/or transmission upgrades through long-term 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 04:35–09:55
CONASTON-PEACHBOT 5012B 500 KV	BC	21	22:20–23:45	00:40
CABOT-KEYSTONE 5002B 500 KV	APS	1	12:25	
BROADFO2 T6 XFORMER H 765 KV	AEP	28	09:15–11:10 12:30–12:45 12:55	

Note: A complete list of binding constraints is available at Data Miner.

Figure 62 presents the locational impact of congestion for a sample interval on the evening of Dec. 23.

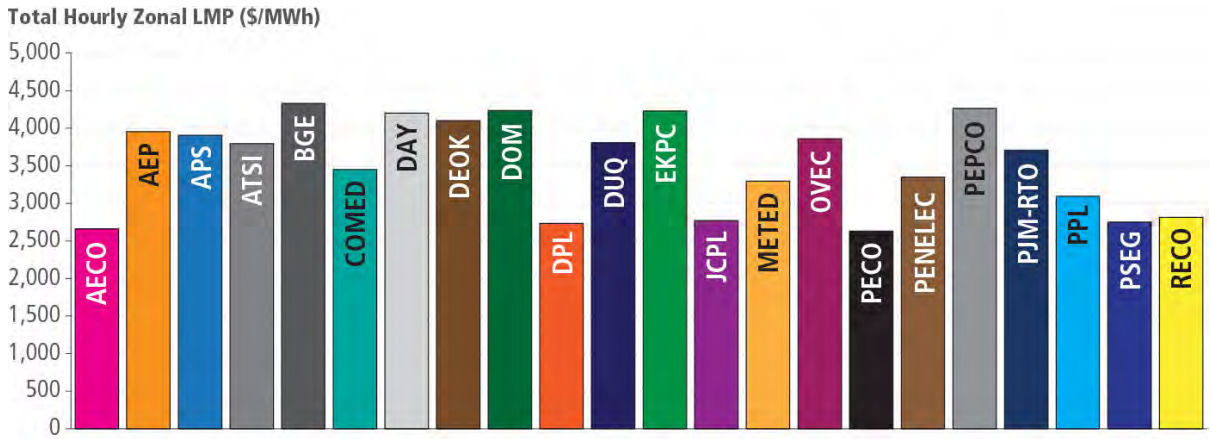
Figure 62. Dec. 23 17:00 Total Hourly Zonal LMP



Given that the System Energy Price cannot rise above $3,700/MWh, the difference can be attributed primarily to the impacts of congestion.

Figure 63 presents the locational impact of congestion for a sample interval on the evening of Dec. 24.

Figure 63. Dec. 24 08:00 Total Hourly Zonal LMP



FTRs were fully funded during the extent of Winter Storm Elliott. From Dec. 23 through Dec. 25, FTR target credits totaled $99,017,903.99. Day-ahead congestion, which is the sum of the target and surplus, over that same time period was $130,319,840.29, resulting in a $33,919,216.32 surplus. For further information on FTR accounting, please see PJM Manual 6, Section 8.

Balancing Congestion is captured in Figure 64 for the period between Dec. 20 and Dec. 26.

Figure 64. Balancing Congestion Dec. 20–26



On Dec. 23, Net Balancing Congestion was $22,134,094 and $23,504,649 for Dec. 24. Net Balancing Congestion is positive for both days, indicating some active real-time constraints were not triggered in the day-ahead solution. The reason for the imbalance is, in part, tied to the lower cleared load in the Day-Ahead Market compared to the actual load realized during the operating days of Dec. 23 and Dec. 24.

Real-Time Load and Prices

On both Dec. 23 and Dec. 24, PJM had insufficient reserves available to meet the reserve requirements. If during the execution of the pricing run, the Locational Pricing Calculator (LPC) determines that a reserve shortage exists, PJM

deems this to be a reserve shortage, triggering shortage pricing. Shortage pricing is a market rule that ensures energy and reserve prices reflect the state of the system, both leading up to and during times of reserve shortages. A reserve shortage occurs when there are insufficient resources available to maintain the balance of generation, load and reserve requirements. PJM implements shortage pricing through the inclusion of the applicable Reserve Penalty Factors in the Real-Time LMP and reserve pricing calculations.

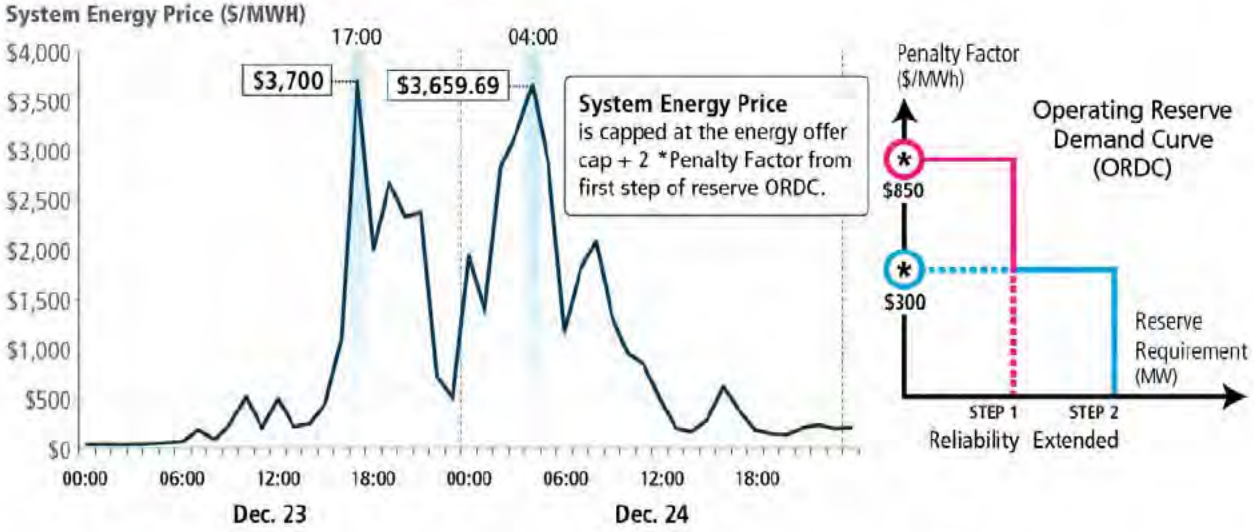
PJM uses Operating Reserve Demand Curves (ORDCs) to set the demand and willingness to pay for each of its reserve products. Like the TCPF, the ORDCs contain Reserve Penalty Factors that function as a cap on the $/MWh cost willing to be incurred to maintain a specific reserve requirement in a specific location. All Reserve Penalty Factors are currently set at either $300/MWh or $850/MWh depending on the segment of the ORDC.

The maximum reserve prices are capped as follows:

- Synchronized Reserves are capped at two times the penalty factor ($1,700).
- Non-Synchronized Reserves are capped at 1.5 times the penalty factor ($1,275).
- Secondary Reserves capped at one time the penalty factor ($850).

Figure 65 presents the System Energy Price on Dec. 23 and Dec. 24:

Figure 65. Dec. 23 and Dec. 24 System Energy Price



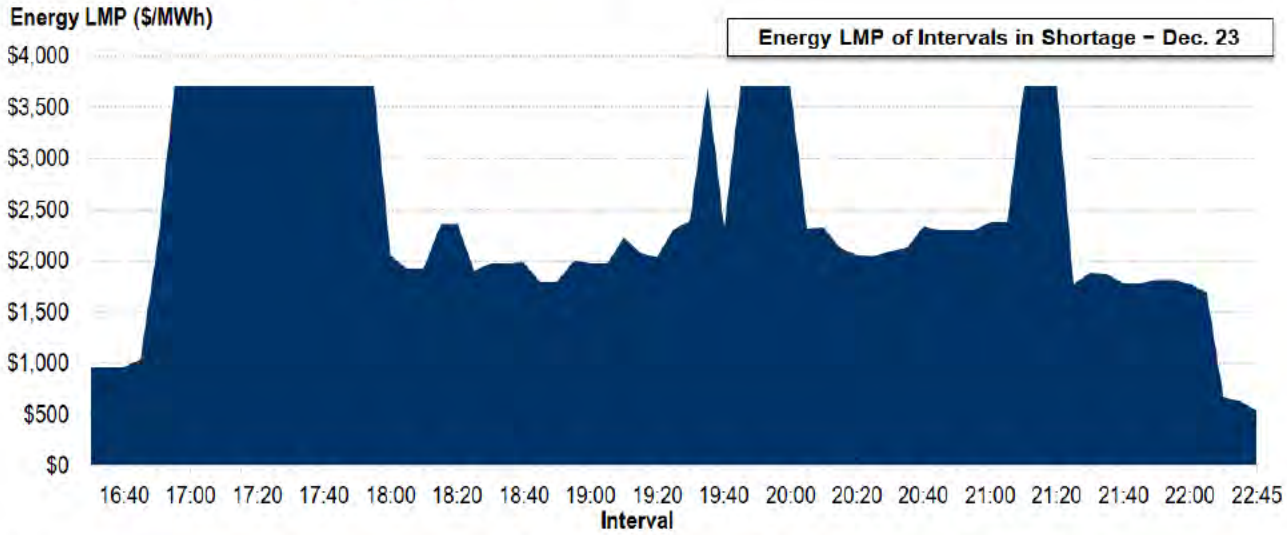
There were 71 shortage intervals approved by PJM Dispatch between 16:30 and 22:45 on Dec. 23. **Table 5** reflects the breakdown by Reserve Sub-Zones.

Table 5. Shortage Intervals by Reserve Sub-Zones

	Reserve Penalty Factors
45	MAD & RTO – Primary
21	MAD & RTO – Primary & Synchronized
2	MAD & RTO – Primary & RTO – Synchronized
3	RTO Primary

Figure 66 presents the LMPs during the shortage intervals on Dec. 23.

Figure 66. Dec. 23 LMPs During Shortage Intervals



PJM currently has rules in place that place a cap on the System Energy Price of $3,700/MWh. This cap was reached during various intervals on Dec. 23 as shown **Figure 66**. Total LMPs exceeded $3,700/MWh in some locations during these shortage intervals due to the addition of congestion and losses.

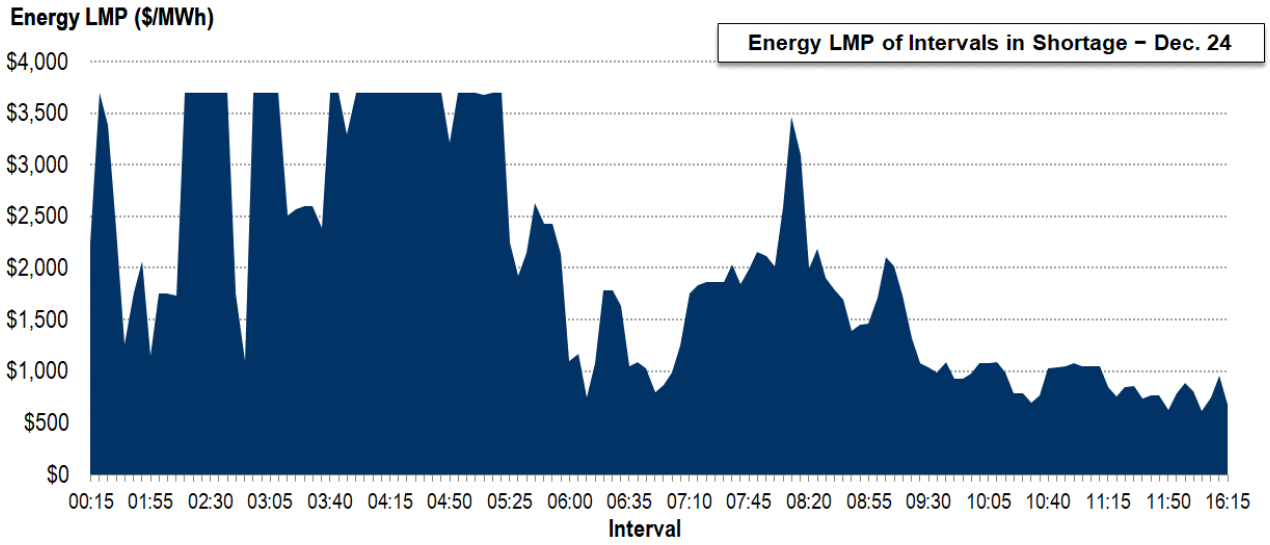
There were 134 shortage intervals approved by PJM Dispatch between 00:15 and 16:15 on Dec. 24. **Table 6** presents the breakdown of the shortage intervals by Reserve Sub-Zones.

Table 6. Shortage Intervals by Reserve Sub-Zones

	Reserve Penalty Factors
69	MAD & RTO – Primary
37	MAD & RTO – Primary & Synchronized
16	MAD & RTO – 30-Minute
1	MAD & RTO – Primary & RTO – Synchronized
11	RTO Primary

Similarly, Figure 67 presents the LMPs during the shortage intervals on Dec. 24.

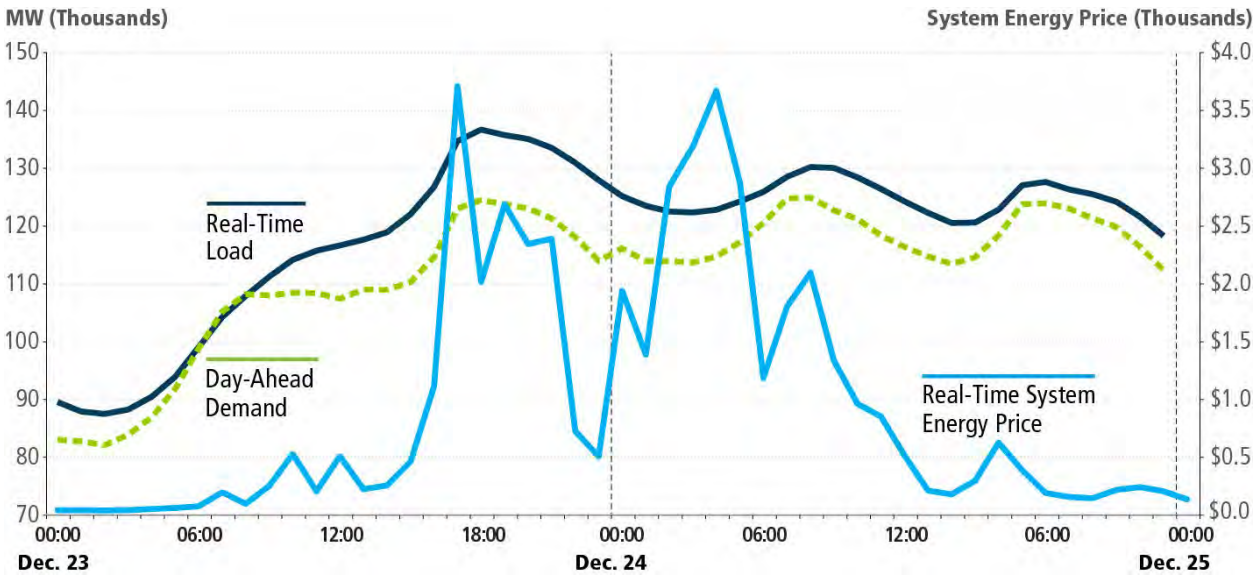
Figure 67. Dec. 24 LMPs During Shortage Intervals



On Dec. 24, the System Energy Price was $3,700/MWh during shortage intervals, as shown in Figure 67. During these intervals, there were locations on the system where LMP exceeded this price level when congestion and losses were also included.

Starting in the evening on Dec. 23, PJM experienced elevated pricing for energy and reserves, consistent with the multiple emergency procedures that were initiated due to extreme system conditions. Factors driving those extreme conditions included higher-than-anticipated loads and unprecedented forced generator outages. As a result, Real-Time Market operations accurately reflected multiple five-minute intervals with strained power balance, locational congestion management and extended periods of shortage pricing. Figure 68 overlays the System Energy Price, day-ahead forecasted load and real-time load.

Figure 68. System Energy Price, Day-Ahead Forecasted Load and Real-Time Load

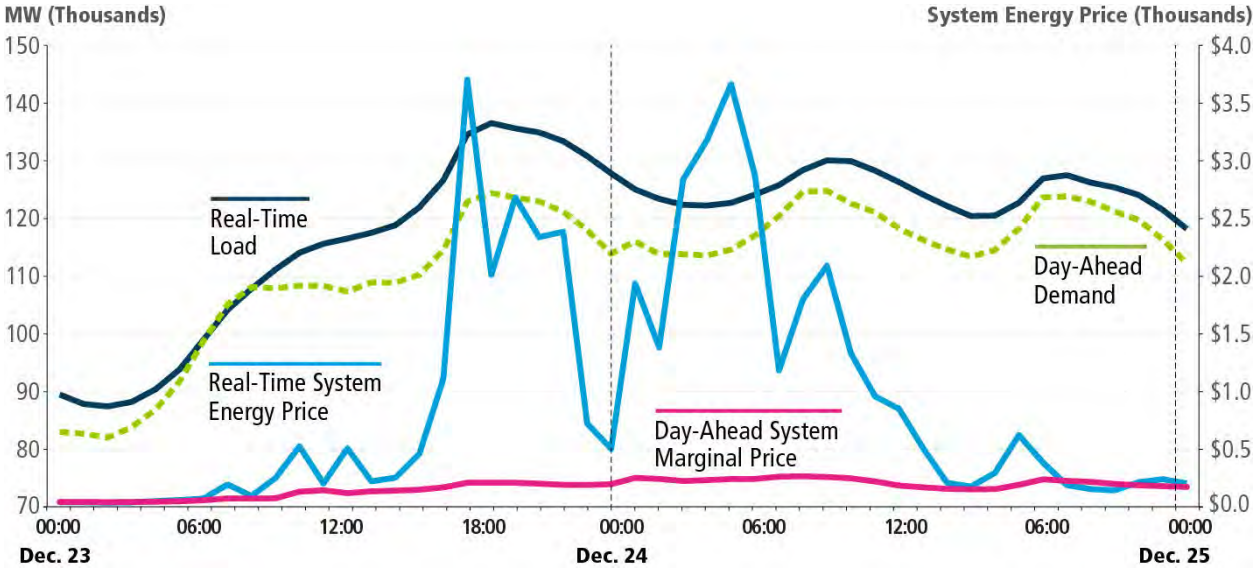


Real-Time LMPs are calculated based on five-minute intervals. Both generation and emergency Demand Response resources can and did set the price.

Day-Ahead Versus Real-Time Prices

Figure 69 presents the average day-ahead hourly load and prices compared to the real-time average load and prices.

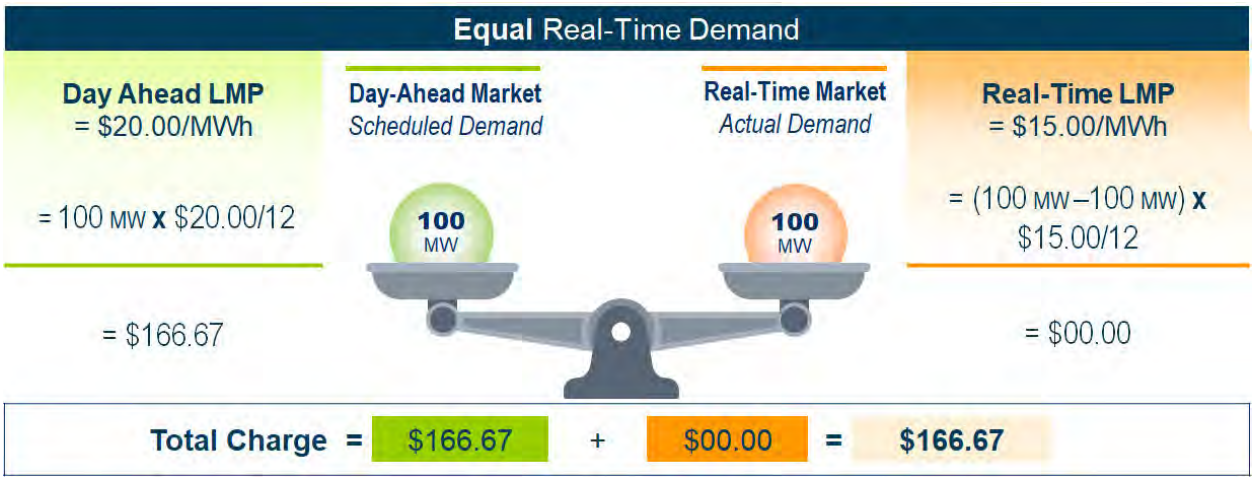
Figure 69. Day-Ahead and Real-Time Load and Day-Ahead and Real-Time Hourly System Energy Price



There is a significant difference between the day-ahead and the actual real-time load (approximately 12,172 MW), as shown in Figure 69. The difference between the Day-Ahead and Real-Time Market prices, due primarily to the unavailability of generation in real-time and under-forecasting of load in day-ahead, creates a potential for exposure to Real-Time pricing. Cleared day-ahead demand for Dec. 23 was 10,400 MW lower than the actual metered load realized at the peak. In comparison, cleared day-ahead demand for Dec. 24 was approximately 9,000 MW lower than the actual metered load realized during the morning peak. The demand that was cleared in the Day-Ahead Market was subject to the Day-Ahead LMP of $207/MWh on Dec. 23 and $262/MWh on Dec. 24. Real-time load that was not hedged in the Day-Ahead Market during the peak periods on these days was exposed to Real-Time LMPs of approximately $3,700 in both instances.

Figure 70 presents an example of a settlement example for an LSE that is fully hedged.

Figure 70. Fully Hedged LSE Settlement Example



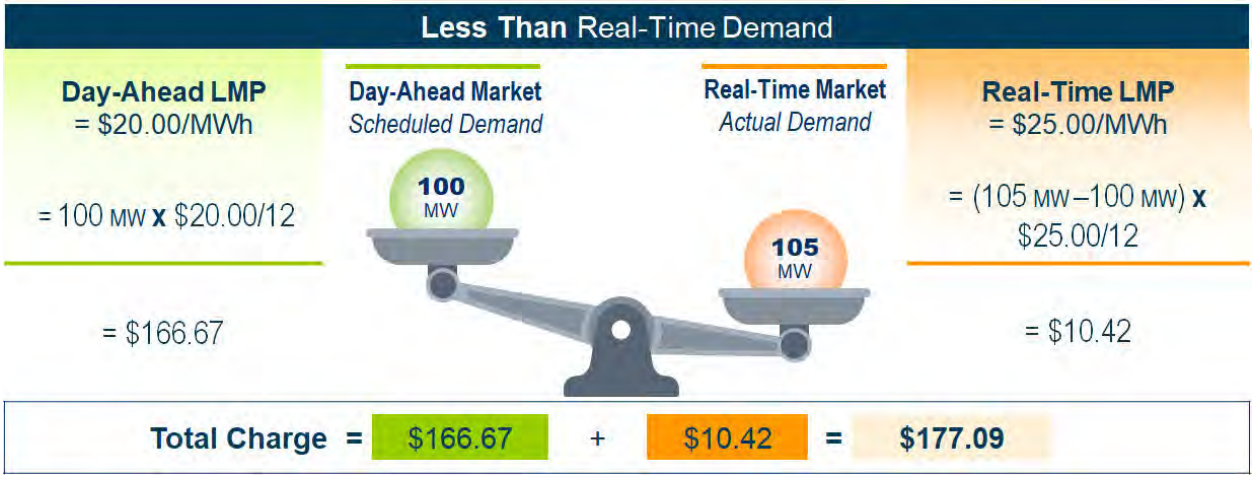
In Figure 70, the LSE submitted a 100 MW bid in the Day-Ahead Market. The Day-Ahead Market cleared at $20.00/MWh. The Day-Ahead Market settlement for this five-minute interval is the day-ahead scheduled demand multiplied by the Day-Ahead LMP divided by 12 (there are 12 five-minute intervals in an hour), or $166.67.

In the Real-Time Market, the LSE's actual demand is 100 MW. The balancing settlement for this five-minute interval is the difference between Real-Time Market actual demand and the Day-Ahead Market scheduled demand, multiplied by the Real-Time Market LMP divided by 12. Since the LSE's Real-Time Market actual demand and the Day-Ahead Market scheduled demand are both 100 MW, the LSE is fully hedged and is not exposed to the Real-Time Market prices. The Real-Time Market settlement is $0.00.

The total charge for this LSE for this sample five-minute interval is the Day-Ahead Market charge plus the Real-Time Market charge, or $166.67.

Figure 71 presents a settlement example for an LSE that is under-hedged.

Figure 71. Under-Hedged Load Settlement Example



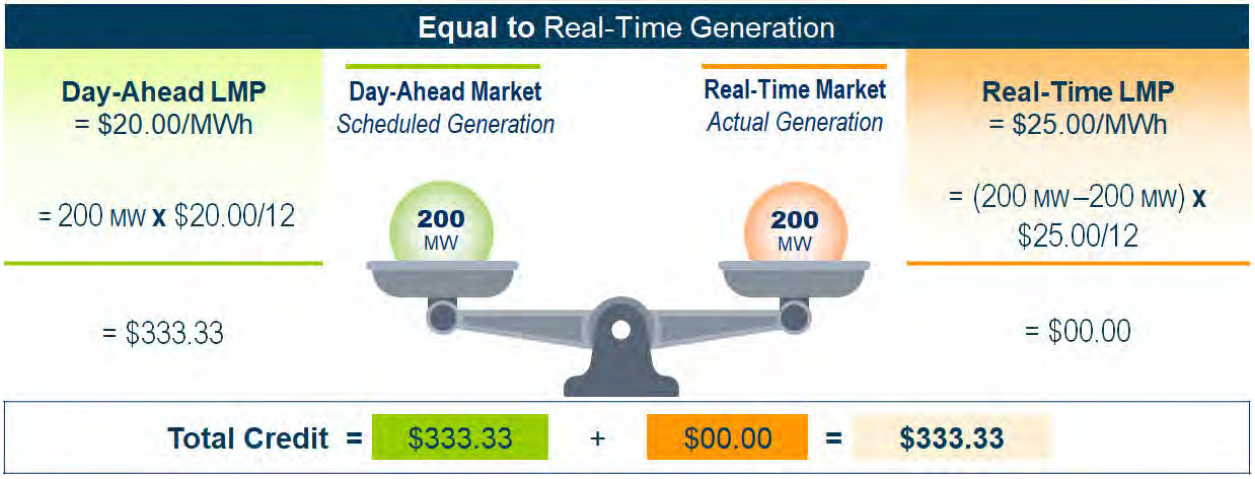
In Figure 71, the LSE submitted a 100 MW bid in the Day-Ahead Market. The Day-Ahead Market cleared at $20.00/MWh. The resulting Day-Ahead Market settlement for this sample five-minute interval is the Day-Ahead scheduled demand multiplied by the Day-Ahead Market LMP, in this case the Day-Ahead Market settlement is $166.67.

In real time, the Load Serving Entity's actual demand is 105 MW, 5 MW greater than the Day-Ahead Market. Therefore, the LSE is exposed to the Real-Time Market prices or is "under-hedged" for the additional 5 MW. The LSE purchases the 5 MW at the Real-Time LMP. The balancing settlement for this sample five-minute interval is the difference between the Real-Time actual demand minus the Day-Ahead Market scheduled demand. In this case, the LSE scheduled 100 MW in the Day-Ahead Market and the actual demand is 105 MW. The Real-Time Settlement is therefore 5 MW multiplied by the Real-Time Market LMP of $25.00/MWh, divided by 12, for a total of $10.41.

The total charge for this LSE for this five-minute interval is the Day-Ahead Market charge plus the Real-Time Market charge, or $177.09

Figure 72 presents a settlement example for a generator that is fully hedged.

Figure 72. Fully Hedged Generator Settlement Example



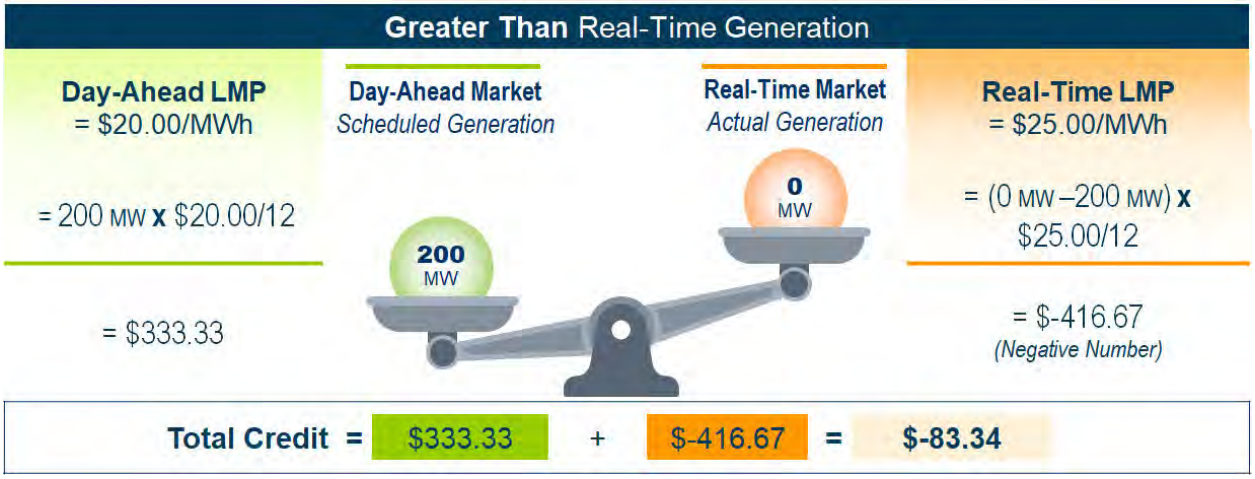
In Figure 72, the Generator submitted a 200 MW offer in the Day-Ahead Market. The Day-Ahead Market cleared at $20.00/MWh. The Day-Ahead Market settlement for the generator is the Day-Ahead Market scheduled generation multiplied by the Day-Ahead Market price, or 200 MW multiplied by $20.00 MW/h, divided by 12. The Day-Ahead Market credit for this generator is $333.33.

In real time, the Generator produced 200 MW. The balancing settlement is the difference between the Real-Time Market actual generation and the Day-Ahead Market scheduled generation. In this case, the generator was committed for 200 MW in Day-Ahead Market and produced 200 MW in real time. The generator is fully hedged (not exposed to real-time prices.) The balancing settlement is therefore $0.00.

The Total Credit for this generator for this five-minute interval is $333.33.

Figure 73 presents a settlement example for a generator that is committed in the Day-Ahead Market and trips during real time.

Figure 73. Day-Ahead Committed Generator That Trips in Real-Time Settlement Example



In Figure 73, the generator submitted a 200 MW offer in the Day-Ahead Market. The Day-Ahead Market cleared at $20.00/MWh. The Day-Ahead Market settlement for the generator is the Day-Ahead Market scheduled generation multiplied by the Day-Ahead Market price, or 200 MW multiplied by $20.00 MW/h divided by 12. The Day-Ahead Market credit for this generator is $333.33.

In real time, the generator tripped and therefore did not produce any energy. The balancing settlement is the difference between the Real-Time Market actual generation and the Day-Ahead Market scheduled generation. In this case, the generator was committed for 200 MW in the Day-Ahead Market but produced 0 MW in the Real-Time Market. The generator needs to buy back the megawatts committed in the Day-Ahead Market at the Real-Time LMP. The balancing settlement for this five-minute interval is the difference between the Real-Time Market actual generation and the Day-Ahead scheduled generation, multiplied by the Real-Time Market LMP (divided by 12). The balancing settlement for this five-minute interval is -$416.67.

The total credit for this generator for this five-minute interval is -$83.34.

Interchange

Figure 74 and Figure 75 provide hourly net interchange values between PJM and neighboring market areas NYISO and MISO along with interface price values for PJM and the neighboring market areas. Interface pricing enables Market Participants to the profitability of scheduling energy transfers between or through neighboring Balancing Authorities.

During periods where the system is stressed and internal supply is close to or inadequate to meet energy and reserve needs, interface prices are used to incentivize Market Participants in neighboring regions to sell available power to PJM to relieve emergency conditions. On Dec. 23 and Dec. 24, interchange flows were generally into PJM from NYISO, which is reflected in the interface prices. Conversely, interchange flows for both days were generally out of PJM to MISO and our southern non-market neighbors [Tennessee Valley Authority (TVA), Louisville Gas and Electric Company and Kentucky Utilities Company (LGE-KU), Duke Energy Progress East (DEP-East), and Duke Energy Progress West (DEP-W)]. In those cases, system conditions were more stressed in the neighboring areas.

Figure 74. NYISO Net Interchange

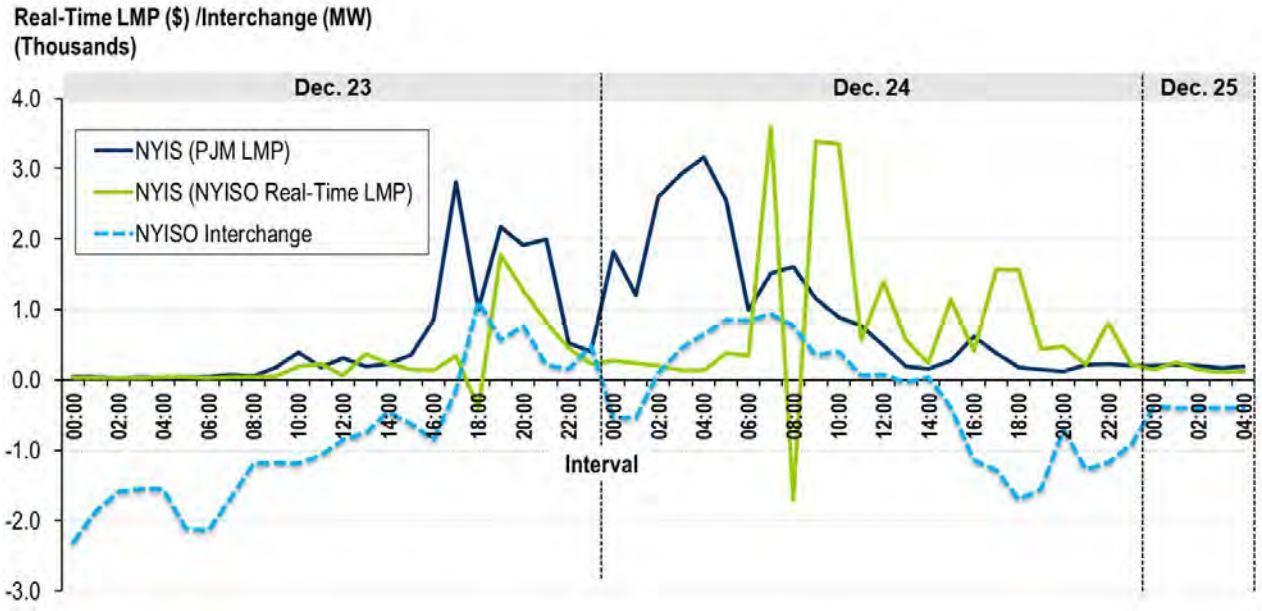


Figure 75. MISO Net Interchange

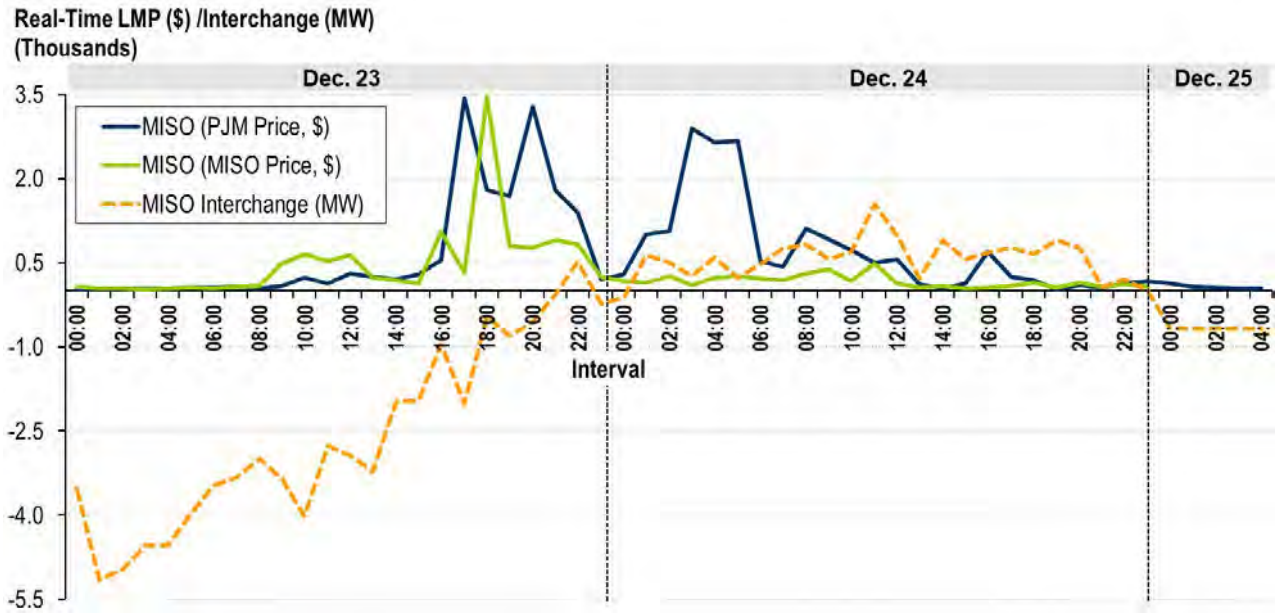


Figure 76 provides hourly net interchange values between PJM and the aggregate net interchange for LG&E-KU, TVA, Duke, DEP-East, and DEP-West, along with interface price values for PJM.

Figure 76. South Net Interchange

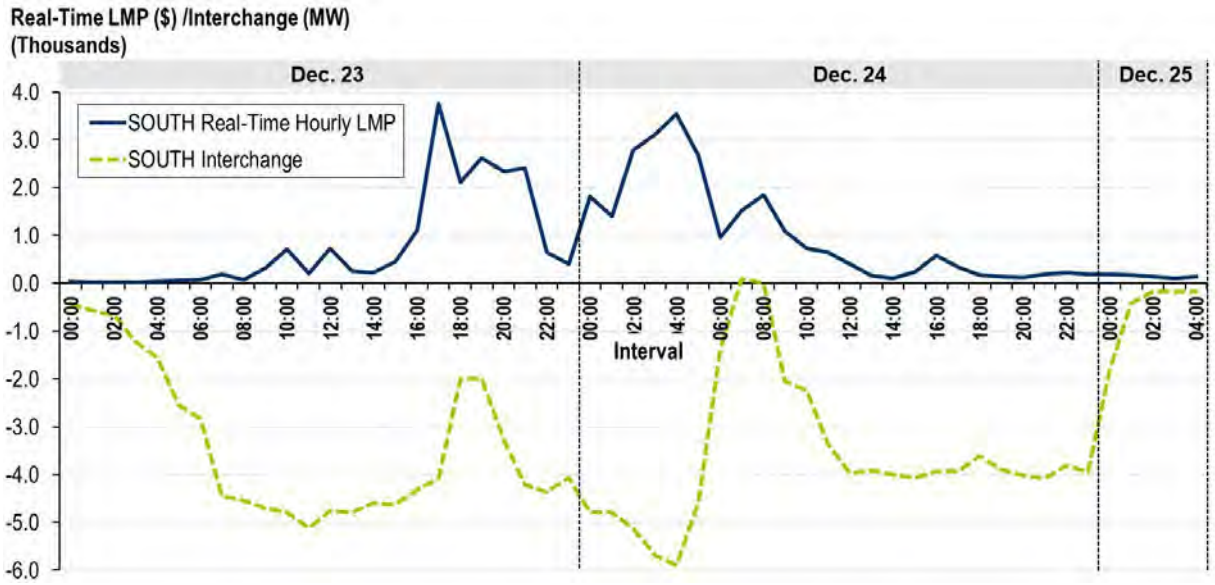
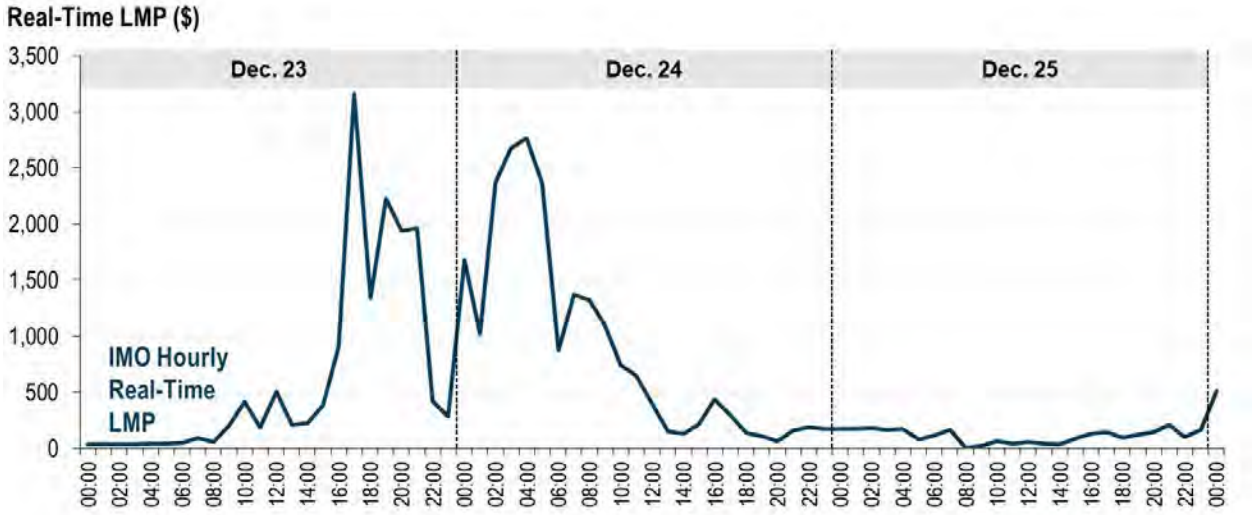


Figure 77 provides hourly pricing for the IMO interface. This information can be used by Market Participants during real time to make energy transfer decisions.

Figure 77. IMO Net Interchange



Ancillary Services: Regulation and Reserves

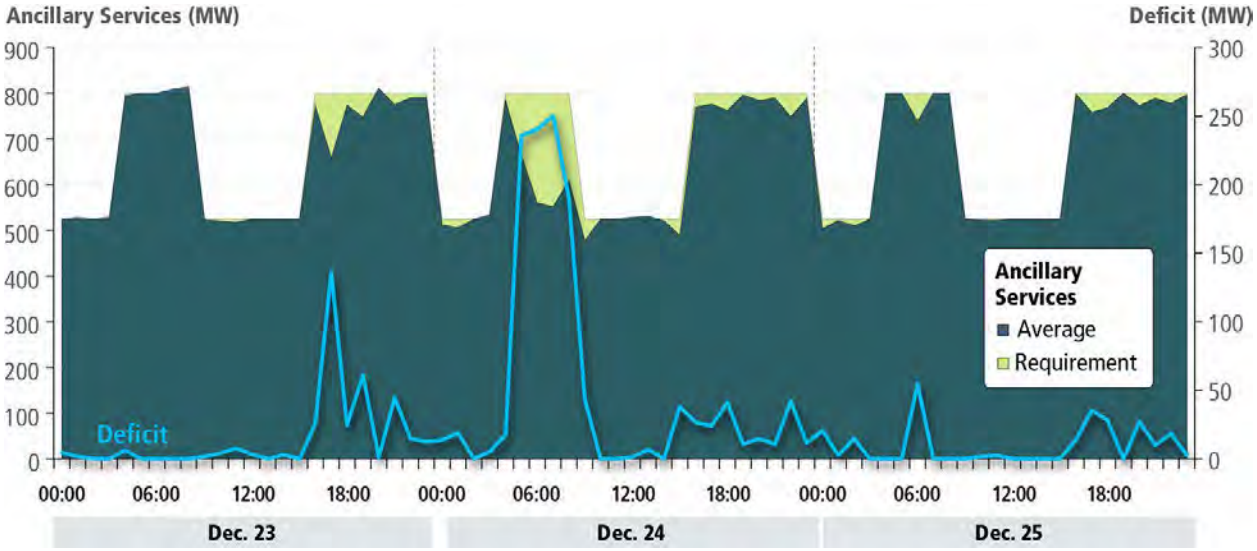
During Winter Storm Elliott, high prices for regulation, synchronized reserve, and Non-Synchronized Reserves occurred at the same time as high Real-Time Energy LMPs. During these stressed conditions, ancillary service prices increased as the reserve margin decreased, and system capacity competed to meet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

Regulation Market Results

Regulation service corrects for short-term changes in electricity use that might affect the stability of the power system. It helps match generation and load and adjusts generation output to maintain the desired system frequency of 60 hertz. PJM's Regulation Market aligns compensation with actual performance for resources that provide regulation service. Resources are compensated for their accuracy, speed and precision of response in providing regulation service to the system.

On Dec. 23, as well as Dec. 24, PJM was deficit regulation, as presented in Figure 78, which presents the regulation megawatts, on average, by hour:

Figure 78. Regulation MW, on Average, by Hour

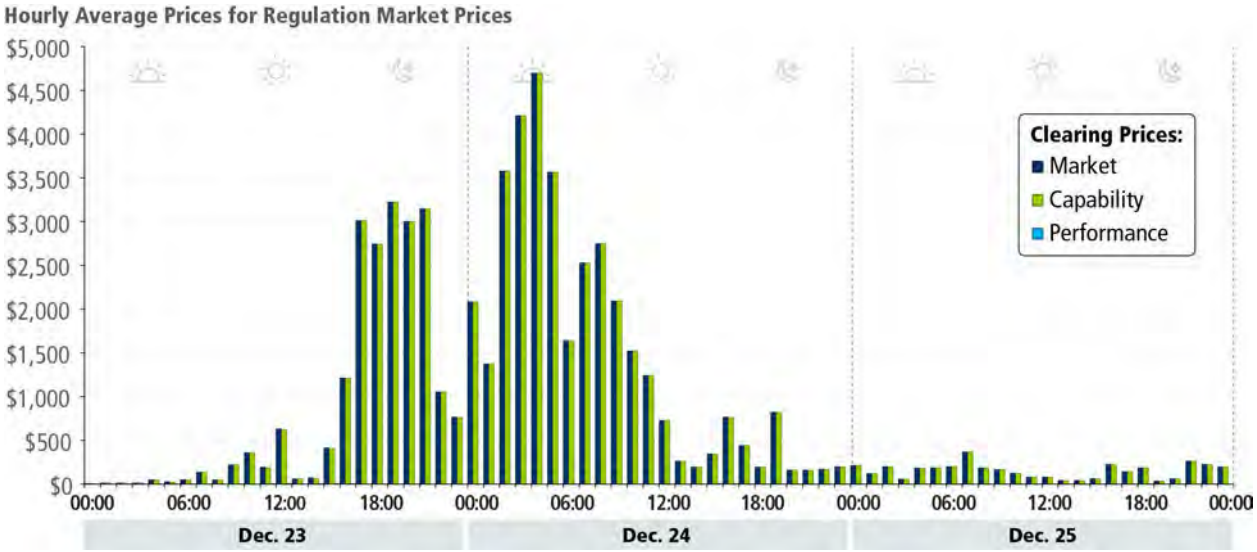


The regulation deficit is caused by the generator availability issues detailed in this report that resulted in a lack of available regulation-capable resources to commit. The regulation price spikes seen on Dec. 23 and Dec. 24 can be attributed to the low performance factor of the marginal unit for regulation as high-performing generators were being used for energy and reserves instead of regulation. High lost opportunity costs (LOC) were also a contributing factor to the high regulation prices. Recall that LOC is intended to capture foregone energy revenues from providing a service other than energy. When those foregone energy revenues are high because energy prices are high, regulation LOC and regulation prices can also be high to ensure resources are incentivized to provide needed regulation and not energy.

Unlike reserves, regulation is not co-optimized with energy in real-time. Similarly, there is also no explicit mechanism for shortage pricing of regulation as there is for reserves. As stated, regulation prices rose and fell roughly in correlation with energy prices during the evening of Dec. 23 and morning of Dec. 24 because of the calculation of regulation lost opportunity costs based on the high LMPs during these periods, not because of the regulation shortages.

Figure 79 presents the hourly average prices for RMCP for Dec. 23, 24 and 25.

Figure 79. Dec. 23, 24 and 25 Hourly Average Prices for RMCP



For more information on how the Regulation Market prices are calculated, please reference Manual 11, Section 3.

Reserve Market Price Trends

Reserves represent the generating capability that is "standing by," ready for service in the event that something happens on the power system, such as the loss of a large generator. The severity of the event determines how quickly the reserves have to be picked up.

In Oct. 2022, PJM implemented Reserve Price formation, resulting in the following changes:

- Consolidation of Tier 1 and Tier 2 Synchronized Reserve products
- Alignment of reserve products in day-ahead and real-time to ensure that the reserves needed for real-time operation are recognized on a forward basis during the scheduling processes for the next operating day
- Flexible modeling of reserve subzones

Figure 80 presents the market clearing prices (MCPs) for Synchronized Reserve (SRMCP), Non-Synchronized Reserve (NSMCP), and Secondary Reserve Market Clearing Price (SecRMCP) for Oct. 2022 through Dec. 2022. Notwithstanding Dec. 2022, the SRMCP, NSRMCP and SecRMCP prices have been at or near $0.00/MWh since the Oct. 2022 implementation of the Reserve Price Formation changes.

Figure 80. SRMCPs, NSMCPs and SecRMCPs

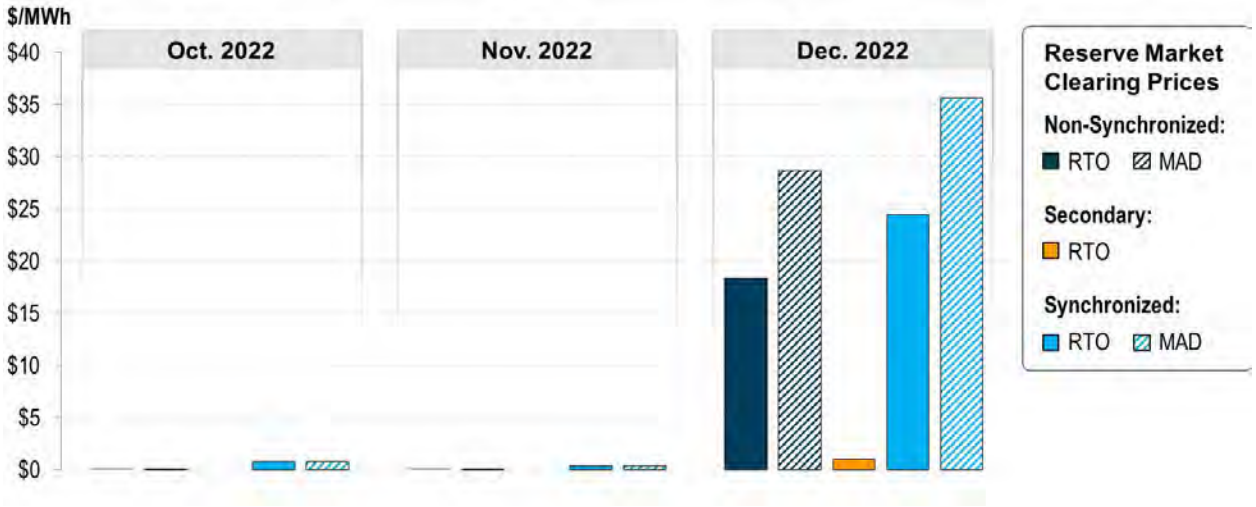


Figure 81 presents daily max and daily average SRMCPs since Oct. 1, 2022. This figure shows that the drivers of the high monthly averages SRMCPs observed in Dec. 2022 and displayed in Figure 80 are driven almost entirely by the operational events and market outcomes related to Winter Storm Elliott.

Figure 81. Shortage Pricing Impacts on SRMCP

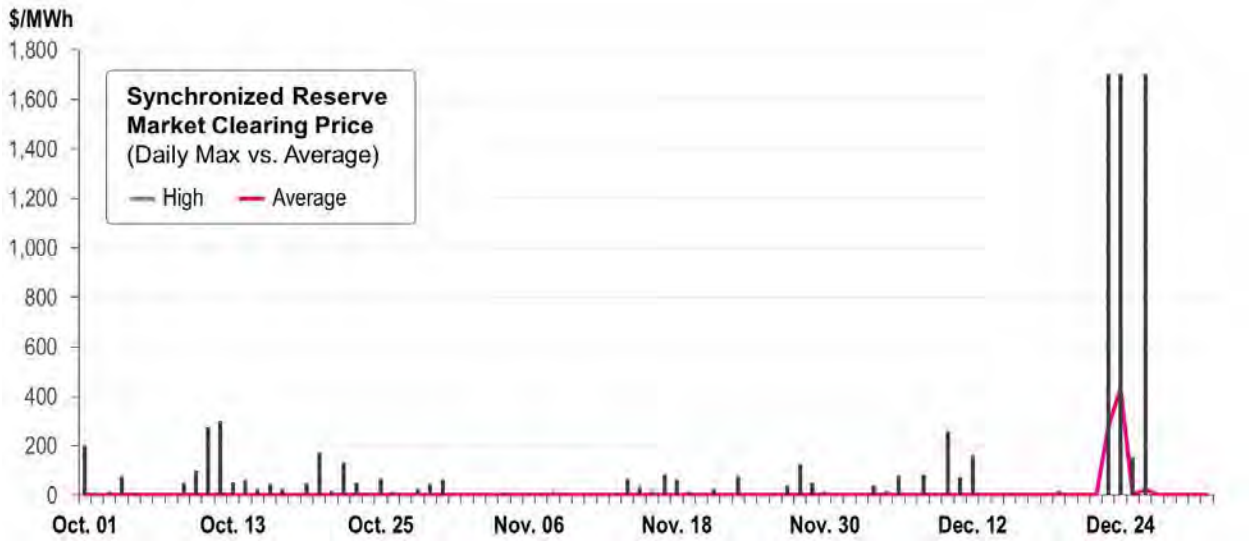
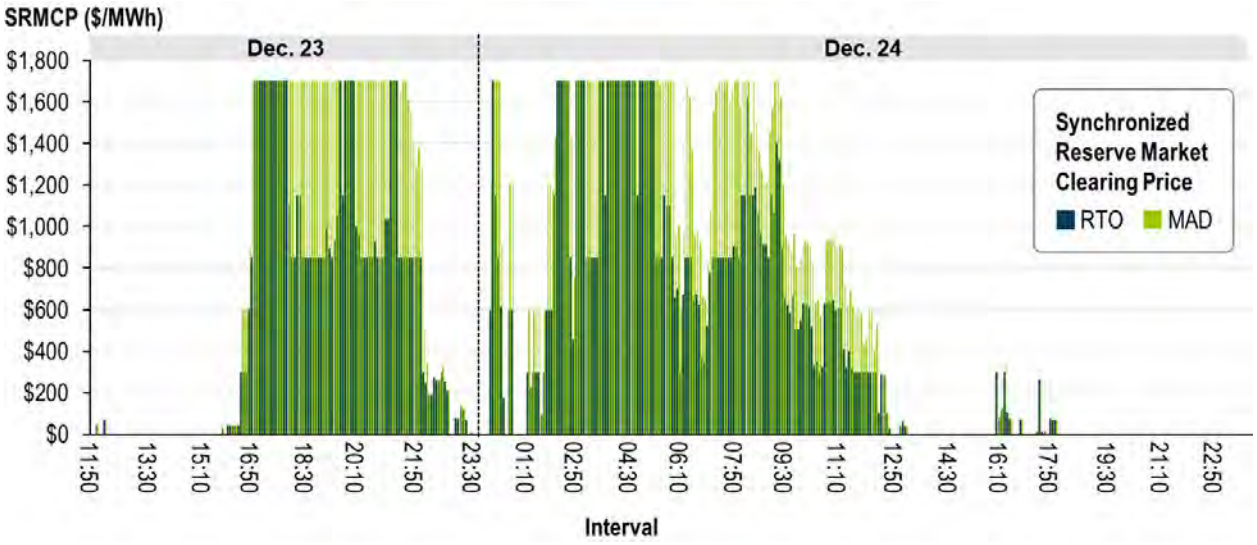


Figure 82 presents the Real-Time SRMCPs for Dec. 23 and Dec. 24.

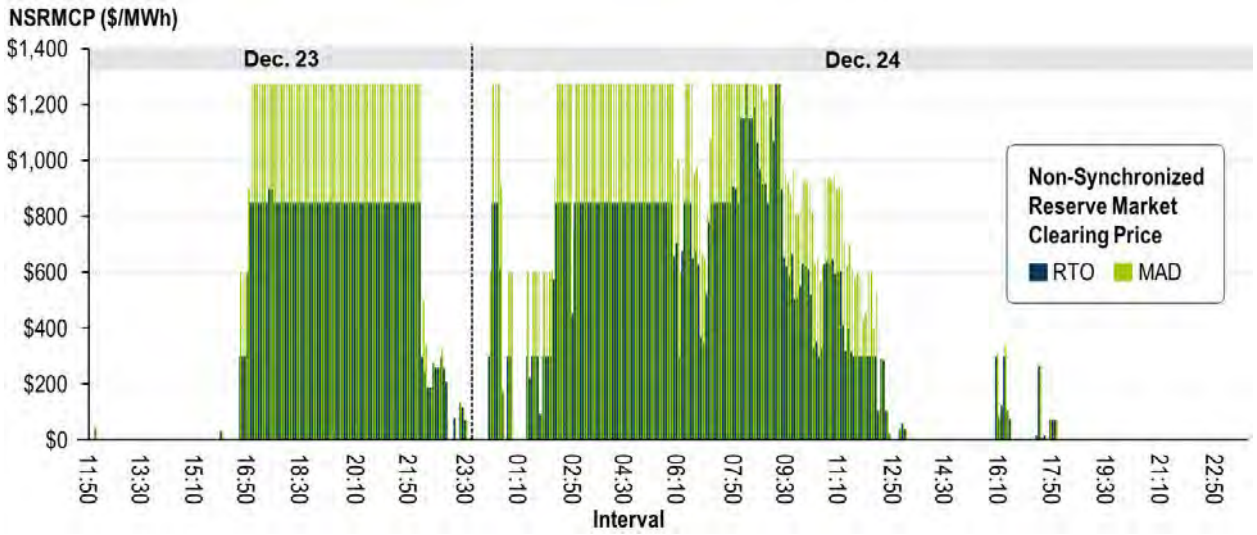
Figure 82. Dec. 23 and 24 Real-Time SRMCPs



The SRMCPs in many intervals are either at a level of $850/MWh or $1,700/MWh depending on the reserve product that was short and the location it was short. The price level of $1,700/MWh represents the price cap that exists for this product.

Figure 83 presents the Real-Time NSRMCPs for Dec. 23 and Dec. 24.

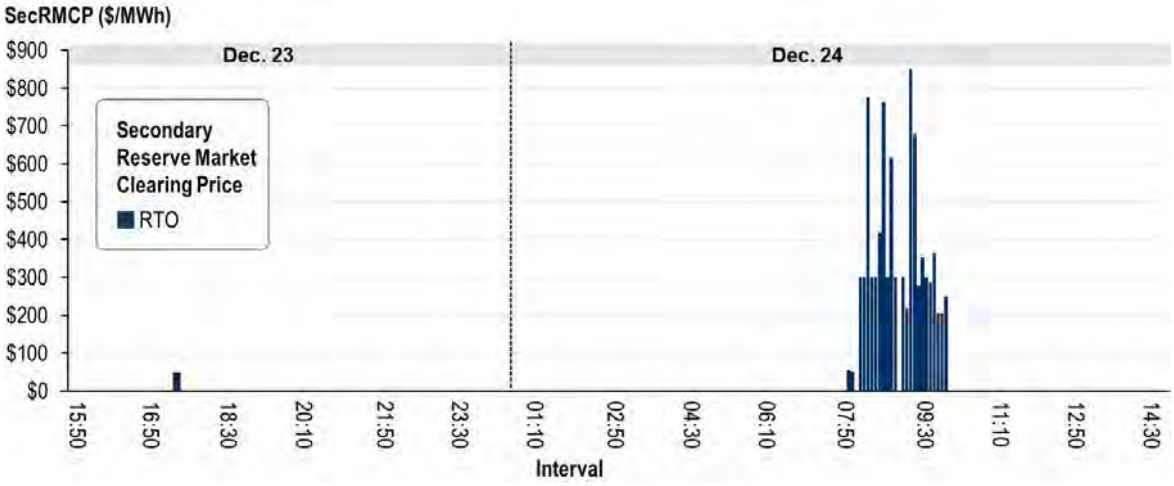
Figure 83. Dec. 23 and Dec. 24 Real-Time NSRMCPs



The Non-Synchronized Reserve Market Clearing Price (NSRMCP) is the clearing price paid to offline resources that can start within 10-minutes and be used to satisfy the Primary Reserve and 30-minute requirements. Market Sellers offer prices for the Non-Synchronized Reserve and Secondary Reserve products are $0.00/MWh; however, a Non-Synchronized Reserves LOC is estimated by the PJM market clearing engines. This LOC represents the foregone revenue an eligible offline resource could have received if had operated, given the forecasted LMP produced by the IT SCED engine. The current price cap Non-Synchronized Reserve is 1.5 times the Reserve Penalty Factor of $850/MWh, or $1,275/MWh.

Figure 84 presents the Real-Time SecRMCPs for Dec. 23 and Dec. 24.

Figure 84. Dec. 23 and Dec. 24 Real-Time SecRMCPs



The SecRMCP was $0.00/MWh of most of the Winter Storm Elliot event except for approximately two hours on Dec. 24. During that period, the SecRMCP reached its price cap of $850/MWh for one interval.

Given the observed issues with reserve performance and availability during Winter Storm Elliott and other inefficiencies PJM believes exist in the design of these markets, PJM believes there is a need to evaluate various aspects of its reserve market design including the products, offer structure, levels procured, performance incentives, and deployment practices to ensure the necessary amount of reserves is being procured, priced by the market and incentivized to perform at a high level. PJM plans to bring a Problem Statement and Issue Charge to Stakeholders to address these items in the near future.

Synchronized Reserve Events and Reserve Performance

As described earlier, Synchronized Reserves are reserve generators that are already synchronized to the grid and can be loaded within 10 minutes. PJM carries enough Synchronized Reserves to cover the unexpected loss of the largest single generation contingency operating on the PJM system at that time, plus a small margin. Typically, this reserve requirement is approximately 1,600 MW.

The conditions of Winter Storm Elliott led to PJM requesting the loading of Synchronized Reserve generation on five separate occasions during the two-day period of Dec. 23 and Dec. 24. Four of these events were called in response to a low ACE caused by increasing load combined with generation tripping and start failures. One of the events was called in direct response to the loss of a unit.

Five Synchronized Reserve Events over a two-day period is very unusual. Note that the average duration between Synchronized Reserve Events in 2021 was 22 days. All five of the events during Winter Storm Elliott exceeded 10 minutes in duration. Two of the events exceeded one hour in duration at 1 hour 51 minutes and 1 hour 27 minutes. The average duration for these five events was 53 minutes and 17 seconds. The average duration of the other 18 Synchronized Reserve Events that occurred in 2022 was 9 minutes and 57 seconds.

System conditions and ACE control prevented the PJM system operators from ending these Synchronized Reserve Events earlier, as all available reserve megawatts were required to support the ACE and provide overall system control. Table 7 provides details of these five events.

Table 7. Five Synchronized Reserve Events

Event Date	Start (EST)	End (EST)	Duration	Zone	Reason	PAI in effect
Dec. 23	10:14	10:25	00:11:07	RTO	Low ACE	No
	16:17	18:09	01:51:29			Yes (17:30–18:09)
Dec. 24	00:05	00:30	00:25:43			No
	02:23	02:54	00:30:35		Unit Trip	No
	04:23	05:51	01:27:32		Low ACE	Yes (04:25–01:27)

PJM measures the response of resources with a Real-Time Synchronized Reserves commitment as detailed in PJM Manual 11, Section 4.5. Note, Day-Ahead Synchronized Reserve commitments are reevaluated in real time, and only those resources that have a real-time commitment are obligated to respond.

For each Synchronized Reserve Event, the magnitude of each resource's response is the difference between the resources' output at the start of the event and its output 10 minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, resource output at the start of the event is defined as the lowest telemetered output between one minute prior to and one minute following the start of the event. Similarly, a resource's output 10 minutes after the event is defined as the greatest output achieved between nine and 11 minutes after the start of the event.

Also relevant for the events lasting longer than 10 minutes, all resources must maintain an output level greater than or equal to that which was achieved as of 10 minutes after the event for the duration of the event or 30 minutes from the start of the event, whichever is shorter. The response actually credited to a given resource will be reduced by the amount the megawatt output of that resource falls below the level achieved after 10 minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter. There is no current performance evaluation for events lasting longer than 30 minutes, beyond the initial 30-minute period.

Although not relevant for these events, in cases where an event lasts less than 10 minutes, resources are credited with the amount of reserve capacity they are assigned.

Since PJM's implementation of the Reserve Price Formation changes on Oct. 1, 2022, the entirety of the Synchronized Reserve Requirement is assigned to specific resources in a co-optimization with energy. Resources assigned these reserves each Real-Time interval have an obligation to perform or face a penalty in the amount of non-performance. This penalty consists of two components as follows:

1 | The resource is credited for Synchronized Reserve for the amount that actually responded for all intervals in which the resource had an assignment (either self-scheduled or assigned) on the day the event occurred.

2 | An obligation to refund at the Synchronized Reserve Market Clearing Price the amount of the shortfall for all Real-Time Settlement Intervals that the resource had an assignment for a period of the lesser of a) the average number of days between events or b) the number of days since the resources last non-performance.

Synchronized Reserve response to the five events during Winter Storm Elliott for resources assigned reserves was generally poor.

- The highest response was 86.4% of assignment, as seen during the Dec. 23, 10:14 event, which was the first Synchronized Reserve deployment during Winter Storm Elliott. Not coincidentally, this was also the shortest of the five events at 11:07 minutes.

- The lowest response was 16.8% of assignment, as seen during the Dec. 24, 04:23 event.
- The average response of these five events was 47.8%.
- The average response of assigned Synchronized Reserve since the implementation of the Reserve Price Formation changes on Oct. 1, 2022, excluding these Winter Storm Elliott events, is 49.8%.

Details of the reserve performance for resources assigned Synchronized Reserve can be found in **Table 8**.

Table 8. Assigned Reserve Performance

			Synch Reserve (MW)			
Event Date	Start (EST)	End (EST)	Assignment	Response (Units with assignment)	Shortfall to Assignment (MW)	Response to Assignment (%)
Dec. 23	10:14	10:25	1,791	1,547	244	86.4%
	16:17	18:09	1,846	945	901	51.2%
Dec. 24	00:05	00:30	1,767	930	837	52.6%
	02:23	02:54	1,665	535	1,130	32.1%
	04:23	05:51	1,007	169	838	16.8%

PJM has observed a drop in performance of approximately 20% for resources assigned Synchronized Reserve (excluding Winter Storm Elliott events) since the implementation of Reserve Price Formation on Oct. 1, 2022. Unrelated to the Winter Storm Elliott response, PJM has taken the following actions to address this drop in performance:

- Continued monitoring of Synchronized Reserve Performance and ACE recovery performance
- Identification of data trends including non-performance by specific resource, resource type and resource owner
- Reach out to resource owners with poor performance to identify causes of this poor performance

In addition to Synchronized Reserve response from resources assigned reserve, PJM typically observes significant response from resources that were not specifically assigned reserve at the time of the Synchronized Reserve event. While the All-Call message that announces a Synchronized Reserve Event requests all resources to load any Synchronized Reserve that they have available, resources without a Synchronized Reserve assignment at the start of the event are under no financial obligation to respond to these events and are not subject to nonresponse penalties for Synchronized Reserves. Since the implementation of Reserve Price Formation on Oct. 10, 2022, unassigned resources no longer receive a Tier 1 bonus for reserves provided.

There was also an over-response from some resources that exceeded their Synchronized Reserve assignment, although this was fairly minimal.

In the Dec. 24, 02:23 event, even with the additional contributions of reserves above assignment and from resources not assigned reserve, the total response still fell short of the system assigned reserve requirement. The response in megawatts from both units with and without Synchronized Reserve assignments are shown below in **Table 9**.

Table 9. Unit Synchronized Reserve Assignments Unit Synchronized Reserve Assignments Unit Synchronized MW Response With and Without Assignments

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.

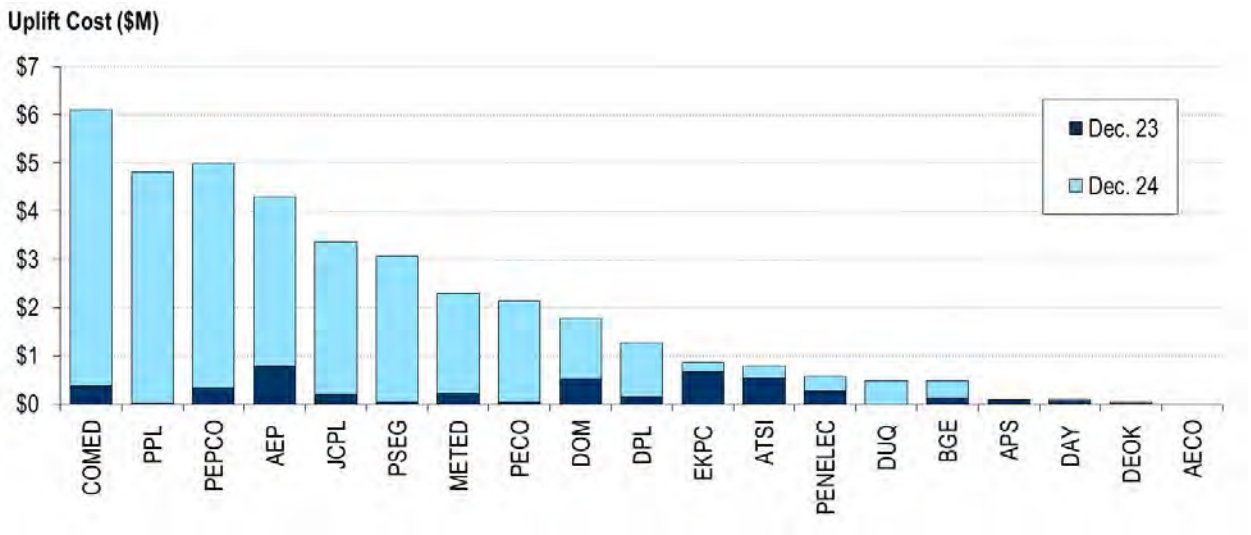
There are two reasons for out-of-market costs:

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

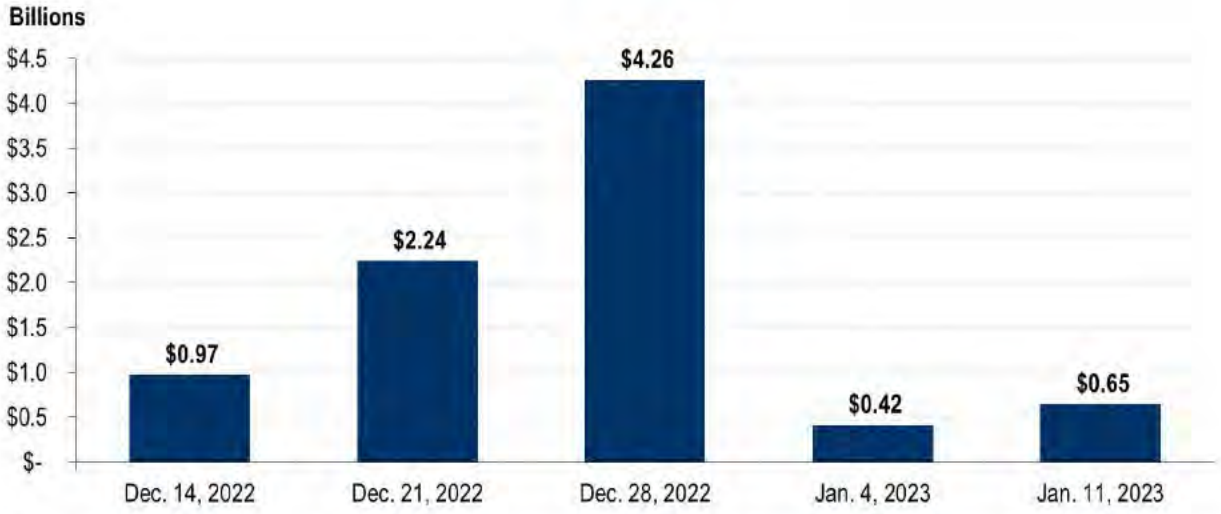
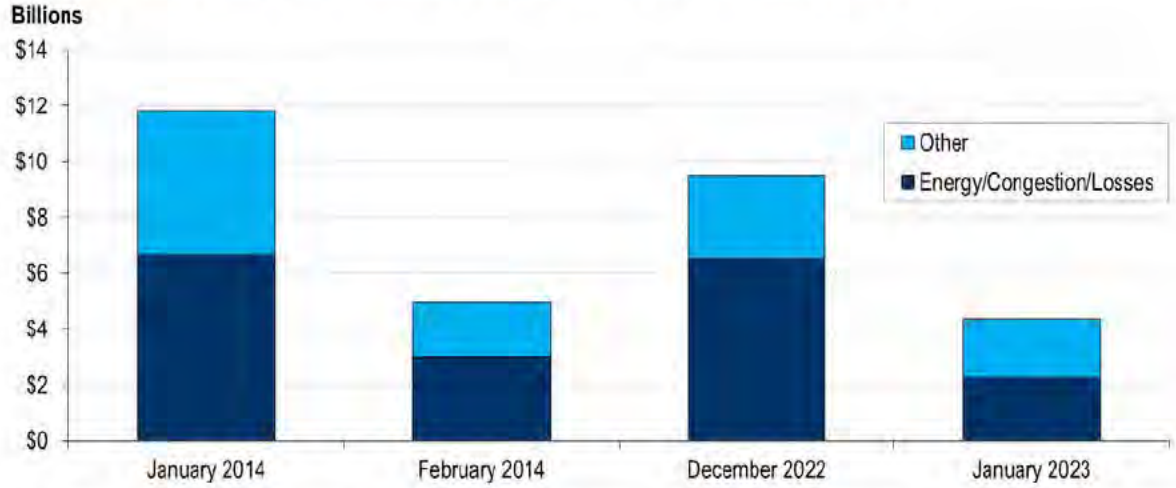


Figure 37 displays gross billing for Dec. 23 and Dec. 24, embedded in the bar chart for the week of Dec. 28. A significant increase in gross billing is observed when comparing the prior two weeks and successive two weeks to the week of Dec. 28. System conditions and operator actions reflecting the status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

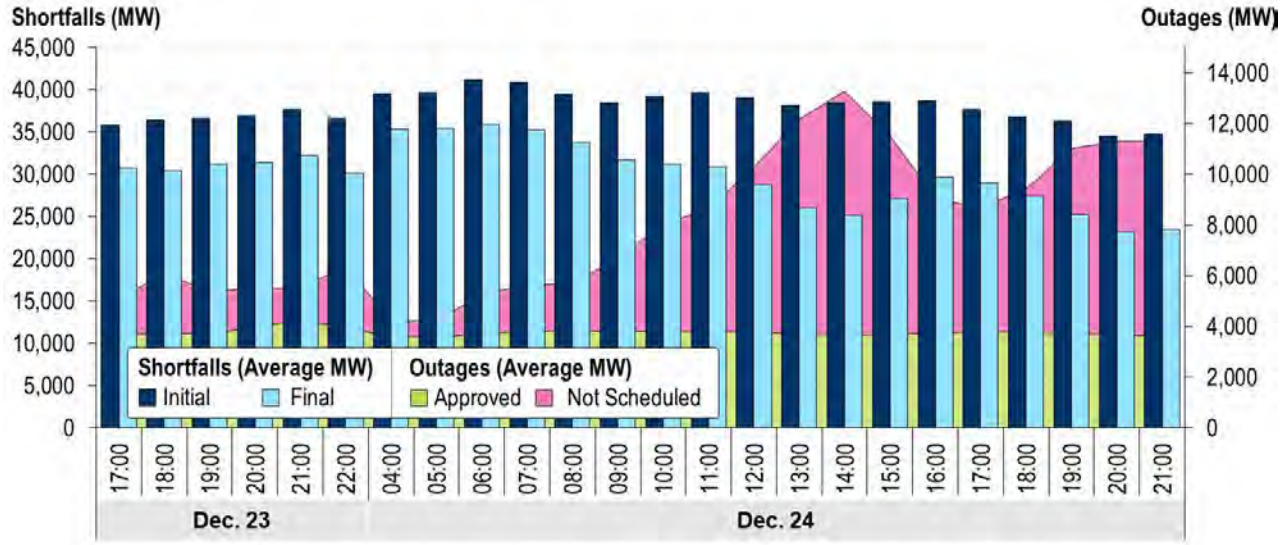
[17] The average DR and PRD shortfall megawatts offset by over-performance by other resources is 230 MW per interval.

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.

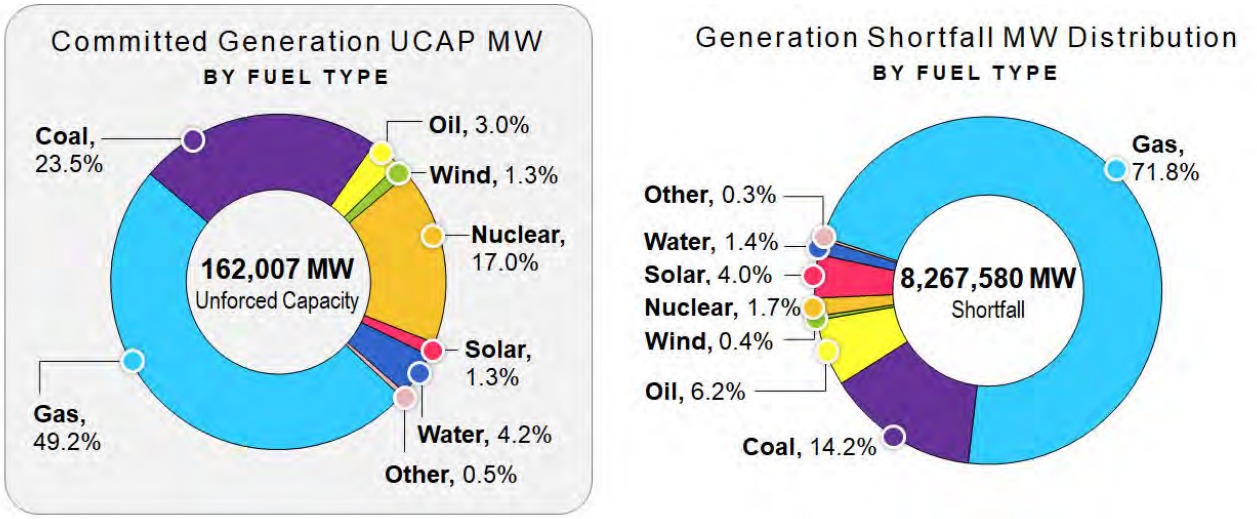
Figure 88. Excusal Megawatts and Final Shortfall MW (hourly average of five-minute interval values)



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)

		Average DR & PRD	
Hour Beginning (EPT)		Initial Shortfall	Final Shortfall
Dec. 23, 2022	17:00	**	**
	18:00	583.8	267.4
	19:00	519.3	197.8
	20:00	526.4	213.7
	21:00	**	**
	22:00	0	0
Dec. 24, 2022	04:00	**	**
	05:00	**	**
	06:00	312.7	14.3
	07:00	528.3	126.3
	08:00	521.5	116.4
	09:00	433.5	38.4
	10:00	382.8	21.6
	11:00	365.3	20.8
	12:00	359.1	22.1
	13:00	337	16.3
	14:00	316.6	15.5
	15:00	315.8	14.8
	16:00	337.7	14.5
	17:00	371.6	16.2
	18:00	357.1	14.9
	19:00	88.6	11.4
	20:00	**	**
	21:00	0	0

Non-Performance Charges

Non-Performance Charge rates are calculated on a modeled RPM Locational Deliverability Area (LDA) basis for the relevant delivery year. The Non-Performance Charge rate for a specific resource is based on the Net Cost of New Entry (Net CONE) ($/MW-day in installed capacity terms) for the LDA in which such resource resides and is calculated as:

Non-Performance Charge Rate ($/MW-5-Minute Interval) =
Net CONE x Number of Days in Delivery Year / 30 Hours / 12 Intervals

The applicable charge rates for the Winter Storm Elliott PAIs for the 2022/2023 Delivery Year are detailed in **Table 19.**[19]

Table 19. Non-Performance Charge Rates by LDA ($/MW-5-Minute Interval)

Non-Performance Charge Rates by Locational Deliverability Area (LDA)					
ATSI	221.83	DPL-SOUTH	227.29	PS-NORTH	258.34
ATSI-CLEVELAND	221.83	EMAAC	249.60	PSEG	258.34
BGE	217.85	MAAC	235.90	RTO	250.69
COMED	238.54	PEPCO	249.76	SWMAAC	233.81
DAY	217.8	PPL	240.99		
DEOK	215.22				

These charge rates are multiplied by the final performance shortfall in each five-minute interval to determine the non-performance financial penalty for committed capacity resources. The Non-Performance Charge is calculated as:

Non-Performance Charge = *Performance Shortfall MW * Non-Performance Charge Rate*

The Non-Performance Charge for the performance assessment event totals approximately $1.80 billion, which was allocated across roughly 750 resources with final performance shortfall megawatts.

This represents 45% of the $3.97 billion in RPM auction credits paid across all committed capacity resources for the 2022/2023 Delivery Year. When isolating only the resources with shortfalls, the $1.80 billion in Non-Performance Charges represents 83% of the $2.17 billion in RPM auction credits collectively received by these under-performing resources for the 2022/2023 Delivery Year.

The hourly average and total Non-Performance Charges by hour are listed in **Table 20**.

[19] Modeled LDA Net CONE values for the 2022/2023 Delivery Year are available on PJM.com.

Table 20. Non-Performance Charges by Hour

Hour Beginning (EPT)		Non-Performance Charges ($)	
		Average of Interval-Level	Total Hourly
Dec. 23, 2022	17:00	6,589,973.18	39,539,839.05
	18:00	6,505,727.97	78,068,735.58
	19:00	6,731,000.98	80,772,011.71
	20:00	6,827,351.73	81,928,220.72
	21:00	7,031,512.93	84,378,155.18
	22:00	6,532,125.94	78,385,511.32
Dec. 24, 2022	04:00	7,785,599.61	54,499,197.25
	05:00	7,799,035.09	93,588,421.11
	06:00	7,733,603.22	92,803,238.65
	07:00	7,768,289.54	93,219,474.49
	08:00	7,473,896.14	89,686,753.62
	09:00	7,034,963.27	84,419,559.27
	10:00	6,910,820.64	82,929,847.71
	11:00	6,858,699.63	82,304,395.52
	12:00	6,370,314.53	76,443,774.40
	13:00	5,704,554.02	68,454,648.19
	14:00	5,508,448.92	66,101,387.04
	15:00	5,831,635.11	69,979,621.27
	16:00	6,365,883.24	76,390,598.86
	17:00	6,103,588.46	73,243,061.57
	18:00	5,739,415.91	68,872,990.94
	19:00	5,314,600.31	63,775,203.73
	20:00	4,951,402.92	59,416,835.04
	21:00	5,033,588.91	60,403,066.98
			$1,799,604,549.20

Stop-loss provisions are in place to limit the total Non-Performance Charge that can be assessed on each capacity resource. For CP resources, the maximum yearly Non-Performance Charge is 1.5 times the modeled LDA Net CONE ($/MW-day in installed capacity terms), times the number of days in the delivery year, times the maximum daily unforced capacity committed by the resource from June 1 of the delivery year through the end of the month for which the Non-Performance Charge was assessed. For all CP resources involved in the Winter Storm Elliott performance assessment event, the calculated Non-Performance Charge for the event was below the maximum yearly Non-Performance Charge. Further, for those Demand Response resources that were also subject to the performance assessment event in June 2022 earlier that same delivery year, the cumulative Non-Performance Charge for the delivery year did not exceed the maximum yearly Non-Performance Charge. As a result, it was not necessary to apply the stop-loss provision to any CP resource for the Winter Storm Elliott performance assessment event.

A resource that does not have enough unforced capacity value to cover the RPM commitment on the resource is subject to a Daily Capacity Resource Deficiency Charge. The Daily Capacity Resource Deficiency Charge is equal to the Daily

Deficiency Rate times the Daily RPM Commitment Shortage for generation resource, Demand Resource or Energy Efficiency Resource.[20]

Resources with Daily Capacity Resource Deficiency Charges may also have Non-Performance Charges during a non-performance event. In this case, a cap is placed on the total amount of deficiency-related charges a resource can be assessed. A resource that is subject to a Non-Performance Charge during one or more intervals occurring during a continuous time period of Daily RPM Commitment Shortages is assessed a charge equal to the greater of: a) the total Daily Capacity Resource Deficiency Charges calculated for shortages associated with Capacity Performance commitments for such continuous time period, or b) the total Non-Performance Charges calculated for the Performance Assessment Intervals occurring during such continuous time period.

The sum of the Daily Capacity Resource Deficiency Charges and Non-Performance Charges actually billed for such continuous time period may not exceed the resultant greater of charge. For the Winter Storm Elliott event, approximately $815,000 in Non-Performance Charges were excluded from the performance assessment billing based on this cap on total deficiency-related charges assessed to deficient resources. This $815,000 is not reflected in the values in Table 20.

Fixed Resource Requirement Shortfall Megawatts and Non-Performance Penalties

Resources that have been committed to a Fixed Resource Requirement (FRR) plan have the same obligation to perform during a performance assessment event as resources with RPM capacity commitments.

Shortfall megawatts from resources committed to FRR plans were included in the above tables summarizing resource performance and Non-Performance Charges, where applicable. Market Participants meeting their capacity obligations through FRR plans have the additional option to elect the physical non-performance assessment option.[21]

Entities that elect the FRR physical option are not assessed Non-Performance Charges and are not eligible for bonus performance credits for any performance associated with their FRR commitments. Instead, these entities must commit an additional megawatt quantity to their FRR capacity plan for the next delivery year in an amount equal to the sum of the net positive shortfalls for resources committed to their FRR plan across all five-minute intervals in the performance assessment event, multiplied by the FRR physical penalty rate.

The physical penalty rate is 0.00139 MW / Performance Assessment Interval [i.e., 0.5 MW / 30 PAHs / 12 intervals per hour]. For example, a resource with 1,000 MW of shortfall summed across all five-minute intervals in the performance assessment event would need to commit an additional 1.4 MW of capacity to their FRR plan for the delivery year following the event. In contrast, if the FRR entity for this resource instead chose the financial non-performance assessment option and was subject to the RTO Non-Performance Charge rate of $250.69/MW per five-minute interval, the resource would be assessed a charge of $250,690.

PJM is unable to report on the breakout of FRR Market Participants that have elected the physical non-performance assessment option vs. the financial non-performance assessment option or the penalties assessed to resources within their plans due to the small number of Market Participants utilizing FRR plans and requirements for posting market-sensitive data.[22]

Bonus Performance

A resource with actual performance above its expected performance is considered to have provided bonus performance, and will be assigned a share of the collected Non-Performance Charge revenues in the form of a bonus performance

[20] See PJM Manual 18, Section 9.1.3 for more information about Daily Capacity Resource Deficiency Charges.
[21] Refer to PJM Manual 11, Section 11.8.7 Physical Non-Performance Assessment.
[22] PJM Manual 33, Section 6.1

credit. Bonus performance from a resource represents greater delivered energy (or reductions), in comparison to the amount of the committed capacity from the resource that was needed during the event. Bonus performance is calculated on all over-performing resources as actual performance minus expected performance.

The expected and actual performance calculations for bonus megawatt evaluations are based on resource type:

- Generation/Storage:
  - Expected Performance = CP Commitment (UCAP) x Balancing Ratio
  - Actual Performance = Metered Energy Output + Reserve/Regulation Adjustment[23]
- Demand Response:
  - Expected Performance = CP Capacity Commitment (ICAP)
  - Actual Performance = Load Reduction + Reserve/Regulation Adjustment
- Energy Efficiency:
  - Expected Performance = CP Capacity Commitment (ICAP)
  - Actual Performance = PJM Approved Post-Installation Load Reduction
- Price Responsive Demand
  - Expected Performance = CP Capacity Commitment (ICAP)
  - Actual Performance = Load Reduction
- Net Imports
  - Expected Performance = 0 MW
  - Actual Performance = Sum (Import MW) – Sum (Export MW)

When calculating bonus megawatts, the actual performance for a generation resource is capped at the megawatt level at which such resource was scheduled and dispatched by PJM during the performance assessment event. PJM caps the megawatt level that a resource is eligible to receive bonus credit for to incent resources to follow dispatch in real time to support operations, and not chase potential bonus credits by over-generating. Resources must also have at least one available schedule with an economic minimum, economic maximum and emergency maximum, and at least one segment on the incremental energy offer curve so that PJM can determine the scheduled megawatts used in the determination of the cap. [24]

On average, approximately 2,700 MWh of energy in excess of expected megawatts was not eligible for bonus credits in each interval due to capping or failure to meet the energy offer requirements. PJM observed that a subset of these ineligible megawatts were from renewable resources that provided energy in excess of their expected megawatts. Many of these resources do not submit fuel cost policies and by default agree to be dispatched as a zero-cost resource in the

[23] The reserve/regulation adjustment made for actual performance for bonus purposes is the same as the adjustment made for shortfall calculation purposes. For calculations for reserve and regulation assignment megawatts factored into actual performance, see the Performance Assessment Settlement Summary.
[24] This rule is defined in Manual 11, Section 2.3.7.

absence of an approved fuel-cost policy. As such, these resources did not enter any segments on their Incremental Energy Offer curve and were therefore excluded from bonus payments.

The average bonus megawatts eligible for bonus credits for the Winter Storm Elliott performance assessment event was 34,318 MW per interval. On average, approximately 70% of these megawatts came from CP resources, while 30% came from energy-only resources (including net energy imports). The larger percent of bonus megawatts from the CP resources are driven by those resources being online and generating, and the average 82.1% balancing ratio. On average, resource output in excess of 82.1% of their capacity commitment, up to the megawatt level at which the resource was scheduled and dispatched, can be attributed to over-performance.

Table 21. Bonus Performance Megawatts by Hour by CP Resources and Energy Resources (hourly average of five-minute interval values)

Hour Beginning (EPT)		Average Bonus MW		Average Total Bonus MW
		CP Resources	Energy Resources	
Dec. 23, 2022	17:00	22,988.9	10,128.8	**33,117.7**
	18:00	23,102.9	10,827.0	**33,930.0**
	19:00	23,342.9	10,555.7	**33,898.6**
	20:00	23,825.6	10,312.1	**34,137.8**
	21:00	25,530.0	10,228.4	**35,758.4**
	22:00	23,059.9	10,717.0	**33,776.9**
Dec. 24, 2022	04:00	25,566.7	11,408.0	**36,974.8**
	05:00	25,850.1	10,984.0	**36,834.1**
	06:00	25,966.6	10,927.8	**36,894.4**
	07:00	24,469.0	11,490.8	**35,959.9**
	08:00	24,406.5	10,500.8	**34,907.3**
	09:00	25,106.4	9,974.4	**35,080.8**
	10:00	25,818.1	10,900.9	**36,719.1**
	11:00	26,328.8	10,850.1	**37,178.9**
	12:00	25,020.0	10,390.9	**35,410.9**
	13:00	22,903.1	10,435.4	**33,338.6**
	14:00	22,955.3	10,782.6	**33,737.9**
	15:00	24,371.7	10,314.0	**34,685.8**
	16:00	25,360.7	9,607.9	**34,968.7**
	17:00	23,723.6	9,569.2	**33,292.8**
	18:00	21,557.6	10,219.8	**31,777.4**
	19:00	21,716.6	9,978.6	**31,695.2**
	20:00	19,887.0	9,678.5	**29,565.6**
	21:00	21,310.7	8,681.8	**29,992.6**

Table 21 breaks out the average total bonus megawatts by resource type. On average, 80% of bonus megawatts were produced by generation, 10% came from net import transactions, 5% were produced by Energy Efficiency resources, and 5% were produced by Demand Response and PRD resources.

Energy Efficiency bonus megawatts are a static 1,720.9 MW across each five-minute interval of the entire performance assessment event. Actual performance for Energy Efficiency resources is established by the average demand reduction reported in the last post-installation measurement and verification report submitted by the Market Seller and approved by PJM prior to the delivery year in question.[25] Energy Efficiency resources automatically receive bonus megawatts for demand reduction in excess of their capacity commitment, as demonstrated in the post-installation measurement and verification report when a Capacity Performance event occurs.

The Demand Response and PRD bonus megawatt values include pre-emergency and emergency load management resources as well as economic Demand Resources cleared for energy or ancillary services. Pre-Emergency and Emergency Load Response resources are only required to interrupt their load between the hours of 06:00 through 21:00 EPT for the months of November through April. As such, even though the emergency and pre-emergency load management reduction actions on Dec. 23 did not end until 21:30 and 22:15, respectively, Capacity Performance Demand Resources were not required to curtail consumption beyond 21:00. The expected megawatts from these resources in the hours outside their mandatory curtailment period is 0 MW. One-hundred percent of the load reductions from pre-emergency and emergency load management resources in such hours are therefore counted as bonus megawatts. This is the reason the Average DR and PRD bonus megawatts for hour beginning 22:00 jumps five-fold from the previous hour.

Table 22. Bonus Performance Megawatts Broken Down by Resource Type (hourly average of five-minute interval values)

Hour (EPT Hour Beginning)		Average Bonus MW			
		Generation	Net Imports	EE	DR & PRD
Dec. 23, 2022	17:00	28,350.9	2,849.5	1,720.9	196.40
	18:00	27,965.0	3,490.5	1,720.9	753.50
	19:00	28,023.9	3,243.0	1,720.9	910.70
	20:00	28,410.3	3,032.2	1,720.9	974.20
	21:00	25,926.2	3,158.3	1,720.9	4,952.90
	22:00	27,974.1	3,834.8	1,720.9	247.00
Dec. 24, 2022	04:00	30,731.4	4,392.8	1,720.9	129.50
	05:00	31,103.6	3,897.8	1,720.9	111.70
	06:00	29,108.1	3,953.5	1,720.9	2,111.80
	07:00	28,213.2	4,289.4	1,720.9	1,736.30
	08:00	27,811.6	3,601.9	1,720.9	1,772.90
	09:00	28,422.5	3,084.0	1,720.9	1,853.30
	10:00	29,135.8	3,953.2	1,720.9	1,909.00
	11:00	29,514.4	3,849.5	1,720.9	2,094.10
	12:00	27,890.1	3,631.0	1,720.9	2,168.90
	13:00	25,798.2	3,603.0	1,720.9	2,216.40
	14:00	25,767.6	3,980.7	1,720.9	2,268.60
	15:00	27,083.5	3,610.1	1,720.9	2,271.20
	16:00	27,785.5	3,287.5	1,720.9	2,174.70
	17:00	26,248.9	3,254.7	1,720.9	2,068.20

[25] See PJM Manual 18, Section 4.4.1: Determination of Nominated value of EE Resources for more detail on how the average demand reduction upon which actual performance for Energy Efficiency resources is established.

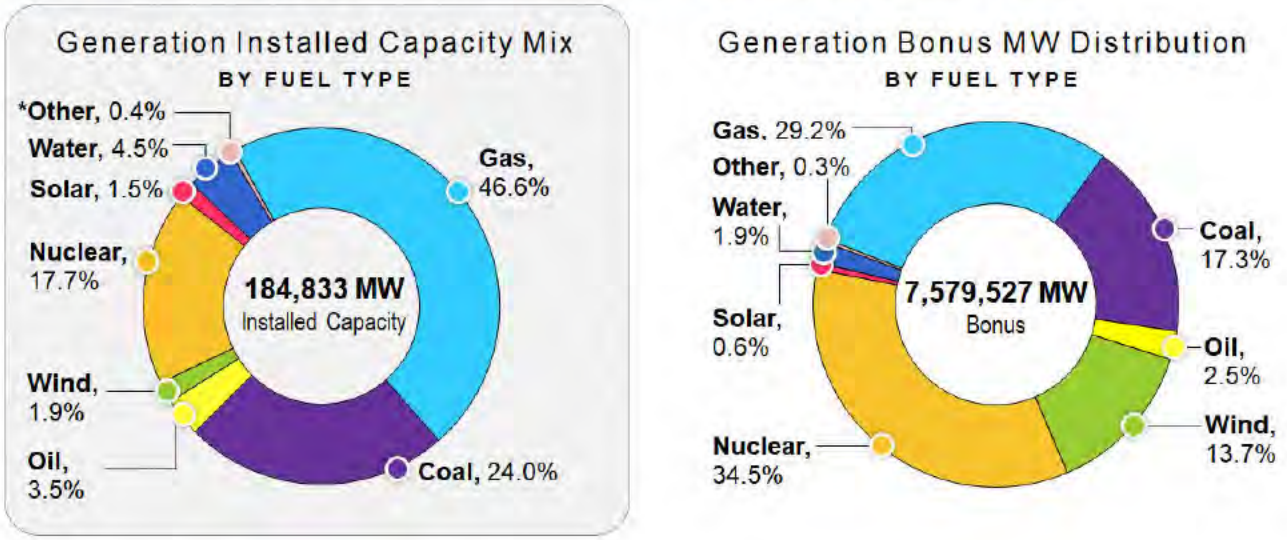
Hour (EPT Hour Beginning)		Average Bonus MW			
		Generation	Net Imports	EE	DR & PRD
	18:00	24,265.0	3,670.7	1,720.9	2,120.80
	19:00	23,588.6	3,549.7	1,720.9	2,835.90
	20:00	23,533.7	3,461.0	1,720.9	849.90
	21:00	25,954.5	2,280.0	1,720.9	37.10

Generation Bonus Performance Distribution by Fuel Type

Figure 90 depicts how the bonus performance megawatts from generation resources was distributed across the generation fleet using primary fuel type. Also provided in this figure is the installed capacity mix of the PJM generation fleet by primary fuel type to assist in understanding how proportionate the bonus performance by fuel type is to that fuel type's share of total generation capability. Consistent with their undersized portion of the shortfall megawatt pool, nuclear and wind resources in particular had outsized shares of the bonus performance pool given their strong performance during Winter Storm Elliott. Nuclear resources represented the largest share of bonus performance megawatts at 34.5%, or roughly double their share of the installed capacity mix. This stems from the high availability factor of both committed and uncommitted nuclear generation resources, the latter of which received bonus performance for all megawatts produced up to the level scheduled and dispatched by PJM.

It bears noting that these figures depict the bonus performance megawatts which received a share of bonus credits. As noted above in this section, resources that do not meet the energy offer requirements are not eligible to receive bonus performance credits and are excluded from the bonus performance megawatt values in this section.

Figure 90. Generation Bonus Performance Distribution by Fuel Type compared to Installed Capacity



Bonus Performance Rates and Credits

Total Non-Performance Charges are allocated, at the account level, as bonus performance credit to resources that have bonus megawatts based on their pro-rata share of total bonus performance megawatts. The average $/MW-interval rate across the performance assessment event for bonus megawatts was $188.85, or 75% of the non-performance penalty rate for the RTO. These rates are based on the total Non-Performance Charges assessed.

Table 23. Average Bonus Performance Rate (hourly average of five-minute interval values)

Hour Beginning (EPT)		Total Bonus MW	Total Non-Performance Charge	Bonus $/MW-Interval
Dec. 23, 2022	17:00	33,117.7	6,589,973.18	198.99
	18:00	33,930	6,505,727.97	191.74
	19:00	33,898.6	6,731,000.98	198.56
	20:00	34,137.8	6,827,351.73	199.99
	21:00	35,758.4	7,031,512.93	196.64
	22:00	33,776.9	6,532,125.94	193.39
Dec. 24, 2022	04:00	36,974.8	7,785,599.61	210.57
	05:00	36,834.1	7,799,035.09	211.73
	06:00	36,894.4	7,733,603.22	209.61
	07:00	35,959.9	7,768,289.54	216.03
	08:00	34,907.3	7,473,896.14	214.11
	09:00	35,080.8	7,034,963.27	200.54
	10:00	36,719.1	6,910,820.64	188.21
	11:00	37,178.9	6,858,699.63	184.48
	12:00	35,410.9	6,370,314.53	179.9
	13:00	33,338.6	5,704,554.02	171.11
	14:00	33,737.9	5,508,448.92	163.27
	15:00	34,685.8	5,831,635.11	168.13
	16:00	34,968.7	6,365,883.24	182.05
	17:00	33,292.8	6,103,588.46	183.33
	18:00	31,777.4	5,739,415.91	180.61
	19:00	31,695.2	5,314,600.31	167.68
	20:00	29,565.6	4,951,402.92	167.47
	21:00	29,992.6	5,033,588.91	167.83

Bonus credits paid to over-performing resources are based on Non-Performance Charges collected from under-performers. The bonus rates in the table above assume 100% collection of all Non-Performance Charges. To the extent that an account with under-performing resources is unable to pay their Non-Performance Charges, the total pool of bonus dollars to be paid out is reduced. This is achieved through the use of a bonus holdback.

Because both Non-Performance Charges and bonus credits for a given month are initially billed in the same billing statement, the amount of Non-Performance Charges that may be uncollected is unknown at the time the bill is issued. A bonus holdback is utilized to withhold an estimate of the potential uncollected Non-Performance Charges from the pool of bonus credits that are paid out in the initial bill. This hedges against the risk of paying out bonus credits that exceed the penalties that will actually be collected.

Once financial settlement occurs, PJM adjusts the bonus holdback to reflect observed nonpayment and issues adjustments to true-up the bonus credits paid with the total Non-Performance Charges collected. Ongoing reporting on the expected and actual bonus holdbacks for the billing of the Winter Storm Elliott performance assessment event is conducted at PJM Risk Management Committee meetings.[26] The Settlement Timelines and Results section of this report contains additional details on the total Non-Performance Charges to be billed each month, and therefore total potential bonus credits to be paid, as well as actual Non-Performance Charges collected as of the time this report was issued.

Resources that have been committed to an FRR plan and elected the physical non-performance assessment option had bonus megawatts calculated for the Winter Storm Elliott performance assessment events. These megawatts are not eligible to receive bonus credits. However, they are eligible to net against shortfall megawatts within the FRR entity's portfolio when calculating the amount of additional capacity the FRR entity will be required to carry in the following delivery year's FRR plan as a result of under-performance during the event. The details on the FRR physical bonus megawatts cannot be posted for data confidentiality reasons.[27]

Demand Response and Price Responsive Demand Performance

Detailed performance of DR for the Winter Storm Elliott Performance assessment event is reviewed in the Load Management Performance Report.[28] A summary of these details on performance, shortfall, bonus and penalties are detailed below. The full report can be referenced for more detailed analysis.

Table 24 summarizes Load Management (emergency and pre-emergency Demand Response) performance for the two days. For Dec. 23, all Load Management resources with 30-minute or 60-minute lead times were dispatched by PJM. For Dec. 24, all Load Management resources were dispatched by PJM (this includes all 30-minute, 60-minute or 120-minute lead times). Overall average event performance during the mandatory compliance period (06:00 through 21:00) was 126%. Capacity compliance is primarily measured based on the "firm service level" approach. This is where a resource is committed to maintain load at or below a defined level. The capacity reduction represents the megawatts reduced based on their load levels during the event, compared to their winter peak load. Capacity load reductions can be significantly different from real-time energy load reductions, since load may already be at the committed level before the resource is dispatched. This is the driver for the relatively strong Capacity Performance for this event, versus the relatively weak energy load reduction performance outlined in the Operating Day section of this report.

Table 24. Load Management Event Summary for Dec. 23 and Dec. 24

Date	Product	Average Capacity		
		Committed (MW)	Reduction (MW)	Performance
Dec. 23	Emergency Load Management	186	167	90%
	Pre-Emergency Load Management	4,042	4,907	121%
Dec. 24	Emergency Load Management	287	218	76%
	Pre-Emergency Load Management	6,888	9,035	131%

[26] Risk Management Committee web page at PJM.com
[27] PJM Manual 33, Section 6.1
[28] See Load Management Performance Report section of PJM DR web page.

Table 25 summarizes PRD performance. PRD is required to ensure load is below the committed level when there is a PAI and LMP greater than the strike price provided by the PRD provider. The capacity reduction represents the megawatts reduced based on their load levels during the event, compared to their peak load contribution.

Table 25. PRD Event Summary for Dec. 23 and Dec. 24

Date	Product	Average Capacity Committed (MW)	Average Capacity Reduction (MW)	Performance
Dec. 23	Price Responsive Demand	209	90	43%
Dec. 24	Price Responsive Demand	230	117	51%

The shortfalls from capacity commitments receive Non-Performance Charges, whereas the performance above the commitment level receives a bonus payment. Economic energy reductions and cleared ancillary services offers during the event intervals are eligible for bonus payments. The non-performance penalty and bonus breakdown for DR and PRD is detailed in **Table 26**. The Load Management and PRD performance values have been aggregated in the table below to adhere to posting rules around market-sensitive data given the small number of Market Participants with PRD resources. [29]

Table 26. DR and PRD Non-Performance Charges and Bonus Credits

Date	Load Management & PRD: Non-Performance Charge ($)	Load Management & PRD: Bonus Credit ($)	Economic Energy / Ancillary Services Bonus Credit ($)
Dec. 23	$2,421,812	$16,193,113.36	$2,546,949.14
Dec. 24	$1,610,469	$62,125,444.36	$5,782,104.47
Total	**$4,032,281**	**$78,318,558**	**$8,329,054**

Settlement Timelines and Results

Non-performance assessments are billed starting three calendar months after the calendar month that included the performance assessment event and are spread across the remaining months in the delivery year. For the Winter Storm Elliott event, this means charges are billed starting in March 2023 and spread in three equal installments through the May 2023 billing statement. However, given the magnitude of the penalties for this event, PJM filed Tariff revisions to provide participants with the option of spreading their Non-Performance Charges across a nine-month period, subject to interest for the additional six months included in this billing option.

Monthly charges are billed by dividing the total dollar amount due for each account by either three or nine months, depending on which billing option the participant selected. Participants electing the nine-month billing option were billed starting in the March 2023 billing statement and will continue to be billed through the November 2023 billing statement. Bonus credits will be paid over the same time frame, with the amount credited each month equal to the amount of Non-Performance Charges collected each month. Based on the aforementioned elections, $524 million, or 30% of the total

[29] PJM Manual 33, Section 6.1

$1.8 billion in Non-Performance Charges for this event, will be billed over a three-month period. The remaining $1,276 million, or 70%, will be billed over a nine-month period and will be assessed $15 million in interest charges. [30]

The following table displays the total charges to be assessed each month, the total Non-Performance Charges that were not collected, and the resulting bonus credits available to be paid to bonus recipients as of June 21, 2023. Ongoing updates will be provided through the PJM Risk Management Committee meetings.

Table 27. Non-Performance Charges and Bonus Credits Invoiced

Billing Month	Total Non-Performance Charges ($)	Total Interest Charges ($)	Total Nonpayment ($)	Total Bonus Credits Paid (including interest) ($)
March 2023	$316,419,632.80	$1,704,168.62	$8,422,793.53	$309,701,007.89
April 2023	$316,419,632.80	$1,704,168.62	$7,877,961.45	$310,245,839.97
May 2023	$316,419,632.80	$1,704,168.62	$7,875,909.02	$310,247,892.40
June 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
July 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
August 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
September 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
October 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
November 2023	$141,724,275.13	$1,704,168.62	TBD	TBD
Total	**$1,799,604,549.20**	**$15,337,517.54**	**$24,176,664.01 (as of 6/21/2023)**	**$930,194,740.26 (as of 6/21/2023)**

Government, Member and Media Outreach

PJM's Corporate Communications, Federal, and State & Member Services teams are responsible for communicating situation updates to, and answering inquiries from, the general public, stakeholders, and state and federal contacts through direct channels, as well as PJM.com, social media and traditional media. Corporate Communications regularly participates in PJM's annual Operations Winter Emergency Procedures Drill and Summer Emergency Procedures Drill. These drills include a call with Transmission Owner communications departments, in which a PJM Operations supervisor and PJM external communications staff provide a situation update and information on how PJM contacts them if needed in an emergency, including through an emergency alert tool managed by PJM's Business Continuity Department. Corporate Communications conducts a roll call of communicators during these drills and uses the occasion to update its Transmission Owner communicator contact list.

PJM's State Government Policy (SGP) Department prepares for emergency procedure communications and coordination with state emergency contacts throughout the year. These state emergency contacts, categorized by email and phone number (all-call list), are informed by the state agencies within the PJM footprint and serve as the primary point of contact to receive standard PJM emergency procedure notifications, which are sent by the designated on-call SGP employee.

SGP tests its ability to successfully communicate with the state emergency email and all-call lists during PJM's summer and winter emergency drills, as well as other emergency drills, such as the November 2022 Grid Security Drill. These summer and winter drills allow for state emergency contacts to familiarize (or re-familiarize) themselves with PJM's

[30] The interest charges collected on a monthly basis will be allocated to bonus performance credit recipients based on their ratio share of total bonus performance credits (under the assumption of 100% collection of all Non-Performance Charges).

emergency notifications, help PJM test its emergency communication channels with the states, and provide biannual checkpoints for PJM to curate the state emergency contact lists. The state emergency contact lists are also updated on an ad-hoc basis.

PJM external-facing communicators also participate in biannual GridEx exercises and Grid Security Drills, coordinating with both member communicators and other ISOs/RTOs as part of the scenarios.

Beginning with the 2021/2022 winter season, SGP and Operations leadership began holding winter operations calls with the PJM states to discuss winter preparedness and operational developments throughout the winter. The calls continued for the 2022/2023 winter season, with one meeting held with the states on Dec. 15, 2022.

The activation of PJM's crisis communication plans and outreach to members, states and the general public through national/local/social media appeared to help reduce electricity use and ensure the reliability of the grid. Member communicators expressed appreciation for PJM's handling of the media and willingness to do local media interviews. In addition, PJM continues to seek additional feedback on opportunities for better coordination to refine and enhance its crisis communications and outreach procedures.

The outreach by Corporate Communications, State & Member Services, and other PJM employees, and coordinated response by both member companies and state partners was effective. The Call for Conservation, which depends on members to relay the message to their retail customers, and the impact of consumers' resulting efforts, appeared to have led to a reduction in demand. Though it is difficult to measure precisely, electricity demand leveled off over the course of Saturday, and peak demand Saturday evening came in less than what was forecast.

While the conservation effort appeared to be successful, PJM is exploring further opportunities to maximize the reach of such appeals with states and Transmission Owners.

Event Communications

Starting on Dec. 21 through Dec. 23, Corporate Communications published on its news site, Inside Lines, a series of articles noting the Cold Weather Advisory and subsequent Cold Weather Alert updates, and amplified them on social media. On Dec. 23, conditions deteriorated as more generators continued to go offline, resulting in a Call for Conservation.

A Call for Conservation, as outlined in Manual 13, "instructs affected Transmission Owners to request the public to conserve electricity because of developing power supply problems." Transmission Owners are the most logical point of contact for retail customers, with PJM also broadcasting the conservation appeal via news release, PJM.com, social media and traditional media.

The decision to issue a Call for Conservation was made at approximately 23:30 on Friday, Dec. 23, so that both Transmission Owners and PJM's press release would reach any outlets or audiences that could respond late Friday into early Saturday morning and have some impact on the morning peak. PJM Corporate Communications and State & Member Services teams relayed system conditions and the Call for Conservation to the communications staff of PJM Transmission Owners, as well as state regulators and elected officials, throughout Winter Storm Elliott from Dec. 23 to Dec. 25.

Corporate Communications posted a news release on PJM.com at 23:54 and sent the release via email to Transmission Owner communicators, members and media contacts, and posted to Twitter and LinkedIn. PJM reissued the news release to our extensive media and member communicators' contact lists at 05:40, Dec. 24, and retweeted the Call for Conservation news release.

Corporate Communications activated its crisis communications plan at 05:45, Dec. 24, to make sure sufficient resources were available to handle outreach and media response needs Saturday and Sunday.

PJM noted the end of the Call for Conservation on Sunday, Dec. 25, with direct email to members, social media posts and video on PJM.com.

Transmission Owner Communicators

At approximately 21:50, Friday, Dec. 23, before PJM had made the decision to issue a Call for Conservation, PJM Corporate Communications scheduled a meeting with Transmission Owner communicators for 08:30, Saturday, Dec. 24, to provide utility partners a situational update. PJM also directly emailed Transmission Owner communicators the news release shortly after 00:00 Saturday.

This 08:30 Saturday meeting became PJM's main venue to request these members' support in broadcasting the Call for Conservation appeal. More than 30 partners (including elected officials and regulators in addition to members) joined in the effort to amplify the Call for Conservation to their customers, gaining nearly 1 million impressions on Twitter alone. PJM believes that the actions of these members, combined with PJM media outreach, helped to broadcast the Call for Conservation and flatten the load beginning at 07:15 Saturday, when the New Jersey Board of Public Utilities issued the first tweet in response to PJM's call.

PJM held an event review with Transmission Owner communicators on Jan. 9. This discussion informed Corporate Communications' observations and lessons learned from the event. Transmission Owner communicators stated that PJM's willingness to do interviews with local media was helpful to them as they dealt with both distribution outages and the transmission challenges highlighted by the Call for Conservation.

Federal

During the winter storm, PJM's Federal Government Policy group kept in close contact with FERC and the Department of Energy (DOE), consistent with its regular practice when emergency procedures are invoked. Communications are directed to FERC commissioners and their advisors, as well as to staff, throughout the Commission and reports on the system conditions with updates after the morning and evening peaks. In addition, PJM utilizes FERC's emergency notification procedures for such notices. PJM's reporting requirements to FERC are identified in in PJM Manual 13 and NERC Standard EOP-4.

In addition, the Federal Government Policy group similarly reaches out to DOE officials in the office of Cybersecurity, Emergency Security and Emergency Response (CESER) with updates after the morning and evening peaks. These early communications represented an early reach-out prior to PJM seeking to invoke the Section 202(c) process to obtain an emergency order from the Secretary of Energy.

Public/Media

PJM posted three video updates from System Operations leadership at the top of PJM.com homepage. The video was retweeted and reposted by customer-facing members as well as elected officials and regulators, used by State & Member Services to inform key stakeholders, and quoted or captured directly by media for use in broadcasts.

PJM responded to approximately 50 media requests, including at least 20 interviews on Dec. 24 and Dec. 25. PJM worked with customer-facing members' communications departments, who referred inquiries to PJM. In follow-up discussions, these members indicated that PJM's willingness to handle local media requests freed them to handle other pressing issues at the distribution level.

PJM deployed Twitter, LinkedIn and Facebook to draw attention to the video updates provided on PJM.com. Posts promoting the video received more than 300,000 impressions. Total impressions from PJM posts during Winter Storm Elliott were:

Twitter – 519,298	Facebook – 27,368	LinkedIn – 27,182

The PJM Now app is a popular source for system alerts (including emergency procedures) and allows users to track energy use, fuel mix and emissions data. More than 1,800 unique users accessed the app during Winter Storm Elliott, and the app was opened 6,600 times on Dec. 25 – compared with an average daily use of 750 app opens. The PJM Now app experienced unprecedented usage that slowed service during the storm, and PJM's Inside Lines news site went down Saturday because of unprecedented usage. Corporate Communications has taken steps to enhance these platforms so that similar usage levels will not result in the same performance issues as experienced during Winter Storm Elliott.

Between Dec. 23 and Dec. 25, Corporate Communications tracked more than 70 news stories noting PJM's Call for Conservation. This included national and newswire coverage from CNN, the Associated Press and Bloomberg, as well as regional coverage from television, radio and print media throughout the region PJM serves.

States

Heading into Winter Storm Elliott, SGP began its emergency procedure communications with the states on Dec. 21, relaying the issuance of a Cold Weather Alert for the Western Region of PJM on Dec. 23. SGP then communicated the issuance of a second Cold Weather Alert on Dec. 23 for the entire PJM region that began on Dec. 24.

As the storm progressed on Dec. 23 and emergency conditions arose, SGP relayed PJM's emergency procedure positioning to the state emergency email contacts as this information was provided to SGP by PJM's Operations Team. This included the escalation and de-escalation of emergency conditions heading into Dec. 24. SGP also communicated PJM's Dec. 24 Call for Conservation to the states, but instead of sending the conservation message to just the standard state emergency contacts, SGP utilized a broader list of state contacts that also included the emergency contacts.

In addition to member utilities, social media reach was greatly extended by participation of elected officials. Two governors tweeted the Call for Conservation and attracted two of the top three Twitter impression totals. Corporate Communications and SGP are working together to maximize impact from state partners when issuing a conservation appeal.

As SGP continued to provide system condition updates to its state emergency contacts the morning of Dec. 24, these communications progressed to individualized updates to the states via the SGP regulatory managers. Periodic system condition updates continued to be provided to the standard state emergency contacts through Dec. 25, although no new emergency procedures were issued by PJM.

Stakeholders

Figure 91 presents the stakeholder messages made between Dec. 23 and Dec. 25, color-coded by audience. These communications are in addition to direct communications made to generators, Load Serving Entities, Market Participants and others in emergency conditions as well as normal operating situations. General email notifications about the start and end of Performance Assessment Intervals are made for general awareness of all members. Members directly impacted by Performance Assessment Intervals receive separate, direct notifications in real time.

Figure 91. Stakeholder Messages

Type	Audience	Message	Time Sent Dec. 23	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: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 45
DOE Order No. 202-21-1

Department of Energy
Washington, DC 20585

Order No. 202-21-1

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

On February 14, 2021, the Electric Reliability Council of Texas (ERCOT), the Independent System Operator (ISO) whose service territory includes 90 percent of the electric customers in the state of Texas, filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of bulk electric power system."

ERCOT is in the beginning stages of an unprecedented cold weather event brought on by a rare, southward excursion of the jet stream into the South Central United States. Temperatures for Sunday and Monday in many parts of Texas are forecasted to drop well below the lowest temperatures experienced in several decades, and abnormally low temperatures are expected to persist for several more days. This weather event is expected to result in record winter electricity demand that will exceed even ERCOT's most extreme seasonal load forecasts.

On February 12, 2021, Greg Abbott, the Governor of the State of Texas declared a state of disaster in all 254 Texas counties due to severe weather posing an "imminent threat of widespread and severe property damage, injury, and loss of life due to prolonged freezing temperatures, heavy snow, and freezing rain statewide." On the morning of February 14, ERCOT issued a system-wide conservation notice addressing the expected system emergency and describing steps that homeowners and businesses can take to reduce system demand.[1] ERCOT has also worked with state agencies to take measures that maximize generation availability in Texas. For example, on February 12, the Railroad Commission of Texas issued an Emergency Order pursuant to Texas Utilities Code affecting the gas utility systems in the state. The order specified increasing the priority of gas supplies to ERCOT generators. ERCOT's application also noted that the "Texas Commission on Environmental Quality has indicated that it will provide enforcement discretion to generators in the ERCOT region that may exceed state emissions requirements during emergency conditions."

According to ERCOT, the measures taken by ERCOT and other state agencies may not prove sufficient to avoid rotating outages of as much as 4,000 MW. Moreover,

[1] ERCOT, *Grid Operator Requests Energy Conservation for System Reliability*, www.ercot.com/news/releases/show/225151.

ERCOT has been alerted that numerous generation units will be unable to operate at full capacity without violating federal air quality or other permit limitations.

ERCOT requests that the Secretary issue an order immediately, effective February 14, 2021 through February 19, 2021, authorizing "the provision of additional energy from all generation units subject to emissions or other permit limits" in the ERCOT region. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-21-1 Resources List, as described below.

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

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

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

A. From February 14, to February 19, 2021, in the event that ERCOT determines that generation from the Specified Resources is necessary to meet the electricity demand that ERCOT anticipates in Texas during this event, I direct ERCOT to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in the ERCOT region when the demand on the ERCOT system exceeds expected energy and reserve requirements. Specified Resources are those natural gas, coal, or distillate fuel oil generating units set forth on the Order 202-21-1 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov. ERCOT is directed to update Exhibit A to its Application with the anticipated category of environmental impact (i.e. sulfur dioxide, nitrogen oxide, mercury, carbon monoxide emissions, wastewater release, other air pollutants) by 21:00 Central Standard Time on February 15, 2021.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by ERCOT for reliability purposes. Consistent with good utility practice, ERCOT shall exhaust all reasonably and

practically available resources, including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions, to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources. ERCOT shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

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

(i) with respect to any Specified Resource that is an ERCOT Generation Resource or Settlement Only Generator whose operator notifies ERCOT that the unit is unable, or expected to be unable, to produce at its maximum output due to an emission or effluent limit in any federal environmental permit, ERCOT shall ensure that such Specified Resource is only allowed to exceed any such limit during a period for which ERCOT has declared an Energy Emergency Alert (EEA) Level 2 or Level 3. This incremental amount of restricted capacity would be offered at a price no lower than $1,500/MWh. Once ERCOT declares that such an EEA Level 2 or Level 3 event has ended, the unit is required to immediately return to operation within its permitted limits; and

(ii) with respect to any Specified Resource that is an ERCOT Generation Resource whose operator notifies ERCOT that the unit is offline or would need to go offline due to an emission or effluent limit in any federal environmental permit, and to which ERCOT has issued a Reliability Unit Commitment (RUC) instruction, the operator may make all of the unit's capacity available to ERCOT for dispatch during a period for which ERCOT has declared an EEA Level 2 or Level 3. This incremental amount of restricted capacity would be offered at a price no lower than $1,500/MWh. Once ERCOT declares that such an EEA Level 2 or Level 3 event has ended, the unit is required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

In the event ERCOT identifies the need to exceed other relevant environmental permitting levels, ERCOT shall specifically identify such permitting levels and DOE will consider ERCOT's request in good faith.

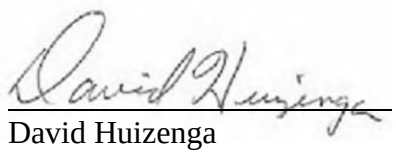
C. All entities must comply with environmental requirements to the maximum extent necessary to operate consistent with the emergency conditions. This Order does not provide relief from an entity's obligations to purchase allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. In the event that ERCOT identifies additional generation units that it deems necessary to operate in excess of federal environmental permitting limits in order to maintain the reliability of the power grid in the ERCOT region when the demand on the ERCOT system exceeds expected energy and reserve requirements, including any such entity to which ERCOT intends to issue a Reliability Unit Commitment (RUC), ERCOT shall provide prompt written notice to the Department of Energy at AskOE@hq.doe.gov identifying in an updated Exhibit A to its Application such additional generation units, the fuel type of such unit, and the anticipated category of environmental impact, at 9:00 Central Standard Time or 21:00 Central Standard Time, whichever follows closest in time to the unit identification by ERCOT to the greatest extent feasible. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department, and ERCOT may dispatch such additional generation units, provided that if the Department of Energy notifies ERCOT that its does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department. The Department shall post an updated Order 202-21-1 Resource List as soon as practicable following notification from ERCOT under this paragraph.

E. ERCOT shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By March 1, 2021, ERCOT shall report all dates between February 14, 2021, and February 19, 2021, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. ERCOT shall submit a final report by March 31, 2021, with any revisions to the information reported on March 1, 2021. In addition, ERCOT shall provide information to the Department quantifying the net revenue associated with generation in excess of environmental limits accruing to non-RUC units in connection with orders issued by the Department pursuant to Section 202(c) of the Federal Power Act.

F. This Order shall be effective upon its issuance, and shall expire at 11:59 p.m. Central Standard Time Friday, February 19, 2021, with the exception of the reporting requirements in paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 8:51 PM Eastern Standard Time on this 14th day of February, 2021.



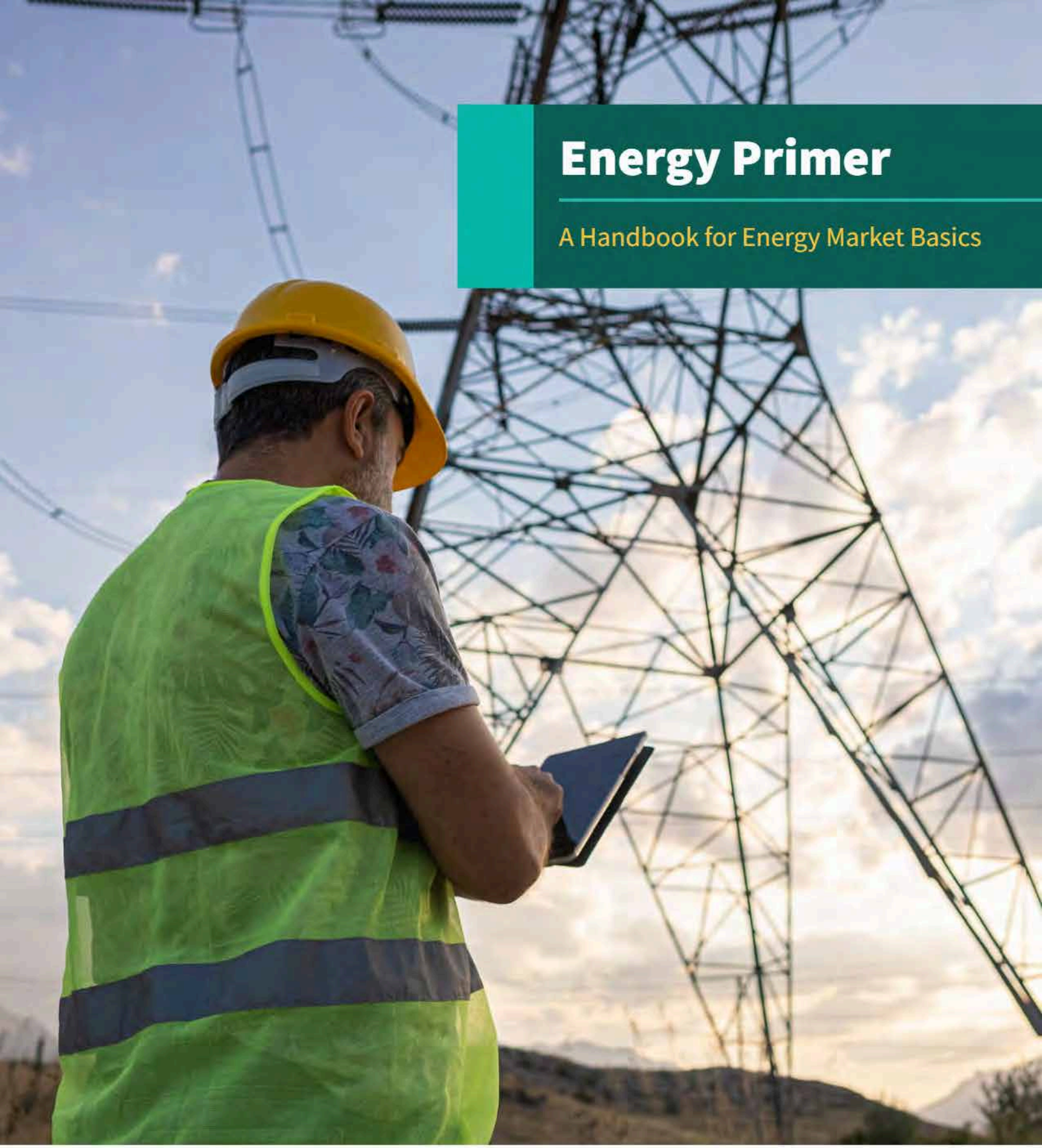
David Huizenga
Acting Secretary of Energy

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 46
FERC Energy Primer



Energy Primer

A Handbook for Energy Market Basics

FEDERAL ENERGY REGULATORY COMMISSION
Office of Energy Policy and Innovation

Energy Primer

A Handbook for Energy Market Basics

FEDERAL ENERGY REGULATORY COMMISSION
Office of Energy Policy and Innovation
December 2023

This report is a product of the staff of the Federal Energy Regulatory Commission (Commission or FERC). The opinions and views expressed in this paper represent the preliminary analysis of the Commission staff. This report does not necessarily reflect the views of the Commission, its Chairman, or individual Commissioners, and is not binding on the Commission.

ACKNOWLEDGMENT

The Energy Market Primer was originally issued in 2012 and has been updated several times since its first issuance. This update to the Energy Market Primer is the result of the combined efforts of many dedicated individuals throughout the Federal Energy Regulatory Commission (FERC or Commission). The team consisted of individuals from the Commission's Office of Energy Policy and Innovation, Office of Enforcement, Office of Energy Market Regulation, and Office of External Affairs. We specifically wanted to recognize the primary contributors to each chapter.

Chapter 1: Wholesale Natural Gas Markets – Eric Primosch

Chapter 2: Wholesale Electricity Markets – Patricia Schaub

Chapter 3: Gas-Electric Interdependency – Thomas Pinkston

Chapter 4: U.S. Crude Oil and Petroleum Products Markets – Eric Primosch

Chapter 5: Trading and Capital Markets – Astrid Rapp and Gareth Jones

Chapter 6: Market Manipulation – Thomas Olson

IN MEMORIAM



Lance Hinrichs

Federal Energy Regulatory Commission
Office of Energy Policy and Innovation

Lance was instrumental in the creation and publication of the Energy Market Primer. He will forever be remembered as a dedicated public servant whose knowledge of energy markets was unsurpassed.



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INTRODUCTION

Natural gas, electricity, and crude oil are forms of energy that are of particular interest to the Federal Energy Regulatory Commission (FERC) pursuant to its authority under the Natural Gas Act, the Federal Power Act, and the Interstate Commerce Act. This primer explores the workings of the wholesale markets for these forms of energy, as well as energy-related financial markets.

Energy markets consist of both physical and financial elements. The physical markets contain the natural resources, infrastructure, institutions and market participants involved in producing energy and delivering it to consumers. The financial markets include the buying and selling of financial instruments that derive value from the price of the physical commodity. These financial markets have their own set of market structures and institutions, market participants, and traded products which have their own drivers of supply and demand. In general, physical and financial markets can be distinguished by the products and by the intentions of the market participants involved.

Much of the wholesale natural gas and electric power industry in the United States trades competitively, while some markets and their prices are established through administrative processes based on the cost of providing service. In competitive markets, prices are largely driven by the economic concepts of supply and demand. Underlying the supply and demand for energy are physical fundamentals - the physical realities of how markets produce and deliver energy to consumers and how they form prices. These physical fundamentals will be covered in Chapter 1 (Wholesale Natural Gas Markets), Chapter 2 (Wholesale Electricity Markets), and Chapter 4 (U.S. Crude Oil and Petroleum Products Markets).

The significant shift in the U.S. fuel mix has heightened the importance over the past decade of the interdependence of the natural gas and electric systems. Given the importance of natural gas in electricity generation, integration of market operations between the natural gas and electricity industries is critical. The primer provides an overview of natural gas and electric system interdependencies in Chapter 3, Gas-Electric Interdependency.

Market participants buy and sell energy based financial contracts for a number of reasons. Physical market participants, such as producers and large consumers, usually use financial contracts to manage price risk and to protect against price volatility. That is, financial contracts can serve as a tool for managing risk akin to insurance. Other market participants use the energy markets to speculate, or to assume a market risk in hope of profiting from market fluctuations. Additionally, companies turn to the capital markets if they need to raise or invest money. This primer explores the market participants, products, market mechanisms and trading at work for natural gas and electricity in the financial markets in Chapter 5, Financial Markets and Trading.

Where there are markets, there will be those who attempt to manipulate the markets for their own benefit. These practices undermine the market's ability to operate efficiently, reduce other market participants' confidence in the markets and distort market outcomes, including prices. Some of these practices are discussed in Chapter 6, Market Manipulation.

This primer is written to be used either as a traditional text – read front to back – or as a reference guide. Consequently, some material is repeated in different sections and references are provided to other parts of the primer where a concept is addressed in greater detail.

Further information about various aspects of energy markets and FERC regulation can be found at www.ferc.gov; then navigate to the Market Oversight tab. You can find the market oversight pages here: https://www.ferc.gov/market-assessments.







Chapter 2
Wholesale Electricity Markets

WHOLESALE ELECTRICITY MARKETS

Electricity is a physical product – the flow of electrical power. It is a secondary energy source, in that it results from the conversion of other energy forms such as natural gas, coal or uranium, or the energy inherent in wind, sunshine or the flow of water in a river. Electricity is not visible or directly observable, but it can be turned on and off and measured.

Quick Facts: *Measuring Electricity*

A key measure of electricity used in industry is the rate at which it is produced, transferred, or consumed – how much energy per unit of time a generator produces, with the units of electricity called watts. Similar measures are kilowatts (kW) – 1,000 watts, and megawatts (MW) – 1,000 kilowatts. A watt, kilowatt, or megawatt is a unit of power.

The amount of electric energy generated, transmitted, or used over time is measured as the number of watt-hours (also expressed as kilowatt-hours, megawatt-hours, or gigawatt-hours).

The amount of electricity a generator can produce in an hour is its capacity, which is typically noted as megawatts. For example, a generator with a capacity of 100 MW can produce 100 MW in an hour. The amount of power consumed at any location is the demand at that point.



Electricity markets have retail and wholesale components. Retail service involves the sales of electricity to consumers and may involve retail markets; wholesale markets typically involve the sales of electricity among electric utilities and electricity traders before it is eventually sold to consumers. Because the Federal Energy Regulatory Commission (FERC) has jurisdiction over wholesale electric rates and not retail electric rates, this document focuses on wholesale electricity markets, although it does address retail demand and other instances where retail markets strongly influence wholesale markets.

Most wholesale electric markets rely upon competitive markets to set prices, but some prices are based on the service provider's cost of service. For wholesale markets, FERC either authorizes jurisdictional entities to sell at market-based rates or at cost-based rates.

Both market-based and cost-of-service prices are affected by physical factors or conditions that drive electric supply and demand – these factors are known as physical fundamentals. For example, weather affects both supply and demand. Fuel costs, capital costs, transmission capacity and constraints, and the operating characteristics of power plants affect the cost at which supply can be provided. The actual price for power is determined by the interaction of supply and demand. For example, extreme heat can drive up demand and require grid operators to activate less-efficient, more-expensive power plants, and consequently drive prices up.

Electric Power Industry

ELECTRICITY ON DEMAND

In the United States and other developed countries, consumers expect electricity to be available whenever they need it. Electricity use has grown as consumers integrate various devices and amenities such as lighting, refrigerators and computers into their everyday lives. Consumers also expect to pay reasonable prices for the electricity that they use.

Meeting these customer expectations requires substantial effort and activity. While technology continues to develop and advance, electric markets can only store a portion of the electricity required to serve electric loads. Thus, the vast majority of electricity must be produced instantaneously as needed. Further, unlike most other markets, electricity's historically inelastic demand does not move with prices. To provide electricity on demand, electric system operations have to be planned and conducted with that goal in mind. In the absence of significant amounts of storage and price responsive demand, operators must plan and operate power plants and the transmission grid so that demand and supply exactly match, every moment of the day, every day of the year, in every location.

ECONOMIES OF SCALE

Electric power is one of the most capital-intensive industries. Generation, transmission and distribution require significant investment in capital intensive equipment, the costs of which are fixed. Spreading these significant fixed costs over more customers helps bring down the cost that each customer pays.

Thomas Edison's first street lighting project in the 1880s grew to electrifying whole neighborhoods, towns, and cities. Providing service over larger areas allowed utilities to take advantage of economies of scale and the cost per unit of production dropped as power plants grew larger and larger. The companies building these facilities were generally self-contained and not connected to each other. They owned and operated generation, transmission, and distribution facilities and were vertically integrated.

While successful for launching the electric utility industry, this market structure had limitations. The larger generating units were difficult to replace if they experienced unexpected shutdowns. As a result, the utilities held and maintained excess capacity in reserve (reserves) to ensure reliable electric service. These reserves were able to quickly replace electricity lost due to an unexpected shutdown or an unexpected increase in electric loads.

RESERVE SHARING

The solution to high reserve costs was to share reserves with adjacent utilities. Instead of building and maintaining all of the capacity required to provide energy and sufficient reserves, utilities were able to pool their reserves and could buy power from their neighbors in times of need cutting their costs significantly as a result. To facilitate reserve sharing, utilities built interconnecting transmission lines between their transmission systems to deliver electricity in the event of a generator outage or some other system disruption. Today's bulk power grid began as a way to maintain reliable service while lowering costs. The value of reserve-sharing agreements led to the formation of power pools, the forerunners of today's regional transmission organizations.

Coordinating exchanges of energy and reserves also led to closer coordination of other utility functions, such as the process of determining which generating units to use to serve electric loads. Operators want to commit just enough capacity to ensure reliability, but no more than is needed. Over time, this coordination ultimately led to the creation of regional transmission organizations that use markets to determine the set of resources to reliably serve electric loads at least cost. These wholesale electricity markets operate over large regions of the country.

Regional coordination also was spurred by special circumstances, particularly in the West. Large federally owned dams on the Columbia and Colorado river systems generate power from the spring runoff of melting mountain snow. When the reservoirs are full and hydroelectric plants are generating plentiful amounts

of power, there is not enough local demand to use the available supply. Since hydropower was cheaper than any alternative, long distance transmission lines were built to deliver the excess power from the Northwest and Southwest to load centers in California. With these transmission interconnections in place, northwestern utilities found that they could get cheaper power from southern power generation at other times of the year. These seasonal and regional disparities in availability and price introduced a lively bilateral trading market.

In the 1960s, the electric power industry created an informal, voluntary organization of operating staff to aid in coordinating the reliable operation of the bulk electric system. Then, in 1965, the largest power blackout until that time hit the northeastern United States and southeastern Ontario, Canada, affecting 30 million people. The blackout led to the development of the National Electric Reliability Council in 1968, shortly thereafter renamed the North American Electric Reliability Council (NERC), and nine regional reliability councils.[74] Rather than serving as a power pool or other entity for sharing reserves, NERC focused on reliability. In 2006, using authority granted in the Energy Policy Act of 2005 (EPAct 2005), FERC certified NERC as the electric reliability organization for the United States, and reliability standards became mandatory and enforceable.

ECONOMY ENERGY TRADE

Transmission interconnections between adjacent utilities were originally built for the primary purpose of delivering reserves in emergencies. However, this created excess transmission capacity, since these events were rare. The interconnections allowed utilities to trade power, which became profitable when the marginal cost of operating their generation was higher or lower than that of their neighbors. Transmission availability provided opportunities for utilities to save money by buying energy when it was cheaper than generating and selling energy to utilities with higher costs. This is called economy energy trading.

EVOLVING PUBLIC POLICIES

Evolving public policies, regulatory constructs and organizational structures shaped the electric power industry over its history. Five concepts that helped shape the electricity industry and markets are outlined below, and still affect the industry today.

REGULATED MONOPOLIES

In the early years of the industry, investors provided funds and took ownership shares in the power stations and electric distribution systems. These utilities became regulated – typically by state agencies – to overcome concern they were natural monopolies in the areas they served, lacking competition, and to bring stability to a capital-intensive industry. Stability came from granting exclusive service territories (or franchises), transparent financial statements, and the formulaic setting of electricity rates that were subject to regulatory oversight and approval. Over time, many of the utilities issued stock, which gave stockholders a share of the company's ownership, commonly referred to as investor-owned utilities (IOUs). The regulatory model for setting electricity rates was almost exclusively cost of service-based until about 30 years ago. Today, retail electric rate regulation is largely still based on cost-of-service, while wholesale electric rate regulation has become increasingly market-based. State regulators are responsible for approving retail rates, as well as utilities' investments in generation and distribution facilities. Some states eventually developed elaborate integrated resource planning (IRP) processes to determine what facilities should be built.[75]

NOT-FOR-PROFIT UTILITIES

Another approach to serving customers emerged in the form of nonprofit electric providers. In the early years of the industry, electrification started in towns and cities

74 In 2006, the North American Electric Reliability Council changed its name to the North American Electric Reliability Corporation (also referred to as NERC).

75 For additional background and context on the early years of the electrification of the U.S., National Museum of American History, *Powering a Generation of Change, Emergence of Electrical Utilities in America* (2002), http://americanhistory.si.edu/powering/past/h1main.htm.

where utility service was provided by municipal power agencies or city governments. The federal government also stepped in to develop and market electricity from the nation's significant hydroelectric resources. Finally, the Depression-era rural electrification program promoted customer-owned rural electric cooperatives and low-interest government loans. There are currently more than 1,700 municipal and almost 900 cooperative utilities in the United States.

POWER POOLS

Power pools are multilateral arrangements with members ceding operational control over their generating units and transmission facilities to a common operator. Members provide incremental cost data about their units and system status data to the operator. The operator then runs an energy management system that uses the unit cost data to optimize the overall unit commitment and economic dispatch.

The first of the power pools was PJM, which began in 1927 for utilities to share their generating resources. The Electric Reliability Council of Texas (ERCOT) and the Southwest Power Pool (SPP) formed in 1941 to pool resources for the war effort. Later, the New York Power Pool was formed in 1966 and the New England Power Pool in 1971, in response to the 1965 Northeast blackout.

COMPETITION, PART 1: COMPETITIVE GENERATION AND OPEN ACCESS

Environmental policy and initiatives to open the airline and trucking industries to competition helped shape the energy industry in the 1970s. A provision in President Carter's energy plan led to passage of the Public Utility Regulatory Policies Act of 1978 (PURPA), which ushered in the next era.

PURPA established a program implemented by states and overseen by FERC to encourage the use of efficient cogeneration (using the heat from industrial or other processes to generate electricity) and small-scale renewable generation. FERC's role was to issue regulations for the program and certify that qualifying facilities (QFs) met statutory requirements. States administratively set the price to be paid to these generators at the cost the utilities would avoid by purchasing the power rather than generating it themselves. Such prices are referred to as avoided-cost rates.

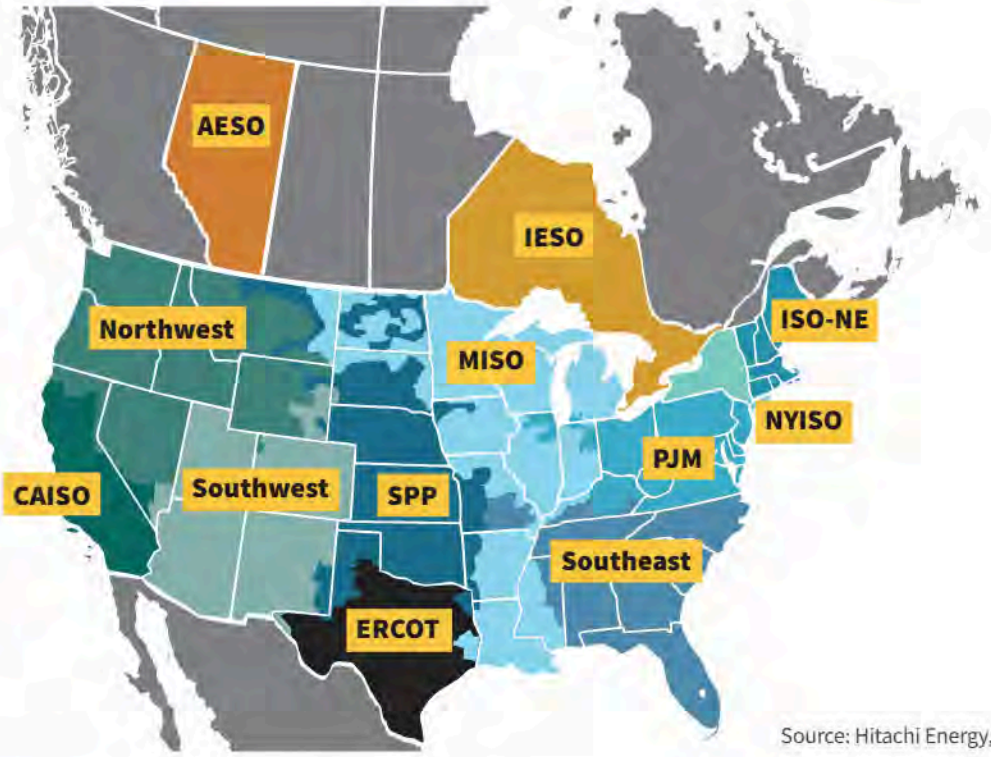
Most states set their avoided-cost rates so low that they got little QF capacity. However, California, Texas, and Massachusetts set relatively generous avoided-cost rates, and were overwhelmed with QF capacity, much of which received prices that turned out to be higher than the actual costs avoided by the purchasing utilities. The rapid growth and size of the QF industry surprised many policymakers and entrepreneurs and got them thinking about the viability of generation independent of regulated monopolies.

Under the original regulated monopoly model, utilities owned and operated the transmission lines with no obligation to allow others to use them. This posed a significant barrier to the development of an independent power industry. FERC started conditioning approval in merger cases on the utility's voluntary provision of open transmission access. The Energy Policy Act of 1992 gave FERC the authority to grant transmission access on request. These approaches to open access resulted in a patchwork of transmission access.

By the mid-1990s, support for opening the transmission grid to all users encouraged FERC to pursue a generic solution. FERC issued Order No. 888 in 1996 and required mandatory open transmission access by all transmitting utilities and a reciprocity provision successfully extended open access to non-jurisdictional entities (municipal, cooperative and federal utilities).

Order No. 889 addressed matters needed to implement open access. The rule established the Internet-based Open Access Same-Time Information System (OASIS) for posting available transmission capacity and reserving transmission capacity. These rules required significant changes to utility control room operations and limited the ability of companies to share transmission-related information with their own power marketing operating units.

Figure 2-1: North American Regional Transmission Organizations, Independent System Operators and Bilateral Regions



Source: Hitachi Energy, Velocity Suite

COMPETITION, PART 2: INTEGRATING MARKETS AND OPERATIONS – ISOS AND RTOS

While the industry had historically traded electricity through bilateral transactions and power pool agreements, Order No. 888 promoted the concept of independent system operators (ISOs). Along with facilitating open access to transmission, an ISO would operate the transmission system independently of wholesale market participants and foster competition for electricity generation. Several groups of transmission owners formed ISOs, some from existing power pools.

In Order No. 2000, FERC encouraged utilities to join regional transmission organizations (RTOs) which, like ISOs, would operate the transmission systems and develop innovative procedures to manage transmission equitably. FERC's proceedings in Order Nos. 888 and 2000, along with the efforts of the states and the industry, led to the voluntary formation of ISOs and RTOs. Each of the ISOs and RTOs subsequently developed full-scale energy and ancillary service markets in which buyers and sellers could bid for or offer generation. Both organizations use bid-based markets to determine economic dispatch. Throughout the subsequent sections of the primer, when referring to the organized RTO and ISO markets generally and collectively, the term RTO/ISO is used.

Major parts of the country operate under more traditional market structures, notably the West (excluding California) and the Southeast. Two-thirds of the nation's electricity load is served in RTO/ISO regions.

Electricity Demand

Americans consume electricity for an ever-increasing range of uses. While consumption has grown over the years, it varies annually based on many influences, such

as weather, economic activity, and other factors. Total generation at utility-scale facilities reached 4,108,303 gigawatt hours in 2021.[76]

Vertically-integrated IOUs, federal entities, municipally owned, and electric cooperatives sell the majority of electric generation to retail consumers. Additionally, some retail consumers generate all or part of the power that they consume. The rest of the electricity ultimately consumed by customers is bought and sold through wholesale electricity markets.

DEMAND CHARACTERISTICS

The amount of electricity consumed (demand) is continuously varying and follows cycles throughout the day and year. Regionally, electric demand may peak in either the summer or the winter. Spring and fall are considered shoulder months, with lower peak demand. Seasonal peaks vary regionally, although the highest levels of power load in almost all regions of the United States occur during summer heat waves, in the late afternoon. However, a minority of regions reach their peak load when the weather is extremely cold. These are primarily areas with significant space-heating requirements and little summer air conditioning load, such as the far northern areas of the United States.

Throughout the year, and in most locations, daily demand typically peaks in the late afternoon, as commercial and domestic activities peak, and in the winter, when lighting needs grow. Electricity use also varies between weekdays and weekends. Commercial and industrial activities are lower on weekends and peoples' noncommercial activities change with their personal schedules. The load on different weekdays can also show distinct usage. For example, Mondays and Fridays, being adjacent to weekends, may have different loads than Tuesday through Thursday. This is particularly true in the summer.

Since supply must rise and fall to provide exactly the amount of electricity customers need, the cost of providing power typically rises as demand grows and falls as demand declines. This is because higher levels of demand require activation of increasingly expensive sources of power generation, and reductions as demand declines. As a result, power prices are typically highest during periods of peak demand.

DEMAND DRIVERS

The amount of electricity demanded is insensitive to prices in the short-term. Electricity is a necessity to most people and businesses. While they may be able to reduce their demand in the short-term – by turning down the thermostat or turning off lights, for example – electricity consumers find it difficult to do without electricity altogether. Further, most customers – especially smaller customers – do not get price signals to which they can respond. A vast majority of residential customers are billed monthly on a preset rate structure. Large industrial customers, on the other hand, may receive real-time price signals.

In the longer-term, options for reducing electricity use include installing insulation and implementing other energy efficiency measures. Larger consumers may also consider building their own generation facilities.

As discussed below, utilities, at the direction of government, have developed demand-response programs, which can provide reduced rates or other compensation to customers who agree to reduce load in periods of electric system stress.

Climate and Weather

Weather is one of the primary factors affecting demand. General climatic trends drive long-term consumption patterns and therefore the infrastructure needed to ensure reliable service.

Weather also can have extreme short-term effects on electricity usage. A sudden cold snap can drive heating use up quickly and a heat wave can push up air conditioning loads. Other, less obvious weather patterns affect demand

76 Derived from EIA, *Electric Power Annual, Table 3.1.A* (released November 8, 2022), www.eia.gov/electricity/annual/html/epa_03_01_a.html.

– rain and wind, for example, may result in sudden cooling, affecting heating or air conditioning usage.

Economic Activity

The overall level of economic activity affects power demand. During periods of robust activity, loads increase. Conversely, loads drop during recessions. These changes are most evident in the industrial sector, where businesses and plants may close, downsize, or eliminate factory shifts. In addition to reducing overall demand, these changes affect the pattern of demand; for example, a factory may eliminate a night shift, cutting off-peak use but continue its use of power during peak hours. In some cases, these effects can be significant. For example, the COVID-19 pandemic changed how consumers used electricity as communities and companies implemented social distancing and stay-at-home measures to combat the spread of COVID-19 in the spring of 2020. Electricity demand shifted from commercial and industrial uses to residential consumption. Overall, electricity demand in the U.S. dropped about 4% in 2020, as commercial and industrial demand dropped 6% and 8%, respectively, and residential demand rose 1%.[77]

Energy Policies and Regulations

State regulatory agencies, such as public utility commissions, oversee retail electric rates and set policies affecting retail customer service. Some states allow utilities to offer retail rate structures that enable customers to receive more accurate price signals. They include, among other things, rates that vary with the time of day and the cost of providing electricity.

Efforts to reduce overall demand by improving energy efficiency are also supported by governmental and utility programs. These include rebates for the purchase of energy efficient appliances and home improvements, as well as capacity market payments for load reductions, also known as demand response, that are made available in certain markets.

Quick Facts: *Heating and Cooling Degree Days*

In the United States, engineers developed the concept of heating and cooling degree days to measure the effects of temperature on demand. Average daily temperatures are compared to a 65°F standard - those in excess of 65° yield cooling degree days; those below 65° yield heating degree days. For example, a day with an average temperature of 66° would yield one cooling degree day.



Retail Customer Mix

Most electric utilities serve three distinct classes of customers: residential, commercial, and industrial. Each class uses electricity differently, resulting in a differing load profile, or the amount of energy each customer class uses throughout the day. If a consumer uses electricity consistently throughout the day and seasons, the load shape is flat. Another consumer may use more at some times than others. More variable demand is typically more expensive to serve, especially if the peak occurs at the same time as other customers' use peaks. Consequently, the mix of customer types affects a region's overall demand and costs.

77 EIA, *Short-Term Annual Outlook*, at 3 (January 2020).

Residential consumers form one of the top two customer segments in the United States at approximately 39 percent of electricity demand in 2021. Residential consumers use electricity for air conditioning, refrigerators, space and water heating, lighting, washers and dryers, computers, televisions, and other appliances. Prices for residential service are typically highest, reflecting both residential customers' load shape and their service from lower-voltage distribution facilities, meaning that more power lines and related assets are needed to provide service to them.

Commercial use, the next largest customer segment, represented approximately 35 percent of electricity demand in 2021.[78] This customer segment includes office buildings, hotels and motels, restaurants, street lighting, retail stores, wholesale businesses, and medical, religious, educational, and social facilities. More than half of commercial consumers' electricity use is for heating and lighting.

Industrial consumers use about 26 percent of the nation's electricity.[79] This customer segment includes manufacturing, construction, mining, agriculture and forestry operations. Industrial customers often see the lowest rates, reflecting their relatively flat load profile and their ability to take service at higher voltage levels.

Transportation demand for electricity stems primarily from trains and urban transportation systems. This is less than 1 percent of total electricity demand.[80] However, state and federal policies that advance electrification of the transportation fleet are expected to increase electric load growth in the near future.

LOAD FORECASTING

Demand is constantly changing, which challenges grid operators and suppliers who are responsible for ensuring that supply will meet demand at all times. Consequently, they expend considerable resources to forecast demand.

Load forecasting uses mathematical models to predict demand across a region, such as a utility service territory or an RTO/ISO footprint. Forecasts can be divided into three categories: short-term forecasts, which range from one hour to one week ahead; medium-term forecasts, usually a week to a year ahead; and long-term forecasts, which are longer than a year. It is possible to predict the next-day load with an accuracy of approximately one to three percent of what will actually happen. The accuracy of these forecasts is limited by the accuracy of the weather forecasts used in their preparation and the uncertainties of human behavior.

The forecasts for different time horizons are important for different operations within a utility company. Short-term load forecasting can help to estimate transmission system power flows and to make decisions that can prevent overloading of transmission systems. Timely implementation of such decisions leads to the improvement of network reliability and to reduced occurrences of equipment failures and blackouts. Forecasted weather parameters are the most important factors in short-term load forecasts, with temperature and humidity as the most commonly used load predictors.

The medium- and long-term forecasts take into account historical load and weather data, the number of customers in different customer classes, appliances used in the area and their characteristics, economic and demographic data, and other factors. For the next-year peak forecast, it is possible to provide an estimated peak load based on historical loads and weather conditions. Long-term forecasts extending 10 to 20 years into the future are used for system infrastructure planning and are meant to ensure that there are sufficient resources available to meet the needs of the expected future peak demand.

Forecasts are necessary for the variety of actions that must occur to ensure that sufficient supply is available in the immediate and long term. These include the

78 Derived from EIA, *Electric Power Annual*, *Table 2.5* (November 7, 2022), www.eia.gov/electricity/annual/html/epa_02_05.html.

79 *Id.*

80 *Id.*

planning of long-term infrastructure, purchasing fuel and other supplies, and ensuring adequate staffing of specific personnel. Load forecasts are also extremely important for suppliers, financial institutions, and other participants in electric energy generation, transmission, distribution, and trading. Missed forecasts, when actual demand differs significantly from the forecast, can cause wholesale prices to be significantly higher or lower than they otherwise might have been.

DEMAND RESPONSE

Electricity demand is generally insensitive to price, meaning that demand does not typically fall when prices rise. This occurs for several reasons, including that most end-use consumers of electricity are not exposed to real-time electricity prices. However, some utilities and grid operators have developed ways to stimulate a response from consumers through demand-response programs.

Demand response is the reduction in consumption of electricity by customers from their expected consumption levels, in response to either reliability needs or price signals. Customers will forego power use for short periods, shift some energy use from peak periods to other times, or use on-site generation in response to price signals or incentives for load reduction. The signals to respond to electric power system needs or high market prices may come from a utility or other load-serving entity, an RTO/ISO, or an independent provider of demand response. Both retail and wholesale entities administer these programs. Demand response has the potential to lower system-wide power costs and assist in maintaining reliability. It can also mitigate system stress and allow operators to resolve shortages, avoid operating inefficient power plants, or relieve transmission congestion. There can also be environmental benefits, such as lower levels of power plant-related emissions that result from not operating peaking units.

Measuring and verifying the amount of reduced consumption during a demand response activation requires development of consumers' baseline usage, against which their actual use is measured.

Demand-Response Programs

Programs generally fall into three categories: curtailing, shifting, or on-site generation.

Curtailing, or forgoing, involves reducing power use (load) during times of high prices or threats to reliability without making up the use later. For example, residential customers might turn off lights or raise thermostats during hot weather. Commercial facilities may turn off office equipment, lower building lighting or change thermostat settings by a few degrees.

Shifting involves moving or rescheduling high energy-use activities in response to high prices or demand response program events to off-peak periods – evenings, nights, or weekends. Industrial customers might reschedule batch production processes to evening hours or the next day. Commercial establishments may delay high-energy operations. Residential customers may wait until evening or night to use high energy consuming appliances, such as clothes dryers or dishwashers. In shifting, the lost amenity or service is made up at a subsequent time.

On-site generation is when customers respond by turning on an on-site or backup emergency generator to supply some or all of their electricity needs. Although these customers may have little or no interruption to their electrical usage, their net load and requirements from the power system are reduced. The ability to use on-site generation is most common for institutional customers, such as hospitals, large schools, or data centers.

Demand response programs can be further distinguished by whether they are controlled by the system operator (dispatchable) or the customer (non-dispatchable). Dispatchable demand response refers to programs where the system operator can direct the customer to reduce its energy use, such as direct load control of residential appliances or directed reductions to industrial customers. Dispatchable demand response programs can be used for both reliability and economic reasons. Non-dispatchable demand response lets the retail customer decide whether and when to reduce

consumption in response to the price of power. This includes time-sensitive pricing programs that are based on rates that charge higher prices during high-demand hours and lower prices at other times.

As a result of technological innovations and policy directions, new types and applications of demand response are emerging that encompass the use of smart appliances that respond in near real-time to price or other signals. These models may allow customers to respond more easily, as they require little customer monitoring or interaction.

Retail Demand Response Programs

Utilities and third-party aggregators offer a variety of demand response programs that include time-based rates and interruptible contracts. Also, some states mandate energy efficiency resource standards that include peak load reduction targets.

Time-based rates include time-of-use rates and dynamic pricing. Time-based rates depend on advanced meters at customer premises that can record usage over short increments, typically groupings of hours or individual hours. In time-of-use programs, customers are charged different prices at different times of the day, with hours on or near peak demand costing more than off-peak hours. Dynamic pricing is a category of programs where rates change frequently to better reflect system costs. The practice of adjusting prices as costs change provides an incentive for consumers to shift load to other periods or to reduce peak load. One form of dynamic pricing is termed real-time pricing. In these programs, customers are charged prices reflecting the immediate cost of power. Industrial or very large commercial customers are the most likely to choose real-time tariffs.

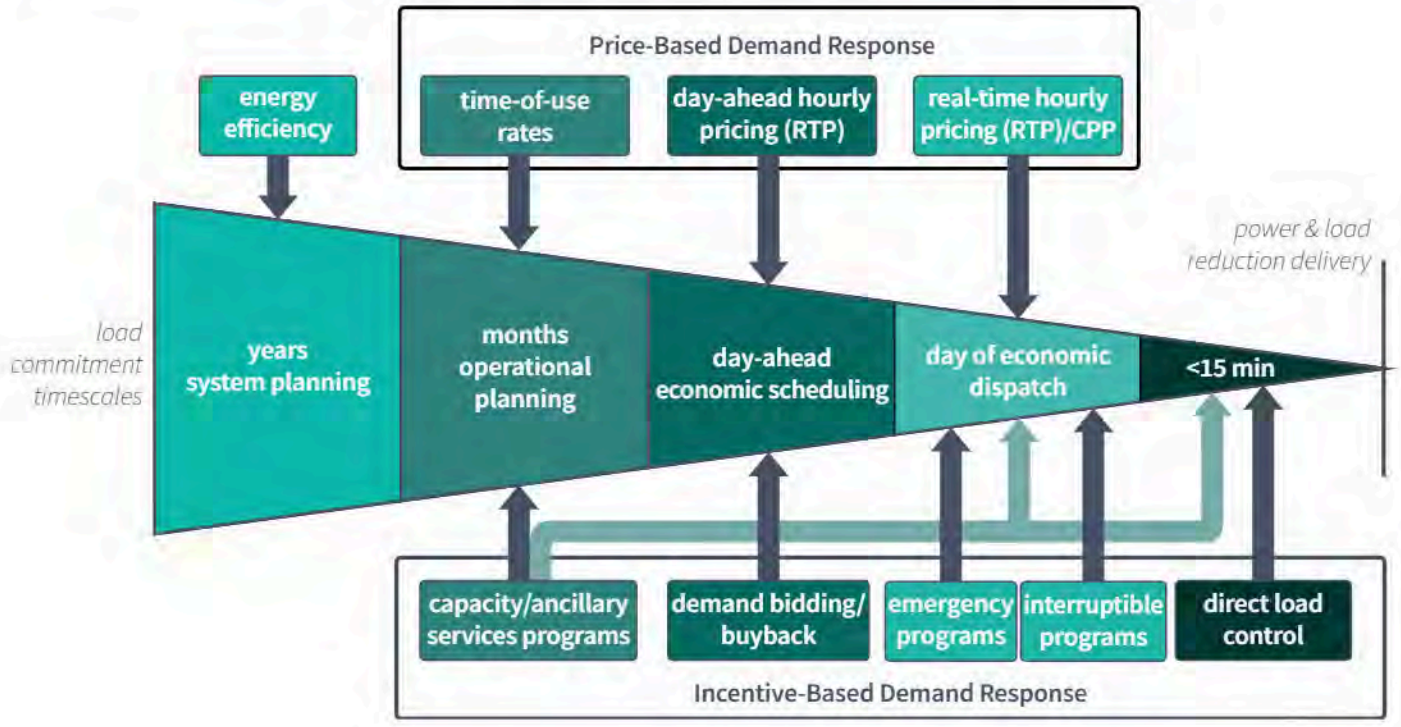
Another form of dynamic pricing is critical peak pricing. These programs use real-time prices at times of extreme system peak but are restricted to a limited number of hours annually. They feature higher prices than time-of-use prices during the critical peak. Consumers do not know in advance when a critical peak might be called. Critical peak programs for residential customers typically use rebates as an incentive to participate in the program, but customers take the risk of paying higher prices or reducing load during critical peak periods. These programs seek to have customers respond to price signals, as opposed to penalizing them, if they do not lower their use in the critical peak hours.

Interruptible contracts are used by utilities to control load and address potential reliability issues, such as reducing stress on the electric system during heat waves. The two primary forms of this category of demand response are direct load control and interruptible rates. Direct load control entails the utility curtailing a portion of customer load as described above. Under interruptible rates, customers agree to turn off equipment or switch their energy supply to an on-site generator.

Energy efficiency resource standards exist in 25 states, while five states and the District of Columbia. have energy efficiency goals.[81] The standards typically require utilities to achieve electric energy savings, and many include peak load reduction targets. These mandates provide incentives for utilities to reduce customers' energy consumption and include mechanisms that decouple profits from the amount of electricity sold or performance bonuses for utilities that meet or exceed reduction targets.

81 DSIRE, N.C. Clean Energy Technology Center, *Energy Efficiency Resource Standards (and Goals)* at 1 (September 2021), https://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2021/09/Energy-Efficiency-Resource-Standards_Sept-2021.pdf.

Figure 2-2: Demand Response and Energy Efficiency in Electric System Planning and Operations



Source: U.S. Department of Energy[82]

Wholesale Market Demand Response Programs

On the wholesale level, market operators have some programs that dispatch the demand response resources. Other demand response programs are dispatched by the utilities or aggregators that sponsor the programs, rather than the market operator. Note that with most retail demand response programs, which can also aid wholesale markets, market operators may not be able to invoke them or even see the specific amount of response that occurs.

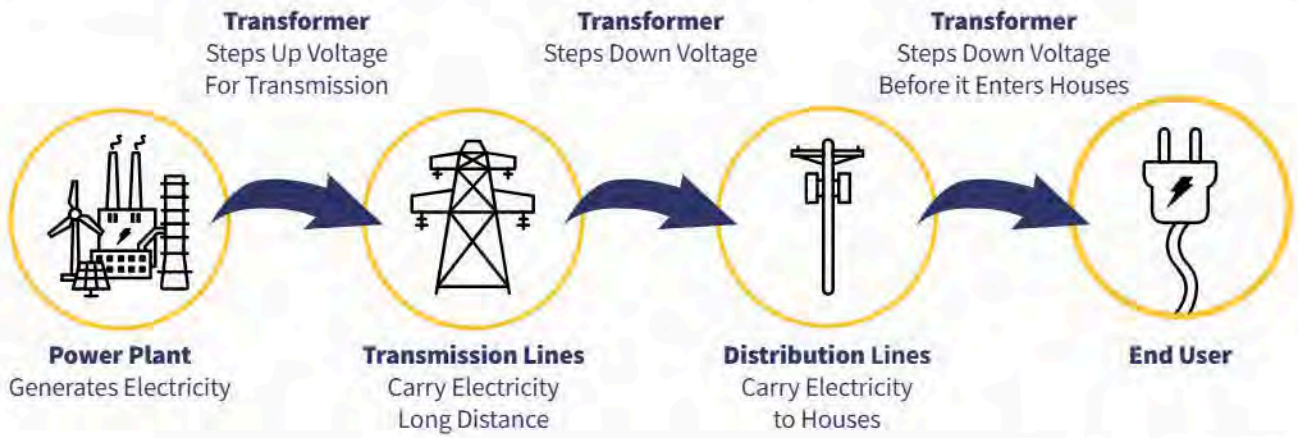
Demand response participation in RTO/ISOs has been encouraged in U.S. national energy policy and by various FERC orders.[83] Overall, approximately 30.8 GW of demand response participated in RTOs/ISOs in 2020.[84] These resources primarily participate in RTO/ISOs as capacity resources and receive advance reservation payments in return for their commitment to participate when called upon or activated. Additionally, demand resources may offer into the RTO/ISO day-ahead markets, specifying the hours, number of MWs and price at which they are willing to curtail.

82 U.S. Department of Energy, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005*, at 15, (2006), https://www.energy.gov/oe/articles/benefits-demand-response-electricity-markets-and-recommendations-achieving-them-report.

83 EPAct 2005 included policy encouraging time-based pricing and other forms of demand response and the elimination of barriers to demand response participation in the energy, capacity, and ancillary services markets. Examples of FERC orders include Order No. 719, 128¶61,059, (July 16, 2009); Order No. 745, 134¶61,187 (March 15, 2011); and Order No. 2222, 174¶61,197, (March 18, 2021).

84 *See* FERC, *Assessment of Demand Response and Advanced Metering Staff Report*, at 3 (December 2021), https://www.ferc.gov/media/2021-assessment-demand-response-and-advanced-metering.

Figure 2-3: Electricity Supply and Delivery



Source: The NEED Project[85]

Some of the RTO/ISO demand response comes from individual entities; the rest is accumulated through third-party aggregators, or curtailment service providers, who recruit customers too small to participate on their own, such as schools, commercial chains or groups of residential customers. In aggregating small customers, curtailment service providers have increased customer participation in many wholesale reliability and emergency programs.

Demand Response and Energy Efficiency in Planning and Operations

Different demand response programs can be used at various times to support planning and operations (see Figure 2-2). Energy efficiency programs that reduce baseload or peak demand over the long-term are incorporated into system planning. Dispatchable programs that are quickly implemented and targeted for short-term peak reductions – such as direct load control – lie on the other end of the spectrum and are used in the moment of operation.

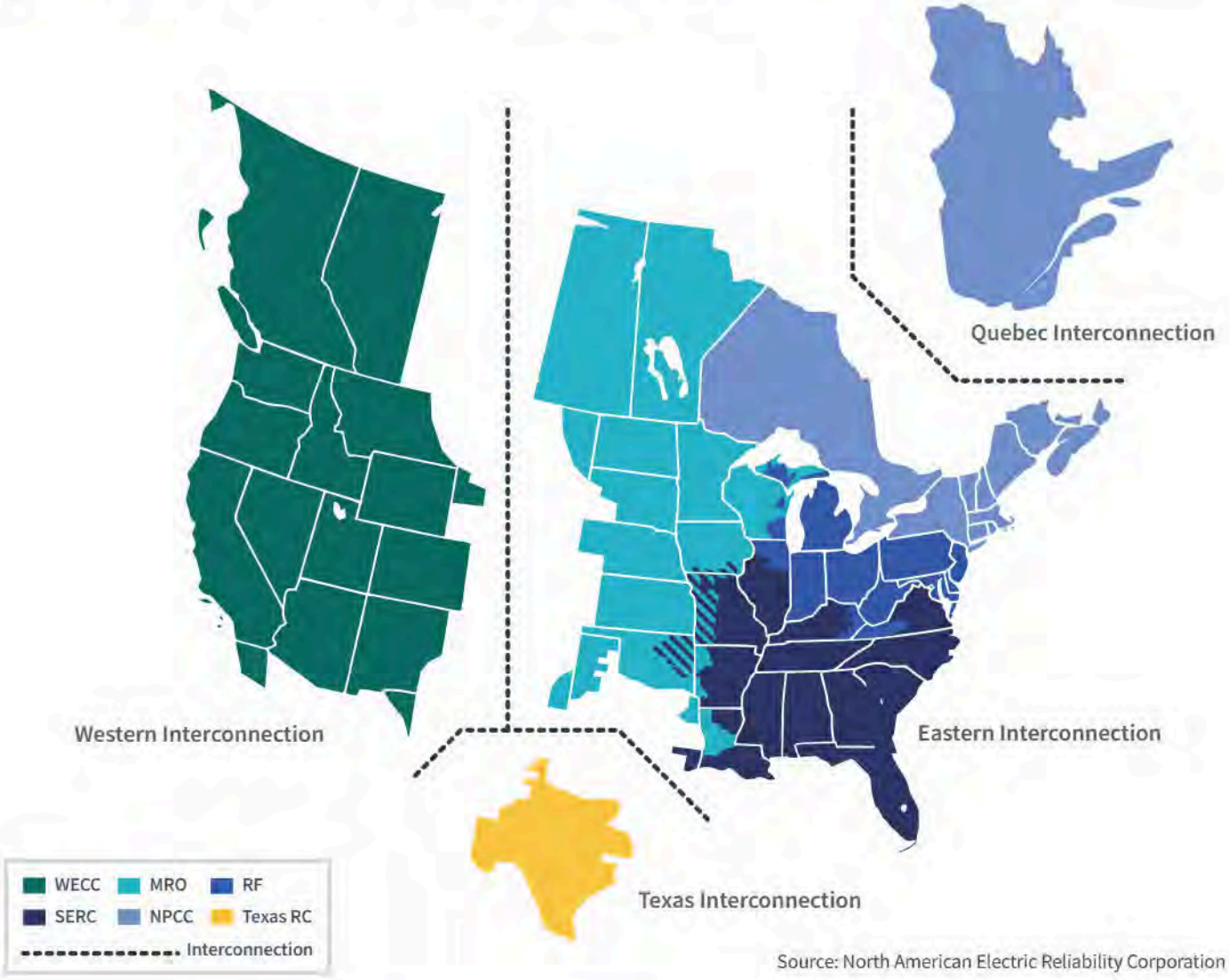
Electricity Supply and Delivery

Unlike many other products, electricity cannot be stored in any appreciable quantity relative to the total consumed across the country each day. Further, electricity is a necessity for most consumers, whose use responds little to price changes. Finally, electric equipment and appliances are tuned to very specific standards of power, measured as voltage and frequency. For example, deviations in voltage can cause devices to operate poorly or may even damage them. Consequently, the supply side of the electricity market must provide and deliver exactly the amount of power customers want at all times, at all locations. This requires constant monitoring of the grid and close coordination among industry participants.

Electricity service relies on a complex system of infrastructure that falls into two general categories: generation and delivery services of transmission and distribution. Together, the power generation and high-voltage transmission lines that deliver power to distribution facilities constitute the bulk power system. Transmission and distribution facilities are also referred to as the power grid. These are coordinated, and at times operated by, a grid coordinator.

85 National Energy Education Development Project, *Electricity*, at 56 (2017), http://www.need.org/Files/curriculum/infobook/Elec1S.pdf.

Figure 2-4: North American Electric Reliability Corporation Regions



Source: North American Electric Reliability Corporation

Nationally, the grid is geographically split into three main sections – the Western, Eastern and Texas Interconnections. These sections operate independently and have limited interconnections between them.

The nation, along with Canada and a small part of Mexico, is also divided into regional entities for reliability purposes. The regional reliability entities fall under the purview of North American Electric Reliability Corporations (NERC), which was designated by FERC as the nation's electric reliability organization, and which develops and enforces mandatory reliability standards to better ensure the reliable operation of the nation's bulk-power system (the interconnected transmission grid). The reliability standards, once approved by FERC, must be met by applicable industry participants as designated in each reliability standard. Consequently, the grid is planned and operated to meet these standards.

NERC's regions include:

- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- Reliability First Corporation (RFC)
- SERC Reliability Corporation (SERC)
- Texas Reliability Entity (TRE)
- Western Electricity Coordinating Council (WECC)

FERC JURISDICTION

Under the Federal Power Act (FPA), FERC regulates the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce. The FPA requires that every public utility file with FERC all rates and charges for any transmission or sale subject to the jurisdiction of FERC. Under Sections 205 and 206 of the FPA, 16 U.S.C. §§ 824d, 824e, FERC ensures that the rates and charges made, demanded, or received by any public utility for, or in connection with, the transmission or sale of electric energy subject to the jurisdiction of FERC, and all rules and regulations affecting, or pertaining to, such rates or charges are just and reasonable and not unduly preferential or unduly discriminatory.

GENERATION

Power generators are typically categorized by the fuel that they use and subcategorized by their specific operating technology. In 2021, the United States had approximately 1,218 GW of total generating capacity.[86] The majority of power generation is produced from coal, natural gas, nuclear fuels, and renewables.

Power plants each have differing costs and operational characteristics, both of which determine when, where and how plants will be built and operated. Plant costs fall into two general categories: capital investment costs, which are amounts spent to build the plant, and operational costs, the amounts spent to maintain and run the plant. In general, there is a trade-off between these expenses: more capital-intensive plants tend to be cheaper to run – they have lower variable costs – and, conversely, the least capital intensive plants tend to be more expensive to run – they have higher variable cost. For example, nuclear plants produce vast amounts of power at low variable costs but are expensive to build. Conversely, natural gas-fired combustion turbines are far less expensive to build but can be more expensive to run. Grid operators dispatch plants – or call them into service – with the simultaneous goals of providing reliable power at the lowest cost. Because various generation technologies have differing variable costs, plants are dispatched only when they are part of the most economic combination of plants needed to supply the customers on the grid. For plants operating in RTOs/ISOs, this cost is determined by the price that generators offer. In other areas, it is determined by the marginal cost of the available generating plants.

CONVENTIONAL GENERATION

Generation is often described as conventional or renewable (described further in the Renewable Generation section below). Conventional generation typically includes natural gas-, oil-, coal- or nuclear-powered generation.

Natural Gas-Fired Generation

Natural gas power plants consist of three major technologies, each with its distinct set of market advantages and limitations. They are steam boilers, gas turbines and combined cycle generators. Natural gas fuels nearly a third of U.S. electricity generation.

Steam boiler technology is an older design that burns gas in a large boiler furnace to generate steam at both high pressure and high temperature. The steam is then run through a turbine that is attached to a generator, which spins and produces electricity. Typical plant size ranges from 300 MW to 1,000 MW. Because of their size and the limited flexibility that is inherent in the centralized boiler design, these plants require fairly long start-up times to become operational and are limited in their flexibility to produce power output beyond a certain range. Furthermore, these plants are generally not as economical or easy to site as some newer technologies – which explains why few have been built in recent years.

86 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (February 2022), https://www.eia.gov/electricity/data/eia860m/.

Gas turbines (GT) are small, quick-start units similar to an aircraft jet engine. These plants are also called simple cycle turbines or combustion turbines (CT). GTs are relatively inexpensive to build but are expensive to operate because they are relatively inefficient, providing low power output for the amount of gas burned, and have high maintenance costs. They are not designed to run on a continuous basis and are used to serve the highest demand during peak periods, such as hot summer afternoons. GTs also run when there are system-wide shortages, such as when a power line or generator trips offline. GTs typically have a short operational life due to the wear-and-tear caused by cycling. The typical capacity of a GT is 10-50 MW, and they are usually installed in banks of multiple units.

Combined cycle power plants (CCPPs) are a hybrid of the GT and steam boiler technologies. Specifically, this design incorporates a gas-combustion turbine unit along with an associated generator, and a heat recovery steam generator along with its own steam turbine. The result is a highly efficient power plant. They produce negligible amounts of SO2, and particulate emissions and their NOx and CO2 emissions are significantly lower than a conventional coal plant. CCPPs, on average, require 80 percent less land than a coal-fired plant, typically 100 acres for a CCPP versus 500 acres for comparable coal plant, and CCPPs also use modest amounts of water compared to other technologies.

Coal-Fired Generation

Coal plants produced approximately 22 percent of the electricity in the United States in 2021.[87] These facilities generate power by creating steam which is used to spin a very large turbine. These plants tend to be used as baseload units, meaning that they run continuously and are not especially flexible in raising or lowering their power output. They have high initial capital costs, with complex designs and operational requirements. However, coal plants have low marginal costs and can produce substantial amounts of power. Most of the coal-fired plants in the United States are located in the Southeast and Midwest.

Oil-Fired Generation

Oil plants generally produce only a small amount of the total electricity generated in the U.S. power markets. These facilities are expensive to run and also emit more pollutants than natural gas plants. They are frequently uneconomic and typically run at low-capacity factors. Like natural gas-fired generators, there are several types of units that burn oil; primarily, these are steam boilers and combustion turbines. Most dual-fuel power plants are located in the eastern half of the United States, especially on the East Coast.[88]

Generally, two types of oil are used for power generation: number 2 and number 6 (bunker) fuel oil. Number 2 is a lighter and cleaner fuel. It is more expensive, but because it produces fewer pollutants when burned, it is better for locations with stringent environmental regulations such as major metropolitan areas. Conversely, number 6 fuel oil is cheaper, but considered dirty because of its higher emissions. It is highly viscous (thick and heavy), and it comes from the bottom of the barrel in the refining process.

Nuclear Generation

Nuclear plants provided roughly 19 percent of the nation's electricity in 2021, when 93 nuclear plants operated in the United States with a total capacity of approximately 100 GW.[89] Like generating units that use coal, nuclear plants tend to be large, baseload units that run continuously. Nuclear plants have high capital and fixed costs, but low variable costs, which includes fuel cost. They typically run at full power for 18 or 24 months, which is the duration of a unit's fuel cycle, and are then taken offline for refueling and maintenance. Outages

87 EIA, *Electric Power Annual* (November 7, 2022), *Generation at Utility Scale Facilities*, *Tables 3.1A. and 3.1.B*, (accessed December 2022), www.eia.gov/electricity/annual/html/epa_01_02.html.

88 Derived from Hitachi Energy, Velocity Suite data (Accessed March 28, 2023).

89 EIA, *Form EIA-860* (November 2022), www.eia.gov/electricity/data/eia860/.

typically last from 20 days to significantly longer, depending on the work needed. Of the 92 operating nuclear plants, most reside in the eastern United States. Only six are in the West, four in Texas. Illinois had the largest number of plants at 11, followed by Pennsylvania at eight, and South Carolina at seven.[90]

RENEWABLE GENERATION

Renewable resources use fuels that are naturally replaced, such as wind, solar, hydroelectric and geothermal or which use fuels that are readily replaceable, such as biomass and biogas.

Such generation (generation termed renewable generation or renewables) is an increasingly important part of total U.S. supply, accounting for 29 percent of electric energy produced in 2021.[91] As total generation from all fuels has remained relatively constant in recent years, renewable generation's share has risen, spurred by technological advancements, state policy, and federal tax credits.[92]

Wind and solar capacity have grown faster than other renewable resources in recent years. Wind capacity grew substantially, from approximately 10 GW in 2006 to 193 GW in 2021.[93] Utility-scale solar capacity grew even faster, from approximately 0.1 GW to 61 GW over the same period. [94]

Additions of renewable generation capacity are usually reported in megawatts of nameplate capacity. Actual capability varies from the nameplate for any unit type due to such factors as age, wear, maintenance and ambient conditions. But as renewable resources are often weather-dependent, their capacity factors – the ratio of average generation to the nameplate capacity for a specific period – have been lower (for example, approximately 30 percent), depending on the technology type, than for fossil-fuel generation. Grid operators pay close attention to the difference between nameplate and capacity factor values when they evaluate capacity available to cover expected load, however, capacity factors have risen with technological innovation and improved manufacturing processes.

Wind

Wind generation is among the fastest-growing renewable resource, in part due to cost declines and technology improvements, as well as receipt of federal tax credits. Increases in average hub heights and rotor diameters have increased average wind turbine capacity. Because the best wind resources are often located far from load centers, obtaining sufficient transmission presents a challenge to delivering wind output. Other market challenges for future wind development include its variable output, which is often inversely correlated to demand (seasonally and daily); system operators' limited ability to dispatch wind resources to meet load increases; difficulties related to accurately forecasting its ramping; and the need for companion generation (usually fossil-fueled) or energy storage to be available to balance wind generation when the wind is not blowing.

Solar

Solar generation transforms sunlight into electricity using one of two technologies: photovoltaic (PV) or concentrating solar power (CSP). PV modules, or panels, transform sunlight directly into power using cells made of silicon or thin-film materials. They can be installed on roofs of buildings or at ground-level PV farms. CSP plants use a two-step process to transform the sun's energy. First, mirrors direct sunlight towards a receiver that captures

90 EIA, *Form EIA-860M* (February 2023), www.eia.gov/electricity/data/eia860M/.

91 Derived from EIA, *Electricity Annual* (September 2022), www.eia.gov/electricity/annual/html/epa_01_01.html.

92 Lawrence Berkeley National Lab, *U.S. State Renewables Portfolio and Clean Electricity Standards: 2023 Status Update* (June 2023), https://eta-publications.lbl.gov/sites/default/files/lbnl_rps_ces_status_report_2023_edition.pdf.

93 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (February 2022), https://www.eia.gov/electricity/data/eia860m/.

94 *Id.*

the heat. CSP then employs a thermal process to create steam, driving an engine or turbine to produce electricity. CSP plants, which are dispatchable, can include low-cost energy storage that extends their availability later in peak hours. PV growth has increased greatly as a result of policy incentives and cost declines. Total PV generation for 2021 was 161.5 GW, with approximately two-thirds of that generation coming from utility-scale facilities and one-third from small-scale generation.[95]

By the end of 2021, 1.5 GW of CSP was operational – a decline from 2017 when CSP capacity was 1.8 GW.[96] Total CSP capacity is significantly lower than PV owing to PV's lower costs.[97] Seven western and southwestern states have extensive CSP potential: Utah, New Mexico, Arizona, Nevada, Texas, California and Colorado.[98] Developing that potential will require overcoming challenges of cost, siting, transmission, and the need for extensive water supplies to clean mirrors.

Hydroelectric

Hydroelectric generation is powered by the kinetic energy of falling water that drives turbine generators, which convert the energy into electricity. There are two types of hydroelectric projects: conventional and pumped storage. Conventional projects, which use a dam in a waterway, can operate in a run-of-river mode, in which water outflow from the project approximates inflow, or in a peaking mode, in which the reservoir is mostly drained to generate power during peak periods when energy is more valuable. Pumped storage projects use bodies of water at two different elevations. Water is pumped into elevated storage reservoirs during off-peak periods when pumping energy is cheaper; the water is then used to generate power during peak periods as it flows back to the lower elevation reservoir. In 2021, total U.S. hydro-electric capacity (including conventional and pumped-storage capacity) reached 246 GW. Conventional hydro-electric capacity was 285.3 GW and pumped storage hydro-electric capacity was 5.1 GW.[99]

Geothermal

Geothermal generation taps into reservoirs of steam and hot water deep beneath the earth's surface to produce power. The majority of the plants are based in California and Nevada. Geothermal potential is determined by thermal conductivity, thickness of sedimentary rock, geothermal gradient, heat flow and surface temperature. Geothermal generation, which stood at 16 GW in 2021, increased from 0.6 GW in 2011, but has decreased as a portion of total renewable output, due to the growth of other renewables. California hosts about 76 percent of geothermal U.S. operating capacity.[100]

Biomass

Biomass generation includes power production from many waste byproducts, such as agricultural residues, landfill gas, municipal solid waste, and wood resources. The largest biomass category is wood waste, burned for heat and power in the lumber, pulp and paper industries. Challenges to biomass production include impacts on food supplies (for example, converting corn into ethanol), conserving natural resources, and minimizing water pollution. In 2021, net utility-scale power generation using biomass fuel sources was 54.3 GWh - composed of 36.5 GWh from wood and wood-derived fuels as well as 17.8 GWh from other biomass sources.[101]

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95 Derived from EIA, *Electric Power Annual, Tables 3.1.A. and 3.1.B* (released November 7, 2022 and accessed December 2022), www.eia.gov/electricity/annual/html/epa_01_02.html.

96 Derived from EIA, See table 4.3 in *Electric Power Annual 2021 and Electric Power Annual 2017*, www.eia.gov/electricity/annual/html/epa_04_03.html and www.eia.gov/electricity/annual/archive/pdf/03482017.pdf.

97 *See* National Renewable Energy Laboratory, *Annual Technology Baseline* (July 2018), https://atb.nrel.gov/electricity/2018/summary.html

98 EIA, *Form EIA-860*, (September 13, 2018), https://www.eia.gov/electricity/data/eia860/.

99 Derived from EIA, *Electric Power Annual* (November 7, 2022), *Generation at Utility Scale Facilities, Tables 3.1.A and 3.1.B* (accessed December 2022), www.eia.gov/electricity/annual/html/epa_01_02.html.

100 Derived from EIA, *Form EIA-860* (accessed November 2017), https://www.eia.gov/electricity/data/eia860/.

101 *Id.*

Biogas

Biogas energy is created through the anaerobic (without oxygen) bacterial decomposition of biodegradable waste, which is turned into a gas containing 60-70 percent methane. Biogas recovery is typically installed at farms and used to run farm operations and reduce methane emissions from natural manure decomposition.

Renewable Energy Policies

Renewable generation development is frequently tied to policies promoting their use, which include tax credits, low-cost loans, rebates and production incentives. Federal funding of research and development has played an important role in lowering the costs or reducing the time it takes for renewable technologies to become commercially viable.

Congress has provided tax incentives to spur renewable resource investments. Originally enacted in 1992, federal production tax credits (PTC) are available for wind, biomass, geothermal, and other forms of renewable generation based on a facility's production. An inflation-adjusted credit, the PTC generally has a duration of 10 years from the date the facility goes online. The PTC has been revised several times, most recently in August 2022 under the Inflation Reduction Act, which extended the PTC for projects that begin construction before 2025, including solar projects that had previously been excluded from the PTC program.[102] After 2024, the PTC becomes technology neutral and emission based, and phases out starting in 2032, or when the U.S. electricity sector emissions are 75% below 2022 levels. If projects over 1 MW meet certain labor requirements, their PTC is 2.6 c/kWh; if the projects do not meet the labor requirements, the PTC would be 0.3 c/kWh. A further 10% adder on the PTC and ITC can be obtained if a project uses U.S. steel and roughly half the of manufactured components (as measured by cost) are sourced in the United States.

Another form of tax credit for renewables, including solar and other types of projects, has been a federal investment tax credit (ITC). The ITC has generally been set at 30 percent of a project's equipment and construction costs. The Inflation Reduction Act also revised the ITC, with the same terms as for the PTC. Projects meeting labor requirements may receive a 30% ITC, otherwise the ITC drops to 6%. Projects may also receive a 10% increase in the ITC if they use U.S. components, as described for the PTC.

State renewable portfolio standards (RPS) and renewable energy standards (RES) have been significant drivers in the growth of investment in renewable generation. An RPS requires a certain percentage of energy sales measured by megawatt-hours (MWh) to come from renewable resources. Percentages usually increase incrementally from a base year to an ultimate target. Currently, 30 states plus Washington, D.C., have an RPS with financial penalties for non-achievement.[103] As utilities and independent developers build more renewable-powered generation, the markets in which they participate continue to address the integration of renewable output into their day-ahead and real-time operations, and incorporate the expected growth of renewable generation in their long-term transmission-planning processes.

Renewable energy certificates (RECs) allow state regulators to track compliance with mandatory RPS targets or verify progress in voluntary state renewable programs. They also allow compliance entities to purchase credits – subject to state-imposed limits on amount and price – if they have not generated or bought enough renewable energy to meet their annual requirements.

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102 Congress.gov, *H.R. 5376-Inflation Reduction Act of 2022*, (became law August 4, 2022) https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

103 Barbose, Galen. Lawrence Berkeley National Laboratory, *U.S. Renewables Portfolio Standards: 2021 Status Update: Early Release* (February 2021), https://eta-publications.lbl.gov/sites/default/files/rps_status_update-2021_early_release.pdf.

ELECTRIC STORAGE

Historically, utility-scale storage of electricity for later use had been limited to pumped-hydro storage facilities. Recent advances in technology have made other types of electric storage resources, including batteries and flywheels, more economically feasible. The lower costs and improved capabilities of electric storage, along with favorable state and federal policies, increased penetration of variable energy resources, and a continued focus on grid reliability have helped spur the development of electric storage resources.[104]

As of 2021, the combined capacities of utility-scale electric storage and battery storage represented less than 2 percent of total generating capacity in the United States.[105] The majority of storage capacity consists of pumped-hydro storage (21 GW in 2021), which has grown very slowly. Battery storage capacity, in contrast, has grown from 3 MW in 2016 to 4,482 MW in 2021.[106] EIA projects that total U.S. battery storage capacity could reach 30 GW by 2025.[107]

Electric storage projects are increasingly available to help balance supply and demand particularly during periods of high demand or excess supply. These resources can charge during periods of low demand or excess generation, when electricity is less expensive, and discharge when demand is high and electricity is more expensive. Batteries, flywheels, and other fast-acting electric storage technologies can also provide ancillary services which help maintain grid reliability. The vast majority of battery storage capacity in the electricity markets is used to provide ancillary services or capacity, because these applications provide the most revenue for storage owners.[108]

Some states have passed legislation to incentivize investment in storage projects. In 2013, California adopted targets for utilities to procure 1,325 MW of energy storage capacity by 2024 and subsequently increased the capacity requirement target and compressed the timeline for reaching that target.[109] As of May 2021, five states besides California also set energy storage requirements or targets: Oregon, Massachusetts, New York, New Jersey and Virginia. Additionally, some states which do not have formal energy storage requirements offer financial incentives such as grants and tax incentives, while others have begun requiring utilities to include storage in integrated resource plans.

DISTRIBUTED ENERGY RESOURCES

In Order No. 2222, the Commission defined Distributed Energy Resources (DERs) as any resource located on the distribution system, any subsystem thereof or behind a meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment.[110] In most instances, these resources are located close to the

104 FERC has issued various orders to help remove barriers to the participation of electric storage resources in FERC-jurisdictional markets. *See, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 841, 162 FERC ¶61,127 (2018); Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 2222*, 172 FERC ¶ 61,247 (2020).

105 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (February 2022), https://www.eia.gov/electricity/data/eia860m/.

106 *Id.*

107 EIA, *U.S. battery storage capacity will increase significantly by 2025* (December 8, 2022), https://www.eia.gov/todayinenergy/detail.php?id=54939#:~:text=As%20of%20October%202022%2C%207.8%20GW%20of%20utility-scale,add%20another%2020.8%20GW%20of%20battery%20storage%20capacity.

108 EIA, *U.S. Battery Storage Market Trends*, 13-15 (August 2021), https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage_2021.pdf.

109 California Public Utilities Commission, *Energy Storage* (accessed December 1, 2022), www.cpuc.ca.gov/industries-and-topics/electrical-energy/energy-storage.

110 Order No. 2222, 172¶61,247, (September 17, 2020), at 4.

end user of power. While individual installations of DER tend to have capacities much smaller than that of central station power plants (for example DER installations may range from a fraction of a kW to systems producing less than 10 MW), the overall quantity of DER installations has grown tremendously, particularly in states with beneficial policies toward DERs.

One such policy is known as net metering, which is a system in which DERs are connected behind the meter to a distribution system and any surplus power is transferred onto the grid, allowing customers to offset the cost of power drawn from a distribution utility. Such surplus flow typically occurs during periods when the DER's production outstrips the customer's total demand. Under one measure of DER, as tracked by EIA, total net-metered capacity grew by approximately 277 percent between 2014 and 2020, from approximately 7.5 GW of capacity to 28.3 GW. The bulk of this capacity was solar PV, which made up 94 percent of net-metered capacity in 2020, with 62 percent of that capacity owned by residential customers.[111] In some cases, surplus power from a large DER or a set of net metered DERs may flow onto the transmission system.

TRANSMISSION

The alternating current (AC) power grid operates like an interconnected web, where, with a few exceptions, the flow of power is not specifically controlled by the operators on a line-by-line basis. Instead, power flows from sources of generation to consumers across any number of lines simultaneously, following the path of least resistance. There are also a limited number of direct current (DC) lines, which are set up as specific paths with definite beginning and end points for scheduling and moving power. These lines are controllable by operators and have other characteristics that make them attractive to grid planners and operators, such as providing greater grid stability and lower line losses. However, DC lines cost significantly more than AC lines to construct. Consequently, DC lines are typically built for certain specialized applications such as the movement of large amounts of power over long distances, for example the Pacific Intertie, which extends between the Northwest and California.

Transmission lines provide a certain amount of resistance to the flow of power as electricity travels through them. This resistance is not unlike the wind resistance that a car must overcome as it travels along a highway. The resistance in power lines creates losses: the amount of power injected into a power line diminishes as it travels through the line. The amount of these losses is contingent on many factors including the voltage of the transmission facilities.

111 EIA, *Electric Power Annual* (December 2022), (March 2022), www.eia.gov/electricity/annual/html/epa_04_10.html.

Wholesale Electricity Markets and Trading

Electric markets encompass different organizational structures and different mechanisms for buying and selling power at the wholesale level. Electric systems for delivering power to consumers in the United States are split into two structures: traditional systems and those run by RTO/ISOs. Traditional systems are typically vertically integrated, rely on management to make operational decisions, and sell electricity to retail customers based on their cost of service. In general, RTO/ISOs use their markets to make operational decisions, such as generator dispatch, and to price the resulting electricity. Load-serving entities then buy the power through the RTOs/ISOs for resale to retail customers.

Both traditional systems and RTOs/ISOs conduct certain functions, although they may perform these functions in different ways. These include:

- Ensuring the electric grid operates reliably in a defined geographic footprint
- Balancing supply and demand instantaneously and maintaining sufficient operating reserves
- Dispatching system resources as economically as possible
- Coordinating system dispatch with neighboring balancing authority areas (BAAs)
- Planning for transmission in its footprint
- Coordinating system development with neighboring systems and participating in regional planning efforts
- Providing non-discriminatory transmission access

Buying and selling electricity in the wholesale markets – trading – occurs through bilateral and RTO/ISO transactions, as discussed below. Bilateral transactions occur in both traditional systems and in RTO/ISO regions. Pricing for bilateral transactions in both RTO/ISO and traditional regions incorporates both cost-based and market-based rates.

SUPPLYING LOAD

Load serving entities (LSE) serve customer load through a combination of self-supply, bilateral market purchases and purchases from RTO/ISO markets. Self-supply means that the LSE generates power from plants it owns or operates to meet demand. With bilateral purchases, the LSE buys power from a supplier. RTO/ISO market purchases means the supplying company purchases power through the RTO's/ISO's markets.

LSEs' sources of energy vary considerably. In ISO-NE, NYISO, and CAISO, the LSEs have divested much or all their generation. In these circumstances, LSEs supply their customers' requirements through bilateral and RTO/ISO market purchases. In PJM, MISO, and SPP, LSEs may own significant amounts of generation, either directly or through affiliates, and therefore use self-supply as well as bilateral and RTO market purchases.

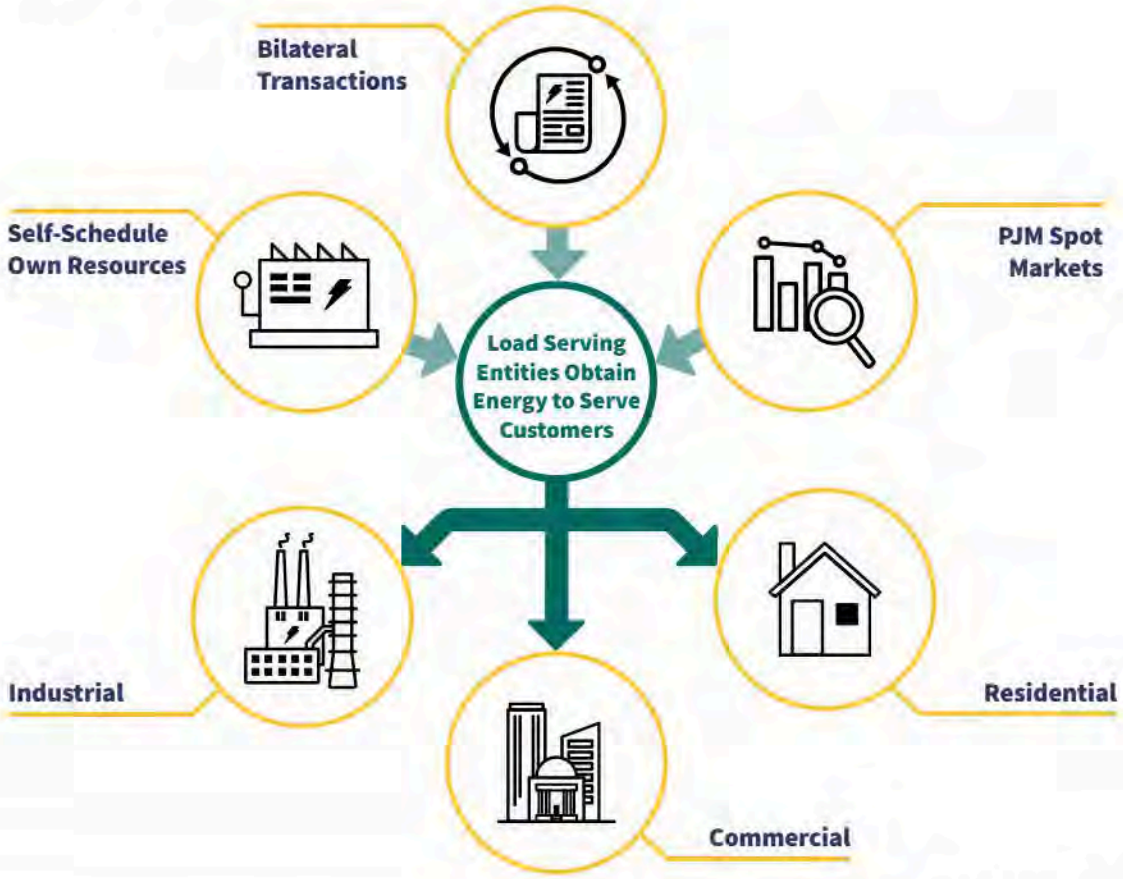
BILATERAL TRANSACTIONS

Bilateral transactions between two parties do not occur through an RTO/ISO and can occur through direct contact and negotiation, through a voice broker or through an electronic brokerage platform, such as the Intercontinental Exchange (ICE). The deals can range from standardized contract packages, such as those traded on ICE, to customized, complex contracts known as structured transactions. In bilateral transactions, buyers and sellers know the identity of the party with whom they are doing business.

Whether the trade is done on ICE, directly between parties or through another type of broker, the trading of standard physical and financial products, such as next-day on-peak firm or swaps, allows index providers to survey traders and publish price indexes. These indices provide price transparency.

Physical bilateral trades involving the movement of energy from one point to another require the parties to reserve transmission capacity to move the power over the transmission grid. Transmitting utilities are required to post the availability of transmission capacity and offer

Figure 2-5: Options for Energy Supply



Source: PJM Traditional Wholesale Electricity Markets

service on an OASIS website. Traders usually reserve transmission capacity on OASIS at the same time they arrange the power contract.

Transfers of power between Balancing Authority Areas (BAAs) require one of the parties to the transaction to submit a request for interchange, also known as an eTag.[112] The receiving BAA (the entity to which the power is transferred or sinks), or its agent, will process the eTag, ensure a reliability assessment has been completed, and send it to all parties named on the eTag. This ensures an orderly transfer of energy and provides transmission system operators with the information that they need to institute curtailments, as needed. Curtailments may be necessary when a change in system conditions reduces the capability of the transmission system to move power and requires some transactions to be reduced or cut.

Bilateral physical transactions that are conducted in RTO/ISOs are settled financially. Generators offer their power into the markets, and load is served through the power dispatched by the RTO/ISO. The RTO/ISO then settles bilateral transactions based on the prices in the contracts and the prices that occurred in their markets.

112 A BAA is a collection of generation, transmission, and loads within the metered boundaries of the entity (a Balancing Authority) that is responsible for balancing load, generation, and net interchange between other BAAs. Glossary of Terms Used in NERC Reliability Standards (March 2022), https://www.nerc.com/files/glossary_of_terms.pdf.

COST-BASED RATES

Cost-based rates are used to price most transmission services and some electricity when FERC determines that market-based rates are not appropriate, or when an entity does not seek market-based rate authority. Cost-based rates are set to recover costs associated with providing service and give a fair return on capital. These rates are typically listed in a published tariff.

The following are major inputs to setting cost-based electricity rates:

- Determining used-and-useful electricity plant costs. This may include the cost of generation facilities, transmission facilities, distribution plants and office and related administration facilities.
- Determining expenses for the production, transmission and distribution of electricity, including fuel and purchased power, taxes and administrative expenses.
- Establishing a fair return on capital, known as the cost of capital. This includes determining the cost of debt, common equity, preferred stock and commercial paper and other forms of short-term borrowing, such as lines of credit used to finance projects and provide cash for day-to-day operations.
- Allocating electric plant and other expenses among various customer classes and setting the rate structure and rate levels.

MARKET-BASED RATES

Under market-based rates, the terms of an electric transaction are negotiated by the sellers and buyers in bilateral markets or through RTO/ISO market operations. FERC grants market-based rate authority to electricity sellers that demonstrate that they and their affiliates lack, or have adequately mitigated, horizontal market power (typically based on whether the seller is a pivotal supplier and on the percent of generation owned by the seller relative to the total amount of generation available in a market). Sellers must also show that they lack, or have adequately mitigated, vertical market power (the ability to erect barriers to entry or influence the cost of production for competitive electricity suppliers). Wholesale sellers who have market-based rate authority and sell into day-ahead or real-time markets administered by an RTO/ISO do so subject to the specific RTO/ISO market rules approved by FERC. Thus, a seller in such markets must have an authorization from FERC and must also abide by the additional rules contained in the RTO/ISO tariff.

TRANSMISSION SERVICE

FERC requires that public utilities that own transmission lines used in interstate commerce offer transmission service on a nondiscriminatory basis to all eligible customers. The rates and terms of service are published in each utility's Open Access Transmission Tariff (OATT). Each utility's OATT specifies the transmission services available. Customers submit requests for transmission service through the OASIS. Utilities evaluate each transmission-service request using a model of the grid called a state estimator. Based on the model's estimation of the effects on the system, the request for transmission service is either approved or denied.

The two most common types of transmission service are network and point-to-point service. Network service allows a transmission customer the use of the entire transmission network to deliver generation from specified resources to specified loads. The price for service is cost-based and published in the OATT. Network service has higher priority than point-to-point service.

Point-to-point service involves paying for and reserving a fixed quantity of transmission capacity and moving power up to the reservation amount from one location, the point of receipt (POR), to another location, the point of delivery (POD). The POR and POD may be outside the transmission operator's footprint. Depending on availability, customers may purchase firm or non-firm point-to-point service for durations of one hour to multiple years.

Customers holding firm point-to-point transmission capacity may sell that capacity in a secondary market – such a sale is known as capacity reassignment. An entity holding transmission rights may want to resell

that capacity to another transmission customer in the secondary market because it is unneeded, or to make a profit. Resellers of transmission capacity are permitted to charge market-based rates for capacity reassignments, instead of the original cost-based rate at which they purchased the capacity. Most capacity reassignments are hourly, although capacity can also be reassigned on a daily, weekly, monthly, or yearly basis.[113]

If the market price of energy is greater at the POD than at the POR, the transmission has value. The transmission holder can capture this value by using the transmission – buying energy at the POR, moving it to the POD and selling it. Alternatively, the transmission holder can sell the transmission through a capacity reassignment. Thus, the price of a capacity reassignment should be consistent with, and rarely exceed, the expected price differential between the POD and the POR.

Transmission Planning

Each transmission-operating utility must participate in regional planning processes that identify transmission system additions and improvements needed to maintain reliability. Studies are conducted to test the transmission system against mandatory national reliability standards, as well as regional reliability standards. Planning studies may look 10-15 years into the future to identify transmission overloads, voltage limitations, and other reliability problems.

GRID OPERATIONS

Grid operators dispatch their systems using the least costly generation, consistent with the constraints of the transmission system and reliability requirements. The dispatch process occurs in two stages. For RTOs/ISOs, the market determines a day-ahead unit commitment, then updates the unit commitment and dispatches in real time. Grid operators in traditional utilities plan for the next day's dispatch, then update and implement that dispatch in real time.

Dispatch Planning

Grid operators decide which generating units should be committed in advance of actual operations. For RTOs/ISOs, this is done, in part, through the day-ahead markets and forecasts. For operators in traditional utilities, this is done through various planning and forecasting processes. Planning dispatch in advance of real-time operations is needed because some generating units need to obtain fuel or require several hours of lead time before they are brought online. In selecting the most economic generators to commit, operators take into account forecast load requirements and each unit's physical operating characteristics, such as how quickly output can be changed, maximum and minimum output levels and the minimum time a generator must run once it is started. Operators must also take into account each generating unit's cost factors, such as fuel and nonfuel operating costs, and the cost of environmental compliance.

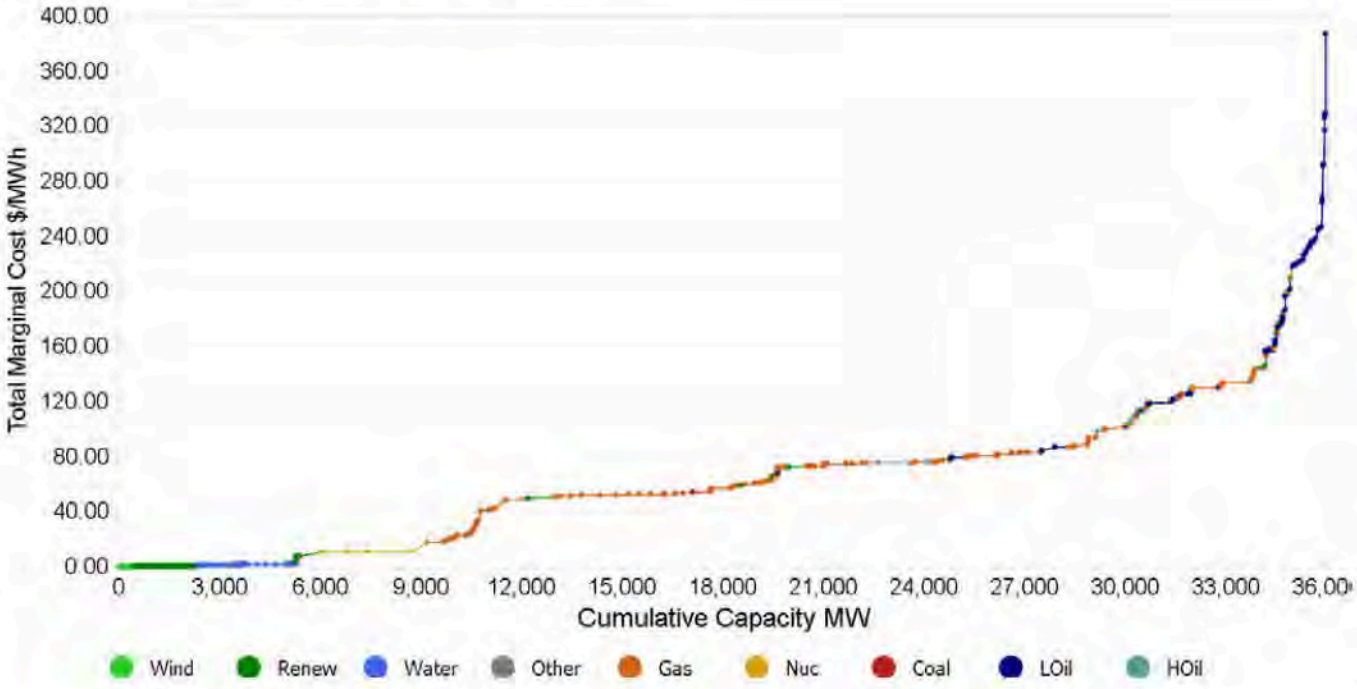
Forecast conditions can also affect how the transmission grid is optimally dispatched to reliably meet load. This is the security aspect of commitment analysis. The factors that can affect grid capabilities include generation and transmission facility outages, line capacities as affected by loading levels and flow direction, and weather conditions. If the security analysis indicates that the optimal economic dispatch cannot be carried out reliably, relatively expensive generators may have to be called upon to replace less-expensive units.

System and Unit Dispatch

Grid operators must decide the actual level at which each available resource should be operated, given the actual real-time load and grid conditions, so that reliability is maintained and overall production costs are minimized. Actual conditions will vary from those forecast prior to real-time, and grid operators must adjust the dispatch accordingly. As part of real-time operations, demand, generation and interchange (imports and exports) must be continually kept in balance to maintain a system frequency of 60 hertz.

113 FERC, *Electric Quarterly Reports, Downloads, Quarterly Filings* (2021), https://eqrreportviewer.ferc.gov.

Figure 2-6: Market Supply Curve for NYISO (Illustrative)



Source: Hitachi Energy, Velocity Suite[114]

This is typically done by automatic generation control (AGC) to change the generation dispatch as needed.

In general, dispatch occurs based on the cost of generation from given resources, with the lowest-cost resources dispatched first and the higher-cost resources dispatched last. The chart above is a depiction of the market supply curve for the New York Independent System Operator (NYISO). This is also commonly called the supply stack. In it, all the generating units in the New York market are shown, sorted according to their marginal cost of production. Their cost of production is shown on the vertical axis in terms of dollars per MWh. The cheapest units to run are to the left and the most expensive to the right.

Dispatch in New York, for example, first calls upon wind generating units, followed successively by hydroelectric, nuclear and coal-, gas- and oil-fired generating units.

This assumes that the generating units have sufficient resources – enough wind for the wind-powered generators or enough river flow for the hydroelectric plants, for example – and that sufficient transmission capability exists to deliver generator output and meet reliability needs.

In addition to these considerations, transmission flows must be monitored to ensure that the grid operates within voltage and reliability limits. If transmission flows exceed accepted limits, the operator must take corrective action, which could involve curtailing schedules, changing the dispatch or shedding load. Operators may check conditions and issue adjusted dispatch instructions as often as every five minutes.

ANCILLARY SERVICES

Ancillary services maintain electric reliability and support the transmission of electricity. These services

114 Derived from Hitachi Energy, Velocity Suite, *Supply Curve Analyst, Form EIA 860, NERC Electric Supply and Demand database, FERC Form 1, FERC Form 714, ISO Load Data, Hitachi Energy Primary Research, et al* (February 2023).

are produced and consumed in real-time, or in the very near term. NERC and regional entities establish the minimum amount of each ancillary service that is required for maintaining grid reliability.[115]

Regulation matches generation with very short-term changes in load by moving the output of selected resources up and down via an automatic control signal, typically every few seconds. The changes to output are designed to maintain system frequency at 60 hertz. Failure to maintain a 60-hertz frequency can result in systemic failure of an electric grid.

Operating reserves are needed to restore load and generation balance when a supply resource trips offline. Operating reserves are provided by generating units and demand resources that can act quickly, by increasing output or reducing demand, to make up a generation deficiency. There are three types: spinning reserves, non-spinning reserves and supplemental reserves.

Spinning reserves are provided by generators that are online (synchronized to the system frequency) with some unloaded (spare) capacity and capable of increasing its electricity output within a specified period, such as 10 minutes. During normal operation, these reserves are provided by increasing output on electrically synchronized equipment or by reducing load on pumped storage hydroelectric facilities. Synchronized reserve can also be provided by demand-side resources.

Non-spinning reserves are provided by generating units that are not necessarily synchronized to the power grid but can be brought online within a specified amount of time, such as 10 minutes. Non-spinning reserve can also be provided by demand-side resources.

Supplemental reserves are provided by generating units that can be made available within a specified amount of time, such as 30 minutes and are not necessarily synchronized with the system frequency.

Blackstart generating units have the ability to go from a shutdown condition to an operating conditi on and start delivering power without any outside assistance from the electric grid. Hydroelectric facilities and diesel generators predominately have this capability. These are the first facilities to be started up in the event of a system failure or blackout to restore the rest of the grid.

Reactive power: Electricity consists of current, the flow of electrons, and voltage, the force that pushes the current through the wire. Reactive power is the portion of power that establishes and maintains electric and magnetic fields in AC equipment. It is necessary for transporting AC power over transmission lines, and for operating magnetic equipment, including rotating machinery and transformers. It is consumed by current as it flows. As the amount of electricity flowing on a line increases, so does the amount of reactive power needed to maintain voltage and move current. Power plants can produce both real and reactive power and can change the output of both. Special equipment installed on the transmission grid is also capable of injecting reactive power to maintain voltage.

WEATHER

Weather is the single most important factor affecting the level of electricity demand and, thus, is a major factor in grid operations. System operators therefore rely heavily on weather forecasts to ensure they have the right generation, in the right locations, to run the grid reliably.

Weather affects grid operations in other ways, as well. Primary among these is on the productivity of certain types of power generators: wind and hydroelectric. Wind turbines' power output changes

115 For additional information on the definitions of ancillary services, NERC, *Glossary of Terms Used in NERC Reliability Standards*, (March 2022), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

with wind availability and speed, which affects cost of wholesale power. Solar generation declines with cloud cover, which not only decreases available generation but can increase demand as behind-the-meter solar, such as residential and commercial installations, decrease their supply to retail users.

Hydroelectric plants rely on rain and snowfall to provide the river flow needed for their output. Geographically, this is most important in the Pacific Northwest, where seasonal hydroelectric plant output is a critical source of power. Rain and the melting of winter snowpack feed the Columbia and Snake River systems. Surplus power from these generators is typically exported to California to help meet summer peak demand, increase reliability and lower prices.

Temperature can also affect the output of other power plants and capacity of transmission lines. Thermal plants that use a turbine – coal, gas, oil, and nuclear plants – become less efficient at higher temperatures. Additionally, the capacity of transmission lines is limited by heat because the conductive material used in fabrication becomes more electrically resistant as they heat up, limiting their throughput capability.

Traditional Electricity Systems

Traditional wholesale electricity markets exist primarily in the Southeast and the West outside of California, where utilities are responsible for system operations and management, and, typically, for providing power to retail consumers. Utilities in these markets are frequently vertically integrated – they own the generation, transmission and distribution systems used to serve electricity consumers. They may also include federal systems, such as the Bonneville Power Administration (BPA), the Tennessee Valley Authority and the Western Area Power Administration. Wholesale physical power trading typically occurs through bilateral transactions. In addition to the responsibilities listed in the overview to this section, a utility in a traditional region has the following responsibilities:

- Generating or obtaining the power needed to serve customers (this varies by state)
- Dispatching resources based on some cost minimizing algorithm
- Ensuring the reliability of the transmission grid

Southeast Wholesale Market Region

The Southeast electricity market is a bilateral market that includes all or parts of Florida, Georgia, Alabama, Mississippi, North Carolina, South Carolina, Missouri, and Tennessee. It encompasses the Southeastern Electric Reliability Council (SERC) NERC region. Major hubs include Into Southern and the Tennessee Valley Authority (TVA). The Southeast region's hourly peak demand is greater than 203 GW.[116] While traditional bilateral trading continues in the Southeast, some utilities in the region have created a trading platform, the Southeast Energy Exchange Market (SEEM), discussed further below. Southern Company also conducts an auction for some of its available generation, also discussed further below.

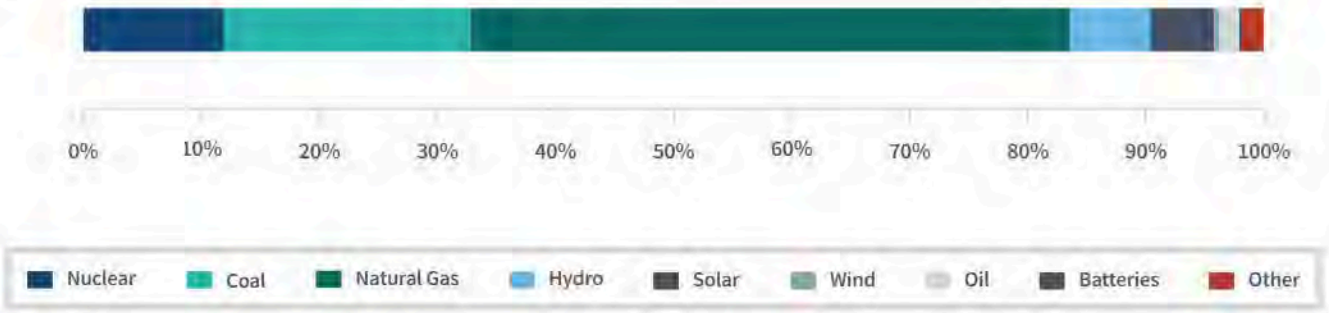
Figure 2-7: Southeast Electric Region



Source: Hitachi Energy, Velocity Suite

116 The hourly peak demand observed between 2000 and 2020. Based on FERC Form 714, Annual Electric Balancing Authority Area and Planning Area Report. Derived from the Balancing Authority Areas within the SERC NERC region, using the Hitachi Energy, Velocity Suite, Balancing Authority Area Net Energy for Load & Peak Demand dataset.

Figure 2-8: Southeast Electric Region Capacity Mix



Source: EIA Form 860-M[117]

Supply Resources

The total generating capacity in the Southeast Electric Region is over 256 GW and is predominately composed of natural gas and coal-fired generators. Hydroelectric and nuclear capacity are also substantial resources in the region.

The Southeast generates most of its electricity from coal, nuclear, and natural gas-fired plants, as shown in the bar chart above.

The TVA sub-region has a majority of its capacity and output from coal and nuclear, while the Virginia-Carolina (VACAR) sub-region has the highest utilization of nuclear generation in the Southeast.

TRADING AND MARKET FEATURES

Physical sales in the Southeast are done bilaterally and long-term energy transactions are particularly prominent, compared to short-term transactions. Many long-term agreements involve full-requirements contracts or long-term power purchase agreements. For example, Southern Company's short-term transactions account for around 30 percent of its total wholesale energy sales in 2021.[118]

Short-term energy is traded among various entities, including investor-owned utilities, municipal utilities, public utility districts, independent power producers, and marketers. Some of the largest sellers of short-term power include Southern Company, North Carolina Municipal Power Agency, Cargill, and Exelon.

Industry-referenced trading points for short-term bilateral transactions in the Southeast include the following locations: Into Southern, TVA, VACAR, and Florida. Volumes for short-term transactions can be low, particularly under normal weather conditions. Overall demand for short-term transactions tends to rise during periods of system stress, for example summer heat waves or winter cold snaps.

The Southeast has relatively low volumes of short-term trades compared to the Western regions. Thus, there is limited data on that price index publishers have on which to base their price reporting. Given the bilateral nature of wholesale power transactions in the Southeast, and a relatively small market for short-term transactions, interest in financial power products in the Southeast is weak.

117 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory* (based on Form EIA-860M) (released February 2022), https://www.eia.gov/electricity/data/eia860m/.

118 FERC, *Electric Quarterly Reports, Downloads, Quarterly Filings* (2021), https://eqrreportviewer.ferc.gov.

SOUTHEAST ENERGY EXCHANGE MARKET

The Southeast Energy Exchange Market (SEEM) launched on November 9, 2022. However, on July 14, 2023, the U.S. Court of Appeals for the D.C. Circuited remanded to FERC orders addressing the Seem. Consequently, the SEEM proposal is now pending before the Commission once again.

SOUTHERN COMPANY AUCTION

Southern Company has held daily and hourly auctions for power within its balancing area since April 2009 as a requirement of Southern Company's market-based rate tariff. This BAA encompasses the service territories of Southern Company utilities: Georgia Power, Alabama Power, Mississippi Power, and Gulf Power. The products included in the auction are day-ahead power and real-time power.

According to the auction rules, Southern Company must offer all of its available uncommitted thermal generation capacity into the auction, after regulation and contingency reserves are met. The auction is intended to mitigate the potential ability of Southern Company to exercise market power within its balancing authority area and certain adjacent balancing authority areas. In February 2017, Southern Company revised its market-based rate tariff to cap all market-based sales of less than one year outside of the auction at a cost-based tariff rate.[119]

Western Wholesale Market Regions

The power markets in the western United States are primarily bilateral markets. A key exception is most of California and portions of Nevada, which operate under CAISO. Further, several entities buy and sell electricity in a regional, short-term markets run by CAISO, called the Western Energy Imbalance Market (WEIM), and the SPP-run Western Energy Imbalance Service (WEIS). CAISO and SPP are discussed further in the RTO and ISO Markets section. The West includes the Western Power Pool (WPP), the Rocky Mountain Power Area, and the Arizona, New Mexico, Southern Nevada Power Area within the Western Electricity Coordinating Council (WECC), a regional entity. These areas contain over 30 balancing authority areas responsible for dispatching generation, procuring power, operating the transmission grid reliably, and maintaining adequate reserves.[120]

NORTHWEST ELECTRIC REGION

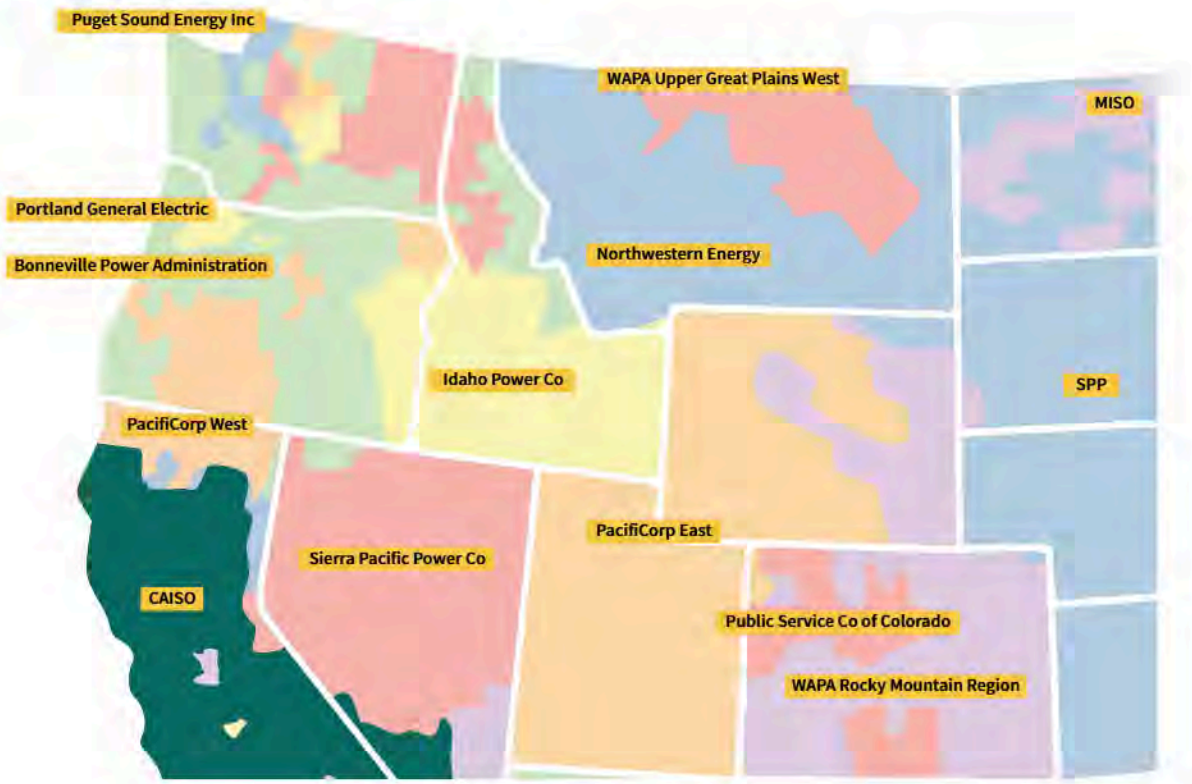
The Northwest Electric Region is composed of the Northwest Power Pool (NWPP) NERC region in the northwestern section of the Western Electric Coordinating Council (WECC) NERC region. The hourly peak demand is approximately 49 GW[121]

119 *Alabama Power Company*, 158 FERC ¶ 61,131 (2017) (February 2, 2017 Order) (order accepting market-based rate tariff revisions subject to condition).

120 Western Electricity Coordinating Council, *Western Interconnection Balancing Authorities* (accessed November 2022), https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Administrative/Balancing_Authorities_JAN17.pdf&action=default&DefaultItemOpen=1.

121 The hourly peak demand observed in a given month between 2000 and 2020. Based on FERC Form 714, *Annual Electric Balancing Authority Area and Planning Area Report*. Derived from the Balancing Authority Areas within the NWPP NERC subregion, using the Hitachi Energy, Velocity Suite, Balancing Authority Area Net Energy for Load & Peak Demand dataset.

Figure 2-9: Northwest Electric Region



Source: Hitachi Energy, Velocity Suite

Supply Resources

The total capacity in the Northwest Electric Region is approximately 79 GW and is primarily composed of hydroelectric, natural gas, and coal-fired generators, as shown in the bar chart below. Wind generator capacity is also a significant resource for the region.

The Northwest has a unique resource mix, as demonstrated in the bar chart below, with hydroelectric generation capacity comprising approximately 40 percent of the power supply, which is sourced from many dams that are in the Columbia River system. The largest dam, Grand Coulee, can produce up to as much power as six nuclear plants. Due to the large amount of hydroelectric generation, the Northwest typically has low-cost power during the spring and early summer. During these periods, the region exports power to neighboring regions, especially California, where power prices are typically higher.

The amount of hydroelectric power produced depends on a number of factors, some natural and some controllable. On a seasonal basis, the intensity and duration of the water flow is driven by snowpack in the mountains, the fullness of the reservoirs, and rainfall. On a short-term basis, the levels of hydroelectric power generation output are influenced by decisions to release water locally and upstream to generate power, as well as local water-use decisions that are independent of the economics of the power markets, based on recreation, irrigation, and wildlife considerations, for example. The peak hydroelectric power generation period begins in the spring, when the snow melts, and may last into early summer. When less water is available, the Northwest may rely more on its coal and natural gas generation, and occasionally import power from neighboring regions, including Canada, when loads are high.

Figure 2-10: Northwest Electric Region Capacity Mix

Source: EIA Form 860-M



Trading and Market Features

Two Canadian BAAs, Alberta Electric System Operator

The water forecast affects the forward market for electricity in the Northwest. Similarly, the daily water flow conditions influence the prices in the daily physical market. When there is an abundance of hydroelectric generation, the Northwest will export as much as possible on the transmission lines leading into California and elsewhere in the West. Sometimes in off-peak hours, more electricity is available than can move through transmission lines or be used locally, so electric prices become negative.

The largest seller of wholesale power in the region is the BPA, a federal agency that markets the output from federally owned hydroelectric facilities, as well as a non-federal nuclear plant and several other smaller non-federal power plants. BPA meets approximately one-third of the firm energy supply in its service territory and owns 75 percent of the region's high-voltage transmission.[122] BPA gives preference to municipal and other publicly owned electric systems in allocating and pricing its generation output.[123]

and British Columbia Hydro, are also substantial suppliers of energy to the United States via the Northwest Electric Region. These Canadian BAAs often import power to, and export power from, the United States, depending on market conditions. The Canadian BAAs generally import power from the United States when prices are low in order to save water in their hydroelectric reservoirs. The water is later released to generate and sell hydroelectric power during higher-priced periods[124]

The Northwest region trading points for bilateral transactions include Mid-Columbia (Mid-C), California-Oregon Border (COB), Nevada-Oregon Border (NOB), and Mona (Utah). Of these, Mid-C is the most actively traded location.

SOUTHWEST ELECTRIC REGION

The Southwest electric market encompasses Arizona, New Mexico, and Southern Nevada in the WECC NERC region. The hourly peak demand is approximately 25 GW.[125]

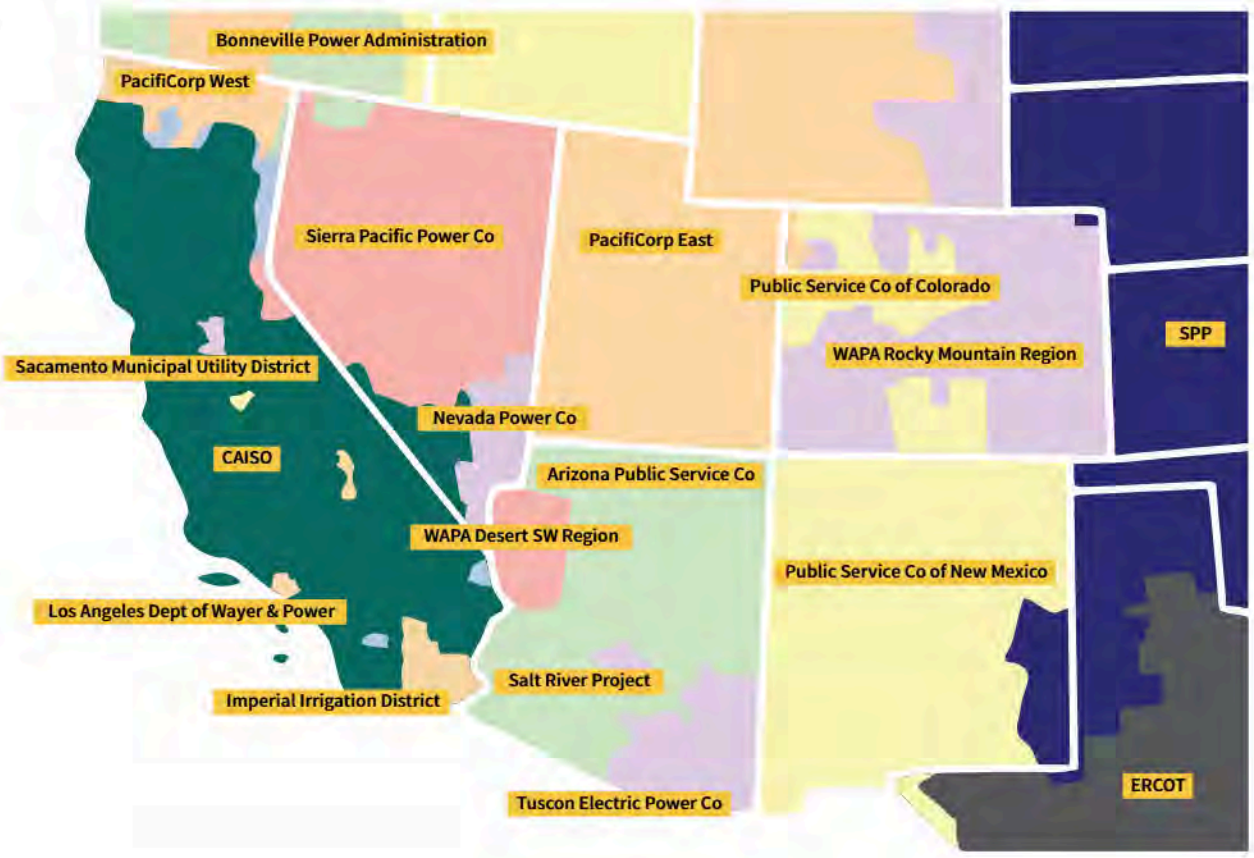
122 Bonneville Power Administration, *BPA Overview*, 45, https://energy.gov/sites/prod/files/2016/01/f28/0911review_ikakoula.pdf.

123 Bonneville Project Act, 16 U.S.C. §§ 832-832m (2000).

124 National Energy Board, *Market Snapshot: Which states trade electricity with British Columbia?* (September 2022) https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/; National Energy Board, *Market Snapshot: Why Canada is one of the world's largest electricity consumers* (August 2022), https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/

125 The hourly peak demand observed between 2000 and 2020. Based on *FERC Form 714, Annual Electric Balancing Authority Area and Planning Area Report*. Derived from the Balancing Authority Areas within the AZ/NM/SNV NERC subregion, using the Hitachi Energy, Velocity Suite, Balancing Authority Area Net Energy for Load & Peak Demand dataset.

Figure 2-11: Southwest Electric Region



Source: Hitachi Energy, Velocity Suite

Supply Resources

The total capacity in the Southwest Electric Region is over 40 GW and is predominately composed of natural gas and coal-fired generators. Hydroelectric, wind, solar, and nuclear capacity account for the majority of the remaining capacity, as shown in the bar chart below.

The majority of generation in the Southwest is produced from natural gas and coal, as demonstrated in the bar chart above. The coal generators are generally located in close proximity to coal mines, resulting in low delivered fuel costs. Some generation is jointly owned among multiple nearby utilities, including the Palo Verde nuclear plant, a plant with three units totaling approximately 4,000 MW,[126] which has owners in California and the Southwest.[127] The Southwest is also characterized by large amounts of solar capacity, as this region has the highest solar potential in the nation.[128]

Trading and Market Features

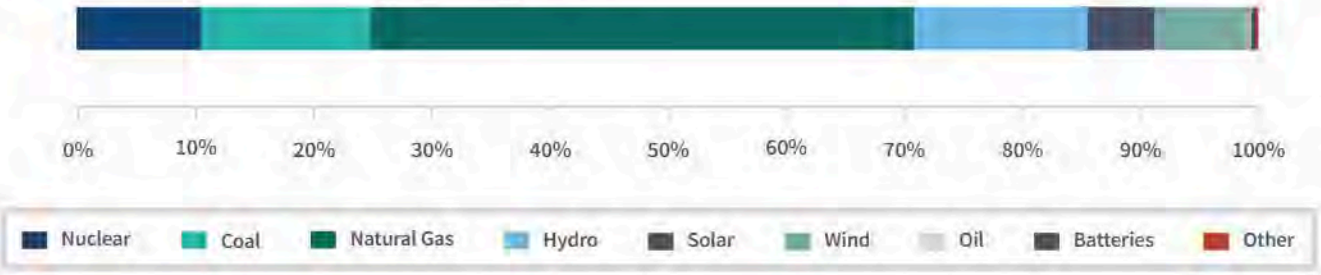
The Southwest region is summer-peaking and experiences peak loads coincident with air conditioning demand. The daily high temperature averages above 100 degrees from June through mid-September in Phoenix.

126 Derived from EIA, *Form EIA-860, 3-1-Generator_Y2021 Report*, (2021), https://www.eia.gov/electricity/data/eia860/.

127 Plant Operating License, Palo Verde, Unit 1, Current Facility Operating License NpF-41, Tech Specs, Revised 08/18/2022, https://www.nrc.gov/info-finder/reactors/palo1.html.

128 Western Electricity Coordinating Council, *State of the Interconnection*, at 9 (September 2017), https://www.wecc.biz/epubs/StateOfTheInterconnection/.

Figure 2-12: Southwest Electric Region Capacity Mix



Source: EIA Form 860-M[129]

However, power prices tend to be the highest when there is also hot weather in Southern California, creating competition for the region's generation resources. The Southwest trading points include Palo Verde, Four Corners, and West Wing. Of these, Palo Verde is the most actively traded location.

RTO and ISO Markets

Two-thirds of the population of the United States is served by electricity markets run by regional RTOs/ISOs. A key distinction between RTO/ISO markets and vertically integrated utilities, municipal utilities and co-ops is that RTO/ISO markets deliver electricity through competitive market mechanisms coordinated by a non-profit entity over a large geographic footprint. Further, RTOs/ISOs do not own or conduct maintenance on the transmission or other resources involved in providing electric service.

Currently, seven RTO/ISOs operate in the United States, listed below in order of the size of their all-time peak load.[130] FERC regulates all RTOs/ISOs except ERCOT. In addition to operating RTOs/ISOs, SPP and CAISO also operate regional short-term or imbalance energy markets, which, while not RTOs/ISOs, provide markets for real-time energy sales and purchases. SPP operates the WEIS and CAISO runs the WEIM, which are discussed at the end of the SPP and CAISO sections below.

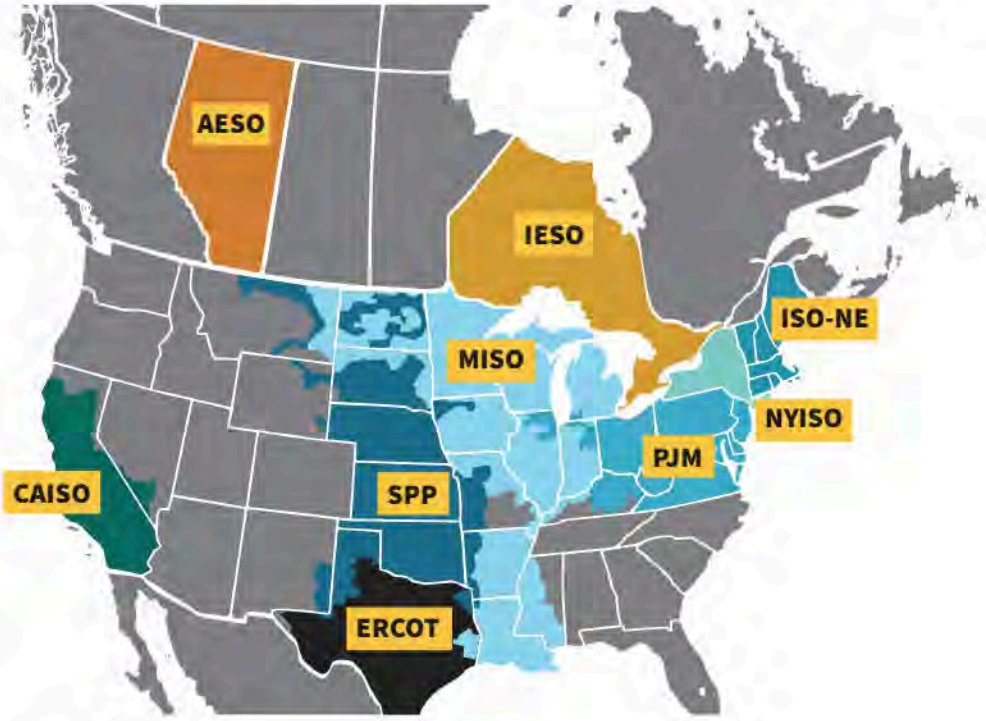
- PJM, 165 GW (summer of 2006)
- MISO, 127 GW (summer of 2011)
- ERCOT, 80 GW (summer of 2022)
- SPP, 53 GW (summer of 2022)
- CAISO, 52 GW (summer of 2022)
- NYISO, 34 GW (summer of 2013)
- ISO-NE, 28 GW (summer of 2006)

Unlike traditional electricity systems, RTOs/ISOs also operate competitive, nondiscriminatory electricity markets, which allow resource owners to offer resources and load-serving entities to submit bids for generation. These markets are the primary mechanism for dispatching resources, managing transmission congestion and pricing electricity. RTOs/ISOs work in conjunction with the resources and transmission-owning resources that participate in the RTO/ISO to maintain reliability. RTOs/ISOs also coordinate the maintenance of generation and transmission systems and oversee a transmission planning process to identify needed upgrades in both the near- and long-term.

129 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. EIA, *Preliminary Monthly Electric Generator Inventory* (based on Form EIA-860M) (February 2022), https://www.eia.gov/electricity/data/eia860m/.

130 For source information on the peak load statistics for PJM Interconnection, Midcontinent ISO, Southwest Power Pool, California ISO, New York ISO, and New England ISO, see the individual region's description later in this chapter. For ERCOT, see *ERCOT, Fact Sheet*, (October 2022), https://www.ercot.com/files/docs/2022/02/08/ERCOT_Fact_Sheet.pdf.

Figure 2-13: North American Regional Transmission Organizations and Independent System Operators



Source: Hitachi Energy, Velocity Suite

RTO/ISO FEATURES

All RTOs/ISOs function as non-profit entities that operate markets to dispatch and price electricity across a large, defined footprint. To do this, the RTOs/ISOs perform functions such as operating day-ahead and real-time markets, but also perform an array of functions not directly part of the markets, but essential to allow their efficient performance. For example, RTOs/ISOs manage the flow of payments between market participants. The next section discusses markets operated by RTOs/ISOs. The remainder of this section discusses key RTO/ISO support features or functions.

Governance

RTOs/ISOs, resource owners and operators, investor-owned, public and cooperative utilities, marketers and financial entities participate in the RTO/ISO under a governance structure and rules determined through RTO/ISO-run processes.[131] RTO/ISO governance typically involves a board of directors and stakeholder committees, which, among other things, review rule revisions. Rules underlying RTO/ISO functions are included in the RTO's/ISO's tariff and are subject to FERC's approval. Details on rule implementation can be found in RTO's/ISO's Business Practice Manuals.

Financial Policies

Financial settlement is the process through which payments due from customers, and to generators, are calculated. Such settlements are based upon day-ahead schedules, real-time metering, interchange schedules, internal energy schedules, ancillary service obligations, transmission reservations, energy prices, Financial Transmission Rights (FTR) positions, and capacity positions. Each market participant's invoice of charges and credits includes the costs of services used to serve load and the costs for operating the RTO/ISO.

131 Order No. 2000, *Regional Transmission Organizations*, 89¶61,285, (December 20, 1999).

Generally, customers receive weekly or monthly invoices stating their charges and credits. Weekly invoices must be settled within a few days of being issued, while monthly invoices must be paid within either one or two weeks, depending on the policies of each RTO/ISO. All payments are made electronically.

While RTO/ISO energy and ancillary service markets operate to price electricity at a level that compensates resources for their energy supply and meet other requirements of their tariffs, instances do occur where additional cost recovery is needed – this is commonly known as uplift. The need for uplift may arise, for example, when unplanned transmission and generation outages occur, resulting in actual operations differing from the assumptions included in the market models underlying the energy and ancillary service markets.[132]

Credit Policies

RTOs/ISOs settle the many financial charges that are paid by, or to, market participants. As RTOs/ISOs are non-profit entities with no financial interest in the markets they operate, any financial shortfall or over-collection goes to the various market participants. To protect the RTO/ISO and its market participants, each RTO/ISO has tariff provisions and other policies to ensure that market participants have the ability to pay, known as credit policies.[133] Defaults by market participants in RTOs/ISOs are rare and the costs have generally been spread across the market. Credit policies contain provisions related to credit evaluations, credit limits, forms of collateral, and the consequences of violations or defaults.

Transmission Planning

RTO/ISOs coordinate transmission planning for their footprint as required under Order 1000, a comprehensive transmission rule issued by FERC in 2011.[134] Each of the RTO/ISOs has system-wide or regional planning processes that identify transmission system additions and improvements that are needed to keep electricity flowing. Studies are conducted to test the transmission system against mandatory national reliability standards, as well as regional reliability standards. The RTO/ISO transmission planning studies may look 10-15 years into the future to identify transmission overloads, voltage limitations, and other reliability problems. RTO/ISOs then develop transmission plans in collaboration with transmission owners to resolve potential problems that could otherwise lead to overloads and blackouts. This process culminates in one recommended plan for the entire RTO/ISO footprint.

RTO/ISO MARKETS AND ASSOCIATED FUNCTIONS

RTOs/ISOs operate several markets and functions that address the physical supply of electricity and its pricing – energy and capacity markets. To physically provide the supply of electricity at all times in all places, RTOs/ISOs operate energy markets that LSEs use to procure energy and ancillary services. Some RTOs/ISOs also operate capacity markets, which, along with underlying resource adequacy rules, ensure sufficient capacity is available. RTOs/ISOs also operate financial markets associated with the energy markets – financial transmission rights and virtual transactions.

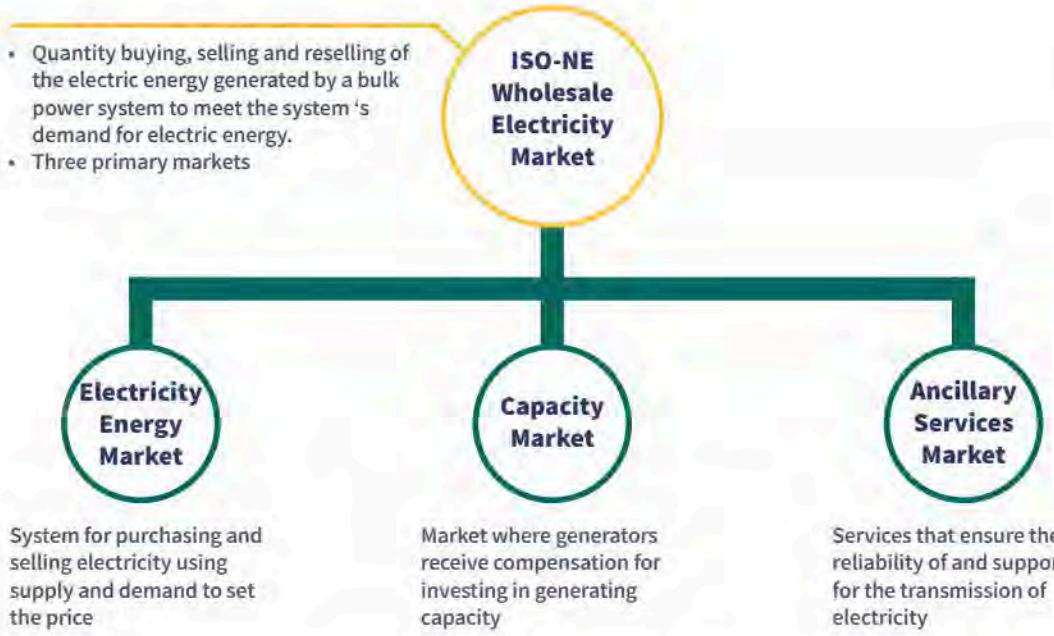
RTOs/ISOs must define rules and operate programs needed to ensure efficient market operations. The operations of the markets are discussed further below. Underlying these market operations are an extensive list of detailed rules and functions. For example, these rules detail what types of resources can participate, at limits on what prices resources can offer, and the operation of an independent market monitoring program:

132 Order No. 844, *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 163¶61,041, (April 19, 2018).

133 Order No. 741, *Credit Reforms in Organized Wholesale Electric Markets*, 133¶61,060, (October 21, 2010).

134 Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 135¶61,051, (July 21, 2011).

Figure 2-14: ISO-NE Wholesale Electricity Market



Source: ISO-NE

Resource Participation In addition to generation, demand response resources (DR), DER, energy efficiency and batteries may participate in RTO/ISO markets.[135]

Offer Caps Each RTO/ISO caps a resource's supply offer at $1,000. If a resource's costs exceed $1,000, they may request authority to offer at a higher price that reflects their verified costs. Offers up to $2,000 may be used by the RTO/ISO to set the locational marginal price.[136]

Market Monitoring Each RTO/ISO must have independent market monitors which oversee various aspects of the RTO's/ISO's markets and performance, such as market power mitigation, assessment and referral of market manipulation and assessing and reporting on the competitiveness of market operations.[137]

Energy Markets

All RTOs/ISOs have day-ahead and real-time markets. The day-ahead market schedules electricity production, ancillary services commitments and consumption before the operating day, whereas the real-time market reconciles any differences between the schedule in the day-ahead market and the real-time conditions. Both the day-ahead and real-time markets reflect reliability criteria and infrastructure conditions, such as transmission topology and limitations, resource outages, and resource operating limits.

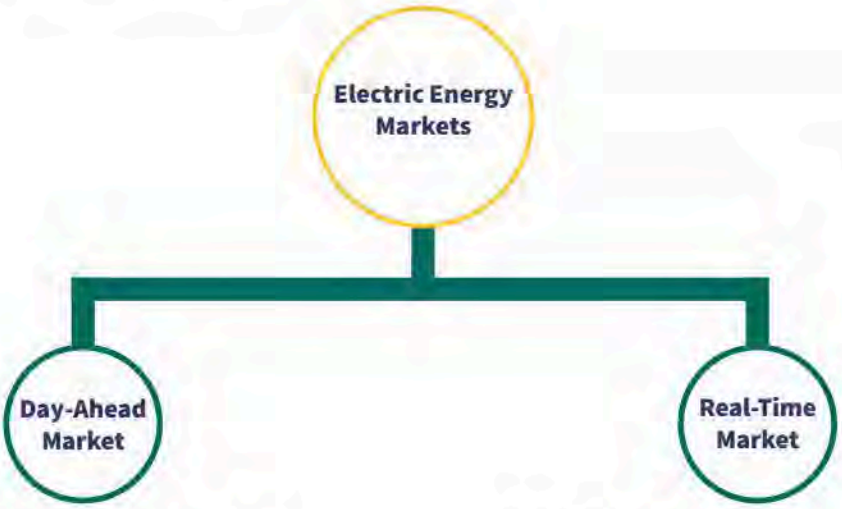
Energy markets operate to match the supply options offered by resource oprators to the demand bid in by LSEs and RTO/ISO demand forecasts. The market models select the most economic supply offers available,

135 Order No. 2222, *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172¶61,247; Order No. 841, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 162¶61,127 (2018); Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, 134¶61,187, (March 15, 2011).

136 Order No. 831, *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 157¶61,115, (November 17, 2016).

137 Order No. 719, *Wholesale Competition in Regions with Organized Electric Markets*, 125¶61,071.

Figure 2-15: ISO-NE Wholesale Electricity Market



Source: ISO-NE

recognizing physical resource and transmission limitation. The overall market price for electricity is determined by the highest offer accepted. However, transmission limitations may require the market to adjust the offers selected, which can change the price for different locations in the RTO/ISO – the locational marginal price (LMP). The RTO/ISO markets calculate the LMP at each location on the power grid. The LMP reflects the marginal cost of serving load at the specific location, given the set of resources that are being dispatched and the limitations of the transmission system. LMP has three elements: an energy charge, a congestion charge, and a charge for transmission system energy losses.

If there are no transmission constraints, known as transmission congestion, LMPs will not vary significantly across the RTO/ISO footprint. However, when transmission congestion occurs, LMPs will vary across the footprint because operators are not able to dispatch the least-cost generators across the entire region and some more expensive generation must be dispatched to meet demand in the constrained area.

When transmission is constrained, the highest variable cost unit that must be dispatched to meet load within transmission-constrained boundaries will set the LMP in that area. All sellers receive the LMP for their location and all buyers pay the price for their location.

The primary means used for relieving transmission congestion constraints is by changing the output of generation at different locations on the grid. The market-based LMP sends price signals that reflect congestion costs to market participants. Thus, LMPs take into account both the impact of specific generators on the constrained facility and the cost to change (redispatch) the generation output to serve load. This process is known as security-constrained economic dispatch.

This redispatch could be implemented by using non-market procedures, such as transmission loading relief (TLR). NERC established the TLR process for dealing with reliability concerns when the transmission network becomes overloaded and power flows must be reduced to protect the network. A TLR is used to ration transmission capacity when the demand for transmission is greater than the available transmission capacity (ATC). The rationing is a priority system that cuts power flows

based on size, contractual terms and scheduling.

Day-Ahead Energy Markets

The day-ahead energy market produces financially binding schedules for the production and consumption of electricity one day before its production and use (the operating day). The purpose of the day-ahead market is to give generators and load-serving entities a means for scheduling their activities with sufficient lead time to procure fuel or bring up resources with longer start times. The day-ahead bids and offers are based on a forecast of loads and are consistent with resources' business strategies.

In day-ahead markets, offers of supply and demand bids are compiled hours ahead of the beginning of the operating day. The RTO/ISO then runs a computerized market model that matches demand and supply throughout the market footprint for each hour of the day. Additionally, the model must account for changing system capabilities that occur, based on weather and equipment outages, transmission and resource capabilities, and the rules and procedures that are used to ensure system reliability.[138] The market rules dictate that generators submit supply offers and that loads submit demand bids to the RTO/ISO by a deadline that is typically in the morning of the day-ahead scheduling. Typically, 95 percent of all load is scheduled in the day-ahead market and the rest is scheduled in real-time. Generation and demand bids that are scheduled in the day-ahead market are settled at the day-ahead market prices.

Inputs into setting a day-ahead market schedule include:

- Generators' offers to sell electricity for each hour
- Load-serving entities' bids to buy electricity for each hour
- Demand-response offers by customers to curtail usage of electricity
- Virtual demand bids and supply offers
- Operational information about the transmission grid and generating resources, including planned or known transmission and generator outages, the physical characteristics of generating resources including minimum and maximum output levels and minimum run time, and the status of interconnections to external markets.

Real-Time Energy Markets

The real-time market is used to balance the differences between the day-ahead scheduled amounts of electricity cleared in the day-ahead market and the actual real-time load and supply. The real-time market is run in five-minute intervals and clears a much smaller volume of energy and ancillary services than the day-ahead market (some RTOs/ISOs also run hour-ahead and 15 minutes- ahead of the operating interval). The real-time market also provides supply resources additional opportunities for offering energy into the market. When the real-time generation and load are different from the day-ahead cleared amount, the difference is settled at the real-time price.

Real-time market prices are significantly more volatile than day-ahead market prices. This stems from demand uncertainty, transmission and generator forced outages, and other unforeseen events. Since the day-ahead market generally is not presented with these events, it produces more stable prices than in real-time. Also, because the volumes in the real-time market are much smaller, there is an increased likelihood of supply and demand imbalances, which can lead to both positive and negative price movements.

Ancillary Services

RTOs/ISOs procure ancillary services, which are described in the Electricity Supply and Delivery Section, through the day-ahead and real-time market dispatch. RTOs/ISOs primarily procure ancillary service through their market mechanisms, although they compensate blackstart and voltage service based on the cost of providing the service (cost-of-service). Changes in the

138 In evaluating which generators provide the power to meet hourly load, the market model assesses whether the power flows can travel without exceeding the physical capability of any transmission path. If the model shows such a violation of transmission capability, the combination of assigned generators will be changed in a process known as redispatch.

resources providing supply have necessitated changes in ancillary service procurement and compensation. For example, the advent of faster-ramping resources led to changes in compensation for frequency regulation.[139]

While not an ancillary service, ramping capacity is a service for which some RTOs/ISOs have developed products. The growth of renewable generation has increased the need for generation that can increase its production rapidly to offset swings in generation or load.

Shortage Pricing

RTO/ISO markets dispatch energy and ancillary services to meet demand and reserve requirements. However, the markets may find that not enough supply is available. If the RTOs/ISOs cannot procure sufficient generation to meet demand and reserve requirements in the real-time market, they trigger shortage pricing[140] to send price signals to incentivize resources to increase the supply offered. Shortage events can be caused by unexpectedly high electric loads, supply disruptions, or both.

The common method that RTO/ISOs employ to implement shortage pricing is through the use of an operating reserve demand curve. The demand curve specifies price levels for the degree of the shortages.[141] The price of the reserves, reflecting shortage as determined by the demand curves, sets the price for ancillary services and energy.

Market Power Mitigation

RTO/ISO energy and capacity markets are typically competitive, allowing the markets to set the price. However, situations may occur that result in certain resources being essential to serving demand, thus enabling those resources to increase prices in a specific area – in other words, the ability to exercise market power. Typically, this occurs when a transmission constraint limits the amount of electricity that can flow into an area, rendering generation located inside that area essential to serving that local load. RTOs/ISOs have mechanisms for determining whether such market power may occur, and if appropriate, to mitigate the price at which affected resources may offer their supply. RTO/ISO market power mitigation typically examines whether a resource has the potential to exert market power; whether they actually offer in a way that could be an exertion of market power (conduct test); and whether any potential exertion of market power actually affected the market price (impact test).

RTO/ISO Capacity Markets and Resource Adequacy

RTO/ISOs, like other electric systems, are required to maintain adequate generation and demand-resource capacity to meet load and reliability requirements. LSEs have typically satisfied their reserve obligations with owned generation or bilateral contracts with other suppliers. In general, LSEs are required to procure sufficient capacity to meet their load. Some RTOs/ISOs also have mechanisms through which LSEs can obtain capacity commitments, such as capacity auctions and capacity payments.

Most RTOs/ISOs run a capacity market that allows LSEs to satisfy their reserve obligation. The markets cover short-term capacity, such as a month, season or year. PJM and ISO-NE run capacity auctions up to three years prior to when the capacity is needed. The capacity markets are intended to provide more certainty for investment in new capacity resources while including an opportunity for all resources to recover their fixed costs over time.

Other ISOs/RTOs, such as SPP and CAISO, rely on resource adequacy programs, in which the RTO/ISO determines the capacity each LSE is required to provide

139 Order No. 755, Frequency Regulation Compensation in the Organized Wholesale Power Markets, 137¶61,064, (October 20, 2011).

140 Order No. 825, *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 155¶61,276 (June 16, 2016).

141 RTO/ISOs apply shortage pricing in the LMP for all intervals in which the operating software indicates that there is insufficient available energy to provide system or localized demand and reserves. *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 825, 81 Fed. Reg. 42,882 (June 30, 2016), FERC Stats. & Regs. ¶ 31,384 (2016).

at different times of the year. These programs require each LSE to show the RTO/ISO that it has procured the required capacity for different times of the year.

Special Provisions for Essential Resource Retirements
Reliability must-run (RMR) units are generating plants that would otherwise retire but that the RTO/ISO has deemed necessary to ensure reliability. They can also be units that have market power due to their location on the grid. RTO/ISOs enter into cost-based contracts with these generating units and allocate the cost of the contract to transmission customers. In return for these payments to the generator, the RTO/ISO may call on the owner of an RMR generating unit to run the unit for grid reliability. The payment must be sufficient to pay for the cost of owning and maintaining the unit, even if it does not operate. Transmission upgrades can reduce the need for RMR units by increasing generation deliverability throughout the RTOs/ISOs.

Financial Transmission Rights

Financial transmission rights (FTRs) are contracts that give market participants an offset, or hedge, against transmission congestion costs in the day-ahead market.

FTRs were originally developed in part to give native LSEs in the nascent RTOs/ISOs price certainty similar to that available to traditional vertically integrated utilities operating in non-RTO/ISO markets. This practice continues, as FTRs are allocated to load-serving entities, transmission owners, or firm transmission right holders in RTOs/ISOs, typically based on historical usage. Entities that fund the construction of specific new transmission facilities may also be eligible to receive FTRs. The details of the allocations vary by RTO/ISO.

FTRs allow customers to protect against the risk of congestion-driven price increases in the day-ahead market in the RTOs/ISOs. Specifically, FTRs grant their holders the right to day-ahead congestion revenues over specific paths and periods of time. Congestion costs occur as the demand for scheduled power over a transmission path exceeds that path's flow capabilities. This causes the price at the source to decline or the price at the sink to increase, or both, causing the congestion cost of serving Point B from Point A to increase. By buying an FTR over the path from Point A to Point B, the FTR holder is paid the difference of the congestion price components at the sink and source, thus allowing it to hedge against the congestion costs incurred in the day-ahead market.

FTRs are acquired through allocations and purchases. Purchases take place in the RTO-administered auctions or in a secondary market. Allocations stem from a related product, the auction revenue rights (ARR). ARRs provide the firm transmission capacity holders, transmission owners or LSEs with the rights to revenue from the FTR auctions. In general, ARRs are allocated based on historical load served and, in some RTO/ISOs, ARRs can be converted to FTRs. If ARRs are converted to FTRs, the holder receives revenue from congestion. If ARRs are kept as such, the holder receives revenue from the FTR auction.

The main method for procuring FTRs is through an auction, which typically includes an annual (or multiyear) auction of one-year FTRs and monthly (or semiannual) auctions of shorter-term FTRs provided by existing FTR holders or made available by the RTO/ISO. The auctions are scheduled and run by the RTO, which requires bidding parties to post credit to cover the positions taken. FTR auction revenues are used to pay the holders of ARRs and assist the funding of future congestion payments to FTR holders. There is also a secondary market for FTRs (such as PJM's eFTR), but historically only a small number of transactions have been reported.

The quantity of FTRs made available by the RTO/ISO is bounded by the physical limits of the grid, as determined by a simultaneous feasibility test across all potential flowgates. This test is performed by the RTO/ISO prior to making FTRs available at auction and takes into account existing FTR positions and system constraints. The resulting portfolio of FTRs allocated or offered at auction represents an absolute constraint on the size of the net positions that can be held by the market. Participants in FTR auctions can procure counterflow FTRs, which directly offset prevailing flow FTR capacity, thereby allowing the

value at risk on a given path to exceed the physical limits of the line. However, such bids are physically constrained, as the net position held on the path must always conform to the simultaneous feasibility test.

FTRs can also be purchased by a creditworthy entity seeking their financial attributes as a speculative investment. In this regard, FTRs are similar to financial swaps that are executed as a contract for differences between two day-ahead LMPs (swaps are explained in Chapter 5, Trading and Capital Markets). However, FTRs are substantially different from swaps in that the quantity of FTRs is linked to physical constraints in the transmission grid, while the quantity of swaps is not. Further, FTRs are procured by allocation or FTR auction, while swaps are procured through financial over-the-counter markets or exchanges.

All six FERC-jurisdictional RTOs/ISOs trade FTRs or FTR-equivalent products. However, the types and qualities of the rights traded across the organized markets vary, as do the methods used to allocate, auction, and transfer these rights. These attributes of the FTR markets are discussed below.

Flow Type: Prevailing Flow and Counterflow. A prevailing flow FTR generally has a source in a historical generation-rich location and a sink that is in a historical load-heavy location. Alternatively, the source of a prevailing flow FTR is on the unconstrained side of a transmission interface and the sink on the constrained side. Auction clearing prices for prevailing flow FTRs are positive. Conversely, a counterflow FTR often has a source in a historical load-heavy location and a sink in a historical generation-rich location. As a result, auction clearing prices for counterflow FTRs are negative; bidders are paid to take the counterflow FTR position.

Peak Type: On-peak, Off-peak, 24-hour. FTRs can be purchased for either 16-hour on-peak blocks, 8-hour off-peak blocks or around-the-clock. Only PJM offers all three peak-type products. NYISO offers only the 24-hour product. The other RTO/ISOs offer on-peak and off-peak products.

Allocated Rights: The RTO/ISOs allocate transmission rights to transmission owners or load-serving entities within their markets. In PJM, MISO, SPP, and ISO-NE, these are allocated as auction revenue rights (ARRs), which give their holders the right to receive a share of the funds raised during the FTR auctions. CAISO allocates congestion revenue rights (CRR), which provide their holders a stream of payments based on the actual congestion occurring on associated paths. NYISO allocates both auction-based and congestion-based rights through multiple instruments. PJM and MISO allow ARR holders to convert all these rights to FTRs; NYISO allows only a portion of ARR-equivalent instruments to be converted to its version of FTRs, called Transmission Congestion Credits (TCCs). ISO-NE does not allow such conversions, while CAISO's allocation is already in a form equivalent to an FTR. Converted ARRs are fully fungible in PJM, MISO, and NYISO; CAISO only allows the sale of allocated CRRs in its secondary market, and ISO-NE has no converted instruments to sell.

Auctioned Rights: All RTOs provide FTRs (or equivalent CRRs or TCCs) for sale to the public through two or more auctions held at various times of the year. The products vary by market and by auction, with some products made available only at specific auctions.

Secondary Markets: With the exception of NYISO, each of the markets that auction FTRs also operates a bulletin board or similar venue designed to enable a secondary trading platform for FTRs. However, none of these platforms has had significant volume. NYISO offered to create a bulletin board for its participants, if requested, but received no requests.

Virtual Transactions

Virtual bids and offers (collectively, virtuals) are a form of financial trading used by market participants to hedge physical positions and by speculative traders to profit from differences between day-ahead and real-time prices. The quantity of MW purchased or sold in the day-ahead market is offset by a sale or purchase of an identical quantity of MW in the real-time, so that the net effect on the market quantity traded is zero. A virtual

trader pays (or is paid) the day-ahead price while being paid (or paying) the real-time price.

Although a trader does not have to deliver power, the transaction is not strictly financial as virtual transactions can set LMPs; the price is applied to physical as well as financial transactions. Virtual transactions can also affect the resource selection in the day-ahead market.

For each hour in the day-ahead market, virtual trades are added to the demand – day-ahead scheduled load – if virtual demand is greater than virtual supply. This has the effect of raising the price in the day-ahead market and, more importantly, increasing the amount of generation resources procured by the RTO/ISO. Since these generation resources will be available to the real-time market, the fact that virtual load does not carry forward into the real-time market will decrease the real-time demand below day-ahead scheduled load, thus placing downward pressure on real-time prices. The placement of virtuals affects the dispatch of physical capacity.

The primary benefits of virtual transactions are achieved through their financial impact on the markets. Virtuals sometimes are referred to as convergence bidding, as a competitive virtual market should theoretically cause the day-ahead and real-time prices to converge in each hour. The convergence of day-ahead and real-time prices within the RTOs/ISOs is intended to mitigate market power and improve the efficiency of serving load.

Figure 2-16: New England Independent System Operator



Source: Hitachi Energy, Velocity Suite

ISO-New England (ISO-NE)

MARKET PROFILE

ISO-NE serves the six New England states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. As the RTO for New England, ISO-NE is responsible for operating wholesale power markets that trade electricity, capacity, transmission congestion contracts, and related products, in addition to administering auctions for the sale of capacity.[142] ISO-NE operates the region's high-voltage transmission network and performs long-term planning for the New England system. ISO-NE operates its master control center in Holyoke, Mass.

Peak Demand

New England's all-time peak demand was 28 GW in summer 2006.[143]

Imports and Exports

ISO-NE is interconnected with the NYISO, TransEnergie (Québec), and the New Brunswick System Operator and imports around 15 percent of its annual energy needs. New England receives imports from Québec and New

142 ISO-New England Inc. Internal Market Monitor, *An Overview of New England's Wholesale Electricity Markets, A Market Primer* (June 5, 2023), https://www.iso-ne.com/static-assets/documents/2023/06/imm-markets-primer.pdf.

143 ISO New England, *Key Grid and Market Stats*, https://www.iso-ne.com/about/key-stats/.

Brunswick in most hours, and power flows in alternate directions between New England and New York, depending on market conditions.

Market Participants

The ISO-NE participants consist of end-users, IOUs, publicly owned utilities, generators, transmission owners, and financial institutions.

Membership and Governance

ISO-NE is a not-for-profit entity governed by a 10-member, independent, non-stakeholder board of directors. The sitting members of the board elect people to fill board vacancies.

NEPOOL is the principal stakeholder organization for the ISO-NE and is authorized to represent its more than 440 members in proceedings before FERC. It was organized in 1971 and its members include all the electric utilities rendering or receiving services under the ISO-NE Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers, developers, end users, and a merchant transmission provider.

Transmission Owners

ISO-NE's largest transmission owners include:

- Central Maine Power Company
- Cross Sound Cable Company, LLC
- Emera Maine, Inc.
- Eversource Energy Service Company
- Maine Electric Power Company
- National Grid USA
- NSTAR Electric Company
- The United Illuminating Company
- VT Transco, LLC

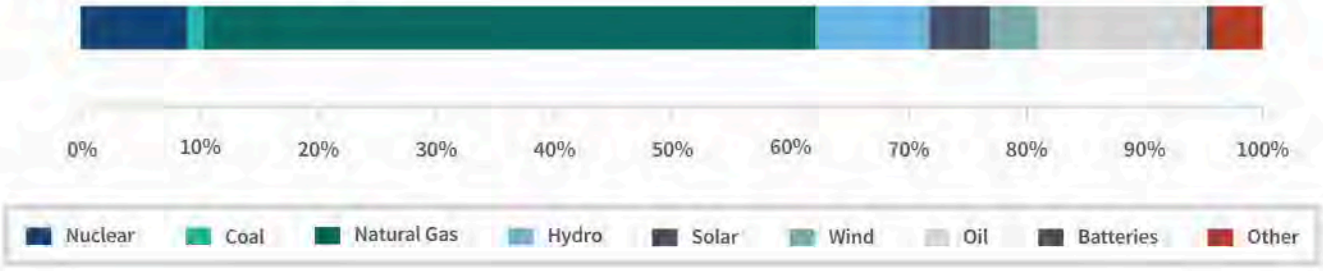
Chronic Constraints

Overall, transmission upgrades have reduced transmission constraints in ISO-NE. Constraints in ISO-NE may occur in regions affected by intermittent resources (notably wind), or by major interconnections with New Brunswick, Hydro-Quebec, and New York.[144]

Transmission Planning

Each year, ISO-NE prepares a comprehensive 10-year regional system plan (RSP) that reports on the results of ISO system planning processes. Each plan includes forecasts of future loads (the demand for electricity measured in megawatts) and addresses how this demand may be satisfied by adding supply resources; demand resources, including demand response and energy efficiency; and new or upgraded transmission facilities. The plans also summarize the region's overall needs, as well as the needs in specific areas, and includes solutions and processes required to ensure the

Figure 2-17: ISO-NE Capacity Mix



Source: EIA Form 860-M[146]

144 ISO-New England Internal Market Monitor, *2021 Annual Markets Report* (May 26, 2022), https://www.iso-ne.com/static-assets/documents/2022/05/2021-annual-markets-report.pdf.

145 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory* (based on Form EIA-860M) (February 2022), https://www.eia.gov/electricity/data/eia860m/.

reliable and economic performance of the New England power system.

Supply Resources

The total capacity in ISO-NE is over 38 GW and is predominately composed of natural gas-fired, oil-fired, and nuclear generators, as shown in the bar chart below. The region has a substantial proportion of oil-fired generation that is a particularly important resource to address potential power plant fuel shortages in the winter months during periods of local natural gas market stress.

Demand Response

ISO-NE administers the following demand-response programs for the New England wholesale electricity market:

- Real-Time Demand Response Resources (RTDR): These resources are required to respond within 30 minutes of the ISO's instructions.
- Real-Time Emergency Generation Resources that the ISO calls on to operate during a 5-percent voltage reduction that requires more than 10 minutes to implement. They must begin operating within 30 minutes of receiving a dispatch instruction.
- Transitional Price-Response Demand: An optional program that allows market participants with assets registered as RTDRs to offer load reductions in response to day-ahead LMP. The participant is paid the day-ahead LMP for the cleared interruptions, and real-time deviations are charged or credited at the real-time LMP.
- Price Responsive Demand (PRD): In June 2018, ISO New England launched a new PRD structure that fully integrates active demand resources into the regional wholesale electricity marketplace. With PRD, ISO-NE deploys its active demand resources as part of the energy dispatch and reserve-designation process along with generating resources. PRD incorporates demand response into the energy market, the reserves market and the capacity market.[146]

MARKET FEATURES

Energy Markets

ISO-NE operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. In the real-time market, ISO-NE uses 5-minute intervals. Market participants can offer imports or request exports of electricity from neighboring control areas with at least one hour's notice throughout the day.

Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. ISO-NE procures and sets prices for ancillary services in the real-time and forward reserve markets.

Market Power Mitigation

In ISO-NE, market power mitigation is applied for physical withholding, economic withholding, uneconomic production, certain types of virtual transactions and other conduct, if the activity has a material effect on prices or uplift payments. The market monitor uses defined thresholds to identify physical and economic withholding and uneconomic generation. Additionally, defined thresholds determine whether bids and offers would, if not mitigated, cause a material effect on LMPs or uplift charges.

Capacity Markets

ISO-NE's capacity market is termed the Forward Capacity Market (FCM). The FCM includes annual Forward Capacity Auctions (FCA) where both generator and demand resources offer capacity three years in advance of the period for which capacity will be supplied. The three-year lead time is intended to encourage new resource entry by affording market participants additional time to plan and make decisions relative to the forward market prices. Resources whose capacity clears the FCA acquire capacity supply obligations (CSOs). ISO-NE held its first two FCAs in 2008 for the 2010-11 and 2011-12 delivery years. The first full year of

146 ISO-NE, *Price-responsive demand explained: Q&A with Henry Yoshimura, ISO Director of Demand Resource Strategy* (June 6, 2018), http://isonewswire.com/updates/2018/6/6/price-responsive-demand-explained-qa-with-henry-yoshimura-is.html.

capacity market commitments began on June 1, 2010. The FCA process includes the modeling of transmission constraints to determine if load zones will be import- or export-constrained.

The FCM includes rules known as Pay-for-Performance, which mandate performance-based financial incentives for capacity resources during times of system stress.[147] Under Pay-For-Performance, resource owners are subject to charges or incentive payments, based on performance during shortage conditions. Those resources unable to fulfill their CSOs are penalized and compensate the overperforming resources that relieve the capacity shortfall. ISO-NE additionally requires the owners of capacity resources to offer into the day-ahead and real-time energy markets.

Special Provisions for Essential Resource Retirements

When a resource owner requests to withdraw from the capacity market (termed a delist bid) or to retire the resource (termed a non-price retirement request), the ISO evaluates whether the resource is needed for reliability, such as when a resource's withdrawal could lead to a violation of a reliability requirement, such as inadequate reserve margins or a loss of electric system stability.

In New England, the resource owner has the option to retire the unit or continue to operate it while the ISO works with regional stakeholders to find alternate supply or engineering solutions that could allow the resource to retire and still maintain grid reliability. Alternative solutions might include obtaining emergency sources of generation or more expensive generation from outside the region. If no other alternative is available, the ISO may compensate the unit through certain payment provisions of the capacity market or by entering into a cost-of-service agreement with the resource owner while other options are pursued.

Financial Transmission Rights

New England FTRs are monthly and annual products that provide market participants with a means to offset or hedge against transmission congestion costs in the day-ahead energy market. An FTR is an instrument that entitles the FTR holder to a payment for costs that arise with transmission congestion over a selected path, or source-and-sink pairs of locations on the grid. The FTR also requires its holder to pay a charge for those hours when congestion occurs in the opposite direction of the selected source-and-sink pair. The RTO holds FTR auctions to allow market participants the opportunity to acquire FTRs or to sell FTRs they currently hold. In New England, ARRs represent the right to receive revenues from the FTR auctions. ISO-NE allocates ARRs to both LSEs, in relation to historical load, and to entities who make transmission upgrades that increase the capability of the transmission system.

Virtual Transactions

New England's market includes a virtual transaction feature, as generally described in the Virtual Transactions part of the RTO/ISO Features section.

Credit Requirements

ISO-NE's tariff includes credit requirements for participants that assist in mitigating the potential effects of defaults that would otherwise be borne among all market participants. ISO-NE assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. ISO-NE then establishes a credit limit for each market participant in accordance with tariff formulas that include various creditworthiness-related specifications, such as tangible net worth and total amounts due to the ISO-NE market.

147 ISO-NE's Pay-For-Performance rules became effective June 1, 2018, for Forward Capacity Auction 9. ISO-NE, Internal Market Monitor, *2017 Annual Markets Report*, at 138 (2018), https://www.iso-ne.com/static-assets/documents/2018/05/2017-annual-markets-report.pdf.

Figure 2-18: New York Independent System Operator



Source: Hitachi Energy, Velocity Suite

New York Independent System Operator (NYISO)

MARKET PROFILE

The NYISO footprint covers the entire state of New York. Prior to restructuring of the electric industry in the 1990s, New York's private utilities and public power authorities owned and operated New York's electric system. Operation of the electric grid was coordinated by a voluntary collaboration of the utilities and power authorities known as the New York Power Pool (NYPP). The creation of the NYISO was authorized by FERC in 1998. The formal transfer of the NYPP's responsibilities to the NYISO took place on Dec. 1, 1999. NYISO operates its system from control centers in Rensselaer, NY, and Guilderland, NY.

NYISO is responsible for operating wholesale power markets that trade electricity, capacity, transmission congestion contracts, and related products, in addition to administering auctions for the sale of capacity. NYISO operates New York's high-voltage transmission network and performs long-term planning. NYISO also serves as the reliability coordinator for its footprint.

Peak Demand

NYISO's all-time peak demand was 34 GW in summer 2013.[148]

Imports and Exports

NYISO imports and exports energy through interconnections with ISO-NE, PJM, TransEnergie (Quebec) and Ontario.

Market Participants

NYISO's market participants include generators, transmission owners, financial institutions, traditional local utilities, electric co-ops, and industrials.

Membership and Governance

NYISO is governed by an independent 10-member board of directors, ISO management, and the business issues and operating committees. Each committee oversees its own set of working groups or subcommittees. These committees comprise transmission owners, generation owners and other suppliers, consumers, public power, and environmental entities. Tariff revisions on market rules and operating procedures filed with FERC are largely developed through consensus by these committees. The members of the board, as well as all employees, must not be directly associated with any market participant or stakeholder.

Transmission Owners

NYISO's largest transmission owners include:

- Central Hudson Gas & Electric Corp.
- Consolidated Edison Co. of New York
- Long Island Power Authority (LIPA)

148 New York Independent System Operator, Gold Book, *2022 Load & Capacity Data Report 67* (April 2022), https://www.nyiso.com/documents/20142/2226333/2022-Gold-Book-Final-Public.pdf/cd2fb218-fd1e-8428-7f19-df3e0cf4df3e.pdf.

Figure 2-19: NYISO Capacity Mix



Source: EIA Form 860-M[150]

- New York Power Authority (NYPA)
- New York State Electric and Gas Corp. (NYSEG)
- National Grid
- Orange & Rockland Utilities
- Rochester Gas and Electric Corp.

Chronic Constraints

The chronic transmission constraints in NYISO are in the southeastern portion of the state, leading into New York City and Long Island. As a result of their dense populations, New York City and Long Island are the largest consumers of electricity. Consequently, energy flows from the west and the north towards these two large markets, frequently requiring transmission facilities to operate near their limits. This results in transmission constraints in several key areas, often resulting in higher prices in the New York City and Long Island markets.

Transmission Planning

NYISO conducts a biennial transmission planning process with stakeholders that includes both short-term and long-term projects as part of its Comprehensive System Planning Process. This work evaluates the adequacy and security of the bulk power system in New York over a ten-year study period. Reliability needs are addressed through the development of a reliability plan. Planning focuses on congestion on the bulk power system and possible projects to alleviate the congestion.

A component of NYISO's transmission planning includes evaluating proposals to meet transmission needs driven by public policy requirements identified by the New York Public Service Commission.

Supply Resources

The total capacity in NYISO is over 43 GW and is predominately composed of natural gas-fired, hydroelectric, nuclear and oil-fired generators, as shown in the bar chart below. The region's hydroelectric capacity is particularly important and includes the Niagara Falls and St. Lawrence facilities.

Demand Response

NYISO has four demand-response programs: the emergency demand-response program (EDRP), the installed capacity (ICAP) special case resources program (SCR), the Day-Ahead Demand-Response Program (DADRP) and the Demand-Side Ancillary Services Program (DSASP).

Both the emergency and special case programs can be deployed in energy shortage situations to maintain the reliability of the bulk power grid. The participants in these programs are paid by NYISO for reducing energy consumption when asked to do so and reductions are voluntary for EDRP participants.However, SCR participants are required to reduce power usage as part of their agreement and are compensated for this obligation.

149 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (February 2022), https://www.eia.gov/electricity/data/eia860m/.

NYISO's DADRP program allows energy users to bid their load reductions into the day-ahead market and offers that are determined to be economic are paid the market clearing price. Under day-ahead demand-response, flexible loads may effectively increase the amount of supply in the market and moderate prices.

The DSASP provides retail customers that can meet telemetry and other qualifications with the ability to bid their load curtailment capability into either the day-ahead market or real-time market to provide reserves and regulation service. Accepted offers are paid the market clearing price for the supplied reserves or regulation services.

MARKET FEATURES

Energy Markets

NYISO operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. In the real-time market, NYISO uses 5-minute intervals. Market participants can offer imports or request exports of electricity from neighboring control areas with at least one hour's notice throughout the day. NYISO refers to LMPs as locational-based marginal prices, or LBMPs.

NYISO's real-time market also offers an hour-ahead feature. The hour-ahead market allows buyers and sellers of electricity to balance unexpected increases or decreases of electricity consumption after the day-ahead market closes. Bids and offers are submitted an hour ahead of time and prices are set based on those bids and offers, generally for use in matching generation and load requirements, but those prices are advisory only. Hour-ahead scheduling is completed at least 45 minutes prior to the beginning of the dispatch hour after NYISO reviews transmission outages, the load forecast, reserve requirements and hour-ahead generation and firm transaction bids, among other things.

Ancillary and Other Services

NYISO co-optimizes ancillary services with the energy through its markets. Operating reserves and regulation are typically provided by generators, but NYISO also allows demand-side providers to participate in these markets.

Ancillary services are those functions performed by electric generating, transmission and system-control equipment to support the transmission of electric power from generating resources to load. RTOs procure or direct the supply of ancillary services to maintain the reliability of the transmission system.

Market Power Mitigation

ISO-NE conducts automatic market power mitigation in its day-ahead and real-time markets. This automated mitigation performs conduct and impact tests and applies mitigation where it deems appropriate. The categories of conduct that may warrant mitigation by NYISO include physical withholding, economic withholding, and uneconomic production by a generator or transmission facility to obtain benefits from a transmission constraint. NYISO does not impose mitigation unless the conduct causes or contributes to a material change in prices, or substantially increases guarantee payments to participants.

Generators in New York City are subject to automated market power mitigation procedures because New York City is frequently separated by transmission congestion from other parts of New York. Additionally, generators in New York City have been deemed to have market power. These automated procedures determine whether any day-ahead or real-time energy bids, including start-up cost bids and minimum generation bids, but excluding ancillary services bids, exceed the tariff's thresholds for economic withholding. The protocols also determine whether such bids would cause material price effects or changes in guaranteed payments. If these two tests are met, mitigation is imposed automatically, and the applicable reference level is substituted for the entity's actual bid to determine the clearing price.

Capacity Markets

NYISO's capacity market requires LSEs to procure capacity through installed-capacity (ICAP) auctions, self-supply or bilateral arrangements based on their forecasted peak

load plus a margin. New York has capacity requirements for four zones: New York City, Long Island, Lower Hudson Valley, and New York-Rest of State. NYISO conducts auctions for three time periods: the capability period auction (covering six months), the monthly auction and the spot market auction. The resource requirements do not change in the monthly auctions and spot market auctions relative to the capability period auction. The shorter monthly auctions are designed to account for incremental changes in LSEs' load forecasts.

Under the NYISO capacity auction rules, entities that offer capacity into an auction that is subsequently purchased by load are required to offer that amount of capacity into the day-ahead energy market. This rule ensures that capacity sold through the capacity auctions is actually delivered into the market.

Capacity for New York City is subject to offer caps and floors. Offer caps in New York City are based on the projected clearing price for capacity in the spot market.[150] Capacity from generators within New York City must be offered in each ICAP spot market auction, unless that capacity has been exported out of New York or sold to meet ICAP requirements outside New York City.[151]

Special Provisions for Essential Resource Retirements

Generation owners within New York that seek to retire or suspend a generator must first obtain approval from state regulators. After an assessment, if the generator is found to be necessary for reliability purposes, the local transmission owner can be compelled to reach a contract with the generator that includes compensation to support continued operation of the plant until the reliability need is resolved.

Financial Transmission Rights

The NYISO refers to FTRs as Transmission Congestion Contracts (TCCs). A TCC is an instrument that entitles the holder to a payment for the costs that arise with transmission congestion over a selected path, or source-and-sink pair of locations (or nodes) on the grid. The TCC also requires its holder to pay a charge for those hours when congestion is in the opposite direction of the selected source-and-sink pair. The payment, or charges, are calculated relative to the difference in congestion prices in the day-ahead market across the specified FTR transmission path.

Virtual Transactions

NYISO's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. Virtual trading in NYISO takes place on a zonal level, not a nodal level.

Credit Requirements

NYISO's tariff includes credit requirements that assist in mitigating the effects of defaults that would otherwise be borne among all market participants. NYISO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions. NYISO must review the entity's request relative to various creditworthiness-related specifications such as investment grade or equivalency rating and payment history.

150 New York Independent System Operator, Inc., NYISO *MST - Market Administration and Control Area Services Tariff (MST) - 23MST Att H - ISO Market Power Mitigation Measures - 23.2 MST Att H Conduct Warranting Mitigation at 625* (accessed October 6, 2022), https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf; New York Independent System Operator, Inc., *NYISO MST - Market Administration and Control Area Services Tariff (MST) - 23 MST Att H - ISO Market Power Mitigation Measures - 23.4.5 MST Att Installed Capacity Market Mitigation Measures - 23.4.5.2 MST Att H at 705* (accessed October 6, 2022), https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf.

151 New York Independent System Operator, Inc., *NYISO MST - Market Administration and Control Area Services Tariff (MST) - 23 MST Att H - ISO Market Power Mitigation Measures - 23.4.5 MST Att Installed Capacity Market Mitigation Measures - 23.4.5.4 MST Att H* at 708 (accessed October 6, 2022), https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOMST.pdf.

PJM

MARKET PROFILE

PJM centrally dispatches generation and coordinates the movement of wholesale electricity in all or part of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia) and the District of Columbia. PJM operates two fully functional dispatch centers at Valley Forge and Milford, Pennsylvania. The control rooms operate simultaneously with parallel operations. PJM operates a competitive wholesale electricity market and manages the reliability of its transmission grid. PJM provides open access to the transmission system it manages and performs long-term planning. PJM's markets include energy (day-ahead and real-time), capacity and ancillary services.

PJM was founded in 1927 as a power pool of three utilities serving customers in Pennsylvania and New Jersey. In 1956, with the addition of two Maryland utilities, it became the Pennsylvania-New Jersey-Maryland Interconnection, or PJM. PJM became a fully functioning ISO in 1996 and, in 1997, it introduced markets with bid-based pricing and locational market pricing. PJM was designated an RTO in 2001.

Peak Demand

PJM's all-time peak demand was 165.6 GW in summer 2006.[152]

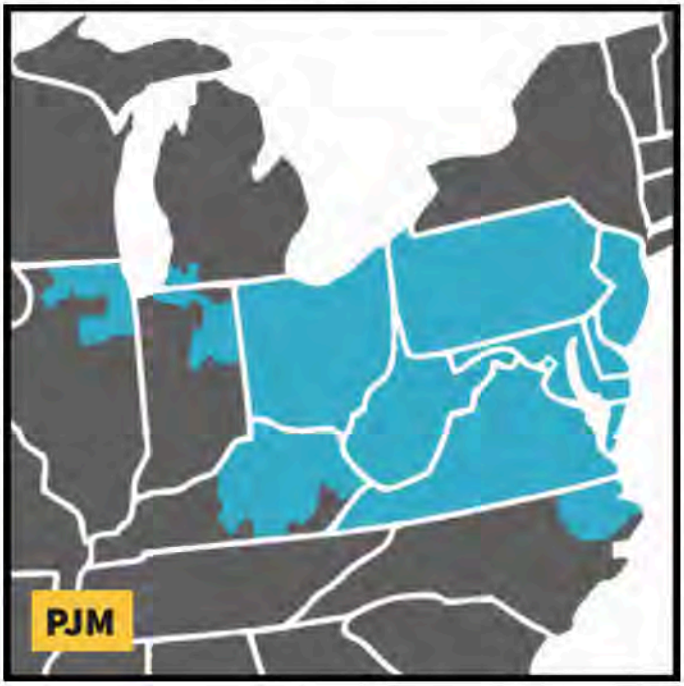
Imports and Exports

PJM has interconnections with MISO and the NYISO. PJM also has direct interconnections with TVA, Progress Energy Carolinas and the VACAR, among other systems. PJM market participants import energy from, and export energy to, external regions continuously. PJM is a primarily a net exporter of electricity, but occasionally is a net importer during periods of system stress.

Market Participants

PJM's market participants include power generators, transmission owners, electric distributors, power marketers, large consumers, and financial traders.

Figure 2-20: The PJM Interconnection



Source: Hitachi Energy, Velocity Suite

Membership and Governance

PJM has a two-tiered governance model consisting of a board of managers and the members committee. PJM is governed by a 10-member board, nine of whom PJM members elect. The board appoints the tenth, the president and CEO, to supervise day-to-day operations. The board is generally responsible for oversight of system reliability, operating efficiency and short- and long-term planning. The board ensures that no member or group of members exerts undue influence. The members committee, which advises the board, is composed of five voting sectors representing power generators, transmission owners, electric distributors, power marketers and large consumers.

Transmission Owners

PJM transmission owners eligible to vote in PJM

152 PJM Interconnection, PJM 2021 *Annual Report, Summer Performance by the Numbers*, https://services.pjm.com/annualreport2021/operations/.

stakeholder proceedings include:

- Appalachian Power Company, AEP Subsidiary[153]
- AMP Transmission, LLC
- Dayton Power & Light Company, AES Subsidiary
- Duke Energy Business Services, LLC[154]
- Duquesne Light Company
- East Kentucky Power Cooperative, Inc.
- Exelon Business Services Company, LLC[155]
- ITC Interconnection LLC
- Linden VFT LLC
- Monongahela Power d/b/a Allegheny Power, First Energy Subsidiary [156]
- Neptune Regional Transmission System, LLC[157]
- PPL Electric Utilities Corporation, d/b/a PPL Utilities[158]
- Public Service Electric and Gas Company
- Rockland Electric Company
- Virginia Electric and Power Company

Chronic Constraints

The most severe constraints occur on 230 kV transmission facilities moving power south from Pennsylvania and New Jersey to Maryland, Delaware, and Virginia. Local congestion also occurs on low-voltage lines near load centers in northern Illinois, New Jersey, eastern Pennsylvania, central and eastern Maryland, northern Virginia, the District of Columbia, and Delaware.

Transmission Planning

PJM's Regional Transmission Expansion Plan identifies transmission system additions and improvements needed to keep electricity flowing within PJM. Studies are conducted to test the transmission system against national and regional reliability standards. These studies look forward to identify future transmission overloads, voltage limitations, and other reliability standards violations. PJM then develops transmission plans to resolve violations that could otherwise lead to overloads and blackouts.

Supply Resources

The total capacity in PJM is over 219 GW and is predominately comprised of natural gas, coal, and nuclear generators, as shown in the bar chart below. Much of PJM's gas-fired capacity is located near the Marcellus and Utica shale formations. Of note, 40.6 gigawatts of coal-fired capacity are projected to retire in PJM between 2011 and 2026.[159]

Demand Response

End-use customers providing demand response have the opportunity to participate in PJM's energy, capacity, synchronized reserve, and regulation markets. PJM's demand response programs can be grouped into emergency or economic programs. The emergency program compensates end-use customers who reduce their usage during emergency conditions on the PJM system. Participation in the emergency program may be voluntary or mandatory and payments may include energy payments, capacity payments or both.

The economic program allows end-use customers to reduce electricity consumption in the energy markets and receive a payment when LMPs are high. Under this program, all hours are eligible and all participation is voluntary. Participation in the program takes three forms: submitting an offer into the day-ahead market

153 Transmission Companies represented: AEP Appalachian Transmission, AEP Energy Partners, AEP Energy, AEP Indiana Michigan Transmission, AEP Kentucky Transmission, AEP Ohio Transmission, AEP West Virginia Transmission, Appalachian Power, Indiana Michigan Power, Kentucky Power, Kingsport Power, Ohio Power, Ohio Valley Electric, PATH West Virginia Transmission, Transource Energy, Wheeling Power.

154 Transmission Companies represented: Duke Energy Kentucky, Duke Energy Ohio.

155 Transmission Companies represented: Commonwealth Edison, PECO Energy, Baltimore Gas and Electric.

156 Transmission Companies represented: American Transmission Systems, Jersey Central Power & Light, Mid-Atlantic Interstate Transmission, PATH Allegheny Transmission, Potomac Edison, Trans-Allegheny Interstate Line, West Penn Power.

157 Transmission Companies represented: Hudson Transmission Partners.

158 Transmission companies represented: Louisville Gas and Electric, Kentucky Utilities.

159 Monitoring Analytics, *2022 Quarterly State of the Market Report, January Through June*, Section 12, p. 673 (https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022q2-som-pjm-sec12.pdf).

Figure 2-21: PJM Capacity Mix



Source: EIA Form 860-M[161]

that clears; submitting an offer into the real-time market that is dispatched; and self-scheduling load reductions while providing notification to PJM. End-use customers participate in demand response in PJM through members called curtailment service providers who act as agents for the customers. Curtailment service providers aggregate the demand of retail customers, register that demand with PJM, submit the verification of demand reductions for payment by PJM and receive the payment from PJM.

MARKET FEATURES

Energy Markets

Energy Markets: PJM operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. In the real-time market, PJM uses 5-minute intervals. Generators that are available but not selected in the day-ahead scheduling may alter their offers for use in the real-time market during the generation rebidding period from 4 p.m. to 6 p.m.; otherwise, their original day-ahead market offers remain in effect for the real-time market.

Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. PJM procures most ancillary services via its energy markets. Blackstart service and reactive power are compensated on a cost-of-service basis.

Market Power Mitigation

PJM caps offers for any hour in which there are three or fewer generation suppliers available for redispatch that are jointly pivotal, meaning they have the ability to increase the market price above the competitive level. This is called the Three Pivotal Supplier Test. When this occurs, generator offers are adjusted to price levels reflecting short-run marginal cost.

Capacity Markets

PJM's capacity market is called the Reliability Pricing Model (RPM). The RPM market was implemented in 2007 and is designed to ensure the future availability of capacity resources, including demand-resources and energy-efficiency resources that will be needed to keep the regional power grid operating reliably. The RPM market design is based on three-year, forward-looking annual obligations for locational capacity, under which supply offers are cleared against a downward-sloping demand curve, called the variable resource requirement (VRR) curve. The VRR curve establishes the amount of capacity that PJM requires its LSE customers to purchase, and the price for that capacity, in each capacity zone (locational deliverability area or LDA). Under RPM, when an LDA is transmission-constrained in the auction (limited in the amount of generation that can be imported into those areas), capacity prices generally rise in that area relative to the overall PJM footprint.

160 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (released February 2022), https://www.eia.gov/electricity/data/eia860m/.

Annual auctions are referred to as Base Residual Auctions (BRA). LSEs that are able to fully supply their own capacity needs can choose not to participate in the auctions. The largest amounts of capacity in PJM are procured through the BRA, with lesser quantities procured through self-supply and contracted (bilateral) resources.

Market power mitigation in PJM's capacity market includes rules delineating a must-offer requirement, offer caps, minimum offer prices, exceptions for competitive entry, among others. Demand resources and energy efficiency resources may be offered into RPM auctions and receive the clearing price without mitigation.

Specific RPM rules, termed Capacity Performance, provide performance incentives for power plants, demand response, and energy efficiency resources to provide electricity at peak demand regardless of extreme weather events and system emergencies. Capacity Performance rules provide performance bonus payments for resources that over-perform during system emergencies, and severe financial penalties for resources that do not perform during such events.

Existing generation that qualifies as a capacity resource must be offered into RPM auctions, except for resources owned by entities that elect the fixed resource requirement option. The fixed resource option allows LSEs to meet their supply obligation outside PJM's capacity market, using, for example, resources they own.[161] Intermittent and capacity storage resources, including hydro, and demand response and energy efficiency, are also exempt from must-offer requirements. An administratively determined demand curve defines scarcity pricing levels and, with the supply curve derived from capacity offers, determines market prices in each BRA. Participation by load-serving entities is mandatory, except for those entities that elect the fixed resource requirement option. Also, any generator that has a commitment from the capacity market must submit an offer into the day-ahead energy market.

Special Provisions for Essential Resource Retirements

A generator owner who wishes to retire a unit must request permission from PJM to deactivate the unit at least 90 days in advance of the planned date. The request includes an estimate of the amount of project investment necessary to keep the unit in operation. PJM, in turn, analyzes if the retirement would lead to a reliability issue. Additionally, PJM estimates the period of time it would take to complete transmission upgrades necessary to alleviate the reliability issue.

If PJM requests the unit to operate past the desired deactivation date, the generator owner may file with FERC for cost recovery associated with operating the unit until it may be deactivated. Alternatively, the owner may choose to receive avoided cost compensation calculated according to PJM's tariff.

Financial Transmission Rights

PJM conducts auctions for selling and buying FTRs made available for the PJM transmission system. Proceeds from the auctions are paid to Auction Revenue Right (ARR) holders, where the ARRs are allocated to firm transmission service customers. PJM conducts its auctions on a long-term, annual, and monthly basis. In PJM, market participants are able to acquire financial transmission rights in the form of options or obligations. The RTO includes a secondary market for its FTRs, which facilitates bilateral trading of existing FTRs between PJM members through an internet-based computer application.

Virtual Transactions

PJM's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. In addition to the types of transaction discussed above, PJM offers Up to Congestion (UTC) transactions, a spread bid. In a UTC transaction, a market participant submits an offer to simultaneously inject energy at a specified source and withdraw the same megawatt

161 PJM, *Securing Fixed Resources*, (accessed December 2, 2022), https://pjm.com/-/media/about-pjm/newsroom/fact-sheets/securing-resources-through-fixed-resource-requirement-fact-sheet.ashx.

quantity at a specified sink in the day-ahead marketand specifies the maximum difference in locational marginal prices (LMP) at the transaction's source and sink that the market participant is willing to pay. PJM accepts the bid if the day-ahead LMP differential, i.e., the difference in day-ahead LMPs at the sink and the source, does not exceed the participant's UTC transaction bid. UTC positions are liquidated in the real-time energy market.

Credit Requirements

PJM's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. The RTO assesses and calculates the required credit amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions. The RTO must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth and credit scores.

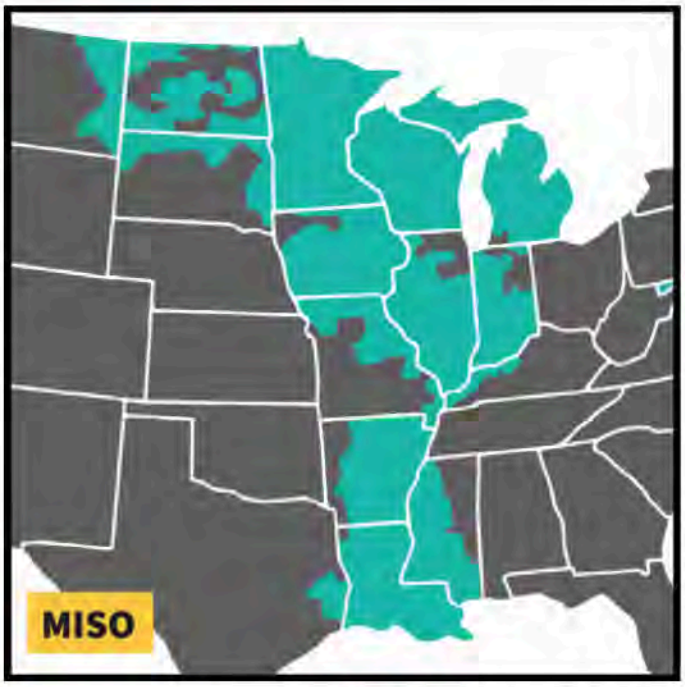
Midcontinent Independent System Operator (MISO)

MARKET PROFILE

MISO operates the transmission system and a centrally dispatched market in portions of 15 states in the Midwest and the South, extending from Michigan and Indiana to Montana and from the Canadian border to the southern areas of Louisiana and Mississippi. The system is operated from three control centers: Carmel, Indiana; Eagan, Minnesota; and Little Rock, Arkansas. MISO also serves as the reliability coordinator for additional systems outsideof its market area, primarily to the north and northwest of the market footprint.

MISO was not a power pool before organizing as an ISO in December 2001. It began market operations in April 2005.

Figure 2-22: Midcontinent Independent System Operator



Source: Hitachi Energy, Velocity Suite

In January 2009, MISO implemented a market redesign that added auctioned and optimized ancillary services along with energy. As part of the market update, MISO combined its 24 separate balancing areas into a single balancing area. In 2013, the RTO began operations in the MISO South region, including the utility footprints of Entergy, Cleco, and South Mississippi Electric Power Association, among others, in parts of Arkansas, Mississippi, Louisiana, and Texas.

Peak Demand

MISO's all-time peak demand was 127 GW in summer 2011.[162]

Imports and Exports

MISO has interconnections with the PJM and SPP RTOs. It is also directly connected to Southern Company, TVA, the electric systems of Manitoba and Ontario, and several smaller systems. MISO is a net importer of power overall, but the interchange with some areas can flow

162 MISO, Corporate Fact Sheet, at 1 (June 2022), https://www.misoenergy.org/about/media-center/corporate-fact-sheet.

in either direction, depending on the relative loads and prices in the adjoining regions. Manitoba Hydro supplies a large part of MISO's load with its excess capacity, particularly in the summer.

Market Participants

MISO includes approximately 56 transmission owners, whose assets define the MISO market area. MISO's market participants include generators, power marketers, transmission-dependent utilities and load-serving entities.[163]

Membership and Governance

An independent board of directors of ten members, including the CEO, governs MISO. Directors are elected by the MISO membership from candidates provided by the board.[164]

MISO relies upon a stakeholder process that works to find collaborative solutions to problems faced by the RTO. These entities have an interest in MISO's peration and include state regulators, consumer advocates, transmission owners, independent power producers, power marketers and brokers, municipal and cooperative utilities and large-volume customers.

Transmission Owners

MISO's largest transmission owners include:

- American Transmission Co.
- Ameren (Missouri and Illinois)
- American Transmission Systems
- Duke
- Cleco
- Entergy
- Indianapolis Power and Light
- ITC
- Michigan Public Power Agency
- NSP Companies (Xcel)
- Northern Indiana Public Service Co.
- Otter Tail Power
- MidAmerican Energy

Chronic Constraints

MISO has certain pathways that are more likely to become congested, but the likelihood and pattern of congestion in any area is subject to weather patterns, wind production, and interchange with external regions. When load is high in the eastern part of MISO and to the east in PJM, constraints occur on pathways from the Minnesota and Wisconsin areas through Chicago and across Indiana. A particular congestion point with this pattern is northern Indiana. When colder weather occurs in Minnesota and the Dakotas, there is often congestion in the northern direction, particularly in Iowa. Higher wind production can cause localized constraints in some areas and can cause congestion in pathways from southern Minnesota and western Iowa moving eastward. New Orleans and East Texas are two constrained areas in MISO South. Additionally, constraints frequently arise between MISO Midwest and MISO South.

Transmission Planning

The main vehicle MISO uses for transmission planning is the MISO Transmission Expansion Plan developed by the MISO planning department in collaboration with transmission owners and other stakeholders who form the planning advisory committee. The plan is updated annually. Once approved by the board, the plan becomes the responsibility of the transmission owners.

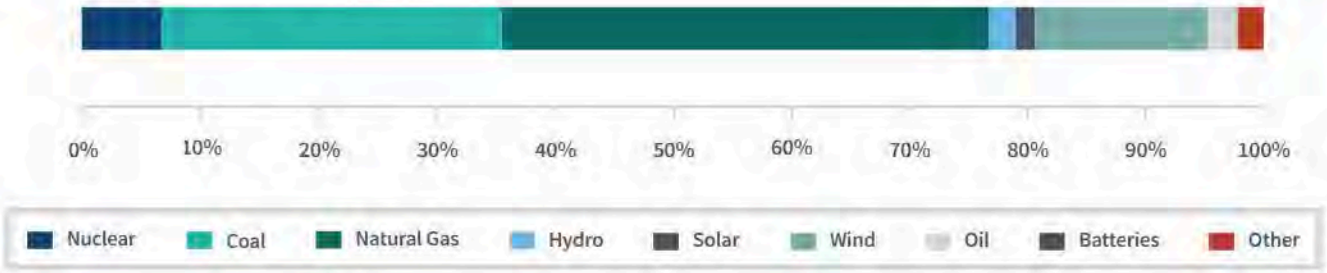
Supply Resources

The total capacity in MISO is over 197 GW and is predominately composed of coal and natural gas-fired generators, providing roughly 70 percent of the total capacity combined, as shown in the bar chart below. Nuclear and wind are also important resources for the region.

163 *Id.*

164 MISO, *Principals of Corporate Governance*, at 3, https://cdn.misoenergy.org/Principles%20of%20Corporate%20Governance110859.pdf.

Figure 2-23: MISO Capacity Mix



Source: EIA Form 860-M[165]

Demand Response

MISO has more than 12.2 GW of demand response resources, including behind-the-meter generation. A number of these resources are operated through local utility programs and are not under the direct control of MISO. MISO has provisions allowing demand-side resources to participate in the energy and reserve markets, but participation is a small part of demand response. Some of the demand response under MISO's direct control is only available under emergency conditions.[166]

MARKET FEATURES

Energy Markets

MISO operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. MISO's real-time market operates for 5-minutes intervals.

Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. MISO procures ancillary services via the co-optimized energy and ancillary services market.

In addition to ancillary services, MISO has implemented a ramping product that provides capacity that can increase output rapidly to help offset shifts in generation or load, known as the Ramp Capability Product (RCP).

Market Power Mitigation

When congestion occurs, there may be limits on the number of generators that can satisfy load in some areas, so that they may be able to exercise market power. In response, MISO may impose mitigation for those generators whose offers are significantly higher than their costs and have a significant impact on one or more LMPs. When these conditions are met, MISO reduces the generator's offer to an offer that is consistent with a competitive result.

Capacity Markets

MISO maintains an annual capacity requirement on all LSEs based on the load forecast plus reserves. LSEs are required to specify to MISO what physical capacity, including demand-side resources, they have designated to meet their load forecast. This capacity can be acquired either through an annual capacity auction, bilateral purchase, or self-supply. For the capacity market, MISO is divided into 10 zones whose forecast demand must be met by internal generation, demand-side resources, or deliverable external capacity.

165 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (released February 2022), https://www.eia.gov/electricity/data/eia860m/.

166 Potomac Economics, *2021 State of the Market Report for the MISO Electricity Markets,* at 100 (June 2022), https://www.potomaceconomics.com/wp-content/uploads/2022/06/2021-MISO-SOM_Report_Body_Final.pdf.

Resources used to meet LSEs' annual capacity requirements must offer that capacity into MISO's energy markets and, when qualified, into the ancillary services markets, for each hour of each day for the entire planning year. Must-offer requirements support MISO's mitigation process by providing an objective measure with which to identify physical withholding.

Special Provisions for Essential Resource Retirements

Power plant owners that seek to retire or suspend a generator must first obtain approval from MISO. The RTO evaluates plant retirement or suspension requests against reliability needs, and System Support Resource (SSR) designations are made where reliability is threatened. Once an agreement has been reached, SSRs receive compensation associated with remaining online and available.

Financial Transmission Rights

MISO holds FTR auctions to allow market participants the opportunity to acquire FTRs, sell FTRs that they currently hold, or to convert ARRs to FTRs. ARRs provide LSEs, and entities who make transmission upgrades, with a share of the revenues generated in the FTR auctions. MISO allocates ARRs to transmission customers relative to historical usage, or upgraded capability, of the transmission system. MISO FTRs are monthly and annual products.

Virtual Transactions

MISO's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. Virtual transactions allow for more participation in the day-ahead, price-setting process, allow participants to manage risk, and promote price convergence between the day-ahead and real-time markets.

These transactions are a component of the day-ahead market where the bids and offers are included in the determination of the LMP along with physical resource offers and actual load bids. Market participants, whose virtual transactions clear in the day-ahead market, have their positions cleared in the real-time market at the real-time price. Virtual bids and offers are allowed in MISO at any pricing node or aggregate of pricing nodes.

Credit Requirements

MISO's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. The RTO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions. The RTO must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth and credit scores.

Southwest Power Pool (SPP)

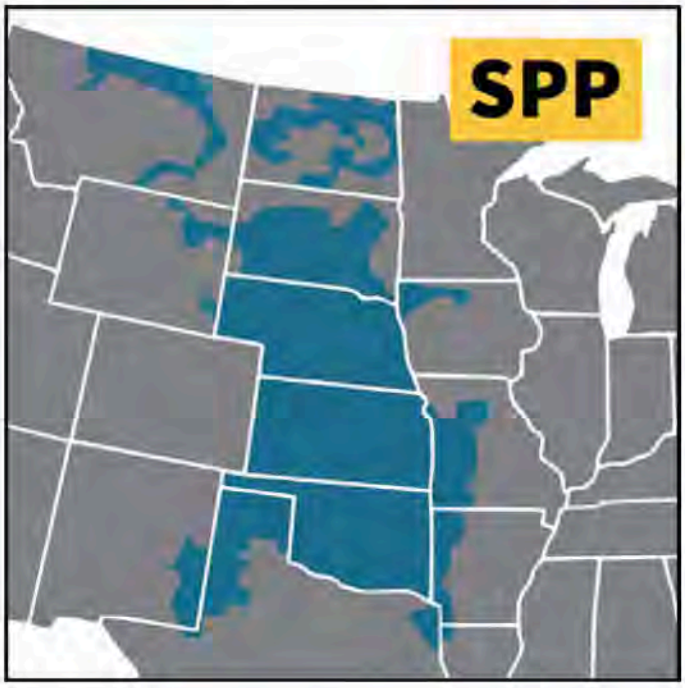
MARKET PROFILE

SPP's RTO manages transmission in fourteen states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. Founded as an 11-member tight power pool in 1941, SPP achieved RTO status in 2004, ensuring reliable power supplies, adequate transmission infrastructure, and competitive wholesale electricity prices for its members. SPP operates through its control center in Little Rock, Ar.

SPP began operating its real-time Energy Imbalance Service (EIS) market in 2007. In the same year, SPP became a FERC-approved Regional Entity. The SPP Regional Entity serves as the reliability coordinator for the NERC region, overseeing compliance with reliability standards.

SPP implemented its Integrated Marketplace in March 2014 which includes a day-ahead energy market, a real-time energy market, and an operating reserve market. SPP's Integrated Marketplace also includes a market for Transmission Congestion Rights. The SPP Integrated Marketplace co-optimizes the deployment of energy and operating reserves to dispatch resources on a least-cost basis.

Figure 2-24: Southwest Power Pool



Source: Hitachi Energy, Velocity Suite

SPP expanded its footprint in 2015, incorporating the Western Area Power Administration – Upper Great Plains region, the Basin Electric Power Cooperative, and the Heartland Consumers Power District. The expansion nearly doubled SPP's service territory by square miles, adding more the 5 GW of peak demand and over 7 GW of generating capacity.[167]

SPP also operates a real-time energy imbalance market in the Western Interconnect, which is described further below.

Peak Demand

SPP's all-time peak demand of 53 GW occurred in summer 2022.[168]

Imports and Exports

SPP has interties with MISO, TVA, and other systems. Additionally, SPP has two DC interties with ERCOT and seven DC interties to the Western Interconnection through New Mexico, Colorado, Nebraska, South Dakota and Montana. At times, SPP is both a net importer and net exporter of electricity at times.

Market Participants

SPP's market participants include investor-owned utilities, generation and transmission cooperatives, independent power producers, municipal utilities, state authorities, independent transmission companies, power marketers, financial participants, and a federal power marketing administration.

Membership and Governance

SPP is governed by a board of directors representing and elected by its members. Supporting the board is the members committee, which provides non-binding input. The members' committee is composed of representatives from each sector of SPP's membership. The SPP Regional State Committee represents retail regulatory commissions from state agencies and provides input on matters of regional importance related to the development and operation of bulk electric transmission.

Transmission Owners

SPP's largest transmission owners include:

- American Electric Power
- Oklahoma Gas and Electric
- Westar Energy
- Southwestern Public Service (Xcel Energy)
- Great Plains Energy
- Kansas City Power & Light
- Omaha Public Power District
- Nebraska Public Power District
- Tri-State Generation and Transmission
- Empire District Electric
- Western Area Power Administration – Upper Great Plains
- Western Farmers Electric Cooperative

167 Southwest Power Pool, *Western, Basin, Heartland join Southwest Power Pool,* at 1 (October 2015), https://www.spp.org/about-us/newsroom/western-basin-heartland-join-southwest-power-pool/.

168 Southwest Power Pool, *Fast Facts*, https://www.spp.org/about-us/fast-facts/.

Chronic Constraints

SPP has certain pathways that are more likely to become congested, based on the physical characteristics of the transmission grid and associated transfer capability, the geographic distribution of load, and the geographic differences in fuel costs. The eastern side of the SPP footprint has a higher concentration of load and congestion can occur when wind-powered generation from the west tries to travel across limited connections to the east. The most significant congestion has typically occurred in the Oklahoma and Texas Panhandle region.[169]

Transmission Planning

SPP conducts its transmission planning according to its Integrated Transmission Planning process,which is a three-year planning process that includes 20-year, 10-year, and near-term assessments designed to identify transmission solutions that address both near-term and long-term transmission needs. The Integrated Transmission Planning process focuses on identifying cost-effective regional transmission solutions, which are identified in an annual SPP Transmission Expansion Plan report.

Supply Resources

The total capacity in SPP is approximately 94 GW and is predominately composed of natural gas and coal-fired generators, as shown in the bar chart below. Wind is an important and growing resource in the region.

Demand Response

SPP allows demand response resources to register in its market.[170] As of December 31, 2021, 102 demand resources participated in SPP's markets, representing 176 MW of nameplate capacity. While the demand response resources can participate in SPP's markets, they are rarely dispatched.

SPP allows Market Participants to register two types of demand response resources: Block Demand Response (BDR) resources and Dispatchable Demand Response (DDR) resources. BDR resources can participate in SPP's markets by providing energy and reserves in 60-minute blocks. DDR resources can participate in SPP's markets by providing energy, regulation, and reserves in 5-minute blocks.

MARKET FEATURES

Energy Markets

SPP operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. SPP's real-time market operates in 5-minute intervals.

Figure 2-25: SPP Capacity Resources



Source: EIA Form 860-M[171]

169 See Southwest Power Pool Market Monitoring Unit, *State of the Market 2022* (May 2022), at 202, https://www.spp.org/documents/67104/2021%20annual%20state%20of%20the%20market%20report.pdf.

170 SPP Market Monitor, State of the Market 2021 (May 10, 2021), at 49, https://www.spp.org/documents/67104/2021%20annual%20state%20of%20the%20market%20report.pdf.

171 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (released February 2022), https://www.eia.gov/electricity/data/eia860m/.

Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. SPP procures ancillary services via the co-optimized energy and ancillary services market. Separately, SPP has a ramping product to procure capacity that can quickly increase output to offset both anticipated and unforeseen future changes in generation or load within the hour, known as the Ramp Capability Product. SPP launched this ramp product in March 2022.

Market Power Mitigation

SPP applies a set of behavioral and market outcomes tests to determine if the local market is competitive and if generator offers should be adjusted to approximate short-run marginal costs. SPP's mitigation test includes a local market power test, a conduct test, and a market impact test. Where mitigation measures are triggered by the tests, SPP generates a mitigated resource offer that the RTO then uses for dispatch, commitment, and settlement purposes.

Capacity Markets

SPP does not offer a capacity market. However, it requires each Load Responsible Entity (LRE) to have sufficient energy supply (capacity) to cover its energy obligations. SPP develops and implements policies and processes necessary to ensure resource adequacy and determines the amount of capacity each LRE must have available to meet its energy obligations. [172]

Special Provisions for Essential Resource Retirements

A generator owner who wishes to retire a unit must request that SPP study the retirement of the resource no less than one year from the expected retirement date. SPP will then conduct studies to examine the potential effects of the resource retirement including the need for transmission network upgrades, if any.

Otherwise, SPP prepares annual reliability studies as part of its system planning responsibilities. In the event that the studies reveal a potential constraint on SPP's ability to deliver power to a local area on the transmission system, SPP works with regional stakeholders to find alternate transmission, operating procedure, or generation solutions for the constraint and thus maintain grid reliability. The SPP parties then determine an appropriate sharing of the costs, and, if unable to reach agreement, SPP will submit a proposed cost-sharing arrangement to FERC for approval.

Financial Transmission Rights

SPP refers to FTRs as Transmission Congestion Rights (TCR). A TCR is an instrument that entitles the holder to receive compensation, or requires the holder to pay a charge, for costs that arise from transmission congestion over a selected path, or source-and-sink pair of locations on the grid. A TCR provides the holder with revenue, or charges, equal to the difference in congestion prices in the day-ahead market across the selected TCR transmission path. SPP TCRs include monthly and annual products, as well as a long-term instrument called Long-Term Congestion Rights.

A related product, ARRs, provide their holders with a share of the revenue generated in the TCR auctions. In general, ARRs are allocated based on firm transmission rights. As with TCRs, ARRs provide transmission owners and eligible transmission service customers an offset or hedge against transmission congestion costs in the day-ahead market.

Virtual Transactions

SPP's market includes a virtual transaction feature that allows a participant to buy or sell power in the day-ahead market without requiring physical generation or load. In SPP, virtual bids are sometimes used in the day-ahead market as a placeholder or hedge for wind generation expected in the real-time market.

Credit Requirements

SPP's tariff includes credit requirements that a market participant needs to meet in order to participate in the

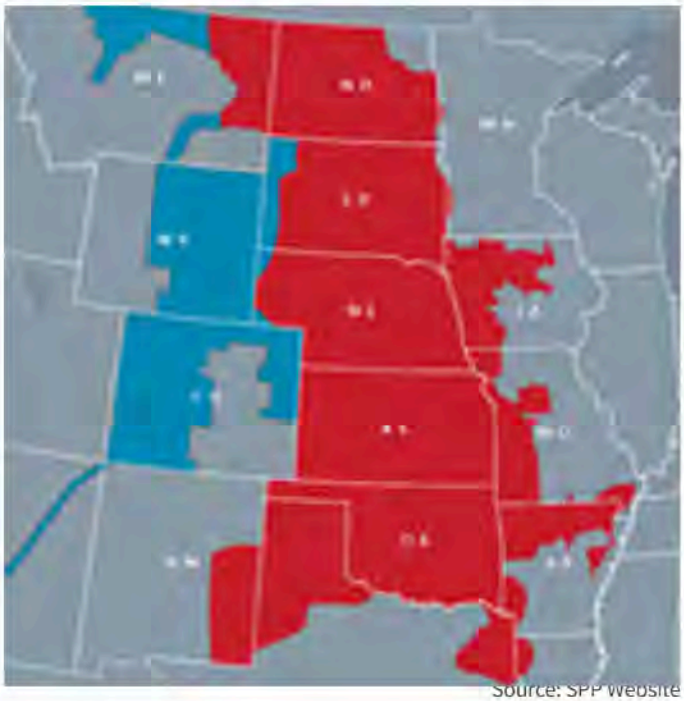
172 *Southwest Power Pool Market Monitoring Unit, State of the Market 2022 (May 2022), at 202,* https://www.spp.org/documents/67104/2021%20annual%20state%20of%20the%20market%20report.pdf

market. The credit requirements assist in mitigating the effects of defaults that would otherwise be borne among all market participants. The RTO assesses and calculates the required credit amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to certain restrictions. SPP must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth and various financial measures.

Western Energy Imbalance Service (WEIS)

SPP launched its WEIS market in February 2021. The WEIS market balances generation and load regionally in real time for participants in the Western Interconnection. SPP's WEIS market centrally dispatches generation from participating resources every five minutes using the lowest-cost resource available to meet demand. As of August 2022, ten entities participate or plan to participate in the WEIS Market with three more anticipated to join in April 2023: Basic Electric Power Cooperative, BlackHills Energy (April 2023), Colorado Springs Utilities, Deseret Power Electric Cooperative, Guzman Energy, Municipal Energy Agency of Nebraska, Platte River Power Authority (April 2023), Tri-State Generation and Transmission Association, WAPA (Upper Great Plains West, Rocky Mountain, and Colorado River Storage Projects regions), and Xcel Energy (April 2023). The following map shows SPP's footprint in red and the WEIS in blue.

Figure 2-26: Western Energy Imbalance Service



Source: SPP Website

California Independent System Operator (CAISO)

MARKET PROFILE

CAISO operates an ISO serving most of California and part of Nevada. CAISO is a California nonprofit public benefit corporation started in 1998 when the state restructured its electric power industry. CAISO manages wholesale electricity markets, centrally dispatching electric generators. In managing the grid, CAISO provides open access to the transmission system and performs long-term transmission planning. It manages energy and ancillary markets in day-ahead and real-time markets and is responsible for regional reliability. CAISO also operates a real-time energy imbalance market, the Western Energy Imbalance Market (WEIM), which is discussed further below. CAISO operates its grid out of its main control center in Folsom, CA.

Peak Demand

CAISO's all-time peak demand was 52 GW in summer 2022.[173]

Imports and Exports

Up to about one-third of CAISO's energy is supplied by imports, principally from the Southwest (Arizona, Nevada, and New Mexico) and the Pacific Northwest (Oregon, Washington, and British Columbia). Imports from the Pacific Northwest generally increase in the

173 California ISO, *California ISO Peak Load History 1998 through 2022*, at 1 (n.d.), http://www.caiso.com/documents/californiaisopeakloadhistory.pdf.

late spring when hydroelectric production peaks from increases in winter snowmelt and runoff.

Market Participants

CAISO's market participants include load-serving investor-owned utilities, load-serving municipal utilities, generators, power marketers, utility customers, and financial entities.

Membership and Governance

The CAISO has a board of governors that consists of five members appointed by the governor and confirmed by the California Senate. The board provides corporate direction, reviews and approves management's annual strategic plans, and approves CAISO's operating and capital budgets.

CAISO uses an informal stakeholder process to propose solutions to problems that may ultimately require a filing at FERC. Unlike other RTOs, which have a formal committee structure, CAISO's stakeholder process generally consists of rounds of dialogue with stakeholders on major policy issues.

Transmission Owners

CAISO's largest transmission owners include:

- Pacific Gas and Electric
- Southern California Edison
- San Diego Gas and Electric
- Valley Electric Association
- Municipal utilities such as Vernon, Anaheim, and Riverside

Chronic Constraints

CAISO has several locally constrained areas, typically near population centers and where transmission lines have relatively low voltage (115 kV and below). The locally constrained areas that have local capacity requirements include the Greater Bay Area, Greater Fresno, Sierra, Humboldt, Los Angeles Basin, San Diego, and North Coast/North Bay.

Transmission Planning

CAISO conducts an annual transmission planning process with stakeholders that includes both short-term and long-term projects.

Figure 2-27: California Independent System Operator



Source: Hitachi Energy Velocity Suite

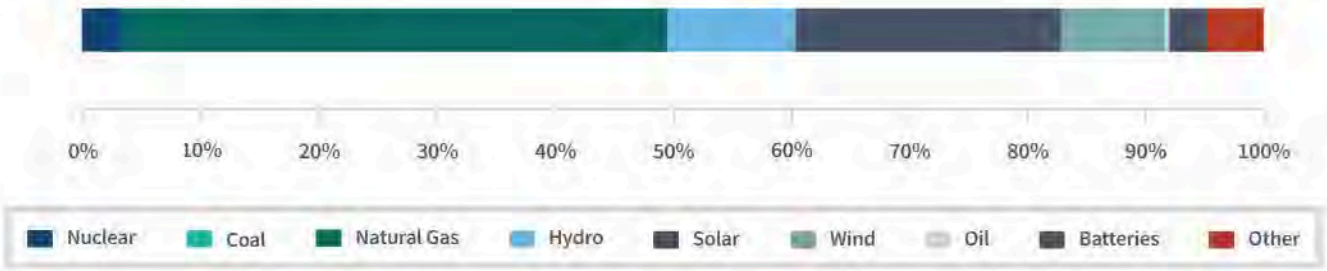
Supply Resources

The total capacity in CAISO is over 70 GW and is predominately composed of natural gas-fired and hydroelectric generators, as shown in the bar chart below. CAISO also has substantial renewable resources, including roughly half of the installed solar capacity in the U.S.

Demand Response

Demand response participation in the wholesale energy market includes programs entitled Proxy Demand Response, Reliability Demand Response Resources, and CAISO's Participating Load program. Proxy Demand Response allows for customer loads, aggregated by LSEs or third-party providers, to offer load reduction into CAISO's day-ahead, real-time, and ancillary services markets in return for compensation. Reliability Demand Response Resources allows customer loads, also aggregated by LSEs or third-party providers, to reduce load for compensation when triggered for

Figure 2-28: CAISO Capacity Mix



Source: EIA Form 860-M[175]

reliability-related events. Reliability Demand Response Resources can also offer into the day-ahead market. The Participating Load program allows the CAISO operators to directly curtail end-users' load, rather than through aggregators. This is a relatively small program that is primarily composed of the power demand from California's water pumping projects. Other demand response in California consists of programs for managing peak summer demands operated by the state's electric utilities. In general, activation of the utility demand response programs is based on criteria that are internal to the utility or when CAISO issues a Flex Alert. Flex Alerts also inform consumers of how and when to conserve electricity usage.

MARKET FEATURES

Energy Markets

CAISO operates day-ahead and real-time markets, generally consistent with the discussion in the RTO/ISO Features section of this report. CAISO operates a 15-minute market to adjust schedules from those determined in the day-ahead market, then a 5-minute market to balance supply and load in real-time. Real-time bids can be submitted up to 75 minutes before the start of the operating hour.

CAISO also procures capacity in the real-time market to provide upward and downward ramping of generation in order to accommodate changes in net load with the Flexible Ramping Product.[175] This service provides compensation to the generators selected to provide the desired flexible ramping capability.[176]

Ancillary and Other Services

Ancillary services, described in the Electricity Supply and Delivery section, are services that support the grid and reliability. CAISO procures ancillary services via its co-optimization of energy and ancillary services in its energy markets

In addition to ancillary services, CAISO has implemented a ramping product to procure capacity that can quickly increase output to offset changes in generation or load, known as the Flexible Ramping Product.

Market Power Mitigation

CAISO applies a set of behavioral and market outcome tests to determine if the local market is competitive and if generator offers should be adjusted to approximate price levels that would be seen in a competitive market – close to short-run marginal costs.

174 Installed nameplate capacity is assessed through December 2021 and captures Operating and Standby resources available. Note that these estimates do not imply that generation output will match the nameplate capacity of a resource type. Derived from EIA, *Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M)* (released February 2022), https://www.eia.gov/electricity/data/eia860m/.

175 Net load in CAISO is total market demand minus generation output from solar and wind resources.

176 CAISO describes ramping capability as a resource's ability to move from one energy output to a higher (upward ramp) or lower (downward ramp) energy output; *California Independent System Operator Corp.*, 156 FERC ¶ 61,226, at P 2 (2016).

Figure 2-29: Western Energy Imbalance Market



Copyright © 2023 California ISO

Capacity Markets

CAISO does not operate a formal capacity market, but it does have a mandatory resource adequacy (RA) requirement. The program requires LSEs to procure 115 percent of their aggregate system load on a monthly basis, unless a different reserve margin is mandated by the LSE's local regulatory authority. The program provides deliverability criteria that each LSE must meet, as well as system and local capacity requirements and flexibility requirements.

The CAISO market rules also include must-offer provisions pertaining to resources procured as RA resources. These resources must make themselves available to the CAISO day-ahead and real-time markets for the capacity for which they were counted.

Special Provisions for Essential Resource Retirements

CAISO employs RMR contracts to assure that it has the ability to reliably serve load in local import-constrained areas. RMR contracts also help to mitigate any local market power that one or more units may have. Over time, CAISO has been able to significantly decrease its RMR designations in much of the system. Remaining generators with RMR contracts are located primarily near the San Francisco and Los Angeles areas.

Financial Transmission Rights

In California, FTRs are referred to as Congestion Revenue Rights (CRR). A CRR is an instrument that entitles the CRR holder to a payment for costs that arise with transmission congestion over a selected path, or source-and-sink pair of locations on the grid. The CRR also requires its holder to pay a charge for those hours when congestion occurs in the opposite direction of the selected source-and-sink pair. CRRs are monthly or quarterly products. CRRs can be bought at auction or allocated by CAISO. Allocated CRRs receive the congestion value for a specific path, similar to a converted FTR. CAISO also allocates open market CRR auction revenues to LSEs, based on their physical participation in the market, similar to an ARR in other markets.

Virtual Transactions

CAISO's market includes a virtual transactions feature, termed convergence bidding. CAISO's convergence bidding includes both virtual supply and virtual demand transactions.

Credit Requirements

CAISO's tariff includes credit requirements that a market participant needs to meet in order to participate in the market. The credit requirements assist in mitigating the effects of defaults that would otherwise be absorbed by all market participants. CAISO assesses and calculates the required credit dollar amounts for the segments of the market in which an entity requests to participate. The market participant may request an unsecured credit allowance subject to

certain restrictions – CAISO must review the entity's request relative to various creditworthiness-related specifications such as tangible net worth, net assets, and credit rating.

Western Energy Imbalance Market (WEIM)

On Nov. 1, 2014, CAISO began operation of an energy imbalance market (EIM) with PacifiCorp's two BAAs, PacifiCorp East and PacifiCorp West. The EIM is an extension of the CAISO's real-time market into other BAAs in the Western Interconnection. The market dispatches resources inside the participating entities' BAAs to meet intra-hour changes in their energy demand and supply. The EIM's imbalance energy helps the BAAs meet their energy demand in real-time. Overall, EIM energy represents about two to three percent of the energy used to meet load in the participating BAAs. With the balancing authorities in the Pacific Northwest, the EIM integrates low-cost hydroelectric power generation with the significant amount of solar and wind generation capacity in CAISO.

The EIM is a voluntary market where the participating balancing authorities can choose which resources to include in the market. The market participants have the flexibility to add and remove capacity from the EIM on an hourly basis. The transmission system operators for each participating BAA preserve the responsibility and flexibility to respond to events such as a sudden large imbalance between load and supply caused by a loss of a power plant or transmission line.

As of November 2022, the EIM consisted of the following LSEs and their respective BAAs: BPA, Puget Sound Energy, Portland General Electric, PacifiCorp West, PacifiCorp East, Idaho Power, NV Energy, Tucson Electric Power, Avista, NorthWestern Energy, Los Angeles Department of Water & Power, Public Service Company of New Mexico, Turlock Irrigation District, Salt River Project, Seattle City Light, Balancing Authority of Northern California, Idaho Power Company, Portland General Electric, Puget Sound, NV Energy, Arizona Public Service, and CAISO. Additionally, Powerex (the marketing arm of the Canadian utility, BC Hydro) joined the EIM, providing contributions of generation and load imbalance (the difference between generation supply and demand schedules).[177] Other balancing authorities have expressed interest in becoming EIM Entities.

The EIM provides a market mechanism for dispatching generation resources to meet imbalance energy needs along with a limited amount of power flows between the participating BAAs. The market dispatches generation based on the relative cost of the resources, resulting in cost savings for the participants. Before the EIM, a balancing authority such as PacifiCorp West or PacifiCorp East resolved imbalances between energy demand and supply in real-time by dispatching its resources and using ancillary services (mainly regulation). Under the EIM, by contrast, the market automates the dispatch of enough resource capacity within the BAAs, along with transmission flows between BAAs, to resolve energy imbalances.[178] The automated EIM sets LMPs at both 15-minute and 5-minute intervals.

Along with dispatch cost savings, the EIM also helps integrate renewable generation resources. Prior to the EIM, CAISO imported power from outside its service territory to balance load throughout most hours of the day. However, with the growth of solar and wind generation, particularly in California, there were periods when these resources were forced to curtail because there was too much energy offered into the market. Now, with the EIM, any excess power can be exported throughout the participating BAAs. In some hours, this results in power exports from CAISO to other BAAs.[179]

177 Powerex (BC Hydro) also makes transmission rights available to the EIM, providing its power to the EIM at the British Columbia-U.S. border

178 The EIM software calculates dispatch solutions for the EIM market area as a whole. Consequently, participating balancing authorities need not maintain high levels of reserves.

179 *See* Department of Market Monitoring – California ISO, *2017 Annual Report on Market Issues & Performance*, at 118 (June 2018), http://www.caiso.com/Documents/2017AnnualReportonMarketIssuesandPerformance.pdf.

As the independent system operator of the EIM, CAISO addresses local market power mitigation at 5-minute and 15-minute intervals across the EIM area, which includes the non-CAISO balancing authority areas. CAISO also procures a Flexible Ramp Product to provide upward and downward flexible capacity to meet energy ramp requirements. In these respects, CAISO's operator responsibilities have grown in the EIM as enhancements to the market design have been implemented.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 48
Utility Dive, *MISO begins reviewing*
6.1 GW — 70% of it gas — in fast-track interconnection study
(Dec. 2, 2025)

UTILITY DIVE

MISO begins reviewing 6.1 GW — 70% of it gas — in fast-track interconnection study

The grid operator's Expedited Resource Addition Study process has grown to 11.2 GW, with an additional 18 GW seeking to join the initiative.

Published Dec. 2, 2025



Ethan Howland
Senior Reporter

The 620-MW, gas-fired Fox Energy Center, owned by Wisconsin Public Service, in Wrightstown, Wis. The Midcontinent Independent System Operator is studying 4.1 GW in gas-fired projects in its latest fast-track interconnection review process cycle, the grid operator said on Dec. 1, 2025. The image by chaddavis.photography is licensed under CC BY-SA 2.0

About 6.1 GW of potential projects have entered into the Midcontinent Independent System Operator's fast-track interconnection review process' second cycle, bringing the total capacity under review to about 11.2 GW, the grid operator said Monday.

Gas-fired generation in the Expedited Resource Addition Study's second study cycle totals 4.3 GW, or 70% of the total capacity in the cycle, according to a summary of the pending ERAS projects. Battery projects totaled 800 MW in network interconnection capacity, followed by wind projects at 580 MW and solar at 475 MW.

"Cycle 2 builds on the momentum of Cycle 1 and reflects the continued demand for timely, reliable interconnection solutions," Aubrey Johnson, MISO's vice president of system planning, said in

a news release. “These projects are essential to meeting near-term reliability needs and ensuring new resource additions are online to meet load growth.”

Three Cycle 1 projects have executed generator interconnection agreements and MISO said it expects the seven remaining projects in the cycle will complete interconnection agreements this month.

MISO said it has accepted or is reviewing 51 projects totaling almost 30 GW into ERAS, which aims to bring power supplies online quickly to meet near-term grid needs. The process allows planned resources that meet eligibility criteria to sidestep MISO’s standard interconnection queue reviews.

Under the ERAS process, MISO is studying up to 15 projects per quarter on a first-come, first-served basis. MISO will study up to 68 projects before the program ends on Aug. 31, 2027.

Last month, public interest groups sued to overturn the Federal Energy Regulatory Commission approval of MISO’s fast-track interconnection review program, along with that of the Southwest Power Pool, arguing in part that they give the reviewed projects an unfair advantage over projects in the grid operators’ standard interconnection queues.

MISO fast-track queue grows to 11.2 GW

Gas-fired generation makes up most of the capacity in the ERAS review process.

Interconnection Customer	Request Status	State	Study Cycle	Summer MW	
Alliant Energy / IPL	Active	IA	1	798 MW	
Alliant Energy / IPL	Active	IA	1	360 MW	
Alliant Energy / WPL	Active	MN	2	162 MW	
Ameren Missouri	Active	MO	2	258 MW	
Ameren Missouri	Active	MO	1	310 MW	
Benton Solar II	Active	MN	2	106 MW	
DTE Electric	Active	MI	2	432 MW	
DTE Electric	Active	MI	2	180 MW	
DTE Electric	Active	MI	2	213 MW	
Entergy Louisiana	Active	LA	2	478 MW	
Entergy Louisiana	Done	LA	1	1,640 MW	
Entergy Mississippi	Active	MS	2	820 MW	
Entergy Mississippi	Active	MS	2	820 MW	
Entergy Texas	Active	TX	2	820 MW	
Indiana Municipal Power Agency	Active	IN	2	268 MW	
Invenergy Cannon Falls	Active	MN	2	428 MW	
Invenergy Clean Power Dev.	Active	WI	2	1,211 MW	
Lincoln Capital Land	Active	IL	1	128 MW	
MidAmerican Energy	Active	IA	1	265 MW	
Minn. Municipal Power Agency	Done	MN	1	394 MW	
Minnesota Power	Active	MN	1	87 MW	

Minnesota Power	Active	MN	1	87 MW	
NextEra Energy Resources	Active	LA	2	208 MW	
Otter Tail Power	Active	MN	1	91 MW	
Red Butte Wind	Active	ND	2	457 MW	
Red Oak Ridge Energy Center	Done	WI	1	1,211 MW	

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 49
2025 Energy Innovation Dataset

State	Increase in Coal Power Cost By State ($/MWh)	Weighted Avg Cost of Coal Power by State in 2024 ($/MWh)
AL	37.93393999	7.480297212
AR	41.90122231	5.944721732
AZ	56.51554642	14.08344442
CA		
CO	39.33535838	10.30820944
CT		
DC		
DE	221.8761029	127.3387759
FL	53.50549995	5.689998956
GA	66.71100175	19.00841935
IA	38.63343192	9.725805912
ID		
IL	38.81721467	7.571739858
IN	58.81188822	14.90842856
KS	42.54800667	9.509355837
KY	46.35093349	9.308201802
LA	63.2739221	18.79729695
MA		
MD	73.70844799	17.10580366
ME		
MI	45.07020455	10.30771609
MN	41.18833898	5.034647863
MO	34.34030065	5.707797427
MS	60.76349909	15.46149471
MT	41.0604362	7.122524784
NC	68.01818431	19.01343787
ND	34.53581284	6.265181942
NE	27.86386333	4.19594737
NH	202.3922844	94.96768747
NJ		
NM	61.31310294	8.548435411
NV	79.4294835	28.32650169
NY		
OH	48.82266897	13.98484121
OK	53.95115581	16.43031007
OR		
PA	60.74068094	17.62564958
RI		
SC	54.28073668	7.077291056
SD	46.0068521	9.695183185
TN	53.30676073	12.71282206
TX	39.11171011	6.261700769
UT	58.53091529	23.6707588

VA	89.18327645	31.34968258
VT		
WA	46.8715898	8.836472222
WI	40.58935338	5.864332044
WV	50.24364994	14.67356958
WY	33.81029024	4.901115837

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 50
2025 Energy Innovation Coal Cost Report

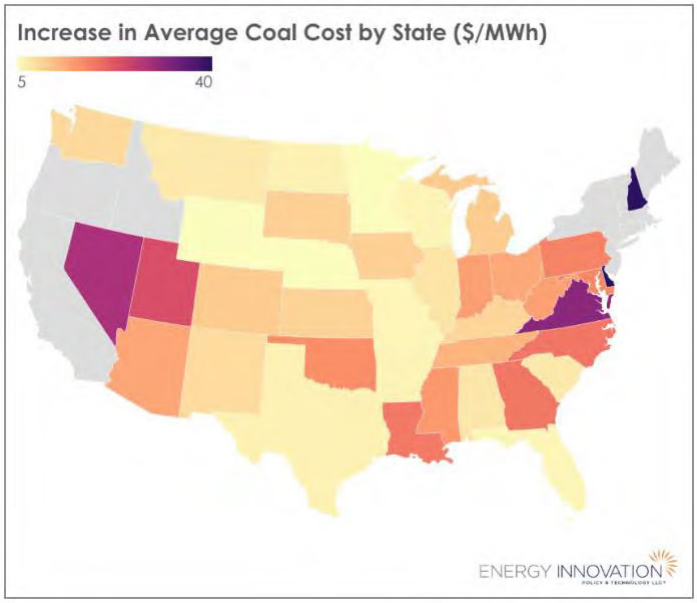
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San Francisco, CA 94111

COAL POWER 28 PERCENT MORE EXPENSIVE IN 2024 THAN IN 2021

Since 2021, the cost to generate coal power in the United States has increased faster than inflation, on average, meaning that coal is putting further inflationary pressure on American electricity consumers. This updated analysis on coal costs shows that in 2024, coal power was 28 percent more expensive than in 2021, costing consumers $6.2 billion more to generate power via coal than it would have cost in 2021.

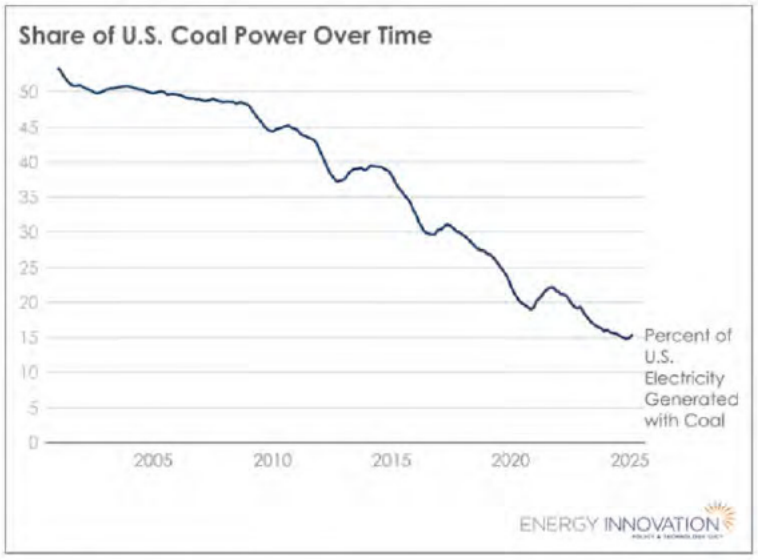
Coal power is declining across the United States, largely because of these poor economics. Total coal power use peaked in 2007 and has fallen ever since, generating barely 15 percent at the beginning of 2025. Between 2021 and the beginning of 2025, nearly 50 plants retired or are no longer burning coal, and over a third of the remaining fleet is expected to retire by 2030.[1]



This reality sits in stark contrast to U.S. federal power policy. The Trump administration issued a series of executive orders in April 2025 aiming to keep coal plants running despite their impact on electricity consumers. These include orders to reduce the number of plants subject to the U.S. Environmental Protection Agency's Mercury and Air Toxics Standards,[2] and to keep uneconomic plants running long-term using short-term emergency powers.[3] This has already resulted in a plant ordered to remain open – the J.H Campbell plant owned by Consumers Energy in Michigan which was scheduled to close May 31.[4]

[1] https://ieefa.org/resources/nowhere-go-down-us-coal-capacity-generation
[2] https://www.whitehouse.gov/presidential-actions/2025/04/rregulatory-relief-for-certain-stationary-sources-to-promote-american-energy/?utm_source=chatgpt.com
[3] https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/
[4] https://apnews.com/article/michigan-power-plant-coal-trump-aa6244ce5e7cca4326e582c849e0bc98

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Source: U.S. Energy Information Administration

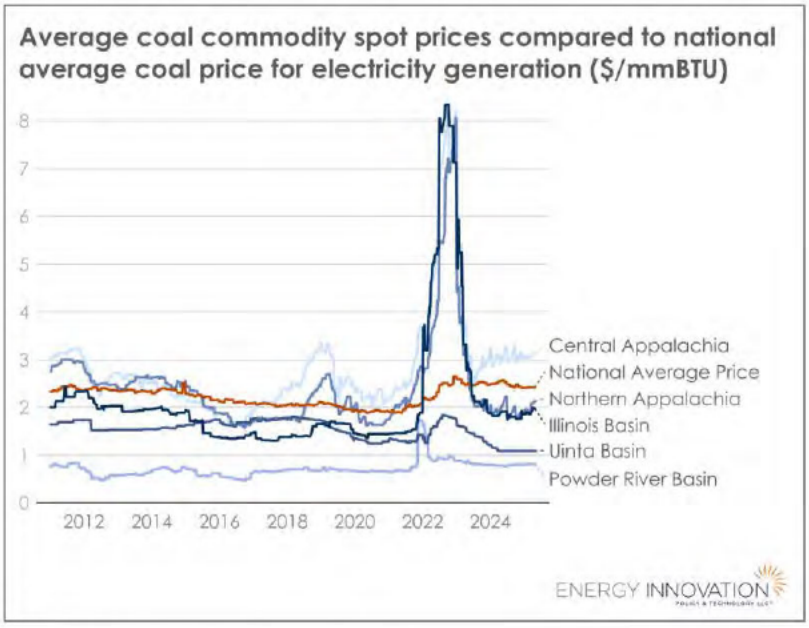
But these orders ignore the economic fundamentals underpinning coal's decline: wind, solar, batteries, natural gas, and efficiency are simply cheaper than coal power. Previous Energy Innovation research showed that 99 percent of coal plants were more expensive to continue operating compared to replacement with local wind or solar.[5] Attempts to keep coal running beyond plants' economic lifetime will force Americans to pay higher electricity bills.

As the new analysis detailed here shows, coal plants have only gotten more expensive since our last analysis based on the 2021 coal fleet, which largely followed the trends of the overall cost of coal for fuel.

Prices spiked in 2022, after Russia invaded Ukraine. This event increased all fossil fuel prices. While coal fuel prices fell after 2022, they remained elevated over 2021 levels in most regions of the country, and the national average price of coal delivered to the electricity sector remained elevated, too.

These higher prices are seen most acutely in the Appalachian coal producing regions, where coal has been more expensive for years due to the depth of coal within the mines, a problem that only becomes more acute with more mining.[6]

Our updated analysis uses the same methodology as detailed in the Coal Cost Crossover 3.0 for calculation of coal costs,[7] and shows coal's economic decline has continued.



Source: U.S. Energy Information Administration

[5] https://energyinnovation.org/report/the-coal-cost-crossover-3-0/
[6] https://www.eia.gov/energyexplained/coal/prices-and-outlook.php
[7] This methodology does not account for any increases in cost due to very large capital expenditures such as those required to comply with air pollutant regulations. Any pollution upgrades would significantly increase the costs of plants beyond what is calculated here.

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KEY FINDINGS

Power generated by coal in 2024 was 28 percent more expensive on average than in 2021

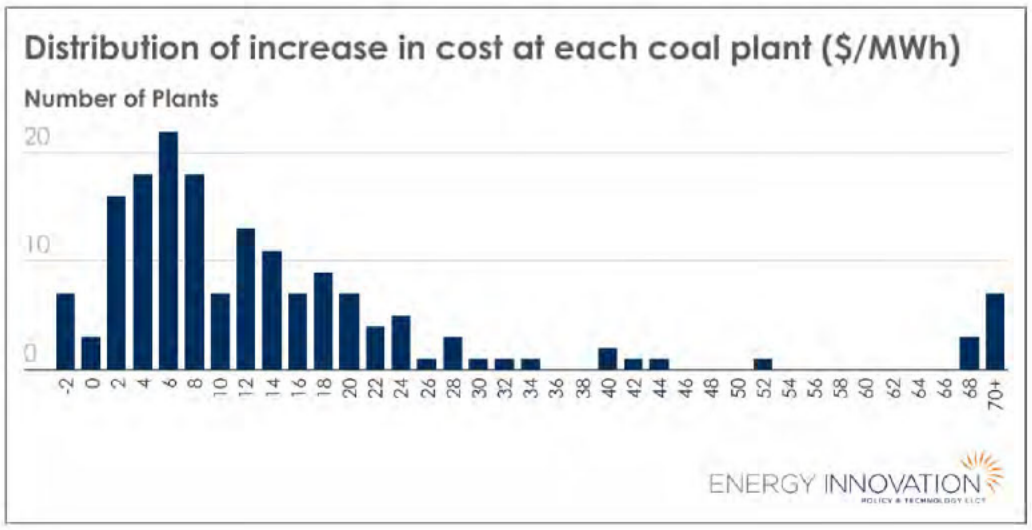
In 2021, the weighted average cost of a megawatt-hour (MWh) of power generated by coal-fired power plants was $36/MWh, while in 2024, this number rose to $46/MWh, or a 28 percent increase across the U.S. coal fleet. The Consumer Price Index, a proxy for inflation, increased by 16 percent from 2021 to 2024,[8] which means the cost of power generated by coal grew significantly faster than inflation.

Factors contributing to this increase include a rise in the cost of fuel for plants, as well as increased operations and maintenance costs and capital costs due to aging plants and inflation. Plants also ran less on average, which drives up their cost in dollars per MWh, with our analysis showing that the average coal plant capacity factors dropped to 38 percent in 2024 from 46 percent in 2021.

With 622 million megawatt hours of power generated by coal in 2024, this means coal plant owners spent over $6.2 billion more than they would have spent for that same amount of electricity generated by coal in 2021, costs that are directly passed onto consumers through electricity rates.

95 percent of remaining coal plants generated power at a higher cost than they did in 2021

We analyzed 162 plants, consisting of 181 GW of capacity, that were still operating at the beginning of 2025. Almost every plant saw costs increase but increases ranged widely between plants. 95 percent of plants were more expensive, and 76 percent of plants (142 GW) saw costs rise faster than inflation since 2021. Nearly half of these saw cost increases double the rate of inflation over this period.



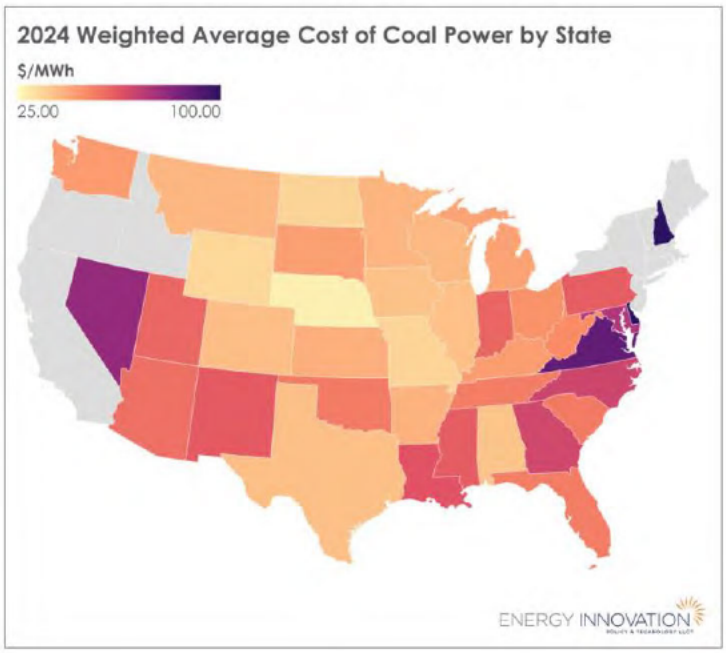
[8] https://www.minneapolisfed.org/about-us/monetary-policy/inflation-calculator/consumer-price-index-1913-

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The cost of coal was highest in the Mid-Atlantic, Southeast, and Southwest

Delaware and New Hampshire saw the highest coal costs on average in 2024. Each state has only one plant still in operation, and plans to shut these plants down are imminent, with Delaware's scheduled for retirement in 2026 and New Hampshire's in 2028. Outside of these two, the states with the highest coal cost were Georgia, Louisiana, Maryland, Mississippi, Nevada, New Mexico, North Carolina, and Virginia.

Many of the most expensive coal-burning states source coal from the most expensive mines, with states east of the Mississippi generally seeing more expensive average costs than those in the West.



Despite these high costs, states like Georgia and South Carolina have extended the lives of several plants, including Plant Bowen and Williams. Plant Bowen was originally scheduled for retirement in 2028, but Georgia Power has recently extended its life to 2035.[9] Its costs increased by $26/MWh, from $46/MWh to $72/MWh. Williams, a 659 MW plant in South Carolina has had its retirement pushed from 2028 to 2031 or even later in Dominion Energy's recent integrated resource plan. This delay comes even as this analysis shows the plant has increased in cost by $27/MWh, or over 50 percent.[10]

States in the West were not insulated from cost increases. Cost increases in Utah were particularly high, largely due to the Hunter and Huntington plants, which were previously scheduled for retirement in 2032, but instead are now planned to stay online indefinitely. The cost increase is largely due to issues with the mine that supplies coal to these plants, the Lila Coal Mine, which caught on fire in 2022, was declared "idled indefinitely" at the end of 2023 and all 150 workers laid off.[11] Costs to run these two plants nearly doubled from around $30/MWh to over $60/MWh. Even plants that have functioning dedicated mines in the cheapest coal region of the country, the Powder River Basin, have still seen significant increases in coal costs.

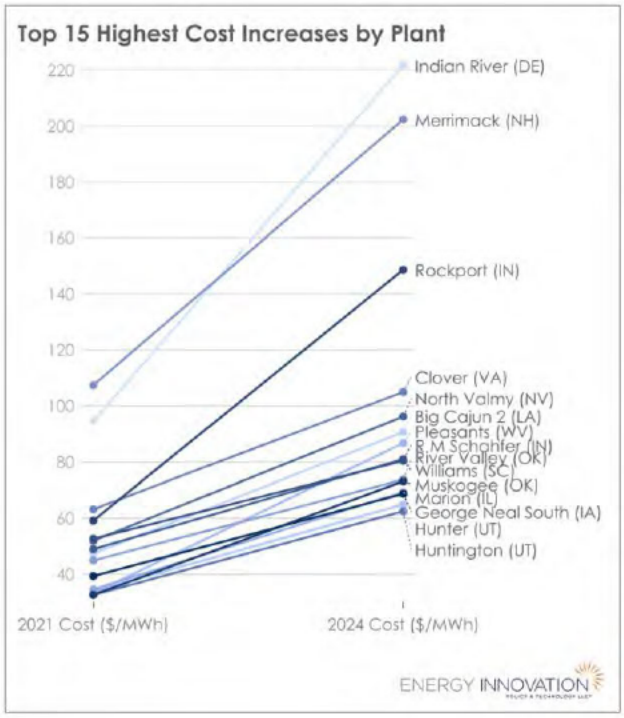
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[9]https://georgiarecorder.com/briefs/two-georgia-power-coal-plants-among-the-dozens-now-exempt-from-biden-era-pollution-rule/
[10]https://www.wfyi.org/news/articles/duke-energy-plans-to-delay-gibson-coal-plant-retirement-activists-say-its-a-step-backward
[11]https://www.sierraclub.org/press-releases/2025/04/dominion-energy-keeps-south-carolina-s-coal-plants-operating-2025-irp-update#:~:text=Dominion%20has%20already%20pushed%20back,potentially%20as%20late%20as%202034.

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ACTIONS TO PROTECT CONSUMERS FROM RISING COSTS

Because the cost of coal power is increasing faster than inflation, the Trump administration's executive orders and attempts to keep coal-fired power plants running will increase the cost of electricity.



Coal-fired power increases its cost burden on customers year after year, and the period from 2021 to 2024 was no different. With costs increasing across America's entire fleet, states that continue to rely on coal, like Kentucky and West Virginia, have unsurprisingly suffered electric rates climbing faster than even those coal-heavy states that have begun to incorporate renewable power.[12] Even as this coal reliance has harmed electricity customers and neighboring states have declined cost recovery for upgrades, regulators in West Virginia have required plants to stay online. Meanwhile, residential electricity rates in West Virginia have risen 24 percent since 2021.

While keeping coal power online longer to meet growing load may seem like an attractive option, continuing to rely on these aging plants with high fuel costs will likely continue harming those captive customers whose policymakers force expensive plants to stay online, even as cheaper options are available. Strategies like moving new generation and battery storage through interconnection queues more quickly,[13] getting more out of the grid by upgrading transmission lines[14] and utilizing surplus interconnection capacity,[15] and deploying demand response and efficiency[16] can help ensure America has the capacity needed to meet growing load while protecting consumers from paying the price to subsidize uneconomic coal.

Comprehensive planning and competitive procurement are also essential to ensuring that electricity customers pay the cheapest price for power. Using best practices in integrated resource planning will make sure that least-cost resource portfolios are selected. These include inclusive stakeholder processes with technical experts participating, developing model inputs and cost estimates that align with real-world data and high quality forecasts, and analyzing multiple scenarios and sensitivities.[17]

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[12]https://kentuckylantern.com/2025/04/10/heavy-reliance-on-coal-has-eroded-a-ky-economic-advantage-can-trump-reverse-the-trend/
[13]https://collaborative.evergreenaction.com/memos/approving-clean-energy-projects-faster-could-save-consumers-505-a-year-in-these-13-states-16
[14] https://www.2035report.com/reconductoring/
[15] https://www.utilitydive.com/news/surplus-interconnection-gridlab-berkeley-report/740262/
[16] https://energyinnovation.org/wp-content/uploads/2024/03/MEETING-GROWING-ELECTRICITY-DEMAND-WITHOUT-GAS.pdf
[17] https://emp.lbl.gov/publications/best-practices-integrated-resource

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Beyond good planning, all-source competitive procurement, or the process by which all technologies are fairly considered to meet grid needs, can make sure that the cheapest plans turn into the cheapest projects built.[18]

Common-sense policies can also help reduce the impact of expensive coal plants on consumers. For instance, in many states, coal plants are permitted to run even when they are not the cheapest resource to meet the need. This is called "uneconomic dispatch," costs consumers over $2 billion annually, and is most prevalent in the Southeast and West where the lack of regional transmission operator reduces pricing transparency. Where full electricity markets are not implemented, moving towards day ahead or real time energy markets that are coordinated by a centralized entity is key to ensuring consumers pay a fair price, and utility regulators can push for better operational practices to save customers money.[19]

Electricity planners have options to keep the lights on, but electricity consumers generally have little to no choice in the price they pay for power. As costs continue to rise, now is not the time to double down on coal. It is up to the regulators and policymakers overseeing the coal fleet to protect consumers, and find cheaper, cleaner options to help Americans thrive.

[18]https://energyinnovation.org/report/making-the-most-of-the-power-plant-market-best-practices-for-all-source-procurement-of-electric-generation/
[19] https://rmi.org/how-utilities-can-save-customers-billions-of-dollars/

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 51
2023 Energy Innovation Coal Cost Report

Coal Cost Crossover 3.0: Local Renewables Plus Storage Create New Opportunities for Customer Savings and Community Reinvestment

MICHELLE SOLOMON, ERIC GIMON, MIKE O'BOYLE (ENERGY INNOVATION®), UMED PALIWAL, AND AMOL PHADKE (UNIVERSITY OF CALIFORNIA, BERKELEY)

JANUARY 2023

EXECUTIVE SUMMARY

The cost of operating existing coal power plants in the United States continues to increase while coal jobs, generation, and mining all decrease.[i] New coal retirement announcements seem to happen faster, even as natural gas prices skyrocket, and renewable energy prices keep dropping.

The Inflation Reduction Act (IRA), which extended and expanded clean energy tax credits, along with new funding to guarantee loans for refinancing fossil assets and reinvesting in clean energy infrastructure, has shifted the economic scale even further toward wind and solar. But it also creates thoughtful new investment opportunities in areas burdened by existing coal plants with a 10 percent tax credit boost for projects located in nearby communities.

These factors underpin the third iteration of our Coal Cost Crossover analysis, which shows wind and solar energy are unequivocally cheaper than coal-fired generation across the country. This study finds 99 percent of all coal-fired power plants in the U.S. are more expensive to operate on a forward-

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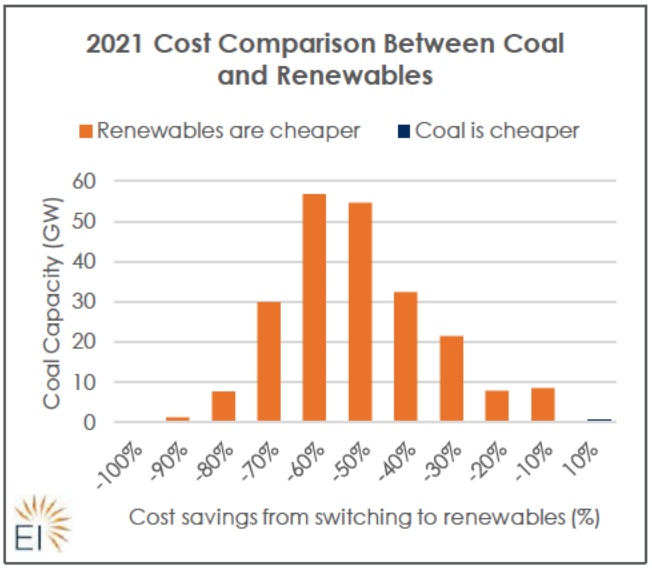
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looking basis than the all-in cost of replacement renewable energy projects, and 97 percent are more expensive than renewable energy projects sited within 45 kilometers (approximately 30 miles), a significant acceleration from our two previous analyses. For more than three quarters of U.S. coal capacity, the all-in cost per MWh of the cheapest renewable option is at least a third cheaper than the going-forward costs for the coal it would replace.

In this report we compare the cost of operating each continental U.S. coal plant in 2021, totaling 220 gigawatts (GW) of coal capacity across the country, to the estimated costs of building new wind and solar generation. We consider the wind and solar costs within two geographic scopes: local to the coal plants (within 45 kilometers) and regionally (roughly within the utility balancing area), finding that nearly all existing coal plants have multiple lower-cost clean energy replacement options.



This research shows all but one of the country's 210 coal plants are more expensive to operate than either new wind or new solar. If the IRA's new energy community tax credit is included in the equation, 199 of the 210 plants are more expensive to operate compared to local solar resources sited within 45 kilometers of the plant. Local wind resources are also cost-effective and readily available, with 104 plants having cheaper wind resources within 45 kilometers.

Altogether, 205 plants have local renewable options that would be cheaper than coal-fired electricity. This potential to replace existing coal plants with cheap, local clean energy generation creates significant economic benefits for community transition. Our analysis finds replacing these plants with local solar or wind would drive $589 billion in local capital investment that could support economic diversification, job creation, and tax revenue.

These local wind and solar resources could also help solve the problem of long interconnection queues—a significant barrier to renewables deployment. Renewable projects built near a retiring coal plant could use the existing plant's interconnection, helping to further lower costs. If more policymakers consider this dynamic, they can streamline economic replacement and anticipate coal retirements, which are accelerating due to the cost dynamics analyzed in this report.

While solar and wind replacement resources provide significant low-cost energy and reliability value to the grid, savings generated by switching from more expensive coal to cheaper clean energy can finance other resources to provide additional energy and reliability value.

We find that the savings generated by shifting to local solar could fund the addition of 137 GW of four-hour batteries across all plants, and 80 percent or more of the capacity at a third of existing coal plants – the economics of replacing coal with renewables are so favorable that they could fund a massive battery storage buildout to add reliability value along with emissions reductions. However, it is important to remember reliability is a system attribute—replacement renewable

portfolios need not bear sole responsibility for replacing the reliability services of individual coal plants.

While the economic case is clear and virtually universal, barriers remain to replacing coal with clean energy, and policymakers must act to unlock the cost savings and human health benefits for coal communities while reducing climate pollution.

Several policies can enable a faster coal-to-clean transition. Specifically:

- To prepare the way for coal transition, regulators and system operators should:
  - Improve methods to assess reliability and resource adequacy reflecting the reliability value of renewable portfolios and valuing the reliability attributes of a high-renewables grid.
  - Update interconnection study rules to leveraging existing coal plant interconnection rights to speed grid connection processes for local renewable replacement resources.
- To proactively pursue the transition, regulators should:
  - Encourage utilities to utilize IRA financing programs available through the Departments of Energy and Agriculture to remove financial barriers to coal community economic transition and investment.
  - Enable competitive resource procurement.
  - Require re-assessment of any utility investment plan, including integrated resource plans and market-based solicitations for renewable supply, completed prior to IRA as renewables costs are now out of date.
- To create a just transition for affected communities, state legislatures and energy offices should:
  - Plan for and fund a coal community-centered economic transition, where local clean energy resources are the anchor for a more expansive economic transition plan.

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INTRODUCTION

The U.S. power sector is in transition, with coal-fired power generation falling to 55 percent of its 2007 peak in 2021. This transition is also decreasing the number of coal mines, power plants, and workers. Over the same period, utility-scale solar and wind generation have increased more than

18,000 percent and 1,000 percent, respectively, as costs declined by 90 percent for solar and 72 percent for wind.[1,ii]

In 2019, Energy Innovation Policy & Technology LLC® partnered with Vibrant Clean Energy to compile and analyze a 2018 dataset of capital, operations and maintenance, and fuel costs for coal, wind, and solar. Our first Coal Cost Crossover report found that 62 percent of existing coal capacity was uneconomic compared to producing the same amount of energy with new local wind or solar. To make this comparison, we evaluated the marginal cost of running each coal plant with the levelized cost of new wind and solar, where the levelized cost of energy (LCOE) is the cost of building and operating a new resource divided by its energy production over its lifetime. The analysis projected that by 2025, more than 80 percent of the coal fleet would be unable to compete against new renewables or would be retired, even without federal incentives.[2]

In 2021, we completed a similar analysis of 2019 data that considered the National Renewable Energy Laboratory's (NREL) 2018 Annual Technology Baseline (ATB) forecast showing steep cost declines for solar and wind energy, as well as an extension of the federal investment tax credit for solar coupled with a continued production tax credit for wind. The Coal Cost Crossover 2.0 report found that the coal crossover had significantly expanded, with 72 percent of coal capacity and 80 percent of plants already more expensive to run compared to either new solar or wind, including tax credits in effect.[3]

This Coal Cost Crossover 3.0 report uses new 2021 data to reevaluate the coal crossover economic dynamic. Since our 2.0 report, solar and wind costs continued fall, coal prices kept rising, and coal plant capacity factors continued decreasing, all continuing the trends observed between 2017-2019.[iii]

Now, new federal tax credits in the IRA make the economic case for replacing coal with clean energy unequivocal. IRA incentive bonuses for clean energy projects located near retired coal infrastructure offer new, additional savings and reinvestment opportunities. This report combines elements of the previous two studies, analyzing both regional and local renewable resources, but now accounts for the new incentives.[4] Given the IRA's expanded tax credits, we find all coal plants but one are more costly to run compared to new wind and solar energy, and all but five are more expensive than wind or solar sited within a 45 kilometer (km) radius.

Of course, examining relative economics using levelized cost faces limitations. The overall value of these power plants depends on much more than just cost. While the coal cost crossover describes a scenario in which renewable resources replace coal generation on a one-to-one basis, the reality is that coal retirement is a complex process that depends on the reliability needs of the local and

[ii] Coal generation decreased from 2,016,455 gigawatt-hours (GWh) in 2007 to 875,885 GWh in 2021. Solar generation increased from only 612 GWh in 2007 to 115,258 GWh in 2021. Wind generation increased from 34,449 GWh in 2007 to 378,196 GWh in 2021. In total, coal generation was still higher in 2021 than wind and solar in the U.S. by 382 GWh.
[iii] Renewable costs continued to fall through 2021, the year we used for this analysis. Costs across the energy industry rose in 2022 due to supply chain constraints but are expected to fall again as supply issues ease.

regional electricity grid, which in turn, depends on the entire resource portfolio's dynamics. For example, in some regions one-to-one replacement with a combination of wind and solar resources may not adversely affect reliability. In others it may, depending on what other resources are serving the power grid.

Many communities also depend on coal plants for jobs and tax revenue. In addition to reliability value, policymakers must consider the potential of replacement energy resources to provide similar economic value. The new IRA incentives to locate replacement resources in the same communities where coal plants sit can contribute to a sustainable, economic transition. As we show in this report, these incentives fundamentally improve the prospect for coal communities to benefit from new clean energy resource development.

This report traces the shifting role of coal in the U.S. power sector and identifies key changes in the economics of coal-fired electricity generation due to the IRA's passage. We explain our coal cost crossover calculations, including how we compiled the coal dataset using publicly available data, and how we calculated the LCOE for both local and regional wind and solar using open-source modeling tools developed by NREL.

Four scenarios compare new renewable generation costs to marginal coal costs: regional wind, regional solar, local wind, and local solar, effectively assessing the replacement of every unit of energy produced by the coal plants. For the local solar scenario, we also analyze the economics of adding four hours of battery storage capacity to the solar resources. This analysis demonstrates a clean alternative to coal generation with added reliability value and an opportunity for local investment and economic diversification.

Finally, we provide policy recommendations to help policymakers successfully transition away from polluting, higher cost coal power to cheaper, clean energy. Because the IRA aligns the aims of least-cost electricity planning and procurement with an economic transition for coal communities, we highlight the opportunity for gradual economic transition centered around replacing coal generation with local renewables and storage. Local replacement also has the advantage of potentially being able to leverage existing grid interconnection rights. We describe how utilities can directly take advantage of key IRA provisions, as well as how policymakers can ensure utilities account for the changing economic landscape in their planning and procurement. We also explain how just transition planning, accurate reliability assessments, and transmission buildout can speed up and smooth out coal's phaseout in the U.S.

COAL'S ROLE IN THE U.S. POWER SECTOR

Coal-fired power was the bedrock of a reliable, affordable U.S. power sector for nearly a century. But since 2010, coal generation has declined 52 percent, and renewable power generation exceeded coal generation for the first time in 2020. In 2011, the U.S. had 317.6 GW of coal-fired

electricity generation capacity,[5] but that number fell to 221 GW in 2021. Nearly a quarter of the remaining fleet is slated for retirement by 2029.[6]

Several factors explain this decline, including pollution control standards requiring costly retrofits, cheap natural gas and renewable power, state clean energy policies, and improved building and industrial efficiency.[7] Coal's decline has been accompanied by a precipitous fall in coal industry employment.[8] But even as employment fell, reduced pollution from coal plants dramatically improved public health. Annual deaths attributed to air pollution from coal plants fell from 30,000 deaths in 2000 to less than 3,000 in 2019.[9]

Coal's role in electricity system reliability has shrunk considerably. Coal-fired power plants operate as part of an integrated power system where supply and demand must remain in constant balance. The decline in coal-fired generation and capacity, and replacement by a more diverse portfolio of gas and renewable power plants with vastly different operational characteristics indicates that coal is not necessary for reliable power systems. For example, the United Kingdom reliably operated its grid without any coal generation for two straight months in 2020.[10]

The role of coal plants and their operation in the electricity system has also changed over time. Historically, coal plants operated as "baseload" power plants, relying on a relatively low-cost fuel supply to run at a constant, high output. But now markets are pushing coal plants to operate more variably, ramping up and down as the economics and availability of renewable energy fluctuate throughout the day and over a season.[11] Coal plants in our dataset had an average capacity factor of 46 percent, which means they ran, on average, only 46 percent of the time. This on-again, off-again operation increases wear and tear on coal plants designed for a different operating paradigm.

Displacement by cheaper gas and renewables means baseload operation is increasingly unprofitable for existing coal—operating at high output when plentiful clean energy resources operate at zero marginal cost is a waste of fuel. According to RMI, since 2012 utilities could have saved customers $1–$2 billion per year by turning down coal and relying on lower-cost, less polluting resources. This is partially due to self-scheduling, a practice through which monopoly utilities uneconomically run their coal plants in wholesale markets and charge captive customers the difference.[12]

Replacing coal with clean energy is not a one-to-one exercise. System operators and utilities only gain confidence that coal retirements won't adversely affect system reliability by evaluating the reliability of the entire energy portfolio. A recent North American Electric Reliability Corporation (NERC) assessment highlighted the need to build new generation before retiring old generation when reliability risks are present.[13] But recent studies such as the 2030 Report, which found an 80 percent clean, coal-free electricity system to be both reliable and affordable, confirm we can maintain a dependable electricity system without coal.[14]

The U.S. will continue relying on coal plants for reliability until we add enough new clean resources (including demand-side resources and transmission) to replace their reliability and energy services.

The Coal Cost Crossover 3.0 analysis highlights opportunities to economically displace coal-fired generation and replace those services in part. With the IRA's passage, the economic case for shifting from coal to renewables is stronger than ever.

INFLATION REDUCTION ACT IMPACTS ON U.S. ENERGY ECONOMICS

The IRA will significantly affect the relative economics of coal and clean power in the U.S. In this analysis, the IRA's extended and improved tax credits, along with a pair of refinancing programs, have the greatest effect on the cost of coal compared to renewables.

Tax Credits

Clean energy tax credits have arguably been the most important federal climate policies to date, driving nationwide solar and wind growth. The IRA builds upon this successful policy to make the clean energy transition cost effective for the long term, with earlier Energy Innovation® analysis finding the credits to be the most impactful IRA provision for electricity sector decarbonization.[15]

The production tax credit (PTC) and investment tax credit (ITC) are the IRA's two key tax credits for new clean electricity resources. Historically, the PTC has primarily supported wind energy resources, and at its full value paid approximately $26 per megawatt-hour (MWh) in 2022 dollars over the first 10 years of a wind project's commercial operations.[16] The ITC has largely supported solar resources, and at its full value offered a tax credit for 30 percent of total system cost, paid out when it is first placed in service. Prior to the IRA's passage, the PTC had expired, and the ITC had begun phasing out with a value of 26 percent for projects starting construction in 2022.[17] The IRA created long-term certainty for these tax credits, with the extension lasting through 2032 or until electricity sector greenhouse gas (GHG) emissions fall 75 percent below 2022 levels, whichever is later.

The IRA also immediately revived a long-expired option for solar projects placed in service in 2022 or later to elect the PTC instead of the ITC, which ensures that tax credits will stay impactful as solar capital costs continue to fall. In addition, the IRA provides an ITC for stand-alone energy storage technologies placed in service in 2022 or later, removing prior restrictions that required storage to be co-located with and charged primarily from solar energy resources.

Beyond the extension and increased flexibility, the IRA created several human impact bonuses that increase the value of the tax credit. To qualify for the full credit, a project must meet prevailing wage and apprenticeship requirements. Additionally, a project can earn a 10 percent boost for meeting domestic content requirements and an additional 10 percent for locating the project in an energy community (which includes census tracts in which coal-fired power plants have been retired since 2009 and adjacent census tracts, as defined by the IRA, see Figure 1).[iv]

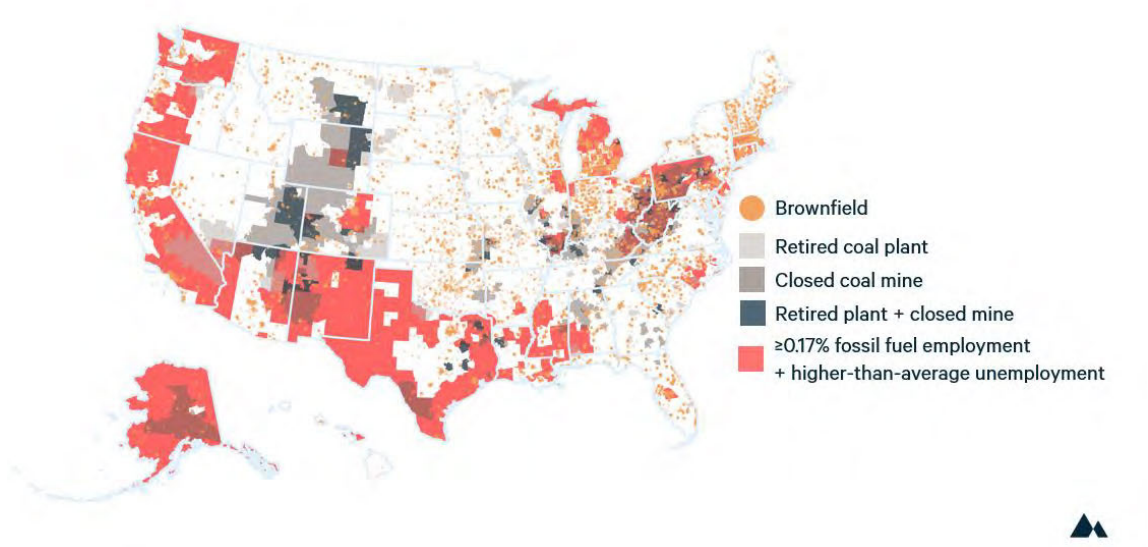


Figure 1. Map of probable energy communities, as defined by the IRA. Source: Resources for the Future.[18]

The combined impacts of energy community, labor, and domestic content bonuses reshape solar economics in coal communities. The median cost of new solar in these communities is about $24/MWh with low variance, while the median marginal cost of coal is $36/MWh with higher variance (see Figure 2). As discussed later in this report, this cost differential provides significant headroom for additional battery storage, which can also qualify for energy community bonuses.

[iv] The 10 percent credit boost for siting projects in energy communities works slightly differently for the ITC and PTC, providing a 10-percentage point ITC bonus and a 10 percent bonus on the PTC credit value.

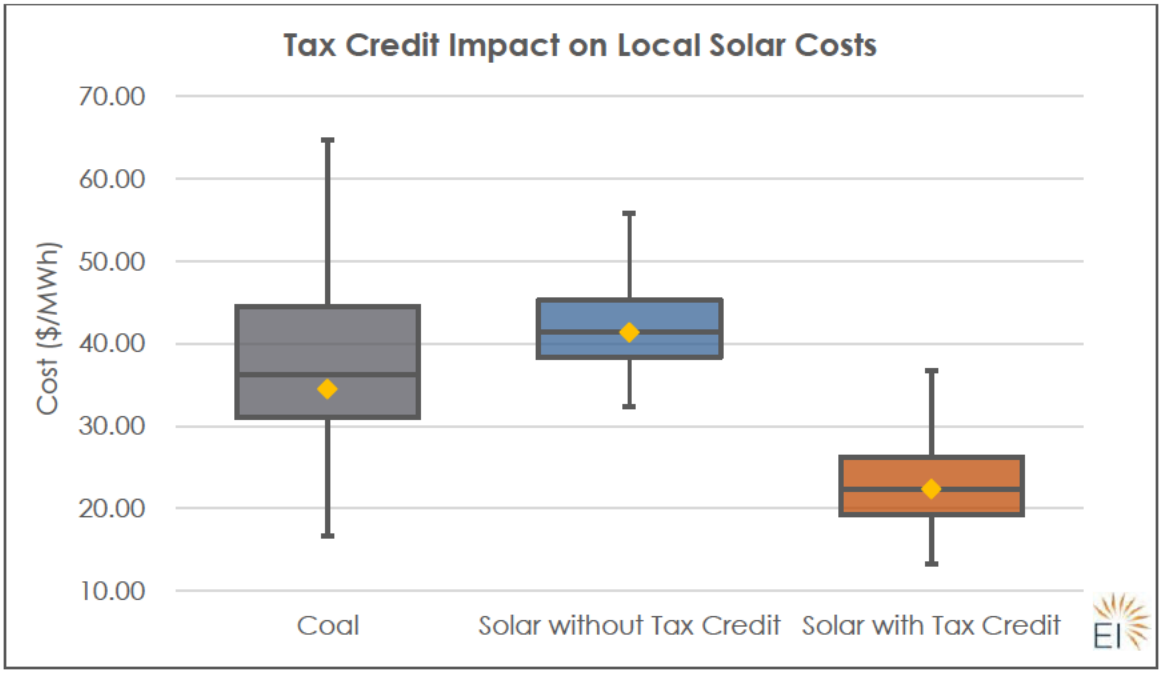


Figure 2. Impact of tax credits on local solar LCOEs in our analysis, including the energy community bonus. The yellow diamond indicates the average cost of each resource (weighted by generation). With the IRA, the economic case for local solar becomes unequivocal.

Revinvestment Financing

The PTC and ITC play the crucial role of decreasing the cost of developing clean electricity resources, but upfront cost is far from the only barrier to moving from coal generation to clean alternatives. One of the biggest hurdles to this transition is the rate impacts of adding large capital investments to utility rates when billions are still owed to debtors and investors on uneconomic coal assets. But a new IRA financing program to invest in clean energy infrastructure in current or former coal communities can overcome this hurdle. As the program only lasts until 2026, time is of the essence.

Most U.S. coal capacity is owned and operated by monopoly utilities, which collectively hold at least $176 billion in unpaid fossil plant balances[v]—accounting ledgers that represent the debt and equity capital structures utilities used to finance these plants over time. Utilities include this capital cost in electricity rates, typically recovered over the plant's entire lifetime in a financial arrangement somewhat similar to a conventional 30-year mortgage (albeit one that is continuously extended as new capital is invested at coal plants). As long as the plant remains in operation or

until the investment is fully depreciated, customers are generally obligated to continue to cover these costs, which include substantial returns for utility shareholders. Without a change to this structure, monopoly utilities have little to gain from early coal plant retirement and they may perceive retirement or partial replacement as putting cost recovery at risk.

New IRA programs provide flexible, low-cost financing to clean up utility balance sheets by reducing the cost of investing in new local clean energy infrastructure, including wind, solar, batteries, transmission infrastructure, and reuse of the coal plant itself. Utilities and other power plant operators, such as independent power producers, can access low-cost government-backed loans to reduce the rate impacts associated with large capital expenditures required to transition from coal to clean and stimulate local economic development. The IRA created two novel programs to support utilities in transition:

First, the IRA appropriated $5 billion to the U.S. Department of Energy's (DOE) Loan Programs Office (LPO) via the Energy Infrastructure Reinvestment (EIR) program to support $250 billion in loan-making authority to facilitate refinancing and reinvestment in capital projects at fossil infrastructure sites, using below-market interest rates. Funds can be used flexibly to "re-tool, re-power, re-purpose, or replace" fossil infrastructure across the entire energy industry (including non-utilities), reducing the cost of replacement resources and creating numerous pathways for community diversification and redevelopment. The financing provisions are flexible enough to work for all parties—utilities, consumers, and communities. These stakeholders can use the financing to reduce the near-term rate impacts of capital transition, allowing new investment to arrive sooner in these communities that sorely need it as aging fossil plants ramp down.

Second, the IRA authorized a $9.7 billion program specifically for rural electric cooperatives through the U.S. Department of Agriculture (USDA). Rural electric cooperatives provide electricity to more than 40 million people. Their power supply is particularly coal-heavy, with coal accounting for 28 percent of generation in 2020 compared to 19 percent nationwide.[19] This means surrounding rural communities bear a disproportionate burden of coal-related pollution, while member-owned cooperative customers remain tethered to coal debt. While members may want to transition to clean energy to capture pollution and cost savings, this debt holds them back. Furthermore, simply shutting down cooperative coal plants could impact communities that rely on relatively high-paying jobs where economic opportunities are sparse. To address these challenges, the IRA funds USDA to provide direct grants or loans for rural electric cooperatives to procure clean energy, with an express purpose of reducing GHG emissions.

METHODOLOGY

As in the previous two coal cost crossover studies, this report compares the marginal cost of energy (MCOE) for existing coal plants across the U.S. with the LCOE for solar and wind. We compare the same coal costs to four different cost scenarios for renewables. Scenarios vary by resource type

(wind or solar) and by geographic scope (regional or local). For the first two scenarios, regional solar and regional wind, we separately examine the costs of solar and wind located within the same region as a given coal plant, calculating the LCOE to replace each plant's annual generation within a nearby region that corresponds roughly to the utility's service territory.[vi]

For the last two scenarios, local solar and local wind, we look at local costs for solar and wind separately, calculating the cost if all replacement renewables are sited within a 45 km radius of the existing coal plant. Local solar and wind projects get the additional energy community tax credit bonuses in the IRA, which helps to offset losses in power resource quality due to the local siting constraint. A more detailed explanation of our methodology is available in this report's Appendix.

Coal Economics

To calculate the MCOE at each coal plant, we sum three cost components: the cost of fuel, the fixed and variable costs of operations and maintenance, and the going-forward routine capital expenditure costs, each calculated on a per-MWh basis. Using 2021 U.S. Energy Information Administration (EIA) data, we calculate the total going-forward marginal cost for all coal plants operated by utilities or independent power producers in the continental U.S., excluding plants that are used for co-generation of heat. These costs appropriately comprise marginal cost because they would not be paid if the coal plant retired. By contrast, we do not include unpaid capital balances as part of the MCOE because their payment does not depend on whether the plant retires.[vii]

Renewable Economics

We used NREL's Regional Energy Deployment System (ReEDS) model to calculate solar and wind LCOE values, which are all-in estimates of the cost of energy output in MWh, taking into account all capital expenditure, operations, and maintenance costs. We used the 2021 actual cost values from the 2022 NREL ATB.

The ReEDS model uses solar and wind resource potential values at around 50,000 sites across the country, accounting for comprehensive exclusion criteria, including land cover, elevation, slope, environmentally sensitive areas, and local siting regulations. The model also provides annual capacity factors at each of these sites. The site-specific LCOE is then calculated based on capacity factor, as well as a comprehensive list of parameters including capital costs, fixed operation and maintenance costs, equity costs, interest rates, construction costs by location, construction period,

[vi] We use regions defined by NREL's Regional Energy Deployment System model, explained in detail in the appendix.
[vii] These remaining balances are the primary target of the reinvestment programs created by the IRA. Though we don't include the balances in our cost calculations, the potential to refinance and replace with clean energy is another path toward reducing coal generation beyond operating costs.

IRA tax credits, and depreciation. We calculate the LCOE after accounting for both the ITC and PTC 2022 tax credit values, using the cheaper of the two.

Renewables key assumptions

Across the four renewable scenarios, we make several key assumptions:

- Regional solar and wind costs include new grid interconnection costs, while local resources do not.
- All renewable resources qualify for the prevailing wage and apprenticeship hour tax credit bonus.
- All wind resources qualify for the full domestic content bonus, while 42 percent of solar resources qualify for the domestic content tax credit bonus based on current domestic content levels.[20]
- Storage does not qualify for the domestic content credit bonus.
- All tax credits are reduced by 10 percent to account for transfer losses.

Regional renewables scenarios

For the two regional renewable cost scenarios, regional wind and regional solar, we start by finding the LCOE for regional wind and solar that could replace each plant's 2021 annual generation. The region we study for each plant is based on the ReEDS balancing area (of which there are 134, see Appendix) in which the plant is located, corresponding roughly to the utility territory. For each coal plant, we sort the wind and solar sites available in that region by LCOE and choose the best sites based on capacity factor to replace the coal generation. For selected sites within each region, we capacity-weight the site-level LCOEs to estimate the weighted average regional LCOE. Interconnection costs associated with transmission lines that connect the project to the grid are also added into these LCOEs, while we make no assumption about broader grid impacts.

Local renewables scenarios

For the local wind and local solar scenarios, we first determine the viability of the local wind or solar replacements for each coal plant. Using the plant's latitude and longitude as the center, we create concentric circles around each coal plant, starting with a radius of 5 km and moving up to 45 km in 5 km increments. We identify the solar and wind sites that fall within each of these concentric circles and separately estimate the site-level capacity and annual generation potential for solar and wind resources. We then estimate the minimum radius needed to replace the annual generation from each coal power plant with solar or wind resources.

If there is enough generation found within the 45 km radius, we then determine the local LCOE by capacity-weighting the site-level LCOEs for the maximum radius needed to match the existing

plant's generation. For solar, nearly all plants meet the generation requirement within a 20 km radius while for wind, the average radius is much larger and there are many plants without enough wind generation within 45 km because of the more site-specific nature of wind energy potential and the larger land footprint (see Figure 3).

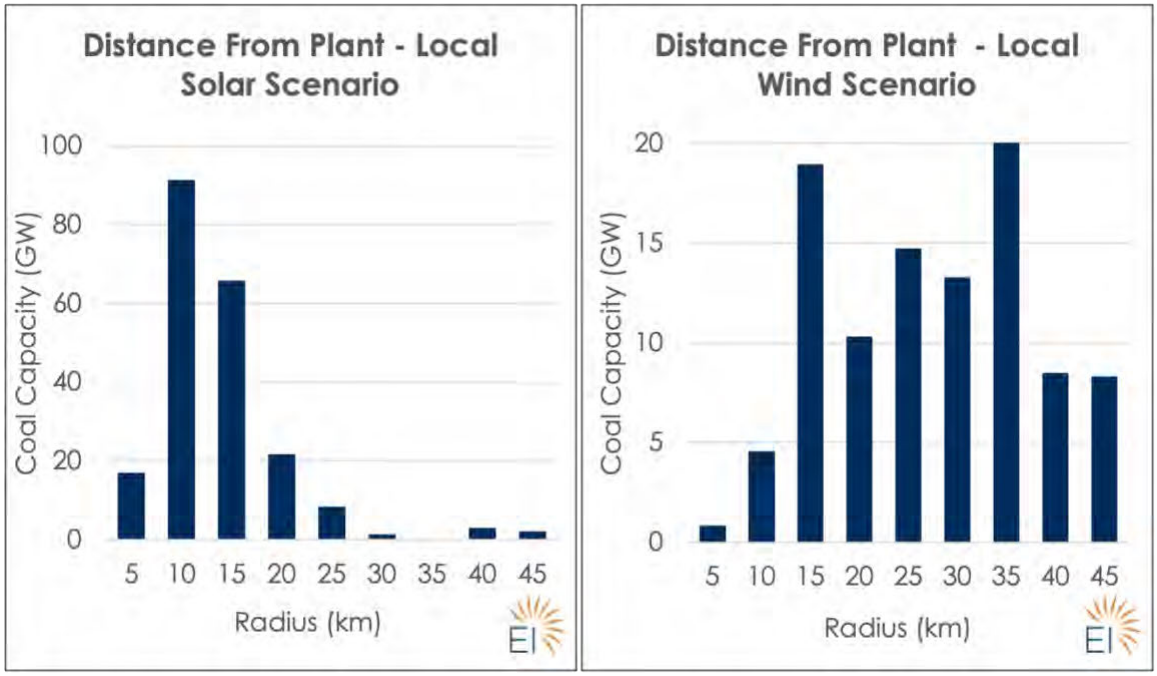


Figure 3. This figure plots the radius needed to match each plant's generation, while still being cheaper than coal, for both local solar and local wind. The majority of coal capacity has enough solar potential within a 20 km radius to meet the plant's entire annual generation in our local analysis and still provide cheaper energy than coal. While many plants have sufficient and cost-effective local wind nearby, less potential is available in close proximity for local wind.

For the local scenarios, we assume that all projects sited within 45 km of the plant will receive the IRA's 10 percent energy community bonus tax credit, given that both the census tract and neighboring census tract to any retiring coal plant fit the IRA's definition of an energy community. For these scenarios, interconnection costs are not included in the LCOEs as we assume that the new resources can utilize the existing plant's interconnection infrastructure.

Storage analysis

For the local solar scenario, we also analyze the economic feasibility of installing four-hour battery storage capacity along with the solar to provide additional reliability services to the grid. For this analysis, we start with a $330 per kilowatt-hour (kWh) price for the storage,[viii] and we include a 36

[viii] This price is based on the 2021 actual storage costs in the NREL 2022 ATB.

percent ITC (the full credit plus the energy community bonus, minus transferability losses). After calculating the savings from replacing the coal generation with local solar generation, we then determine how much battery capacity those cost savings would fund. Due to uncertainty in the battery price going forward, we calculate the battery capacity funded for storage prices ranging from $100 to $400/kWh.

RESULTS & DISCUSSION

Main findings:

1. >99 percent of plants studied are more expensive to run than to replace with new renewable wind or solar energy.
2. >97 percent of plants studied are more expensive to run than to replace with either local solar or local wind energy within 45 km (approximately 30 miles) of the coal plant.
3. Replacing coal generation with local solar resources could drive up to $589 billion in clean energy investment in energy communities across the U.S.
4. Replacing coal generation with local renewable resources could save enough to finance installation of 137 GW of four-hour battery storage—62 percent of the coal fleet's nameplate capacity.

Overall comparison between coal and renewable costs

For this report we combined elements of the two previous Coal Cost Crossover reports: We looked at replacing coal power with regional wind or solar resources *and* at replacing coal power with local wind or solar resources close enough to a plant to take advantage of its transmission connection and the energy community bonus tax credit. Across these four scenarios, we found that:

- 199 plants are more expensive to run than to replace with regional wind.
- 190 plants are more expensive to run than to replace than regional solar.
- 104 plants are more expensive to run than to replace than local wind.
- 199 plants are more expensive to run than to replace than local solar.

Analyzing these scenarios together, we found all but a single coal plant[ix] in the dataset of U.S. coal plants to be more expensive (lower renewable LCOE than coal MCOE) compared to replacement by at least one of these renewable options. Between local solar and local wind, 205 out of 210 plants had at least one cost-effective local renewable option. Of these, 98 had *both* local solar and local wind options that were cheaper than coal (see Figure 4). This represents a sharp acceleration

[ix] The single coal plant is the Dry Forks Station in Wyoming. It is the newest and among the cleanest coal plants in the U.S. coal fleet and is still only $0.32/MWh cheaper to operate than available regional wind. It is also a testbed for carbon capture use and storage (see https://www.powermag.com/dry-fork-a-model-of-modern-u-s-coal-power/). A similar plant built today would include capital costs and would not be competitive with new renewables.

in the previously observed trend in our coal cost crossover reports (see Figure 5). The full results of all four scenarios can be viewed in the accompanying spreadsheet.

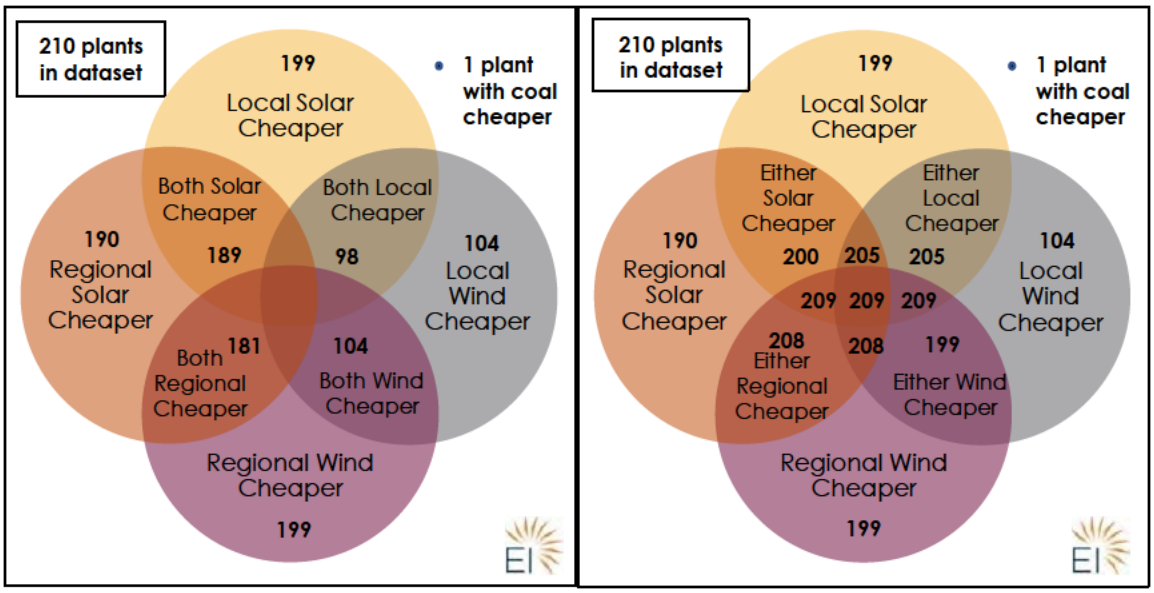


Figure 4. A closer look at the 210 coal plants in our data set based on the specific comparison with renewables that was made. The Venn diagram on the right looks at inclusive intersections (either resource is cheaper than coal) while the one on the left looks at exclusive intersections (both resources are cheaper than coal). We did not analyze any hybrid combinations of wind and solar, although this is clearly a possibility in the local context (98 plants) and the regional context (181 plants).

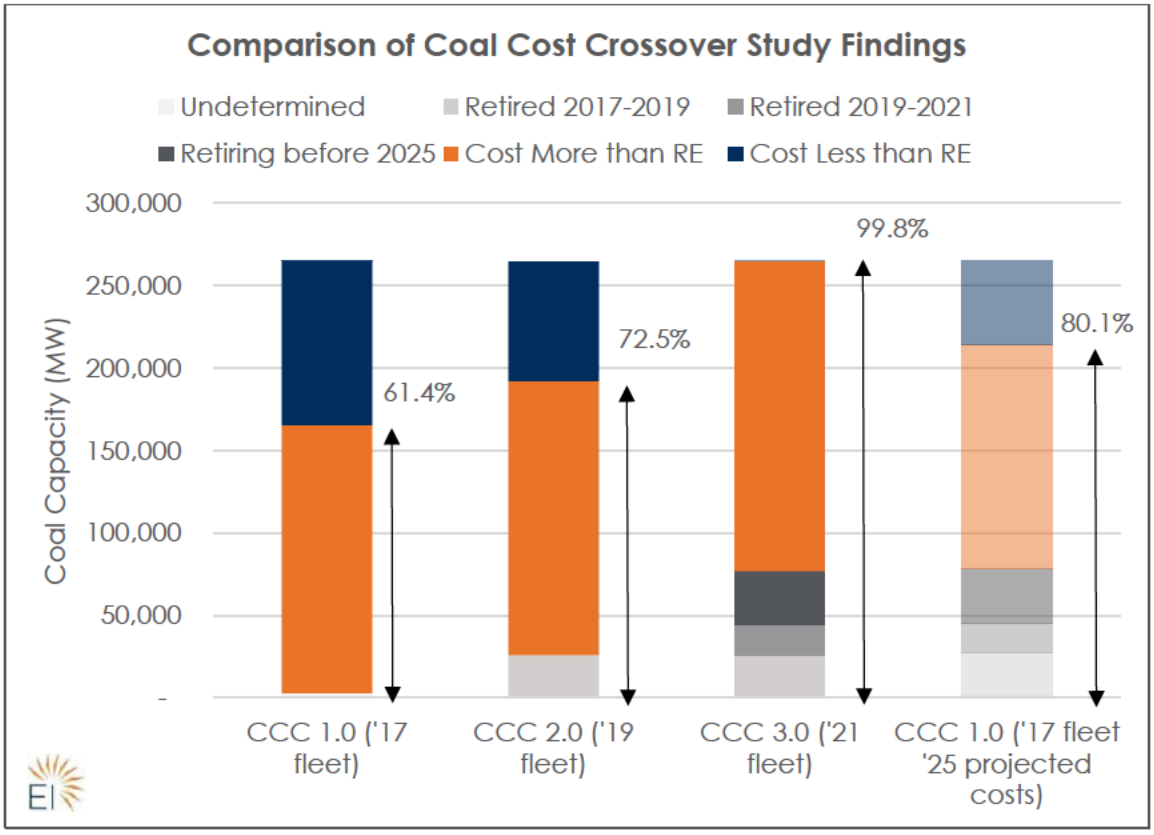


Figure 5. Comparison of our two original analyses of renewables and coal cost-competitiveness. The first included a 2025 projection for renewable costs to compare with 2017 coal going-forward costs. This comparison highlights how much the trend for coal being uneconomic compared to replacement by renewables has accelerated since the first report published in 2019.

Comparison between coal and cheapest available wind or solar resource

For the plants that were uneconomic, multiple renewable options were less expensive than coal generation, but regional wind and local solar were most frequently the cheapest overall resources (see Figure 6 and Figure 7). Regional wind was the cheapest option for 117 plants, while the most economic resource was local solar for 75 plants, local wind for 13, and regional solar for only four.

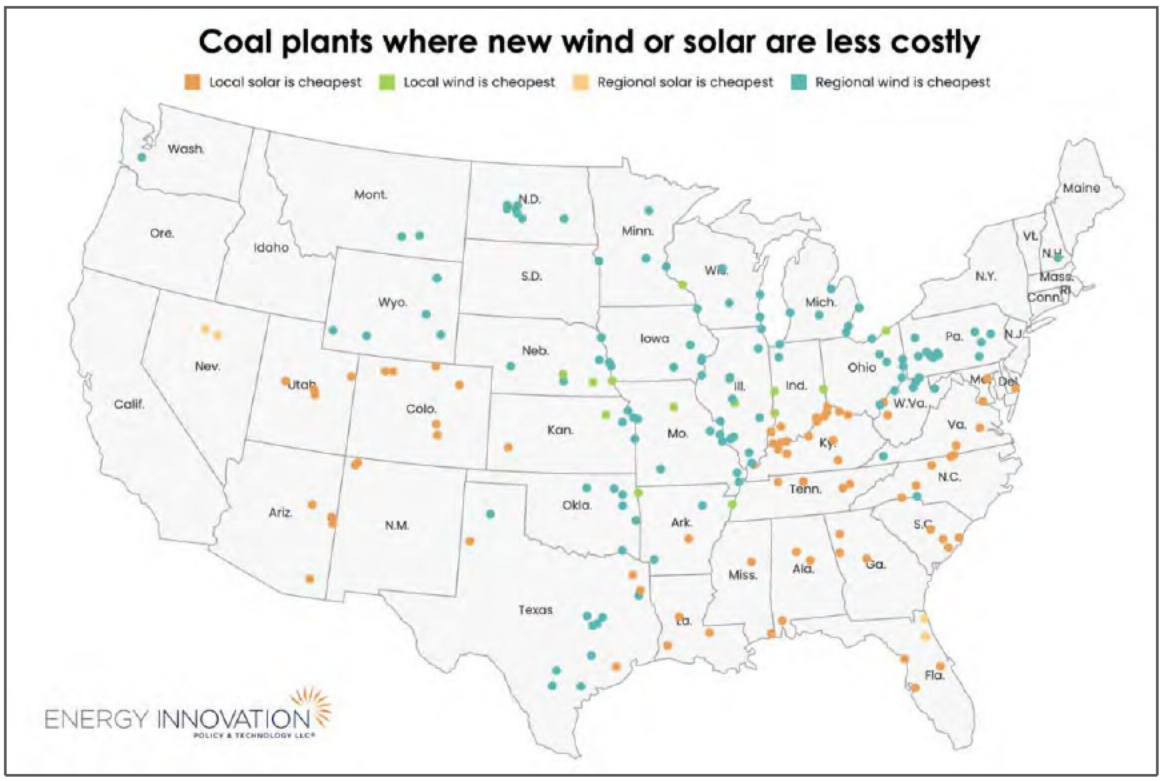


Figure 6. While most plants have multiple cheaper renewable options, the overall cheapest renewable resource varies by geography.

Notably, for solar, local replacement is cheaper than regional replacement in many cases due to low regional cost variability, lower transmission spur line costs,[x] and IRA energy community bonuses. For regional versus local wind, however, regional resources tend to be cheaper even with the added costs due to higher variation in resource quality for wind—going further from the plant often yields significantly better wind energy sites.

[x] A "spur line" is the transmission line that connects a renewable project to the bulk system at a point of interconnection. In this analysis, we do not make assumptions about interconnection costs beyond the cost of building the spur line. In this limited respect, we anticipate that local wind and solar costs would be lower than regional renewables, because local renewables are adjacent to the coal plant's point of interconnection. We recognize that interconnection costs for renewables have been increasing for a variety of reasons as they sit in ever-growing interconnection queues around the country, but also hypothesize that some renewables could reuse existing coal plant interconnection rights with very low interconnection costs. See https://emp.lbl.gov/news/pjm-data-show-substantial-increases.

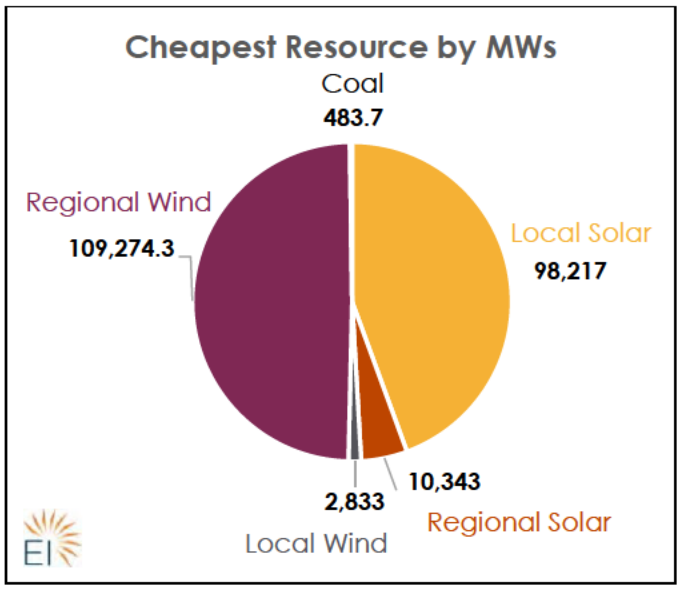


Figure 7. This chart shows the cheapest renewable resource option for each MW of coal capacity studied in this report. Local solar and regional wind are the cheapest renewable resources for nearly all plants.

We still see a wide range in the relative economics between existing coal and new wind or solar, with the all-in costs for the cheapest renewable option anywhere from zero (for one plant) up to 80 percent cheaper than the going-forward costs for coal, absent a few edge cases. Typically, the least economic plants have low capacity factors that result in very high fixed marginal costs per MWh or very high fuel costs.

For more than three-quarters of U.S. coal capacity, the all-in cost per MWh of the cheapest renewable option is at least a third cheaper than the going-forward costs for the coal it would replace (see Figure 8).

The substantial cost savings from replacing coal with renewables indicates the potential to invest in additional resources that provide complementary services like flexibility and transmission, without raising costs. Policymakers should consider a portfolio of clean resources that together provides adequate value and any needed reliability services. These resources could include storage,

regional or interregional transmission upgrades, demand-side resources, and complementary portfolios of wind and solar.

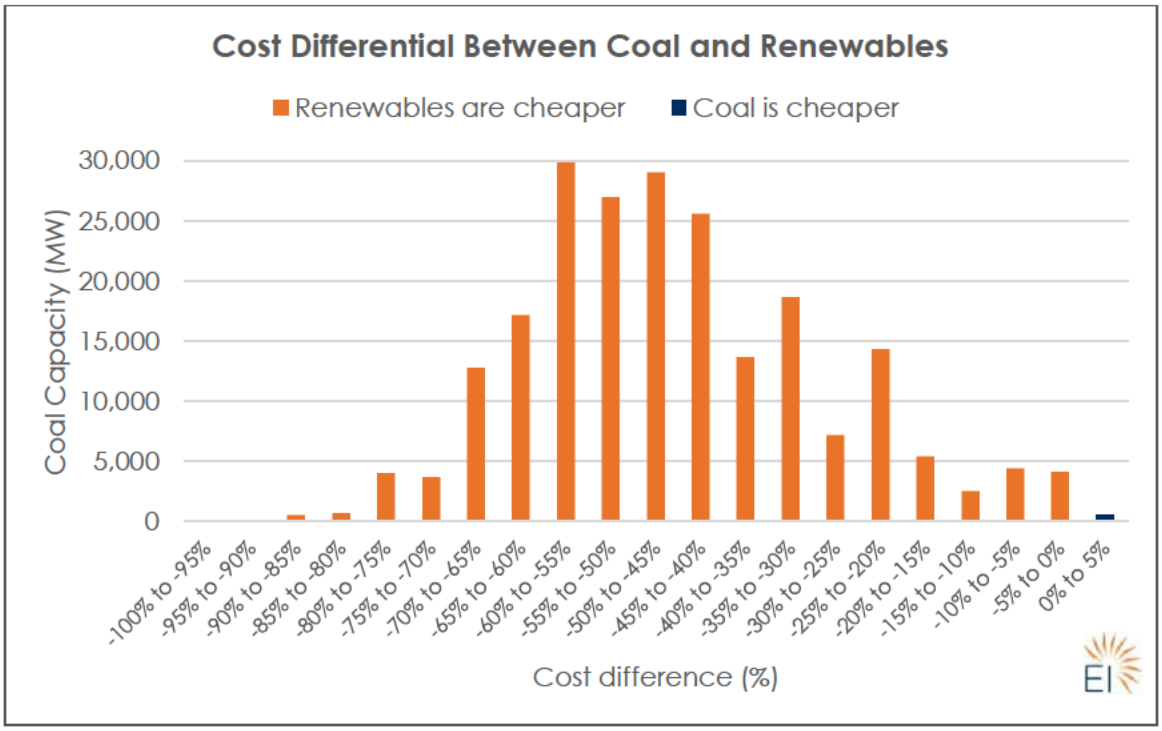


Figure 8. Aggregated plant capacity shown as percent difference between renewables LCOE and coal going-forward cost. The orange bars indicate capacity where renewables are cheaper than coal and coal is deemed "uneconomic." The one blue bar indicates the sole plant that is still cheaper to operate than replace with renewables.

Local replacement of coal

Local solar and wind

For 199 of the 210 plants studied we find that local solar replacement is more economic than coal, based on energy generation alone, and for 75 plants it is the cheapest option entirely. Local wind is also a viable option for many plants, with 104 plants having cost-effective local wind resources and 13 having local wind as the cheapest option. For 98 plants, both local wind and local solar were

cheaper than coal. While we did not study any combinations of the two, this result indicates that a portfolio that includes both local wind and local solar would likely be a viable option with additional reliability value near many plants.

In these local replacement scenarios, we looked at replacing all the annual electricity generated by a given coal plant with either local wind or local solar within 45 km of the plant. This allowed us to assume lower interconnection costs[xi] (a significant barrier for new projects)[21] while taking advantage of the IRA's energy community tax credit bonus. In nearly all cases we studied, the reduced interconnection costs and added tax credit compensates for potentially lower resource quality when restricting site selection in areas close to the plant. We find particularly good resource quality in the local solar scenario, where 191 plants have sufficient sites nearby such that their generation can be replaced within 20 km.

Solar plus storage stepping in at North Valmy

In Nevada, NV Energy has already realized the cost and community benefits of using solar plus storage in place of the 567 MW North Valmy Generating Station, near Winnemucca. Two new solar plus storage facilities located within the same county will replace this plant when they are completed by 2025. The two replacement projects will provide 250 MW solar capacity plus 200 MW of storage, and 350 MW of solar plus 280 MW of storage. These projects will also create several hundred construction jobs, and the storage will help shift the solar generation to the times of day it is most needed, serving the reliability needs of the area. This is consistent with our analysis, which finds that it would be cheaper to use solar plus storage up to the full plant's capacity than to continue to run the coal plant. Plants across the country can now follow Valmy's example and effectively decarbonize with solar plus storage.

Local replacement offers three other benefits. First, local replacement can help preserve livelihoods and tax revenue for surrounding communities through the energy transition.[xii] Second, local resource replacement falls into the category of projects that can qualify for loans via the DOE's

[xi] In our modeling, we use ReEDS spur line costs as a proxy for interconnection costs of regional renewables. For local renewables, we assume no interconnection costs because the point of interconnection already exists at the coal plant. This is a simplification—each site will be different and will require an interconnection study or transmission plan to ascertain the interconnection costs.

[xii] New renewable energy installations are only one piece of the puzzle when it comes to community transition as they typically do not provide as many jobs or as much tax revenue as a coal plant. While local energy replacement can contribute, further community re-development and economic diversification is needed, as discussed further in the policy recommendations section.

EIR program, as the projects would be a direct reinvestment in energy infrastructure. Our analysis shows investment in local solar resources could drive $589 billion in capital investment to energy communities across the country (see Figure 9).

Third, siting renewables in proximity to plants creates the possibility that these new resources could use the existing plant's grid interconnection. Recent analysis of PJM's interconnection process shows that the median interconnection cost from 2020 to 2022 grew ten-fold over the costs from 2017 to 2019, largely due to transmission network upgrade costs.[22] While we considered reduced interconnection costs for local resources, the advantage of local replacement could be even more considerable as the cost of the line is only a part of the problem. For clean energy projects across the country, long interconnection wait times are also a major hurdle to overcome.

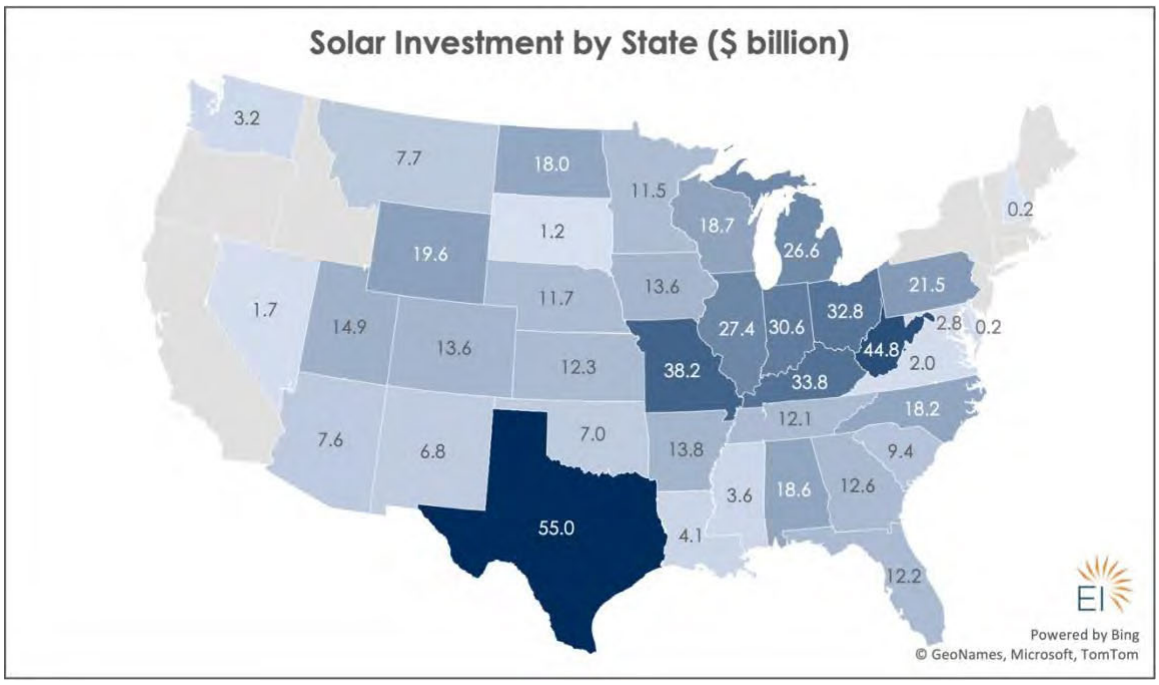


Figure 9. The solar capacity needed to provide enough energy to make up for coal generation across the country would drive hundreds of billions in investment. States with no investment number had no plants in our data set.

Local solar plus storage

We followed up on our local solar scenario by looking at a solar plus storage replacement option for each plant that includes local solar energy plus four-hour batteries to provide additional capacity value and higher market profitability in some cases. We find that the savings available from switching from coal generation to local solar generation can finance 137 GW of four-hour battery capacity at a price of $330/kWh across the coal fleet.

For more than a third of the coal capacity studied, we find that in addition to energy generation replacement with local solar, 80 percent or more of the plant's capacity can be replaced with four-hour batteries at a combined levelized cost that is still less than the going forward cost of the plant. For the remaining plants, the percentage of capacity that can be economically replaced is still quite significant: We find that savings from renewable generation could fund storage at more than 50 percent plant capacity at 136 plants.

Renewable options cheaper than expensive upgrades at Mitchell plant

In 2021, American Electric Power determined it would likely be more cost-effective to retire West Virginia's Mitchell Power Plant than pay for expensive pollution control upgrades required by the U.S. Environmental Protection Agency (EPA). However, the West Virginia Public Service Commission (PSC) ruled that the utility had to keep the plant open, and that WV ratepayers must pay for the upgrades. At the same time, in Kentucky and Virginia, who were also receiving power from the plant declined to make their state's customers pay, leaving West Virginians to shoulder a $448 million price tag. Our analysis shows taking advantage of regional wind resources would be 48 percent cheaper than continuing to run this polluting plant. Replacement with local solar and battery storage would be 50 percent cheaper and would provide the reliability the PSC seeks while saving ratepayers hundreds of dollars every year.

This local solar plus storage arrangement has at least three advantages:

First, solar plus storage provides resources with a significant capacity and ancillary service value at the same place on the power grid, addressing in part possible reliability concerns that may be associated with coal plant retirement.

Second, the new storage ITC means batteries do not need to be co-located with renewables to take advantage of the tax credit. This means that while local renewables may need to be sited a short distance from the plant, storage can be placed directly at the coal plant site and use existing electrical infrastructure to act as a central collection site for renewables. This arrangement also bolsters economic development opportunities in coal communities.

Third, combining solar and storage empowers a gradual coal phase-out, benefiting communities and grid reliability. Electricity generated from coal can be reduced, while keeping the coal boiler and generator available for emergencies. If needed, the generator can eventually be transformed into a piece of grid regulation hardware requiring no boiler, and batteries can store and release renewable energy to make the whole system available at times of highest grid demand. Renewable energy can

be a part of an economic diversification package that may include other re-purposing of the site, such as a plant in Michigan that was re-developed into an insurance company's headquarters.[23]

The reliability implications of coal plant retirement should be evaluated for each specific plant. A one-to-one replacement is often not necessary given the capabilities of the remaining power plant fleet. For example, the battery capacity necessary to take over the reliability burden of any given coal plant is varied, depending on the role of the plant and broader resource mix, and it is not needed at all in many cases. Wind and solar (especially in a complementary combination) already tend to provide a measure of capacity value to the regional grid. Other assets like faster, more flexible gas units or behind-the-meter resources may already be carrying more of the regional reliability burden, and transmission expansion can help reduce the need for dispatchable generation for resource adequacy as well. Therefore, coal capacity is not always necessary for reliability depending on the resource adequacy in each region as determined by the balancing authority.[24]

Figure 10 shows the percentage of battery capacity at each plant that can be funded by coal replacement with local solar, providing a range of options for combining renewables with storage.

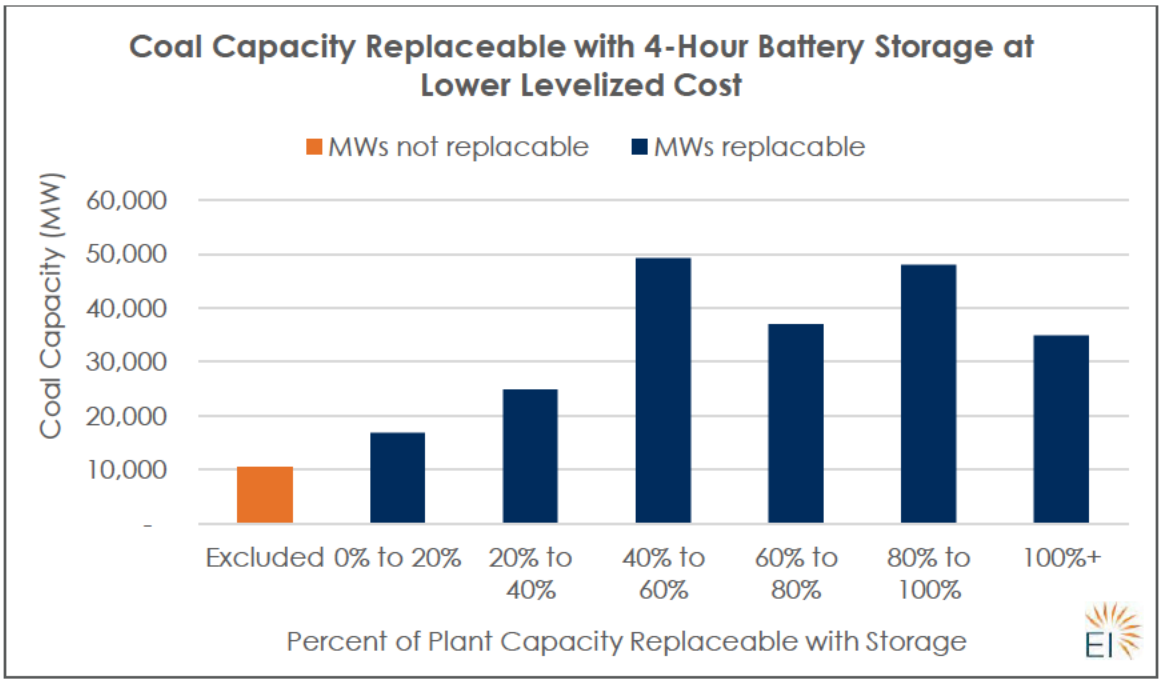


Figure 10. Coal plant capacity (in MW) by the percentage that can be replaced using only coal crossover savings. "Excluded" indicates plants for which local solar generation was available but was not cheaper than coal.

The economics of battery replacement for capacity are highly dependent on battery costs. For the analysis above, we used $330/kWh as the cost of storage, which is the 2021 cost for storage in the NREL 2022 ATB.[25] Our cost accounted for the new standalone storage ITC and energy community tax credit. To study the sensitivity of these findings to battery prices, we evaluated the potential for capacity replacement across prices ranging from $100/kWh to $400/kWh (see Figure 10).

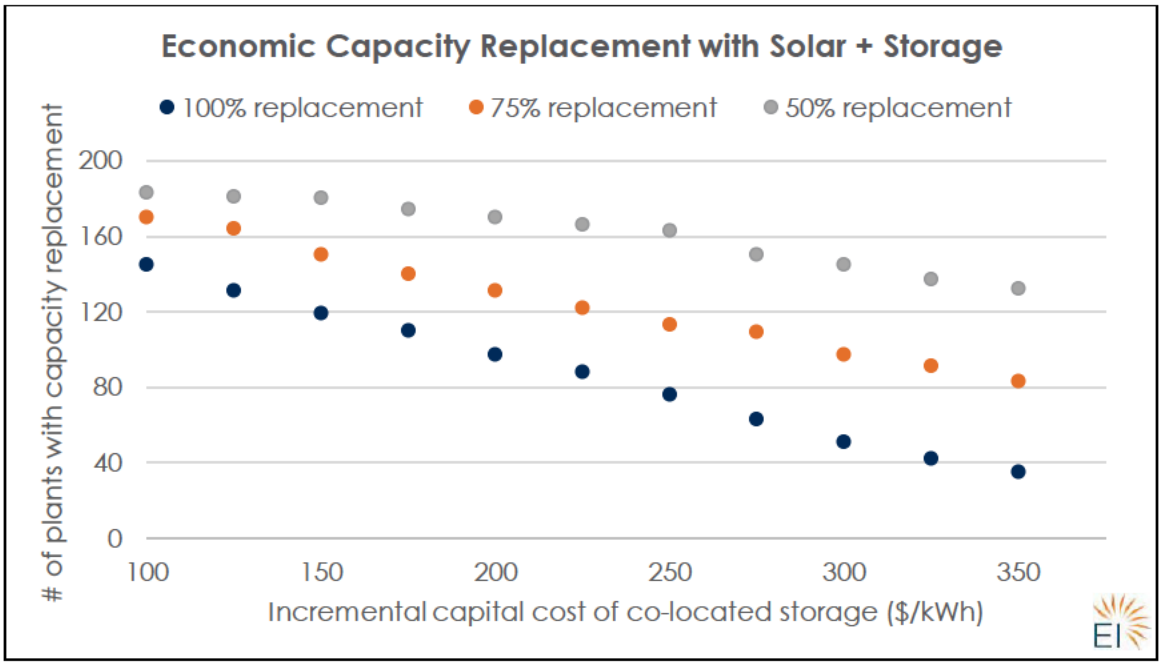


Figure 11. Economic battery capacity relative to battery price by percent capacity that can be replaced at each plant.

Utilizing additional financing to fund local resources: Ameren's Rush Island Plant

It is important to note, however, that fuel savings are not the only source of savings that could help finance replacement batteries in a coal-to-local renewables swap.

For example, Ameren's Rush Island power plant in Missouri is not a strong candidate for financing batteries solely with savings from switching to local renewables. Yet by also accounting for needed upgrades, the plant's remaining balance, and reliability concerns, the case for financing batteries for reliability value becomes stronger.

Ameren was planning to retire the 1,195 MW coal plant in September 2022 partially due to the expense of adding court-ordered selective catalytic reduction (SCR) to address air pollution

noncompliance, with a price tag of $310 million[xiii] to $1 billion.[26] Unfortunately, because early retirement could cause severe voltage stability problems leading to cascading power outages, the Midcontinent Independent System Operator (MISO) sought to keep the plant online and received Federal Energy Regulatory Commission (FERC) approval for a 12-month system support resource agreement to be renewed annually.[xiv] According to the grid operator, potential renewable energy additions or possible demand-response programs wouldn't adequately address the location-specific voltage problem. However, due to the geographic nature of the potential voltage instability, local renewables coupled with batteries could go a long way toward mitigating this concern without waiting for the transmission upgrades MISO deemed necessary.

Our initial analysis finds that switching to renewables could generate savings to pay for replacing replacement of only 4 percent of the plant's capacity with batteries. However, the IRA now creates new possibilities. Because Ameren faces capital expenditures in the $300 million to $1 billion range, and already holds an estimated $600 million for the plant in its rate-base (interest on which is paid by its customers at standard utility rate of return), existing state public utility commission securitization authority could be used to refinance this obligation in combination with the EIR program, generating much greater customer savings.[xv] Investing these savings in four-hour battery storage could match 85 to 165 percent of the plant's capacity. Furthermore, batteries would only be necessary if the local renewables on their own were not sufficient to provide voltage support or if the proposed transmission solutions proved too slow or expensive.[xvi]

New IRA financing and tax credits make replacing coal plants with a combination of local wind and solar power supported by batteries an attractive option for most coal plants in the U.S. Such replacement can be done with a minimum of disruption to the grid while keeping jobs in affected communities—not to mention the great improvements to public health from reduced pollution.

POLICY RECOMMENDATIONS

Our analysis makes it clear the comprehensive the IRA tax incentives have created a favorable policy environment for the coal-to-clean transition. However, the transition can be made even more cost-effective if utilities harness the IRA's loan and grant programs and use best practices to assess cost-saving replacement options.

[xiii] Assuming $250/kW all-in costs. See https://www.powermag.com/estimating-scr-installation-costs/.

[xiv] MISO identified four transmission upgrades that are needed to maintain voltage on the grid, with the last one expected online by June 2025, according to the grid operator. See https://www.utilitydive.com/news/ameren-missouri-coal-rush-island-miso-ferc/630226/.

[xv] The interest rate on the securitized loans or government-backed loans through EIR are assumed to be 2.95 percent, or the average of the 20-treasury yield across the last 10 years plus 0.375 percent. Missouri law already allows for coal plant securitization.

[xvi] While MISO investigated replacement of the plant with renewable energy, it does not appear that MISO considered renewables in geographic proximity to the plant.

Planners and policymakers should make sure they are not caught unprepared by a wave of retirements, and that replacement renewables and complementary flexible resources can be deployed in a timely manner. Advocates and policymakers interested in capturing the economic and public policy benefits of shifting away from coal can take several actions to ensure that power plant operators take advantage of the moment by requiring utilities to account for IRA incentives and funding programs in planning and procurement. Finally, our analysis suggests that IRA provisions designed to encourage a just transition for coal communities are well positioned to spur new investment in generation and grid balancing resources in the immediate vicinity of existing plants, but experience has shown that a just transition will only happen with the careful attention of legislators and regulators alongside local communities.

Reliability assessment keeping expensive Indian River plant online

Delaware's only remaining coal plant, Indian River Generating Station, was planned for retirement by June 2022—until the grid operator, PJM, requested it remain open until 2026. PJM had determined that transmission upgrades would be needed to stabilize the grid before the plant could be taken offline. The plant, which only has one remaining unit, is historically the worst polluter in Delaware and also the eighth most expensive plant we analyzed due to low capacity factor and high estimated fuel costs. Local replacement of this plant could assuage reliability concerns by providing generation and capacity needs at the same location on the grid. Our local analysis finds that 246 MW of storage could be funded via savings. At over 50 percent of the plant's capacity, this is a good candidate for re-assessment of reliability needs.

Preparing the way for coal transition

Improving interconnection and transmission processes

The Rush Island Power Station example discussed above is not unique and blocking retirement of uneconomic plants due to broader system stability concerns and transmission requirements harms customers. To move forward while maintaining reliability, independent system operators (ISOs) and regional transmission organizations (RTOs) should proactively study solutions that can enable plant retirements. The alternative—overriding utility retirement plans and requiring FERC approval for expensive stopgap payments to keep high-cost plants running—is not good for utilities or their customers.

Our analysis shows that post-IRA, almost every coal plant has reached its economic tipping point. As pollution standards and clean energy policies continue to worsen coal plant economics, ISO/RTOs will increasingly encounter situations where innovative resource

portfolios will be needed to economically and reliably replace coal plants, including transmission. As neutral arbiters of just and reasonable rates, system operators must be ready to enable cheaper electricity and public policy goals by allowing utilities to retire uneconomic plants. Proactive transmission planning and deployment, alongside improvements to interconnection processes are both crucial to prepare for uneconomic plant replacement.

Absent regulators stepping in, retiring a plant is much easier than building a new renewable project. Price signals may induce coal retirements before new renewable projects can be approved and built to take their place. The growing interconnection queue backlog is of particular concern here. As of 2022, the two largest power markets in the U.S., MISO and PJM, had about three times more renewables capacity waiting in the queue than they had existing coal capacity.

For PJM, this backlog was deemed insurmountable. While PJM works through its existing interconnection requests, it will not review new requests until early 2026. It is clear that additional measures to improve the interconnection process, including better regional transmission planning, are needed to avoid similarly extreme measures in the future.[27] FERC is currently considering interconnection policy changes, but state public utility commissions can also help by examining their state's queue and assessing whether proactive transmission buildout could connect cost-effective clean energy. In states outside an ISO/RTO, states hold sole responsibility for proactive transmission and planning process reform to reduce wait times and hasten the pace of in-state clean energy investment.

Building local: accelerating deployment while maintaining reliability

Action from FERC and other policymakers on interconnection reform and transmission buildout cannot come too soon. A recent brief from Lawrence Berkeley National Lab (LBNL) analyzing interconnection costs in the PJM region finds that, alongside the tremendous lengthening of the interconnection queue, interconnection costs have increased substantially in recent years.[28] The main driver behind these increases has been broader network upgrade costs, reflecting system changes due to the influx of renewables and the fact that optimal renewable sites are often far from the coal they might replace.

There is no doubt that variable renewable resources are fundamentally different from dispatchable fossil generators, but variability does not imply unreliability. Studies are clear: A coal-free U.S. electricity system can be dependable.[29] Yet renewables do require a different resource adequacy framework, which makes resource diversity, energy sufficiency, regional and interregional transmission, and demand response more important. As system operators design new resource adequacy metrics, regulators should support them by defining minimum resource adequacy requirements and soliciting cost information.[30]

In a high-renewables environment, interregional electricity transfer can help manage local weather variation, providing higher reliability at lower cost. RTOs and regulators can enable interregional

coordination by expanding planning areas or subsidizing transmission lines that provide for specific reliability needs. Finally, regulators and state legislatures can require resources that bolster reliability like energy storage has become a cost-effective way to integrate renewables, as this report shows. However, storage still lags in investment. A legislative storage mandate, like the one passed in California in 2013 can help accelerate storage deployment.[31]

Ultimately, building out the network to include and adapt to some of the best available renewable resources, evolving the bulk power system's resource adequacy framework, and improving inter-regional coordination supports a least-cost, reliable electricity system given the new IRA incentives. But, as is evidenced by the delays described above, all this takes time. Building local resources closer to or at the same site as coal plants could dramatically accelerate clean energy deployment while providing significant incremental reliability value.

Prior to the IRA, local replacement was not always economic on an annual generation cost basis relative to the cost of maintaining a coal plant. However, to support a just transition, the IRA includes additional incentives for building new clean resources near coal plants or "energy communities." Our analysis shows that local wind or local solar plus storage could create a cheaper electricity portfolio than nearly every plant, while delivering the same amount of electricity and providing significant reliability value. Even if a coal plant weren't completely shut down, it could work in tandem with cleaner, cheaper resources fed through the same point of interconnection to deliver cheaper, cleaner electricity without materially affecting the transmission system and system operations (it might even improve these). Utilities, ISO/RTOs, and state and federal regulators should move swiftly to develop standard templates that allow for coal plant hybridization or replacement with clean portfolios. These templates would have to be generically robust enough to satisfy system reliability and stability concerns under a variety of conditions to replace coal without a lengthy interconnection process.[xvii]

Proactively pursuing transition

Re-evaluation of integrated resource plans and improving competitive procurement

While measures to proactively plan for and better accommodate new renewable projects are necessary to capture the huge economic benefits of transitioning expensive coal plants to cheaper renewables, they are not sufficient. Utility integrated resource plans routinely overestimate new renewable costs, and the IRA programs will likely make these overestimations even higher. Any

[xvii] There may be concerns about undermining competition if some resources are allowed to skip ahead of the line, but presumably standard templates will involve costlier investments than what might be proscribed in a more specific interconnection study. In any case, it makes sense to recognize that providing replacement resources at or near an existing resource is easier and simpler for the network, and the benefits of just transition and accelerated deployment should be balanced against competition concerns.

investment plan or market-based solicitation for renewable contracts completed before August 2022 is now out of date. Regulators can expect independent power producers to offer lower bids for just about any clean energy technology. Under their authority to set just and reasonable rates, PUCs should insist that utilities redo integrated resource plans and resource solicitations, despite the procedural complexity. For example, advocates have already submitted evidence to the North Carolina Utility Commission that such a re-examination would be prudent for Duke Energy's Integrated Resource Plan and Carbon Plan.[32]

In addition to cost updates, integrated resource plans should account for the benefits of location-based procurement to replace coal generation. In New Mexico, the Energy Transition Act required the Public Service Company of New Mexico to site some of the replacement resources for the San Juan Generating Station in the nearby school district to replace lost tax revenue.[33] Because of location-specific tax credit bonuses, traditional regulatory requirements to minimize consumer costs now require an examination of local investment in replacement wind, solar, and battery resources.

FERC and NERC should work with the ISO/RTOs to create standardized approaches to gradual replacement with local resources and eventual development of reliable resource portfolios that include renewables, transmission, and emerging technologies like power electronics and synchronous condensers.

In addition to accurately assessing renewables during planning processes, enabling competitive procurement is crucial to getting steel in the ground. Even before the IRA, unsubsidized renewables were the cheapest new resource in most of the country. However, regulators can have difficulty discerning the true cost of clean energy or comparing variable clean resources with dispatchable fossil power providing different services. Such assessments generally depend on limited utility information.

All-source procurement is a way around this—it is a well-established but underutilized process that requires the utility to provide assessments of resource need, then bid these services to the market. For example, Xcel Energy Colorado achieved record-low wind, solar, and storage prices that shocked the electricity world with an all-source procurement in 2018, avoiding costly investments in gas and accelerating coal retirement.[34] PUCs should establish all-source procurement rules that link these solicitations as inputs to integrated resource planning processes that ultimately result in resource procurement—a key part of the Colorado planning process.[35] These solicitations also provide the opportunity to assess and define needed system reliability attributes after coal plants retire and allow supply-side, demand-side, transmission expansion, and regional market resources all compete to fill that need.[36]

Utilizing IRA funding and financing programs

Our comparison of the going-forward costs of existing coal plants with regional or local renewables doesn't capture all the economic advantages of such a transition. The IRA also includes measures that facilitate savings from lower cost financing.

First, the IRA created a $9.7 billion fund for rural electric cooperatives to reduce GHG emissions via a myriad of methods. With cooperative assets highly tied up in coal and without the same access to capital as investor-owned utilities, the transition to cheaper clean resources can be particularly challenging. To take advantage of these funds as soon as possible, co-ops should develop clear plans that use new clean energy and coal generation replacement to achieve deep GHG emissions reductions, in accordance with the IRA's statutory language.[37] For their part, states should provide resources to support the planning and application processes. With nearly 18 GW of plants in this analysis majority-owned by cooperatives, this program, if used to its greatest potential, could spur billions in rural economic development.

In addition to rural cooperative funding, the IRA provides substantial debt refinancing potential, when paired with reinvestment in new clean energy infrastructure. While we find all but one plant are uneconomic when compared to replacement with new wind and solar, many plants have large debt burdens that hamper the customer savings available from clean energy replacement. Some states have explicitly allowed utilities to refinance these remaining balances via securitization, but now all power plant owners have access to flexible low-cost capital to finance new clean energy projects reusing coal-

Cleaning up coal ash at the G G Allen Steam Plant

In 2014, the now-retired Dan River Power Station leaked 39,000 tons of coal ash into the Dan River—leaving residents without drinking water for years and requiring a $3 million clean-up. It also kicked off an investigation of Duke Energy in North Carolina that found all 14 coal plants in the state were leaking coal ash. G G Allen has the largest amount of coal ash on site out of all the plants with 19 million tons of that need to be removed. In addition to this high pollution impact, it is also the second most expensive coal plant to run in the U.S. according to our analysis. But it needn't be this way. North Carolinians can have clean air and water with cheaper clean energy. All four renewable scenarios in our analysis were cheaper than running the G G Allen plant. In addition to clean energy replacement, the use of a DOE loan guarantee could save ratepayers even more by using low-cost financing for replacement infrastructure including the coal ash remediation.

plant infrastructure via the DOE's new loan program.[38] PUCs should require utilities to update prior investment and coal retirement plans to reflect the low-cost capital now available for reinvestment in communities.

Particularly for independent power producers, which own 23 percent of the coal capacity we studied, these DOE loans will be significantly cheaper than those without government backing. The loan guarantee must be used to reduce GHG emissions and reinvest in that same community.[39] Funds can be used for a wide range of applications including partial or full coal replacement with renewable resources, transmission and storage, and even remediation of former fossil fuel sites, improving environmental conditions and serving as another source of job creation for the local community. Given the flexibility of the program, this is far from an exhaustive list.To smooth community transition, loans need not require immediate plant retirement, but instead could support projects that gradually reduce coal while increasing renewable generation and diversifying the community's economy.[40] The local renewable replacement plus storage scenario we study fits this approach.

Just transition in Colorado

In 2019, the Colorado legislature passed a bill creating the first Office of Just Transition (OJT), and just in time. With six coal mines and seven coal-fired power plants still operating, small communities, particularly in Western Colorado, risked near-total economic collapse. Since the legislation passed, the OJT created a Just Transition Action Plan to support economic diversification and job retraining. The town of Nucla illustrates how this plan can work. When their coal plant shut down three years ahead of schedule, it was the largest employer. The plant also provided nearly half the tax revenue that supported the whole region—including the fire department and school district. Residents were rightfully concerned, but Nucla has worked with OJT to transition their economy to focus on tourism and small businesses. Nucla still has a way to go and more funding is needed, but Nucla shows how pre-emptive planning can help ease the sting of coal closures. Now, newly appropriated OJT funds will continue to help Nucla restructure while preparing other Colorado coal communities.

Just transition for affected communities

State PUCs, legislatures, and state energy offices all have a role to play ensuring a just transition for coal communities. New IRA funding mechanisms mean traditional, least-cost utility planning practices now require reinvestment in communities whose economic prosperity depends on coal plants and coal mining. Assessing and including reinvestment in

these places is now essential to "least cost, best fit" resource planning.

Of course, the nuances of community needs are more complex than simple economics, and fully considering viable transition strategies in integrated resource plans is not possible unless state regulators and utilities seek input from affected communities at the beginning of the planning process. Seeking community input is not typically part of existing integrated resource planning processes, and it can be challenging for resource-constrained PUCs or utilities to incorporate new, innovative approaches to stakeholder engagement and ultimately community transition.[41]

State legislation should require PUCs and utilities to plan for community transition and assess the value of federal loan guarantees and tax credits for community transition, starting with outreach in an investigatory proceeding that provides access by holding commission forums in those communities. With this input, utility investment plans can better meet community economic needs, which can include tax revenue, workforce development, infrastructure investment, pollution clean-up, and community ownership models like community solar.

While the IRA has several reinvestment programs, energy communities cannot rely on clean energy alone to fully replace coal jobs and tax revenue. However, local clean energy can provide the opportunity for additional industrial development if new data centers or industrial facilities like synthetic fuel producers seek direct on-site access to low-cost clean energy. Proactive diversification of local economies is another path for success, which would benefit from state resources. The transition can even begin before the plant retires—gradual replacement and interconnection could ramp up in anticipation of the plant's eventual retirement, growing jobs and reducing pollution along the way.

Legislators should consider creating and funding a just transition office, following Colorado's example, to help coal communities develop transition plans. In addition to these legislative actions, PUCs can consider putting community transition funding into rates or creating ratepayer and shareholder cost sharing arrangements, similar to the arrangement made following closure of the coal plant in Colstrip, Montana.[42]

CONCLUSION

The economic case for replacing highly polluting and expensive coal-fired generation with clean energy is stronger than ever. Our new analysis, based on 2021 data, already surpasses our previous projection for 2025, finding that 99 percent of all U.S. coal plants are more expensive to run compared to new clean energy generation. Local replacement is more attractive than ever due to the IRA's new incentive and funding programs. Including battery storage along with local renewable generation can be an economic way to bolster the reliability value that these renewable projects provide to the grid. Building new wind or solar before completely retiring existing coal can be a recipe for success, a paradigm supported by the DOE's new loan authority. The near-complete crossover of coal economics versus renewables makes the imperative to transition clearer than

ever before, but policymakers, utilities, consumers, and coal-dependent communities must recognize the benefits and seize this moment.

APPENDIX: DETAILED METHODOLOGY

Coal Costs

Our goal was to develop an accurate estimate of the going-forward cost of running U.S. coal plants using publicly available data from EIA, FERC, and EPA. In assembling a master list of U.S. coal plants, we restricted ourselves to plants running mostly coal (excluding wood waste and petroleum coke burning units) operated by utilities and independent power-producers (sectors 1 and 2, in EIA parlance), excluding plants used for combined heat and power, for which the economics are more complicated because these plants receive other revenues from providing heat.

As a matter of convenience, we limited ourselves to coal plants in the lower 48 states and excluded a few plants for various practical reasons like corrupted or unavailable data. The companion spreadsheet to this report lists these in detail. In any case, these cuts did not materially reduce the number of GWs of capacity we covered. Finally, we grouped boilers and generating units together at one location as single plants, while excluding boilers and generating units fueled mostly with natural gas. The final master list of 210 coal plants is available in the companion spreadsheet to this report.

The going-forward cost for each coal plant in our master list comprises three principal components

- The cost of fuel on a per MWh of coal generation basis.
- The operation and maintenance cost of each plant levelized over the total generation from each included boiler and generating unit.
- The average annual going-forward costs for capital investments needed to replace and upgrade part of the power plant levelized over the total generation from each included boiler and generating unit.

This Appendix reviews our methodology for each of these three elements in more detail.

Cost of Fuel

Our principal method for calculating fuel cost for any given coal plant comes from first computing its cost of energy inputs in dollars per million British Thermal Units ($/mmBTU). We need a heat rate in mmBTU/MWh to convert this input into a cost of delivered energy in $/MWh. The heat rate is a number particular to any given plant that varies according to any number of contextual factors (e.g., fuel-type, technology, age, outside temperature, capacity factor). As a matter of simple expediency, we use a heat rate for each power plant defined by the sum of BTUs from all non-

natural gas fuels burned at that plant in 2021 divided by all the net-generation from these fuels as defined in the first page of EIA Form 923. We used this to convert input fuel costs into output electricity fuel costs.

We then used EIA data on fuel contracts paid by the plant; listed on page 5, "Fuel Receipts and Costs," of EIA Form 923. The EIA 923 spreadsheet lists fuel contracts with heat contents (mmBTU per fuel unit) and price paid in cents per mmBTU. From these contracts we can establish an mmBTU-weighted cost per mmBTU for coal, which we use as an input cost for that plant. Note that this does not include fuel processing costs that might be covered in values reported to FERC. Probably the most important example of fuel processing comes from plants that report burning so-called "refined coal" on one part of Form 923 while at the same time reporting direct purchases of other coal, e.g., bituminous coal, on another part of the form. This discrepancy is due to the fact that "refined coal" involves processing purchased coal (usually by spraying it with certain chemical agents) to reduce emissions from the smokestack. It is hard to know how much this extra processing costs on a per mmBTU basis, but we understand that the economic rationale for doing so is driven mostly by a tax credit. Historical trend analysis of some plants that burn "refined coal" shows that they sometimes choose to apply this processing and sometimes not reflecting, in our opinion, the likelihood that there is only a small impact on fuel costs to "refining" after netting out processing costs and tax credit income.

For plants that do not report input fuel costs to a regulator, however, other less plant-specific sources of information were required. In these cases, instead of specifically reported plant data, we used state-based data on the average cost of coal from EIA. To accurately reflect the diversity of coal types and relative mix of types that various plants consume, we used a combination of total plant coal consumption and state average coal costs from EIA as well as historical fuel consumption trends at the plant to estimate source coal type and marginal fuel costs. We used the following procedure:

Step 1: Extract the various mmBTU quantities of coal by type used by the boilers in each coal plant of interest from the 2021 EIA Form 923.

Step 2: Link each coal type with a state benchmark input fuel price in $/mmBTU. We establish that benchmark price by combining information on electric power sector coal prices by coal type and plant state from EIA's Coal Data Browser with coal heat content (mmBTU/ton) by state and coal type, also from EIA's Coal Data Browser (if heat content for a given coal type was unavailable for the 2021 reporting year, we used the most recent year).

Step 3: Tag "refined coal." One type of coal that appears in boiler consumption figures but not price tables is "refined coal." To price this type of consumption, we assigned each instance of "refined coal" to a coal sub-type. Depending on the plant, the source coal for "refined coal" might be bituminous, sub-bituminous, or lignite. With some painstaking work, we were able to infer from other nearby plants and historical fuel consumption trends at the plant which coal type was being refined with high confidence.

Step 4: Combine coal types to get a plant fuel cost. We combined price and consumption levels at each plant to get a weighted fuel input cost in $/mmBTU. We then converted this to $/MWh using the heat rate—just like the plants that report their input fuel costs.

Operation and Maintenance Costs

We used plant-by-plant operation and maintenance estimates obtained from the Electricity Market Module (EMM) in EIA's North American Energy Modeling Systems (NEMS). For some plants, no NEMS value for operation and maintenance was available and we used a national average value.

Going forward capital costs — National Energy Modeling System (NEMS)

The third element in our overall coal going-forward cost estimate is the going-forward capital cost. For this element we used a fairly simple method. We started by taking the average age (weighted by generator capacity) of a given coal power plant and compared it to the EIA NEMS table found in Figure 12. From this NEMS table and the average age of the plant, we obtained a per kW-year going-forward cost, which we multiplied by the overall capacity of the plant. We then divided by the total net MWh output from the plant (defined by the included set of generators) as reported on EIA Form 923. This includes any natural gas-fueled generation and results in a $/MWh, which then factors into the complete coal going-forward cost.

Age	Annual Capital Investment Requirement ($/kW-yr)
0 - 10 years	$ 17.16
10 - 20 years	$ 18.42
20 - 30 years	$ 19.68
30 - 40 years	$ 20.94
40 - 50 years	$ 22.20
50 - 60 years	$ 23.46
60 - 70 years	$ 24.72
70 - 80 years	$ 25.98

Figure 12. NEMS estimates of going forward capital costs by age of plant.

Renewables Costs

Identifying Renewable Energy Sites

We use NREL's ReEDS model that provides high spatial resolution solar and wind potential datasets in the U.S. The solar and wind potential numbers in ReEDS are, in turn, taken from the Renewable Energy Potential (ReV) model, which assesses the wind and solar energy potential at 11.2 km x 11.2 km spatial resolution after applying comprehensive exclusion criteria, including land cover, elevation, slope, environmentally sensitive areas, local siting regulations, etc. Across the continental U.S., ReV and ReEDS identify nearly 50,000 individual solar sites totaling a potential of 96,000 GW, and around 50,000 individual wind sites totaling a potential of 6,600 GW. The ReEDS model also provides annual capacity factors at each of these sites, which are estimated using the wind speed, solar irradiance, temperature, and other weather parameters from the Wind

Integration National Dataset (WIND) and National Solar Radiation Database (NSRDB). More information on this can be found in ReEDS documentation.

Technology Costs

We run the ReEDS model using technology costs from ATB 2022 and IRA incentives and estimate the wind and solar LCOE at each of the 50,000 sites. ReEDS uses a comprehensive list of parameters to estimate a site-specific LCOE including capital costs, fixed operation and maintenance costs, equity costs, interest rates, construction costs differentiated by location across the U.S., construction period, ITC and PTC incentives per IRA, tax equity haircuts, depreciation, and taxes (see Figure 13). Additional details on LCOE estimation could be found in ReEDS documentation.

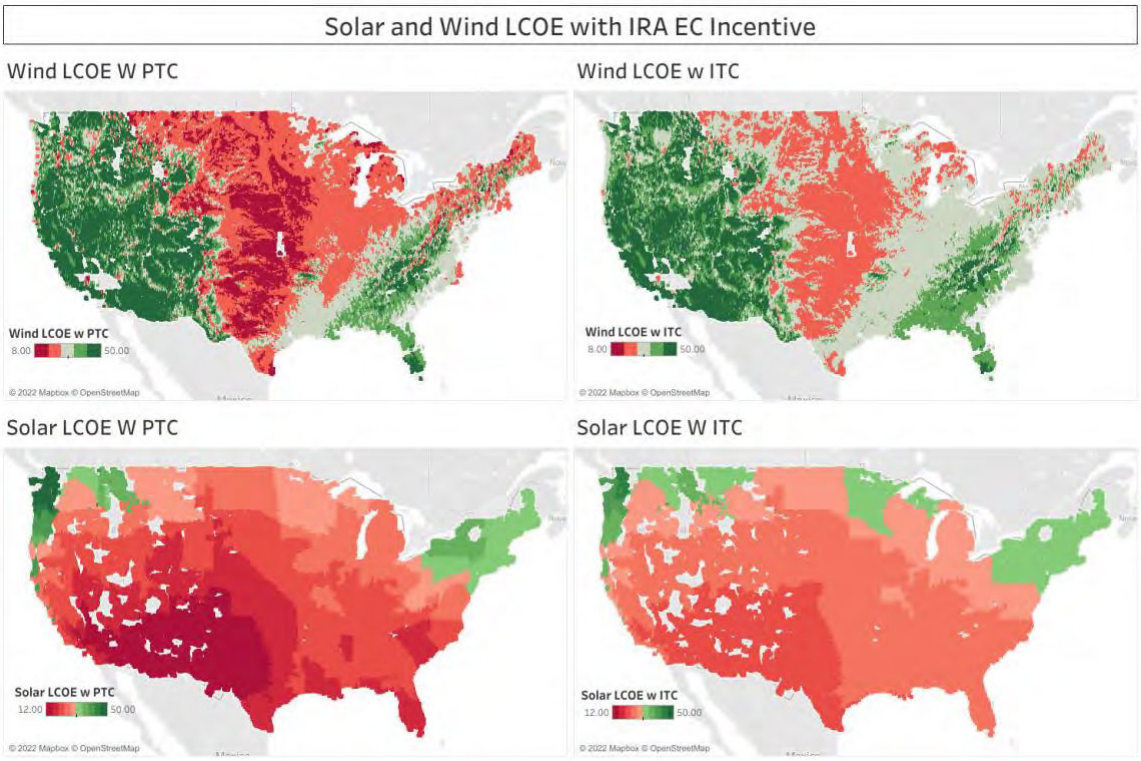


Figure 13. Wind and Solar LCOE including IRA incentives (including energy community) at each of the individual 50,000 sites across the U.S.

Assessing Hyperlocal Potential and LCOEs

The objective of this exercise is to assess the physically closest (hyperlocal) solar or wind resources that could replace the generation from each coal power plant in the country. We start with the location (latitude and longitude) of each of the 210 coal plants in the US. We then create concentric circles around each coal plant with radiuses starting from 5 km up to 45 km in increments of 5 km. Within each of these concentric circles, we identify the solar and wind sites that fall within that circle and estimate the site-level capacity and annual generation potential for solar and wind resources separately, using the high-resolution solar and wind datasets available from ReEDS, as described earlier. We then estimate the minimum circle radius ("hyperlocal circle") needed to replace the annual generation from each coal power plant with solar or wind resources. Within each hyperlocal circle, we assume that the solar and wind projects get the Energy Community Tax Credit per IRA and will not incur any interconnection costs since they could continue using the coal plant interconnection. We weight the site-level LCOEs within each hyperlocal circle by the site-level capacity potential to arrive at a weighted average hyperlocal LCOE to replace the generation from each coal power plant.

We find that annual generation at almost all coal power plants can be cost-effectively replaced by solar resources within a 20 km radius. The minimum radius for wind is much higher.

Regional LCOEs

In addition to the hyperlocal LCOEs, we also estimate the regional LCOEs in the regions where coal plants are located. The ReEDS model divides the contiguous U.S. into 134 regions which are generally aligned with the utility territories (see Figure 14). These regions never cross state boundaries

The rationale for estimating the regional LCOEs in addition to the hyperlocal LCOEs is that the higher-quality resources might not be available in the near vicinity of the coal plants but slightly farther away, and so from the perspective of the developer, it might make sense to move further from the coal plants to access the higher quality resource. This is more important for wind as wind speeds can vary significantly over short distances. As compared to wind, solar is more energy dense, as we can get almost 10 times the capacity of solar in the same amount of land as wind.

The methodology used for estimating regional LCOEs is very similar to that of hyperlocal LCOEs. For each coal plant, we sort the wind and solar sites available in that region (i.e., ReEDS balancing area) by LCOE and choose the best sites to replace the coal generation. For selected sites within each region, we capacity-weight the site-level LCOEs to estimate the weighted average regional LCOE. For the regional LCOE, we do not account for the Energy Community tax credit available in IRA. We also add the interconnection costs to the LCOEs as we assume that these sites may not be able to access the existing coal power plant interconnection.

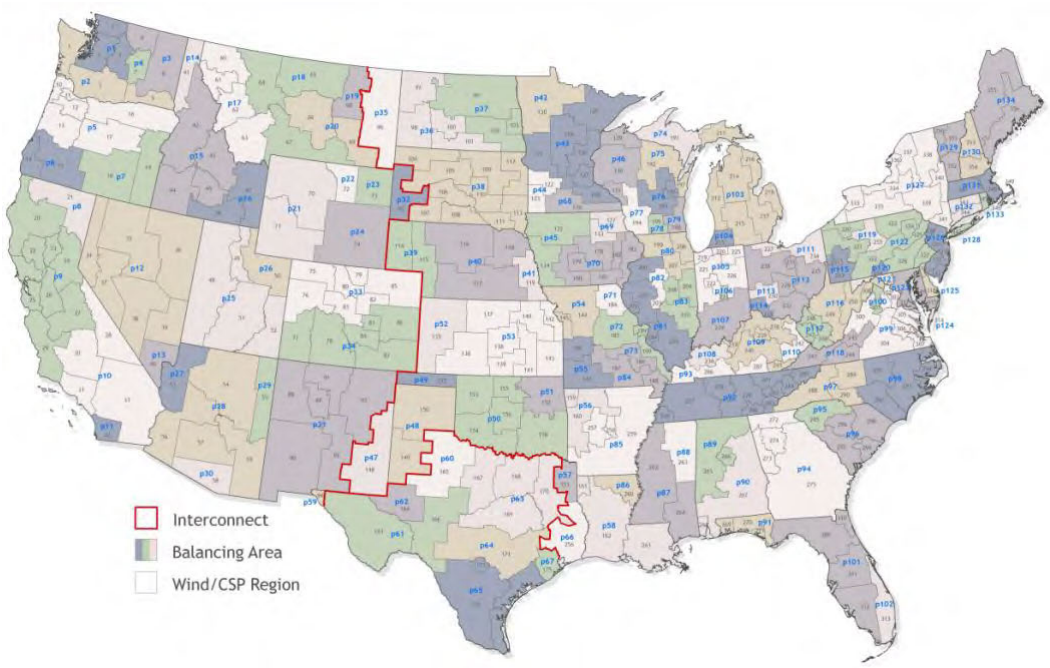


Figure 14. ReEDS balancing areas, used for our regional analysis and roughly corresponding to utility service territories, are highlighted by the different colors in this map. Source: National Renewable Energy Laboratory.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 52
Department Export Authorization EA-365-C (Oct. 21, 2025)

United States
Department of Energy

Grid Deployment Office

Research Power Corporation
(formerly known as Centre Lane Trading Ltd.)
GDO Docket No. EA-365-C

Order Authorizing Electricity Exports to Canada

Order No. EA-365-C

October 21, 2025

Research Power Corporation
(formerly known as Centre Lane Trading Ltd.)
Order No. EA-365-C
Authorizing Electricity Exports to Canada

I. BACKGROUND

The Department of Energy (DOE or Department) regulates electricity exports from the United States to a foreign country in accordance with Federal Power Act (FPA) § 202(e) (16 U.S.C. § 824a(e)) and regulations thereunder (10 C.F.R. §§ 205.300 *et seq.*). This authority was transferred to DOE under §§ 301(b) and 402(f) of the DOE Organization Act (42 U.S.C. §§ 7151(b) and 7172(f)). On April 10, 2023, this authority was delegated to the DOE's Grid Deployment Office (GDO) by Redelegation Order No. S3-DEL-GD1-2023.

An entity that seeks to export electricity must obtain an order from DOE authorizing it to do so. Under FPA § 202(e), DOE "shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States or would impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE]." 16 U.S.C. § 824a(e). DOE has discretion to condition the order as necessary or appropriate; the Department "may by its order grant such application in whole or in part, with such modifications and upon such terms and conditions as [DOE] may find necessary or appropriate, and may from time to time, after opportunity for hearing and for good cause shown, make such supplemental orders in the premises as it may find necessary or appropriate." *Id*.

A. Application for Export Authorization

Research Power Corporation (the Applicant) is a power marketer seeking renewal of its authorization to export electric energy to Canada, which was originally granted in Order No. EA-365-A on June 29, 2015, and subsequently renewed (EA-365-B) on April 29, 2020. On December 26, 2024, Centre Lane filed an application with DOE (Application or App.) requesting renewal of its export authority for a five-year term. App. at 1. On July 7, 2025, the Applicant notified DOE of its corporate name change from Centre Lane Trading Ltd. to Research Power Corporation.

According to the Application, Research Power Corporation (formerly known as Centre Lane Trading Ltd.) "is a Canadian Corporation with its principal place of business in Toronto, Ontario" that is "organized under the *Business Corporations Act* of the Province of Ontario, Canada." *Id*. The Applicant states that it "does not own, operate or control any generation or transmission facilities in any region, nor is it affiliated with any entity that owns, operates or controls generation or transmission facilities, and is not affiliated with any franchised public utility." *Id* at 1-2. The applicant further represents that it is a "[Federal Energy Regulatory Commission]-authorized power marketer engaging in the purchase and sale of physical and/or

virtual energy in the Day-ahead and Real-time Markets of various Independent System Operators and Regional Transmission Organizations." App at 2.

Research Power Corporation represents that it "has no electric power supply system on which the proposed exports could have a reliability, fuel use system or stability impact." App. at 3. The Applicant states that it "has no obligation to serve native load usually associated with a franchised service area, and, thus, the exports proposed by [Research Power Corporation] will not impair its ability to meet current and prospective power supply obligations." *Id.* The Applicant further affirms that it "will purchase power to be exported from a variety of sources such as power marketers, independent power producers, or U.S. electric utilities and federal power marketing entities as those terms are defined in Sections 3(22) and 3(19) of the FPA" and that "such power is surplus to the system of the generator and, therefore, the electric power that [Research Power Corporation] will export on either a firm or interruptible basis will not impair the sufficiency of the electric power supply within the U.S." *Id*.

The applicant states that it "will make all necessary commercial arrangements and will obtain any and all other regulatory approvals required in order to schedule and deliver power exports." *Id*. The Applicant further states that it will "schedule its transactions with the appropriate balancing authority areas in compliance with the reliability criteria standards and guidelines established by the North American Electric Reliability Corporation[.]" *Id*. Research Power Corporation also attests to not exceed the export limits for the facilities, or otherwise cause a violation of the terms and conditions set forth in the export authorizations for each. App at 4.

B. Procedural History

On December 26, 2024, Centre Lane filed a renewal application with DOE for export authority for a five-year term. *Id* at 1. On June 16, 2025, DOE published notice of Centre Lane's Application in the Federal Register (90 Fed. Reg. 25252) and asked for any interested parties to submit comments on the Application by July 16, 2025. On July 7, 2025, DOE received notice of Centre Lane's corporate name change to Research Power Corporation.

C. Public Comments

No public comments were received.

II. DISCUSSION AND ANALYSIS

DOE is statutorily obligated under FPA § 202(e) to grant requests for export authorization unless the Department finds that the proposed export would negatively impact either: (i) the sufficiency of electric supply, or (ii) the coordination of the electric grid. Regarding the first exception criterion, DOE shall approve an electricity export application "unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States …." 16 U.S.C. § 824a(e). DOE has interpreted this criterion to mean that sufficient generating capacity and electric energy must exist such that the export could be made without compromising the energy needs of the exporting region, including

serving all load obligations in the region while maintaining appropriate reserve levels. *See, e.g.*, *BP Energy Co.*, Order No. EA-314, at 1-2 (Feb. 22, 2007), *renewed*, Order No. EA-314-A, at 2 (May 3, 2012), Order No. EA-314-B, at 2 (Feb. 28, 2017), *renewed,* Order No. EA-314-C, at 4 (Dec. 20, 2021).

Under the second exception criterion, DOE shall approve an electricity export application "unless, after opportunity for hearing, it finds that the proposed transmission would … impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE]." 16 U.S.C. § 824a(e). DOE has interpreted this criterion primarily as an issue of the operational reliability of the domestic electric transmission system. Accordingly, the export must not compromise transmission system security and reliability. *See, e.g.*, Order No. EA-314-C, at 4.

A. Research Power Corporation Will Not Impair the Sufficiency of the Electric Supply in the United States

Sufficiency of supply, the first exception criterion, addresses whether regional electricity needs are met in the current market. DOE has analyzed this issue from both an economic and a reliability perspective. The economic perspective concerns the supply available to wholesale market participants. The reliability perspective focuses on preventing problems that could result from inadequate supplies. Taken together, DOE examines whether existing electric supply is available via market mechanisms, and whether potential reliability issues linked to supply problems are mitigated by reliability enforcement mechanisms.

From an economic perspective, DOE finds that the wholesale energy markets are sufficiently robust to make supplies available to exporters and other market participants serving United States regions along the Canadian and Mexican borders. Following enactment of the Energy Policy Act of 1992, Pub. L. No. 102-486, which encouraged the Federal Energy Regulatory Commission (FERC) to foster competition in the wholesale energy markets through open access to transmission facilities, energy markets developed across the United States to provide opportunities for a more efficient availability of supply. Subsequently, the Energy Policy Act of 2005, Pub. L. No. 109-58, reaffirmed the Government's commitment to competition in wholesale energy markets as national policy. FERC has continued to encourage the expansion of wholesale energy markets through its orders to remove barriers[1] and to ensure that these markets are functioning properly.[2] As a result, market participants have access to traditional bilateral contracts, as well as organized electricity markets run by regional transmission organizations (RTOs) or independent system operators (ISOs). FERC oversees these interstate wholesale electricity markets across most of the lower 48 states. Absent an indication in the record that the geographic markets relevant to this export authorization analysis are flawed and result in

[1] *See, e.g.*, *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009).

[2] *See, e.g.*, *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *as amended*, 126 FERC ¶ 61,261, *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

uneconomic exports that jeopardize regional supply, DOE finds that the proposed transmission for export does not impair the sufficiency of electric supply within the United States.

From a reliability perspective,[3] DOE focuses on the prevention of cascading outages and other problems that could result from inadequate resources.[4] Reliability oversight is addressed by the authority granted to FERC through the Energy Policy Act of 2005. That Act added section 215 to the FPA, which directed FERC to certify an electric reliability organization and develop procedures for establishing, approving, and enforcing mandatory electric reliability standards. 16 U.S.C. § 824o. FERC certified the North American Electric Reliability Corporation (NERC) in 2006 to develop and enforce reliability standards for the bulk-power system in the United States. *Order Certifying NERC as the Electric Reliability Organization and Ordering Compliance Filing*, FERC Docket No. RR06-1-000, 116 FERC ¶ 61,062 (July 20, 2006). FERC approves these standards, at which point they become mandatory and enforceable. NERC Reliability Standards address areas such as resource and demand balancing, critical infrastructure protection, communications, emergency preparedness and operations, facilities design, transmission operations, transmission planning, modelling, nuclear, personnel performance and training, protection and controls, voltage and reactive, interchange scheduling and coordination, and interconnection reliability operations and coordination.

NERC Reliability Standards are enforceable throughout the continental United States, most of Canada south of the 60th parallel, and the Mexican state of Baja California Norte. Through enforcement by FERC, NERC, and six Regional Entities overseen by NERC,[5] all bulk-power system owners, operators, and users are held responsible for complying with reliability standards. The reliability standards are structured so that many entities have overlapping responsibility for the electric grid, thereby resulting in several layers of reliability monitoring. Entities such as reliability coordinators and balancing authorities coordinate power generation and transmission among multiple utilities to serve demand within an integrated regional wholesale market. One of the principal functions of these entities is to schedule adequate generating and reserve capacity. This allows them to serve demand at the regional level and to ensure that there is sufficient power supply to maintain system reliability. Reliability Standard IRO-001-4 "establish[es] the responsibility of Reliability Coordinators to act or direct other entities to act."[6] Requirement R1 states that "[e]ach Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions."[7] Reliability oversight is designed through coordinated efforts amongst Reliability Coordinators to preserve the benefits of interconnected operations and ensure that operations in one area will not adversely impact other areas.[8] Reliability Standard IRO-014-3 R1 provides that "[e]ach Reliability Coordinator shall have and implement Operating Procedures, Operating

[3] A related reliability analysis follows in the next section of this Order.

[4] This focus should not be confused with resource adequacy planning and capacity requirements that have traditionally been the domain of state regulatory commissions, NERC-certified Regional Entities, and RTOs/ISOs.

[5] The six entities are the Midwest Reliability Organization, Northeast Power Coordinating Council, ReliabilityFirst Corporation, SERC Reliability Corporation, Texas Reliability Entity, and Western Electricity Coordinating Council.

[6] Standard IRO-001-4 (Reliability Coordination – Responsibilities), at ¶ A.3.

[7] *Id.* ¶ B.R1.

[8] *See* Standard IRO-014-3 (Coordination Among Reliability Coordinators), at ¶ A.3.

Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability."[9]

DOE finds that NERC's FERC-approved comprehensive enforcement mechanism ensures that bulk-power system owners, operators, and users have a strong incentive both to maintain system resources and to prevent reliability problems that could result from movement of electric supplies through export. As a result of this reliability oversight, DOE finds that the sufficiency of supply is not impaired by Research Power Corporation's proposed export authorization.

DOE's sufficiency of supply findings are further supported by the fact that power marketers, such as Research Power Corporation, do not have an obligation to serve a franchised territory. Before the current role of power marketers emerged in the industry, the FPA § 202(e) inquiry into sufficiency of supply had a narrower focus and was designed for an applicant that was a vertically integrated utility[10] with an obligation to serve native load. Under that traditional scenario, the inquiry regarding sufficiency of supply logically sought to confirm that exports would be surplus to the needs of a vertically-integrated utility's native load obligations and reserve margins. As explained in DOE's notice of the first application by a power marketer for export authorization, the sufficiency of supply inquiry became unnecessary when applied to power marketers:

> The Applicant also is required to demonstrate that it would have sufficient generating capacity to sustain the proposed export under the terms and conditions of its export agreement, while still complying with any established reserve criteria.
>
> Since marketers generally could not be seen as having any "native load" requirements, the latter criterion of maintaining sufficient reserve margins appears inappropriate and unnecessary in this instance.

59 Fed. Reg. 54900 (Nov. 2, 1994). Power marketers do not have franchised service areas and, consequently, do not have native load obligations like a traditional local distribution utility that could be impaired by exports.

In sum, market mechanisms and reliability oversight protect against the possibility that Research Power Corporation's exports would jeopardize domestic sufficiency of supply. Therefore, an export by Research Power Corporation would not trigger the first exception criterion of FPA § 202(e) regarding the sufficiency of electric supply within the United States.

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[9] *Id.* ¶ B.R1.

[10] The Supreme Court of the United States has explained: "In 1935, when the FPA became law, most electricity was sold by vertically integrated utilities that had constructed their own power plants, transmission lines, and local delivery systems…[M]ost operated as separate, local monopolies subject to state or local regulation. Their sales were 'bundled,' meaning that consumers paid a single charge that included both the cost of the electric energy and the cost of its delivery. Competition among utilities was not prevalent." *New York v. FERC*, 535 US 1, 5 (2002).

B. Research Power Corporation's Requested Authorization Will Not Adversely Affect Either the Reliability or the Security of the United States Electric Transmission System

Reliability, the second exception criterion under FPA § 202(e), addresses operational reliability and security of the domestic electric transmission system. In evaluating the operational reliability impacts of export proposals, DOE has used a variety of methodologies and information, including established industry guidelines, operating procedures, and technical studies where available and appropriate. When determining these impacts, it is convenient to separate the export transaction into two parts: (i) moving the export from the source to a border system that owns the international transmission connection, and (ii) moving the export through that border system and across the border.

Moving Electricity to a Border System. Moving electricity for export to a border system necessarily involves the use of the bulk-power system. As noted in the preceding section, bulk-power system reliability concerns are addressed under the FPA by FERC and NERC and involve the enforcement of mandatory reliability standards. These standards ensure that all owners, operators, and users of the bulk-power system have an obligation to maintain system security and reliability. The standards are structured so that there are always entities with broader responsibilities than the applicant, such as reliability coordinators and balancing authorities, to keep a constant watch over the domestic transmission system.

To deliver the export from the source to a border system, the applicant must make the necessary commercial arrangements and obtain sufficient transmission capacity to wheel the exported energy to the border system. The applicant would be expected to follow FERC orders regarding open transmission access and to schedule delivery of the export with the appropriate RTO, ISO, and/or balancing authority (formerly the control area operator).

It is the responsibility of the RTO, ISO, and/or balancing authority to schedule the delivery of the export consistent with established and mandatory operational reliability criteria. During each step of the process of obtaining transmission service, the owners and/or operators of the transmission facilities will evaluate the impact on the system and schedule the movement of the export *only* if it would not violate established operating reliability standards. As a failsafe, the reliability coordinator in each region has the authority and responsibility to curtail, cancel, or deny scheduled flows to avoid shortages or to restore necessary energy and capacity reserves. Reliability Standard EOP-011-1 R2 provides that "[e]ach Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area."[11]

Specifically, the reliability coordinator has the authority to suspend exports if the electric energy would be needed to support the regional power grid. *See* Reliability Standard IRO-001-4 R1 ("Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions"), R2 ("Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the

[11] EOP-011-1 (Emergency Operations), at ¶ B.R2.

Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements"), and R3 ("Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R1").

DOE has determined that the existing industry procedures for obtaining transmission capacity on the domestic transmission system (described above) provide adequate assurance that any export will not cause an operational reliability problem. Therefore, Research Power Corporation's export authorization has been conditioned to ensure that the export will not cause operational issues on regional transmission systems to fall outside of established industry reliability criteria, or cause or exacerbate a transmission operating problem on the United States' electric power supply system (*see* Order below, Section VII, paragraphs C, D, and I).

Moving Electricity Through a Border System. The second part of DOE's reliability inquiry, addressing the transmission of the export through a border system and across the border, is a question of whether the border system is reliable and secure. To a large extent, this question is addressed by the jurisdiction of NERC. NERC and Regional Entities—including the Midwest Reliability Organization, the Northeast Power Coordinating Council, and the Western Electricity Coordinating Council—oversee the United States-Canadian border system and a significant part of the United States-Mexican border system. Those border systems are generally subject to the same reliability standards as domestic systems. *See, e.g.*, http://www.ieso.ca/sector-participants/system-reliability/reliability-standards-framework.

DOE also relies on the System Impact Studies submitted in conjunction with an application for a DOE-issued Presidential permit[12] to construct a new international transmission line. As DOE has previously reviewed System Impact Studies submitted with Presidential permit applications,[13] DOE does not need to perform additional impact assessments here, provided the maximum rate of transmission for all exports through a border system does not exceed the authorized limit of the system (*see* Order below, Section VII, paragraph (A)). In its application, Research Power Corporation committed to complying with all reliability limits on border facilities. *See* App. at 3. The second part of the reliability inquiry is therefore satisfied by DOE regulatory oversight, in addition to NERC's reliability enforcement.

III. FINDINGS AND DECISION

A. Research Power Corporation Meets the Statutory Requirements to Export Electric Energy to Canada

[12] DOE issues Presidential permits pursuant to Executive Order 10,485, as amended by Executive Order 12,038. *See* 10 C.F.R. §§ 205.320-205.329.

[13] *See, e.g.*, *AEP Tex. Cent. Co*., Order No. PP-317, at 2-3 (Jan. 22, 2007); *Mont. Alta. Tie Ltd.*, Order No. PP-305, at 2-4 (Nov. 17, 2008).

As explained above, DOE has assessed the impact that the proposed export would have on the reliability of the United States electric power supply system. DOE has determined that the export of electric energy to Canada by Research Power Corporation, as ordered below, would not impair the sufficiency of electric power supply within the United States and would not impede or tend to impede the coordination in the public interest of facilities within the meaning of FPA § 202(e).

B. Research Power Corporation Qualifies for a NEPA Categorical Exclusion for Exports of Electric Energy

Research Power Corporation's Application qualifies for DOE's categorical exclusion for exports of electric energy under the National Environmental Policy Act of 1969, as amended (NEPA), 42 U.S.C. § 4321 *et seq*. DOE's NEPA Implementing Procedures (June 2025) set forth this categorical exclusion, codified as "B4.2," as follows:

> Export of electric energy as provided by Section 202(e) of the Federal Power Act over existing transmission lines or using transmission system changes that are themselves categorically excluded.

10 C.F.R. Part 1021, App. B, § B4.2.

DOE has determined that actions in this category do not normally have a significant effect on the human environment and that, therefore, neither an environmental assessment nor an environmental impact statement normally is required. 10 C.F.R. § 1021.102(a).

To invoke this categorical exclusion, DOE must determine that, in relevant part, "[t]here are no extraordinary circumstances related to the proposal that may affect the significance of the environmental effects of the proposal." 10 C.F.R. § 1021.102(b)(2). "Extraordinary circumstances" include "unique situations" such as "scientific controversy about the environmental effects of the proposal; uncertain effects or effects involving unique or unknown risks; and unresolved conflicts concerning alternative uses of available resources." *Id*. DOE finds that granting Research Power Corporation's request for export authorization does not present such extraordinary circumstances. Research Power Corporation seeks to deliver electricity over existing international electric transmission facilities, which fits squarely within the B4.2 categorical exclusion. For these reasons, DOE will not require more detailed NEPA review in connection with this Application.

C. Conclusion

DOE grants Research Power Corporation's request for export authorization. Research Power Corporation is authorized to export electricity to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties, subject to the limitations and conditions described in this Order. The authorization shall be effective for a five (5) year term consistent with DOE's standard term for new electricity export authorizations.

IV. DATA COLLECTION AND REPORTING REQUIREMENTS

The responsibility for the data collection and reporting under orders authorizing electricity exports to a foreign country currently rests with the U.S. Energy Information Administration (EIA) within DOE. The Applicant is instructed to follow EIA instructions in completing this data exchange. Questions regarding the data collection and reporting requirements can be directed to EIA by email at EIA4USA@eia.gov or by phone at 1-855-342-4872.

Additionally, any change to the tariff of an entity with an export authorization must be provided to DOE's Grid Deployment Office via email at *electricity.exports@hq.doe.gov*. 10 C.F.R. § 205.308(b).

V. COMPLIANCE

Obtaining a valid order from DOE authorizing the export of electricity under FPA § 202(e) is a necessary condition before engaging in the export. Failure to obtain such an order or continuing to export after the expiration of such an order may result in a denial of authorization to export in the future and subject the exporter to sanctions and penalties under the FPA. DOE expects transmitting utilities owning border facilities and entities charged with the operational control of those border facilities, such as ISOs, RTOs, or balancing authorities, to verify that companies seeking to schedule an electricity export have the requisite authority from DOE to export such energy.

DOE expects Research Power Corporation to abide by the terms and conditions established for its authority to export electric energy to Canada, as set forth below. DOE intends to monitor Research Power Corporation compliance with these terms and conditions, including the requirement in paragraph G of this Order that Research Power Corporation create and preserve full and complete records and file reports with EIA as discussed above.

A violation of any of these terms and conditions, including the failure to submit timely and accurate reports, may result in the loss of authority to export electricity and subject Research Power Corporation to any applicable sanctions and penalties under the FPA.

VI. OPEN ACCESS POLICY

An export authorization issued under FPA § 202(e) does not impose a requirement on transmitting utilities to provide service. However, DOE expects transmitting utilities that own border facilities to provide open access transmission service across the border in accordance with the principles of comparable open access and non-discrimination contained in the FPA and articulated in FERC Order No. 888 (Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, FERC Statutes and Regulations ¶ 31,036 (1996)), as amended. The actual rates, terms, and conditions of transmission service should be consistent with the non-discrimination principles of the FPA and the transmitting utility's Open-Access Transmission Tariff on file with FERC.

All recipients of export authorizations, including owners of border facilities for which Presidential permits have been issued, are required by their export authorization to conduct operations in accordance with the applicable principles of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended. Cross-border electric trade ought to be subject to the same principles of comparable open access and non-discrimination that apply to transmission in interstate commerce. *See Enron Power Mktg., Inc. v. El Paso Elec. Co.*, 77 FERC ¶ 61,013 (1996), *reh'g denied*, 83 FERC ¶ 61,213 (1998). Thus, DOE expects owners of border facilities to comply with the same principles of comparable open access and non-discrimination that apply to the domestic, interstate transmission of electricity.

VII. ORDER

Accordingly, pursuant to FPA § 202(e) and the Rules and Regulations issued thereunder (10 C.F.R. §§ 205.300-309), it is hereby ordered that Research Power Corporation is authorized to export electric energy to Canada under the following terms and conditions:

(A) The electric energy exported by Research Power Corporation pursuant to this Order may be delivered to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties in accordance with the export limits authorized by DOE.

(1) The following international transmission facilities located at the United States border with Canada are currently authorized by Presidential permit and available for open access transmission:[14, 15]

Owner	**Location**	**Voltage**	**Permit No.**[16]
Bangor Hydro-Electric Company	Baileyville, ME	345 kV	PP-89
Basin Electric Power Cooperative	Tioga, ND	230 kV	PP-64
Bonneville Power Administration (BPA)	Blaine, WA	2x 500 kV	PP-10
	Nelway, WA	230 kV	PP-36
	Nelway, WA	230 kV	PP-46
CHPE, LLC	Champlain, NY	±230 kV DC	PP-481[17]

[14] This Order authorizes the export of electricity over any "authorized international transmission facility," which is intended to include both large transmission lines and smaller distribution lines that have received a Presidential permit. However, the list in subparagraph (A)(1) of current facilities only includes transmission lines.

[15] The Applicant submitted a list identifying currently authorized transmission facilities (Attachment 1 of the Application). However, as information about some of those facilities may have changed since the Application was submitted, the table of transmission facilities in this Order may differ from the Applicant's submission to reflect those changes.

[16] These Presidential permit numbers refer to the generic DOE permit number and are intended to include any subsequent amendments to the permit authorizing the facility.

[17] Currently under construction and not yet operational as of September 2025.

Eastern Maine Electric Cooperative	Calais, ME	69 kV	PP-32
International Transmission Company	Detroit, MI	230 kV	PP-230
	Marysville, MI	230 kV	PP-230
	St. Claire, MI	230 kV	PP-230
	St. Claire, MI	345 kV	PP-230
Lake Erie Connector Transmission, LLC	Erie County, PA	320 kV	PP-412[18]
Long Sault, Inc.	Massena, NY	2x 115 kV	PP-24
Maine Electric Power Company	Houlton, ME	345 kV	PP-43
Minnesota Power, Inc.	International Falls, MN	115 kV	PP-78
Minnesota Power, Inc.	Roseau County, MN	500 kV	PP-398
Minnkota Power Cooperative	Roseau County, MN	230 kV	PP-61
Montana Alberta Tie Ltd.	Cut Bank, MT	230 kV	PP-399
NECEC Transmission LLC	Beattie Twp, ME	±320 kV	PP-438[19]
New York Power Authority	Massena, NY	765 kV	PP-56
	Massena, NY	2x 230 kV	PP-25
	Niagara Falls, NY	2x 345 kV	PP-74
	Devils Hole, NY	230 kV	PP-30
Niagara Mohawk Power Corp.	Devils Hole, NY	230 kV	PP-190
Northern States Power Company	Red River, ND	230 kV	PP-45
	Roseau County, MN	500 kV	PP-63
	Rugby, ND	230 kV	PP-231
Sea Breeze Olympic Converter LP	Port Angeles, WA	±450 kV DC	PP-299[20]
TDI New England	Alburgh, VT	±320 kV DC	PP-400[21]

[18] These transmission facilities have been authorized but not yet constructed or placed into operation.
[19] These transmission facilities have been authorized but not yet constructed or placed into operation.
[20] These transmission facilities have been authorized but not yet constructed or placed into operation.
[21] These transmission facilities have been authorized but not yet constructed or placed into operation.

Vermont Electric Power Co.	Derby Line, VT	120 kV	PP-66
Vermont Electric Transmission Co.	Norton, VT	±450 kV DC	PP-76
Vermont Transco LLC	Highgate, VT	120 kV	PP-82
Versant Power	Fort Fairfield, ME	69 kV	PP-497
	Madawaska, ME	138 kV	PP-498
	Easton, ME	7.2 kV	PP-499
	Baileyville, ME	345kV	PP-500

(2) The following are the authorized export limits for the international transmission lines listed above in subparagraph (A)(1):

(a) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on facilities authorized by Presidential Permit PP-64 (issued to Basin Electric Power Coop.) to exceed an instantaneous transmission rate of 150 megawatts (MW). The gross amount of energy that Research Power Corporation may export over the PP-64 facilities shall not exceed 900,000 megawatt-hours (MWH) during any consecutive 12-month period.

(b) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-32 (issued to Eastern Maine Electric Coop.) to exceed an instantaneous transmission rate of 15 MW. The gross amount of energy that Research Power Corporation may export over the PP-32 facilities shall not exceed 7,500 MWH annually.

(c) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-481-2 (issued to CHPE, LLC) to exceed an instantaneous transmission rate of 1,250 MW.

(d) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-230 (issued to International Transmission Company) to exceed a coincident, instantaneous transmission rate of 2.2 billion volt-amperes (2,200 MVA).

(e) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-412-1 (issued to Lake Erie Connector Transmission, LLC) to exceed an instantaneous transmission rate of 1,000 MW.

(f) Exports by Research Power Corporation made pursuant to this Order shall not cause the scheduled rate of transmission over a combination of facilities

authorized by Presidential Permits PP-43 (issued to Maine Electric Power Company) and PP-500 (issued to Bangor Hydro-Electric) to exceed 550 MW.

(g) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the combination of facilities authorized by Presidential Permits PP-497 and PP-498 (issued to Versant Power) to exceed a coincident, instantaneous transmission rate of 134 MW.

(h) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-78-1 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 100 MW. Exports by Research Power Corporation may cause total exports on the PP-78-1 facilities to exceed 100 MW only when total exports between the Mid-Continent Area Power Pool (MAPP) and Manitoba Hydro are below maximum transfer limits and/or whenever operating conditions within the MAPP system permit exports on the PP-78-1 facilities above the 100-MW level without violating established MAPP reliability criteria. However, under no circumstances shall exports by Research Power Corporation cause the total exports on the PP-78-1 facilities to exceed 150 MW.

(i) Exports made by Research Power Corporation pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-398 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 750 MW.

(j) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on a combination of the international transmission lines authorized by Presidential Permits PP-45 and PP-63 (issued to Northern States Power Company), PP-61 (issued to Minnkota Power), and PP-231 (issued to Northern States Power Company, d/b/a Excel Energy Inc. (Xcel)), to exceed an instantaneous transmission rate of 700 MW on a firm basis and 1,050 MW on a non-firm basis.

(k) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-66 (issued to Vermont Electric Power Co.) to exceed an instantaneous transmission rate of 50 MW. The gross amount of energy that Research Power Corporation may export over the PP-66 facilities shall not exceed 50,000 MWH annually.

(l) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-56 (issued to NYPA) to exceed an instantaneous transmission rate of 1,000 MW.

(m) Exports by Research Power Corporation made pursuant to this Order shall not cause: (a) the total exports on the facilities authorized by Presidential Permits PP-25, PP-30, PP-74 (issued to NYPA), and PP-190 (issued to Niagara Mohawk Power Corp.) to exceed a combined instantaneous transmission rate of 1,650

MW; and (b) the total exports on the 115-kV facilities authorized by Presidential Permit PP-24 (issued to Long Sault, Inc.) to exceed an instantaneous transmission rate of 100 MW. In addition, the gross amount of energy that Research Power Corporation may export over the PP-24 facilities shall not exceed 300,000 MWH annually.

(n) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on the two 500-kV lines authorized by Presidential Permit PP-10, the 230-kV line authorized by Presidential Permit PP-36, and the 230-kV line authorized by Presidential Permit PP-46 (issued to BPA) to exceed the following limits:

Condition	PP-36 & PP-46 Limit	PP-10 Limit	Total Export Limit
All lines in service	400 MW	1500 MW	1900 MW
1-500 kV line out	400 MW	300 MW	700 MW
2-500 kV lines out	400 MW	0 MW	400 MW
1-230 kV line out	400 MW	1500 MW	1900 MW
2-230 kV line out	0 MW	1500 MW	1500 MW

(o) Exports by Research Power Corporation made pursuant to this Order shall not cause a violation of the following conditions as they apply to exports over the facilities authorized by Presidential Permit PP-76-1, as amended (issued to the Vermont Electric Transmission Company):

Exports Through	NEPOOL Load Condition	Export Limit
Comerford converter	Summer, Heavy	650 MW
Comerford converter	Winter, Heavy	660 MW
Comerford converter	Summer, Light	690 MW
Comerford converter	Winter, Light	690 MW
Comerford & Sandy Pond converters	All	2,000 MW

(p) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-399 (issued to Montana Alberta Tie Ltd.) shall not exceed an instantaneous transmission rate of 300 MW.

(q) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-438 (issued to NECEC Transmission LLC) shall not exceed an instantaneous transmission rate of 1,200 MW.

(r) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-299

(issued to Sea Breeze Olympic Converter LP) shall not exceed an instantaneous transmission rate of 550 MW.

(s) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-400 (issued to TDI-New England) to exceed an instantaneous transmission rate of 1,000 MW.

(t) Exports by Research Power Corporation made pursuant to this Order shall neither cause the total exports on the facilities authorized by Presidential Permit PP-82-6 (issued to Vermont Transco LLC) to exceed an instantaneous transmission rate of 250 MW.

(B) Changes by DOE to the export limits in other orders shall result in a concomitant change to the export limits contained in subparagraph (A)(2) of this Order. Changes to the export limits contained in subparagraphs (A)(2)(l), (m), and (n) will be made by DOE after submission of appropriate information demonstrating a change in the transmission transfer capability between the electric systems in New York State and Ontario and New York State and Quebec, and between BPA and BC Hydro or BPA and West Kootenay Power. Notice of these changes will be provided to Research Power Corporation.

(C) Research Power Corporation shall obtain any and all other Federal and state regulatory approvals required to execute any power exports to Canada. The scheduling and delivery of electricity exports to Canada shall comply with all reliability criteria, standards, and guidelines of NERC, reliability coordinators, Regional Entities, RTOs, ISOs or balancing authorities, or their successors, as appropriate, on such terms as expressed therein, and as such criteria, standards, and guidelines may be amended from time to time.

(D) Exports made pursuant to this authorization shall be conducted in accordance with the applicable provisions of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended.

(E) The authorization herein granted may be modified from time to time or terminated by further order of DOE. In no event shall such authorization to export over a particular transmission facility identified in subparagraphs (A)(1) and (2) extend beyond the date of termination of the Presidential permit or treaty authorizing such facility.

(F) This authorization shall be without prejudice to the authority of any state or state regulatory commission for the exercise of any lawful authority vested in such state or state regulatory commission.

(G) Research Power Corporation shall make and preserve full and complete records with respect to the electric energy transactions between the United States and Canada. Research Power Corporation shall collect and submit the data to EIA as required by and in accordance with the procedures of Form EIA-111, "Quarterly Electricity Imports and Exports Report," and all successor forms.

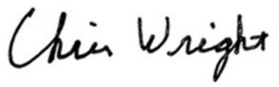
(H) In accordance with 10 C.F.R. § 205.305, this export authorization is not transferable or assignable, except in the event of involuntary transfer by operation of law. Provided written notice of the involuntary transfer is given to DOE within 30 days, this authorization shall remain in effect temporarily. The authorization shall terminate unless an application for a new export authorization has been received by DOE within 60 days of the involuntary transfer. Upon receipt by DOE of such an application, this existing authorization shall continue in effect pending a decision on the new application. In the event of a proposed voluntary transfer of this authority to export electricity, the transferee and the transferor shall file a joint application for a new export authorization, together with a statement of the reasons for the transfer.

(I) Nothing in this Order is intended to prevent the transmission system operator from being able to reduce or suspend the exports authorized herein, as necessary and appropriate, whenever a continuation of those exports would cause or exacerbate a transmission operating problem or would negatively impact the security or reliability of the transmission system.

(J) Research Power Corporation has a continuing obligation to give DOE written notification as soon as practicable of any prospective or actual changes of a substantive nature in the circumstances upon which this Order was based, including but not limited to changes in authorized entity contact information or NERC compliance registry status.

(K) This authorization shall be effective as of October 21, 2025 and shall remain in effect for a period of five (5) years from that date. Application for renewal of this authorization may be filed within six (6) months prior to its expiration. Failure to provide DOE with at least one hundred and twenty (120) days to process a renewal application and provide adequate opportunity for public comment may result in a gap in Research Power Corporation's authority to export electricity.

Issued in Washington, D.C., on October 21, 2025.



Chris Wright
Secretary of Energy
U.S. Department of Energy

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

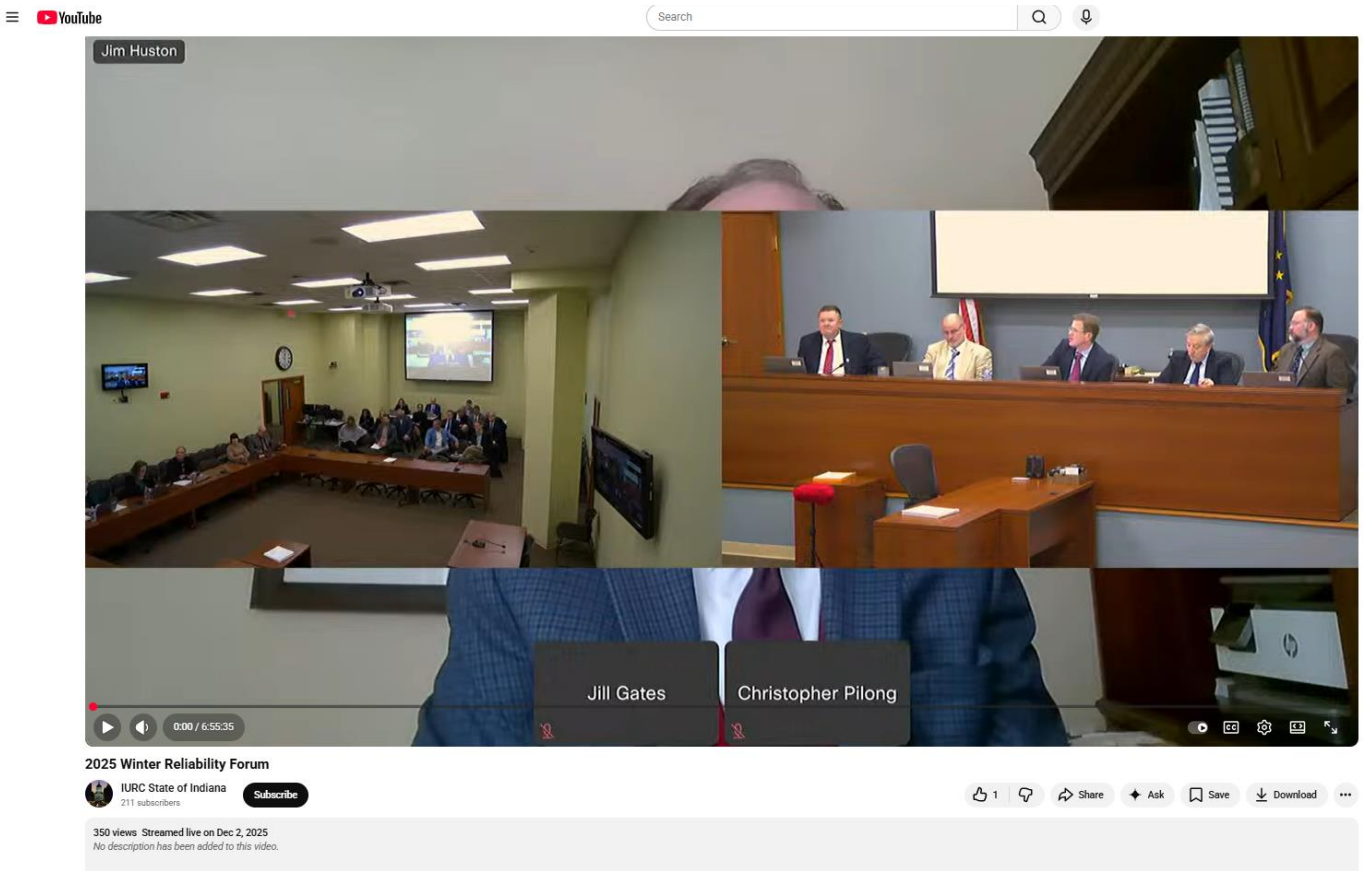
Exhibit 53
IURC 2025 Winter Reliability Forum (December 2, 2025)

Indiana Utility Regulatory Commission

2025 Winter Reliability Forum (December 2, 2025)

Actual exhibit is a digital excerpt in .MP4 format of the video recording, from the 51:00 to 54:09 timestamps of the full recording.

Video recording of the full event is also available on YouTube at:
https://www.youtube.com/watch?v=bCzALF4V45M



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 54
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/

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 55
IEA Flexibility Report

Increasing the flexibility of coal-fired power plants

Colin Henderson

September 2014

© IEA Clean Coal Centre

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

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

Exhibit 56
Bradford Coal Inventory Testimony

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a CENTERPOINT ENERGY INDIANA SOUTH
(CEI SOUTH)

IURC CAUSE NO. 38708 FAC 149

DIRECT TESTIMONY

OF

F. SHANE BRADFORD

VICE PRESIDENT OF INDIANA ELECTRIC

ON

PURCHASED POWER AND COAL INVENTORY

SPONSORING ATTACHMENT FSB-1

DIRECT TESTIMONY OF F. SHANE BRADFORD

INTRODUCTION

Q. Please state your name and business address.

A. My name is F. Shane Bradford. My business address is 211 NW Riverside Drive, Evansville, Indiana 47708.

Q. By whom are you employed?

A. I am employed by Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("CEI South," "Petitioner," or "Company"), which is an indirect subsidiary of CenterPoint Energy, Inc.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting testimony on behalf of CEI South.

Q. What is your role with respect to Petitioner CEI South?

A. I am the Vice President of Indiana Electric.

Q. Please describe your educational background.

A. I received a Bachelor of Science in Civil Engineering (1992) from the University of Dayton and a Master in Business Administration (2002) from Indiana State University.

Q. Please describe your professional experience.

A. My career in the utility industry began at Dayton Power and Light Co., where I worked in maintenance and production roles within electric generation from 1992 to 1999. I then joined Cinergy's electric generation division until 2003, when I became a plant manager for one of Cinergy's subsidiaries, Trigen Cinergy Solutions LLC. In 2004, I joined CEI South[1] as Power Plant Director, overseeing safe, reliable, and

[1] For the sake of clarity, my testimony refers to CEI South, even though in certain situations, I may be referring to Southern Indiana Gas and Electric Company operating under a prior assumed business name.

environmentally responsible electric generation. By 2021, I transitioned to Director of Power Supply Service, focusing on Wholesale Power Marketing, Market Settlements, and Market Development. In January 2023, I was promoted to Vice President of Power Generation Operations, managing budgeting, operations, maintenance, and personnel decisions for CEI South's generation fleet. In that role, I had responsibility for ensuring customer demand is met sustainably and affordably while complying with environmental regulations. I also oversaw cost inputs for the Integrated Resource Plan ("IRP") process and managed commercial negotiations with generation resources. I assumed my current position in July 2024.

Q. Please describe your present duties and responsibilities as CEI South's Vice-President, Indiana Electric.

A. I am responsible for all operations within CEI South's electric utility sector in Indiana, alongside managing the Company's Generation Transition Plan, as outlined in the 2019/2020 IRP and the 2022/2023 IRP, the latter of which was submitted to the Indiana Utility Regulatory Commission (the "IURC" or "Commission") in May 2023. My responsibilities include the oversight of operations and maintenance ("O&M"), capital budgets, transmission and distribution operations, engineering, generation, development of new renewable projects, and construction of natural gas generation projects to complement renewables.

Q. Have you previously testified before the Indiana Utility Regulatory Commission ("Commission")?

A. Yes. I have testified before the Commission on behalf of CEI South for a certificate of public convenience and necessity ("CPCN") in Cause Nos. 45501, 45564, 45754, 45836, 45847, and 45903. Similarly, I've testified for approval of Power Purchase Agreements ("PPAs") in Cause Nos. 46058 and 46218. Additionally, I have testified on behalf of CEI South in its Fuel Adjustment Clause ("FAC") proceedings and the FAC 137 sub docket under Cause No. 38708; its Clean Energy Cost Adjustment ("CECA") under Cause No. 44909; its Environmental Cost Adjustment ("ECA") under Cause No. 45052; the Midcontinent Independent System Operator ("MISO") Cost and Revenue Adjustment ("MCRA") under Cause No. 43354; and Reliability Cost and

Revenue Adjustment ("RCRA") under Cause No. 43406. I also provided testimony before the Commission in Cause No. 45990 in support of CEI South's electric rate case and in Cause No. 46140 in support of CEI South's request for approval of a disposal agreement to effectuate the sale of CEI South's interest in the Warrick Unit 4 Generating Unit.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide information regarding CEI South's power purchases and related costs as a participant in the MISO Energy Market, CEI South's fuel supply, and to sponsor Attachment FSB-1, which consists of schedules that present the calculations of the MISO components included in fuel costs, the calculations of the daily benchmark prices applicable to purchased power for June 2025 through August 2025 (the "Reconciliation Period"), and information about over-benchmark purchased power costs that are reasonable and recoverable under the applicable settlement. Lastly, I will also present an update to the 2025 coal plan.

MISO

Q. Are you generally familiar with the operations of MISO, including MISO Day 2 Market Initiative and Day 3 Ancillary Services Market ("ASM")?

A. Yes, I am.

Q. Have you reviewed the Commission's June 1, 2005, Order in Cause No. 42685 ("42685 Order") and June 30, 2009, Phase II Order in Cause No. 43426 ("ASM Phase II Order")?

A. Yes.

Q. Is CEI South's proposed recovery of costs for the Reconciliation Period consistent with your understanding of the Commission's 42685 Order and ASM Phase II Order?

A. Yes, CEI South's FAC 149 filing is consistent with my understanding of those Commission Orders.

Q. Please summarize your understanding of the impact of MISO Day 2 on CEI South's operations.

A. MISO's implementation of the Day 2 Market Initiative resulted in operational changes for CEI South. MISO Day 2 features a wide-area security constrained centralized dispatch across a significant geographic footprint spanning 36 Local Balancing Authorities across fifteen states and Manitoba. Through centralized dispatch, this market brings about an integration of system operations and market operations unlike what existed in this region prior to the start of Day 2. This caused both changes to existing operating procedures and the creation of new operational infrastructure. These operational changes result in costs and cost structures that differ in form from those that previously existed.

As a result of the existence of the Day 2 market, the cost for CEI South to serve its native load customers now includes both its own generation and MISO dispatched economic energy purchases.

Q. Briefly describe the MISO costs and revenues that CEI South is seeking to include in this FAC proceeding.

A. Consistent with the 42685 Order, CEI South is requesting that fuel-related MISO costs and revenues track through its current FAC. Attachment FSB-1, Schedule 1, contains a summary of the determination of MISO Components of Fuel Costs, exclusive of purchased power costs, for the Reconciliation Period. In addition, CEI South is requesting recovery of projected MISO costs for the period of February through April 2026 ("FAC Period"). These projected costs include the estimated level of the net effect of delta Locational Marginal Pricing ("LMPs"), Day Ahead and Reliability Assessment Commitment ("RAC") recovery of unit commitment costs, Financial Transmission Right ("FTR") revenue and expenses, and Real Time Marginal Loss Surplus credits.

Q. Are costs associated with MISO's ASM included in the amounts for which you are seeking recovery in this FAC?

A. Yes. Consistent with the Commission's Phase I Order in Cause No. 43426, dated August 13, 2008, CEI South has included for recovery in the FAC those costs for charge types identified as "modified" under the ASM and which were previously recovered in the FAC. Additionally, the Commission issued its ASM Phase II Order on June 30, 2009, that authorized CEI South to include certain new MISO charges and credits as a cost of fuel for recovery in its FAC proceedings.

Q. Did the ASM Phase II Order contain any reporting requirements?

A. Yes. In compliance with the Phase II Order, CEI South must report the monthly average ASM Cost Distribution average dollar per megawatt hours ("MWh") paid for Regulation, Spinning, Supplemental, and Short-Term Reserves. The amounts for the Reconciliation Period are as follows:

	Regulation	Spinning	Supplemental	Short-Term
June 2025	$0.0778	$0.0475	$0.0029	$0.1073
July 2025	$0.0568	$0.0449	$0.0354	$0.2900
August 2025	$0.0516	$0.0342	$0.0206	$0.2759

Q. Given the centralized MISO economic dispatch structure of the Day 2 market, how does CEI South explicitly identify the quantity of purchased power and wholesale sales in each hour?

A. If in a given hour CEI South withdraws more MWh from the grid at its load zone than CEI South generating units inject to the grid, those excess MWh withdrawn are purchased power amounts. Conversely, if in a given hour CEI South generating units inject more MWh to the grid than CEI South withdraws from the grid at its load zone, those excess MWh injected are allocated to wholesale sale amounts.

Q. Is the proposed pass through of Revenue Sufficiency Guarantee ("RSG") amounts in this Cause consistent with your understanding of the Commission's July 16, 2008, Order in Cause No. 43475?

A. Yes.

Q. Are MISO fuel components also included in this FAC?

A. Yes. All the requested MISO components qualify for recovery in this FAC pursuant to

the Commission's Orders in Cause Nos. 42685, 43475, 43426, and 38708 FAC 73. In addition, as a result of the Federal Energy Regulatory Commission ("FERC") Order 719 (issued on October 17, 2008) and FERC Order 745 (issued on March 15, 2011) additional charge types have been included for recovery. These charge types were effective June 12, 2012, and discussed in FAC 96 and FAC 97.

PURCHASED POWER RECOVERY

Q. Please describe the mechanism in place for recovery of the cost of energy purchased in MISO Energy Markets.

A. Pursuant to an approved settlement, the cost associated with each purchase is calculated for a given hour as the product of the number of MW purchased for that hour and the purchase price for that hour. To assist in the FAC review of the reasonableness of power purchases, the settlement provides that a benchmark price is applied to purchases and any purchases made in the course of MISO's economic dispatch regime to meet jurisdictional retail load are a cost of fuel and are fully recoverable in the FAC up to the benchmark.

Above-benchmark purchases are also recoverable, so long as the purchases can be shown to be reasonable based on an evaluation conducted with factors set forth in the settlement. As explained by the Commission in Cause No. 41363:

> Our March 10, 1999, Docket Entry was clear that we contemplated that a benchmark would merely be a triggering mechanism-that is, if a benchmark is exceeded the utility would have the opportunity to submit additional evidence demonstrating the reasonableness of its power purchases for cost recovery purposes. Every electric generating utility should have the opportunity to request recovery of and justify the reasonableness of purchased power costs above the benchmark. In the event a utility exceeds the benchmark, the standard to be used to review such purchases will be of the reasonableness of the decisions under the circumstances which were known (or which reasonably should have been known) at the time the purchases were made, not an after the fact focus using hindsight judgment.

(IURC Order, Aug. 18, 1999, p. 11).

Q. What is CEI South's benchmark for purchased power costs?

A. In Cause No. 43414, the Commission approved the establishment of daily benchmarks. The daily benchmarks are established based upon a generic Gas Turbine ("GT"), using a generic GT heat rate of 12,500 Btu/kWh, and using the NYMEX Henry Hub Gas Day Ahead price plus $0.60/MMBtu gas transport charge for a generic gas-fired GT. Changes were approved in Cause No. 43414 to the parameters used to determine amounts over the daily benchmarks.

Q. Is a Schedule showing the Daily Benchmarks for purchased power for the Reconciliation Period included in this Cause?

A. Yes. Attachment FSB-1, Schedule 2, presents the Daily Benchmark amounts for each day in the Reconciliation Period.

Q. What are the amounts of purchased power in excess of the Daily Benchmarks incurred by CEI South during the Reconciliation Period?

A. As shown on Attachment FSB-1, Schedule 3, CEI South determined that purchased power costs exceeded the Daily Benchmarks during the Reconciliation Period as follows: June 2025, $2,596,988.28; July 2025, $3,604,233.44; and August 2025, $1,556,991.21. These costs were incurred pursuant to MISO's security constrained economic dispatch across its footprint because MISO elected to utilize other generation when CEI South needed additional power.

Q. Are all over-benchmark purchases during the Reconciliation Period determined to be recoverable?

A. No. Applying the criteria established by the Benchmark Settlement, CEI South has determined that $159,908.71 of the $7,758,212.93 over benchmark purchases are non-recoverable. The remaining $7,598,304.22 over benchmark purchases are recoverable. Attachment FSB-1, Schedule 3 provides the reason each purchase was made. As contemplated by the Commission in its Order in Cause No. 42770, all these purchases were within "the utility's reasonably expected cost of purchased power under an economic dispatch regime." CEI South acted appropriately in the operation of its generation and its participation in MISO to maintain safe, adequate, and reliable

service to its retail customers. The beneficiaries of these purchases were CEI South's retail customers. Without these purchases, CEI South could not have met the demands of its retail customers while complying with MISO dispatch instructions. Recovery of these purchased power costs only makes CEI South whole for costs incurred to meet the demand of retail customers.

Q. Why does MISO at times choose to instruct CEI South to purchase from the market rather than operate generation internal to its control area?

A. Since the 42685 Order, MISO has dispatched generation. MISO first considers its security constrained economic dispatch model to determine what generation is necessary to meet the next day's system demand with the lowest total cost. If this evaluation shows that the total daily cost is predicted to be less using market purchases rather than calling for CEI South's internal generation, then that is the MISO directive CEI South will be given for the Day Ahead market. Additional consideration will be given to the potential impact to system congestion, which is impacted by market purchases versus CEI South peaking generation operation. The summation of these variables is that every day's evaluation has a different set of conditions and inputs which can only be evaluated by MISO on a regional basis. Thus, like any generator, CEI South is sometimes required by MISO to make economic purchases at the lowest cost reasonably possible. With the influx of new generation sources such as wind, and the dramatic reduction in gas prices, other generation sources now are available in the market at competitive prices. Some of these sources, like wind, are so inexpensive in off peak hours that they are selected in the Day Ahead market. The reasonable purchase costs reflected in the FAC are the product of MISO's economic dispatch.

Q. Does CEI South ever deviate from MISO dispatch in order to operate its gas peaking generation?

A. Generally, CEI South follows instructions from MISO on when to operate gas peaking generation. CEI South's on-duty system generation operators are provided plans from MISO, and they follow those dispatch plans. Most often, MISO will call on peaking units in the Real Time (intra-day) market but will on occasion also call for a Peaker through the Day Ahead market. The system generation operators will generally vary

from these MISO plans only when notified by local transmission system operators that there is a local distribution or transmission constraint that would be eliminated by the use of peaking generation.

In terms of determining whether to operate the peaking units for purely economic reasons, CEI South's system generation operator evaluates the Real Time Market price of power and compares it to the alternative of starting a natural gas peaking unit for a brief period. The operator monitors the five-minute price signals to determine if they believe the hourly market price will integrate high enough to justify starting a gas turbine. This determination is made knowing that the next five-minute price signal will likely change. A higher price often exists due to an event on the system that sends a price signal for generators to increase production. Once generation is increased, the price will drop; therefore, given these conditions the operator will almost always choose to follow the MISO dispatch signal rather than betting on a sustained higher price.

In addition, when evaluating the operation of a specific gas turbine, the operator must consider, among other things, (1) the time it takes to bring the unit on line, (2) the actual cost of fuel consumed during the period of time from initial firing until the unit is synchronized to the system, as well as the cost of gas used during controlled unit shut down, and (3) the likelihood that the unit will run at a reduced capacity factor, which increases the heat rate, adding to run costs. These must be spread over the total cost of the MWh produced by the machine. These are reasons why the cost of production during short periods often exceeds the price of power purchased from the economic marketplace.

Moreover, failure to comply with MISO's dispatch directive would result in assessment of uninstructed deviation charges of unknown amounts to CEI South. Given these cost and price risks, absent unusual market conditions, it is unlikely CEI South will ignore MISO dispatch and operate its peaking units for economic reasons.

Q. Are any purchases from the Benton County Wind Farm ("BCWF") and Fowler Ridge II ("FRII") included in this FAC?

A. Yes. Pursuant to the approval received in Cause No. 43259, CEI South began receiving power from BCWF on May 7, 2008, when the facility began commercial operation. CEI South's Renewable Energy Purchase Agreement ("REPA") with FRII was approved in Cause No. 43635 on June 17, 2009, and FRII began commercial operation on December 16, 2009. Consistent with the order in Cause No. 43635, CEI South has included in this FAC those charges or credits related to the REPA that are treated by the Commission as components of fuel.

Q. Are there any amounts shown as purchased power from BCWF and FRII included in the monthly work papers?

A. Yes. The details of power purchased from BCWF and FRII are included in the confidential work papers provided to the OUCC.

Q. How has CEI South estimated the generation received from BCWF in this FAC?

A. In response to the fluctuations in CEI South's share of generation of BCWF, CEI South's projections reflect recent historical output from BCWF. CEI South has created an output profile for BCWF that is based on CEI South's monthly average actual share of generation received from BCWF since March 2013 when BCWF was designated a Dispatchable Intermittent Resource ("DIR"). CEI South will update this output profile and its estimates for BCWF in each future FAC based on recent historical data.

Q. Have negative LMPs from BCWF or FRII been experienced?

A. Yes. LMPs can be negative whenever there is congestion on a node. MISO uses negative pricing to rein in a bottleneck, which can occur with wind energy. For the FAC period there were 103 hours when the LMP was negative at BCWF, and 10 hours when the LMP was negative at FRII. This resulted in total charges of $10,626.28.

Q. Please describe how CEI South uses the DIR designation.

A. MISO has attempted to address the operational challenges associated with the variable nature of wind power by allowing these resources to participate fully in MISO's

economic dispatch under a DIR resource designation. After consulting with MISO regarding requirements and stipulations around registering wind farms, CEI South was notified that it was required to register BCWF as a DIR. The registration was completed in December 2012, and BCWF became a DIR on March 1, 2013. CEI South is not required to register FRII as a DIR because it meets an exception through its firm transmission into MISO.

Q. How has DIR impacted CEI South and its customers?

A. Generally, since BCWF was registered as a DIR in March of 2013, generation output for CEI South customers has been reduced.

Q. Does CEI South have new power purchase agreement ("PPA") resources anticipated to become available in the next 12 months? If so, please provide the resource type, installed capacity, and the anticipated commercial operation date ("COD").

A. Yes, CEI South has three (3) renewable PPA resources with an anticipated COD in the next 12 months:

1. Salt Creek Wind PPA (170 MW) – anticipated COD of Q1 2026.
2. Wheatland Solar PPA (150 MW) – anticipated COD of Q1 2026.
3. Galesburg Wind PPA (147 MW) – anticipated COD of Q3 2026.

SALES OF RENEWABLE ENERGY CERTIFICATES

Q. Did CEI South include sales of Renewable Energy Certificates ("RECs") in this FAC?

A. Yes. Sales of RECs were recorded in the Reconciliation Period. The net amounts of those sales are included, as reductions to the cost of purchased power, in the calculation of purchased power costs for the respective months. For the Reconciliation Period, purchased power costs have been reduced by the net REC sales proceeds of $(792,086.90).

FUEL FOR GENERATION

Q. What sources of fuel does CEI South use for generating purposes, and what costs are incurred?

A. CEI South utilizes coal and natural gas for electric generation and incurs the costs of purchasing those fuels, including fuel-related transportation and storage costs. In addition, CEI South has solar, wind, battery storage, and landfill gas as part of the electric generation portfolio.

Q. Please describe CEI South's coal purchasing practices.

A. CEI South utilizes Indiana coal as its primary fuel source for electric generation. Coal is purchased primarily under a multi-year contract to maintain a reliable source of coal.

Q. Has CEI South made every reasonable effort to provide power as economically as possible?

A. Yes. CEI South's generating units are offered into the MISO Day Ahead and Real Time markets and are dispatched by the MISO on an economic basis. CEI South has contracted through competitive processes to purchase its coal requirements from a nearby mine at a reasonable market price. Purchasing from a mine in close proximity to CEI South's generating stations helps minimize transportation costs while providing a reliable, reasonably priced fuel supply.

COAL INVENTORY AND CULLEY UNIT 3 UPDATE

Q. What is the status of CEI South's coal inventory?

A. As of October 31, 2025, coal inventory at CEI South's coal-fired generating plant(s) stood at approximately 354,195 tons. This is an increase of 66,158 tons from the inventory level reported in FAC 148.

Q. Please provide the month-ending coal inventory level for Culley Generating Station.

A. The following table shows the month-ending coal inventory for 2025.

Month	Culley
January	226,197
February	241,106
March	307,436
April	327,859
May	284,583
June	307,345
July	288,037
August	289,218
September	317,183
October	354,195
November	
December	

Q. What is the contributing factor for the increased coal inventory in recent months?

A. Culley Unit 3 started its scheduled major turbine overhaul outage in early September. The outage is scheduled to last into late November; however, an unexpected delay with the turbine overhaul may push the unit return into early December. In addition, Culley Unit 2 operation is limited during the Culley Unit 3 scheduled outage due to National Pollutant Discharge Elimination System ("NPDES") wastewater permitting requirements.

Q. Does CEI South have an inventory target to assure reliability?

A. Yes. CEI South's target inventory is driven in part by the risk CEI South is willing to take regarding deliveries being suspended due to a mine issue (safety, Mine Safety and Health Administration, productivity issues, employee retention or strike, etc.), or truck transportation issues (equipment issues or employee retention or strikes), and how long these supply interruptions might reasonably be expected to last. The target inventory also attempts to account for the carrying costs for holding the inventory. Considering these various factors of mine risks, transportation risks, and carrying costs, CEI South generally targets a reserve inventory of about 60 days ± 30 days dependent on contractual commitment. The level of burn can vary, and therefore,

target inventory should fall within a range. For CEI South's operating purposes, inventory of approximately [redacted] tons is considered a reasonable target.

Q. What is a contributing factor for the increased coal inventory over CEI South's target range?

A. Culley Unit 3 experienced a main transformer failure forced outage on February 15, 2025, due to an external electrical system disturbance believed to be a lightning strike. Culley Unit 3 remained offline for approximately 9 weeks to replace the main transformer. Culley Unit 3 returned to service on April 18, 2025. Also, as mentioned above, Culley Unit 2 operation was limited during the Culley Unit 3 forced outage due to NPDES wastewater permitting requirements. The combination of Culley Unit 3 forced outage and Culley Unit 2 operational limitations caused the coal inventory to increase.

COAL SUPPLY PLAN

Q. Please summarize CEI South's 2025 coal supply to include delivery options with [redacted].

A. CEI South entered 2025 with 263,321 tons of coal in inventory. For 2025, CEI South has in place coal deliveries priced under one contract previously reviewed by the Commission. Because CEI South negotiated the ability to adjust the contract amount in any given year, CEI South can reduce the total 2025 specified contract volume of [redacted] tons to a firm commitment of [redacted] tons or increase the firm commitment to [redacted] tons. The table below shows the contract, and the [redacted] associated with each.

2025 Contract	Contracted Volume	[redacted]	[redacted]
[redacted] Contract	[redacted]	[redacted]	[redacted]

The following table shows the contract [redacted] that can be exercised.

2025 Contract	Contracted Volume	[redacted]	[redacted]
[redacted] Contract	[redacted]	[redacted]	[redacted]

The [redacted] must be decided by [redacted] of the year prior to the actual year the coal is taken or, in this case, by [redacted] for coal to be taken in 2025. [redacted] CEI South decided to exercise the [redacted] to decrease the contract volume by [redacted].

[redacted] must be decided [redacted] before the beginning of each calendar quarter. CEI South did not choose to exercise the first [redacted] 2025 [redacted] to adjust the contract [redacted]. For the second 2024 [redacted], CEI South chose to decrease the contract by [redacted]. [redacted].

Q. Please provide an update to the 2025 coal plan.

A. The following table shows the 2025 starting inventory, forecasted contractual deliveries, projected coal burn, total available inventory, and ending inventory in 2025 – making the 2025 year-end inventory [redacted] than the target range stated above.

2024 Ending Inventory	[redacted]
2025 Projected Contractual Deliveries	[redacted]
2025 Projected Coal Burn	[redacted]
2025 Projected Year-end Inventory	[redacted]

Q. Can CEI South manage contractual obligations without creating a Culley coal pile inventory concern?

A. Yes. CEI South and the coal supplier have agreed [redacted] which should avoid exceeding Culley's coal pile maximum limitation.

SOLAR GENERATION

Q. What was the total Troy Solar field generation for the Reconciliation Period?

A. Production for the Reconciliation Period from the Troy Solar field was 34,888 MWh. "Solar Generation" production estimates for the FAC Period are included on Petitioner's Exhibit 2, Attachment BKA-2, Schedule 1, Line 6.

Q. What was the total Posey Solar field generation for the Reconciliation Period?

A. Production for the Reconciliation Period from the Posey Solar field was 140,483 MWh. "Solar Generation" production estimates for the FAC Period are included on Petitioner's Exhibit 2, Attachment BKA-2, Schedule 1, Line 6.

CONFIDENTIALITY

Q. What portions of this testimony is CEI South requesting to be treated as confidential information?

A. CEI South's confidentiality request relates to the pricing for winter gas procurement, [redacted] with some coal supply contracts as well as other contractual terms, re-pricing of coal contracts and other concessions, tonnage figures calculated using such optionality, and other details related to costs ("Confidential Provisions"). Confidentiality also relates to rail transportation rates, fuel surcharges, competitive bids, and minimum requirements.

Q. Why has CEI South requested that such information be treated as confidential?

A. These Confidential Provisions of the testimony contain pricing for gas procurement and [redacted] and other confidential terms that were negotiated between CEI South and its natural gas and coal suppliers. If the pricing and optionality became generally known or readily ascertainable to the other parties with whom CEI South is negotiating or to other utilities with whom CEI South would compete, this knowledge would provide considerable economic value to such parties. In effect, knowledge of pricing and optionality provisions by other suppliers would establish a floor in future negotiations, thereby limiting the potential terms and benefits that could accrue to ratepayers, shareholders, and CEI South. Knowledge of the pricing and optionality provisions by potential coal suppliers could enable them to gain an unfair advantage in future competitive situations and negotiate a lower price and optionality provision than would otherwise be possible. The lower optionality provisions would diminish the flexibility available to CEI South's operations to the disadvantage of CEI South and its customers. Further, disclosure of the coal suppliers' optionality provisions would be of significant value to the coal suppliers' competitors, which could

prove harmful to the coal suppliers. In addition, CEI South requests that coal transportation rates, competitive bids, and contract terms remain confidential to protect supplier's confidential information as well as the economic value competitive parties could gain from this information in an open energy market. CEI South is requesting that, pursuant to Indiana Code § 5-14-3-4(a)(4), the Commission find that the Confidential Provisions of the Contract contain "trade secrets" as that term is defined in Indiana Code § 24-2-3-2 and are thereby exempt from public access.

Q. Has CEI South taken any steps to maintain the confidentiality of this information?

A. Yes. In accordance with Indiana Code § 24-2-3-2, the information contained in the Confidential Provisions of the testimony has been the subject of efforts that are reasonable under the circumstances to maintain its secrecy. Within CEI South, this information will be disclosed only to those people directly involved with negotiating coal supply contracts. Outside of CEI South, this information will be disclosed only to individuals who have signed a confidentiality agreement.

CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, at the present time.

VERIFICATION

I affirm under penalties for perjury that the foregoing representations are true to the best of my knowledge, information, and belief.

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A CENTERPOINT ENERGY INDIANA SOUTH

F. Shane Bradford
Vice President, Power Generation Operations

November 17, 2025
Date

CENTERPOINT ENERGY INDIANA SOUTH
Determination of MISO Components of Fuel Cost
June, July and August 2025

Line No.	Energy Market & ASM FAC Adjustment Components	Actual June 2025	Actual July 2025	Actual August 2025
1	Delta LMP	$ (148,004.48)	$ (810,518.54)	$ (1,460,922.32)
2	DA Virtuals Bids and Offers for Load	-	-	-
3	DA RSG 1st Pass Distribution Amount	14,735.60	15,696.67	10,650.97
4	DA RSG Make Whole Payment	(17,738.24)	(3,472.15)	(5,518.77)
5	DA Regulation Amount	(46,774.60)	(46,558.86)	(52,063.49)
6	DA Spinning Reserve Amount	(12,880.90)	(16,700.30)	(7,672.89)
7	DA Supplemental Reserve Amount	(10.47)	(1,002.58)	(165.95)
8	DA Ramp Capability Amount	(29,591.63)	(5,130.38)	(4,280.58)
9	DA Short-Term Reserve Amount	(43,785.31)	(122,243.92)	(86,526.39)
10	RT Marg. Loss Surplus Credit	(96,308.32)	(402,602.04)	(272,635.05)
11	RT Virtuals Bids and Offers for Load	-	-	-
12	RT RSG 1st Pass Distribution Amount	18,413.41	8,903.88	13,494.89
13	RT RSG Make Whole Payment Amount	(53,153.73)	(12,687.61)	(6,272.18)
14	RT Price Volatility Make Whole Payment Amount	(8,754.24)	(16,332.68)	(13,287.85)
15	RT Net Inadvertent Energy	8,426.37	(14,481.99)	2,601.68
16	RT Revenue from Uninstructed Deviation	-	-	-
17	RT Uninstructed Deviation	-	-	-
18	RT Demand Response Allocation Uplift Charge	0.16	7.65	4,148.79
19	RT Regulation Amount	13,020.53	17,984.74	14,483.09
20	RT Spinning Reserve Amount	180.68	8,783.55	(2,736.80)
21	RT Supplemental Reserve Amount	(408.30)	(299.94)	(358.87)
22	RT Regulation Cost Distribution Amount	39,843.63	31,988.92	25,767.78
23	RT Spinning Reserve Cost Distribution Amount	24,314.05	25,309.90	17,066.59
24	RT Supplemental Reserve Cost Distribution Amount	1,498.98	19,949.36	10,292.90
25	RT Excessive Deficient Energy Deployment Charge Amount	28,392.67	20,018.03	24,891.66
26	RT Contingency Reserve Deployment Failure Charge Amount	1,328.18	-	-
27	RT Net Regulation Adjustment Amount	4,073.61	(95.76)	42.52
28	RT Ramp Capability Amount	(3,067.22)	(4,095.23)	(2,312.12)
29	RT Short-Tem Reserve Amount	(10,969.70)	(5,995.22)	(10,890.58)
30	Short-Term Reserve Cost Distribution Amount	54,911.01	163,387.11	137,736.53
31	Short-Term Reserve Deployment Failure Charge Amount			
32	FTR (Revenue) / Expenses	(405.96)	-	-
33	ARR (Revenue) / Expenses	178,618.30	178,618.30	178,618.30
34	Subtotal	(84,095.92)	(971,569.09)	(1,485,848.14)
35	Plus: Residual Load Adjustment Volume Changes			
36	Plus: MISO Charges (above) on sales billed to IMPA	-	-	-
37	Total (To BKA-2, Sch 5, line 23)	$ (84,095.92)	$ (971,569.09)	$ (1,485,848.14)

Negative amount is a credit to expense (payment from MISO)
Positive amount is a debit to expense (payment to MISO)

CENTERPOINT ENERGY INDIANA SOUTH
Calculation of Daily Benchmark
Based on NYMEX Henry Hub Day Ahead Natural Gas Price

June 2025						July 2025						August 2025					
Date	Day Ahead Cost $/MMBtu	Transportation $/MMBtu	Allowed Gas Price $/MMBtu	Heat Rate Btu/kWh	Daily Benchmark $/MWh	Date	Day Ahead Cost $/MMBtu	Transportation $/MMBtu	Allowed Gas Price $/MMBtu	Heat Rate Btu/kWh	Daily Benchmark $/MWh	Date	Day Ahead Cost $/MMBtu	Transportation $/MMBtu	Allowed Gas Price $/MMBtu	Heat Rate Btu/kWh	Daily Benchmark $/MWh
06/01/25	2.800	0.60	3.40	12,500	42.50	07/01/25	3.280	0.60	3.88 [4]	12,500	48.50	08/01/25	2.950	0.60	3.55 [4]	12,500	44.38
06/02/25	2.800	0.60	3.40	12,500	42.50	07/02/25	3.140	0.60	3.74	12,500	46.75	08/02/25	2.990	0.60	3.59	12,500	44.88
06/03/25	2.980	0.60	3.58	12,500	44.75	07/03/25	3.130	0.60	3.73	12,500	46.63	08/03/25	2.990	0.60	3.59	12,500	44.88
06/04/25	2.820	0.60	3.42	12,500	42.75	07/04/25	3.220	0.60	3.82	12,500	47.75	08/04/25	2.990	0.60	3.59	12,500	44.88
06/05/25	2.815	0.60	3.42	12,500	42.69	07/05/25	3.220	0.60	3.82	12,500	47.75	08/05/25	2.865	0.60	3.47	12,500	43.31
06/06/25	2.850	0.60	3.45	12,500	43.13	07/06/25	3.220	0.60	3.82	12,500	47.75	08/06/25	2.975	0.60	3.58	12,500	44.69
06/07/25	2.675	0.60	3.28	12,500	40.94	07/07/25	3.220	0.60	3.82	12,500	47.75	08/07/25	3.020	0.60	3.62	12,500	45.25
06/08/25	2.675	0.60	3.28	12,500	40.94	07/08/25	3.240	0.60	3.84	12,500	48.00	08/08/25	3.045	0.60	3.65	12,500	45.56
06/09/25	2.675	0.60	3.28	12,500	40.94	07/09/25	3.200	0.60	3.80	12,500	47.50	08/09/25	3.040	0.60	3.64	12,500	45.50
06/10/25	3.090	0.60	3.69	12,500	46.13	07/10/25	3.080	0.60	3.68	12,500	46.00	08/10/25	3.040	0.60	3.64	12,500	45.50
06/11/25	2.750	0.60	3.35	12,500	41.88	07/11/25	3.110	0.60	3.71	12,500	46.38	08/11/25	3.040	0.60	3.64	12,500	45.50
06/12/25	2.735	0.60	3.34	12,500	41.69	07/12/25	3.210	0.60	3.81	12,500	47.63	08/12/25	3.010	0.60	3.61	12,500	45.13
06/13/25	2.895	0.60	3.50	12,500	43.69	07/13/25	3.210	0.60	3.81	12,500	47.63	08/13/25	2.930	0.60	3.53	12,500	44.13
06/14/25	2.640	0.60	3.24	12,500	40.50	07/14/25	3.210	0.60	3.81	12,500	47.63	08/14/25	2.915	0.60	3.52	12,500	43.94
06/15/25	2.640	0.60	3.24	12,500	40.50	07/15/25	3.225	0.60	3.83	12,500	47.81	08/15/25	2.770	0.60	3.37	12,500	42.13
06/16/25	2.640	0.60	3.24	12,500	40.50	07/16/25	3.295	0.60	3.90	12,500	48.69	08/16/25	2.970	0.60	3.57	12,500	44.63
06/17/25	2.890	0.60	3.49	12,500	43.63	07/17/25	3.425	0.60	4.03	12,500	50.31	08/17/25	2.970	0.60	3.57	12,500	44.63
06/18/25	2.895	0.60	3.50	12,500	43.69	07/18/25	3.500	0.60	4.10	12,500	51.25	08/18/25	2.970	0.60	3.57	12,500	44.63
06/19/25	3.475	0.60	4.08	12,500	50.94	07/19/25	3.505	0.60	4.11	12,500	51.31	08/19/25	2.960	0.60	3.56	12,500	44.50
06/20/25	3.475	0.60	4.08	12,500	50.94	07/20/25	3.505	0.60	4.11	12,500	51.31	08/20/25	2.860	0.60	3.46	12,500	43.25
06/21/25	3.100	0.60	3.70	12,500	46.25	07/21/25	3.505	0.60	4.11	12,500	51.31	08/21/25	2.805	0.60	3.41	12,500	42.56
06/22/25	3.100	0.60	3.70	12,500	46.25	07/22/25	3.470	0.60	4.07	12,500	50.88	08/22/25	2.880	0.60	3.48	12,500	43.50
06/23/25	3.100	0.60	3.70	12,500	46.25	07/23/25	3.205	0.60	3.81	12,500	47.56	08/23/25	2.790	0.60	3.39	12,500	42.38
06/24/25	3.515	0.60	4.12	12,500	51.44	07/24/25	3.070	0.60	3.67	12,500	45.88	08/24/25	2.790	0.60	3.39	12,500	42.38
06/25/25	3.305	0.60	3.91	12,500	48.81	07/25/25	3.115	0.60	3.72	12,500	46.44	08/25/25	2.790	0.60	3.39	12,500	42.38
06/26/25	3.255	0.60	3.86	12,500	48.19	07/26/25	3.090	0.60	3.69	12,500	46.13	08/26/25	2.755	0.60	3.36	12,500	41.94
06/27/25	3.230	0.60	3.83	12,500	47.88	07/27/25	3.090	0.60	3.69	12,500	46.13	08/27/25	2.820	0.60	3.42	12,500	42.75
06/28/25	3.225	0.60	3.83	12,500	47.81	07/28/25	3.090	0.60	3.69	12,500	46.13	08/28/25	2.875	0.60	3.48	12,500	43.44
06/29/25	3.225	0.60	3.83	12,500	47.81	07/29/25	3.125	0.60	3.73	12,500	46.56	08/29/25	2.895	0.60	3.50	12,500	43.69
06/30/25	3.225	0.60	3.83	12,500	47.81	07/30/25	3.075	0.60	3.68	12,500	45.94	08/30/25	2.895	0.60	3.50	12,500	43.69
						07/31/25	2.975	0.60	3.58	12,500	44.69	08/31/25	2.895	0.60	3.50	12,500	43.69

Total (To BKA-2, Sch 5, line 21)

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 06/30

Jun Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	Test for Outages and Derates: 11% of Summer Rated Capacity 791	Test for Outages and Derates: Are Unit MWs Out of Service > 11% Summer Capacity?	Test for Outages and Derates: Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
42.50	06/01/2025	19	$ 12,046.33	239.520	$ 50.29	$ 10,179.60	$ 1,866.73	*Brown 3 Brown 4 and Culley 2 were on Reserve Shutdown*	330.145	-	$ -	12.000	87.01	NO	85	-	$ 7.79	$ -
42.50	06/01/2025	20	$ 8,661.13	168.800	$ 51.31	$ 7,174.00	$ 1,487.13		286.127	-	$ -	12.000	87.01	NO	85	-	$ 8.81	$ -
42.50	06/01/2025	21	$ 6,764.67	149.100	$ 45.37	$ 6,336.75	$ 427.92		302.000	-	$ -	12.000	87.01	NO	85	-	$ 2.87	$ -
42.50	06/02/2025	17	$ 4,258.60	99.500	$ 42.80	$ 4,228.75	$ 29.85		376.737	-	$ -	12.000	87.01	NO	85	-	$ 0.30	$ -
42.50	06/02/2025	18	$ 6,468.80	136.300	$ 47.46	$ 5,792.75	$ 676.05	*Brown 3 Brown 4 and Culley 2 were on Reserve Shutdown*	366.000	-	$ -	12.000	87.01	NO	85	-	$ 4.96	$ -
42.50	06/02/2025	19	$ 8,929.06	161.000	$ 55.46	$ 6,842.50	$ 2,086.56		344.000	-	$ -	12.000	87.01	NO	85	-	$ 12.96	$ -
42.50	06/02/2025	20	$ 12,630.60	233.900	$ 54.00	$ 9,940.75	$ 2,689.85		272.975	-	$ -	12.000	87.01	NO	85	-	$ 11.50	$ -
42.50	06/02/2025	21	$ 11,350.16	250.500	$ 45.31	$ 10,646.25	$ 703.91		260.938	-	$ -	12.000	87.01	NO	85	-	$ 2.81	$ -
44.75	06/03/2025	16	$ 6,313.44	136.330	$ 46.31	$ 6,100.77	$ 212.67		75.441	60.89	$ 94.99	413.000	87.01	YES	100	-	$ 1.56	$ -
44.75	06/03/2025	17	$ 7,547.45	135.990	$ 55.50	$ 6,085.55	$ 1,461.90		31.850	104.14	$ 1,119.51	413.000	87.01	YES	100	-	$ 10.75	$ -
44.75	06/03/2025	18	$ 9,813.47	155.720	$ 63.02	$ 6,968.47	$ 2,845.00	*Brown 3 Brown 4 and Brown 6 were on Outage*	24.425	131.30	$ 2,398.76	426.000	87.01	YES	100	-	$ 18.27	$ -
44.75	06/03/2025	19	$ 15,865.30	235.740	$ 67.30	$ 10,549.37	$ 5,315.94		0.625	235.12	$ 5,301.84	446.000	87.01	YES	100	-	$ 22.55	$ -
44.75	06/03/2025	20	$ 18,364.76	286.100	$ 64.19	$ 12,802.98	$ 5,561.79		5.454	280.65	$ 5,455.76	446.000	87.01	YES	100	-	$ 19.44	$ -
44.75	06/03/2025	21	$ 16,125.00	293.930	$ 54.86	$ 13,153.37	$ 2,971.63		6.398	287.53	$ 2,906.95	446.000	87.01	YES	100	-	$ 10.11	$ -
44.75	06/03/2025	22	$ 12,277.23	273.070	$ 44.96	$ 12,219.88	$ 57.35		17.583	255.49	$ 53.65	446.000	87.01	YES	100	-	$ 0.21	$ -
42.75	06/04/2025	19	$ 1,547.11	22.910	$ 67.53	$ 979.40	$ 567.71		77.000	-	$ -	19.000	87.01	NO	85	-	$ 24.78	$ -
42.75	06/04/2025	20	$ 3,196.25	48.590	$ 65.78	$ 2,077.22	$ 1,119.03	*Brown 3 was on Reserve Shutdown all other units online*	83.417	-	$ -	19.000	87.01	NO	85	-	$ 23.03	$ -
42.75	06/04/2025	21	$ 5,708.93	94.550	$ 60.38	$ 4,042.01	$ 1,666.92		92.833	1.72	$ 30.27	19.000	87.01	NO	85	1.72	$ 17.63	$ 4.54
42.75	06/04/2025	22	$ 8,392.62	164.400	$ 51.05	$ 7,028.10	$ 1,364.52		159.971	4.43	$ 36.76	19.000	87.01	NO	85	4.43	$ 8.30	$ 5.51
42.69	06/05/2025	6	$ 2,737.81	49.580	$ 55.22	$ 2,116.47	$ 621.34		146.625	-	$ -	59.000	87.01	NO	85	-	$ 12.53	$ -
42.69	06/05/2025	17	$ 3,492.02	79.800	$ 43.76	$ 3,406.50	$ 85.52		150.117	-	$ -	19.000	87.01	NO	85	-	$ 1.07	$ -
42.69	06/05/2025	18	$ 90.10	1.600	$ 56.31	$ 68.30	$ 21.80		76.183	-	$ -	19.000	87.01	NO	85	-	$ 13.62	$ -
42.69	06/05/2025	19	$ 2,072.86	34.200	$ 60.61	$ 1,459.93	$ 612.93	*All units online load greater than generation*	65.825	-	$ -	19.000	87.01	NO	85	-	$ 17.92	$ -
42.69	06/05/2025	20	$ 4,138.02	71.100	$ 58.20	$ 3,035.12	$ 1,102.90		94.892	-	$ -	19.000	87.01	NO	85	-	$ 15.51	$ -
42.69	06/05/2025	21	$ 5,957.52	114.700	$ 51.94	$ 4,896.31	$ 1,061.21		158.262	-	$ -	19.000	87.01	NO	85	-	$ 9.25	$ -
42.69	06/05/2025	22	$ 10,817.69	221.700	$ 48.79	$ 9,463.93	$ 1,353.76		191.137	30.56	$ 186.63	19.000	87.01	NO	85	30.56	$ 6.11	$ 27.99
42.69	06/05/2025	24	$ 4,685.97	77.840	$ 60.20	$ 3,322.83	$ 1,363.14		184.033	-	$ -	19.000	87.01	NO	85	-	$ 17.51	$ -
43.13	06/06/2025	8	$ 4,519.46	84.400	$ 53.55	$ 3,639.75	$ 879.71		173.875	-	$ -	25.000	87.01	NO	85	-	$ 10.42	$ -
43.13	06/06/2025	10	$ 6,142.80	119.500	$ 51.40	$ 5,153.44	$ 989.36		170.497	-	$ -	25.000	87.01	NO	85	-	$ 8.28	$ -
43.13	06/06/2025	12	$ 90.76	2.100	$ 43.22	$ 90.56	$ 0.20		169.475	-	$ -	25.000	87.01	NO	85	-	$ 0.09	$ -
43.13	06/06/2025	15	$ 2,448.01	51.200	$ 47.81	$ 2,208.00	$ 240.01		65.667	-	$ -	25.000	87.01	NO	85	-	$ 4.69	$ -
43.13	06/06/2025	16	$ 5,976.17	119.690	$ 49.93	$ 5,161.63	$ 814.54	*All units online load greater than generation*	65.825	53.87	$ 366.57	25.000	87.01	NO	85	53.87	$ 6.81	$ 54.99
43.13	06/06/2025	17	$ 3,128.90	64.500	$ 48.51	$ 2,781.56	$ 347.34		72.658	-	$ -	25.000	87.01	NO	85	-	$ 5.39	$ -
43.13	06/06/2025	18	$ 3,417.94	68.100	$ 50.19	$ 2,936.81	$ 481.13		79.563	-	$ -	25.000	87.01	NO	85	-	$ 7.07	$ -
43.13	06/06/2025	19	$ 4,101.92	83.700	$ 49.01	$ 3,609.56	$ 492.36		97.417	-	$ -	25.000	87.01	NO	85	-	$ 5.88	$ -
43.13	06/06/2025	20	$ 4,669.81	99.400	$ 46.98	$ 4,286.63	$ 383.19		129.517	-	$ -	25.000	87.01	NO	85	-	$ 3.85	$ -
43.13	06/06/2025	21	$ 4,638.10	103.900	$ 44.64	$ 4,480.69	$ 157.41		172.950	-	$ -	25.000	87.01	NO	85	-	$ 1.52	$ -
43.13	06/06/2025	22	$ 110.57	2.240	$ 49.36	$ 96.60	$ 13.97		179.917	-	$ -	25.000	87.01	NO	85	-	$ 6.24	$ -
40.94	06/07/2025	17	$ 4,727.13	109.780	$ 43.06	$ 4,494.17	$ 232.96		212.250	-	$ -	27.000	87.01	NO	85	-	$ 2.12	$ -
40.94	06/07/2025	18	$ 5,509.15	119.660	$ 46.04	$ 4,898.64	$ 610.51	*Brown 3 and Culley 2 were on Reserve Shutdown*	189.775	-	$ -	27.000	87.01	NO	85	-	$ 5.10	$ -
40.94	06/07/2025	19	$ 5,186.10	116.150	$ 44.65	$ 4,754.95	$ 431.15		188.208	-	$ -	27.000	87.01	NO	85	-	$ 3.71	$ -
40.94	06/07/2025	20	$ 7,386.08	172.250	$ 42.88	$ 7,051.57	$ 334.51		229.833	-	$ -	27.000	87.01	NO	85	-	$ 1.94	$ -
40.94	06/08/2025	19	$ 5,584.31	121.240	$ 46.06	$ 4,963.32	$ 620.99	*Brown 3 Brown 4 and Culley 2 were on Reserve Shutdown*	250.088	-	$ -	29.000	87.01	NO	85	-	$ 5.12	$ -
40.94	06/08/2025	20	$ 8,437.10	184.700	$ 45.68	$ 7,561.25	$ 875.85		245.583	-	$ -	29.000	87.01	NO	85	-	$ 4.74	$ -
40.94	06/08/2025	21	$ 8,830.50	210.300	$ 41.99	$ 8,609.26	$ 221.24		289.079	-	$ -	29.000	87.01	NO	85	-	$ 1.05	$ -
40.94	06/09/2025	19	$ 6,105.52	144.100	$ 42.37	$ 5,899.17	$ 206.35	*Brown 3 Brown 4 and Culley 2 were on Reserve Shutdown*	366.392	-	$ -	43.000	87.01	NO	85	-	$ 1.43	$ -
40.94	06/09/2025	20	$ 11,832.44	231.440	$ 51.13	$ 9,474.69	$ 2,357.75		322.117	-	$ -	43.000	87.01	NO	85	-	$ 10.19	$ -
40.94	06/09/2025	21	$ 9,275.31	173.500	$ 53.46	$ 7,102.74	$ 2,172.57		336.717	-	$ -	43.000	87.01	NO	85	-	$ 12.52	$ -
46.13	06/10/2025	19	$ 5,002.43	101.100	$ 49.48	$ 4,663.24	$ 339.19	*Brown 3 and Brown 4 were on Reserve Shutdown*	253.967	-	$ -	33.000	87.01	NO	85	-	$ 3.36	$ -
46.13	06/10/2025	20	$ 6,173.97	116.600	$ 52.95	$ 5,378.18	$ 795.80		222.862	-	$ -	33.000	87.01	NO	85	-	$ 6.83	$ -
41.88	06/11/2025	19	$ 1,696.38	35.480	$ 47.81	$ 1,485.73	$ 210.66	*Brown 3 was on Reserve Shutdown all other units online*	116.000	-	$ -	37.000	87.01	NO	85	-	$ 5.94	$ -
41.88	06/11/2025	20	$ 7,266.06	111.000	$ 65.46	$ 4,648.13	$ 2,617.94		133.208	-	$ -	37.000	87.01	NO	85	-	$ 23.59	$ -
41.88	06/11/2025	21	$ 8,597.47	162.800	$ 52.81	$ 6,817.25	$ 1,780.22		260.084	-	$ -	37.000	87.01	NO	85	-	$ 10.94	$ -
41.69	06/12/2025	13	$ 1,294.92	29.310	$ 44.18	$ 1,221.88	$ 73.04		442.000	-	$ -	45.000	87.01	NO	85	-	$ 2.49	$ -
41.69	06/12/2025	14	$ 4,818.64	107.200	$ 44.95	$ 4,468.95	$ 349.69		344.884	-	$ -	45.000	87.01	NO	85	-	$ 3.26	$ -
41.69	06/12/2025	15	$ 7,263.02	135.580	$ 53.57	$ 5,652.06	$ 1,610.96		258.000	-	$ -	45.000	87.01	NO	85	-	$ 11.88	$ -
41.69	06/12/2025	16	$ 9,218.63	185.270	$ 49.76	$ 7,723.54	$ 1,495.09		232.331	-	$ -	45.000	87.01	NO	85	-	$ 8.07	$ -
41.69	06/12/2025	17	$ 14,039.54	232.120	$ 60.48	$ 9,676.62	$ 4,362.92	*Brown 3 and Culley 2 were on Reserve Shutdown*	241.642	-	$ -	45.000	87.01	NO	85	-	$ 18.80	$ -
41.69	06/12/2025	18	$ 14,403.46	168.720	$ 85.37	$ 7,033.60	$ 7,369.86		162.208	6.51	$ 284.45	45.000	87.01	NO	85	6.51	$ 43.68	$ 42.67
41.69	06/12/2025	19	$ 8,400.67	129.700	$ 64.77	$ 5,406.93	$ 2,993.74		219.758	-	$ -	45.000	87.01	NO	85	-	$ 23.08	$ -
41.69	06/12/2025	20	$ 13,067.52	220.400	$ 59.29	$ 9,188.04	$ 3,879.48		303.200	-	$ -	45.000	87.01	NO	85	-	$ 17.60	$ -
41.69	06/12/2025	21	$ 14,059.15	274.700	$ 51.18	$ 11,451.69	$ 2,607.46		310.487	-	$ -	45.000	87.01	NO	85	-	$ 9.49	$ -

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 06/30

Jun Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
41.69	06/12/2025	23	$ 553.70	7.610	$ 72.76	$ 317.25	$ 236.45		472.000	-	$ -	45.000	87.01	NO	85	-	$ 31.07	$ -
43.69	06/13/2025	17	$ 16,439.73	355.300	$ 46.27	$ 15,522.35	$ 917.38	*Brown 3 Brown 4 Brown 6 and Culley 2 were on Reserve Shutdown*	458.000	-	$ -	43.000	87.01	NO	85	-	$ 2.58	$ -
40.50	06/14/2025	19	$ 14,666.12	333.700	$ 43.95	$ 13,514.85	$ 1,151.27	*Brown 3 Brown 4 Brown 6 and*	452.483	-	$ -	49.000	87.01	NO	85	-	$ 3.45	$ -
40.50	06/14/2025	20	$ 15,848.52	381.800	$ 41.51	$ 15,462.90	$ 385.62	*Culley 2 were on Reserve Shutdown*	454.546	-	$ -	49.000	87.01	NO	85	-	$ 1.01	$ -
40.50	06/15/2025	17	$ 5,322.41	118.460	$ 44.93	$ 4,797.63	$ 524.78		345.154	-	$ -	45.000	87.01	NO	85	-	$ 4.43	$ -
40.50	06/15/2025	18	$ 7,074.72	136.000	$ 52.02	$ 5,508.00	$ 1,566.72		382.154	-	$ -	45.000	87.01	NO	85	-	$ 11.52	$ -
40.50	06/15/2025	19	$ 9,268.97	166.200	$ 55.77	$ 6,731.10	$ 2,537.87	*Brown 3 Brown 4 and Culley 2 were*	369.258	-	$ -	45.000	87.01	NO	85	-	$ 15.27	$ -
40.50	06/15/2025	20	$ 12,383.35	215.400	$ 57.49	$ 8,723.70	$ 3,659.65	*on Reserve Shutdown*	356.833	-	$ -	45.000	87.01	NO	85	-	$ 16.99	$ -
40.50	06/15/2025	21	$ 10,486.15	200.500	$ 52.30	$ 8,120.25	$ 2,365.90		337.350	-	$ -	45.000	87.01	NO	85	-	$ 11.80	$ -
40.50	06/15/2025	22	$ 11,239.54	251.500	$ 44.69	$ 10,185.75	$ 1,053.79		372.292	-	$ -	45.000	87.01	NO	85	-	$ 4.19	$ -
40.50	06/16/2025	14	$ 2,805.22	69.060	$ 40.62	$ 2,796.93	$ 8.29		449.000	-	$ -	52.000	87.01	NO	85	-	$ 0.12	$ -
40.50	06/16/2025	15	$ 14,256.41	339.600	$ 41.98	$ 13,753.80	$ 502.61		434.000	-	$ -	52.000	87.01	NO	85	-	$ 1.48	$ -
40.50	06/16/2025	16	$ 13,697.55	262.950	$ 52.09	$ 10,649.48	$ 3,048.08		251.000	11.95	$ 138.52	52.000	87.01	NO	85	11.95	$ 11.59	$ 20.78
40.50	06/16/2025	17	$ 7,372.47	144.700	$ 50.95	$ 5,860.35	$ 1,512.12	*Brown 3 Brown 4 and Culley 2 were*	305.917	-	$ -	52.000	87.01	NO	85	-	$ 10.45	$ -
40.50	06/16/2025	18	$ 9,010.50	165.300	$ 54.51	$ 6,694.65	$ 2,315.85	*on Reserve Shutdown*	302.917	-	$ -	52.000	87.01	NO	85	-	$ 14.01	$ -
40.50	06/16/2025	19	$ 14,235.00	266.070	$ 53.50	$ 10,775.84	$ 3,459.17		250.308	15.76	$ 204.92	52.000	87.01	NO	85	15.76	$ 13.00	$ 30.74
40.50	06/16/2025	20	$ 17,315.18	289.600	$ 59.79	$ 11,728.80	$ 5,586.38		306.775	-	$ -	52.000	87.01	NO	85	-	$ 19.29	$ -
40.50	06/16/2025	21	$ 13,192.79	258.530	$ 51.03	$ 10,470.47	$ 2,722.33		289.604	-	$ -	52.000	87.01	NO	85	-	$ 10.53	$ -
43.63	06/17/2025	13	$ 339.38	7.300	$ 46.49	$ 318.46	$ 20.92		165.133	-	$ -	33.000	87.01	NO	85	-	$ 2.87	$ -
43.63	06/17/2025	16	$ 126.42	2.100	$ 60.20	$ 91.61	$ 34.81		98.817	-	$ -	54.000	87.01	NO	85	-	$ 16.58	$ -
43.63	06/17/2025	18	$ 291.99	6.370	$ 45.84	$ 277.89	$ 14.10		86.754	-	$ -	66.000	87.01	NO	85	-	$ 2.21	$ -
43.63	06/17/2025	19	$ 4,118.37	12.070	$ 341.21	$ 526.55	$ 3,591.82	*All units online load greater than*	49.537	-	$ -	66.000	87.01	NO	85	-	$ 297.58	$ -
43.63	06/17/2025	20	$ 8,538.66	117.340	$ 72.77	$ 5,118.96	$ 3,419.70	*generation*	76.908	40.43	$ 1,178.33	66.000	87.01	NO	85	40.43	$ 29.14	$ 176.75
43.63	06/17/2025	21	$ 13,497.20	102.910	$ 131.16	$ 4,489.45	$ 9,007.75		62.909	40.00	$ 3,501.30	66.000	87.01	NO	85	40.00	$ 87.53	$ 525.20
43.63	06/17/2025	22	$ 5,331.88	96.400	$ 55.31	$ 4,205.45	$ 1,126.43		81.254	15.15	$ 176.98	66.000	87.01	NO	85	15.15	$ 11.68	$ 26.55
43.63	06/17/2025	23	$ 644.44	13.040	$ 49.42	$ 568.87	$ 75.57		231.175	-	$ -	66.000	87.01	NO	85	-	$ 5.80	$ -
43.69	06/18/2025	6	$ 1,081.19	6.020	$ 179.60	$ 263.00	$ 818.19		374.167	-	$ -	321.000	87.01	YES	100	-	$ 135.91	$ -
43.69	06/18/2025	7	$ 219.79	1.090	$ 201.64	$ 47.62	$ 172.17		375.083	-	$ -	321.000	87.01	YES	100	-	$ 157.95	$ -
43.69	06/18/2025	13	$ 3,105.47	69.420	$ 44.73	$ 3,032.82	$ 72.65		165.724	-	$ -	321.000	87.01	YES	100	-	$ 1.05	$ -
43.69	06/18/2025	14	$ 12,465.16	279.300	$ 44.63	$ 12,202.06	$ 263.10		140.221	139.08	$ 131.01	321.000	87.01	YES	100	-	$ 0.94	$ -
43.69	06/18/2025	15	$ 16,905.13	359.720	$ 47.00	$ 15,715.45	$ 1,189.68	*Culley 3 was on outage all other units*	114.075	245.65	$ 812.41	321.000	87.01	YES	100	-	$ 3.31	$ -
43.69	06/18/2025	16	$ 15,354.64	305.140	$ 50.32	$ 13,330.96	$ 2,023.68	*online*	125.119	180.02	$ 1,193.90	321.000	87.01	YES	100	-	$ 6.63	$ -
43.69	06/18/2025	17	$ 13,201.00	248.700	$ 53.08	$ 10,865.21	$ 2,335.79		141.625	107.08	$ 1,005.65	321.000	87.01	YES	100	-	$ 9.39	$ -
43.69	06/18/2025	18	$ 15,893.83	298.700	$ 53.21	$ 13,049.61	$ 2,844.22		140.833	157.87	$ 1,503.21	326.000	87.01	YES	100	-	$ 9.52	$ -
43.69	06/18/2025	19	$ 17,963.25	308.700	$ 58.19	$ 13,486.49	$ 4,476.76		144.558	164.14	$ 2,380.39	326.000	87.01	YES	100	-	$ 14.50	$ -
43.69	06/18/2025	20	$ 19,377.40	346.520	$ 55.92	$ 15,138.77	$ 4,238.63		112.621	233.90	$ 2,861.05	326.000	87.01	YES	100	-	$ 12.23	$ -
43.69	06/18/2025	21	$ 19,147.44	361.000	$ 53.04	$ 15,771.37	$ 3,376.07		125.208	235.79	$ 2,205.13	326.000	87.01	YES	100	-	$ 9.35	$ -
50.94	06/19/2025	17	$ 14,877.24	268.300	$ 55.45	$ 13,666.67	$ 1,210.57		182.867	85.43	$ 385.48	325.000	87.01	YES	100	-	$ 4.51	$ -
50.94	06/19/2025	18	$ 16,346.87	280.200	$ 58.34	$ 14,272.83	$ 2,074.04	*Culley 3 was on outage all other units*	157.075	123.13	$ 911.37	325.000	87.01	YES	100	-	$ 7.40	$ -
50.94	06/19/2025	19	$ 18,543.00	262.500	$ 70.64	$ 13,371.23	$ 5,171.78	*online*	101.534	160.97	$ 3,171.35	325.000	87.01	YES	100	-	$ 19.70	$ -
50.94	06/19/2025	20	$ 21,602.16	328.500	$ 65.76	$ 16,733.13	$ 4,869.03		84.291	244.21	$ 3,619.67	325.000	87.01	YES	100	-	$ 14.82	$ -
50.94	06/19/2025	21	$ 19,937.57	368.600	$ 54.09	$ 18,775.75	$ 1,161.82		171.983	196.62	$ 619.73	325.000	87.01	YES	100	-	$ 3.15	$ -
50.94	06/20/2025	17	$ 36,912.81	669.560	$ 55.13	$ 34,106.05	$ 2,806.76	*Culley 3 was on outage Culley 2*	440.000	229.56	$ 962.30	321.000	87.01	YES	100	-	$ 4.19	$ -
50.94	06/20/2025	18	$ 36,624.41	676.660	$ 54.13	$ 34,467.71	$ 2,156.70	*Brown 3 Brown 4 and Brown 6 were*	440.000	236.66	$ 754.30	321.000	87.01	YES	100	-	$ 3.19	$ -
50.94	06/20/2025	19	$ 33,277.92	635.560	$ 52.36	$ 32,374.16	$ 903.76	*on Reserve Shutdown*	440.000	195.56	$ 278.09	321.000	87.01	YES	100	-	$ 1.42	$ -
46.25	06/21/2025	11	$ 967.45	16.060	$ 60.24	$ 742.78	$ 224.68		448.000	-	$ -	313.000	87.01	YES	100	-	$ 13.99	$ -
46.25	06/21/2025	12	$ 1,754.45	16.860	$ 104.06	$ 779.78	$ 974.68		448.000	-	$ -	313.000	87.01	YES	100	-	$ 57.81	$ -
46.25	06/21/2025	13	$ 2,859.20	35.860	$ 79.73	$ 1,658.53	$ 1,200.68		448.000	-	$ -	313.000	87.01	YES	100	-	$ 33.48	$ -
46.25	06/21/2025	14	$ 6,180.18	54.660	$ 113.07	$ 2,528.03	$ 3,652.16		448.000	-	$ -	313.000	87.01	YES	100	-	$ 66.82	$ -
46.25	06/21/2025	17	$ 11,786.72	248.560	$ 47.42	$ 11,495.90	$ 290.82	*Culley 2 was on Reserve Shutdown*	89.950	158.61	$ 185.58	313.000	87.01	YES	100	-	$ 1.17	$ -
46.25	06/21/2025	18	$ 17,722.24	318.860	$ 55.58	$ 14,747.28	$ 2,974.97	*and Culley 3 was on outage*	150.417	168.44	$ 1,571.57	313.000	87.01	YES	100	-	$ 9.33	$ -
46.25	06/21/2025	19	$ 23,300.08	398.360	$ 58.49	$ 18,424.15	$ 4,875.93		167.832	230.53	$ 2,821.66	313.000	87.01	YES	100	-	$ 12.24	$ -
46.25	06/21/2025	20	$ 26,233.41	410.860	$ 63.85	$ 19,002.28	$ 7,231.14		97.000	313.86	$ 5,523.94	313.000	87.01	YES	100	0.86	$ 17.60	$ 2.27
46.25	06/21/2025	21	$ 24,910.33	484.260	$ 51.44	$ 22,397.03	$ 2,513.31		157.890	326.37	$ 1,693.86	313.000	87.01	YES	100	13.37	$ 5.19	$ 10.41
46.25	06/22/2025	14	$ 11,519.46	240.540	$ 47.89	$ 11,124.98	$ 394.49		58.819	181.72	$ 298.02	314.000	87.01	YES	100	-	$ 1.64	$ -
46.25	06/22/2025	15	$ 13,952.56	253.960	$ 54.94	$ 11,745.65	$ 2,206.91		66.000	187.96	$ 1,633.37	314.000	87.01	YES	100	-	$ 8.69	$ -
46.25	06/22/2025	16	$ 17,005.37	275.060	$ 61.82	$ 12,721.53	$ 4,283.85		66.108	208.95	$ 3,254.26	314.000	87.01	YES	100	-	$ 15.57	$ -
46.25	06/22/2025	17	$ 19,495.89	242.150	$ 80.51	$ 11,199.44	$ 8,296.45	*Culley 3 was on outage all other units*	15.338	226.81	$ 7,770.95	314.000	87.01	YES	100	-	$ 34.26	$ -
46.25	06/22/2025	18	$ 26,412.49	261.160	$ 101.14	$ 12,078.65	$ 14,333.84	*online*	3.106	258.05	$ 14,163.37	314.000	87.01	YES	100	-	$ 54.89	$ -
46.25	06/22/2025	19	$ 44,803.58	334.090	$ 134.11	$ 15,451.66	$ 29,351.92		18.292	315.80	$ 27,744.85	314.000	87.01	YES	100	1.80	$ 87.86	$ 23.69
46.25	06/22/2025	20	$ 49,466.51	408.970	$ 120.95	$ 18,914.86	$ 30,551.65		5.424	403.55	$ 30,146.45	314.000	87.01	YES	100	89.55	$ 74.70	$ 1,003.42
46.25	06/22/2025	21	$ 31,158.95	419.280	$ 74.32	$ 19,391.70	$ 11,767.25		17.333	401.95	$ 11,280.79	314.000	87.01	YES	100	87.95	$ 28.07	$ 370.24

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 06/30

Jun Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
46.25	06/22/2025	22	$ 23,627.02	421.610	$ 56.04	$ 19,499.46	$ 4,127.56		76.942	344.67	$ 3,374.30	314.000	87.01	YES	100	30.67	$ 9.79	$ 45.04
46.25	06/23/2025	9	$ 22,273.64	455.680	$ 48.88	$ 21,075.20	$ 1,198.44		353.208	102.47	$ 269.50	314.000	87.01	YES	100	-	$ 2.63	$ -
46.25	06/23/2025	10	$ 16,455.98	294.910	$ 55.80	$ 13,639.59	$ 2,816.39		184.542	110.37	$ 1,054.02	314.000	87.01	YES	100	-	$ 9.55	$ -
46.25	06/23/2025	11	$ 17,140.84	257.370	$ 66.60	$ 11,903.36	$ 5,237.48		103.783	153.59	$ 3,125.49	314.000	87.01	YES	100	-	$ 20.35	$ -
46.25	06/23/2025	12	$ 22,772.50	234.970	$ 96.92	$ 10,867.36	$ 11,905.14		28.767	206.20	$ 10,447.61	314.000	87.01	YES	100	-	$ 50.67	$ -
46.25	06/23/2025	13	$ 28,626.38	241.300	$ 118.63	$ 11,160.13	$ 17,466.26		0.000	241.30	$ 17,466.26	287.000	87.01	YES	100	-	$ 72.38	$ -
46.25	06/23/2025	14	$ 34,957.54	252.290	$ 138.56	$ 11,668.41	$ 23,289.13		0.067	252.22	$ 23,282.94	287.000	87.01	YES	100	-	$ 92.31	$ -
46.25	06/23/2025	15	$ 47,465.84	296.220	$ 160.24	$ 13,700.18	$ 33,765.67		16.000	280.22	$ 31,941.85	287.000	87.01	YES	100	-	$ 113.99	$ -
46.25	06/23/2025	16	$ 58,213.08	258.640	$ 225.07	$ 11,962.10	$ 46,250.98	*Culley 3 was on outage all other units online*	3.234	255.41	$ 45,672.66	287.000	87.01	YES	100	-	$ 178.82	$ -
46.25	06/23/2025	17	$ 71,408.02	270.690	$ 263.80	$ 12,519.41	$ 58,888.61		1.971	268.72	$ 58,459.82	287.000	87.01	YES	100	-	$ 217.55	$ -
46.25	06/23/2025	18	$ 77,069.97	282.380	$ 272.93	$ 13,060.08	$ 64,009.90		3.550	278.83	$ 63,205.18	282.000	87.01	YES	100	-	$ 226.68	$ -
46.25	06/23/2025	19	$ 93,526.86	318.780	$ 293.39	$ 14,743.58	$ 78,783.29		0.625	318.16	$ 78,628.82	282.000	87.01	YES	100	36.16	$ 247.14	$ 1,340.30
46.25	06/23/2025	20	$ 120,796.68	405.290	$ 298.05	$ 18,744.66	$ 102,052.02		0.000	405.29	$ 102,052.02	283.000	87.01	YES	100	122.29	$ 251.80	$ 4,618.89
46.25	06/23/2025	21	$ 107,832.39	426.450	$ 252.86	$ 19,723.31	$ 88,109.08		4.750	421.70	$ 87,127.68	302.000	87.01	YES	100	119.70	$ 206.61	$ 3,709.69
46.25	06/23/2025	22	$ 80,231.68	474.620	$ 169.04	$ 21,951.18	$ 58,280.51		72.558	402.06	$ 49,370.82	304.000	87.01	YES	100	98.06	$ 122.79	$ 1,806.21
46.25	06/23/2025	23	$ 42,702.86	423.010	$ 100.95	$ 19,564.21	$ 23,138.65		74.209	348.80	$ 19,079.42	308.000	87.01	YES	100	40.80	$ 54.70	$ 334.77
46.25	06/23/2025	24	$ 28,322.35	409.460	$ 69.17	$ 18,937.53	$ 9,384.83		123.216	286.24	$ 6,560.71	308.000	87.01	YES	100	-	$ 22.92	$ -
51.44	06/24/2025	1	$ 23,999.89	358.850	$ 66.88	$ 18,458.53	$ 5,541.36		154.005	204.85	$ 3,163.22	302.000	87.01	YES	100	-	$ 15.44	$ -
51.44	06/24/2025	7	$ 16,877.33	276.270	$ 61.09	$ 14,210.78	$ 2,666.55		161.771	114.50	$ 1,105.14	302.000	87.01	YES	100	-	$ 9.65	$ -
51.44	06/24/2025	8	$ 13,977.08	216.330	$ 64.61	$ 11,127.58	$ 2,849.50		128.205	88.13	$ 1,160.78	302.000	87.01	YES	100	-	$ 13.17	$ -
51.44	06/24/2025	9	$ 13,003.77	187.780	$ 69.25	$ 9,659.03	$ 3,344.74		100.346	87.43	$ 1,557.38	302.000	87.01	YES	100	-	$ 17.81	$ -
51.44	06/24/2025	10	$ 15,288.02	202.760	$ 75.40	$ 10,429.57	$ 4,858.45		72.171	130.59	$ 3,129.12	302.000	87.01	YES	100	-	$ 23.96	$ -
51.44	06/24/2025	11	$ 14,777.79	155.180	$ 95.23	$ 7,982.15	$ 6,795.64		7.071	148.11	$ 6,485.99	302.000	87.01	YES	100	-	$ 43.79	$ -
51.44	06/24/2025	12	$ 24,404.55	187.850	$ 129.92	$ 9,662.63	$ 14,741.92		0.000	187.85	$ 14,741.92	302.000	87.01	YES	100	-	$ 78.48	$ -
51.44	06/24/2025	13	$ 42,708.38	226.020	$ 188.96	$ 11,626.02	$ 31,082.36		0.000	226.02	$ 31,082.36	281.000	87.01	YES	100	-	$ 137.52	$ -
51.44	06/24/2025	14	$ 49,881.26	261.320	$ 190.88	$ 13,441.78	$ 36,439.48		0.000	261.32	$ 36,439.48	281.000	87.01	YES	100	-	$ 139.44	$ -
51.44	06/24/2025	15	$ 54,867.37	283.240	$ 193.71	$ 14,569.30	$ 40,298.07	*Culley 3 was on outage all other units online*	0.000	283.24	$ 40,298.07	281.000	87.01	YES	100	2.24	$ 142.28	$ 47.80
51.44	06/24/2025	16	$ 90,702.02	365.940	$ 247.86	$ 18,823.22	$ 71,878.80		0.000	365.94	$ 71,878.80	281.000	87.01	YES	100	84.94	$ 196.42	$ 2,502.62
51.44	06/24/2025	17	$ 126,785.23	409.210	$ 309.83	$ 21,048.94	$ 105,736.29		0.000	409.21	$ 105,736.29	280.000	87.01	YES	100	129.21	$ 258.39	$ 5,008.01
51.44	06/24/2025	18	$ 113,275.24	361.590	$ 313.27	$ 18,599.47	$ 94,675.77		10.417	351.17	$ 91,948.27	280.000	87.01	YES	100	71.17	$ 261.83	$ 2,795.30
51.44	06/24/2025	19	$ 121,062.44	349.680	$ 346.21	$ 17,986.84	$ 103,075.60		10.000	339.68	$ 100,127.89	281.000	87.01	YES	100	58.68	$ 294.77	$ 2,594.58
51.44	06/24/2025	20	$ 100,687.16	350.460	$ 287.30	$ 18,026.96	$ 82,660.20		0.000	350.46	$ 82,660.20	279.000	87.01	YES	100	71.46	$ 235.86	$ 2,528.20
51.44	06/24/2025	21	$ 71,901.80	371.970	$ 193.30	$ 19,133.39	$ 52,768.41		4.000	367.97	$ 52,200.96	301.000	87.01	YES	100	66.97	$ 141.86	$ 1,425.07
51.44	06/24/2025	22	$ 50,246.94	427.910	$ 117.42	$ 22,010.83	$ 28,236.11		84.100	343.81	$ 22,686.68	302.000	87.01	YES	100	41.81	$ 65.99	$ 413.83
51.44	06/24/2025	23	$ 31,446.02	390.510	$ 80.53	$ 20,087.05	$ 11,358.97		109.408	281.10	$ 8,176.56	302.000	87.01	YES	100	-	$ 29.09	$ -
51.44	06/24/2025	24	$ 22,253.32	375.520	$ 59.26	$ 19,316.00	$ 2,937.32		145.539	229.98	$ 1,798.91	302.000	87.01	YES	100	-	$ 7.82	$ -
48.81	06/25/2025	1	$ 23,886.29	448.570	$ 53.25	$ 21,896.05	$ 1,990.24		245.498	203.07	$ 901.00	304.000	87.01	YES	100	-	$ 4.44	$ -
48.81	06/25/2025	7	$ 19,985.66	392.800	$ 50.88	$ 19,173.75	$ 811.91		256.292	136.51	$ 282.16	304.000	87.01	YES	100	-	$ 2.07	$ -
48.81	06/25/2025	8	$ 15,998.06	310.100	$ 51.59	$ 15,136.91	$ 861.15		232.245	77.86	$ 216.20	304.000	87.01	YES	100	-	$ 2.78	$ -
48.81	06/25/2025	9	$ 15,338.75	274.200	$ 55.94	$ 13,384.52	$ 1,954.23		248.862	25.34	$ 180.58	304.000	87.01	YES	100	-	$ 7.13	$ -
48.81	06/25/2025	10	$ 16,290.68	292.000	$ 55.79	$ 14,253.40	$ 2,037.28		202.000	90.00	$ 627.93	304.000	87.01	YES	100	-	$ 6.98	$ -
48.81	06/25/2025	11	$ 23,635.03	329.500	$ 71.73	$ 16,083.88	$ 7,551.15		91.943	237.56	$ 5,444.09	304.000	87.01	YES	100	-	$ 22.92	$ -
48.81	06/25/2025	12	$ 19,841.88	259.100	$ 76.58	$ 12,647.45	$ 7,194.43		86.254	172.85	$ 4,799.42	304.000	87.01	YES	100	-	$ 27.77	$ -
48.81	06/25/2025	13	$ 38,849.41	350.860	$ 110.73	$ 17,126.53	$ 21,722.88		13.916	336.94	$ 20,861.30	283.000	87.01	YES	100	53.94	$ 61.91	$ 500.98
48.81	06/25/2025	14	$ 38,501.08	349.790	$ 110.07	$ 17,074.30	$ 21,426.78	*Culley 3 was on outage all other units online*	1.013	348.78	$ 21,364.73	283.000	87.01	YES	100	65.78	$ 61.26	$ 604.39
48.81	06/25/2025	15	$ 41,419.76	412.400	$ 100.44	$ 20,130.48	$ 21,289.28		11.000	401.40	$ 20,721.43	283.000	87.01	YES	100	118.40	$ 51.62	$ 916.82
48.81	06/25/2025	16	$ 40,715.76	389.700	$ 104.48	$ 19,022.43	$ 21,693.33		8.000	381.70	$ 21,248.00	283.000	87.01	YES	100	98.70	$ 55.67	$ 824.15
48.81	06/25/2025	17	$ 67,927.35	440.060	$ 154.36	$ 21,480.65	$ 46,446.70		0.000	440.06	$ 46,446.70	283.000	87.01	YES	100	157.06	$ 105.55	$ 2,486.57
48.81	06/25/2025	18	$ 68,933.08	426.120	$ 161.77	$ 20,800.20	$ 48,132.88		0.000	426.12	$ 48,132.88	283.000	87.01	YES	100	143.12	$ 112.96	$ 2,424.94
48.81	06/25/2025	19	$ 65,341.80	439.740	$ 148.59	$ 21,465.03	$ 43,876.77		1.746	437.99	$ 43,702.56	283.000	87.01	YES	100	154.99	$ 99.78	$ 2,319.77
48.81	06/25/2025	20	$ 65,116.89	509.510	$ 127.80	$ 24,870.71	$ 40,246.18		6.000	503.51	$ 39,772.24	283.000	87.01	YES	100	220.51	$ 78.99	$ 2,612.71
48.81	06/25/2025	21	$ 47,234.72	520.350	$ 90.77	$ 25,399.84	$ 21,834.88		23.388	496.96	$ 20,853.47	304.000	87.01	YES	100	192.96	$ 41.96	$ 1,214.56
48.81	06/25/2025	22	$ 38,831.13	547.730	$ 70.89	$ 26,736.34	$ 12,094.79		89.096	458.63	$ 10,127.40	304.000	87.01	YES	100	154.63	$ 22.08	$ 512.19
48.81	06/25/2025	23	$ 30,881.70	564.170	$ 54.74	$ 27,538.83	$ 3,342.87		174.021	390.15	$ 2,311.75	304.000	87.01	YES	100	86.15	$ 5.93	$ 76.57
48.19	06/26/2025	7	$ 29,334.81	601.000	$ 48.81	$ 28,960.99	$ 373.82		367.000	234.00	$ 145.55	304.000	87.01	YES	100	-	$ 0.62	$ -
48.19	06/26/2025	8	$ 26,362.02	524.200	$ 50.29	$ 25,260.15	$ 1,101.87		345.000	179.20	$ 376.68	304.000	87.01	YES	100	-	$ 2.10	$ -
48.19	06/26/2025	9	$ 15,541.64	295.300	$ 52.63	$ 14,229.92	$ 1,311.72		212.271	83.03	$ 368.82	304.000	87.01	YES	100	-	$ 4.44	$ -
48.19	06/26/2025	10	$ 18,352.16	323.500	$ 56.73	$ 15,588.82	$ 2,763.34		192.417	131.08	$ 1,119.71	304.000	87.01	YES	100	-	$ 8.54	$ -
48.19	06/26/2025	11	$ 19,067.02	291.500	$ 65.41	$ 14,046.80	$ 5,020.22		153.242	138.26	$ 2,381.08	304.000	87.01	YES	100	-	$ 17.22	$ -
48.19	06/26/2025	12	$ 28,783.39	362.050	$ 79.50	$ 17,446.47	$ 11,336.92		107.000	255.05	$ 7,986.42	304.000	87.01	YES	100	-	$ 31.31	$ -
48.19	06/26/2025	13	$ 35,850.88	371.820	$ 96.42	$ 17,917.26	$ 17,933.62		55.000	316.82	$ 15,280.86	283.000	87.01	YES	100	33.82	$ 48.23	$ 244.68
48.19	06/26/2025	14	$ 43,179.27	390.930	$ 110.45	$ 18,838.13	$ 24,341.14		56.000	334.93	$ 20,854.31	283.000	87.01	YES	100	51.93	$ 62.26	$ 485.01
48.19	06/26/2025	15	$ 40,188.20	336.500	$ 119.43	$ 16,215.26	$ 23,972.94	*Culley 3 was on outage all other units online*	55.000	281.50	$ 20,054.63	283.000	87.01	YES	100	-	$ 71.24	$ -
48.19	06/26/2025	16	$ 36,749.36	298.000	$ 123.32	$ 14,360.02	$ 22,389.34		56.000	242.00	$ 18,181.94	283.000	87.01	YES	100	-	$ 75.13	$ -
48.19	06/26/2025	17	$ 48,744.38	344.800	$ 141.37	$ 16,615.22	$ 32,129.16		54.000	290.80	$ 27,097.33	283.000	87.01	YES	100	7.80	$ 93.18	$ 109.02
48.19	06/26/2025	18	$ 47,265.36	320.900	$ 147.29	$ 15,463.53	$ 31,801.83		56.000	264.90	$ 26,252.12	283.000	87.01	YES	100	-	$ 99.10	$ -
48.19	06/26/2025	19	$ 76,596.98	485.900	$ 157.64	$ 23,414.55	$ 53,182.43		56.000	429.90	$ 47,053.15	283.000	87.01	YES	100	146.90	$ 109.45	$ 2,411.76
48.19	06/26/2025	20	$ 84,387.29	538.380	$ 156.74	$ 25,943.46	$ 58,443.83		55.000	483.38	$ 52,473.31	283.000	87.01	YES	100	200.38	$ 108.55	$ 3,262.84
48.19	06/26/2025	21	$ 54,822.62	444.700	$ 123.28	$ 21,429.20	$ 33,393.42		146.317	298.38	$ 22,406.18	304.000	87.01	YES	100	-	$ 75.09	$ -
48.19	06/26/2025	22	$ 36,176.60	464.100	$ 77.95	$ 22,364.05	$ 13,812.55		140.867	323.23	$ 9,620.06	304.000	87.01	YES	100	19.23	$ 29.76	$ 85.86

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 06/30

Jun Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
48.19	06/26/2025	23	$ 28,897.10	509.200	$ 56.75	$ 24,537.33	$ 4,359.77		257.267	251.93	$ 2,157.05	304.000	87.01	YES	100	-	$ 8.56	$ -
48.19	06/26/2025	24	$ 23,784.99	486.500	$ 48.89	$ 23,443.46	$ 341.53		267.517	218.98	$ 153.73	304.000	87.01	YES	100	-	$ 0.70	$ -
47.88	06/27/2025	11	$ 20,489.21	379.500	$ 53.99	$ 18,168.56	$ 2,320.65		248.987	130.51	$ 798.09	304.000	87.01	YES	100	-	$ 6.12	$ -
47.88	06/27/2025	12	$ 25,118.62	423.300	$ 59.34	$ 20,265.49	$ 4,853.13		216.930	206.37	$ 2,366.03	304.000	87.01	YES	100	-	$ 11.46	$ -
47.88	06/27/2025	13	$ 22,049.94	321.100	$ 68.67	$ 15,372.66	$ 6,677.28		86.000	235.10	$ 4,888.91	283.000	87.01	YES	100	-	$ 20.80	$ -
47.88	06/27/2025	14	$ 22,753.62	298.800	$ 76.15	$ 14,305.05	$ 8,448.57		56.000	242.80	$ 6,865.17	283.000	87.01	YES	100	-	$ 28.28	$ -
47.88	06/27/2025	15	$ 30,279.26	404.140	$ 74.92	$ 19,348.20	$ 10,931.06		55.000	349.14	$ 9,443.43	283.000	87.01	YES	100	66.14	$ 27.05	$ 268.34
47.88	06/27/2025	16	$ 30,978.56	429.670	$ 72.10	$ 20,570.45	$ 10,408.11	*Culley 3 was on outage all other units online*	55.000	374.67	$ 9,075.82	283.000	87.01	YES	100	91.67	$ 24.22	$ 333.09
47.88	06/27/2025	17	$ 28,004.79	331.300	$ 84.53	$ 15,860.99	$ 12,143.80		56.000	275.30	$ 10,091.12	283.000	87.01	YES	100	-	$ 36.66	$ -
47.88	06/27/2025	18	$ 27,314.78	328.500	$ 83.15	$ 15,726.94	$ 11,587.84		55.000	273.50	$ 9,647.72	283.000	87.01	YES	100	-	$ 35.28	$ -
47.88	06/27/2025	19	$ 33,826.12	363.800	$ 92.98	$ 17,416.93	$ 16,409.20		55.000	308.80	$ 13,928.42	283.000	87.01	YES	100	25.80	$ 45.10	$ 174.56
47.88	06/27/2025	20	$ 36,950.34	468.200	$ 78.92	$ 22,415.08	$ 14,535.27		55.000	413.20	$ 12,827.79	283.000	87.01	YES	100	130.20	$ 31.04	$ 606.31
47.88	06/27/2025	21	$ 34,466.25	487.500	$ 70.70	$ 23,339.06	$ 11,127.19		200.408	287.09	$ 6,552.87	304.000	87.01	YES	100	-	$ 22.83	$ -
47.88	06/27/2025	22	$ 26,568.41	531.900	$ 49.95	$ 25,464.71	$ 1,103.70		245.144	286.76	$ 595.02	304.000	87.01	YES	100	-	$ 2.08	$ -
47.81	06/28/2025	5	$ 1,082.87	20.080	$ 53.93	$ 960.09	$ 122.78		393.669	-	$ -	314.000	87.01	YES	100	-	$ 6.11	$ -
47.81	06/28/2025	10	$ 3,699.62	58.000	$ 63.79	$ 2,773.15	$ 926.47		377.058	-	$ -	314.000	87.01	YES	100	-	$ 15.97	$ -
47.81	06/28/2025	11	$ 3,268.03	56.300	$ 58.05	$ 2,691.87	$ 576.16		375.700	-	$ -	314.000	87.01	YES	100	-	$ 10.23	$ -
47.81	06/28/2025	13	$ 2,722.40	53.800	$ 50.60	$ 2,572.34	$ 150.06		376.117	-	$ -	314.000	87.01	YES	100	-	$ 2.79	$ -
47.81	06/28/2025	15	$ 25,229.88	526.500	$ 47.92	$ 25,173.54	$ 56.34	*Brown 3 was on Reserve Shutdown*	361.292	165.21	$ 17.68	314.000	87.01	YES	100	-	$ 0.11	$ -
47.81	06/28/2025	16	$ 16,009.95	313.000	$ 51.15	$ 14,965.47	$ 1,044.48	*Culley 3 was on outage all other units online*	264.921	48.08	$ 160.44	314.000	87.01	YES	100	-	$ 3.34	$ -
47.81	06/28/2025	17	$ 19,379.63	363.800	$ 53.27	$ 17,394.37	$ 1,985.26		180.075	183.73	$ 1,002.59	314.000	87.01	YES	100	-	$ 5.46	$ -
47.81	06/28/2025	18	$ 17,681.90	283.500	$ 62.37	$ 13,554.99	$ 4,126.91		154.675	128.83	$ 1,875.31	314.000	87.01	YES	100	-	$ 14.56	$ -
47.81	06/28/2025	19	$ 30,370.84	446.200	$ 68.07	$ 21,334.16	$ 9,036.68		111.879	334.32	$ 6,770.85	314.000	87.01	YES	100	20.32	$ 20.25	$ 61.73
47.81	06/28/2025	20	$ 31,375.51	449.400	$ 69.82	$ 21,487.16	$ 9,888.35		100.678	348.72	$ 7,673.09	314.000	87.01	YES	100	34.72	$ 22.00	$ 114.60
47.81	06/28/2025	21	$ 24,899.15	427.600	$ 58.23	$ 20,444.84	$ 4,454.31		209.125	218.48	$ 2,275.86	314.000	87.01	YES	100	-	$ 10.42	$ -
47.81	06/29/2025	10	$ 3,818.11	68.500	$ 55.74	$ 3,275.19	$ 542.92		393.000	-	$ -	314.000	87.01	YES	100	-	$ 7.93	$ -
47.81	06/29/2025	13	$ 12,291.93	250.600	$ 49.05	$ 11,981.94	$ 309.99		179.741	70.86	$ 87.65	314.000	87.01	YES	100	-	$ 1.24	$ -
47.81	06/29/2025	14	$ 13,251.05	263.860	$ 50.22	$ 12,615.94	$ 635.11		157.200	106.66	$ 256.73	314.000	87.01	YES	100	-	$ 2.41	$ -
47.81	06/29/2025	15	$ 12,904.99	244.830	$ 52.71	$ 11,706.06	$ 1,198.93		140.000	104.83	$ 513.35	314.000	87.01	YES	100	-	$ 4.90	$ -
47.81	06/29/2025	16	$ 15,062.04	240.800	$ 62.55	$ 11,513.37	$ 3,548.67		120.479	120.32	$ 1,773.17	314.000	87.01	YES	100	-	$ 14.74	$ -
47.81	06/29/2025	17	$ 21,698.72	301.280	$ 72.02	$ 14,405.10	$ 7,293.62	*Culley 3 was on outage all other units online*	48.096	253.18	$ 6,129.27	314.000	87.01	YES	100	-	$ 24.21	$ -
47.81	06/29/2025	18	$ 23,953.14	268.560	$ 89.19	$ 12,840.66	$ 11,112.48		25.224	243.34	$ 10,068.76	314.000	87.01	YES	100	-	$ 41.38	$ -
47.81	06/29/2025	19	$ 25,499.18	261.530	$ 97.50	$ 12,504.53	$ 12,994.65		13.000	248.53	$ 12,348.71	314.000	87.01	YES	100	-	$ 49.69	$ -
47.81	06/29/2025	20	$ 30,356.38	295.900	$ 102.59	$ 14,147.87	$ 16,208.51		26.000	269.90	$ 14,784.31	314.000	87.01	YES	100	-	$ 54.78	$ -
47.81	06/29/2025	21	$ 23,509.17	312.830	$ 75.15	$ 14,957.34	$ 8,551.83		43.492	269.34	$ 7,362.89	314.000	87.01	YES	100	-	$ 27.34	$ -
47.81	06/29/2025	22	$ 26,414.30	386.400	$ 68.36	$ 18,474.94	$ 7,939.36		143.178	243.22	$ 4,997.48	314.000	87.01	YES	100	-	$ 20.55	$ -
47.81	06/29/2025	23	$ 21,939.91	414.900	$ 52.88	$ 19,837.61	$ 2,102.30		249.192	165.71	$ 839.64	314.000	87.01	YES	100	-	$ 5.07	$ -
47.81	06/30/2025	9	$ 22,740.83	462.400	$ 49.18	$ 22,108.73	$ 632.10		381.650	80.75	$ 110.38	314.000	87.01	YES	100	-	$ 1.37	$ -
47.81	06/30/2025	10	$ 34,440.64	570.000	$ 60.42	$ 27,253.41	$ 7,187.23		352.000	218.00	$ 2,748.80	314.000	87.01	YES	100	-	$ 12.61	$ -
47.81	06/30/2025	11	$ 21,439.36	395.390	$ 54.22	$ 18,904.78	$ 2,534.58		187.742	207.65	$ 1,331.09	314.000	87.01	YES	100	-	$ 6.41	$ -
47.81	06/30/2025	12	$ 20,679.28	324.330	$ 63.76	$ 15,507.19	$ 5,172.09		153.696	170.63	$ 2,721.10	314.000	87.01	YES	100	-	$ 15.95	$ -
47.81	06/30/2025	13	$ 12,311.27	168.740	$ 72.96	$ 8,067.97	$ 4,243.30		83.592	85.15	$ 2,141.22	314.000	87.01	YES	100	-	$ 25.15	$ -
47.81	06/30/2025	14	$ 11,876.72	169.160	$ 70.21	$ 8,088.05	$ 3,788.67		75.000	94.16	$ 2,108.90	314.000	87.01	YES	100	-	$ 22.40	$ -
47.81	06/30/2025	15	$ 16,109.41	230.860	$ 69.78	$ 11,038.11	$ 5,071.30		78.000	152.86	$ 3,357.88	314.000	87.01	YES	100	-	$ 21.97	$ -
47.81	06/30/2025	16	$ 18,354.64	259.760	$ 70.66	$ 12,419.90	$ 5,934.74	*Culley 3 was on outage all other units online*	75.000	184.76	$ 4,221.21	314.000	87.01	YES	100	-	$ 22.85	$ -
47.81	06/30/2025	17	$ 20,763.25	290.030	$ 71.59	$ 13,867.20	$ 6,896.05		47.000	243.03	$ 5,778.53	314.000	87.01	YES	100	-	$ 23.78	$ -
47.81	06/30/2025	18	$ 18,593.14	229.460	$ 81.03	$ 10,971.17	$ 7,621.97		12.250	217.21	$ 7,215.06	314.000	87.01	YES	100	-	$ 33.22	$ -
47.81	06/30/2025	19	$ 27,979.47	353.710	$ 79.10	$ 16,911.94	$ 11,067.53		43.396	310.31	$ 9,709.68	314.000	87.01	YES	100	-	$ 31.29	$ -
47.81	06/30/2025	20	$ 30,419.00	380.000	$ 80.05	$ 18,168.94	$ 12,250.06		112.283	267.72	$ 8,630.39	314.000	87.01	YES	100	-	$ 32.24	$ -
47.81	06/30/2025	21	$ 30,940.18	450.140	$ 68.73	$ 21,522.54	$ 9,417.64		67.942	382.20	$ 7,996.18	314.000	87.01	YES	100	68.20	$ 20.92	$ 214.02
47.81	06/30/2025	22	$ 30,199.20	520.050	$ 58.07	$ 24,865.15	$ 5,334.05		174.709	345.34	$ 3,542.09	314.000	87.01	YES	100	31.34	$ 10.26	$ 48.22
47.81	06/30/2025	23	$ 1,792.94	33.740	$ 53.14	$ 1,613.21	$ 179.73		330.858	-	$ -	314.000	87.01	YES	100	-	$ 5.33	$ -
47.81	06/30/2025	24	$ 2,884.22	53.650	$ 53.76	$ 2,565.17	$ 319.05		372.550	-	$ -	314.000	87.01	YES	100	-	$ 5.95	$ -
Total			**$ 5,659,219.15**	**65,237.190**		**$ 3,062,231.00**	**$ 2,596,988.28**		**40,547.153**	**37,530.399**	**$ 2,241,404.46**	**54,377.000**				**3,762.762**		**$ 54,409.75**

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 07/31

Jul Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity 791	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
48.50	07/01/2025	1	$ 3,503.35	72.130	$ 48.57	$ 3,498.31	$ 5.05		384.058	-	$ -	312.000	87.01	YES	100	-	$ 0.07	$ -
48.50	07/01/2025	13	$ 16,008.16	325.700	$ 49.15	$ 15,796.45	$ 211.71		156.796	168.90	$ 109.79	291.000	87.01	YES	100	-	$ 0.65	$ -
48.50	07/01/2025	14	$ 16,758.25	328.400	$ 51.03	$ 15,927.40	$ 830.85		151.000	177.40	$ 448.82	291.000	87.01	YES	100	-	$ 2.53	$ -
48.50	07/01/2025	15	$ 17,304.31	334.060	$ 51.80	$ 16,201.91	$ 1,102.40		148.000	186.06	$ 614.00	291.000	87.01	YES	100	-	$ 3.30	$ -
48.50	07/01/2025	16	$ 13,319.54	229.410	$ 58.06	$ 11,126.39	$ 2,193.16		81.000	148.41	$ 1,418.80	291.000	87.01	YES	100	-	$ 9.56	$ -
48.50	07/01/2025	17	$ 19,638.19	265.740	$ 73.90	$ 12,888.39	$ 6,749.80	*Culley 3 was on outage all other units online*	53.000	212.74	$ 5,403.60	291.000	87.01	YES	100	-	$ 25.40	$ -
48.50	07/01/2025	18	$ 22,897.53	283.000	$ 80.91	$ 13,725.50	$ 9,172.03		59.000	224.00	$ 7,259.84	291.000	87.01	YES	100	-	$ 32.41	$ -
48.50	07/01/2025	19	$ 32,472.92	299.400	$ 108.46	$ 14,520.90	$ 17,952.02		52.992	246.41	$ 14,774.62	291.000	87.01	YES	100	-	$ 59.96	$ -
48.50	07/01/2025	20	$ 34,009.29	328.910	$ 103.40	$ 15,952.14	$ 18,057.16		25.000	303.91	$ 16,684.66	291.000	87.01	YES	100	12.91	$ 54.90	$ 106.31
48.50	07/01/2025	21	$ 29,865.21	381.380	$ 78.31	$ 18,496.93	$ 11,368.28		58.833	322.55	$ 9,614.57	312.000	87.01	YES	100	10.55	$ 29.81	$ 47.16
48.50	07/01/2025	22	$ 26,101.36	418.090	$ 62.43	$ 20,277.37	$ 5,824.00		135.837	282.25	$ 3,931.79	312.000	87.01	YES	100	-	$ 13.93	$ -
48.50	07/01/2025	23	$ 22,314.34	448.800	$ 49.72	$ 21,766.80	$ 547.54		205.855	242.95	$ 296.40	312.000	87.01	YES	100	-	$ 1.22	$ -
46.75	07/02/2025	12	$ 3,072.22	60.800	$ 50.53	$ 2,842.40	$ 229.82		366.896	-	$ -	42.000	87.01	NO	85	-	$ 3.78	$ -
46.75	07/02/2025	13	$ 2,485.10	45.200	$ 54.98	$ 2,113.10	$ 372.00		222.496	-	$ -	21.000	87.01	NO	85	-	$ 8.23	$ -
46.75	07/02/2025	14	$ 5,735.09	97.670	$ 58.72	$ 4,566.07	$ 1,169.02		216.583	-	$ -	21.000	87.01	NO	85	-	$ 11.97	$ -
46.75	07/02/2025	15	$ 5,175.31	90.430	$ 57.23	$ 4,227.60	$ 947.71		155.225	-	$ -	21.000	87.01	NO	85	-	$ 10.48	$ -
46.75	07/02/2025	16	$ 1.36	0.020	$ 68.00	$ 0.94	$ 0.43	*All units online load greater than generation*	106.271	-	$ -	21.000	87.01	NO	85	-	$ 21.25	$ -
46.75	07/02/2025	18	$ 3,014.88	35.900	$ 83.98	$ 1,678.33	$ 1,336.56		68.017	-	$ -	21.000	87.01	NO	85	-	$ 37.23	$ -
46.75	07/02/2025	19	$ 5,374.92	54.210	$ 99.15	$ 2,534.32	$ 2,840.60		59.000	-	$ -	21.000	87.01	NO	85	-	$ 52.40	$ -
46.75	07/02/2025	20	$ 13,875.47	141.370	$ 98.15	$ 6,609.05	$ 7,266.42		59.000	82.37	$ 4,233.82	21.000	87.01	NO	85	82.37	$ 51.40	$ 635.07
46.75	07/02/2025	21	$ 10,338.50	145.000	$ 71.30	$ 6,778.75	$ 3,559.75		127.558	17.44	$ 428.20	42.000	87.01	NO	85	17.44	$ 24.55	$ 64.23
46.75	07/02/2025	22	$ 10,909.00	207.830	$ 52.49	$ 9,716.05	$ 1,192.95		212.388	-	$ -	42.000	87.01	NO	85	-	$ 5.74	$ -
46.63	07/03/2025	12	$ 1,528.36	27.900	$ 54.78	$ 1,300.84	$ 227.52		214.862	-	$ -	44.000	87.01	NO	85	-	$ 8.15	$ -
46.63	07/03/2025	14	$ 4,298.98	73.600	$ 58.41	$ 3,431.60	$ 867.38		149.000	-	$ -	23.000	87.01	NO	85	-	$ 11.79	$ -
46.63	07/03/2025	19	$ 1,174.18	12.100	$ 97.04	$ 564.16	$ 610.02	*All units online load greater than generation*	45.533	-	$ -	23.000	87.01	NO	85	-	$ 50.41	$ -
46.63	07/03/2025	20	$ 12,382.56	140.090	$ 88.39	$ 6,531.70	$ 5,850.86		57.000	83.09	$ 3,470.26	23.000	87.01	NO	85	83.09	$ 41.77	$ 520.54
46.63	07/03/2025	21	$ 13,211.46	222.490	$ 59.38	$ 10,373.60	$ 2,837.86		169.412	53.08	$ 677.01	44.000	87.01	NO	85	53.08	$ 12.76	$ 101.55
46.63	07/03/2025	22	$ 14,103.61	288.890	$ 48.82	$ 13,469.50	$ 634.11		236.353	52.54	$ 115.32	44.000	87.01	NO	85	52.54	$ 2.20	$ 17.30
47.75	07/04/2025	15	$ 11,941.70	238.500	$ 50.07	$ 11,388.38	$ 553.33		364.730	-	$ -	44.000	87.01	NO	85	-	$ 2.32	$ -
47.75	07/04/2025	16	$ 7,221.44	127.700	$ 56.55	$ 6,097.68	$ 1,123.77		289.138	-	$ -	44.000	87.01	NO	85	-	$ 8.80	$ -
47.75	07/04/2025	17	$ 9,313.35	145.000	$ 64.23	$ 6,923.75	$ 2,389.60	*Brown 3 was on Reserve Shutdown all other units online*	243.706	-	$ -	44.000	87.01	NO	85	-	$ 16.48	$ -
47.75	07/04/2025	18	$ 6,409.09	89.600	$ 71.53	$ 4,278.40	$ 2,130.69		193.993	-	$ -	44.000	87.01	NO	85	-	$ 23.78	$ -
47.75	07/04/2025	19	$ 9,605.98	127.080	$ 75.59	$ 6,068.07	$ 3,537.91		162.558	-	$ -	44.000	87.01	NO	85	-	$ 27.84	$ -
47.75	07/04/2025	20	$ 10,279.58	141.670	$ 72.56	$ 6,764.74	$ 3,514.84		91.433	50.24	$ 1,246.38	44.000	87.01	NO	85	50.24	$ 24.81	$ 186.96
47.75	07/04/2025	21	$ 14,406.57	272.800	$ 52.81	$ 13,026.20	$ 1,380.37		242.408	30.39	$ 153.78	44.000	87.01	NO	85	30.39	$ 5.06	$ 23.07
47.75	07/05/2025	14	$ 14,206.09	277.710	$ 51.15	$ 13,260.65	$ 945.44		367.000	-	$ -	92.000	87.01	YES	100	-	$ 3.40	$ -
47.75	07/05/2025	15	$ 9,990.04	202.720	$ 49.28	$ 9,679.88	$ 310.16		280.000	-	$ -	68.000	87.01	NO	85	-	$ 1.53	$ -
47.75	07/05/2025	16	$ 6,670.77	114.500	$ 58.26	$ 5,467.38	$ 1,203.40		215.733	-	$ -	46.000	87.01	NO	85	-	$ 10.51	$ -
47.75	07/05/2025	17	$ 3,552.82	54.600	$ 65.07	$ 2,607.15	$ 945.67	*All units online load greater than generation*	166.416	-	$ -	46.000	87.01	NO	85	-	$ 17.32	$ -
47.75	07/05/2025	18	$ 4,852.56	61.100	$ 79.42	$ 2,917.53	$ 1,935.04		119.254	-	$ -	46.000	87.01	NO	85	-	$ 31.67	$ -
47.75	07/05/2025	19	$ 8,541.88	136.010	$ 62.80	$ 6,494.48	$ 2,047.40		84.000	52.01	$ 782.92	46.000	87.01	NO	85	52.01	$ 15.05	$ 117.44
47.75	07/05/2025	20	$ 12,704.83	144.900	$ 87.68	$ 6,918.98	$ 5,785.86		103.233	41.67	$ 1,663.76	46.000	87.01	NO	85	41.67	$ 39.93	$ 249.56
47.75	07/05/2025	21	$ 17,049.93	268.700	$ 63.45	$ 12,830.43	$ 4,219.51		142.863	125.84	$ 1,976.07	46.000	87.01	NO	85	125.84	$ 15.70	$ 296.41
47.75	07/05/2025	22	$ 12,774.68	239.900	$ 53.25	$ 11,455.23	$ 1,319.46		261.417	-	$ -	46.000	87.01	NO	85	-	$ 5.50	$ -
47.75	07/06/2025	12	$ 12,034.73	251.720	$ 47.81	$ 12,019.63	$ 15.10		432.725	-	$ -	46.000	87.01	NO	85	-	$ 0.06	$ -
47.75	07/06/2025	13	$ 4,121.21	77.700	$ 53.04	$ 3,710.18	$ 411.04		308.000	-	$ -	46.000	87.01	NO	85	-	$ 5.29	$ -
47.75	07/06/2025	14	$ 6,565.26	124.060	$ 52.92	$ 5,923.87	$ 641.40		263.862	-	$ -	46.000	87.01	NO	85	-	$ 5.17	$ -
47.75	07/06/2025	15	$ 6,224.27	113.810	$ 54.69	$ 5,434.43	$ 789.84		269.612	-	$ -	46.000	87.01	NO	85	-	$ 6.94	$ -
47.75	07/06/2025	16	$ 6,834.60	118.430	$ 57.71	$ 5,655.03	$ 1,179.57	*Culley 2 was on Reserve Shutdown all other units on ine*	258.008	-	$ -	46.000	87.01	NO	85	-	$ 9.96	$ -
47.75	07/06/2025	17	$ 10,316.42	149.600	$ 68.96	$ 7,143.40	$ 3,173.02		245.000	-	$ -	46.000	87.01	NO	85	-	$ 21.21	$ -
47.75	07/06/2025	18	$ 7,910.25	99.400	$ 79.58	$ 4,746.35	$ 3,163.90		186.446	-	$ -	46.000	87.01	NO	85	-	$ 31.83	$ -
47.75	07/06/2025	19	$ 17,350.75	218.540	$ 79.39	$ 10,435.29	$ 6,915.47		156.000	62.54	$ 1,979.01	46.000	87.01	NO	85	62.54	$ 31.64	$ 296.85
47.75	07/06/2025	20	$ 18,697.95	224.600	$ 83.25	$ 10,724.65	$ 7,973.30		180.242	44.36	$ 1,574.71	46.000	87.01	NO	85	44.36	$ 35.50	$ 236.21
47.75	07/06/2025	21	$ 16,183.98	258.200	$ 62.68	$ 12,329.05	$ 3,854.93		217.000	41.20	$ 615.12	46.000	87.01	NO	85	41.20	$ 14.93	$ 92.27
47.75	07/06/2025	22	$ 17,133.32	307.600	$ 55.70	$ 14,687.90	$ 2,445.42		323.575	-	$ -	46.000	87.01	NO	85	-	$ 7.95	$ -
47.75	07/07/2025	11	$ 5,757.35	113.200	$ 50.86	$ 5,405.30	$ 352.05		314.458	-	$ -	56.000	87.01	NO	85	-	$ 3.11	$ -
47.75	07/07/2025	12	$ 5,929.32	106.700	$ 55.57	$ 5,094.93	$ 834.40		196.000	-	$ -	56.000	87.01	NO	85	-	$ 7.82	$ -
47.75	07/07/2025	13	$ 5,464.18	91.100	$ 59.98	$ 4,350.03	$ 1,114.16		168.883	-	$ -	56.000	87.01	NO	85	-	$ 12.23	$ -
47.75	07/07/2025	14	$ 10,113.32	160.180	$ 63.14	$ 7,648.60	$ 2,464.73		172.275	-	$ -	56.000	87.01	NO	85	-	$ 15.39	$ -
47.75	07/07/2025	15	$ 4,475.16	72.180	$ 62.00	$ 3,446.60	$ 1,028.57		99.392	-	$ -	56.000	87.01	NO	85	-	$ 14.25	$ -
47.75	07/07/2025	16	$ 5,718.38	77.380	$ 73.90	$ 3,694.90	$ 2,023.49	*All units online load greater than generation*	151.725	-	$ -	56.000	87.01	NO	85	-	$ 26.15	$ -
47.75	07/07/2025	17	$ 1,168.87	15.390	$ 75.95	$ 734.87	$ 434.00		128.000	-	$ -	56.000	87.01	NO	85	-	$ 28.20	$ -
47.75	07/07/2025	18	$ 1,228.90	14.840	$ 82.81	$ 708.61	$ 520.29		68.117	-	$ -	56.000	87.01	NO	85	-	$ 35.06	$ -
47.75	07/07/2025	19	$ 4,727.78	46.870	$ 100.87	$ 2,238.04	$ 2,489.74		27.942	18.93	$ 1,005.46	56.000	87.01	NO	85	18.93	$ 53.12	$ 150.82
47.75	07/07/2025	20	$ 12,761.83	151.800	$ 84.07	$ 7,248.45	$ 5,513.38		58.096	93.70	$ 3,403.33	56.000	87.01	NO	85	93.70	$ 36.32	$ 510.50
47.75	07/07/2025	21	$ 10,672.10	140.700	$ 75.85	$ 6,718.43	$ 3,953.68		128.193	12.51	$ 351.45	56.000	87.01	NO	85	12.51	$ 28.10	$ 52.72
47.75	07/07/2025	22	$ 15,764.75	258.100	$ 61.08	$ 12,324.28	$ 3,440.48		218.295	39.81	$ 530.60	56.000	87.01	NO	85	39.81	$ 13.33	$ 79.59

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 07/31

Jul Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
48.00	07/08/2025	11	$ 3,319.64	66.300	$ 50.07	$ 3,182.40	$ 137.24		237.950	-	$ -	54.000	87.01	NO	85	-	$ 2.07	$ -
48.00	07/08/2025	12	$ 2,258.27	38.570	$ 58.55	$ 1,851.36	$ 406.91		162.000	-	$ -	54.000	87.01	NO	85	-	$ 10.55	$ -
48.00	07/08/2025	13	$ 2,566.61	49.150	$ 52.22	$ 2,359.20	$ 207.41		101.874	-	$ -	54.000	87.01	NO	85	-	$ 4.22	$ -
48.00	07/08/2025	14	$ 11,479.26	72.300	$ 158.77	$ 3,470.40	$ 8,008.86		75.000	-	$ -	54.000	87.01	NO	85	-	$ 110.77	$ -
48.00	07/08/2025	15	$ 2,257.17	33.140	$ 68.11	$ 1,590.72	$ 666.45	*All units online load greater than generation*	35.000	-	$ -	51.000	87.01	NO	85	-	$ 20.11	$ -
48.00	07/08/2025	19	$ 5,962.98	56.650	$ 105.26	$ 2,719.20	$ 3,243.78		60.767	-	$ -	54.000	87.01	NO	85	-	$ 57.26	$ -
48.00	07/08/2025	20	$ 12,475.81	137.900	$ 90.47	$ 6,619.20	$ 5,856.61		91.075	46.83	$ 1,988.66	54.000	87.01	NO	85	46.83	$ 42.47	$ 298.30
48.00	07/08/2025	21	$ 10,243.38	133.100	$ 76.96	$ 6,388.80	$ 3,854.58		97.875	35.23	$ 1,020.12	54.000	87.01	NO	85	35.23	$ 28.96	$ 153.02
48.00	07/08/2025	22	$ 14,779.82	234.340	$ 63.07	$ 11,248.32	$ 3,531.50		185.941	48.40	$ 729.37	54.000	87.01	NO	85	48.40	$ 15.07	$ 109.41
48.00	07/08/2025	23	$ 10,922.18	202.300	$ 53.99	$ 9,710.40	$ 1,211.78		227.179	-	$ -	54.000	87.01	NO	85	-	$ 5.99	$ -
47.50	07/09/2025	6	$ 1,863.12	36.500	$ 51.04	$ 1,733.75	$ 129.37		372.250	-	$ -	187.000	87.01	YES	100	-	$ 3.54	$ -
47.50	07/09/2025	9	$ 9,740.10	203.300	$ 47.91	$ 9,656.75	$ 83.35		388.633	-	$ -	52.000	87.01	NO	85	-	$ 0.41	$ -
47.50	07/09/2025	10	$ 11,601.52	239.800	$ 48.38	$ 11,390.50	$ 211.02		372.442	-	$ -	52.000	87.01	NO	85	-	$ 0.88	$ -
47.50	07/09/2025	11	$ 3,469.58	65.600	$ 52.89	$ 3,116.00	$ 353.58		234.862	-	$ -	52.000	87.01	NO	85	-	$ 5.39	$ -
47.50	07/09/2025	12	$ 4,321.11	77.900	$ 55.47	$ 3,700.25	$ 620.86		207.316	-	$ -	52.000	87.01	NO	85	-	$ 7.97	$ -
47.50	07/09/2025	13	$ 3,238.83	54.390	$ 59.55	$ 2,583.53	$ 655.31		189.009	-	$ -	52.000	87.01	NO	85	-	$ 12.05	$ -
47.50	07/09/2025	14	$ 2,665.85	42.060	$ 63.38	$ 1,997.85	$ 668.00		102.625	-	$ -	42.000	87.01	NO	85	-	$ 15.88	$ -
47.50	07/09/2025	15	$ 2,189.38	38.940	$ 56.22	$ 1,849.65	$ 339.73	*Brown 3 short run time all other units online.*	112.570	-	$ -	42.000	87.01	NO	85	-	$ 8.72	$ -
47.50	07/09/2025	16	$ 1,119.89	21.720	$ 51.56	$ 1,031.70	$ 88.19		93.783	-	$ -	42.000	87.01	NO	85	-	$ 4.06	$ -
47.50	07/09/2025	17	$ 1,457.56	18.800	$ 77.53	$ 893.00	$ 564.56		118.350	-	$ -	42.000	87.01	NO	85	-	$ 30.03	$ -
47.50	07/09/2025	18	$ 1,986.35	23.800	$ 83.46	$ 1,130.50	$ 855.85		135.287	-	$ -	42.000	87.01	NO	85	-	$ 35.96	$ -
47.50	07/09/2025	19	$ 4,807.69	49.800	$ 96.54	$ 2,365.50	$ 2,442.19		157.642	-	$ -	42.000	87.01	NO	85	-	$ 49.04	$ -
47.50	07/09/2025	20	$ 9,608.60	109.800	$ 87.51	$ 5,215.50	$ 4,393.10		112.737	-	$ -	42.000	87.01	NO	85	-	$ 40.01	$ -
47.50	07/09/2025	21	$ 9,247.06	142.900	$ 64.71	$ 6,787.75	$ 2,459.31		134.247	8.65	$ 148.92	42.000	87.01	NO	85	8.65	$ 17.21	$ 22.34
47.50	07/09/2025	22	$ 11,613.89	206.800	$ 56.16	$ 9,823.00	$ 1,790.89		235.254	-	$ -	42.000	87.01	NO	85	-	$ 8.66	$ -
46.00	07/10/2025	7	$ 3,534.53	73.400	$ 48.15	$ 3,376.40	$ 158.13		402.511	-	$ -	84.000	87.01	NO	85	-	$ 2.15	$ -
46.00	07/10/2025	8	$ 13,096.40	186.900	$ 70.07	$ 8,597.40	$ 4,499.00		376.196	-	$ -	110.000	87.01	YES	100	-	$ 24.07	$ -
46.00	07/10/2025	9	$ 9,720.30	182.100	$ 53.38	$ 8,376.60	$ 1,343.70		422.596	-	$ -	44.000	87.01	NO	85	-	$ 7.38	$ -
46.00	07/10/2025	10	$ 1,961.02	41.600	$ 47.14	$ 1,913.60	$ 47.42		424.542	-	$ -	44.000	87.01	NO	85	-	$ 1.14	$ -
46.00	07/10/2025	11	$ 8,695.33	95.100	$ 91.43	$ 4,374.60	$ 4,320.73		404.568	-	$ -	44.000	87.01	NO	85	-	$ 45.43	$ -
46.00	07/10/2025	12	$ 2,542.32	49.500	$ 51.36	$ 2,277.00	$ 265.32		148.812	-	$ -	119.000	87.01	YES	100	-	$ 5.36	$ -
46.00	07/10/2025	13	$ 1,415.69	25.900	$ 54.66	$ 1,191.40	$ 224.29		138.824	-	$ -	119.000	87.01	YES	100	-	$ 8.66	$ -
46.00	07/10/2025	14	$ 4,898.84	73.800	$ 66.38	$ 3,394.80	$ 1,504.04		135.125	-	$ -	127.000	87.01	YES	100	-	$ 20.38	$ -
46.00	07/10/2025	15	$ 5,817.59	96.700	$ 60.16	$ 4,448.20	$ 1,369.39	*Brown 3 was returning from outage all other units online.*	76.538	20.16	$ 285.52	127.000	87.01	YES	100	-	$ 14.16	$ -
46.00	07/10/2025	16	$ 4,832.23	77.100	$ 62.67	$ 3,546.60	$ 1,285.63		66.760	10.34	$ 172.42	127.000	87.01	YES	100	-	$ 16.67	$ -
46.00	07/10/2025	17	$ 2,772.61	25.100	$ 110.46	$ 1,154.60	$ 1,618.01		79.855	-	$ -	52.000	87.01	NO	85	-	$ 64.46	$ -
46.00	07/10/2025	18	$ 1,765.66	27.730	$ 63.67	$ 1,275.58	$ 490.08		69.225	-	$ -	52.000	87.01	NO	85	-	$ 17.67	$ -
46.00	07/10/2025	19	$ 6,634.01	77.800	$ 85.27	$ 3,578.80	$ 3,055.21		42.570	35.23	$ 1,383.48	52.000	87.01	NO	85	35.23	$ 39.27	$ 207.52
46.00	07/10/2025	20	$ 10,587.14	131.550	$ 80.48	$ 6,051.30	$ 4,535.84		33.937	97.61	$ 3,365.69	52.000	87.01	NO	85	97.61	$ 34.48	$ 504.85
46.00	07/10/2025	21	$ 12,741.76	201.190	$ 63.33	$ 9,254.74	$ 3,487.02		99.017	102.17	$ 1,770.86	52.000	87.01	NO	85	102.17	$ 17.33	$ 265.63
46.00	07/10/2025	22	$ 9,087.30	179.520	$ 50.62	$ 8,257.92	$ 829.38		114.112	65.41	$ 302.18	52.000	87.01	NO	85	65.41	$ 4.62	$ 45.33
46.00	07/10/2025	23	$ 1,203.25	6.600	$ 182.31	$ 303.60	$ 899.65		366.166	-	$ -	52.000	87.01	NO	85	-	$ 136.31	$ -
46.00	07/10/2025	24	$ 1,265.15	12.400	$ 102.03	$ 570.40	$ 694.75		376.145	-	$ -	52.000	87.01	NO	85	-	$ 56.03	$ -
46.38	07/11/2025	10	$ 5,802.41	99.290	$ 58.44	$ 4,604.57	$ 1,197.84		229.783	-	$ -	54.000	87.01	NO	85	-	$ 12.06	$ -
46.38	07/11/2025	11	$ 2,063.15	33.080	$ 62.37	$ 1,534.09	$ 529.07		178.460	-	$ -	54.000	87.01	NO	85	-	$ 15.99	$ -
46.38	07/11/2025	13	$ 3,888.90	82.280	$ 47.26	$ 3,815.74	$ 73.16		130.952	-	$ -	54.000	87.01	NO	85	-	$ 0.89	$ -
46.38	07/11/2025	14	$ 4,663.09	85.380	$ 54.62	$ 3,959.50	$ 703.59		120.971	-	$ -	54.000	87.01	NO	85	-	$ 8.24	$ -
46.38	07/11/2025	15	$ 4,573.11	82.740	$ 55.27	$ 3,837.07	$ 736.04		120.796	-	$ -	54.000	87.01	NO	85	-	$ 8.90	$ -
46.38	07/11/2025	16	$ 2,049.61	41.620	$ 49.25	$ 1,930.13	$ 119.48	*Brown 3 short run time all other units online.*	113.221	-	$ -	54.000	87.01	NO	85	-	$ 2.87	$ -
46.38	07/11/2025	18	$ 5,545.41	115.020	$ 48.21	$ 5,334.05	$ 211.36		72.531	42.49	$ 78.08	54.000	87.01	NO	85	42.49	$ 1.84	$ 11.71
46.38	07/11/2025	19	$ 5,106.88	57.400	$ 88.97	$ 2,661.93	$ 2,444.96		101.629	-	$ -	54.000	87.01	NO	85	-	$ 42.60	$ -
46.38	07/11/2025	20	$ 17,306.97	253.640	$ 68.23	$ 11,762.56	$ 5,544.42		70.979	182.66	$ 3,992.86	54.000	87.01	NO	85	182.66	$ 21.86	$ 598.93
46.38	07/11/2025	21	$ 18,752.18	287.260	$ 65.28	$ 13,321.68	$ 5,430.50		118.259	169.00	$ 3,194.87	54.000	87.01	NO	85	169.00	$ 18.90	$ 479.23
46.38	07/11/2025	22	$ 19,694.46	298.550	$ 65.97	$ 13,845.26	$ 5,849.20		180.129	118.42	$ 2,320.11	54.000	87.01	NO	85	118.42	$ 19.59	$ 348.02
46.38	07/11/2025	23	$ 10,472.27	217.900	$ 48.06	$ 10,105.11	$ 367.16		292.250	-	$ -	54.000	87.01	NO	85	-	$ 1.68	$ -
47.63	07/12/2025	1	$ 4,234.55	67.100	$ 63.11	$ 3,195.64	$ 1,038.91		388.250	-	$ -	52.000	87.01	NO	85	-	$ 15.48	$ -
47.63	07/12/2025	11	$ 20,894.96	352.180	$ 59.33	$ 16,772.57	$ 4,122.39		371.417	-	$ -	312.000	87.01	YES	100	-	$ 11.71	$ -
47.63	07/12/2025	14	$ 12,209.23	250.600	$ 48.72	$ 11,934.83	$ 274.40		372.121	-	$ -	194.000	87.01	YES	100	-	$ 1.09	$ -
47.63	07/12/2025	15	$ 25,092.06	513.410	$ 48.87	$ 24,451.15	$ 640.91		357.000	156.41	$ 195.25	190.000	87.01	YES	100	-	$ 1.25	$ -
47.63	07/12/2025	16	$ 1,241.63	24.100	$ 51.52	$ 1,147.76	$ 93.87		202.000	-	$ -	188.000	87.01	YES	100	-	$ 3.89	$ -
47.63	07/12/2025	17	$ 1,014.47	17.300	$ 58.64	$ 823.91	$ 190.56	*Brown 3 was on Reserve Shutdown all other units online.*	203.315	-	$ -	150.000	87.01	YES	100	-	$ 11.01	$ -
47.63	07/12/2025	18	$ 287.51	4.500	$ 63.89	$ 214.31	$ 73.20		193.333	-	$ -	84.000	87.01	NO	85	-	$ 16.27	$ -
47.63	07/12/2025	19	$ 5,130.95	61.500	$ 83.43	$ 2,928.94	$ 2,202.01		156.150	-	$ -	58.000	87.01	NO	85	-	$ 35.81	$ -
47.63	07/12/2025	20	$ 8,692.23	112.100	$ 77.54	$ 5,338.76	$ 3,353.47		161.871	-	$ -	52.000	87.01	NO	85	-	$ 29.91	$ -
47.63	07/12/2025	21	$ 5,464.05	90.300	$ 60.51	$ 4,300.54	$ 1,163.51		192.546	-	$ -	52.000	87.01	NO	85	-	$ 12.88	$ -
47.63	07/12/2025	22	$ 9,716.76	184.000	$ 52.81	$ 8,763.00	$ 953.76		238.613	-	$ -	52.000	87.01	NO	85	-	$ 5.18	$ -
47.63	07/13/2025	10	$ 2,412.43	39.400	$ 61.23	$ 1,876.43	$ 536.01		383.487	-	$ -	54.000	87.01	NO	85	-	$ 13.60	$ -
47.63	07/13/2025	11	$ 4,073.76	55.200	$ 73.80	$ 2,628.90	$ 1,444.86		375.704	-	$ -	54.000	87.01	NO	85	-	$ 26.18	$ -

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 07/31

Jul Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
47.63	07/13/2025	12	$ 3,362.69	38.400	$ 87.57	$ 1,828.80	$ 1,533.89		374.388	-	$ -	54.000	87.01	NO	85	-	$ 39.95	$ -
47.63	07/13/2025	13	$ 6,888.51	82.300	$ 83.70	$ 3,919.54	$ 2,968.97		370.458	-	$ -	54.000	87.01	NO	85	-	$ 36.08	$ -
47.63	07/13/2025	15	$ 19,474.82	183.460	$ 106.15	$ 8,737.28	$ 10,737.54	*Culley 2 tripped offline all other units online*	439.000	-	$ -	54.000	87.01	NO	85	-	$ 58.53	$ -
47.63	07/13/2025	16	$ 469.68	9.500	$ 49.44	$ 452.44	$ 17.24		191.000	-	$ -	132.000	87.01	YES	100	-	$ 1.82	$ -
47.63	07/13/2025	19	$ 7,587.66	149.900	$ 50.62	$ 7,138.99	$ 448.67		73.000	76.90	$ 230.17	132.000	87.01	YES	100	-	$ 2.99	$ -
47.63	07/13/2025	20	$ 8,829.62	95.800	$ 92.17	$ 4,562.48	$ 4,267.15		40.000	55.80	$ 2,485.46	132.000	87.01	YES	100	-	$ 44.54	$ -
47.63	07/13/2025	21	$ 10,500.35	180.100	$ 58.30	$ 8,577.26	$ 1,923.09		97.200	82.90	$ 885.20	132.000	87.01	YES	100	-	$ 10.68	$ -
47.63	07/13/2025	22	$ 9,377.47	165.300	$ 56.73	$ 7,872.41	$ 1,505.06		202.967	-	$ -	132.000	87.01	YES	100	-	$ 9.11	$ -
47.63	07/14/2025	8	$ 1,361.23	27.600	$ 49.32	$ 1,314.45	$ 46.78		208.000	-	$ -	122.000	87.01	YES	100	-	$ 1.69	$ -
47.63	07/14/2025	12	$ 2,407.52	40.300	$ 59.74	$ 1,919.29	$ 488.23		114.000	-	$ -	122.000	87.01	YES	100	-	$ 12.11	$ -
47.63	07/14/2025	15	$ 2,878.42	46.000	$ 62.57	$ 2,190.75	$ 687.67		40.000	6.00	$ 89.70	122.000	87.01	YES	100	-	$ 14.95	$ -
47.63	07/14/2025	16	$ 6,246.30	55.800	$ 111.94	$ 2,657.48	$ 3,588.83		14.884	40.92	$ 2,631.55	122.000	87.01	YES	100	-	$ 64.32	$ -
47.63	07/14/2025	17	$ 3,215.36	63.300	$ 50.80	$ 3,014.66	$ 200.70		31.796	31.50	$ 99.89	122.000	87.01	YES	100	-	$ 3.17	$ -
47.63	07/14/2025	18	$ 10,119.20	176.800	$ 57.24	$ 8,420.10	$ 1,699.10	*Culley 2 was on outage all other units online*	53.767	123.03	$ 1,182.38	122.000	87.01	YES	100	1.03	$ 9.61	$ 1.49
47.63	07/14/2025	19	$ 13,548.39	171.400	$ 79.05	$ 8,162.93	$ 5,385.47		44.113	127.29	$ 3,999.41	122.000	87.01	YES	100	5.29	$ 31.42	$ 24.92
47.63	07/14/2025	20	$ 19,823.82	188.500	$ 105.17	$ 8,977.31	$ 10,846.51		36.000	152.50	$ 8,775.03	122.000	87.01	YES	100	30.50	$ 57.54	$ 263.25
47.63	07/14/2025	21	$ 13,825.21	206.000	$ 67.11	$ 9,810.75	$ 4,014.46		65.475	140.53	$ 2,738.50	122.000	87.01	YES	100	18.53	$ 19.49	$ 54.15
47.63	07/14/2025	22	$ 8,421.24	120.700	$ 69.77	$ 5,748.34	$ 2,672.90		178.304	-	$ -	122.000	87.01	YES	100	-	$ 22.15	$ -
47.63	07/14/2025	23	$ 8,240.04	141.000	$ 58.44	$ 6,715.13	$ 1,524.92		258.229	-	$ -	122.000	87.01	YES	100	-	$ 10.82	$ -
47.63	07/14/2025	24	$ 15,602.53	322.900	$ 48.32	$ 15,378.11	$ 224.42		363.558	-	$ -	122.000	87.01	YES	100	-	$ 0.70	$ -
47.81	07/15/2025	9	$ 12,910.78	239.000	$ 54.02	$ 11,427.31	$ 1,483.47		140.000	99.00	$ 614.49	101.000	87.01	YES	100	-	$ 6.21	$ -
47.81	07/15/2025	10	$ 11,873.36	193.000	$ 61.52	$ 9,227.91	$ 2,645.45		97.000	96.00	$ 1,315.87	101.000	87.01	YES	100	-	$ 13.71	$ -
47.81	07/15/2025	11	$ 14,521.47	212.800	$ 68.24	$ 10,174.61	$ 4,346.86		99.000	113.80	$ 2,324.59	101.000	87.01	YES	100	12.80	$ 20.43	$ 39.22
47.81	07/15/2025	12	$ 14,152.80	207.580	$ 68.18	$ 9,925.02	$ 4,227.78		96.000	111.58	$ 2,272.55	342.000	87.01	YES	100	-	$ 20.37	$ -
47.81	07/15/2025	13	$ 16,252.07	196.210	$ 82.83	$ 9,381.39	$ 6,870.68		82.000	114.21	$ 3,999.29	342.000	87.01	YES	100	-	$ 35.02	$ -
47.81	07/15/2025	14	$ 20,901.25	247.070	$ 84.60	$ 11,813.16	$ 9,088.09		41.000	206.07	$ 7,579.97	342.000	87.01	YES	100	-	$ 36.78	$ -
47.81	07/15/2025	15	$ 21,791.94	224.620	$ 97.02	$ 10,739.76	$ 11,052.18		26.879	197.74	$ 9,729.63	342.000	87.01	YES	100	-	$ 49.20	$ -
47.81	07/15/2025	16	$ 30,139.59	224.470	$ 134.27	$ 10,732.58	$ 19,407.01	*Brown 6 and Culley 2 were on outage*	16.696	207.77	$ 17,963.52	342.000	87.01	YES	100	-	$ 86.46	$ -
47.81	07/15/2025	17	$ 125,519.64	261.680	$ 479.67	$ 12,511.71	$ 113,007.93		0.125	261.56	$ 112,953.95	342.000	87.01	YES	100	-	$ 431.86	$ -
47.81	07/15/2025	18	$ 55,675.28	349.910	$ 159.11	$ 16,730.25	$ 38,945.03		4.000	345.91	$ 38,499.83	342.000	87.01	YES	100	3.91	$ 111.30	$ 65.28
47.81	07/15/2025	19	$ 53,286.29	351.620	$ 151.55	$ 16,812.01	$ 36,474.28		11.000	340.62	$ 35,333.23	341.000	87.01	YES	100	-	$ 103.73	$ -
47.81	07/15/2025	20	$ 37,752.54	399.690	$ 94.45	$ 19,110.38	$ 18,642.16		49.000	350.69	$ 16,356.73	342.000	87.01	YES	100	8.69	$ 46.64	$ 60.80
47.81	07/15/2025	21	$ 16,113.87	166.500	$ 96.78	$ 7,960.86	$ 8,153.01		58.000	108.50	$ 5,312.92	342.000	87.01	YES	100	-	$ 48.97	$ -
47.81	07/15/2025	22	$ 17,616.04	235.100	$ 74.93	$ 11,240.84	$ 6,375.20		97.000	138.10	$ 3,744.86	342.000	87.01	YES	100	-	$ 27.12	$ -
47.81	07/15/2025	23	$ 14,515.42	259.900	$ 55.85	$ 12,426.60	$ 2,088.82		133.850	126.05	$ 1,013.07	342.000	87.01	YES	100	-	$ 8.04	$ -
48.69	07/16/2025	9	$ 6,292.33	126.200	$ 49.86	$ 6,144.43	$ 147.90		151.000	-	$ -	340.000	87.01	YES	100	-	$ 1.17	$ -
48.69	07/16/2025	10	$ 7,523.82	139.900	$ 53.78	$ 6,811.45	$ 712.37		142.000	-	$ -	340.000	87.01	YES	100	-	$ 5.09	$ -
48.69	07/16/2025	11	$ 12,521.60	196.000	$ 63.89	$ 9,542.85	$ 2,978.75		94.000	102.00	$ 1,550.17	340.000	87.01	YES	100	-	$ 15.20	$ -
48.69	07/16/2025	12	$ 13,590.50	192.000	$ 70.78	$ 9,348.10	$ 4,242.40		86.000	106.00	$ 2,342.16	340.000	87.01	YES	100	-	$ 22.10	$ -
48.69	07/16/2025	13	$ 12,412.11	172.080	$ 72.13	$ 8,378.23	$ 4,033.88		37.375	134.71	$ 3,157.74	340.000	87.01	YES	100	-	$ 23.44	$ -
48.69	07/16/2025	14	$ 17,833.62	145.340	$ 122.70	$ 7,076.31	$ 10,757.31		8.650	136.69	$ 10,117.08	318.000	87.01	YES	100	-	$ 74.01	$ -
48.69	07/16/2025	15	$ 11,408.73	139.410	$ 81.84	$ 6,787.59	$ 4,621.14	*Brown 6 was on outage*	40.000	99.41	$ 3,295.22	99.000	87.01	YES	100	0.41	$ 33.15	$ 2.04
48.69	07/16/2025	16	$ 6,170.79	66.450	$ 92.86	$ 3,235.32	$ 2,935.47		47.696	18.75	$ 828.47	99.000	87.01	YES	100	-	$ 44.18	$ -
48.69	07/16/2025	17	$ 9,345.46	93.370	$ 100.09	$ 4,546.00	$ 4,799.46		48.313	45.06	$ 2,316.05	99.000	87.01	YES	100	-	$ 51.40	$ -
48.69	07/16/2025	18	$ 186.57	3.820	$ 48.84	$ 185.99	$ 0.58		94.259	-	$ -	114.000	87.01	YES	100	-	$ 0.15	$ -
48.69	07/16/2025	19	$ 3,658.22	34.900	$ 104.82	$ 1,699.21	$ 1,959.01		107.912	-	$ -	102.000	87.01	YES	100	-	$ 56.13	$ -
48.69	07/16/2025	20	$ 12,348.38	127.500	$ 96.85	$ 6,207.72	$ 6,140.66		127.200	0.30	$ 14.45	90.000	87.01	YES	100	-	$ 48.16	$ -
48.69	07/16/2025	21	$ 9,767.39	115.700	$ 84.42	$ 5,633.20	$ 4,134.19		152.075	-	$ -	72.000	87.01	NO	85	-	$ 35.73	$ -
48.69	07/16/2025	22	$ 13,917.69	239.300	$ 58.16	$ 11,651.04	$ 2,266.65		272.028	-	$ -	42.000	87.01	NO	85	-	$ 9.47	$ -
50.31	07/17/2025	1	$ 15,842.01	292.720	$ 54.12	$ 14,727.62	$ 1,114.39		369.000	-	$ -	32.000	87.01	NO	85	-	$ 3.81	$ -
50.31	07/17/2025	6	$ 15,264.48	294.000	$ 51.92	$ 14,792.02	$ 472.46		0.000	294.00	$ 472.46	401.000	87.01	YES	100	-	$ 1.61	$ -
50.31	07/17/2025	9	$ 12,363.32	204.150	$ 60.56	$ 10,271.40	$ 2,091.92		149.000	55.15	$ 565.12	11.000	87.01	NO	85	55.15	$ 10.25	$ 84.77
50.31	07/17/2025	10	$ 6,393.53	96.100	$ 66.53	$ 4,835.08	$ 1,558.45		137.000	-	$ -	11.000	87.01	NO	85	-	$ 16.22	$ -
50.31	07/17/2025	13	$ 3,855.08	36.600	$ 105.33	$ 1,841.46	$ 2,013.62		58.000	-	$ -	11.000	87.01	NO	85	-	$ 55.02	$ -
50.31	07/17/2025	14	$ 12,515.42	102.100	$ 122.58	$ 5,136.96	$ 7,378.46		55.000	47.10	$ 3,403.78	11.000	87.01	NO	85	47.10	$ 72.27	$ 510.57
50.31	07/17/2025	15	$ 21,190.28	158.290	$ 133.87	$ 7,964.04	$ 13,226.24		56.000	102.29	$ 8,547.04	11.000	87.01	NO	85	102.29	$ 83.56	$ 1,282.06
50.31	07/17/2025	16	$ 25,070.74	261.050	$ 96.04	$ 13,134.21	$ 11,936.53	*Brown 6 was on Reserve Shutdown*	49.000	212.05	$ 9,696.00	11.000	87.01	NO	85	212.05	$ 45.73	$ 1,454.40
50.31	07/17/2025	17	$ 31,281.16	273.520	$ 114.37	$ 13,761.61	$ 17,519.55		271.000	2.52	$ 161.41	32.000	87.01	NO	85	2.52	$ 64.05	$ 24.21
50.31	07/17/2025	18	$ 27,904.86	218.340	$ 127.80	$ 10,985.34	$ 16,919.52		260.000	-	$ -	32.000	87.01	NO	85	-	$ 77.49	$ -
50.31	07/17/2025	19	$ 32,440.91	253.740	$ 127.85	$ 12,766.42	$ 19,674.49		274.000	-	$ -	32.000	87.01	NO	85	-	$ 77.54	$ -
50.31	07/17/2025	20	$ 27,865.93	232.100	$ 120.06	$ 11,677.65	$ 16,188.28		278.000	-	$ -	32.000	87.01	NO	85	-	$ 69.75	$ -
50.31	07/17/2025	21	$ 21,078.10	205.000	$ 102.82	$ 10,314.17	$ 10,763.94		268.000	-	$ -	32.000	87.01	NO	85	-	$ 52.51	$ -
50.31	07/17/2025	22	$ 18,112.74	285.240	$ 63.50	$ 14,351.28	$ 3,761.46		361.775	-	$ -	32.000	87.01	NO	85	-	$ 13.19	$ -
50.31	07/17/2025	23	$ 16,496.66	275.910	$ 59.79	$ 13,881.86	$ 2,614.80		369.000	-	$ -	32.000	87.01	NO	85	-	$ 9.48	$ -
51.25	07/18/2025	13	$ 16,698.13	311.300	$ 53.64	$ 15,954.13	$ 744.01		151.625	159.68	$ 381.62	272.000	87.01	YES	100	-	$ 2.39	$ -
51.25	07/18/2025	14	$ 19,076.01	326.700	$ 58.39	$ 16,743.38	$ 2,332.64		151.283	175.42	$ 1,252.48	272.000	87.01	YES	100	-	$ 7.14	$ -
51.25	07/18/2025	15	$ 20,266.92	343.100	$ 59.07	$ 17,583.88	$ 2,683.05		151.837	191.26	$ 1,495.68	272.000	87.01	YES	100	-	$ 7.82	$ -
51.25	07/18/2025	16	$ 20,806.37	343.000	$ 60.66	$ 17,578.75	$ 3,227.62	*Brown 3 and Brown 4 were on*	151.000	192.00	$ 1,806.71	272.000	87.01	YES	100	-	$ 9.41	$ -
51.25	07/18/2025	17	$ 24,097.48	372.300	$ 64.73	$ 19,080.38	$ 5,017.11	*Reserve Shutdown Brown 6 was on*	151.000	221.30	$ 2,982.23	272.000	87.01	YES	100	-	$ 13.48	$ -

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 07/31

Jul Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
51.25	07/18/2025	18	$ 27,034.46	410.600	$ 65.84	$ 21,043.25	$ 5,991.21	*outage*	151.000	259.60	$ 3,787.92	272.000	87.01	YES	100	-	$ 14.59	$ -
51.25	07/18/2025	19	$ 36,727.43	477.800	$ 76.87	$ 24,487.25	$ 12,240.18		151.000	326.80	$ 8,371.89	272.000	87.01	YES	100	54.80	$ 25.62	$ 210.58
51.25	07/18/2025	20	$ 30,263.88	471.400	$ 64.20	$ 24,159.25	$ 6,104.63		151.000	320.40	$ 4,149.18	272.000	87.01	YES	100	48.40	$ 12.95	$ 94.02
51.25	07/18/2025	21	$ 25,910.65	435.400	$ 59.51	$ 22,314.25	$ 3,596.40		151.208	284.19	$ 2,347.42	272.000	87.01	YES	100	12.19	$ 8.26	$ 15.11
51.31	07/19/2025	13	$ 8,789.36	151.020	$ 58.20	$ 7,749.29	$ 1,040.07		151.000	0.02	$ 0.14	272.000	87.01	YES	100	-	$ 6.89	$ -
51.31	07/19/2025	14	$ 12,244.26	211.290	$ 57.95	$ 10,841.92	$ 1,402.34		151.625	59.67	$ 396.00	272.000	87.01	YES	100	-	$ 6.64	$ -
51.31	07/19/2025	15	$ 12,742.17	218.900	$ 58.21	$ 11,232.42	$ 1,509.75		151.208	67.69	$ 466.87	272.000	87.01	YES	100	-	$ 6.90	$ -
51.31	07/19/2025	16	$ 9,292.18	148.390	$ 62.62	$ 7,614.34	$ 1,677.84		99.000	49.39	$ 558.45	272.000	87.01	YES	100	-	$ 11.31	$ -
51.31	07/19/2025	17	$ 9,771.96	140.160	$ 69.72	$ 7,192.03	$ 2,579.93	*Brown 3 was on Reserve Shutdown*	91.000	49.16	$ 904.89	272.000	87.01	YES	100	-	$ 18.41	$ -
51.31	07/19/2025	18	$ 12,403.59	168.550	$ 73.59	$ 8,648.81	$ 3,754.78	*Brown 6 was on outage*	100.000	68.55	$ 1,527.09	272.000	87.01	YES	100	-	$ 22.28	$ -
51.31	07/19/2025	19	$ 10,309.71	142.360	$ 72.42	$ 7,304.92	$ 3,004.79		99.000	43.36	$ 915.20	272.000	87.01	YES	100	-	$ 21.11	$ -
51.31	07/19/2025	20	$ 9,403.20	143.670	$ 65.45	$ 7,372.14	$ 2,031.06		99.000	44.67	$ 631.50	272.000	87.01	YES	100	-	$ 14.14	$ -
51.31	07/19/2025	21	$ 14,435.33	241.960	$ 59.66	$ 12,415.69	$ 2,019.64		148.395	93.57	$ 780.99	272.000	87.01	YES	100	-	$ 8.35	$ -
51.31	07/19/2025	22	$ 13,650.81	241.010	$ 56.64	$ 12,366.95	$ 1,283.86		161.009	80.00	$ 426.17	272.000	87.01	YES	100	-	$ 5.33	$ -
51.31	07/20/2025	14	$ 12,624.82	241.300	$ 52.32	$ 12,381.83	$ 242.99		149.000	92.30	$ 92.95	274.000	87.01	YES	100	-	$ 1.01	$ -
51.31	07/20/2025	15	$ 14,754.71	258.900	$ 56.99	$ 13,284.94	$ 1,469.77		149.000	109.90	$ 623.90	274.000	87.01	YES	100	-	$ 5.68	$ -
51.31	07/20/2025	16	$ 16,876.47	283.400	$ 59.55	$ 14,542.10	$ 2,334.37		126.208	157.19	$ 1,294.79	274.000	87.01	YES	100	-	$ 8.24	$ -
51.31	07/20/2025	17	$ 16,772.94	253.100	$ 66.27	$ 12,987.32	$ 3,785.62		87.000	166.10	$ 2,484.36	279.000	87.01	YES	100	-	$ 14.96	$ -
51.31	07/20/2025	18	$ 20,799.71	272.640	$ 76.29	$ 13,989.98	$ 6,809.73	*Brown 3 was on Reserve Shutdown*	94.000	178.64	$ 4,461.89	279.000	87.01	YES	100	-	$ 24.98	$ -
51.31	07/20/2025	19	$ 26,491.23	324.250	$ 81.70	$ 16,638.24	$ 9,852.99	*Brown 6 was on outage*	94.833	229.42	$ 6,971.30	279.000	87.01	YES	100	-	$ 30.39	$ -
51.31	07/20/2025	20	$ 33,137.16	411.080	$ 80.61	$ 21,093.75	$ 12,043.41		93.775	317.31	$ 9,296.09	279.000	87.01	YES	100	38.30	$ 29.30	$ 168.33
51.31	07/20/2025	21	$ 28,701.66	459.300	$ 62.49	$ 23,568.06	$ 5,133.60		149.208	310.09	$ 3,465.90	279.000	87.01	YES	100	31.09	$ 11.18	$ 52.13
51.31	07/20/2025	22	$ 21,734.30	419.500	$ 51.81	$ 21,525.80	$ 208.50		157.704	261.80	$ 130.12	279.000	87.01	YES	100	-	$ 0.50	$ -
51.31	07/21/2025	14	$ 18,422.66	356.890	$ 51.62	$ 18,313.10	$ 109.56		168.342	188.55	$ 57.88	282.000	87.01	YES	100	-	$ 0.31	$ -
51.31	07/21/2025	15	$ 14,685.02	276.190	$ 53.17	$ 14,172.14	$ 512.88		160.492	115.70	$ 214.85	282.000	87.01	YES	100	-	$ 1.86	$ -
51.31	07/21/2025	16	$ 16,795.24	287.000	$ 58.52	$ 14,726.83	$ 2,068.41		145.650	141.35	$ 1,018.71	282.000	87.01	YES	100	-	$ 7.21	$ -
51.31	07/21/2025	17	$ 17,274.48	245.900	$ 70.25	$ 12,617.87	$ 4,656.61		99.000	146.90	$ 2,781.85	282.000	87.01	YES	100	-	$ 18.94	$ -
51.31	07/21/2025	18	$ 21,218.64	317.220	$ 66.89	$ 16,277.51	$ 4,941.13	*Brown 6 was on outage all other units online*	89.000	228.22	$ 3,554.83	282.000	87.01	YES	100	-	$ 15.58	$ -
51.31	07/21/2025	19	$ 21,727.36	272.000	$ 79.88	$ 13,957.14	$ 7,770.22		59.000	213.00	$ 6,084.77	282.000	87.01	YES	100	-	$ 28.57	$ -
51.31	07/21/2025	20	$ 29,041.99	368.600	$ 78.79	$ 18,913.97	$ 10,128.02		59.000	309.60	$ 8,506.88	282.000	87.01	YES	100	27.60	$ 27.48	$ 113.75
51.31	07/21/2025	21	$ 23,974.90	394.000	$ 60.85	$ 20,217.32	$ 3,757.58		106.334	287.67	$ 2,743.47	282.000	87.01	YES	100	5.67	$ 9.54	$ 8.11
51.31	07/21/2025	22	$ 21,213.71	410.800	$ 51.64	$ 21,079.38	$ 134.33		155.863	254.94	$ 83.36	282.000	87.01	YES	100	-	$ 0.33	$ -
50.88	07/22/2025	13	$ 4,909.73	83.970	$ 58.47	$ 4,271.97	$ 637.76		155.667	-	$ -	274.000	87.01	YES	100	-	$ 7.60	$ -
50.88	07/22/2025	16	$ 14,771.06	281.300	$ 52.51	$ 14,311.14	$ 459.92		145.304	136.00	$ 222.35	284.000	87.01	YES	100	-	$ 1.63	$ -
50.88	07/22/2025	17	$ 14,517.22	227.400	$ 63.84	$ 11,568.98	$ 2,948.25		98.000	129.40	$ 1,677.67	284.000	87.01	YES	100	-	$ 12.97	$ -
50.88	07/22/2025	18	$ 18,588.02	263.100	$ 70.65	$ 13,385.21	$ 5,202.81	*Brown 6 was on outage all other units*	88.000	175.10	$ 3,462.61	284.000	87.01	YES	100	-	$ 19.78	$ -
50.88	07/22/2025	19	$ 85,701.86	330.310	$ 259.46	$ 16,804.52	$ 68,897.34	*online*	29.412	300.90	$ 62,762.47	284.000	87.01	YES	100	16.90	$ 208.58	$ 528.70
50.88	07/22/2025	20	$ 37,012.72	398.620	$ 92.85	$ 20,279.79	$ 16,732.93		28.000	370.62	$ 15,557.57	272.000	87.01	YES	100	98.62	$ 41.98	$ 620.97
50.88	07/22/2025	21	$ 24,957.24	388.500	$ 64.24	$ 19,764.94	$ 5,192.30		93.729	294.77	$ 3,939.61	272.000	87.01	YES	100	22.77	$ 13.37	$ 45.65
50.88	07/22/2025	22	$ 28,714.51	482.250	$ 59.54	$ 24,534.47	$ 4,180.04		154.071	328.18	$ 2,844.59	272.000	87.01	YES	100	56.18	$ 8.67	$ 73.04
47.56	07/23/2025	12	$ 16,069.85	280.500	$ 57.29	$ 13,341.42	$ 2,728.43		193.658	86.84	$ 844.71	284.000	87.01	YES	100	-	$ 9.73	$ -
47.56	07/23/2025	13	$ 20,011.01	325.700	$ 61.44	$ 15,491.27	$ 4,519.74		159.700	166.00	$ 2,303.58	282.000	87.01	YES	100	-	$ 13.88	$ -
47.56	07/23/2025	14	$ 23,343.98	323.100	$ 72.25	$ 15,367.61	$ 7,976.37		112.000	211.10	$ 5,211.43	274.000	87.01	YES	100	-	$ 24.69	$ -
47.56	07/23/2025	15	$ 18,635.18	249.300	$ 74.75	$ 11,857.46	$ 6,777.72		72.267	177.03	$ 4,813.00	269.000	87.01	YES	100	-	$ 27.19	$ -
47.56	07/23/2025	16	$ 16,848.34	206.500	$ 81.59	$ 9,821.76	$ 7,026.58		67.150	139.35	$ 4,741.67	269.000	87.01	YES	100	-	$ 34.03	$ -
47.56	07/23/2025	17	$ 21,499.41	217.100	$ 99.03	$ 10,325.93	$ 11,173.48		58.767	158.33	$ 8,148.92	183.000	87.01	YES	100	-	$ 51.47	$ -
47.56	07/23/2025	18	$ 24,900.03	220.980	$ 112.68	$ 10,510.47	$ 14,389.56	*Brown 6 was on outage all other units online*	58.417	162.56	$ 10,585.62	93.000	87.01	YES	100	69.56	$ 65.12	$ 679.46
47.56	07/23/2025	19	$ 48,889.27	452.860	$ 107.96	$ 21,539.38	$ 27,349.89		54.792	398.07	$ 24,040.80	269.000	87.01	YES	100	129.07	$ 60.39	$ 1,169.23
47.56	07/23/2025	20	$ 62,122.19	485.190	$ 128.04	$ 23,077.09	$ 39,045.10		50.050	435.14	$ 35,017.38	269.000	87.01	YES	100	166.14	$ 80.47	$ 2,005.49
47.56	07/23/2025	21	$ 36,588.02	389.400	$ 93.96	$ 18,521.03	$ 18,066.99		60.970	328.43	$ 15,238.16	269.000	87.01	YES	100	59.43	$ 46.40	$ 413.61
47.56	07/23/2025	22	$ 30,295.39	393.600	$ 76.97	$ 18,720.80	$ 11,574.59		109.796	283.80	$ 8,345.82	268.000	87.01	YES	100	15.80	$ 29.41	$ 69.71
47.56	07/23/2025	23	$ 23,831.59	409.900	$ 58.14	$ 19,496.07	$ 4,335.52		176.934	232.97	$ 2,464.08	269.000	87.01	YES	100	-	$ 10.58	$ -
47.56	07/23/2025	24	$ 17,066.95	358.700	$ 47.58	$ 17,060.85	$ 6.10		175.392	183.31	$ 3.12	269.000	87.01	YES	100	-	$ 0.02	$ -
45.88	07/24/2025	9	$ 10,376.96	222.300	$ 46.68	$ 10,198.01	$ 178.95		188.384	33.92	$ 27.30	274.000	87.01	YES	100	-	$ 0.80	$ -
45.88	07/24/2025	10	$ 11,132.59	221.500	$ 50.26	$ 10,161.31	$ 971.28		162.521	58.98	$ 258.62	274.000	87.01	YES	100	-	$ 4.39	$ -
45.88	07/24/2025	11	$ 12,607.45	205.400	$ 61.38	$ 9,422.73	$ 3,184.73		95.471	109.93	$ 1,704.45	274.000	87.01	YES	100	-	$ 15.50	$ -
45.88	07/24/2025	12	$ 19,028.68	222.280	$ 85.61	$ 10,197.10	$ 8,831.59		41.875	180.41	$ 7,167.82	268.000	87.01	YES	100	-	$ 39.73	$ -
45.88	07/24/2025	13	$ 21,192.80	202.260	$ 104.78	$ 9,278.68	$ 11,914.12		8.183	194.08	$ 11,432.10	268.000	87.01	YES	100	-	$ 58.90	$ -
45.88	07/24/2025	14	$ 37,930.63	295.940	$ 128.17	$ 13,576.25	$ 24,354.38		22.000	273.94	$ 22,543.89	269.000	87.01	YES	100	4.94	$ 82.30	$ 60.98
45.88	07/24/2025	15	$ 38,971.88	283.040	$ 137.69	$ 12,984.46	$ 25,987.42		9.000	274.04	$ 25,161.08	269.000	87.01	YES	100	5.04	$ 91.82	$ 69.41
45.88	07/24/2025	16	$ 41,320.76	289.580	$ 142.69	$ 13,284.48	$ 28,036.28	*Brown 6 was on outage all other units*	57.000	232.58	$ 22,517.71	274.000	87.01	YES	100	-	$ 96.82	$ -
45.88	07/24/2025	17	$ 53,022.04	345.870	$ 153.30	$ 15,866.79	$ 37,155.25	*online*	57.000	288.87	$ 31,032.00	274.000	87.01	YES	100	14.87	$ 107.43	$ 239.61
45.88	07/24/2025	18	$ 61,749.22	380.680	$ 162.21	$ 17,463.70	$ 44,285.53		58.000	322.68	$ 37,538.23	274.000	87.01	YES	100	48.68	$ 116.33	$ 849.46
45.88	07/24/2025	19	$ 95,709.31	451.030	$ 212.20	$ 20,691.00	$ 75,018.31		39.987	411.04	$ 68,367.41	274.000	87.01	YES	100	137.04	$ 166.33	$ 3,419.09
45.88	07/24/2025	20	$ 104,811.01	533.400	$ 196.50	$ 24,469.73	$ 80,341.29		51.000	482.40	$ 72,659.61	274.000	87.01	YES	100	208.40	$ 150.62	$ 4,708.42
45.88	07/24/2025	21	$ 67,890.06	532.690	$ 127.45	$ 24,437.15	$ 43,452.91		42.692	490.00	$ 39,970.41	274.000	87.01	YES	100	216.00	$ 81.57	$ 2,642.93
45.88	07/24/2025	22	$ 53,039.28	504.420	$ 105.15	$ 23,140.27	$ 29,899.01		62.296	442.12	$ 26,206.48	274.000	87.01	YES	100	168.12	$ 59.27	$ 1,494.81
45.88	07/24/2025	23	$ 26,548.64	333.400	$ 79.63	$ 15,294.73	$ 11,253.92		68.827	264.57	$ 8,930.66	274.000	87.01	YES	100	-	$ 33.75	$ -

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S55's through 07/31

Jul Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
45.88	07/24/2025	24	$ 19,577.60	280.000	$ 69.92	$ 12,845.00	$ 6,732.60		70.792	209.21	$ 5,030.41	274.000	87.01	YES	100	-	$ 24.05	$ -
46.44	07/25/2025	1	$ 20,050.11	356.700	$ 56.21	$ 16,564.43	$ 3,485.68		135.409	221.29	$ 2,162.46	269.000	87.01	YES	100	-	$ 9.77	$ -
46.44	07/25/2025	8	$ 11,889.68	251.900	$ 47.20	$ 11,697.73	$ 191.95		150.608	101.29	$ 77.18	269.000	87.01	YES	100	-	$ 0.76	$ -
46.44	07/25/2025	9	$ 12,340.73	235.600	$ 52.38	$ 10,940.79	$ 1,399.94		156.925	78.68	$ 467.49	269.000	87.01	YES	100	-	$ 5.94	$ -
46.44	07/25/2025	10	$ 12,888.04	231.300	$ 55.72	$ 10,741.11	$ 2,146.93		140.000	91.30	$ 847.45	269.000	87.01	YES	100	-	$ 9.28	$ -
46.44	07/25/2025	11	$ 13,294.82	213.400	$ 62.30	$ 9,909.87	$ 3,384.95		99.667	113.73	$ 1,804.03	269.000	87.01	YES	100	-	$ 15.86	$ -
46.44	07/25/2025	12	$ 16,882.34	239.840	$ 70.39	$ 11,137.69	$ 5,744.65		98.000	141.84	$ 3,397.35	269.000	87.01	YES	100	-	$ 23.95	$ -
46.44	07/25/2025	13	$ 20,619.08	279.240	$ 73.84	$ 12,967.35	$ 7,651.73		98.000	181.24	$ 4,966.34	269.000	87.01	YES	100	-	$ 27.40	$ -
46.44	07/25/2025	14	$ 23,168.33	285.500	$ 81.15	$ 13,258.05	$ 9,910.28		59.000	226.50	$ 7,862.27	269.000	87.01	YES	100	-	$ 34.71	$ -
46.44	07/25/2025	15	$ 24,303.91	261.220	$ 93.04	$ 12,130.53	$ 12,173.38	*Brown 6 was on outage all other units online*	50.000	211.22	$ 9,843.28	269.000	87.01	YES	100	-	$ 46.60	$ -
46.44	07/25/2025	16	$ 24,747.22	251.310	$ 98.47	$ 11,670.33	$ 13,076.89		37.975	213.34	$ 11,100.86	268.000	87.01	YES	100	-	$ 52.03	$ -
46.44	07/25/2025	17	$ 17,741.56	145.530	$ 121.91	$ 6,758.12	$ 10,983.44		17.667	127.86	$ 9,650.07	177.000	87.01	YES	100	-	$ 75.47	$ -
46.44	07/25/2025	18	$ 10,559.56	82.400	$ 128.15	$ 3,826.49	$ 6,733.07		40.708	41.69	$ 3,406.74	53.000	87.01	NO	85	41.69	$ 81.71	$ 511.01
46.44	07/25/2025	19	$ 22,295.98	169.900	$ 131.23	$ 7,889.82	$ 14,406.16		57.000	112.90	$ 9,573.02	47.000	87.01	NO	85	112.90	$ 84.79	$ 1,435.95
46.44	07/25/2025	20	$ 24,348.54	240.100	$ 101.41	$ 11,149.76	$ 13,198.78		57.000	183.10	$ 10,065.37	45.000	87.01	NO	85	183.10	$ 54.97	$ 1,509.81
46.44	07/25/2025	21	$ 17,431.05	227.500	$ 76.62	$ 10,564.65	$ 6,866.41		57.000	170.50	$ 5,146.03	42.000	87.01	NO	85	170.50	$ 30.18	$ 771.90
46.44	07/25/2025	22	$ 16,062.53	248.300	$ 64.69	$ 11,530.56	$ 4,531.97		90.604	157.70	$ 2,878.27	74.000	87.01	NO	85	157.70	$ 18.25	$ 431.74
46.44	07/25/2025	23	$ 20,159.66	428.200	$ 47.08	$ 19,884.75	$ 274.91		159.967	268.23	$ 172.21	259.000	87.01	YES	100	9.23	$ 0.64	$ 0.89
46.13	07/26/2025	1	$ 1,295.75	22.300	$ 58.11	$ 1,028.59	$ 267.16		158.476	-	$ -	264.000	87.01	YES	100	-	$ 11.98	$ -
46.13	07/26/2025	10	$ 2,895.40	36.870	$ 78.53	$ 1,700.63	$ 1,194.77		9.467	27.40	$ 887.99	253.000	87.01	YES	100	-	$ 32.40	$ -
46.13	07/26/2025	12	$ 12,426.09	235.090	$ 52.86	$ 10,843.53	$ 1,582.56		3.742	231.35	$ 1,557.37	253.000	87.01	YES	100	-	$ 6.73	$ -
46.13	07/26/2025	13	$ 11,701.45	218.270	$ 53.61	$ 10,067.70	$ 1,633.75		0.000	218.27	$ 1,633.75	253.000	87.01	YES	100	-	$ 7.48	$ -
46.13	07/26/2025	14	$ 11,327.40	195.300	$ 58.00	$ 9,008.21	$ 2,319.19		91.000	104.30	$ 1,238.56	264.000	87.01	YES	100	-	$ 11.88	$ -
46.13	07/26/2025	15	$ 11,293.38	188.380	$ 59.95	$ 8,689.03	$ 2,604.35		75.000	113.38	$ 1,567.48	264.000	87.01	YES	100	-	$ 13.82	$ -
46.13	07/26/2025	16	$ 14,751.04	246.060	$ 59.95	$ 11,349.52	$ 3,401.52	*Brown 6 was on outage all other units online*	87.000	159.06	$ 2,198.84	264.000	87.01	YES	100	-	$ 13.82	$ -
46.13	07/26/2025	17	$ 14,561.51	199.500	$ 72.99	$ 9,201.94	$ 5,359.57		97.000	102.50	$ 2,753.67	264.000	87.01	YES	100	-	$ 26.87	$ -
46.13	07/26/2025	18	$ 17,092.42	235.340	$ 72.63	$ 10,855.06	$ 6,237.36		56.000	179.34	$ 4,753.16	264.000	87.01	YES	100	-	$ 26.50	$ -
46.13	07/26/2025	19	$ 20,599.68	238.920	$ 86.22	$ 11,020.19	$ 9,579.50		52.000	186.92	$ 7,494.56	264.000	87.01	YES	100	-	$ 40.09	$ -
46.13	07/26/2025	20	$ 22,722.21	318.060	$ 71.44	$ 14,670.52	$ 8,051.69		51.000	267.06	$ 6,760.63	264.000	87.01	YES	100	3.06	$ 25.32	$ 11.62
46.13	07/26/2025	21	$ 22,360.34	347.480	$ 64.35	$ 16,027.52	$ 6,332.83		82.975	264.51	$ 4,820.61	264.000	87.01	YES	100	0.50	$ 18.23	$ 1.38
46.13	07/26/2025	22	$ 21,925.49	400.780	$ 54.71	$ 18,485.98	$ 3,439.51		158.583	242.20	$ 2,078.55	264.000	87.01	YES	100	-	$ 8.58	$ -
46.13	07/27/2025	12	$ 52,032.70	602.880	$ 86.31	$ 27,807.84	$ 24,224.86		149.000	453.88	$ 18,237.76	612.000	87.01	YES	100	-	$ 40.18	$ -
46.13	07/27/2025	13	$ 33,938.08	627.860	$ 54.05	$ 28,960.04	$ 4,978.04		149.000	478.86	$ 3,796.68	612.000	87.01	YES	100	-	$ 7.93	$ -
46.13	07/27/2025	14	$ 38,738.99	622.220	$ 62.26	$ 28,699.90	$ 10,039.09		149.000	473.22	$ 7,635.08	612.000	87.01	YES	100	-	$ 16.13	$ -
46.13	07/27/2025	15	$ 64,196.33	597.520	$ 107.44	$ 27,560.61	$ 36,635.72		95.000	502.52	$ 30,810.99	612.000	87.01	YES	100	-	$ 61.31	$ -
46.13	07/27/2025	16	$ 36,259.15	537.420	$ 67.47	$ 24,788.50	$ 11,470.65	*Brown 6 Culley 2 and Culley 3 were on outage all other units online*	41.000	496.42	$ 10,595.55	612.000	87.01	YES	100	-	$ 21.34	$ -
46.13	07/27/2025	17	$ 32,110.69	513.060	$ 62.59	$ 23,664.89	$ 8,445.80		44.000	469.06	$ 7,721.49	612.000	87.01	YES	100	-	$ 16.46	$ -
46.13	07/27/2025	18	$ 38,597.98	566.380	$ 68.15	$ 26,124.28	$ 12,473.70		44.000	522.38	$ 11,504.67	612.000	87.01	YES	100	-	$ 22.02	$ -
46.13	07/27/2025	19	$ 47,806.22	647.470	$ 73.84	$ 29,864.55	$ 17,941.67		46.163	601.31	$ 16,662.47	604.000	87.01	YES	100	-	$ 27.71	$ -
46.13	07/27/2025	20	$ 48,472.55	627.460	$ 77.25	$ 28,941.59	$ 19,530.96		39.000	588.46	$ 18,317.00	588.000	87.01	YES	100	0.46	$ 31.13	$ 2.15
46.13	07/27/2025	21	$ 38,215.70	660.440	$ 57.86	$ 30,462.80	$ 7,752.90		88.728	571.71	$ 6,711.33	564.000	87.01	YES	100	7.71	$ 11.74	$ 13.58
46.13	07/27/2025	22	$ 21,756.15	397.300	$ 54.76	$ 18,325.46	$ 3,430.69		132.754	264.55	$ 2,284.36	562.000	87.01	YES	100	-	$ 8.64	$ -
46.13	07/28/2025	9	$ 11,797.24	231.500	$ 50.96	$ 10,677.94	$ 1,119.30		431.000	-	$ -	264.000	87.01	YES	100	-	$ 4.84	$ -
46.13	07/28/2025	10	$ 13,160.45	230.400	$ 57.12	$ 10,627.20	$ 2,533.25		415.050	-	$ -	264.000	87.01	YES	100	-	$ 11.00	$ -
46.13	07/28/2025	11	$ 16,206.63	221.100	$ 73.30	$ 10,198.24	$ 6,008.39		341.075	-	$ -	264.000	87.01	YES	100	-	$ 27.18	$ -
46.13	07/28/2025	12	$ 39,926.04	481.590	$ 82.90	$ 22,213.34	$ 17,712.70		320.725	160.87	$ 5,916.55	264.000	87.01	YES	100	-	$ 36.78	$ -
46.13	07/28/2025	13	$ 54,480.28	472.180	$ 115.38	$ 21,779.30	$ 32,700.98		301.000	171.18	$ 11,855.13	264.000	87.01	YES	100	-	$ 69.26	$ -
46.13	07/28/2025	14	$ 83,732.59	500.490	$ 167.30	$ 23,085.10	$ 60,647.49		277.121	223.37	$ 27,067.01	264.000	87.01	YES	100	-	$ 121.18	$ -
46.13	07/28/2025	15	$ 72,905.66	567.300	$ 128.51	$ 26,166.71	$ 46,738.95		311.000	256.30	$ 21,116.15	264.000	87.01	YES	100	-	$ 82.39	$ -
46.13	07/28/2025	16	$ 77,634.07	634.800	$ 122.30	$ 29,280.15	$ 48,353.92	*Culley 3 and Brown 6 were returning from Outage all other units online*	327.000	307.80	$ 23,445.71	264.000	87.01	YES	100	43.80	$ 76.17	$ 500.45
46.13	07/28/2025	17	$ 90,958.02	562.380	$ 161.74	$ 25,939.78	$ 65,018.24		325.000	237.38	$ 27,444.13	155.000	87.01	YES	100	82.38	$ 115.61	$ 1,428.63
46.13	07/28/2025	18	$ 102,546.77	458.130	$ 223.84	$ 21,131.25	$ 81,415.52		323.000	135.13	$ 24,014.32	47.000	87.01	NO	85	135.13	$ 177.71	$ 3,602.15
46.13	07/28/2025	19	$ 277,875.31	398.500	$ 697.30	$ 18,380.81	$ 259,494.50		277.188	121.31	$ 78,995.73	48.000	87.01	NO	85	121.31	$ 651.18	$ 11,849.36
46.13	07/28/2025	20	$ 152,708.81	460.150	$ 331.87	$ 21,224.42	$ 131,484.39		270.312	189.84	$ 54,244.78	44.000	87.01	NO	85	189.84	$ 285.74	$ 8,136.72
46.13	07/28/2025	21	$ 65,205.63	387.000	$ 168.49	$ 17,850.38	$ 47,355.26		272.950	114.05	$ 13,955.73	44.000	87.01	NO	85	114.05	$ 122.37	$ 2,093.36
46.13	07/28/2025	22	$ 46,272.12	391.010	$ 118.34	$ 18,035.34	$ 28,236.78		293.117	97.89	$ 7,069.34	42.000	87.01	NO	85	97.89	$ 72.21	$ 1,060.40
46.13	07/28/2025	23	$ 22,634.32	322.610	$ 70.16	$ 14,880.39	$ 7,753.93		283.859	38.75	$ 931.38	36.000	87.01	NO	85	38.75	$ 24.04	$ 139.71
46.13	07/28/2025	24	$ 16,483.71	284.300	$ 57.98	$ 13,113.34	$ 3,370.37		290.217	-	$ -	36.000	87.01	NO	85	-	$ 11.85	$ -
46.56	07/29/2025	1	$ 24,457.93	506.900	$ 48.25	$ 23,602.78	$ 855.15		172.948	333.95	$ 563.38	388.000	87.01	YES	100	-	$ 1.69	$ -
46.56	07/29/2025	9	$ 19,299.97	341.230	$ 56.56	$ 15,888.69	$ 3,411.28		380.287	-	$ -	193.000	87.01	YES	100	-	$ 10.00	$ -
46.56	07/29/2025	10	$ 20,255.40	334.800	$ 60.50	$ 15,589.29	$ 4,666.11		312.512	22.29	$ 310.63	213.000	87.01	YES	100	-	$ 13.94	$ -
46.56	07/29/2025	11	$ 27,645.50	393.530	$ 70.25	$ 18,323.94	$ 9,321.56		265.867	127.66	$ 3,023.96	213.000	87.01	YES	100	-	$ 23.69	$ -
46.56	07/29/2025	12	$ 35,700.56	342.550	$ 104.22	$ 15,950.16	$ 19,750.40		245.971	96.58	$ 5,568.46	213.000	87.01	YES	100	-	$ 57.66	$ -
46.56	07/29/2025	13	$ 38,848.99	291.200	$ 133.41	$ 13,559.15	$ 25,289.84		187.780	103.42	$ 8,981.72	213.000	87.01	YES	100	-	$ 86.85	$ -
46.56	07/29/2025	14	$ 21,780.96	135.800	$ 160.39	$ 6,323.26	$ 15,457.70		6.408	129.39	$ 14,728.30	213.000	87.01	YES	100	-	$ 113.83	$ -
46.56	07/29/2025	15	$ 31,806.57	159.200	$ 199.79	$ 7,412.83	$ 24,393.74	*Culley 3 was derated all other units online*	0.730	158.47	$ 24,281.88	213.000	87.01	YES	100	-	$ 153.23	$ -
46.56	07/29/2025	16	$ 57,265.77	242.200	$ 236.44	$ 11,277.56	$ 45,988.21		43.148	199.05	$ 37,795.40	213.000	87.01	YES	100	-	$ 189.88	$ -
46.56	07/29/2025	17	$ 76,723.06	270.800	$ 283.32	$ 12,609.26	$ 64,113.80		39.208	231.59	$ 54,831.03	213.000	87.01	YES	100	18.59	$ 236.76	$ 660.27
46.56	07/29/2025	18	$ 83,233.95	269.200	$ 309.19	$ 12,534.76	$ 70,699.19		23.175	246.03	$ 64,612.81	213.000	87.01	YES	100	33.03	$ 262.63	$ 1,300.99

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 07/31

Jul Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
46.56	07/29/2025	19	$ 134,052.70	310.300	$ 432.01	$ 14,448.50	$ 119,604.20		12.479	297.82	$ 114,794.21	213.000	87.01	YES	100	84.82	$ 385.45	$ 4,904.10
46.56	07/29/2025	20	$ 110,301.95	370.900	$ 297.39	$ 17,270.22	$ 93,031.73		2.905	368.00	$ 92,303.08	212.000	87.01	YES	100	156.00	$ 250.83	$ 5,869.16
46.56	07/29/2025	21	$ 57,972.60	374.500	$ 154.80	$ 17,437.84	$ 40,534.76		16.334	358.17	$ 38,766.81	213.000	87.01	YES	100	145.17	$ 108.24	$ 2,356.85
46.56	07/29/2025	22	$ 59,778.63	527.800	$ 113.26	$ 24,575.95	$ 35,202.68		208.014	319.79	$ 21,328.77	213.000	87.01	YES	100	106.79	$ 66.70	$ 1,068.35
46.56	07/29/2025	23	$ 39,362.79	572.300	$ 68.78	$ 26,648.00	$ 12,714.79		315.088	257.21	$ 5,714.48	213.000	87.01	YES	100	44.21	$ 22.22	$ 147.34
46.56	07/29/2025	24	$ 28,728.94	559.800	$ 51.32	$ 26,065.97	$ 2,662.97		360.290	199.51	$ 949.07	213.000	87.01	YES	100	-	$ 4.76	$ -
45.94	07/30/2025	1	$ 29,357.27	589.000	$ 49.84	$ 27,057.48	$ 2,299.79		374.373	214.63	$ 838.02	218.000	87.01	YES	100	-	$ 3.90	$ -
45.94	07/30/2025	5	$ 6,291.43	97.700	$ 64.40	$ 4,488.14	$ 1,803.29		387.258	-	$ -	218.000	87.01	YES	100	-	$ 18.46	$ -
45.94	07/30/2025	6	$ 9,067.15	68.800	$ 131.79	$ 3,160.53	$ 5,906.62		368.900	-	$ -	223.000	87.01	YES	100	-	$ 85.85	$ -
45.94	07/30/2025	7	$ 20,881.81	448.300	$ 46.58	$ 20,594.01	$ 287.80		364.171	84.13	$ 54.01	223.000	87.01	YES	100	-	$ 0.64	$ -
45.94	07/30/2025	8	$ 17,326.67	363.700	$ 47.64	$ 16,707.65	$ 619.02		353.083	10.62	$ 18.07	218.000	87.01	YES	100	-	$ 1.70	$ -
45.94	07/30/2025	9	$ 7,690.76	148.700	$ 51.72	$ 6,830.98	$ 859.78		228.616	-	$ -	218.000	87.01	YES	100	-	$ 5.78	$ -
45.94	07/30/2025	10	$ 9,679.57	162.200	$ 59.68	$ 7,451.14	$ 2,228.43		150.246	11.95	$ 164.23	218.000	87.01	YES	100	-	$ 13.74	$ -
45.94	07/30/2025	11	$ 12,948.09	195.790	$ 66.13	$ 8,994.20	$ 3,953.89		98.696	97.09	$ 1,960.77	218.000	87.01	YES	100	-	$ 20.19	$ -
45.94	07/30/2025	12	$ 15,997.62	165.490	$ 96.67	$ 7,602.28	$ 8,395.34		45.654	119.84	$ 6,079.30	218.000	87.01	YES	100	-	$ 50.73	$ -
45.94	07/30/2025	13	$ 16,724.40	178.360	$ 93.77	$ 8,193.50	$ 8,530.90	*Culley 3 was derated all other units online*	43.611	134.75	$ 6,445.00	218.000	87.01	YES	100	-	$ 47.83	$ -
45.94	07/30/2025	14	$ 19,385.70	170.250	$ 113.87	$ 7,820.94	$ 11,564.76		10.362	159.89	$ 10,860.88	218.000	87.01	YES	100	-	$ 67.93	$ -
45.94	07/30/2025	15	$ 18,259.91	153.200	$ 119.19	$ 7,037.70	$ 11,222.21		6.091	147.11	$ 10,776.03	218.000	87.01	YES	100	-	$ 73.25	$ -
45.94	07/30/2025	16	$ 18,647.56	160.720	$ 116.03	$ 7,383.16	$ 11,264.40		18.333	142.39	$ 9,979.50	218.000	87.01	YES	100	-	$ 70.09	$ -
45.94	07/30/2025	17	$ 25,187.14	243.780	$ 103.32	$ 11,198.77	$ 13,988.37		45.500	198.28	$ 11,377.53	218.000	87.01	YES	100	-	$ 57.38	$ -
45.94	07/30/2025	18	$ 26,203.47	218.360	$ 120.00	$ 10,031.02	$ 16,172.45		23.588	194.77	$ 14,425.44	218.000	87.01	YES	100	-	$ 74.06	$ -
45.94	07/30/2025	19	$ 37,064.90	322.860	$ 114.80	$ 14,831.54	$ 22,233.36		37.092	285.77	$ 19,679.06	218.000	87.01	YES	100	67.77	$ 68.86	$ 700.01
45.94	07/30/2025	20	$ 38,684.94	455.900	$ 84.85	$ 20,943.13	$ 17,741.81		81.750	374.15	$ 14,560.42	218.000	87.01	YES	100	156.15	$ 38.92	$ 911.51
45.94	07/30/2025	21	$ 36,393.28	480.230	$ 75.78	$ 22,060.81	$ 14,332.47		114.566	365.66	$ 10,913.25	218.000	87.01	YES	100	147.66	$ 29.85	$ 661.06
45.94	07/30/2025	22	$ 23,838.19	397.900	$ 59.91	$ 18,278.73	$ 5,559.46		214.896	183.00	$ 2,556.93	218.000	87.01	YES	100	-	$ 13.97	$ -
45.94	07/30/2025	23	$ 1,585.89	26.300	$ 60.30	$ 1,208.17	$ 377.72		306.504	-	$ -	218.000	87.01	YES	100	-	$ 14.36	$ -
45.94	07/30/2025	24	$ 5,134.90	86.060	$ 59.67	$ 3,953.42	$ 1,181.48		384.173	-	$ -	218.000	87.01	YES	100	-	$ 13.73	$ -
44.69	07/31/2025	8	$ 467.38	6.140	$ 76.12	$ 274.38	$ 193.00		379.108	-	$ -	219.000	87.01	YES	100	-	$ 31.43	$ -
44.69	07/31/2025	10	$ 22,675.74	423.460	$ 53.55	$ 18,923.58	$ 3,752.16		389.924	33.54	$ 297.15	219.000	87.01	YES	100	-	$ 8.86	$ -
44.69	07/31/2025	11	$ 15,705.73	285.570	$ 55.00	$ 12,761.55	$ 2,944.18		230.682	54.89	$ 565.89	219.000	87.01	YES	100	-	$ 10.31	$ -
44.69	07/31/2025	12	$ 13,321.15	262.110	$ 50.82	$ 11,713.17	$ 1,607.98		167.179	94.93	$ 582.38	219.000	87.01	YES	100	-	$ 6.13	$ -
44.69	07/31/2025	13	$ 13,946.91	251.870	$ 55.37	$ 11,255.57	$ 2,691.34		147.150	104.72	$ 1,118.98	219.000	87.01	YES	100	-	$ 10.69	$ -
44.69	07/31/2025	14	$ 9,893.57	157.800	$ 62.70	$ 7,051.77	$ 2,841.80		121.387	36.41	$ 655.76	219.000	87.01	YES	100	-	$ 18.01	$ -
44.69	07/31/2025	15	$ 9,660.88	157.600	$ 61.30	$ 7,042.83	$ 2,618.05	*Culley 3 was derated all other units online*	154.404	3.20	$ 53.09	219.000	87.01	YES	100	-	$ 16.61	$ -
44.69	07/31/2025	16	$ 6,143.85	101.200	$ 60.71	$ 4,522.43	$ 1,621.42		144.116	-	$ -	219.000	87.01	YES	100	-	$ 16.02	$ -
44.69	07/31/2025	17	$ 6,223.50	97.900	$ 63.57	$ 4,374.96	$ 1,848.54		179.570	-	$ -	219.000	87.01	YES	100	-	$ 18.88	$ -
44.69	07/31/2025	18	$ 10,002.34	139.600	$ 71.65	$ 6,238.44	$ 3,763.90		188.868	-	$ -	219.000	87.01	YES	100	-	$ 26.96	$ -
44.69	07/31/2025	19	$ 14,963.10	180.300	$ 82.99	$ 8,057.25	$ 6,905.85		184.130	-	$ -	219.000	87.01	YES	100	-	$ 38.30	$ -
44.69	07/31/2025	20	$ 19,416.74	252.100	$ 77.02	$ 11,265.84	$ 8,150.90		228.223	23.88	$ 771.99	219.000	87.01	YES	100	-	$ 32.33	$ -
44.69	07/31/2025	21	$ 14,657.89	305.500	$ 47.98	$ 13,652.18	$ 1,005.71		262.102	43.40	$ 142.87	219.000	87.01	YES	100	-	$ 3.29	$ -
44.69	07/31/2025	22	$ 25,205.33	503.000	$ 50.11	$ 22,478.06	$ 2,727.27		391.001	112.00	$ 607.26	219.000	87.01	YES	100	-	$ 5.42	$ -
Total			**$ 7,756,145.98**	**87,271.400**		**$ 4,151,912.83**	**$ 3,604,233.44**		**59,548.785**	**43,824.159**	**$ 2,279,671.76**	**68,468.000**				**6,503.336**		**$ 82,529.06**

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 08/31

Aug Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity 791	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
44.38	08/01/2025	14	$ 4,534.91	99.800	$ 45.44	$ 4,428.63	$ 106.29		230.658	-	$ -	302.000	87.01	YES	100	-	$ 1.06	$ -
44.38	08/01/2025	15	$ 5,452.87	101.600	$ 53.67	$ 4,508.50	$ 944.37		228.362	-	$ -	302.000	87.01	YES	100	-	$ 9.29	$ -
44.38	08/01/2025	16	$ 5,678.43	97.300	$ 58.36	$ 4,317.69	$ 1,360.74		302.762	-	$ -	227.000	87.01	YES	100	-	$ 13.99	$ -
44.38	08/01/2025	17	$ 6,051.15	104.800	$ 57.74	$ 4,650.50	$ 1,400.65	*Brown 3 and Brown 4 were on Reserve Shutdown*	301.183	-	$ -	227.000	87.01	YES	100	-	$ 13.36	$ -
44.38	08/01/2025	18	$ 9,301.91	161.100	$ 57.74	$ 7,148.81	$ 2,153.10		276.262	-	$ -	227.000	87.01	YES	100	-	$ 13.36	$ -
44.38	08/01/2025	19	$ 19,107.35	297.070	$ 64.32	$ 13,182.48	$ 5,924.87		236.844	60.23	$ 1,201.17	227.000	87.01	YES	100	-	$ 19.94	$ -
44.38	08/01/2025	20	$ 21,653.98	298.100	$ 72.64	$ 13,228.19	$ 8,425.79		301.179	-	$ -	227.000	87.01	YES	100	-	$ 28.26	$ -
44.38	08/01/2025	21	$ 13,741.35	272.700	$ 50.39	$ 12,101.06	$ 1,640.29		289.891	-	$ -	227.000	87.01	YES	100	-	$ 6.01	$ -
44.88	08/02/2025	19	$ 11,533.15	244.450	$ 47.18	$ 10,969.69	$ 563.46	*Brown 3 Brown 4 Brown 6 and Culley 2 were on Reserve Shutdown*	451.583	-	$ -	44.000	87.01	NO	85	-	$ 2.30	$ -
44.88	08/03/2025	18	$ 2,907.92	57.800	$ 50.31	$ 2,593.78	$ 314.15		305.017	-	$ -	42.000	87.01	NO	85	-	$ 5.44	$ -
44.88	08/03/2025	19	$ 6,198.50	101.200	$ 61.25	$ 4,541.35	$ 1,657.15	*Brown 3 Brown 4 and Culley 2 were on Reserve Shutdown*	304.241	-	$ -	42.000	87.01	NO	85	-	$ 16.38	$ -
44.88	08/03/2025	20	$ 9,314.63	178.100	$ 52.30	$ 7,992.24	$ 1,322.39		415.942	-	$ -	42.000	87.01	NO	85	-	$ 7.43	$ -
44.88	08/03/2025	21	$ 78,146.77	315.620	$ 247.60	$ 14,163.45	$ 63,983.32		711.317	-	$ -	42.000	87.01	NO	85	-	$ 202.72	$ -
44.88	08/03/2025	22	$ 16,340.04	303.240	$ 53.88	$ 13,607.90	$ 2,732.15		449.000	-	$ -	312.000	87.01	YES	100	-	$ 9.01	$ -
44.88	08/04/2025	12	$ 9,122.48	194.800	$ 46.83	$ 8,741.65	$ 380.83		376.950	-	$ -	312.000	87.01	YES	100	-	$ 1.95	$ -
44.88	08/04/2025	14	$ 26,040.67	358.440	$ 72.65	$ 16,085.00	$ 9,955.68		158.088	200.35	$ 5,564.78	312.000	87.01	YES	100	-	$ 27.78	$ -
44.88	08/04/2025	19	$ 2,439.39	31.000	$ 78.69	$ 1,391.13	$ 1,048.27		127.626	-	$ -	312.000	87.01	YES	100	-	$ 33.82	$ -
44.88	08/04/2025	20	$ 18,954.32	374.290	$ 50.64	$ 16,796.26	$ 2,158.06	*Brown 3 was on Reserve Shutdown and Culley 3 was on outage*	111.560	262.73	$ 1,514.83	312.000	87.01	YES	100	-	$ 5.77	$ -
44.88	08/04/2025	21	$ 24,365.74	387.480	$ 62.88	$ 17,388.17	$ 6,977.58		124.400	263.08	$ 4,737.43	312.000	87.01	YES	100	-	$ 18.01	$ -
44.88	08/04/2025	22	$ 16,791.15	356.500	$ 47.10	$ 15,997.94	$ 793.21		324.229	32.27	$ 71.80	304.000	87.01	YES	100	-	$ 2.23	$ -
44.88	08/04/2025	23	$ 7,207.01	158.570	$ 45.45	$ 7,115.83	$ 91.18		394.704	-	$ -	232.000	87.01	YES	100	-	$ 0.58	$ -
43.31	08/05/2025	10	$ 8,893.04	201.900	$ 44.05	$ 8,744.89	$ 148.15		391.583	-	$ -	264.000	87.01	YES	100	-	$ 0.73	$ -
43.31	08/05/2025	12	$ 15,089.00	323.340	$ 46.67	$ 14,004.83	$ 1,084.17		389.917	-	$ -	314.000	87.01	YES	100	-	$ 3.35	$ -
43.31	08/05/2025	13	$ 27,433.89	492.380	$ 55.72	$ 21,326.45	$ 6,107.44		373.942	118.44	$ 1,469.09	314.000	87.01	YES	100	-	$ 12.40	$ -
43.31	08/05/2025	14	$ 18,693.46	391.500	$ 47.75	$ 16,957.04	$ 1,736.42		198.833	192.67	$ 854.54	314.000	87.01	YES	100	-	$ 4.44	$ -
43.31	08/05/2025	15	$ 20,390.15	331.400	$ 61.53	$ 14,353.93	$ 6,036.22	*Brown 3 was on Reserve Shutdown and Culley 3 was on outage*	151.500	179.90	$ 3,276.75	314.000	87.01	YES	100	-	$ 18.21	$ -
43.31	08/05/2025	16	$ 1,583.61	26.800	$ 59.09	$ 1,160.79	$ 422.82		191.888	-	$ -	314.000	87.01	YES	100	-	$ 15.78	$ -
43.31	08/05/2025	18	$ 1,377.51	22.200	$ 62.05	$ 961.55	$ 415.96		130.000	-	$ -	314.000	87.01	YES	100	-	$ 18.74	$ -
43.31	08/05/2025	19	$ 21,362.88	423.470	$ 50.45	$ 18,341.76	$ 3,021.12		113.167	310.30	$ 2,213.77	314.000	87.01	YES	100	-	$ 7.13	$ -
43.31	08/05/2025	20	$ 9,163.87	135.500	$ 67.63	$ 5,868.91	$ 3,294.96		121.404	14.10	$ 342.77	314.000	87.01	YES	100	-	$ 24.32	$ -
43.31	08/05/2025	21	$ 26,155.37	512.810	$ 51.00	$ 22,211.34	$ 3,944.03		153.838	358.97	$ 2,760.86	314.000	87.01	YES	100	44.97	$ 7.69	$ 51.88
43.31	08/05/2025	23	$ 16,528.49	302.280	$ 54.68	$ 13,092.65	$ 3,435.84		383.150	-	$ -	314.000	87.01	YES	100	-	$ 11.37	$ -
44.69	08/06/2025	13	$ 13,350.74	266.800	$ 50.04	$ 11,922.76	$ 1,427.98		152.833	113.97	$ 609.98	292.000	87.01	YES	100	-	$ 5.35	$ -
44.69	08/06/2025	14	$ 13,135.18	246.300	$ 53.33	$ 11,006.65	$ 2,128.53		150.000	96.30	$ 832.22	292.000	87.01	YES	100	-	$ 8.64	$ -
44.69	08/06/2025	15	$ 14,964.30	255.800	$ 58.50	$ 11,431.19	$ 3,533.11		133.000	122.80	$ 1,696.11	292.000	87.01	YES	100	-	$ 13.81	$ -
44.69	08/06/2025	16	$ 13,695.74	207.700	$ 65.94	$ 9,281.70	$ 4,414.04		87.000	120.70	$ 2,565.12	292.000	87.01	YES	100	-	$ 21.25	$ -
44.69	08/06/2025	17	$ 16,962.27	237.900	$ 71.30	$ 10,631.28	$ 6,330.99	*Culley 3 and Brown 3 were on outage*	85.000	152.90	$ 4,068.97	292.000	87.01	YES	100	-	$ 26.61	$ -
44.69	08/06/2025	18	$ 21,471.91	272.500	$ 78.80	$ 12,177.48	$ 9,294.43		97.721	174.78	$ 5,961.36	313.000	87.01	YES	100	-	$ 34.11	$ -
44.69	08/06/2025	19	$ 32,773.42	335.000	$ 97.83	$ 14,970.48	$ 17,802.94		75.000	260.00	$ 13,817.21	313.000	87.01	YES	100	-	$ 53.14	$ -
44.69	08/06/2025	20	$ 34,940.94	422.000	$ 82.80	$ 18,858.34	$ 16,082.60		76.000	346.00	$ 13,186.21	313.000	87.01	YES	100	33.00	$ 38.11	$ 188.65
44.69	08/06/2025	21	$ 28,382.71	410.000	$ 69.23	$ 18,322.08	$ 10,060.63		2.291	407.71	$ 10,004.41	388.000	87.01	YES	100	19.71	$ 24.54	$ 72.54
44.69	08/06/2025	22	$ 27,483.12	504.000	$ 54.53	$ 22,522.75	$ 4,960.37		151.075	352.93	$ 3,473.49	389.000	87.01	YES	100	-	$ 9.84	$ -
45.25	08/07/2025	12	$ 19,494.55	429.490	$ 45.39	$ 19,434.42	$ 60.13		213.125	216.37	$ 30.29	388.000	87.01	YES	100	-	$ 0.14	$ -
45.25	08/07/2025	13	$ 13,295.65	261.880	$ 50.77	$ 11,850.07	$ 1,445.58		20.000	241.88	$ 1,335.18	389.000	87.01	YES	100	-	$ 5.52	$ -
45.25	08/07/2025	14	$ 18,350.77	309.770	$ 59.24	$ 14,017.09	$ 4,333.68		22.783	286.99	$ 4,014.94	389.000	87.01	YES	100	-	$ 13.99	$ -
45.25	08/07/2025	15	$ 18,371.65	282.120	$ 65.12	$ 12,765.93	$ 5,605.72		34.496	247.62	$ 4,920.29	335.000	87.01	YES	100	-	$ 19.87	$ -
45.25	08/07/2025	16	$ 20,438.98	296.260	$ 68.99	$ 13,405.77	$ 7,033.22		6.854	289.41	$ 6,870.50	326.000	87.01	YES	100	-	$ 23.74	$ -
45.25	08/07/2025	17	$ 16,805.90	229.840	$ 73.12	$ 10,400.26	$ 6,405.64	*Culley 3 and Brown 3 were on outage*	9.417	220.42	$ 6,143.19	314.000	87.01	YES	100	-	$ 27.87	$ -
45.25	08/07/2025	18	$ 20,999.95	268.370	$ 78.25	$ 12,143.74	$ 8,856.21		33.225	235.15	$ 7,759.78	314.000	87.01	YES	100	-	$ 33.00	$ -
45.25	08/07/2025	19	$ 32,751.95	357.320	$ 91.66	$ 16,168.73	$ 16,583.22		46.117	311.20	$ 14,442.93	314.000	87.01	YES	100	-	$ 46.41	$ -
45.25	08/07/2025	20	$ 34,820.19	441.470	$ 78.87	$ 19,976.52	$ 14,843.67		63.212	378.26	$ 12,718.28	314.000	87.01	YES	100	64.26	$ 33.62	$ 324.08
45.25	08/07/2025	21	$ 28,774.26	471.400	$ 61.04	$ 21,330.85	$ 7,443.41		137.854	333.55	$ 5,266.69	314.000	87.01	YES	100	19.55	$ 15.79	$ 46.29
45.25	08/07/2025	22	$ 25,371.85	510.500	$ 49.70	$ 23,100.13	$ 2,271.73		254.903	255.60	$ 1,137.41	314.000	87.01	YES	100	-	$ 4.45	$ -
45.56	08/08/2025	11	$ 21,536.54	453.210	$ 47.52	$ 20,649.61	$ 886.93		383.000	70.21	$ 137.40	314.000	87.01	YES	100	-	$ 1.96	$ -
45.56	08/08/2025	12	$ 16,799.83	325.200	$ 51.66	$ 14,817.09	$ 1,982.74		234.700	90.50	$ 551.78	314.000	87.01	YES	100	-	$ 6.10	$ -
45.56	08/08/2025	13	$ 19,423.64	342.750	$ 56.67	$ 15,616.72	$ 3,806.92		165.717	177.03	$ 1,966.30	314.000	87.01	YES	100	-	$ 11.11	$ -
45.56	08/08/2025	14	$ 20,981.16	348.640	$ 60.18	$ 15,885.08	$ 5,096.08		154.083	194.56	$ 2,843.84	314.000	87.01	YES	100	-	$ 14.62	$ -
45.56	08/08/2025	15	$ 20,985.60	318.060	$ 65.98	$ 14,491.77	$ 6,493.83		100.721	217.34	$ 4,437.41	314.000	87.01	YES	100	-	$ 20.42	$ -
45.56	08/08/2025	16	$ 25,939.88	381.350	$ 68.02	$ 17,375.45	$ 8,564.43	*Culley 3 was on outage Brown 3 and Brown 4 short run times*	110.779	270.57	$ 6,076.53	314.000	87.01	YES	100	-	$ 22.46	$ -
45.56	08/08/2025	17	$ 25,890.47	360.090	$ 71.90	$ 16,406.78	$ 9,483.69		87.583	272.51	$ 7,177.02	314.000	87.01	YES	100	-	$ 26.34	$ -
45.56	08/08/2025	18	$ 27,799.56	353.100	$ 78.73	$ 16,088.30	$ 11,711.26		74.075	279.03	$ 9,254.42	314.000	87.01	YES	100	-	$ 33.17	$ -
45.56	08/08/2025	19	$ 32,889.82	323.910	$ 101.54	$ 14,758.31	$ 18,131.51		8.609	315.30	$ 17,649.60	314.000	87.01	YES	100	1.30	$ 55.98	$ 10.92
45.56	08/08/2025	20	$ 30,573.44	385.250	$ 79.36	$ 17,553.15	$ 13,020.29		10.488	374.76	$ 12,665.83	314.000	87.01	YES	100	60.76	$ 33.80	$ 308.04
45.56	08/08/2025	21	$ 26,944.39	416.580	$ 64.68	$ 18,980.63	$ 7,963.76		68.480	348.10	$ 6,654.62	314.000	87.01	YES	100	34.10	$ 19.12	$ 97.78

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 08/31

Aug Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
45.56	08/08/2025	22	$ 22,324.34	448.370	$ 49.79	$ 20,429.08	$ 1,895.26		118.204	330.17	$ 1,395.61	314.000	87.01	YES	100	16.17	$ 4.23	$ 10.25
45.50	08/09/2025	12	$ 11,566.18	228.400	$ 50.64	$ 10,392.20	$ 1,173.98		277.625	-	$ -	314.000	87.01	YES	100	-	$ 5.14	$ -
45.50	08/09/2025	13	$ 12,078.91	237.400	$ 50.88	$ 10,801.70	$ 1,277.21		240.000	-	$ -	392.000	87.01	YES	100	-	$ 5.38	$ -
45.50	08/09/2025	14	$ 15,503.76	282.400	$ 54.90	$ 12,849.20	$ 2,654.56		183.000	99.40	$ 934.36	392.000	87.01	YES	100	-	$ 9.40	$ -
45.50	08/09/2025	15	$ 17,670.35	306.380	$ 57.67	$ 13,940.29	$ 3,730.06		167.144	139.24	$ 1,695.15	392.000	87.01	YES	100	-	$ 12.17	$ -
45.50	08/09/2025	16	$ 22,500.96	340.170	$ 66.15	$ 15,477.74	$ 7,023.23		100.063	240.11	$ 4,957.30	392.000	87.01	YES	100	-	$ 20.65	$ -
45.50	08/09/2025	17	$ 22,831.42	316.420	$ 72.16	$ 14,397.11	$ 8,434.31	*Culley 2 and Culley 3 were on outage*	36.650	279.77	$ 7,457.39	392.000	87.01	YES	100	-	$ 26.66	$ -
45.50	08/09/2025	18	$ 24,217.65	359.970	$ 67.28	$ 16,378.64	$ 7,839.02	*all other units online*	51.675	308.30	$ 6,713.70	392.000	87.01	YES	100	-	$ 21.78	$ -
45.50	08/09/2025	19	$ 33,785.28	451.180	$ 74.88	$ 20,528.69	$ 13,256.59		71.875	379.31	$ 11,144.76	392.000	87.01	YES	100	-	$ 29.38	$ -
45.50	08/09/2025	20	$ 36,367.42	518.110	$ 70.19	$ 23,574.01	$ 12,793.42		74.767	443.34	$ 10,947.23	392.000	87.01	YES	100	51.34	$ 24.69	$ 190.17
45.50	08/09/2025	21	$ 36,669.97	615.680	$ 59.56	$ 28,013.44	$ 8,656.53		172.358	443.32	$ 6,233.16	392.000	87.01	YES	100	51.32	$ 14.06	$ 108.24
45.50	08/09/2025	22	$ 23,916.86	490.200	$ 48.79	$ 22,304.10	$ 1,612.76		259.987	230.21	$ 757.40	392.000	87.01	YES	100	-	$ 3.29	$ -
45.50	08/09/2025	24	$ 2,264.37	46.240	$ 48.97	$ 2,103.92	$ 160.45		369.000	-	$ -	392.000	87.01	YES	100	-	$ 3.47	$ -
45.50	08/10/2025	12	$ 14,391.30	249.200	$ 57.75	$ 11,338.60	$ 3,052.70		270.000	-	$ -	392.000	87.01	YES	100	-	$ 12.25	$ -
45.50	08/10/2025	13	$ 15,111.10	261.800	$ 57.72	$ 11,911.90	$ 3,199.20		239.000	22.80	$ 278.62	392.000	87.01	YES	100	-	$ 12.22	$ -
45.50	08/10/2025	14	$ 15,438.90	234.100	$ 65.95	$ 10,651.55	$ 4,787.35		177.029	57.07	$ 1,167.10	392.000	87.01	YES	100	-	$ 20.45	$ -
45.50	08/10/2025	15	$ 18,747.58	255.800	$ 73.29	$ 11,638.90	$ 7,108.68		130.783	125.02	$ 3,474.22	392.000	87.01	YES	100	-	$ 27.79	$ -
45.50	08/10/2025	16	$ 21,792.28	292.200	$ 74.58	$ 13,295.10	$ 8,497.18		119.358	172.84	$ 5,026.25	392.000	87.01	YES	100	-	$ 29.08	$ -
45.50	08/10/2025	17	$ 21,636.92	245.400	$ 88.17	$ 11,165.70	$ 10,471.22		111.278	134.12	$ 5,722.99	392.000	87.01	YES	100	-	$ 42.67	$ -
45.50	08/10/2025	18	$ 32,214.11	290.460	$ 110.91	$ 13,215.93	$ 18,998.18	*Culley 2 and Culley 3 were on outage*	37.675	252.79	$ 16,533.96	392.000	87.01	YES	100	-	$ 65.41	$ -
45.50	08/10/2025	19	$ 57,534.58	372.210	$ 154.58	$ 16,935.56	$ 40,599.03	*all other units online*	33.000	339.21	$ 36,999.53	392.000	87.01	YES	100	-	$ 109.08	$ -
45.50	08/10/2025	20	$ 42,337.59	439.130	$ 96.41	$ 19,980.42	$ 22,357.18		50.192	388.94	$ 19,801.78	392.000	87.01	YES	100	-	$ 50.91	$ -
45.50	08/10/2025	21	$ 36,523.25	484.880	$ 75.32	$ 22,062.04	$ 14,461.21		102.358	382.52	$ 11,408.45	392.000	87.01	YES	100	-	$ 29.82	$ -
45.50	08/10/2025	22	$ 29,664.32	425.600	$ 69.70	$ 19,364.80	$ 10,299.52		188.821	236.78	$ 5,730.05	392.000	87.01	YES	100	-	$ 24.20	$ -
45.50	08/10/2025	23	$ 23,804.46	447.200	$ 53.23	$ 20,347.60	$ 3,456.86		260.792	186.41	$ 1,440.94	392.000	87.01	YES	100	-	$ 7.73	$ -
45.50	08/10/2025	24	$ 26,210.89	566.110	$ 46.30	$ 25,758.01	$ 452.88		361.346	204.76	$ 163.81	392.000	87.01	YES	100	-	$ 0.80	$ -
45.50	08/11/2025	10	$ 16,543.93	324.200	$ 51.03	$ 14,751.10	$ 1,792.83		260.000	64.20	$ 355.03	392.000	87.01	YES	100	-	$ 5.53	$ -
45.50	08/11/2025	11	$ 21,827.94	356.200	$ 61.28	$ 16,207.10	$ 5,620.84		214.000	142.20	$ 2,243.92	392.000	87.01	YES	100	-	$ 15.78	$ -
45.50	08/11/2025	12	$ 24,794.00	322.000	$ 77.00	$ 14,651.00	$ 10,143.00		156.117	165.88	$ 5,225.31	392.000	87.01	YES	100	-	$ 31.50	$ -
45.50	08/11/2025	13	$ 24,520.06	334.250	$ 73.36	$ 15,208.38	$ 9,311.69		95.555	238.70	$ 6,649.67	392.000	87.01	YES	100	-	$ 27.86	$ -
45.50	08/11/2025	14	$ 31,265.72	319.100	$ 97.98	$ 14,519.05	$ 16,746.67		51.367	267.73	$ 14,050.88	392.000	87.01	YES	100	-	$ 52.48	$ -
45.50	08/11/2025	15	$ 36,910.52	346.280	$ 106.59	$ 15,755.74	$ 21,154.78		33.688	312.59	$ 19,096.73	392.000	87.01	YES	100	-	$ 61.09	$ -
45.50	08/11/2025	16	$ 42,190.87	351.580	$ 120.00	$ 15,996.89	$ 26,193.98	*Culley 2 and Culley 3 were on outage*	27.746	323.83	$ 24,126.80	392.000	87.01	YES	100	-	$ 74.50	$ -
45.50	08/11/2025	17	$ 42,691.16	357.400	$ 119.45	$ 16,261.70	$ 26,429.46	*all other units online*	34.000	323.40	$ 23,915.19	392.000	87.01	YES	100	-	$ 73.95	$ -
45.50	08/11/2025	18	$ 44,205.41	357.100	$ 123.79	$ 16,248.05	$ 27,957.36		15.000	342.10	$ 26,783.01	392.000	87.01	YES	100	-	$ 78.29	$ -
45.50	08/11/2025	19	$ 76,991.16	461.610	$ 166.79	$ 21,003.26	$ 55,987.91		29.000	432.61	$ 52,470.54	392.000	87.01	YES	100	40.61	$ 121.29	$ 738.83
45.50	08/11/2025	20	$ 60,001.85	543.330	$ 110.43	$ 24,721.52	$ 35,280.34		36.000	507.33	$ 32,942.73	392.000	87.01	YES	100	115.33	$ 64.93	$ 1,123.32
45.50	08/11/2025	21	$ 46,645.04	522.270	$ 89.31	$ 23,763.29	$ 22,881.76		31.550	490.72	$ 21,499.48	392.000	87.01	YES	100	98.72	$ 43.81	$ 648.77
45.50	08/11/2025	22	$ 35,681.22	539.970	$ 66.08	$ 24,568.64	$ 11,112.59		99.079	440.89	$ 9,073.54	392.000	87.01	YES	100	48.89	$ 20.58	$ 150.93
45.50	08/11/2025	23	$ 28,923.93	568.410	$ 50.89	$ 25,862.66	$ 3,061.28		198.671	369.74	$ 1,991.30	392.000	87.01	YES	100	-	$ 5.39	$ -
45.50	08/11/2025	24	$ 25,106.95	525.800	$ 47.75	$ 23,923.90	$ 1,183.05		242.946	282.85	$ 636.42	392.000	87.01	YES	100	-	$ 2.25	$ -
45.13	08/12/2025	1	$ 2,199.56	35.630	$ 61.73	$ 1,607.80	$ 591.76		439.967	-	$ -	314.000	87.01	YES	100	-	$ 16.61	$ -
45.13	08/12/2025	6	$ 2,890.23	41.470	$ 69.69	$ 1,871.33	$ 1,018.90		376.504	-	$ -	314.000	87.01	YES	100	-	$ 24.57	$ -
45.13	08/12/2025	7	$ 25,641.17	542.900	$ 47.23	$ 24,498.36	$ 1,142.81		380.267	162.63	$ 342.34	314.000	87.01	YES	100	-	$ 2.11	$ -
45.13	08/12/2025	10	$ 11,337.71	223.800	$ 50.66	$ 10,098.98	$ 1,238.74		200.417	23.38	$ 129.43	314.000	87.01	YES	100	-	$ 5.54	$ -
45.13	08/12/2025	11	$ 13,336.13	246.600	$ 54.08	$ 11,127.83	$ 2,208.31		157.617	88.98	$ 796.84	314.000	87.01	YES	100	-	$ 8.96	$ -
45.13	08/12/2025	12	$ 20,365.46	304.040	$ 66.98	$ 13,719.81	$ 6,645.66		107.725	196.32	$ 4,291.02	314.000	87.01	YES	100	-	$ 21.86	$ -
45.13	08/12/2025	13	$ 22,770.35	282.590	$ 80.58	$ 12,751.87	$ 10,018.48		78.016	204.57	$ 7,252.63	314.000	87.01	YES	100	-	$ 35.45	$ -
45.13	08/12/2025	14	$ 28,713.85	440.620	$ 65.17	$ 19,882.98	$ 8,830.87		176.166	264.45	$ 5,300.17	314.000	87.01	YES	100	-	$ 20.04	$ -
45.13	08/12/2025	15	$ 20,655.97	259.040	$ 79.74	$ 11,689.18	$ 8,966.79	*Culley 2 and Culley 3 were on outage*	26.167	232.87	$ 8,061.01	314.000	87.01	YES	100	-	$ 34.62	$ -
45.13	08/12/2025	16	$ 23,993.91	320.540	$ 74.85	$ 14,464.37	$ 9,529.54	*all other units online*	44.950	275.59	$ 8,193.19	314.000	87.01	YES	100	-	$ 29.73	$ -
45.13	08/12/2025	17	$ 25,208.72	317.900	$ 79.30	$ 14,345.24	$ 10,863.48		53.000	264.90	$ 9,052.33	314.000	87.01	YES	100	-	$ 34.17	$ -
45.13	08/12/2025	18	$ 28,124.00	306.870	$ 91.65	$ 13,847.51	$ 14,276.49		55.604	251.27	$ 11,689.63	314.000	87.01	YES	100	-	$ 46.52	$ -
45.13	08/12/2025	19	$ 49,036.25	455.970	$ 107.54	$ 20,575.65	$ 28,460.60		81.838	374.13	$ 23,352.46	314.000	87.01	YES	100	60.13	$ 62.42	$ 563.00
45.13	08/12/2025	20	$ 39,240.09	428.740	$ 91.52	$ 19,346.89	$ 19,893.20		47.800	380.94	$ 17,675.32	314.000	87.01	YES	100	66.94	$ 46.40	$ 465.89
45.13	08/12/2025	21	$ 30,681.13	365.900	$ 83.85	$ 16,511.24	$ 14,169.89		73.517	292.38	$ 11,322.86	314.000	87.01	YES	100	-	$ 38.73	$ -
45.13	08/12/2025	22	$ 28,651.91	428.600	$ 66.85	$ 19,340.58	$ 9,311.34		157.913	270.69	$ 5,880.68	314.000	87.01	YES	100	-	$ 21.73	$ -
45.13	08/12/2025	23	$ 20,233.61	351.400	$ 57.58	$ 15,856.93	$ 4,376.69		217.646	133.75	$ 1,665.91	314.000	87.01	YES	100	-	$ 12.45	$ -
45.13	08/12/2025	24	$ 18,897.23	372.800	$ 50.69	$ 16,822.60	$ 2,074.63		280.909	91.89	$ 511.37	314.000	87.01	YES	100	-	$ 5.56	$ -
44.13	08/13/2025	11	$ 19,033.00	397.100	$ 47.93	$ 17,522.04	$ 1,510.96		372.571	24.53	$ 93.33	315.000	87.01	YES	100	-	$ 3.80	$ -
44.13	08/13/2025	12	$ 21,818.63	415.200	$ 52.55	$ 18,320.70	$ 3,497.93		334.000	81.20	$ 684.08	315.000	87.01	YES	100	-	$ 8.42	$ -
44.13	08/13/2025	13	$ 20,867.39	349.700	$ 59.67	$ 15,430.51	$ 5,436.88		198.000	151.70	$ 2,358.52	315.000	87.01	YES	100	-	$ 15.55	$ -
44.13	08/13/2025	14	$ 16,354.10	239.200	$ 68.37	$ 10,554.70	$ 5,799.40		88.100	151.10	$ 3,663.42	315.000	87.01	YES	100	-	$ 24.24	$ -
44.13	08/13/2025	15	$ 19,280.97	288.600	$ 66.81	$ 12,734.48	$ 6,546.50		88.333	200.27	$ 4,542.78	315.000	87.01	YES	100	-	$ 22.68	$ -
44.13	08/13/2025	16	$ 19,341.56	254.260	$ 76.07	$ 11,219.22	$ 8,122.34	*Culley 3 was on outage all other units*	63.725	190.54	$ 6,086.64	315.000	87.01	YES	100	-	$ 31.95	$ -
44.13	08/13/2025	17	$ 25,754.55	308.750	$ 83.42	$ 13,623.59	$ 12,130.96	*online*	27.000	281.75	$ 11,070.11	315.000	87.01	YES	100	-	$ 39.29	$ -
44.13	08/13/2025	18	$ 31,212.02	416.720	$ 74.90	$ 18,387.77	$ 12,824.25		61.900	354.82	$ 10,919.32	315.000	87.01	YES	100	39.82	$ 30.77	$ 183.81
44.13	08/13/2025	19	$ 45,134.11	609.860	$ 74.01	$ 26,910.07	$ 18,224.04		267.000	342.86	$ 10,245.46	315.000	87.01	YES	100	27.86	$ 29.88	$ 124.88
44.13	08/13/2025	20	$ 32,759.29	440.860	$ 74.31	$ 19,452.95	$ 13,306.34		95.208	345.65	$ 10,432.71	315.000	87.01	YES	100	30.65	$ 30.18	$ 138.77

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 08/31

Aug Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	11% of Summer Rated Capacity	Are Unit MWs Out of Service > 11% Summer Capacity?	Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
44.13	08/13/2025	21	$ 27,524.74	445.810	$ 61.74	$ 19,671.37	$ 7,853.37		97.217	348.59	$ 6,140.80	315.000	87.01	YES	100	33.59	$ 17.62	$ 88.77
44.13	08/13/2025	22	$ 28,464.37	605.110	$ 47.04	$ 26,700.48	$ 1,763.89		310.467	294.64	$ 858.88	315.000	87.01	YES	100	-	$ 2.91	$ -
43.94	08/14/2025	11	$ 20,315.66	455.100	$ 44.64	$ 19,996.18	$ 319.48		392.642	62.46	$ 43.84	314.000	87.01	YES	100	-	$ 0.70	$ -
43.94	08/14/2025	12	$ 27,432.31	560.600	$ 48.93	$ 24,631.64	$ 2,800.67		366.883	193.72	$ 967.78	314.000	87.01	YES	100	-	$ 5.00	$ -
43.94	08/14/2025	13	$ 22,649.13	430.800	$ 52.57	$ 18,928.49	$ 3,720.64		186.383	244.42	$ 2,110.93	314.000	87.01	YES	100	-	$ 8.64	$ -
43.94	08/14/2025	14	$ 20,756.30	340.100	$ 61.03	$ 14,943.31	$ 5,812.99		231.042	109.06	$ 1,864.02	314.000	87.01	YES	100	-	$ 17.09	$ -
43.94	08/14/2025	15	$ 24,696.81	428.700	$ 57.61	$ 18,836.22	$ 5,860.59		132.107	296.59	$ 4,054.61	314.000	87.01	YES	100	-	$ 13.67	$ -
43.94	08/14/2025	16	$ 29,457.14	420.100	$ 70.12	$ 18,458.35	$ 10,998.79	*Culley 3 was on outage and Brown 3 was on Reserve Shutdown*	91.363	328.74	$ 8,606.78	314.000	87.01	YES	100	14.74	$ 26.18	$ 57.88
43.94	08/14/2025	17	$ 21,430.55	311.400	$ 68.82	$ 13,682.29	$ 7,748.26		173.279	138.12	$ 3,436.73	314.000	87.01	YES	100	-	$ 24.88	$ -
43.94	08/14/2025	18	$ 22,975.50	327.800	$ 70.09	$ 14,402.88	$ 8,572.62		160.791	167.01	$ 4,367.62	314.000	87.01	YES	100	-	$ 26.15	$ -
43.94	08/14/2025	19	$ 39,294.94	549.900	$ 71.46	$ 24,161.51	$ 15,133.43		124.283	425.62	$ 11,713.12	314.000	87.01	YES	100	111.62	$ 27.52	$ 460.76
43.94	08/14/2025	20	$ 36,596.91	540.600	$ 67.70	$ 23,752.88	$ 12,844.03		91.383	449.22	$ 10,672.87	314.000	87.01	YES	100	135.22	$ 23.76	$ 481.89
43.94	08/14/2025	21	$ 42,474.47	639.300	$ 66.44	$ 28,089.56	$ 14,384.91		194.029	445.27	$ 10,019.05	314.000	87.01	YES	100	131.27	$ 22.50	$ 443.06
43.94	08/14/2025	22	$ 31,267.22	695.600	$ 44.95	$ 30,563.27	$ 703.95		352.430	343.17	$ 347.29	314.000	87.01	YES	100	29.17	$ 1.01	$ 4.43
42.13	08/15/2025	11	$ 22,884.25	512.640	$ 44.64	$ 21,594.96	$ 1,289.29		357.567	155.07	$ 390.01	314.000	87.01	YES	100	-	$ 2.52	$ -
42.13	08/15/2025	12	$ 68,371.49	322.110	$ 212.26	$ 13,568.88	$ 54,802.61		369.000	-	$ -	49.000	87.01	NO	85	-	$ 170.14	$ -
42.13	08/15/2025	13	$ 4,626.51	80.340	$ 57.59	$ 3,384.32	$ 1,242.19		388.129	-	$ -	49.000	87.01	NO	85	-	$ 15.46	$ -
42.13	08/15/2025	14	$ 13,943.20	297.590	$ 46.85	$ 12,535.98	$ 1,407.22		272.683	24.91	$ 117.78	49.000	87.01	NO	85	24.91	$ 4.73	$ 17.67
42.13	08/15/2025	15	$ 13,905.57	213.990	$ 64.98	$ 9,014.33	$ 4,891.24		161.392	52.60	$ 1,202.25	49.000	87.01	NO	85	52.60	$ 22.86	$ 180.34
42.13	08/15/2025	16	$ 12,969.91	192.400	$ 67.41	$ 8,104.85	$ 4,865.06		133.796	58.60	$ 1,481.87	49.000	87.01	NO	85	58.60	$ 25.29	$ 222.28
42.13	08/15/2025	17	$ 18,686.97	172.670	$ 108.22	$ 7,273.72	$ 11,413.25	*All units online load greater than generation*	92.987	79.68	$ 5,266.94	49.000	87.01	NO	85	79.68	$ 66.10	$ 790.04
42.13	08/15/2025	18	$ 18,669.00	176.900	$ 105.53	$ 7,451.91	$ 11,217.09		89.108	87.79	$ 5,566.82	44.000	87.01	NO	85	87.79	$ 63.41	$ 835.02
42.13	08/15/2025	19	$ 25,423.77	230.500	$ 110.30	$ 9,709.81	$ 15,713.96		60.004	170.50	$ 11,623.28	44.000	87.01	NO	85	170.50	$ 68.17	$ 1,743.49
42.13	08/15/2025	20	$ 16,542.39	222.530	$ 74.34	$ 9,374.08	$ 7,168.31		89.158	133.37	$ 4,296.29	44.000	87.01	NO	85	133.37	$ 32.21	$ 644.44
42.13	08/15/2025	21	$ 12,403.81	177.400	$ 69.92	$ 7,472.98	$ 4,930.84		139.138	38.26	$ 1,063.49	44.000	87.01	NO	85	38.26	$ 27.80	$ 159.52
42.13	08/15/2025	22	$ 14,442.10	267.100	$ 54.07	$ 11,251.59	$ 3,190.51		259.900	7.20	$ 86.00	44.000	87.01	NO	85	7.20	$ 11.95	$ 12.90
42.13	08/15/2025	23	$ 17,639.56	417.900	$ 42.21	$ 17,604.04	$ 35.52		422.783	-	$ -	44.000	87.01	NO	85	-	$ 0.09	$ -
44.63	08/16/2025	14	$ 1,163.42	17.700	$ 65.73	$ 789.86	$ 373.56		95.792	-	$ -	27.000	87.01	NO	85	-	$ 21.10	$ -
44.63	08/16/2025	15	$ 3,262.60	68.110	$ 47.90	$ 3,039.41	$ 223.19		61.083	7.03	$ 23.03	27.000	87.01	NO	85	7.03	$ 3.28	$ 3.45
44.63	08/16/2025	16	$ 1,097.96	13.900	$ 78.99	$ 620.29	$ 477.67		53.000	-	$ -	37.000	87.01	NO	85	-	$ 34.36	$ -
44.63	08/16/2025	17	$ 5,591.69	96.410	$ 58.00	$ 4,302.30	$ 1,289.39		50.000	46.41	$ 620.69	37.000	87.01	NO	85	46.41	$ 13.37	$ 93.10
44.63	08/16/2025	18	$ 8,728.28	132.560	$ 65.84	$ 5,915.49	$ 2,812.79	*All units online load greater than generation*	39.000	93.56	$ 1,985.25	37.000	87.01	NO	85	93.56	$ 21.22	$ 297.79
44.63	08/16/2025	19	$ 10,439.16	88.400	$ 118.09	$ 3,944.85	$ 6,494.31		54.833	33.57	$ 2,466.00	37.000	87.01	NO	85	33.57	$ 73.47	$ 369.90
44.63	08/16/2025	20	$ 11,387.19	124.600	$ 91.39	$ 5,560.28	$ 5,826.92		62.000	62.60	$ 2,927.49	37.000	87.01	NO	85	62.60	$ 46.76	$ 439.12
44.63	08/16/2025	21	$ 12,499.00	187.620	$ 66.62	$ 8,372.54	$ 4,126.46		51.358	136.26	$ 2,996.91	37.000	87.01	NO	85	136.26	$ 21.99	$ 449.54
44.63	08/16/2025	22	$ 11,710.08	203.300	$ 57.60	$ 9,072.26	$ 2,637.82		156.200	47.10	$ 611.12	37.000	87.01	NO	85	47.10	$ 12.98	$ 91.67
44.63	08/17/2025	12	$ 7,749.53	165.200	$ 46.91	$ 7,372.05	$ 377.48		305.000	-	$ -	27.000	87.01	NO	85	-	$ 2.28	$ -
44.63	08/17/2025	13	$ 9,971.93	203.800	$ 48.93	$ 9,094.58	$ 877.36		253.545	-	$ -	27.000	87.01	NO	85	-	$ 4.30	$ -
44.63	08/17/2025	14	$ 11,406.85	224.500	$ 50.81	$ 10,018.31	$ 1,388.54		205.929	18.57	$ 114.86	27.000	87.01	NO	85	18.57	$ 6.19	$ 17.23
44.63	08/17/2025	15	$ 13,266.88	220.600	$ 60.14	$ 9,844.28	$ 3,422.61		171.333	49.27	$ 764.38	27.000	87.01	NO	85	49.27	$ 15.51	$ 114.66
44.63	08/17/2025	16	$ 12,098.28	198.170	$ 61.05	$ 8,843.34	$ 3,254.94		115.500	82.67	$ 1,357.86	27.000	87.01	NO	85	82.67	$ 16.43	$ 203.68
44.63	08/17/2025	17	$ 12,281.55	185.550	$ 66.19	$ 8,280.17	$ 4,001.38	*All units online load greater than generation*	76.992	108.56	$ 2,341.05	27.000	87.01	NO	85	108.56	$ 21.56	$ 351.16
44.63	08/17/2025	18	$ 15,121.53	196.690	$ 76.88	$ 8,777.29	$ 6,344.24		49.856	146.83	$ 4,736.13	27.000	87.01	NO	85	146.83	$ 32.26	$ 710.42
44.63	08/17/2025	19	$ 22,984.08	249.990	$ 91.94	$ 11,155.80	$ 11,828.28		44.400	205.59	$ 9,727.49	27.000	87.01	NO	85	205.59	$ 47.31	$ 1,459.12
44.63	08/17/2025	20	$ 20,020.77	321.000	$ 62.37	$ 14,324.63	$ 5,696.15		92.888	228.11	$ 4,047.85	27.000	87.01	NO	85	228.11	$ 17.75	$ 607.18
44.63	08/17/2025	21	$ 21,240.57	364.020	$ 58.35	$ 16,244.39	$ 4,996.18		160.546	203.47	$ 2,792.68	27.000	87.01	NO	85	203.47	$ 13.73	$ 418.90
44.63	08/17/2025	22	$ 15,792.43	347.010	$ 45.51	$ 15,485.32	$ 307.11		194.083	152.93	$ 135.34	27.000	87.01	NO	85	152.93	$ 0.89	$ 20.30
44.63	08/18/2025	12	$ 7,242.99	145.500	$ 49.78	$ 6,492.94	$ 750.05		309.333	-	$ -	48.000	87.01	NO	85	-	$ 5.16	$ -
44.63	08/18/2025	13	$ 6,912.71	119.000	$ 58.09	$ 5,310.38	$ 1,602.34		246.904	-	$ -	59.000	87.01	NO	85	-	$ 13.47	$ -
44.63	08/18/2025	14	$ 3,920.49	68.600	$ 57.15	$ 3,061.28	$ 859.22		212.738	-	$ -	59.000	87.01	NO	85	-	$ 12.53	$ -
44.63	08/18/2025	15	$ 3,272.25	49.700	$ 65.84	$ 2,217.86	$ 1,054.39		167.433	-	$ -	59.000	87.01	NO	85	-	$ 21.22	$ -
44.63	08/18/2025	16	$ 5,189.24	75.700	$ 68.55	$ 3,378.11	$ 1,811.13		177.575	-	$ -	59.000	87.01	NO	85	-	$ 23.93	$ -
44.63	08/18/2025	17	$ 7,948.71	96.500	$ 82.37	$ 4,306.31	$ 3,642.40	*All units online load greater than generation*	119.529	-	$ -	59.000	87.01	NO	85	-	$ 37.75	$ -
44.63	08/18/2025	18	$ 9,520.03	109.300	$ 87.10	$ 4,877.51	$ 4,642.52		103.659	5.64	$ 239.60	59.000	87.01	NO	85	5.64	$ 42.48	$ 35.94
44.63	08/18/2025	19	$ 25,881.31	195.570	$ 132.34	$ 8,727.31	$ 17,154.00		33.138	162.43	$ 14,247.37	59.000	87.01	NO	85	162.43	$ 87.71	$ 2,137.11
44.63	08/18/2025	20	$ 23,181.77	250.100	$ 92.69	$ 11,160.71	$ 12,021.06		72.975	177.13	$ 8,513.51	59.000	87.01	NO	85	177.13	$ 48.07	$ 1,277.03
44.63	08/18/2025	21	$ 16,208.55	218.150	$ 74.30	$ 9,734.94	$ 6,473.61		36.992	181.16	$ 5,375.87	59.000	87.01	NO	85	181.16	$ 29.68	$ 806.38
44.63	08/18/2025	22	$ 17,404.87	291.100	$ 59.79	$ 12,990.34	$ 4,414.53		204.213	86.89	$ 1,317.64	59.000	87.01	NO	85	86.89	$ 15.17	$ 197.65
44.50	08/19/2025	12	$ 6,024.12	119.550	$ 50.39	$ 5,319.98	$ 704.15		254.429	-	$ -	49.000	87.01	NO	85	-	$ 5.89	$ -
44.50	08/19/2025	13	$ 6,384.66	122.900	$ 51.95	$ 5,469.05	$ 915.61		313.546	-	$ -	49.000	87.01	NO	85	-	$ 7.45	$ -
44.50	08/19/2025	14	$ 7,298.25	131.500	$ 55.50	$ 5,851.75	$ 1,446.50		250.346	-	$ -	49.000	87.01	NO	85	-	$ 11.00	$ -
44.50	08/19/2025	15	$ 13,619.68	261.760	$ 52.03	$ 11,648.32	$ 1,971.36		188.667	73.09	$ 550.48	49.000	87.01	NO	85	73.09	$ 7.53	$ 82.57
44.50	08/19/2025	16	$ 12,096.78	200.920	$ 60.21	$ 8,940.94	$ 3,155.84	*All units online load greater than generation*	114.296	86.62	$ 1,360.60	49.000	87.01	NO	85	86.62	$ 15.71	$ 204.09
44.50	08/19/2025	17	$ 8,074.21	115.610	$ 69.84	$ 5,144.65	$ 2,929.57		21.444	94.17	$ 2,386.17	49.000	87.01	NO	85	94.17	$ 25.34	$ 357.93
44.50	08/19/2025	18	$ 10,177.44	160.790	$ 63.30	$ 7,155.16	$ 3,022.29		64.679	96.11	$ 1,806.55	49.000	87.01	NO	85	96.11	$ 18.80	$ 270.98
44.50	08/19/2025	19	$ 12,350.83	160.130	$ 77.13	$ 7,125.79	$ 5,225.05		111.891	48.24	$ 1,574.04	49.000	87.01	NO	85	48.24	$ 32.63	$ 236.11
44.50	08/19/2025	20	$ 3,845.08	60.070	$ 64.01	$ 2,673.12	$ 1,171.97		50.721	9.35	$ 182.40	49.000	87.01	NO	85	9.35	$ 19.51	$ 27.36
44.50	08/19/2025	21	$ 6,726.52	120.720	$ 55.72	$ 5,372.04	$ 1,354.48		141.708	-	$ -	49.000	87.01	NO	85	-	$ 11.22	$ -

CenterPoint Energy Indiana South
Market Settlements Group
Purchased Power Over Benchmark Explanations Cause No. 38708 FAC 149

S55's through 08/31

Aug Benchmark Costs	Trade Date	HE	Cost of Purchased Power	Purchases Volume	Price	Purchases Volume @ Benchmark $	Amount Over Benchmark $	Reason for Purchasing Power	Available Capacity of Units Not Selected	MISO Economic Dispatch / Purchased MWs above Capacity	Purchase Power Costs at Risk	Test for Outages and Derates: MWs Out of Service	Test for Outages and Derates: 11% of Summer Rated Capacity	Test for Outages and Derates: Are Unit MWs Out of Service > 11% Summer Capacity?	Test for Outages and Derates: Recoverable @ 0%, 85%, or 100%	MWs Subject to 85% 15%	Over Benchmark Price	Total Unrecoverable Dollars
43.25	08/20/2025	9	$ 10,396.08	46.250	$ 224.78	$ 2,000.31	$ 8,395.77		448.800	-	$ -	49.000	87.01	NO	85	-	$ 181.53	$ -
43.25	08/20/2025	10	$ 1,037.36	22.280	$ 46.56	$ 963.61	$ 73.75	*Brown 3 Brown 4 Brown 6 and Culley 2 were on Reserve Shutdown*	454.417	-	$ -	49.000	87.01	NO	85	-	$ 3.31	$ -
43.25	08/20/2025	19	$ 17,682.56	328.550	$ 53.82	$ 14,209.79	$ 3,472.77		446.792	-	$ -	49.000	87.01	NO	85	-	$ 10.57	$ -
43.25	08/20/2025	20	$ 19,083.91	418.140	$ 45.64	$ 18,084.56	$ 999.35		450.333	-	$ -	44.000	87.01	NO	85	-	$ 2.39	$ -
42.56	08/21/2025	14	$ 12,945.95	301.700	$ 42.91	$ 12,841.26	$ 104.69		475.237	-	$ -	42.000	87.01	NO	85	-	$ 0.35	$ -
42.56	08/21/2025	15	$ 13,268.50	297.300	$ 44.63	$ 12,653.98	$ 614.52		440.009	-	$ -	42.000	87.01	NO	85	-	$ 2.07	$ -
42.56	08/21/2025	16	$ 4,332.87	93.000	$ 46.59	$ 3,958.36	$ 374.51		312.925	-	$ -	42.000	87.01	NO	85	-	$ 4.03	$ -
42.56	08/21/2025	17	$ 5,223.62	105.400	$ 49.56	$ 4,486.14	$ 737.48	*Brown 3 Brown 4 and Culley 2 were on Reserve Shutdown*	315.888	-	$ -	42.000	87.01	NO	85	-	$ 7.00	$ -
42.56	08/21/2025	18	$ 7,754.59	145.900	$ 53.15	$ 6,209.94	$ 1,544.65		273.000	-	$ -	42.000	87.01	NO	85	-	$ 10.59	$ -
42.56	08/21/2025	19	$ 14,853.63	214.400	$ 69.28	$ 9,125.51	$ 5,728.12		300.954	-	$ -	42.000	87.01	NO	85	-	$ 26.72	$ -
42.56	08/21/2025	20	$ 13,946.48	231.400	$ 60.27	$ 9,849.08	$ 4,097.40		291.346	-	$ -	42.000	87.01	NO	85	-	$ 17.71	$ -
42.56	08/21/2025	21	$ 12,062.00	222.300	$ 54.26	$ 9,461.75	$ 2,600.25		311.179	-	$ -	42.000	87.01	NO	85	-	$ 11.70	$ -
42.56	08/21/2025	22	$ 17,921.50	400.570	$ 44.74	$ 17,049.46	$ 872.04		455.746	-	$ -	42.000	87.01	NO	85	-	$ 2.18	$ -
43.50	08/22/2025	15	$ 13,173.33	295.300	$ 44.61	$ 12,845.55	$ 327.78		434.158	-	$ -	44.000	87.01	NO	85	-	$ 1.11	$ -
43.50	08/22/2025	16	$ 4,847.68	100.200	$ 48.38	$ 4,358.70	$ 488.98		287.000	-	$ -	44.000	87.01	NO	85	-	$ 4.88	$ -
43.50	08/22/2025	17	$ 6,135.48	119.600	$ 51.30	$ 5,202.60	$ 932.88		286.000	-	$ -	44.000	87.01	NO	85	-	$ 7.80	$ -
43.50	08/22/2025	18	$ 8,441.24	154.800	$ 54.53	$ 6,733.80	$ 1,707.44	*Brown 3 Brown 4 and Culley 2 were on Reserve Shutdown*	294.229	-	$ -	44.000	87.01	NO	85	-	$ 11.03	$ -
43.50	08/22/2025	19	$ 11,289.28	177.700	$ 63.53	$ 7,729.95	$ 3,559.33		268.000	-	$ -	44.000	87.01	NO	85	-	$ 20.03	$ -
43.50	08/22/2025	20	$ 13,512.00	240.000	$ 56.30	$ 10,440.00	$ 3,072.00		273.196	-	$ -	44.000	87.01	NO	85	-	$ 12.80	$ -
43.50	08/22/2025	21	$ 11,326.76	231.300	$ 48.97	$ 10,061.55	$ 1,265.21		336.625	-	$ -	44.000	87.01	NO	85	-	$ 5.47	$ -
42.38	08/23/2025	19	$ 19,631.29	401.540	$ 48.89	$ 17,015.26	$ 2,616.03	*Brown 3 Brown 4 Brown 6 and Culley 2 were on Reserve Shutdown*	464.425	-	$ -	44.000	87.01	NO	85	-	$ 6.51	$ -
42.38	08/23/2025	20	$ 17,406.98	380.730	$ 45.72	$ 16,133.43	$ 1,273.55		457.000	-	$ -	44.000	87.01	NO	85	-	$ 3.35	$ -
42.38	08/23/2025	21	$ 16,492.25	369.450	$ 44.64	$ 15,655.44	$ 836.81		459.042	-	$ -	44.000	87.01	NO	85	-	$ 2.27	$ -
42.38	08/24/2025	20	$ 13,945.92	313.110	$ 44.54	$ 13,268.04	$ 677.88	*Brown 3 Brown 4 Brown 6 and Culley 2 were on Reserve Shutdown*	466.000	-	$ -	35.000	87.01	NO	85	-	$ 2.17	$ -
42.38	08/25/2025	19	$ 14,101.28	286.030	$ 49.30	$ 12,120.52	$ 1,980.76	*Brown 3 Brown 4 Brown 6 and Culley 2 were on Reserve Shutdown*	459.000	-	$ -	32.000	87.01	NO	85	-	$ 6.93	$ -
42.38	08/25/2025	20	$ 16,151.52	336.000	$ 48.07	$ 14,238.00	$ 1,913.52		459.000	-	$ -	32.000	87.01	NO	85	-	$ 5.70	$ -
42.75	08/27/2025	19	$ 10,156.49	224.950	$ 45.15	$ 9,616.61	$ 539.88	*Brown 3 Brown 4 Brown 6 were on Reserve Shutdown Culley 2 was on outage*	505.000	-	$ -	128.000	113.52	YES	100	-	$ 2.40	$ -
43.44	08/28/2025	19	$ 30,309.74	123.170	$ 246.08	$ 5,350.26	$ 24,959.48	*Brown 3 Brown 4 and Brown 6 were on Reserve Shutdown*	396.537	-	$ -	33.000	113.52	NO	85	-	$ 202.64	$ -
43.69	08/29/2025	15	$ 1,666.51	25.350	$ 65.74	$ 1,107.49	$ 559.02	*Brown 3 Brown 4 and Brown 6 were on Reserve Shutdown*	372.000	-	$ -	29.000	113.52	NO	85	-	$ 22.05	$ -
43.69	08/29/2025	19	$ 3,693.75	78.930	$ 46.80	$ 3,448.29	$ 245.46		386.003	-	$ -	50.000	113.52	NO	85	-	$ 3.11	$ -
43.69	08/29/2025	20	$ 4,100.21	88.500	$ 46.33	$ 3,866.39	$ 233.82		416.712	-	$ -	50.000	113.52	NO	85	-	$ 2.64	$ -
43.69	08/30/2025	19	$ 9,013.28	197.400	$ 45.66	$ 8,624.01	$ 389.27	*All Brown units and Culley 2 were on Reserve Shutdown*	757.104	-	$ -	49.000	113.52	NO	85	-	$ 1.97	$ -
43.69	08/31/2025	19	$ 11,484.76	256.700	$ 44.74	$ 11,214.71	$ 270.05	*All Brown units and Culley 2 were on Reserve Shutdown*	733.396	-	$ -	49.000	113.52	NO	85	-	$ 1.05	$ -
Total			**$ 4,561,220.41**	**67,507.510**		**$ 3,004,229.35**	**$ 1,556,991.21**		**47,268.271**	**32,799.783**	**$ 962,436.40**	**51,553.000**				**4,677.307**		**$ 22,969.90**

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 57
2026 EPA IN Haze SIP Approval

EPA Regional Administrator, Anne Vogel, signed the following document on 1/6/2026, and EPA is submitting it for publication in the *Federal Register* (FR). EPA is providing this document solely for the convenience of interested parties. While we have taken steps to ensure the accuracy of this version of the document, the official version will be published in a forthcoming FR publication, which will appear on the Government Printing Office's govinfo website (https://www.govinfo.gov/app/collection/fr) and on Regulations.gov (https://www regulations.gov) in Docket No. EPA-R05-OAR-2021-0963

6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA-R05-OAR-2021-0963; FRL-12589-02-R5]

Air Plan Approval; Indiana; Regional Haze Plan for the Second Implementation Period

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) is approving the Regional Haze State Implementation Plan (SIP) revision for Indiana submitted by the Indiana Department of Environmental Management (IDEM or Indiana) on December 29, 2021, as satisfying applicable requirements under the Clean Air Act (CAA) and EPA's Regional Haze Rule (RHR) for the program's second implementation period. Indiana's SIP submission addresses the requirement that States must periodically revise their long-term strategies for making reasonable progress towards the national goal of preventing any future, and remedying any existing, anthropogenic impairment of visibility, including regional haze, in mandatory Class I Federal areas. Indiana's SIP submission also addresses other applicable requirements for the second implementation period of the regional haze program. EPA is taking this action pursuant to sections 110 and 169A of the CAA.

DATES: This final rule is effective on **[insert date 30 days**

after date of publication in the *Federal Register*].

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA-R05-OAR-2021-0963. All documents in the docket are listed on the *https://www.regulations.gov* web site. Although listed in the index, some information is not publicly available, i.e., Confidential Business Information (CBI), Proprietary Business Information (PBI), or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either through *https://www.regulations.gov* or at the Environmental Protection Agency, Region 5, Air and Radiation Division, 77 West Jackson Boulevard, Chicago, Illinois 60604. This facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding Federal holidays. We recommend that you telephone Charles Hatten, Environmental Engineer, at (312) 886-6031 before visiting the Region 5 office.

FOR FURTHER INFORMATION CONTACT: Charles Hatten, Air and Radiation Division (AR-18J), Environmental Protection Agency, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604, (312) 886-6031, *hatten.charles@epa.gov*.

SUPPLEMENTARY INFORMATION: Throughout this document whenever "we," "us," or "our" is used, we mean EPA.

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I. Background

On December 29, 2021, IDEM submitted a revision to its SIP to address regional haze requirements for the second implementation period. IDEM made this SIP submission to satisfy the requirements of the CAA's regional haze program pursuant to CAA sections 169A and 169B and 40 CFR 51.308.

On June 18, 2025 (90 FR 25944), EPA proposed to approve the Indiana regional haze SIP revision. In the notice of proposed rulemaking (NPRM), EPA proposed to find that Indiana's Regional Haze SIP submission satisfied the regional haze requirements for the second implementation period contained in 40 CFR 51.308(f). As described further in EPA's proposed approval, IDEM utilized

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technical analyses and its source selection methodology to target the sources with the highest potential to impair visibility at mandatory Class I areas.[1] IDEM's initial list of twenty candidate sources for a four-factor analysis represented the majority of Indiana's emissions that may influence visibility impacts on out-of-state Class I areas. IDEM further refined that list by excluding eleven electric generating units (EGUs) that either had existing effective controls or that were not expected to continue operating beyond 2028. IDEM then proceeded with site-specific four-factor analyses for the remining nine non-EGU facilities identified through this process. A detailed analysis of Indiana's plan and EPA's evaluation are contained in the NPRM, dated June 18, 2025 (90 FR 25944), as well as the Technical Support Document (TSD), dated April 22, 2025, and will not be restated here.

II. Public Comment Process

The public review and comment period on EPA's NPRM opened June 18, 2025, and was originally scheduled to close on July 18, 2025. On June 26, 2025, EPA received a comment letter from the National Parks Conservation Association, the Coalition to Protect America's National Parks, and the Sierra Club (Comment 1) requesting that EPA provide an additional 30 days for public

[1] There are no Class I areas in Indiana. However, the RHR requires SIPs to address Class I areas located outside the state that may be affected by emissions from within the state.

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comment on the NPRM. On July 16, 2025 (90 FR 31923), EPA published a NPRM extending the public review and comment period to August 18, 2025.

During the review and comment period, EPA received relevant comments from the following individuals, businesses, agencies, and organizations: an individual identified as Kurtis K. (Comment 2); three anonymous commenters (Comments 3, 4, and 5); IDEM (Comment 6); Power Generators Air Coalition (Comment 7); Ameren Missouri, American Electric Power Company, Inc. on behalf of its operating companies, and Nebraska Public Power District (collectively referred as the "Utilities for Reasonable Progress") (Comment 8); Ohio Valley Electric Corporation (OVEC) and Indiana-Kentucky Electric Corporation (IKEC) (Comment 9); Abrams Environmental Law Clinic, Artists for Environmental Restoration, Inc., Citizens Climate Lobby – Evansville Chapter, Conservation Law Center, Environmental Advocacy Center at the Northwestern Pritzker School of Law, Faith in Place, Hessville Dune Dusters, Izaak Walton League – Indiana Division, Izaak Walton League – Porter County Chapter, Just Transition Northwest Indiana, National Parks Conservation Association, Owen-Putnam Friends of the Forest, Save the Dunes, Sierra Club – Hoosier Chapter, and Tri-State Creation Care (collectively referred to as "Community Organizations") (Comment 10); Mid-Atlantic/Northeast Visibility Union (MANEVU) regional planning

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organization (Comment 11); and National Parks Conservation Association, Sierra Club, Environmental Law & Policy Center, Coalition to Protect America's National Parks, Conservation Law Center, Save the Dunes, and the Indiana Division of the Izaak Walton League of America (collectively referred to as the "Conservation Groups") (Comments 12 through 23).

III. Summary of Public Comments and EPA's Responses

A. Comments Received

All comments received are included in the rulemaking docket for this action. In the December 19, 2025, Response to Comments document (RTC), which is included in the docket for this rulemaking, EPA provides summaries of and detailed responses to all significant comments that further explain the basis for our final action.

In addition to the request to extend the public comment period, EPA received comments on the NPRM addressing several topics including, but not limited to, additional emissions monitoring, increased public engagement, climate resilience, visibility trends, public health, economic benefits, enforceability of retirements, existing effective controls, four-factor analyses,[2] cost considerations, Best Available

[2] Under CAA 169A(g)(1), the four statutory factors are the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources. See also 40 CFR 51.308(f)(2)(i). An evaluation of potential control options for sources of visibility impairing

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Retrofit Technology (BART), and impacts on local communities. Additionally, EPA received several comments regarding EPA's URP policy.[3]

EPA acknowledges the seven comments that were generally supportive of the proposed action and EPA's URP policy from Kurtis K. (Comment 2), two anonymous commenters (Comments 3 – 4), IDEM (Comment 6); PGen (Comment 7), Utilities for Reasonable Progress (Comment 8), as well as OVEC and IKEC (Comment 9). Comments received from the Community Organizations, MANEVU, and the Conservation Groups were generally opposed to EPA's proposed action: Comments 10 - 23. The comments, while summarized below, are available in full in the docket for this rulemaking and are addressed in EPA's December 19, 2025, RTC. The comments and EPA's responses summarized here are divided into two sections for those that are and are not specific to EPA's URP policy.

B. Comments and Responses that are not specific to EPA's URP Policy

Comment and Response 2: Comments from Kurtis K., while supportive of EPA's proposed action, suggested additional emissions monitoring at three facilities and increased public

pollutants based on applying the four statutory factors in CAA section 169A(g)(1) is referred to as a "four-factor" analysis.

[3] A change in Agency policy was introduced in the approval of West Virginia's regional haze plan. See the April 18, 2025, (90 FR 16478) proposed rule) and the July 7, 2025, (90 FR 29737) final rule.

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engagement.

As addressed in the RTC, EPA notes that the type of emissions monitoring suggested is already provided for in the federally enforceable title V permits and considered in the visibility modeling efforts for the three facilities mentioned in the comment. As to providing for public engagement after SIP implementation, EPA notes that the RHR provides for public comment on SIP revisions and the progress of the SIP, generally every five years.

Comments and Responses 3, 4, 6, 7, 8, and 9: Comments received from two anonymous commenters, IDEM, PGen, Utilities for Reasonable Progress, as well as OVEC and IKEC supported EPA's proposed action. EPA acknowledges their support for EPA's proposed approval.

Comment and Response 10: The Community Organizations asserted that EPA's proposed approval will allow pollution to continue harming the air quality, public health, and economy of local and national parks and communities.

As addressed in the RTC, Indiana has taken appropriate steps to reduce pollution that affects air quality in the affected Class I areas, including meaningful sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emission reductions since the beginning of the second implementation period in 2019. Most of these emissions reductions have already occurred during the second

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implementation period and will continue to improve visibility in all Class I areas affected by emissions from Indiana. EPA notes that the visibility program prescribed by CAA sections 169A and 169B and implemented in 40 CFR 51.308 is not a public health-based program, and impacts on park tourism and local economies are not considerations within the Regional Haze statute or rule.

Comment and Response 11: MANEVU raised several items for EPA's consideration relating to changing circumstances since the time that MANEVU sent its "Asks" to Indiana on November 5, 2021, during the State's regional haze planning efforts. MANEVU observed that the Lake Michigan Air Directors Consortium (LADCO) has documented that modeled levels of nitrate in the winter have apparently been underestimated, and that declining trends in visibility impairment appear to have "flattened" in recent years. As a result, MANEVU asserted that additional measures will be needed in the future "to reinvigorate robust visibility improvements."

As discussed in the RTC, EPA provides further explanation of LADCO's modeling and notes that MANEVU did not address a specific regulation or provision in question or recommend a different action on Indiana's 2021 SIP submission from what EPA proposed.

Comment and Response 12: The Conservation Groups assert that reducing haze pollution from Indiana facilities will

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improve visibility in Class I areas[4] and result in economic, public health, and environmental benefits.

As addressed in the RTC, concerns regarding public health, park visitation, and local economies are not considerations within the Regional Haze statute or rule.

Comment and Response 13: The Conservation Groups argue that EPA's proposal to approve the Indiana SIP Revision violates the CAA and RHR. In this regard, the Conservation Groups assert: (a) that EPA's reliance on permit limits and consent decrees, past emission reductions, and ongoing emission reductions to approve Indiana's 2021 SIP Revision is arbitrary and capricious; and (b) that Indiana failed to include federally enforceable measures in the 2021 SIP Revision for source retirements.

As detailed in the RTC, EPA disagrees with the Conservation Groups' assertions. Indiana did not rely on any planned EGU retirements, past emission reductions, reductions in utilization, or ongoing emission reductions that are not already federally enforceable as necessary to make reasonable progress in the second implementation period. As such, Indiana did not request any additional measures for the second implementation

[4] Areas statutorily designated as mandatory Class I Federal areas consist of national parks exceeding 6,000 acres, wilderness areas and national memorial parks exceeding 5,000 acres, and all international parks that were in existence on August 7, 1977. CAA 162(a). There are 156 mandatory Class I areas. The list of areas to which the requirements of the visibility protection program apply is in 40 CFR part 81, subpart D. Class I Federal areas are hereinafter referred to as "Class I areas".

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period be incorporated into the regulatory portion of Indiana's SIP at 40 CFR 52.770.

Comment and Response 14: The Conservation Groups assert that Indiana unreasonably refused to conduct four-factor analyses for sources that the State claimed are effectively controlled. The Conservation Groups argue that neither the CAA nor the RHR allows States to eliminate sources from the four-factor statutory analysis on the basis that they are effectively controlled. The Conservation Groups contend that Indiana's demonstrations of existing effective controls are flawed and that reasonable controls or upgrades are available for these facilities at some of the State's largest sources of regional haze-causing emissions, including Duke – Gibson, Alcoa – Warrick Power Plant, AEP – Rockport, IKEC – Clifty Creek, and Duke – Cayuga.

As further discussed in the RTC, EPA addresses this comment as well as comments regarding each of these five facilities below under Comments and Responses 14a to 14f, respectively.

Comment and Response 14a: **Existing Effective Control Demonstrations.** As described in more detail in the RTC, EPA disagrees with the notion that CAA sections 169A(b)(2) and (g)(1) and the RHR prohibit States from foregoing a four-factor analysis based on a State determination that a source is effectively controlled. As outlined in the 2017 RHR preamble,

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"the EPA has consistently interpreted the CAA to provide States with the flexibility to conduct four-factor analyses for specific sources, groups of sources or even entire source categories, depending on State policy preferences and the specific circumstances of each State."[5] However, within the bounds of the flexibility afforded to States, EPA also stated that States must "exercise reasoned judgment when choosing which sources, groups of sources or source categories to analyze."[6] In the 2019 Guidance, section 3(f), EPA explained when it may be appropriate to forgo a four-factor analysis for sources with existing effective control measures and provided examples where a full four-factor analysis would likely result in the conclusion that no further controls are necessary.[7] EPA evaluated Indiana's Regional Haze SIP submission and concludes that IDEM's source selection methodology, thresholds, and justification for not conducting a four-factor analysis on all sources for this second implementation period are reasonable. EPA also concludes that IDEM sufficiently demonstrated that the sources selected for further evaluation at the facilities listed

[5] 82 FR 3088, January 10, 2017.
[6] 82 FR 3088, January 10, 2017.
[7] *See* section 3(f) of EPA's "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," EPA Office of Air Quality Planning and Standards, Research Triangle Park, August 20, 2019 (2019 Guidance) which is publicly available at *https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf.*

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under this comment below are effectively controlled for the second implementation period.

***Comment and Response 14b*: Duke – Gibson.** The Conservation Groups assert that excluding Duke – Gibson Unit 5 from LADCO's emissions projections in the 2028 visibility modeling was arbitrary and unlawful since there is no legal requirement preventing the unit from continuing to operate beyond 2028. The Conservation Groups further state that the existing NO_X and SO_2 emission controls on Duke – Gibson Units 1, 2, 3, 4, and 5 are underperforming and that upgrades to the existing controls would likely be feasible and cost-effective.

As described in further detail in the RTC, EPA disagrees with this comment and notes that the assumptions used in modeling future projections were based on the best available information at the time. Although there is no current legal obligation for Unit 5 to retire, EPA continues to find that IDEM has sufficiently demonstrated that Units 1, 2, 3, 4, and 5 are effectively controlled for the second implementation period and that a four-factor analysis would not likely result in the conclusion that further controls are necessary for reasonable progress. In this regard, consistent with the 2019 Guidance, IDEM showed that the SO_2 emission rates for all units are below the 2012 Mercury and Air Toxics Standards (MATS) for coal-fired EGUs. Additionally, NO_X emission rates are below the 0.08 pounds

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per million metric British thermal units (lbs/MMBtu) level for EGUs with optimized selective catalytic reduction (SCR) under the Revised Cross-State Air Pollution Rule (CSAPR) Update,[8] flue gas desulfurization (FGD) control efficiencies are greater than 90 percent, and SCR control efficiencies are greater than 80 percent.

***Comment and Response 14c*: Alcoa – Warrick Power Plant.** The Conservation Groups argue that Indiana should conduct a four-factor analysis on Alcoa – Warrick Power Plant's Units 1, 2, 3, and 4.

As described in further detail in the RTC, EPA disagrees with this comment and notes that IDEM has sufficiently demonstrated that Alcoa – Warrick Power Plant Units 1, 2, 3 and 4 are effectively controlled for the second implementation period. All four units are subject to BART emission limitations from the first implementation period on a pollutant-specific basis and continue to operate BART controls. Thus, as described in the 2019 Guidance, although BART-eligible sources should not be categorically excluded from further analysis in each planning period, the source is currently operating controls to meet BART emission limits, and it is unlikely that there will be further available reasonable controls. Based on the information

[8] *See* 86 FR 23054, 23088, April 30, 2021.

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provided in Indiana's SIP submission and the BART analysis, IDEM appropriately demonstrated that a full four-factor analysis would likely result in the conclusion that no further controls are necessary.

***Comment and Response 14d:* AEP – Rockport.** The Conservation Groups state that the existing NO_X and SO_2 emission controls on AEP – Rockport Units 1 and 2 are underperforming and that a four-factor analysis should have been performed.

As further explained in the RTC, EPA disagrees with this comment and maintains that IDEM has sufficiently demonstrated that AEP - Rockport MB1 and MB2 are effectively controlled for the second implementation period. In this regard, as described in the 2019 Guidance, IDEM showed that with the recent installation of enhanced dry sorbent injection (DSI) and SCR on MB2, the SO_2 emission rates for both boilers are below the 0.2 lbs/MMBtu level for coal-fired EGUs in the 2012 MATS, and NO_X emission rates are below the 0.08 lbs/MMBtu level for units with SCR under the Revised CSAPR Update.

***Comment and Response 14e*: IKEC – Clifty Creek.** The Conservation Groups argue that additional cost-effective NO_X and SO_2 emission controls are likely to exist for IKEC – Clifty Creek's six EGUs and that a four-factor analysis should have been performed.

As described in greater detail in the RTC, EPA disagrees

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with this comment and maintains that IDEM has sufficiently demonstrated that IKEC - Clifty Creek Units 1 – 6 are effectively controlled for the second implementation period as described in the 2019 Guidance, with FGDs achieving 98 percent SO_2 control efficiency, SCRs and overfire air achieving 70-90 percent NO_X control on an annual basis, and actual SO_2 emission rates for all six units below the 2012 MATS level for coal-fired EGUs. Additionally, IDEM has thoroughly documented NO_X emissions that are progressively constrained on an annual basis under the Revised CSAPR Update Rule and the lack of potential controls for NO_X that IDEM considers cost-effective.

Comment and Response 14f: **Duke – Cayuga.** The Conservation Groups argue that Indiana should be required to conduct a four-factor analysis on Duke – Cayuga's two coal-fired EGUs Units 2 and 3 and that cost-effective options for additional NO_X emission controls would likely be cost-effective.

As explained in greater detail in the RTC, EPA disagrees with this comment and maintains that IDEM has sufficiently demonstrated that Duke – Cayuga Units 2 and 3 are effectively controlled for the second implementation period. In this regard, as described in the 2019 Guidance, IDEM documented FGD systems achieving 95 percent control efficiency, SO_2 rates that are below MATS for coal fired units, and NO_X emissions that are controlled by low-NOx burners with separated over fire air and

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SCR achieving 88 percent control efficiency.

Comment and Response 15: The Conservation Groups contend that EPA neglected its duty to review Indiana's source-specific four-factor analyses. The Conservation Groups also argue that IDEM did not rigorously analyze controls that the Conservation Groups maintain are likely cost effective and, in so doing, did not appropriately require additional control measures for any of the nine sources IDEM evaluated to reduce emissions to make reasonable progress. The nine sources include: (a) Lone Star Industries, Inc. – Greencastle dba Buzzi Unicem USA; (b) Cleveland-Cliffs Steel, LLC – Indiana Harbor East and Indiana Harbor West; (c) Cleveland-Cliffs Steel, LLC – Burns Harbor; (d) U.S. Steel – Gary Works; (e) SABIC Innovative Plastics – Mt. Vernon, LLC; (f) Warrick Newco LLC, formerly Alcoa Warrick Operations, LLC; (g) Cokenergy, LLC; and (h) Heidleberg Materials US Cement LLC – Mitchell Plant, formerly Lehigh Cement Company, LLC – Mitchell Plant.

As further explained in the RTC and as outlined in our NPRM and April 22, 2025, TSD, EPA carefully evaluated Indiana's 2021 SIP submission along with the comments from the Federal Land Managers (FLMs) consultation and the State's public notice period, as well as the State's responses to those comments. Based on the complete record, EPA explained its decision to approve the SIP and took comment on the proposed approval in the

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NPRM. EPA recognizes that IDEM worked directly with the sources to conduct extensive site-specific technical work and provide full documentation in support of its 2021 SIP to submit complete four-factor analyses evaluating potential feasible and reasonable control measures. In the NPRM and April 22, 2025, TSD, EPA documented the existing controls, permit limitations, control options, potential reductions, and potential costs for new controls that the State relied upon in its four-factor analyses. In making its determinations, IDEM properly considered the four statutory factors along with projected 2028 visibility conditions for Class I areas influenced by emissions from Indiana sources, emission reductions that have occurred, and current control technologies in concluding no additional controls were necessary to make reasonable progress.

Comment and Response 15a: **Lone Star Industries, Inc. – Greencastle dba Buzzi Unicem USA.** The Conservation Groups state that IDEM's four-factor analysis should have also evaluated SCR and lacked documentation with the consideration of selective non-catalytic reduction for the remaining useful life and interest rate in the cost calculations. The Conservation Groups also contend that Indiana reached its conclusions before the FLM consultation period and the public comment period.

As explained in detail in the RTC, EPA disagrees and notes that IDEM did consider SCR in determining feasible control

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options. For each control option evaluated, IDEM also provided extensive site-specific documentation, including an explanation of the control technologies, applicability, the limitations, expected removal efficiencies and performance, as well as considerations for cost analyses for both capital and operating costs and the relationship with reduction efficiency.

Further, EPA disagrees with the Conservation Groups' allegations that IDEM failed to incorporate FLM comments in its planning. EPA believes IDEM genuinely and consistently portrayed its intentions by clearly stating, "it is important to address the FLMs comments as thoroughly as possible to show that Indiana has seriously evaluated the selected sources..."[9] EPA finds in this final rulemaking that Indiana has satisfied the consultation and public notice requirements of 40 CFR 51.102 and 51.308(i).

Comment and Response 15b: **Cleveland-Cliffs Steel, LLC – Indiana Harbor East and Indiana Harbor West.** In addition to the potential controls examined in the four-factor analyses, the Conservation Groups assert that IDEM should have evaluated additional emission controls for the No. 5 Boiler House, Blast Furnace Stoves, Lime Kilns, and Walking Beam Furnaces.

As described in further detail in the RTC, EPA disagrees

[9] Appendix P, p.3 of Indiana's 2021 SIP submission.

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with this comment and notes that IDEM explained that Indiana Harbor East and Indiana Harbor West identified control measures that were commercially demonstrated on similar applications by searching air permits for other iron and steel mills and other similar sources, the Nucor 2010 Best Available Control Technology (BACT) analysis,[10] as well as EPA's Reasonably Available Control Technology (RACT), BACT, and Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC).[11] The RBLC contains case-specific information on the "best available" air pollution technologies that have been required to reduce the emission of air pollutants from stationary sources. EPA maintains that IDEM's approach produced an extensive list of control measures relevant to the industry that had proven effective for certain applications and identified a thorough set of control measures for evaluation.

Regarding the cost analyses, IDEM and Cleveland-Cliffs Steel, LLC provided a thorough explanation, justification, and documentation of the cost parameters used in four-factor analyses as well as in its responses to the comments from the FLMs that appropriately considered site-specific factors. The

[10] Nucor Steel Louisiana "Consolidated Environmental Management Inc. – Nucor Steel Louisiana, Best Available Control Technology Analyses," March 1, 2010 (Nucor 2010 BACT).
[11] EPA's RBLC is available through *https://cfpub.epa.gov/rblc/index.cfm?action=Home.Home and https://www.epa.gov/catc/ractbactlaer-clearinghouse-rblc-basic-information.*

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Conservation Groups provided their own cost calculations, but their estimates did not include site-specific factors.

Comment and Response 15c: **Cleveland-Cliffs Steel, LLC – Burns Harbor.** In addition to the emission control options examined in the four-factor analysis, the Conservation Groups assert that IDEM should have evaluated additional options for the Coke Batteries, Coke Ovens, and Coke Oven Gas Export Line as well as provided better documentation for parameters such as the remaining useful life and interest rate in the cost calculations.

As discussed further in the RTC, EPA disagrees with this comment and notes that IDEM provided sufficient documentation and identified control measures that were commercially demonstrated on similar applications by searching air permits for other iron and steel mills and other similar sources, the Nucor 2010 BACT analysis, as well as EPA's RBLC. EPA notes that IDEM's approach produced an extensive list of control measures relevant to the industry that had proven effective for certain applications and identified a thorough set of control measures for evaluation. For the Coke Batteries, Coke Ovens, and Coke Oven Gas Export Line, the four-factor analysis search found no examples where SCR or wet scrubbers had been installed and successfully operated to control NO_X and SO_2 emissions under similar physical and operating conditions to those at Burns

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Harbor.[12]

Although the Conservations Groups assert that the cost analyses lacked documentation, IDEM and Cleveland-Cliffs Steel, LLC provided a thorough explanation, justification, and documentation of the cost parameters used in the four-factor analysis and in its responses to the comments from the FLMs.

Comment and Response 15d: **U.S. Steel – Gary Works.** In addition to the emission control options examined in the four-factor analysis, the Conservation Groups assert that IDEM should have evaluated SCR for the 84" Strip Mill Reheat Furnace and used different values in the cost analysis for low-NOx burners on the Waste Heat Boilers 1 and 2.

As described in more detail in the RTC, EPA disagrees with this comment. EPA notes that IDEM identified control measures that were commercially demonstrated on similar applications by searching air permits for other iron and steel mills and other similar sources, the Nucor 2010 BACT analysis, and EPA's RBLC. However, IDEM's search did not find a SCR that had been installed and successfully operated on a similar source and under similar operating conditions as Gary Works.

Regarding the cost analyses for low-NO_X burners for Waste Heat Boiler 1, although the Conservations Groups provided their

[12] For lists obtained during the search of EPA's RBLC and air permits, *see* appendices A and B of appendix B of appendix I to Indiana's 2021 SIP submission.

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own cost calculations using different parameters, EPA notes that IDEM and U.S. Steel – Gary Works provided a thorough explanation, justification, and documentation of the cost parameters used in the four-factor analysis[13] and in its responses to the comments from the FLMs[14] that appropriately considered site-specific factors that the Conservation Groups' estimates did not.

Comment and Response 15e: **SABIC Innovative Plastics – Mt. Vernon, LLC.** The Conservation Groups assert that IDEM's four-factor analysis lacked consideration of all emission sources besides the Co-generation Unit and COS Vent Oxidizer as well as appropriate assumptions for costs and remaining useful life.

As detailed further in the RTC, EPA disagrees with this comment and notes that of the emission sources listed in the facility's title V permit,[15] the Co-generation Unit accounted for the largest portion of the facility's total potential to emit NO_X at 39 percent. Based on this, EPA agrees that IDEM appropriately focused its evaluation of potential emission reduction for NO_X on the Co-generation Unit rather than the emissions from the other boilers and units. Although the

[13] *See* section 13.10, 13.11, 13.12 and appendices I and J of Indiana's 2021 SIP submission.
[14] *See* appendix S to Indiana's 2021 SIP submission.
[15] Title V Permit 129-45722-00002 for SABIC Innovative Plastics – Mt. Vernon, LLC issued June 16, 2023, is publicly available at *https://permits.air.idem.in.gov/45722f.pdf.*

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Conservation Groups assert that IDEM did not provide underlying calculations and supporting information, EPA notes that the four-factor analysis provided a solid basis for calculating the total capital investment and cost effectiveness and documentation was provided in Section 15 and appendices I and J of Indiana's 2021 SIP submission.

Comment and Response 15f: **Warrick Newco LLC, formerly Alcoa Warrick Operations, LLC.** The Conservation Groups assert that the four-factor analysis should have evaluated NO_X emissions as well as SO_2 emissions and provided better documentation for figures used in the cost calculations.

As discussed in further detail in the RTC, EPA disagrees with this comment and notes that NO_X emissions from Alcoa Warrick Operations, LLC represented the lowest levels of all the sources that IDEM evaluated for a four-factor analysis. As such, IDEM's decision at the time to focus resources on addressing potential controls in the second implementation period for only SO_2 was well reasoned. EPA also determined that IDEM provided sufficient relevant documentation for the economic and emissions information used in the four-factor analysis.

Comment and Response 15g: **Cokenergy, LLC.** The Conservation Groups claim that the four-factor analysis was not a four-factor analysis, but rather a recitation of studies and projects, and should have also evaluated DSI and upgrades to other existing

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systems.

As further addressed in the RTC, EPA disagrees with this comment and notes that the summaries of the previous studies and projects served to develop a set of technically feasible control options for evaluation and that the four-factor analysis then addressed each of the statutory four factors in turn. Although the Conservation Groups assert that several other specific options should have been addressed, many of those suggested by the Conservation Groups were considered during the course of the studies mentioned above, including evaluations of installing or upgrading DSI, spray dryer absorbers, and atomizers. EPA notes that these options, along with the other options evaluated, represented a reasonable selection of control options.

Comment and Response 15h: **Heidleberg Materials US Cement LLC – Mitchell Plant, formerly Lehigh Cement Company, LLC – Mitchell Plant.** The Conservation Groups note that IDEM selected this source for a four-factor analysis but did not complete one.

As described in additional detail in the RTC, EPA notes that, pursuant to an amended Federal consent decree,[16] Lehigh

[16] *See USA, State of Indiana, State of Iowa, State of Maryland, State of New York, Pennsylvania Department of Environmental Protection, Jefferson County Board of Health, and Bay Area Air Quality Management District v. Lehigh Cement Company, LLC and Lehigh White Cement Company, LLC*, Civil Action No. 5:19-cv-05688-JFL in United States District Court, Eastern District of Pennsylvania. The initial and amended consent decrees are available in the docket and at *https://www.justice.gov/enrd/consent-decree/file/1223121/dl*; *https://www.justice.gov/enrd/consent-decree/file/1352971/dl*.

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will be permanently ending operations of Kilns 1, 2, and 3 by the end of 2025. In the future, Lehigh will be installing and operating SCR and meeting the NSPS for Portland Cement Plants (40 CFR 60, subpart F) for any new kilns.

Comment and Response 16: The Conservation Groups argue that source-specific BART determinations in the first implementation period need to be reassessed. Under 42 USC 7491(b)(2)(A), the Conservation Groups state that the CAA established BART as a mandatory part of "each applicable implementation plan" for "each" BART-eligible source that emits "any" air pollutant which may cause or contribute to "any" impairment of visibility in "any" Class I area.

As explained further in the RTC, EPA disagrees that States are required to conduct BART analyses anew in the second regional haze implementation period and onward. Specifically, EPA disagrees that its second implementation period regulations require a BART analysis for second implementation period SIPs. Pursuant to 40 CFR 51.308(e)(5), once Indiana satisfied the BART requirements in the first implementation period, Indiana's BART-eligible sources were then subject to the long-term strategy requirements in 40 CFR 51.308(f) for the second implementation period. As stated throughout our proposal and this final action, EPA finds that Indiana properly met the long-term strategy requirements of 40 CFR 51.308(f) in the second

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implementation period.

Comment and Response 17: The Conservation Groups assert that EPA should analyze the impact of Indiana regional haze pollution on local communities since the same pollutants contributing to regional haze also contribute disparately to public health impacts on people residing closest to the sources. The Conservation Groups state that people living in these communities tend to be exposed to higher levels of particulate matter and NO_X and tend to have less access to quality health care to treat the impacts of environmental pollution.

As discussed in more detail in the RTC, with respect to public health concerns, the primary national ambient air quality standards provide public health protection. In contrast, the visibility program, prescribed by CAA sections 169A and 169B and implemented in 40 CFR 51.308, is not a health-based program. EPA is acting upon Indiana's 2021 Regional Haze SIP submission as required by regional haze regulations at 40 CFR 51.308.

Comment and Response 23: The Conservation Groups commented that EPA must withdraw its proposal to approve Indiana's 2021 SIP Revision and disapprove it.

For the reasons stated in the NPRM, EPA's April 22, 2025, TSD, EPA's December 19, 2025, RTC, this notice of final rulemaking, and the foregoing summary of responses to comments in this docket, EPA disagrees that Indiana failed to satisfy the

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requirements of the CAA and RHR. EPA also disagrees that EPA's proposed approval of Indiana's 2021 SIP Revision was fundamentally flawed in such a way as to make it ineffective at achieving reasonable progress in the second implementation period. Thus, as proposed in the NPRM, EPA is finalizing its approval of Indiana's 2021 SIP Revision as satisfying the applicable requirements under the CAA and RHR for the program's second implementation period.

C. Comments and Responses that are specific to EPA's URP Policy

EPA received several comments regarding EPA's URP policy. Comments from IDEM (Comment 6), PGen (Comment 7), Utilities for Reasonable Progress (Comment 8), and OVEC and IKEC (Comment 9) were supportive of EPA's URP policy. Comments from the Community Organizations (Comment 10b), MANEVU (Comment 11a) and the Conservation Groups (Comments 18 - 22) were opposed to EPA's URP policy.

In this final action, EPA is affirming that it is now the Agency's policy that, where visibility conditions for a Class I Federal area impacted by a State are below the URP and the State has considered the four statutory factors, the State will have presumptively demonstrated reasonable progress for the second implementation period for that area. EPA acknowledges that this final action reflects a change in policy as to how the URP should be used in the evaluation of regional haze second

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implementation period SIPs but believes that this policy better aligns with the purpose of the statute and RHR: achieving "reasonable" progress towards natural visibility.

As described in the approval of West Virginia's regional haze plan (90 FR 29737, July 7, 2025), EPA has discretion and authority to change its policy. In *FCC* v. *Fox Television Stations, Inc.*, the U.S. Supreme Court plainly stated that an agency is free to change a prior policy and "need not demonstrate ... that the reasons for the new policy are better than the reasons for the old one; it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency believes it to be better." 556 U.S. 502, 515 (2009) (referencing Motor *Vehicle Mfrs. Ass'n of United States, Inc.* v. *State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983)). *See also Perez* v. *Mortgage Bankers Assn.*, 135 S. Ct. 1199 (2015).

The Class I areas impacted by emissions from Indiana sources are all below the 2028 URP, and IDEM's SIP submission demonstrated that the State took into consideration the four reasonable progress factors listed in CAA 169A(g)(1)[17] with respect to an adequate number of emissions sources. Thus, EPA

[17] The four statutory factors required to be taken into consideration in determining reasonable progress are: the costs of compliance, the time necessary for compliance, and the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirements. CAA section 169(g)(1).

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determines that Indiana's SIP revision is fully approvable under the Agency's new URP policy. Indeed, we think this policy better aligns with the statutory goal because it recognizes the considerable improvements in visibility impairment that have been made by a wide variety of State and Federal programs in recent decades.

In developing the regulations required by CAA section 169A(b), EPA established the concept of the URP for each Class I area. The URP is determined by drawing a straight line from the measured 2000 to 2004 baseline conditions (in deciviews) for the 20 percent most impaired days at each Class I area to the estimated natural conditions (in deciviews) for the 20 percent most impaired days in 2064. From this calculation, a URP value can be calculated for each year between 2004 and 2064. EPA developed the URP to address the diverse concerns of Eastern and Western States and account for the varying levels of visibility impairment in Class I areas around the country while ensuring an equitable approach nationwide. For each Class I area, States must calculate the URP for the end of each planning period (*e.g.*, in 2028 for the second implementation period).[18] 40 CFR

[18] We note that RPGs are a regulatory construct that we developed to address the statutory mandate in CAA section 169B(e)(1), which required our regulations to include "criteria for measuring 'reasonable progress' toward the national goal." Under 40 CFR 51.308(f)(3)(ii), RPGs measure the progress that is projected to be achieved by the control measures a State has determined are necessary to make reasonable progress. Consistent with the 1999 RHR, the RPGs are unenforceable, though they create a benchmark that allows for analytical comparisons to the URP and mid-implementation-period course corrections if necessary. 82 FR 3091-3092 (January 10, 2017).

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51.308(f)(1)(vi)(A). States may also adjust the URP to account for impacts from anthropogenic sources outside the United States and/or impacts from certain wildland prescribed fires. 40 CFR 51.308(f)(1)(vi)(B). Then, for each Class I area, States must compare the reasonable progress goal (RPG) for the 20 percent most impaired days to the URP for the end of the planning period. If the RPG is above the URP, then an additional "robust demonstration" requirement is triggered for each State that contributes to that Class I area. 40 CFR 51.308(f)(3)(ii)(B).

In the 2017 RHR Revisions, EPA addressed the role of the URP as it relates to a State's development of its second implementation period SIP. 82 FR 3078 (January 10, 2017). Specifically, in response to comments suggesting that the URP should be considered a "safe harbor" that relieves States of any obligation to consider the four statutory factors, EPA explained that the URP was not intended to be such a safe harbor. *Id.* at 3099. "Some commenters stated a desire for corresponding rule text dealing with situations where RPGs are equal to ('on') or better than ('below') the URP or glidepath. Several commenters stated that the URP or glidepath should be a 'safe harbor,' opining that States should be permitted to analyze whether projected visibility conditions for the end of the implementation period will be on or below the glidepath based on

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on-the-books or on-the-way control measures, and that in such cases a four-factor analysis should not be required." *Id.*

Other comments indicated a similar approach, such as "a somewhat narrower entrance to a 'safe harbor,' by suggesting that if current visibility conditions are already below the end-of-planning-period point on the URP line, a four-factor analysis should not be required." *Id.* EPA stated in its response that we did not agree with either of these recommendations. "The CAA requires that each SIP revision contain long-term strategies for making reasonable progress, and that in determining reasonable progress States must consider the four statutory factors. Treating the URP as a safe harbor would be inconsistent with the statutory requirement that States assess the potential to make further reasonable progress towards natural visibility goal in every implementation period." *Id.*

Importantly, EPA's recently adopted policy does not make the URP a safe harbor. The policy merely creates a presumption that the State's second implementation period SIP is making reasonable progress for a Class I Federal Area if the State has taken into consideration the four statutory factors of 169A(g)(1) and that area is below the URP. This is consistent with the CAA and RHR.

Comment and Response 11a: Instead of relying on the RPGs, MANEVU asserts EPA's URP policy is not permissible and that EPA

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is now using the URP as the determinative metric, to ignore the extensive work of the States, the FLMs, and the public in developing the RPGs.

As discussed further in the RTC, EPA disagrees with MANEVU's comment. EPA's URP policy does not ignore the results of a State's four-factor analysis if a Class I area is below the URP. Consistent with EPA's discussion under the preamble of the 2017 RHR, the URP continues to serve as a regulatory planning metric to inform States' decision making when considering the four statutory factors. EPA's URP policy recognizes the considerable improvements in visibility impairment that have been made by State and Federal programs resulting from decades of work and interaction between members of State and Federal agencies and the public.

Comment and Response 18: The Conservation Groups argue that EPA's URP Policy violates the CAA's visibility provisions. The Conservation Groups raise several issues pertaining to EPA's URP policy: a) EPA's URP policy violates the plain language of the CAA, b) EPA's contemporaneous understanding of the CAA reflects the best reading of the statute, c) the context of the CAA's visibility provisions confirms the best reading of the statute, and d) the purpose of the CAA's visibility provisions confirms the best reading of the statute.

EPA disagrees with each of these comments, including the

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Conservation Groups' position that the URP policy articulated in our proposed approval of Indiana's regional haze SIP submission is inconsistent with the CAA. The Conservation Groups' reading of the statute is not the best, and they misconstrue the recently adopted policy in several ways. EPA notes that the comments and responses on each above point are presented in detail in the RTC document.

EPA's new URP policy is consistent with the CAA. Pursuant to CAA 169A(a)(4), Congress explicitly delegated to EPA the authority to promulgate regulations regarding reasonable progress towards meeting the national goal. In determining the measures necessary to make reasonable progress, Congress mandated "tak[ing] into consideration the cost of compliance, the time necessary for compliance, and the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing source subject to such requirement." CAA 169A(g)(1).

EPA emphasizes that just because a Class I area is below the URP does not mean that a State is relieved of its obligations under the CAA and the RHR to make reasonable progress. In other words, the URP is not a "safe harbor," as that phrase has sometimes been used, because EPA still must review a State's determination whether additional control measures are necessary to make reasonable progress, determine

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whether the State submitted those measures for incorporation into the SIP, and evaluate whether the measures are consistent with other provisions in the CAA.

As required by the statute, Indiana took into consideration the four statutory factors in CAA section 169A(g)(1) and determined that no additional controls were necessary to make reasonable progress at the sources selected. CAA section 169A(b)(2) only requires SIPs to include "such emission limits, schedules of compliance and other measures *as may be necessary* to make reasonable progress" (emphasis added). IDEM concluded that it was not necessary to incorporate any new emission limits, schedules of compliance, or other measures into its SIP in light of the progress already made.

Comments and Responses 10 and 19: Both the Community Organizations and Conservation Groups argued that EPA's URP policy is inconsistent with the RHR.

As discussed in the RTC, EPA disagrees with the commenters' position that the URP policy is inconsistent with the RHR. This comment tracks many of the issues commenters raised with respect to their allegations that EPA's recently adopted URP policy is inconsistent with the CAA. Under the URP policy, and consistent with 40 CFR 51.308(f)(2), States are still required to identify measures necessary for reasonable progress by considering the four statutory factors set forth in CAA 169A(g)(1) and to submit

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measures necessary for reasonable progress to EPA to be reviewed for approvability into the SIP. The URP policy does not create an exemption to either of these provisions.

Comment and Response 20: The Conservations Groups comment that EPA's articulation and application of its new URP policy is unclear and incoherent. In this regard, the Conservation Groups argue: (a) Mere consideration of the four factors is inconsistent with the CAA and the RHR and is fundamentally irrational, (b) EPA fails to explain why a four-factor analysis must be rational when, under the URP policy, its result does not matter and EPA does not substantively review it, and (c) EPA further muddies the waters by considering other factors in an arbitrary and capricious way.

As discussed in detail in the RTC for Responses 20a, 20b, and 20c, EPA disagrees with the Conservation Groups' arguments mentioned above regarding EPA's application of the URP policy being unclear and incoherent. EPA's recently adopted policy is consistent with the CAA and is not arbitrary or capricious. The Conservation Groups incorrectly assert that the URP policy ignores the results of a State's four-factor analysis if a Class I area is below the URP. Just because a Class I area is below the URP does not mean that a State is relieved of its obligations under the CAA and the RHR to make reasonable progress. EPA must still review a State's determination whether

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additional control measures are necessary to make reasonable progress, determine whether the State submitted those measures for incorporation into the SIP, and evaluate whether the measures are consistent with other provisions in the CAA.

Comment and Response 21: The Conservation Groups assert that announcing and applying EPA's new URP policy in state-specific regional actions violates the procedural requirements of the CAA under 306(a)(2) regarding consistency among Regional Offices in implementing the CAA. The Conservation Groups argue that EPA's URP policy unlawfully departs from national policy and is inconsistent with actions across EPA regions.

EPA disagrees with the Conservation Groups' position here as further explained in the RTC. EPA's change in policy is consistent with *FCC v. Fox Television*, 556 U.S 502 (2009). Under *FCC v. Fox*, an agency's change in policy is permissible if the agency acknowledges the change, believes it to be better, and "show[s] that there are good reasons for the new policy." 556 U.S. at 515. We stated our reasons for implementing the recently adopted URP policy in the final action approving the West Virginia SIP for the second implementation period. 90 FR 29737 (Jul. 7, 2025). The reasons for the recently adopted policy were more fully articulated in section V, *The EPA's Rationale for Proposing Approval*, of that proposal. 90 FR 16478 (Apr. 18, 2025). Therefore, EPA has sufficiently justified the

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change in policy under *FCC* v. *Fox.*

The decision in *FCC* v. *Fox* turned primarily on whether the FCC's change in policy would lead to the FCC "arbitrarily punishing parties without notice of the potential consequences of their action." 556 U.S. at 517. The changed policy is prospective, which addresses the primary concern in *FCC* v. *Fox.* Additionally, the recently adopted URP policy "aligns with the purpose of the statute and RHR, which is achieving `reasonable' progress, not maximal progress, toward Congress' natural visibility goal." 90 FR 16478, at 16483. Furthermore, we note that the legislative history of CAA section 169A is consistent with our change in policy. The reconciliation report for the 1977 CAA amendments indicates that the term "maximum feasible progress" in section 169A was changed to "reasonable progress" in the final version of the legislation passed by both chambers. *See* Legislative History of the CAA Amendments of 1977 Public Law 95-95 (1977), *H.R. Rep. No. 95-564,* at 535.

EPA notes that EPA's Regional Consistency regulations at 40 CFR part 56, and in particular 40 CFR 56.5(b), are not relevant to this action. 40 CFR 56.5(b) requires that a "responsible official in a Regional office shall seek concurrence from the appropriate EPA Headquarters office on any interpretation of the Act, or rule, regulation, or program directive when such interpretation may result in application of the act or rule,

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regulation, or program directive that *is inconsistent* with Agency policy" (emphasis added). As we expressly indicated in the proposal for this action, the approval is *consistent* with the change in agency policy, first announced in *Air Plan Approval; West Virginia; Regional Haze State Implementation Plan for the Second Implementation Period*. 90 FR 16478 (Apr. 18, 2025). Therefore, there is no obligation under the EPA's Regional Consistency regulations for anyone in the region to seek concurrence from EPA Headquarters to take action consistent with EPA policy. The lack of relevance of these regulations to this action accounts for the lack of materials related to compliance with the Regional Consistency process in the docket for this rulemaking.

The Conservation Groups also argue that EPA's URP policy effectively revises the RHR and raises the question of whether it has nationwide scope and effect.

EPA disagrees with the Conservation Groups' comment here as further explained in the RTC. EPA notes that this action is "locally or regionally applicable" under CAA section 307(b)(1) because it applies only to a SIP submission from a single State, Indiana. *See Oklahoma* v. *EPA*, 605 U.S. 609, 620 (2025) (a SIP is "a state-specific plan" and "the CAA recognizes this limited scope in enumerating a SIP approval as a locally or regionally applicable action"); *see also, Am. Rd. & Transp. Builders Ass'n,*

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705 F.3d 453, 455 (D.C. Cir. 2013) (describing EPA action to approve a single SIP under CAA section 110 as the "[p]rototypical" locally or regionally applicable action).

Whether our proposal to approve Indiana's second implementation period SIP relies on a new national policy has no bearing on the applicability of EPA's final action. To determine whether an action is "nationally applicable" or "locally or regionally applicable," "court[s] need look only to the face of the agency action, not its practical effects . . . ." *EPA* v. *Calumet Shreveport Refining, L.L.C.,* 605 U.S. 627, 642 (2025) ("[W]e determine an action's range of applicability by 'look[ing] only to the face of the [action], rather than to its practical effects.'") (quoting *Am. Rd. & Transp. Builders Ass'n,* 705 F.3d at 456) and *Oklahoma,* 605 U.S. at 621-622 (basis for EPA action is not relevant to determining its applicability); *see also Sierra Club* v. *EPA,* 926 F.3d 844, 849 (D.C. Cir. 2019) and *RMS of Georgia, LLC* v. *EPA,* 64 F.4th 1368, 1372 (11th Cir. 2023) ("our sister circuits have established a consensus that we should begin our analysis by analyzing the nature of the EPA's action, not the specifics of the petitioner's grievance").

Furthermore, the comments that claim the recently adopted URP policy "amend[s] the nationally applicable RHR" are unsupported and incorrect. This action simply applies our recently adopted policy related to the URP in the context of

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EPA's evaluation of Indiana's regional haze SIP submission. Because this action applies a recently adopted policy to a SIP submission from Indiana alone, it is locally or regionally, not nationally, applicable.

Comments that claim that EPA "must" publish a finding that this action is "based on a determination of nationwide scope [or] effect" are also unsupported and incorrect. The Supreme Court has recognized that "[b]ecause the 'nationwide scope or effect' exception can apply only when 'EPA so finds and publishes' that it does, EPA can decide whether the exception is even potentially relevant." *Calumet Shreveport Refining, L.L.C.*, 605 U.S. at 646, citing *Sierra Club* v. *EPA*, 47 F.4th 738, 746 (D.C. Cir. 2022). As the D.C. Circuit has also stated, the "EPA's decision whether to make and publish a finding of nationwide scope or effect is committed to the agency's discretion and thus is unreviewable." *Sierra Club* v. *EPA*, 47 F.4th at 745; *see also Texas* v. *EPA*, 983 F.3d 826, 835 (5th Cir. 2020) ("when a locally applicable action is based on a determination of nationwide scope or effect, the EPA has discretion to select the venue for judicial review").

The Administrator has not made and published a finding that this action is based on a determination of nationwide scope or effect. Accordingly, any petition for review of this action must be filed in the United States Court of Appeals for the

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appropriate regional circuit.

Comment and Response 22: The Conservation Groups comment that Indiana's 2021 SIP submission does not meet EPA's URP policy for presumptive approval. As such, the Conservation Groups argue that Indiana: a) would not be able to meet the RHR monitoring requirements without the IMPROVE network if its continued operation were threatened, b) relies on adjusted URP glidepaths that do not comply with the RHR, and c) ignores additional out-of-state Class I areas affected by visibility impairing emissions from Indiana.

EPA disagrees with these comments as further discussed in the RTC. Indiana met the requirements of the recently adopted policy. First, the RHR requires States to submit a long-term strategy that addresses regional haze visibility impairment for each mandatory Class I Federal area within the State and for each mandatory Class I Federal area located outside the state that may be affected by emissions from the State. 40 CFR 51.308(f)(2); *see also* CAA 169A(b)(2). However, there is no specific statutory or regulatory requirement to identify the precise set of Class I areas that are affected by emissions from Indiana, and there is no requirement to establish a source contribution threshold in identifying those areas. In this case, Indiana identified affected out-of-state Class I areas, none of which are above the 2028 URP.

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EPA believes Indiana has reasonably documented its impacts to in-state and out-of-state Class I areas, and they are not reasonably anticipated to cause or contribute to any impairment in any area that is above the URP.

In conclusion, IDEM took into consideration the four statutory factors in CAA section 169A(g)(1) and determined that no additional controls were necessary to make reasonable progress for the specific sources selected for four-factor analyses. CAA section 169A(b)(2) only requires SIPs to include "such emission limits, schedules of compliance and other measures *as may be necessary* to make reasonable progress" (emphasis added). IDEM concluded that it was not necessary to incorporate any new emission limitations, schedules of compliance, or other measures into its SIP for these sources. Thus, IDEM did not ignore the results of its consideration of the four statutory factors; rather, as supported by the recently adopted URP policy, the State properly used the URP to inform its final decision making as to the measures necessary to make reasonable progress in the second implementation period.

D. EPA's Final Approval

EPA determines that Indiana reasonably considered the statutory and regulatory requirements and appropriately determined what measures are necessary for reasonable progress for the second implementation period. As such, EPA finds that

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Indiana submitted a Regional Haze SIP revision that meets all the regional haze requirements for the second implementation period.

EPA concludes that Indiana's determinations of the measures necessary for reasonable progress were based on a reasonable consideration of the four statutory factors. IDEM thoroughly evaluated and determined the emission reduction measures that are necessary to make reasonable progress by considering the four statutory factors. IDEM also documented large statewide emissions reductions achieved during the second implementation period.

EPA is finalizing its approval of Indiana's December 29, 2021, Regional Haze SIP submission for the second implementation period as proposed.

IV. Final Action

For the reasons set forth in the June 18, 2025, NPRM, the April 22, 2025, TSD, the December 19, 2025, RTC document, and in this final rule, EPA is approving the Regional Haze SIP revision for Indiana submitted by IDEM on December 29, 2021, as satisfying the regional haze requirements for the second implementation period contained in 40 CFR 51.308(f).

V. Statutory and Executive Order Reviews

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the CAA and

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applicable Federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, EPA's role is to approve State choices, provided that they meet the criteria of the CAA. Accordingly, this action merely approves State law as meeting Federal requirements and does not impose additional requirements beyond those imposed by State law. For that reason, this action:

- Is not a significant regulatory action subject to review by the Office of Management and Budget under Executive Order 12866 (58 FR 51735, October 4, 1993);
- Is not subject to Executive Order 14192 (90 FR 9065, February 6, 2025) because SIP actions are exempt from review under Executive Order 12866;
- Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104-4);
- Does not have federalism implications as specified in

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Executive Order 13132 (64 FR 43255, August 10, 1999);

- Is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it approves a State program;
- Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001); and
- Is not subject to requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA.

In addition, the SIP is not approved to apply on any Indian reservation land or in any other area where EPA or an Indian Tribe has demonstrated that a Tribe has jurisdiction. In those areas of Indian country, the rule does not have Tribal implications and will not impose substantial direct costs on Tribal governments or preempt Tribal law as specified by Executive Order 13175 (65 FR 67249, November 9, 2000).

This action is subject to the Congressional Review Act, and EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a "major rule" as defined by 5 U.S.C. 804(2).

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by **[insert date 60 days after date of publication in the *Federal Register*]**. Filing a

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petition for reconsideration by the Administrator of this final rule does not affect the finality of this action for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2).)

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen dioxide, Ozone, Particulate matter, Sulfur oxides.

Dated: January X, 2026.

Anne Vogel,
Regional Administrator, Region 5.

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For the reasons stated in the preamble, title 40 CFR part 52 is amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

2. In § 52.770, the table in paragraph (e) is amended by adding a new entry for "Regional Haze Plan for the Second Implementation Period" after the entry for "Regional Haze Plan" to read as follows:

§ 52.770 Identification of plan.

* * * * *

(e) * * *

EPA-APPROVED INDIANA NONREGULATORY AND QUASI-REGULATORY PROVISIONS

Title	Indiana date	EPA approval	Explanation
* * *	* * *	*	
Regional Haze Plan for the Second Implementation Period	12/29/2021	**[insert the date of publication in the *Federal Register*]**, 91 FR **[insert *Federal Register* page where the document begins]**	Full approval.
* * *	* * *	*	

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 58
MISO Tariff Module E-1

This Module E-1 provides mandatory requirements to be met by the Transmission Provider, Market Participants serving Load in the Transmission Provider Region or serving Load on behalf of a Load Serving Entity (LSE), or other Market Participants, to ensure access to deliverable, reliable and adequate Planning Resources to meet Coincident Peak Demand and Local Resource Zone Peak Demand requirements on the Transmission System. These requirements recognize and are complementary to the reliability mechanisms of the states and the Regional Entities (RE) within the Transmission Provider Region. Nothing in this Module E-1 affects existing state jurisdiction over the construction of additional capacity or the authority of states to set and enforce compliance with standards for adequacy. The Resource Adequacy Requirements (RAR) in this Module E-1 are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction. To the extent that an LSE's Coincident Peak Demand is physically located within the Transmission Provider's Balancing Authority Area but is pseudo-tied out of the MISO Balancing Authority Area pursuant to the Transmission Provider's Business Practices Manuals (BPM), such Coincident Peak Demand is not subject to the RAR provisions if such Coincident Peak Demand is subject to another Balancing Authority Area's resource adequacy requirements. To accomplish these reliability requirements, Module E-1 includes provisions for: establishing Local Resource Zones and associated limits (*i.e.*, Capacity Import Limits (CIL) and Capacity Export Limits (CEL)); establishing Local Reliability Requirements (LRR); establishing Local Clearing Requirements (LCR); establishing External Resource Zones and associated limits (i.e., Capacity Export Limits (CEL)); determining the Planning Reserve Margin; Coincident Peak Demand forecasting; Local Resource Zone Peak Demand forecasting; qualifying and quantifying Planning Resources; participation of Demand and Planning Resources in the Planning Resource

Auction process; settlement provisions; and Planning Resource performance requirements for each Season.

Establishment of Planning Reserve Margins

The Transmission Provider will determine a Planning Reserve Margin (PRM) in terms of Unforced Capacity for each Season using analytical study methods described in Section 68A.2, provided that if a State Regulatory Authority establishes a PRM for its regulated entities that is higher or lower than the PRM determined by the Transmission Provider, then the State Regulatory Authority-established PRM will apply to the Coincident Peak Demand of LSEs under that state's jurisdiction.

Planning Reserve Margin Analysis

The Transmission Provider shall perform a technical analysis on an annual basis to establish the PRM for each Season for the Transmission Provider Region and the Transmission Provider will publish the results by November 1 preceding the applicable Planning Year. The PRM analysis shall be consistent with Good Utility Practice and the reliability requirements of the REs and the applicable states in the Transmission Provider Region. The PRM analysis shall consider factors including, but not limited to: the Generator Forced Outage rates of Capacity Resources; Generator Planned Outages; expected performance of Demand Response Resources (DRR), Load Modifying Resources (LMR), and Energy Efficiency Resources; load forecast uncertainty; and the Transmission System's import and export capability with external systems. The Transmission Provider annually will calculate and publish on its website the estimated PRM for each of the nine subsequent Planning Years, to provide information for long-term resource planning, without establishing any enforceable specific planning reserve requirements.

Loss of Load Expectation Analysis

The Transmission Provider shall coordinate with Market Participants to determine the appropriate PRM for the applicable Season in the Planning Year based upon the probabilistic analysis of being able to reliably serve the Transmission Provider Region's Demand for the applicable Season in the Planning Year. This probabilistic analysis shall use a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations within the Transmission Provider Region.

The following process will be utilized to determine the minimum PRM requirement for each Season in the Planning Year using the LOLE analysis. First, an LOLE analysis for the Planning Year will be conducted such that the LOLE for the Planning Year is one (1) day in ten (10) years, or 0.1 day per year, by either adding or removing capacity. If the LOLE for the Planning Year is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE for the Planning Year is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year. If the LOLE for a Season is equal to or greater than 0.01 day per year, the minimum PRM requirement for that Season will be calculated based on this LOLE analysis. If the LOLE for any Season is less than 0.01 day per year, an additional LOLE analysis will be performed to determine minimum PRM requirement for that Season by adding a perfect negative unit with zero forced outage rate to that Season until the LOLE in that Season reaches 0.01.

The minimum amount of capacity above Coincident Peak Demand in the Transmission Provider Region required to meet the reliability criteria will be used to establish the PRM for each Season.

The PRM will be established as a requirement in terms of the total Unforced Capacity for the Transmission Provider Region.

No later than September 1st of the year prior to a Planning Year, the Transmission Provider will, as necessary, develop new Local Resource Zones (LRZ) to reflect the need for an adequate amount of Planning Resources to be located in the right physical locations within the Transmission Provider Region to reliably meet Demand and LOLE requirements. The geographic boundaries of each of the LRZs will be based upon analysis that considers: (1) the electrical boundaries of Local Balancing Authorities; (2) state boundaries; (3) the relative strength of transmission interconnections between Local Balancing Authorities; (4) the results of LOLE studies; (5) the relative size of LRZs; and (6) natural geographic boundaries such as lakes and rivers. The Transmission Provider may re-evaluate the boundaries of LRZs if there are significant changes in the Transmission Provider Region based upon the preceding factors, including but not limited to, significant changes in membership, the Transmission System, and/or Resources.

An External Resource Zone (ERZ) will be created for each external Balancing Authority that has External Resources qualifying as Planning Resources, excluding those Balancing Authorities with only Coordinating Owner resources that are qualified to obtain local credit and/or Border External Resources.

Establishment of SRRZs, SRECs and SRICs

The Transmission Provider will establish and publish, on the Transmission Provider's public website, SRRZs, SRECs and SRICs for each Season as soon as practical but no later than the first business day of March for the following Planning Year. To calculate the SRECs and SRICs, the Transmission Provider will determine the transfer limit between SRRZs in accordance with applicable seams agreements, coordination agreements, or transmission service agreements. Next, the Transmission Provider will then complete a feasibility analysis in accordance with the Resource Adequacy Business Practices Manual to review operational events from each Coincident Peak Demand hour during the previous Planning Year, and forecasted expected conditions for each Season in the upcoming Planning Year, to determine if a further reduction to the transfer limit is warranted for reliability. If such a reduction is necessary, the Transmission Provider will reduce the regional directional transfer limit, as appropriate. The Transmission Provider will then subtract the sum of Firm Transmission Service Reservations on the MISO OASIS that utilize the contract path between SRRZs and are exporting from or wheeling through the Transmission Provider's Balancing Authority for the applicable Season in the Planning Year. This difference determines the SREC and SRIC to be utilized for the applicable Season in the Planning Year.

Prior to publishing the SRRZs, SRECs, and SRICs on its public website, Transmission Provider will present the feasibility analysis and resulting SREC and SRIC calculation to stakeholders.

Establishment of CIL and CEL Limits

On or before November 1st of each year, the Transmission Provider will determine preliminary values for the CIL and CEL for each of the LRZs for each Season in the following Planning Year by considering factors, including but not limited to, the following elements: (1) existing and planned Transmission System and Planning Resource additions; (2) transmission import and export capability; and (3) applicable NERC contingencies. To determine the CIL and CEL for each LRZ, the Transmission Provider will use models which contain the physical location of Load and Planning Resources for each Season. Generator output will be assigned to LRZs or ERZs consistent with the PRA representation of Planning Resources. Constraints that are identified as a result of determining the CIL and/or the CEL for each LRZ will be considered in the development of the MISO Transmission Expansion Plan (MTEP) in accordance with Attachment FF.

CIL will be equal to the Zonal Import Ability plus firm capacity commitments to non-MISO load. CEL will be equal to the Zonal Export Ability minus firm capacity commitments to non-MISO load.

The CIL and CEL values for each Season for each LRZ will be updated if needed prior to the Planning Resource Auction, but no later than eight (8) Business Days before the last Business Day in March, due to changes to firm capacity commitments from MISO resources to neighboring regions prior to the Planning Resource Auction.

MISO will determine the CEL for each Season for each ERZ no later than eight (8) Business Days before the last Business Day in March as equal to the ZRC quantity of the External Resources registered to participate in the PRA.

Establishment of Local Reliability Requirement

By November 1st prior to a Planning Year, the Transmission Provider will establish a Local Reliability Requirement (LRR) metric for each LRZ to determine the quantity of Unforced Capacity needed for each Season, without consideration of the benefit of the LRZ's CIL. First, the LOLE analysis for the Planning Year will be conducted by either adding or removing capacity until the LOLE reaches 0.1 day per year for the LRZ. If the LOLE for the Planning Year is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE for the Planning Year is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year. If the LOLE for a Season is equal to or greater than 0.01 day per year for the LRZ, the LRR for that Season will be calculated based on this LOLE analysis. If the LOLE for any Season is less than 0.01 day per year for the LRZ, an additional LOLE analysis will be performed to determine the LRR for that Season by adding a perfect negative unit with zero forced outage rate to that season until the LOLE in that Season reaches 0.01 day per year for the LRZ.

The Transmission Provider will model the location of Load and Planning Resources based on their representation in the Planning Resource Auction to determine the LRR for each LRZ. The minimum amount of capacity above the Local Resource Zone Peak Demand in the LRZ required to meet the reliability criteria will be used to establish the LRR for each Season.

The per unit LRR in each LRZ initially will be established as the ratio of the LRR over the Local Resource Zone Peak Demand modeled in the LOLE study. An LRZ's LRR shall be calculated by multiplying the per unit LRR for the LRZ times the forecasted Local Resource Zone Peak

Demand for each Season as provided by LSEs or EDCs, or as developed by the Transmission Provider, pursuant to Section 69A.1.

Establishment of Local Clearing Requirement

The Local Clearing Requirement for each LRZ for each Season will be determined by subtracting Zonal Import Ability and controllable exports from the LRR, as set forth in the Resource Adequacy Business Practices Manual. Controllable exports are exports from MISO resources that have firm capacity commitments to non-MISO load and that may be committed and dispatched by the Transmission Provider during a declared Energy Emergency. The LCR values will be updated if needed prior to the Planning Resource Auction due to changes in controllable exports.

Establishing Planning Reserve Margin Requirements

a. The Transmission Provider will establish Planning Reserve Margin Requirements (PRMR) for each Season for an LSE's Load within any given LRZ. The Initial PRMR will be determined by multiplying the LSE's forecasted Coincident Peak Demand for each Season, including transmission losses, by (1 + Transmission Provider Region PRM).

b. The Transmission Provider will use the Transmission Provider Region PRM for the Initial PRMR calculation unless an alternate PRM is established by a State Regulatory Authority. In such event, the Transmission Provider will use the alternate PRM that a State Regulatory Authority has created for the geographic area in which the state has jurisdiction. The Transmission Provider will convert any State Regulatory Authority provided PRM to a comparable Unforced Capacity basis.

Calculation of Transmission Losses

a. The Transmission Provider shall calculate the LBA transmission loss percentages for each Season using the process described as follows:

1. The Transmission Provider's State Estimator calculates transmission losses (MW) as part of the solution output process every five (5) minutes.
2. The transmission losses (MW) are computed on all transmission lines and transformers by summing up real power at both ends for each transmission element (retaining the convention for flow direction) or as the difference in real power (without the sign convention for flow direction) for each State Estimator solution.
3. The individual transmission losses (MW) for each element are summed to a total transmission values for each Local Balancing Authorities (LBA) level.
4. These LBA transmission loss values are then integrated across each hour to calculate an hourly transmission loss value (MW) for each LBA.
5. The total transmission loss value (MW) for each LBA will be the hourly integrated transmission losses value (MW) for the hour of the Coincident Peak Demand from the calendar year two years prior to the upcoming Planning Year.
6. For the purposes of the Transmission Provider Region, the LBA transmission loss percentages are calculated as the total LBA transmission losses divided by the total LBA peak data at that MISO peak hour for each Season. For purposes of a Local Resource Zone, the LBA transmission loss percentages are calculated as the

total LBA transmission losses divided by the total LBA peak data at the LRZ peak hour for each Season.

b. The Local Balancing Authority (LBA) transmission loss percentage shall apply to the LSE's applicable LBA Coincident Peak Demand and Local Resource Zone Peak Demand forecast to determine the LSE transmission losses. Behind-the-Meter-Generation Resources that are interconnected to the Transmission System shall be treated like other Resources with respect to transmission losses. Behind-the-Meter-Generation Resources and Distributed Energy Aggregated Resources that are not interconnected to the Transmission System, Demand Resources, and Energy Efficiency Resources shall be adjusted to account for serving load without incurring transmission losses by grossing up the MW quantity of such resources by (1.0 + the appropriate LBA transmission loss percentage).

Marginal Reliability Impact (MRI) Curves

A. The following process will be used to determine the MRI Curves for the Transmission Provider Region for each Season of the upcoming Planning Year. The minimum PRM requirement for each Season established in the LOLE analysis, as described in Section 68A.2, will be the starting point. Then, for each Season, a perfect negative unit(s) with a capacity of at least 50MW and no more than 250MW, or perfect proxy unit(s) with a capacity of at least 50MW and no more than 250MW will be added to the model and the LOLE analysis will be performed. The capacity of both the perfect negative unit(s) and perfect proxy unit(s) will be of equal value. The change in EUE as a result of adding or removing capacity will be calculated. An additional unit(s) with the same capacity value will be added or removed in addition to the first increment or decrement and the LOLE analysis will be performed again. This process will be repeated until sufficient data is available to fit a curve that measures changes to EUE as MWs are added or removed from the minimum PRM requirement.

B. The First Planning Area MRI Curve is a smoothed representation of reliability changes as measured by EUE as more or less MWs are included in the LOLE analysis. The following process will be used to determine the MRI Curves for the First Planning Area for each Season in the Planning Year. Assignment of LOLE risk across the Seasons will be the same as described in Section 68A.2 for the Planning Reserve Margin analysis. A minimum PRM requirement for the First Planning Area for each Season will be established through additional LOLE analysis in which the First Planning Area and Second Planning Area each have the same reliability target established for the

Transmission Provider Region as the starting point. After establishing the starting point, the MW quantity associated with the minimum PRM requirement in the Second Planning Area will be fixed, and capacity in the First Planning Area will then be added or removed to calculate changes to EUE in the First Planning Area.

C. The Second Planning Area MRI curve is a smoothed representation of reliability changes as measured by EUE as more or less MWs are included in the LOLE analysis. The following process will be used to determine the MRI Curves for the Second Planning Area for each Season in the Planning Year. Assignment of LOLE risk across the Seasons will be the same as described in Section 68A.2 for the Planning Reserve Margin analysis. A minimum PRM requirement for the Second Planning Area for each Season will be established through additional LOLE analysis in which the First Planning Area and Second Planning Area each have the same reliability target established for the Transmission Provider Region as the starting point. After establishing the starting point, the MW quantity associated with the minimum PRM requirement in the First Planning Area will be fixed, and capacity in the Second Planning Area will then be added or removed to calculate changes to EUE in the Second Planning Area.

RAR Process

Once the Transmission Provider has established the PRM, LCR, LRR, preliminary Capacity Import Limits and Capacity Export Limits and published such values on the Transmission Provider's website, then LSEs shall provide forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data for the Planning Year. For Retail Choice areas, the EDC shall provide, on behalf of LSEs within the EDC, forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data for the Planning Year to be used by the Transmission Provider. The Transmission Provider will then calculate each LSE's Initial PRMR for each Season. LSEs will meet their RAR obligation by: (i) submitting a Fixed Resource Adequacy Plan; (ii) submitting ZRCs for an RBDC Opt Out; (iii) Self-Scheduling ZRCs; (iv) purchasing ZRCs through the Planning Resource Auction process; and/or (v) paying the Capacity Deficiency Charge to meet a portion of their PRMR. LSEs that submit an RBDC Opt Out may not use any of the other options to satisfy their Final PRMR. LSEs not submitting an RBDC Opt Out may use one or more of all other available options, or any combination of available options, to satisfy their Initial or Final PRMR. The Transmission Provider will enforce the LCRs, final Capacity Import Limits and Capacity Export Limits for each LRZ, and Capacity Export Limits for each ERZ in the Planning Resource Auction. An ACP will be determined through the PRA process for each LRZ and ERZ for each Season and the ACP will be used to credit ZRCs that clear in the auction and to debit LSEs for the volume of their PRMR that is procured through the auction. Market Participants that own Planning Resources used to create ZRCs which clear in the PRA (or are identified in either a submitted Fixed Resource Adequacy Plan or an RBDC Opt Out) must meet the applicable performance requirements as described in sections 69A.3.9 and

69A.5. The Transmission Provider shall provide states, upon request, with relevant resource adequacy information as available, subject to the data confidentiality provisions in Section 38.9 of the Tariff.

Load Serving Entity Responsibilities

a. LSEs shall provide Coincident Peak Demand (and also, if available, Local Resource Zone Peak Demand forecasts) forecasts as specified in Section 69A.1.1b and will also be responsible for meeting their Final PRMR for each LRZ where they serve Load by submitting Fixed Resource Adequacy Plans, by Self-Scheduling ZRCs, by purchasing ZRCs through the PRA process, by submitting ZRCs for an RBDC Opt Out and/or by paying the Capacity Deficiency Charge.

b. The Transmission Provider will use Coincident Peak Demand, Local Resource Zone Peak Demand, and Energy forecasts for each Season that are submitted by an EDC in combination with allocation procedures that are agreed to by the applicable LSEs. These procedures will allow the Transmission Provider to initially allocate appropriate portions of the total forecasted Coincident Peak Demand and Local Resource Zone Peak Demand to each LSE as applicable pursuant to 69A.1.2.1, and to re-assign ZRC-related charges caused by customer switching between suppliers to the appropriate LSE.

c. All LSEs shall report to the Transmission Provider, through the MECT, whether such LSE will meet their PRMR for each LRZ for each Season in which the LSE serves Load by: (i) submitting a Fixed Resource Adequacy Plan; (ii) Self-Scheduling ZRCs; (iii) purchasing ZRCs through the Planning Resource Auction process; (iv) submitting an RBDC Opt Out; and/or, (v) paying the Capacity Deficiency Charge.

Forecasted Demand Identification

a. The Demand forecasts required in Section 69A.1 shall include: (1) the Coincident Peak Demand within each LBA Area in the Transmission Provider Region for the upcoming Planning Year; (2) the monthly non-coincident peak Demand and net Energy for Load within each LBA Area, for the upcoming Planning Year and the following Planning Year; (3) the non-coincident peak Demand and net Energy for Load within each LBA Area, for each Season, for the eight Planning Years subsequent to the two for which monthly values are provided in (2); and (4) the available Local Resource Zone Peak Demand within each LBA Area in the Local Resource Zone for the upcoming Planning Year. All of these forecasts shall be submitted by November 1st prior to each Planning Year and shall be consistent with Good Utility Practice. Forecast providers shall use the MECT or other means described in the BPM for Resource Adequacy to submit the requisite information. Details regarding the items required in the Demand forecasts submittal are in the BPM for Resource Adequacy.

b. The supplied Coincident Peak Demand and Local Resource Zone Peak Demand forecasts shall include the Demand expected for the forecast time period (*e.g.* the Coincident Peak Demand hour) augmented to include the normal Demand from forecasted demand resources, whether registered or not registered with the Transmission Provider, including Demand from any retail demand side management programs and Demand behind a DEAR. Such forecasts shall include Demand that would have occurred but for the existence of Energy Efficiency Resources that have been in operation less than four (4) years. All submissions for such forecast values shall include distribution losses, but not transmission losses. The Transmission Provider will be responsible for the calculation of the applicable transmission losses for the forecasts provided

and for annually publishing such values for each LBA on its website by October 1, as specified in Section 68A.8 and the BPM for Resource Adequacy.

c. In order to assist with the development of the Coincident Peak Demand and Local Resource Zone Peak Demand forecasts, the Transmission Provider will make available the historical monthly peak hours for each of the four months June through September, since 2005, or as available, for the Transmission Provider Region and for each Local Resource Zone. On or before March 1st of each year, the Transmission Provider will review a sampling of submitted Demand forecast methodologies and inputs to ensure accuracy and consistency, in accordance with the BPM for Resource Adequacy. If the Transmission Provider determines that the Demand forecast methodologies are inaccurate or inconsistent, the Transmission Provider shall work with the applicable LSEs to reconcile such issues. If reconciliation is not achieved, or if Local Resource Zone Peak Demand forecasts are not available, then the Transmission Provider will provide the required forecast values.

d. All Coincident Peak Demand and Local Resource Zone Peak Demand forecasts shall reflect a 50% probability that the Demand will not exceed the forecasted Demand for the relevant period.

e. Consistent with Section 69A.1.2.1, the EDC must provide both the Transmission Provider and the respective LSEs with each retail customer's peak load contribution ("PLC") in each Season, including transmission losses and PRM as determined by the Transmission Provider, in the EDC's service territory by December 15th. At least five (5) Business Days before January 15, LSEs must notify the EDC and the Transmission Provider if they disagree with the EDC calculated PLC value.

f. If an LSE knows it will gain a wholesale customer by the beginning of any Season in the next Planning Year, then that LSE may provide the Transmission Provider with the Coincident Peak Demand and the Local Resource Zone Peak Demand forecast for such acquired load by November 1. In all other cases, the existing Market Participant serving such wholesale customer shall provide the Transmission Provider by November 1st with the Market Participant's forecast of the wholesale customer's Coincident Peak Demand and Local Resource Zone Peak Demand.

Accounting for Total Demand Forecasts Given Wholesale and Retail Load Switching

a. On or before January 15th, an EDC must notify the Transmission Provider through the MECT of the Initial PRMR for the LSE's proportion of the EDC's forecast Demand that it expects to serve on the 1st day of each Season in the next Planning Year. The LSE that is the provider of last resort ("POLR") for the EDC area in question will have the obligation to procure capacity for the required PRMR for the remaining Demand (*i.e.*, the remaining Demand is the EDC's forecast Coincident Peak Demand minus the sum of the LSE's allocated portion of forecast Coincident Peak Demand, identified as described above, in the EDC's service territory). The Transmission Provider will notify the POLRs of any remaining Initial PRMR within five (5) Business Days after January 15th.

b. On or before January 15th, to account for wholesale customers that may switch LSEs during the next Planning Year, the PRMR will be met as follows: (1) if an LSE has responsibility to serve a wholesale load on the 1st day of any Season in of the next Planning Year, then such LSE shall have the obligation to procure the required PRMR for such load for such Season; (2) if no LSE has responsibility for serving a wholesale load on of the 1st day of any Season in of the next Planning Year, then the LSE with an obligation to serve such load on November 1 before the Planning Year, shall have the obligation to procure capacity for the required PRMR for each Season in the upcoming Planning Year for such load, provided that such LSE anticipates that the contract for wholesale load will be extended; or (3) if the LSE advises the Transmission Provider that the LSE will not serve the contract for wholesale load, then the customer for such wholesale load shall inform the Transmission Provider by January

30th of the name of the Market Participant that will be responsible for the PRMR obligation for such wholesale load.

Daily Assignment of Coincident Peak Demand Obligations

a. For those areas of service where an LSE's Coincident Peak Demand forecast is included in the Coincident Peak Demand forecast submission of an EDC, the EDC will determine and report each LSE's portion of such Demand to the Transmission Provider, using the default method set forth in Section 69A.1.2.1.

b. In a state that permits retail load switching, the Transmission Provider shall allocate resource capacity costs on a daily basis to LSEs by multiplying the Final PRMR associated with identified customers served by the LSE times the applicable zonal Auction Clearing Price less any zonal deliverability benefits plus any Local Clearing Requirement Charges for the Local Resource Zone where the load is located, consistent with Section 69A.1.2.1.

c. In states where wholesale load may switch, the Transmission Provider shall allocate costs on a daily basis to LSEs. The LSE that acquires wholesale load will be charged for such load based upon the Final PRMR for the wholesale load's forecast Coincident Peak Demand times the applicable zonal Auction Clearing Price less any zonal deliverability benefits plus any Local Clearing Requirement Charges for the Local Resource Zone where the wholesale load is located.

d. An LSE may challenge the EDC Demand forecast under the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

Default Method

a. The method submitted by an EDC must describe in detail the procedures and data used to determine the assignment of the EDC's forecast Coincident Peak Demand to its retail customers, including those served by LSEs providing service within the EDC's area.

b. EDC will assign a peak load contribution ("PLC") value to each retail customer, based on the most recent PLC values derived for each Season from each retail customer's Demand at the time of the Transmission Provider's peak Demand during each Season (*i.e.*, the Prior Seasonal Retail Customer Coincident Peak ("PSRCCP")). Retail customer peak demands should be increased to reflect any load reductions achieved and for which capacity credits are earned, either through retail programs or participation in wholesale markets (*e.g.* LMRs). In the aggregate, the PLCs determined by the EDC must equal the Initial PRMR that is calculated from the forecast Coincident Peak Demand provided by the EDC for each Season. This equality is achieved by multiplying each retail customer's demand at the time of the Transmission Provider's peak Demand during each Season prior to the Planning Year by the same adjustment factor, as shown in the equation below:

$$\Sigma_i \, PLC_i = \text{Initial } PRMR_{EDC}$$

$$\text{Factor} = \text{Initial } PRMR_{EDC} \div \Sigma_i \, PSRCCP_i$$

In other words, for each EDC, the sum of the individual retail customer (*i.e.*, i) PLC values must equal the EDC's Initial PRMR. In addition, a single value ("Factor") is defined as the ratio of the Initial PRMR for any EDC divided by the sum of all of the PSRCCP values for each of the EDC's retail customers. The EDC must use the same Factor in the following equation:

$$PLC_i = \text{Factor} \times PSRCCP_i \quad \forall i$$

Thus, for each EDC it must also be true that the PLC for any individual retail customer shall be equal to the product of that customer's PSRCCP times the same Factor identified in the second equation above. For the purposes of these equations, the following mathematical symbols are used: (1) Σ equals sum; (2) $_i$ equals individual retail customer, as in PLC $_i$ or PSRCCP$_i$; and (3) ∀i equals for all i, as in: for each member of the set of retail customers.

c. The PSRCCP shall be adjusted (upward) to reflect any demand that was reduced during the Coincident Peak for each Season hour through the effect of a Load Modifying Resource, or through the effect of an Energy Efficiency Resource during the first four (4) full Planning Years of the EE Resource's existence. The Transmission Provider will provide to the EDC the amount of measured (or estimated if final settlement data is forthcoming) load reduction that occurred as a result of an ARC or LSE deploying a DRR, LMR or EDR following a Setpoint Instruction, Scheduling Instruction or EDR Dispatch Instruction during the Transmission Provider's Coincident Peak Demand.

Load Switching

Beginning the first Calendar Day of each Season in the Planning Year, the EDC will be responsible for tracking the individual customer Final PRMR values transferred from the originally supplying LSE to the newly supplying LSE now responsible for resource adequacy commitments.

Forecasted Demand for FRP/FRS Agreements

Full Responsibility Purchases/Sales (FRP/FRS) agreements are treated effectively like a transfer of Demand and all RAR obligations from one LSE to another Market Participant. A purchaser under an FRP/FRS agreement shall submit the forecasted Coincident Peak Demand and Local Resource Zone Peak Demand associated with such agreement to the Transmission Provider through the MECT for the applicable Planning Year. A seller under an FRP/FRS agreement is contractually obligated to comply with all of the RAR obligations for the transferred Demand during the Planning Year encompassing the planned Coincident Peak Demand. The purchaser under an FRP/FRS agreement no longer has the RAR obligations for the transferred Demand; provided however, that if the seller under an FRP/FRS agreement is not an LSE under the jurisdiction of the Transmission Provider, then the purchaser under the FRP/FRS agreement will remain responsible for any RAR obligations associated with the Demand transferred under the FRP/FRS agreement. A seller under an FRP/FRS agreement will be responsible for the transferred Demand to meet this additional obligation like it was their own Demand. If a seller and a purchaser under an FRP/FRS agreement cannot agree on whether a particular transaction is an FRP/FRS agreement, then either party may invoke the dispute resolution procedures in Section 12 of the Tariff.

Multiple Region Planning Resources

If an LSE serves Demand both in the Transmission Provider Region and outside the Transmission Provider Region, then the LSE must separately satisfy its Final PRMR in all areas of the Transmission Provider Region. Compliance with RAR shall not affect an LSE's obligation to maintain distinct and separate amounts of resources to cover its applicable planning reserve obligation for the amount of Demand outside the Transmission Provider Region.

Capacity Tracking Tool

To facilitate RAR, the Transmission Provider shall administer the MECT, a title tracking and registration tool that shall include the ability to enable Market Participants and LSEs to meet their RAR responsibilities.

Planning Resource Requirements

Nothing herein shall infringe upon the requirement that LSEs comply with applicable state safety standards, planning reserve margins, or be subject to the enforcement thereof. If the Transmission Provider becomes aware that any Planning Resource fails to meet the requirements of this section, then the Transmission Provider shall promptly notify the Market Participant and specify the reasons for any such failure. Wherever possible, the Transmission Provider and the Market Participant will work in good faith to remedy deficiencies, if any, in meeting the Planning Resource requirements, through informal communications rather than Commission filings.

Capacity Resources

As described below, a Generation Resource, External Resource, Demand Response Resource - Type II, Intermittent Generation, Dispatchable Intermittent Resource, Electric Storage Resource, or Hybrid Resource is eligible to become a Capacity Resource. The Transmission Provider will qualify a Capacity Resource for any applicable Season in the upcoming Planning Year, in accordance with processes specified in the BPM for Resource Adequacy. Electric Storage Resources can be Capacity Resources if they meet all the requirements as specified in the BPM for Resource Adequacy, including the requirement to be able to continuously discharge for a minimum set of four (4) consecutive operating Hours across the Transmission Provider's coincident peak for each day, in accordance with the BPM for Resource Adequacy, provided that an Electric Storage Resource may de-rate its capacity in order to comply with this requirement.

Generation Resources that are not Dispatchable Intermittent Resources or Distributed Energy Aggregated Resources

1. Generation Resources and Electric Storage Resources that are not Dispatchable Intermittent Resources or Distributed Energy Aggregated Resources are eligible to qualify as Capacity Resources by a Market Participant that possesses ownership or equivalent contractual rights for the Resource by:

   (a) registering such resource with the Transmission Provider as documented in the BPM for Market Registration;

   (b) demonstrating GVTC capability for each Season in the Planning Year as established in the BPM for Resource Adequacy;

   (c) submitting generator availability data (including, but not limited to, NERC Generation Availability Data System (GADS) information) into a database provided by the Transmission Provider and as established in the BPM for Resource Adequacy;

   (d) by submitting the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year for existing Capacity Resources unless the Transmission Provider has granted an extension pursuant to Section 69A.3.1.a.4; and

   (e) demonstrating deliverability as described in Section 69A.3.1(g). All new Generation Resources and Electric Storage Resources that are not Dispatchable Intermittent Resources and Distributed Energy Aggregated Resources, or an existing Generation Resource and Electric Storage Resource that is not a Dispatchable Intermittent Resource and s Distributed Energy Aggregated Resource that has an increased installed capacity, shall submit their GVTC to the Transmission Provider prior to qualification, but no later

than March 1 prior to the PRA, as established in the BPM for Resource Adequacy.

2. Installed Capacity (ICAP) Deferral

If a Market Participant for a Generation Resource and Electric Storage Resource that is not a Dispatchable Intermittent Resource (including a Generation Resource and Electric Storage Resource that has the status of Suspend pursuant to Section 38.2.7) and a Distributed Energy Aggregated Resource that has not completed GVTC testing by the deadlines provided in 69A.3.1.a.1, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used in the PRA or in a FRAP (including through bilateral ZRC transactions), subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

3. Reporting generator availability data based on GVTC is not required for a Generation Resource or Electric Storage Resource that is not a Dispatchable Intermittent Resource and a Distributed Energy Aggregated Resource and that is less than 10 MW if the Market Participant has never provided such data for such Resource. A Market Participant that begins reporting generator availability data based on GVTC for a Generation Resource or Electric Storage Resource that is not a Dispatchable Intermittent Resource and that is less than 10 MW must continue to report such data. A Generation Resource or Electric Storage Resource that has provisional Interconnection Service does not qualify as a Capacity Resource.

4. A Market Participant for a Generation Resource required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning

Year. If circumstances prevent the Market Participant from submitting the GVTC results for the Generation Resource by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline. Denial of an extension will not preclude the Market Participant for the Generation Resource from utilizing the ICAP Deferral process as described in Section 69A.7.9.

Demand Response Resources – Type II

1. Demand Response Resources – Type II backed by a Demand Resource are eligible to qualify as Capacity Resources. A Market Participant that possesses ownership or equivalent contractual rights in the DRR – Type II can register such resource as a Capacity Resource with the Transmission Provider for the upcoming Planning Year as documented in the BPM for Market Registration and by meeting the following requirements:
    a. For an existing DRR – Type II that is a Capacity Resource, the Market Participant shall demonstrate capability and availability to reduce Demand in response to instructions from the Transmission Provider for each applicable Season and shall submit such data to the Transmission Provider no later than October 31 prior to such Planning Year unless the Transmission Provider has granted an extension, as established in the BPM for Resource Adequacy.
    b. For a new DRR – Type II or for an existing DRR – Type II that has experienced an increase in its Capacity Rating, and that is backed by a Demand Resource, the Market Participant shall submit test data to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA, as established in the BPM for Resource Adequacy.
2. A Demand Response Resource – Type II that is backed by behind the meter generation is eligible to qualify as Capacity Resources. A Market Participant that possesses ownership or equivalent contractual rights in the DRR – Type II can register such resource as a Capacity Resource with the Transmission Provider for the upcoming Planning Year as

documented in the BPM for Market Registration and by meeting the following requirements:

a. A Market Participant shall demonstrate GVTC capability of the DRR – Type II backed by behind the meter generation for each Season in the Planning Year as established in the BPM for Resource Adequacy;

b. An existing DRR – Type II backed by behind the meter generation shall submit GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year unless the Transmission Provider has granted an extension pursuant to Section 69A.3.1.b.4; and

c. A Market Participant shall submit generator availability data (including, but not limited to, NERC Generation Availability Data System information) for the DRR – Type II backed by behind the meter generation into a database provided by the Transmission Provider.

d. For a new DRR – Type II or an existing DRR – Type II that has an increased installed capacity, and that is backed by behind the meter generation, the Market Participant shall submit GVTC data to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA, as established in the BPM for Resource Adequacy.

3. Installed Capacity (ICAP) Deferral

If a Market Participant for a DRR – Type II has not completed GVTC testing by the deadlines provided in 69A.3.1.b.2, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs

from such capacity may be used in the PRA, in a FRAP (including through bilateral ZRC transactions), or in an RBDC Opt Out (including through bilateral ZRC transactions) subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

4. Reporting generator availability data based on GVTC is not required for a DRR – Type II backed by behind the meter generation facility of less than 10 MW if the Market Participant has never provided such data for such behind the meter generation facility. A Market Participant that begins reporting generator availability data for behind the meter generation facility that is less than 10 MW based on GVTC must continue to report such data. A Demand Response Resource – Type II that has provisional Interconnection Service does not qualify as a Capacity Resource. In accordance with the qualification provisions in the BPM for Resource Adequacy, the Transmission Provider will qualify a Demand Response Resource – Type II for the applicable Season in the upcoming Planning Year.
5. A Market Participant for a DRR – Type II required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the DRR by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline.

Denial of an extension will not preclude the Market Participant for the DRR – Type II from utilizing the ICAP Deferral process as described in Section 69A.7.9.

External Resources:

1. External Resources, including those specified in Diversity Contracts and PPAs (which are subject to additional qualification requirements in section 69A.3.1.c.4), are eligible to qualify as Capacity Resources by a Market Participant that possesses ownership or equivalent contractual rights in External Resources by: (a) registering such resources with the Transmission Provider as documented in the BPM for Resource Adequacy; (b) demonstrating GVTC capability for each Season that the resource will be registered in as established in the BPM for Resource Adequacy by providing operational data, and by submitting the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year for existing Capacity Resources unless the Transmission Provider has granted an extension pursuant to Section 69A.3.1.c.5; (c) submitting generator availability data (including, but not limited to, NERC Generation Availability Data System information) into a database provided by the Transmission Provider and as established in the BPM for Resource Adequacy; (d) identifying one or more specific External Resource(s) that can be verified by the Transmission Provider as Capacity Resource(s) and which does not include any portion(s) of an External Resource that has already qualified as a Capacity Resource; (e) demonstrating that there is firm transmission service for each Season that the resource is to be registered in from the External Resource to the border interface CPNode of the Transmission Provider Region and either that firm Transmission Service has been obtained to deliver capacity on the Transmission System from the border to a Load within an LRZ or demonstrating deliverability as described in Section 69A.3.1.g; and (f) certifying that any External

Resources being identified are not otherwise being used as capacity resources in any other RTO/ISO, in another resource adequacy construct, or in an external balancing authority's resource plan for its firm end-use load and capacity sales requirements within the external balancing authority area.

2. Installed Capacity (ICAP) Deferral

If a Market Participant for an External Resource has not completed GVTC testing by the deadlines provided in 69A.3.1.c.1, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used in the PRA, in a FRAP (including through bilateral ZRC transactions), or in an RBDC Opt Out (including through bilateral ZRC transactions) subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

3. Reporting generator availability data for an External Resource of less than 10 MW based upon GVTC is not required if the Market Participant has never provided such data for such External Resource. A Market Participant that begins reporting generator availability data for an External Resource that is less than 10 MW based on GVTC must continue to report such data. All new External Resources or an existing External Resource that has an increased installed capacity shall submit their GVTC to the Transmission Provider prior to qualification as established in the BPM for Resource Adequacy. In accordance with the qualification provisions in the BPM for Resource Adequacy, the Transmission Provider will qualify an External Resource for the applicable Season in the upcoming Planning Year.

4. In the case of a power purchase agreement (PPA), including, but not limited to a Diversity Contract, then the agreement shall meet the additional qualification requirements set forth below:

   i. A PPA that does not identify the full Installed Capacity of the External Resource from which power will be supplied must specify the portions of each such External Resource that is available under the PPA (i.e. slice-of-system resources) and that are verifiable by the Transmission Provider. Each External Resource specified in such PPA must meet the criteria for a Capacity Resource for all of the portion of the contract amount assigned to the External Resource(s). The capacity from the External Resource will be reduced proportionately to remove amounts that fail to meet such criteria.

   ii. A copy of every PPA must be provided by the Market Participant using External Resources from such PPA as a Capacity Resource to the Transmission Provider to enable it to verify the External Resource(s) that are backing the PPA and to confirm compliance with RAR. Any redacted versions of a PPA submitted by a Market Participant must contain sufficient information to allow the Transmission Provider to verify compliance with RAR. The Transmission Provider will maintain the confidentiality of these agreements in accordance with the confidentiality provisions in Section 38.9 of the Tariff.

   iii. For PPAs executed after April 3, 2014, one of the following must apply regarding the external balancing authority in which the External Resource is located:

(a) In the case of unit specific sales, if the MISO Balancing Authority Area is experiencing an Energy Emergency, the external balancing authority will not interrupt the PPA Schedule from the External Resource unless the generator being used to serve the unit specific sale has a forced outage.

(b) In the case of slice-of-system sales, if the external balancing authority area experiences an Energy Emergency and the MISO Balancing Authority Area is simultaneously experiencing an Energy Emergency, the external balancing authority will only interrupt the PPA Schedule on a pro rata basis with the shedding of firm end-use load in the external balancing authority area. Pro rata interruption of the PPA Schedule from the External Resource will be determined as the ratio of the PPA Schedule to the sum of the external balancing authority firm end-use load plus the PPA Schedule. (c) If the external balancing authority (1) is located within the Transmission Provider's reliability coordinator area; (2) participates in a contingency reserve sharing group with the Transmission Provider; and (3) has a Seams Operating Agreement with the Transmission Provider containing the following features, then in the event that the external balancing authority area experiences an Energy Emergency and the MISO Balancing Authority Area is simultaneously experiencing an Energy Emergency, the Transmission Provider and the external balancing authority will share interruption of PPA Schedules from an External Resource and load shedding in the external balancing authority area on a pro rata basis in proportion to the end-use load in the area under the Energy Emergency. Pro rata sharing shall be

determined as the respective ratio of each of the balancing authority's end-use load in the Energy Emergency Area divided by the sum of the end-use load of each balancing authority in the Energy Emergency Area. The Seams Operating Agreement must (1) ensure that the external balancing authority has established a planning reserve margin and qualifications for planning resources using processes and criteria comparable to the Transmission Provider; (2) specify the actions that will be taken by both entities during an Energy Emergency prior to implementing firm end-use load shedding, and (3) specify that the external balancing authority will submit end-use load estimates to the Transmission Provider in a comparable manner as submitted by Load entities in Module E-1, provide generator GVTC and GADS data for all resources used to serve firm requirements of the external balancing authority, and provide transparency in the form of submittal of fixed resource plans comparable to processes used by Market Participants for Fixed Resource Adequacy Plans in the Transmission Provider's Module E-1.

iv. A PPA executed prior to April 3, 2014 will continue to qualify as a Planning Resource for the full term of the PPA if it is only interruptible as a last resort under Requirement 2 of NERC Standard EOP-011-1. A Diversity Contract executed prior to April 3, 2014 will continue to qualify as a Planning Resource, if it is only interruptible as a last resort under Requirement 2 of the NERC Standard EOP-011-1 between June 1st and September 30th.

v. A Market Participant may only qualify a PPA as a Capacity Resource if such agreement establishes a firm obligation on the part of the seller of the Capacity to deliver the Capacity to the Market Participant.

vi. If the terms and conditions in a PPA do not explicitly conform with every requirement of Section 69A.3.1.c. 4 (i) through (iv) above, the Transmission Provider will use alternative documentation and verification procedures to determine if the PPA qualifies as a Capacity Resource. A party seeking Capacity Resource status for a non-conforming PPA must provide the Transmission Provider with written information regarding whether: (a) the PPA was executed prior to October 20, 2008; (b) an RE has accredited the PPA to satisfy resource adequacy requirement provisions; (c) the PPA has provided reliable capacity to the Transmission Provider Region; (d) the supplier(s) of capacity in the PPA commit(s) to provide the capacity to an LSE in the Transmission Provider Region in a defined amount at a defined location based upon the supplier(s)' portfolio of generation assets; (e) energy from the PPA cannot be interrupted for economic reasons and will only be interrupted for force majeure type conditions as a last resort during Emergency conditions; (f) either the purchaser(s) or the supplier(s) of capacity in the PPA has committed to offer energy into the Day-Ahead Energy and Operating Reserves Market and all pre-Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment processes for all periods for which energy is available under the PPA, consistent with the must offer provisions in Section 69A.5; (g) the physical resource(s) backing the PPA are identified by the

supplier of the PPA; (h) the portion of the physical resources backing the PPA has not otherwise been registered by any other entity as Capacity Resources in the Transmission Provider Region or as capacity resources in any other region; and (i) if the PPA is renewed, the PPA will be modified to comply with the terms of section 69A.3.1.c. 4 (i) through (iv) and (vi). The Transmission Provider will analyze all available alternative documentation and verification information. Based upon such analysis, the Transmission Provider will inform the party seeking Capacity Resource status for the PPA within 30 days whether the PPA qualifies as a Capacity Resource.

vii. No PPA may be qualified as a Capacity Resource if such agreement includes provisions permitting the seller to interrupt deliveries thereunder for reasons other than Force Majeure.

5. A Market Participant for an External Resource required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the External Resource by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline.

Denial of an extension will not preclude the Market Participant for the External Resource from utilizing the ICAP Deferral process as described in Section 69A.7.9.

6. Existing Resources that modify their registration, scheduling and market participation in the Energy and Operating Reserves Markets and become pseudo-tied External Resources after September 1, 2022 will be accredited at the lesser of class average SAC in Schedule 53 or the accreditation provisions governing External Resources in section 69A.4.1.b.

Use Limited Resources

The Market Participant shall identify eligible Generation Resources, Electric Storage Resources, Distributed Energy Aggregated Resources or External Resources to the Transmission Provider that are Use Limited Resources. The Market Participant that seeks to qualify a Generation Resource, Distributed Energy Aggregated Resource or External Resource as a Use Limited Resource under RAR shall meet all the requirements as specified in the BPM for Resource Adequacy. A Use Limited Resource must be able to operate for a minimum set of four (4) consecutive operating Hours across the Transmission Provider's coincident peak for each day in each applicable Season in order to qualify as a Capacity Resource, in accordance with the BPM for Resource Adequacy.

Intermittent Generation, Dispatchable Intermittent Resources, and Distributed Energy Aggregated Resources

Intermittent Generation, Dispatchable Intermittent Resources, and Distributed Energy Aggregated Resources are resources that are eligible to qualify as a Capacity Resource by a Market Participant provided that the Market Participant: (a) possesses ownership or equivalent contractual rights for the resource; (b) supplies historical performance data or required documentation for the resource as established in the BPM for Resource Adequacy; and (c) registers the resource with the Transmission Provider in accordance with the BPM for Market Registration (if the resource is located within the MISO Balancing Authority Area metered boundary), or the BPM for Resource Adequacy (if the resource is located outside the MISO Balancing Authority Area metered boundary).

Curtailments

At its sole discretion, the Transmission Provider may curtail exports not being used as capacity by an external balancing authority and/or recall External Resources, PPAs, and Diversity Contracts sourced from a Capacity Resource during a declared Energy Emergency. Procedures for such actions shall be specified in the operating procedures. With respect to external balancing authorities that have a Seams Operating Agreement with the Transmission Provider pursuant to Section 69 A.3.1.c.4, during a declared Energy Emergency in the MISO Balancing Authority Area, the Transmission Provider shall only interrupt or reduce Export Schedules associated with a sale of capacity on a reciprocal pro rata basis to that required of the external balancing authority in Section 69A.3.1.c.4.(iii).

A. Determination of Deliverability of Generation Resources, Electric Storage Resources, and External Resources:

The Transmission Provider shall be responsible for determining whether Generation Resources, Electric Storage Resources, and External Resources eligible to be Capacity Resources are deliverable to Load. The deliverable amount of such Generation Resources, Electric Storage Resources, and External Resources will be any combination of the following:

i. The amount of Network Resource Interconnection Service under Attachment X;

ii. The amount of Energy Resource Interconnection Service under Attachment X that is coupled with firm Transmission Service;

iii. The amount of firm Transmission Service associated with a Grandfathered Agreement that can only be used to satisfy PRMR within the LRZ of the Load under the Grandfathered Agreement;

iv. The amount of aggregate deliverability that a Generation Resource or External Resource was granted through the market transition deliverability test by the Transmission Provider and could qualify for Network Resource Interconnection Service; or

v. The amount of non-aggregate deliverability that a Generation Resource or External Resource was granted by the transmission provider and confirmed by a Network Customer as a designated Network Resource under the OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that corresponding Transmission Owner's integration date, will be accepted by the Transmission Provider as deliverable to the Network Loads of

the Network Customer for that term of the confirmed designation, as such term may be extended.

B. Determination of Deliverability of Intermittent Generation, Dispatchable Intermittent Resources, and Electric Storage Resources:

The Transmission Provider shall be responsible for determining whether Intermittent Generation, Dispatchable Intermittent Resources, and Electric Storage Resources eligible to be Capacity Resources are deliverable to Load. The deliverable amount of such Intermittent Generation, Dispatchable Intermittent Resources, and Electric Storage Resources will be any combination of the following:

i. The amount of Network Resource Interconnection Service under Attachment X;

ii. The amount of Energy Resource Interconnection Service under Attachment X that is coupled with firm Transmission Service;

iii. The amount of firm Transmission Service associated with a Grandfathered Agreement that can only be used to satisfy PRMR within the LRZ of the Load under the Grandfathered Agreement;

iv. The amount of aggregate deliverability that the Intermittent Generation or Dispatchable Intermittent Resource was granted through the market transition deliverability test by the Transmission Provider and could qualify for Network Resource Interconnection Service; or,

v. The amount of non-aggregate deliverability that a Intermittent Generation or Dispatchable Intermittent Resource was granted by the transmission provider and confirmed by a Network Customer as a designated Network Resource under the

OASIS reservation process in place prior to either the initial effective date of the Energy Market in 2005 or that corresponding Transmission Owner's integration date, will be accepted by the Transmission Provider as deliverable to the Network Loads of the Network Customer for that term of the confirmed designation, as such term may be extended.

C. Determination of Deliverability of Distributed Energy Aggregated Resources

The Transmission Provider shall be responsible for determining whether Distributed Energy Aggregated Resources eligible to be Capacity Resources are deliverable to Load. The Distributed Energy Resource Aggregator will coordinate with the Electric Distribution Company in order for the Electric Distribution Company to perform a technical review of the Distributed Energy Aggregated Resource's transmission system impacts. Any MW found to be injecting onto the transmission system as a result of the technical review must demonstrate deliverability by obtaining External Network Resource Interconnection Service or firm Transmission Service in order to qualify for the Planning Resource Auction or a FRAP.

Retirement, Suspension, Installed Capacity (ICAP) Deferral and Replacement of Planning Resources

a. Retirement, Suspension, ICAP Deferral and Replacement

A Planning Resource for which a Market Participant requests a change in status in accordance with the System Support Resource (SSR) provisions described in Section 38.2.7 will no longer qualify as a Planning Resource effective as of the actual date that the status of the Planning Resource changes to Retire pursuant to Section 38.2.7. A Generation Resource that has the status of Suspend pursuant to Section 38.2.7 will continue to qualify as a Planning Resource in accordance with the BPM for Resource Adequacy. A Planning Resource for which a Market Participant submits an ICAP Deferral Notice will be subject to ICAP Deferral Requirements and Charges pursuant to Section 69A.7.9. As used in this section, "cleared ZRCs" include ZRCs that cleared in the PRA, were used in a FRAP, were used in an RBDC Opt Out, or were used to replace ZRCs in accordance with this section. As used in this section, "uncleared ZRCs" include ZRCs that did not clear in the PRA, were not used in a FRAP, were not used in an RBDC Opt Out or were not used to replace ZRCs in accordance with this section. If a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is Retired or Suspended prior to the end of the Season during the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs. If a Market Participant does not replace such ZRCs associated with a Retired or Suspended Planning Resource, a Capacity Replacement Non-Compliance Charge will be assessed as determined below in this Section. If a Market Participant's Planning Resource fails to satisfy the ICAP deferral requirements set forth in Section 69A.7.9 and the Market Participant does not replace

cleared ZRCs with uncleared ZRCs, an ICAP Deferral Non-Compliance Charge will be assessed pursuant to Section 69A.7.9. If a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Section 69A.5 for greater than thirty-one (31) Days in total due to full or partial Generator Planned Outage during the Season of the Planning Year in which the ZRCs cleared, or for Planning Resources that are subject to Diversity Contracts for greater than one (1) Month during any Season of the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs to transfer the performance requirements applicable to the Planning Resource. If a Market Participant does not replace such ZRCs associated with a Planning Resource, a Capacity Replacement Non-Compliance Charge will be assessed as determined below in this Section. A Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs that are used to replace cleared ZRCs must meet the applicable performance requirements as described in sections 69A.3.3.1 and 69A.5 for the balance of the Season of the Planning Year, subject to the same replacement requirements set forth above. Any combination of cleared or replaced ZRCs that are on full or partial Generator Planned Outage for greater than thirty-one (31) Days in total during a Season, or for any other reason including full or partial Generation Outages that were not planned but were known or could have been reasonably anticipated at the time of the PRA, as set forth in the Market Monitoring and Mitigation Business Practices Manual, or unavailable because subject to a Diversity Contract that is not available for greater than one (1) Month during a Season, will be assessed a Capacity Replacement Non-Compliance Charge. If a Planning Resource for which a Market Participant converts Seasonal Accredited

Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Sections 69A.3.3.1 and 69A.5 due to a Catastrophic Generator Outage any time during the Season(s) of the Planning Year in which the ZRCs cleared such Market Participant may replace the cleared ZRCs with uncleared ZRCs to transfer the performance requirements applicable to the Planning Resource. A Planning Resource may not transfer its performance requirements by replacing the cleared ZRCs with uncleared ZRCs other than in the case of suspension, retirement, ICAP deferral, Catastrophic Generator Outage or full or partial Generator Planned Outages that may exceed thirty-one (31) Days in the Season as discussed immediately above. Cleared ZRCs can be replaced with uncleared ZRCs that are not from the same LRZ or ERZ by examining post-replacement clearing as if it were the PRA clearing results, so that such replacement: (1) does not violate any CIL used in the PRA; (2) does not violate any CEL used in the PRA; (3) does not reduce the remaining total ZRCs for any LRZ of cleared ZRCs below the LCR for that LRZ; and (4) does not exceed any intra-regional flow ranges established under applicable seams agreements, coordination agreements, or transmission service agreements. ZRC replacements from LRZs or ERZs other than that of the cleared ZRCs will be processed in accordance with the following parameters:

i. ZRC replacement shall be processed on a first come, first served basis.
ii. The amount of cleared ZRCs in each LRZ or ERZs at the time of a ZRC replacement shall be based upon the current amounts of cleared ZRCs, including any previous replacement transactions.

ZRC replacement shall have no impact on settlements from the PRA, FRAPs, and RBDC Opt Out, including any assessed Capacity Replacement Non-Compliance Charges.

b. Capacity Replacement Non-Compliance Charge and Distribution

i. Capacity Replacement Non-Compliance Charges will be calculated as follows: the number of days for which the Market Participant had a replacement requirement but failed to replace per section 69A.3.1.h.a above multiplied by the amount of ZRCs that failed to be replaced multiplied by the sum of the ACP for the applicable Season and the daily CONE value (1/365 times CONE). The ACP and the CONE values will be based on the LRZ where the Planning Resource cleared those ZRCs. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in the respective SRRZ. For External Resources represented in ERZs that are connected to multiple SRRZs or that are not connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs.

ii. Distribution of Capacity Replacement Non-Compliance Charges: Capacity Replacement Non-Compliance Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs that have met their Final PRMR during the applicable Season of the Planning Year on a *pro rata* basis, based upon their respective LSEs' share of Final PRMR for the Transmission Provider Region.

Energy Efficiency Resources (EE Resource)

An Energy Efficiency Resource is a Planning Resource, in which the Market Participant possesses ownership or equivalent contractual rights, from an end-use customer project (including the installation of more efficient devices or equipment or implementation of more efficient processes or systems) that was implemented after July 20, 2011, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous reduction in electric energy consumption during On Peak daylight hours, as further described in the BPM for Resource Adequacy. EE Resources are eligible to qualify as Planning Resources by registering such EE Resources as Planning Resources with the Transmission Provider, as documented in the BPM for Resource Adequacy. An EE Resource can qualify as a Planning Resource for ZRCs for each Season for up to four (4) Planning Years immediately following the EE Resource's initial qualification provided that the energy efficiency measures are fully implemented prior to each Planning Year. ZRCs from EE Resources will be grossed-up by the amount of avoided transmission losses in accordance with Section 68A.8.b and also by the applicable PRM in accordance with Section 68A.2. EE Resources shall not require notice, dispatch, or operator intervention, such that the EE Resource will reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service, in accordance with the BPM for Resource Adequacy. The additional requirements for EE Resource measurement and verification are found in Attachment UU.

Demand Response Resources – Type I and Load Modifying Resources

Demand Response Resources – Type I and Load Modifying Resources can be offered as ZRCs in the PRA or can be used in FRAPs pursuant to Section 69A.9 or used in an RBDC Opt Out pursuant to Section 69A.9.1. As described below, a Demand Resource or behind the meter generation is eligible to qualify as a DRR – Type I or a Load Modifying Resource if it meets the following requirements. All DRR – Type I and LMRs that are cleared in the PRA or were submitted in a FRAP for a Season or submitted in an RBDC Opt Out must be available for use in the event of an Emergency as declared by the Transmission Provider, pursuant to the Emergency Operating Procedures of the Transmission Provider, unless replaced with other ZRCs pursuant to Section 69A.3.1.h. In accordance with the BPM for Resource Adequacy, the Transmission Provider will qualify a DRR – Type I or LMR for the applicable Season in the upcoming Planning Year. The Seasonal Accredited Capacity for DRR – Type Is and LMRs will be calculated pursuant to Schedule 53B.

Deployment Procedures for LMR

Procedures for deployment of LMR are found in the BPM for Resource Adequacy and emergency operating procedures. Such procedures shall be consistent with the information provided by the Market Participant regarding availability and notice time. At a minimum the Market Participant will provide the deployment parameters of the LMR (as described in Sections 69A.3.5 and 69A.3.6), during declared Emergencies prior to the use of Operating Reserves to achieve energy balance. The Market Participant shall, at all times, notify the Transmission Provider or Local Balancing Authority when the status or availability of an LMR changes, except for de minimis changes that do not need to be reported, according to procedures specified in the BPM for Resource Adequacy and emergency operating procedures. The Transmission Provider or Local Balancing Authority shall coordinate with the Market Participant that owns or controls such LMR when necessary to deploy or notify such LMR of a planned deployment. The Transmission Provider or Local Balancing Authority shall coordinate with the Market Participant that owns or controls such LMR when necessary to notify such LMR of a planned deployment through the issuance of Scheduling Instructions. Market Participants may be issued Scheduling Instructions during a declared Emergency or in anticipation of an Emergency at the discretion of Transmission Provider. Market Participants shall acknowledge Scheduling Instructions issued in accordance with BPM for Resource Adequacy for its LMRs. In the event of an anticipated Emergency where the Transmission Provider does not declare the actual Emergency at least two hours prior to the anticipated Emergency event, Market Participants are not obligated to meet the Scheduling Instructions issued in anticipation of such Emergency and

will not be penalized for non-performance. This does not apply to Scheduling Instructions issued after the declaration of an Emergency.

A Market Participant that acknowledges Scheduling Instructions for its LMR(s) as required by the BPM for Resource Adequacy will receive credit for one (1) of the minimum deployments or interruptions required for the LMR for the applicable Season whether or not an Emergency is declared. However, a Market Participant that fails to acknowledge the Scheduling Instructions as required by the BPM for Resource Adequacy will not receive credit for such deployment or interruption for its LMR(s).

An LMR that does not perform consistent with the Market Participant's response to its Scheduling Instructions in the event of an Emergency is subject to the penalty provisions of Section 69A.3.9 and will not receive credit as one (1) of the minimum deployments or interruptions required for such resource for the applicable Season.

Demand Resources (DR) with an Emergency Obligation

Demand Resources registered as either a DRR – Type I or LMR may be deployed to reduce Demand consistent with the submitted Capacity Availability submitted by the Market Participant representing the Demand Resource. A Market Participant shall test, validate, and measure its Demand Resources and submit the results to the Transmission Provider, which shall verify all Demand reduction claimed by a Market Participant, consistent with the procedures specified in the BPM for Demand Response. The accrediting, testing, validation, and Measurement and Verification developed by the Transmission Provider shall take into account any applicable State Regulatory Authority, Regional Entity, or other non-jurisdictional entities' requirements regarding duration, frequency and notification processes for the candidate Demand Resource. A Demand Resource that is sensitive to temperature changes or that is using a Statistical Measurement and Verification methodology must identify, at the time of registration, the extent of such parametric sensitivity to the Transmission Provider with sufficient detail to enable the Transmission Provider to verify whether the Demand Resource would be subject to penalties in Section 69A.3.9 for failure to achieve the targeted Demand reduction amount using the appropriate consumption baseline set forth in Attachment TT. Parametric sensitive analysis must include, but is not limited to, identifying the parameter changes and the parameter's elasticity of the LSE's Load, as further described in the BPM for Demand Response. In accordance with the BPM for Resource Adequacy, the Transmission Provider will qualify a DR for each Season in the upcoming Planning Year.

Demand Resource Eligibility

A Market Participant that possesses ownership or equivalent contractual rights in a Demand Resource can register a Demand Resource as a DRR – Type I or an LMR to participate in the Planning Resource Auction as documented in the BPM for Resource Adequacy. The Market Participant registering the Demand Resource must include the contracts with each end-use customer indicating rights to require the Demand Resource to curtail Load. Notwithstanding, a copy of a contract with an end-use customer will not be required if the Market Participant is the end-use customer. In addition, the Market Participant must meet the following requirements:

a. A Market Participant shall be prohibited from registering into the PRA any component of a Demand Resource that is concurrently registered, in whole or in part, under another DRR, LMR, or EDR whether by the same or a different Market Participant. A Demand Resource registering as an LMR shall not also register as either a DRR or EDR.

b. The Demand Resource must be equal to or greater than 100 kW (a grouping of smaller resources aggregated together as a Load Modifying Resource that is capable of reducing an LSE's Demand for the applicable Season may qualify in meeting this standard).

c. The Demand Resource must be available to be scheduled for a Demand reduction with a notification time requirement: (i) less than or equal to six (6) hours to register in the PRA as a DRR – Type I or an LMR – Type I; or, (ii) less than or equal to thirty (30) minutes to register as an LMR – Type II, in the applicable Seasons.

d. When a Demand Resource is issued Setpoint Instructions or Scheduling Instructions, performance will be evaluated as set forth in Attachment TT using the applicable Measurement and Verification.

e. Once the Setpoint Instruction, Scheduling Instruction, or Firm Service Level is achieved, the Demand Resource must be able to maintain the Setpoint Instruction, Scheduling Instruction, or Firm Service Level for at least four (4) continuous Hours.

f. Unless the Demand Resource is unavailable due to Force Majeure:

(i) A Demand Resource participating as a DRR – Type I or an LMR – Type I that is unavailable to respond to all Setpoint Instructions or Scheduling Instructions shall be subject to the penalties set forth in Section 69A.3.9; and

(ii) A Demand Resource participating as an LMR – Type II that is unavailable to respond to any Scheduling Instructions shall be subject to the penalties set forth in Section 69A.3.9.

This obligation only applies to Seasons during which a Demand Resource clears the Planning Resource Auction.

g. A Demand Resource for which curtailment is not an obligation during Emergency events declared by the Transmission Provider pursuant to the Transmission Provider emergency operating procedures, will not qualify to participate in the PRA as a DRR – Type I or qualify as an LMR.

A Market Participant that submits an Offer into the Day-Ahead and/or Real-Time

Energy and Operating Reserve Markets for a Demand Resource is still subject to the requirements to be available during an Emergency pursuant to the Transmission Provider Emergency Operating Procedures, regardless of the projected or actual Real-Time Energy market LMP.

h. A Demand Resource shall submit Metered data at regular intervals as set forth in Attachment TT.

i. A Market Participant must demonstrate demand reduction capability for each Planning Year on an annual basis as established in the BPM for Resource Adequacy. Beginning with the 2020/2021 Planning Year each Demand Resource must validate its performance by meeting the Transmission Provider's Scheduling Instructions when called upon during the prior Planning Year or conducting a real power test. A Demand Resource for which a real power test is conducted will receive credit as one (1) of the minimum deployments or interruptions required for such resource for the applicable Season of the Planning Year in which such a test occurs.

A Demand Resource may provide operational data, or develop an alternative mechanism, subject to the approval of the Transmission Provider, by which the demand reduction capability can be demonstrated without requiring an actual demand reduction if a real power test is precluded or waived due to one of the two conditions as specified below:

1) Such a real power test is precluded by any applicable regulatory restriction and such a limitation is documented during DR registration; or

2) A Market Participant may waive the obligation to conduct a real power test by notifying the Transmission Provider during DR registration and accepting a penalty equal to three (3) times the Hourly Real-Time Ex Post LMP at the Load CPNode described in and distributed pursuant to Section 69A.3.9. A Demand Resource providing such notice must satisfy credit requirements by March 1 prior to the Planning Year totaling the ICAP value registered, but not tested, multiplied by $2,400/MW, where $2,400 is the product of 3 * 4 * $200 to account for the three (3) times energy penalty assumed under the waiver, the four (4) hours of LMR requirements, and a $200 LMP as a proxy for pricing under emergency conditions.

All existing accredited Demand Resources that neither conduct a real power test nor meet Scheduling Instructions issued by the Transmission Provider during the prior Planning Year must participate in training provided by the Transmission Provider on the deployment of LMRs during the prior Planning Year. Any existing accredited Demand Resource must submit (1) the real power test results, (2) reference performance of Scheduling Instructions for demand reduction when called upon during the calendar year prior to the upcoming Planning Year, (3) alternate testing mechanism, relevant data, and a reference of training participation to the Transmission Provider, or (4) a Demand Resource Deferral Notice pursuant to 69A.3.5(l) and a reference of training participation to the Transmission Provider no later than February 1 prior to such Planning Year for

existing accredited DR. For new Demand Resources, (1) a real power test must be conducted and results submitted to the Transmission Provider, (2) alternate testing mechanism must be submitted, or (3) a Demand Resource Deferral Notice must be submitted prior to qualifying as a Demand Resource, but no later than March 1 prior to the PRA in accordance with the BPM for Resource Adequacy. During a transition period that shall apply only to the 2021-2022 Planning Year, Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 for existing accredited Demand Resource, and Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 prior to initially qualifying as a Demand Resource.

j. Market Participants providing physical, regulatory, or contractual limitations of the notice times and availability of Demand Resources must provide appropriate documentation to the Transmission Provider in accordance with the BPM for Resource Adequacy.

h. A Market Participant may defer the obligation to conduct a real power test, as set forth in section 69A.3.5(i), by providing a Demand Resource Deferral Notice to the Transmission Provider in writing and signed by an officer of the company no later than February 1st prior to the Planning Year. During a transition period that shall apply only to the 2021-2022 Planning Year, Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 for existing accredited Demand Resource, and Market Participants may submit a Demand Resource Deferral Notice no later than March 31, 2021 prior to initially

qualifying as a Demand Resource. The Demand Resource Deferral Notice shall contain: (1) the expected Demand Resource test value (in megawatts) from such Demand Resource and if the Demand Resource is new, the LBA or external BA where it is represented; and (2) appropriate information validating that real power test results will be submitted to the Transmission Provider by the last Business Day of May prior to the Planning Year. A Market Participant that provides a Demand Resource Deferral Notice must satisfy credit requirements by March 1 prior to the Planning Year totaling the amount of Demand Resource test value provided in the Demand Resource Deferral Notice multiplied by $2,400/MW, where $2,400 is the product of 3*4* $200 to account for the three (3) times energy penalty assumed under the deferral, the four (4) hours of LMR requirements, and a $200 LMP as a proxy for pricing under emergency conditions. During a transition period that shall apply only to the 2021-2022 Planning Year, Market Participants that have elected to submit a Demand Resource Deferral Notice must satisfy credit requirements by March 31, 2021. If the Market Participant submits the real power test results on or before the last Business Day of May prior to the Planning Year that are equal to or greater than the expected Demand Resource test value, then the Transmission Provider will adjust the Market Participant's credit requirement to account for these changes within twenty (20) Business Days after that real power test is submitted. In the event ZRCs associated with a Planning Resource for which Demand Resource testing has been successfully deferred are unconverted in accordance with section

69A.7.3, the Market Participant may provide notice to the Transmission Provider that it wishes to forfeit the deferred Demand Resource value, in which case the Transmission Provider will adjust the Market Participant's Demand Resource value and credit requirement within twenty (20) Business Days. A Market Participant that provides a Demand Resource Deferral Notice and that either (1) has not submitted any real power test result for such Demand Resource by the last Business Day of May prior to the Planning Year, or (2) has submitted a real power test result by the last Business Day of May prior to the Planning Year that demonstrates fewer megawatts are available than the expected Demand Resource test value submitted in the Demand Resource Deferral Notice, shall be subject to a penalty equal to three (3) times the Hourly Real-Time Ex Post LMP at the Load CPNode for any such deficiency described in and distributed pursuant to Section 69A.3.9. In addition, such Market Participant shall not have their credit released until a real power test result demonstrating the availability of all megawatts submitted in the Demand Resource Deferral Notice is submitted and verified by the Transmission Provider, or the end of the Planning Year, whichever is earlier.

Behind the Meter Generation Eligibility

1. A Market Participant that possesses ownership or equivalent contractual rights in a behind the meter generator can register such behind the meter generator as a DRR – Type I or an LMR to participate in the Planning Resource Auction as documented in the BPM for Resource Adequacy. A behind the meter generator registered as a DRR – Type I or an LMR is a BTMG. The Market Participant registering the BTMG must include the contracts with each end-use customer indicating rights behind the BTMG to generate behind-the-meter generation. Notwithstanding, a copy of a contract with an end-use customer will not be required if the Market Participant is, or has non-contractual legal rights to control, the end use customer. In addition, the Market Participant must meet the following requirements:
    a. A Market Participant shall be prohibited from registering into the PRA any BTMG that is concurrently registered, in whole or in part, under another DRR, LMR, or EDR, whether by the same or a different Market Participant. A BTMG registering as an LMR shall not also register as a DRR or EDR.
    b. The BTMG must be equal to or greater than 100 kW (a grouping of smaller resources aggregated together as a Load Modifying Resource that is capable of reducing an LSE's Demand for the applicable Season may qualify in meeting this standard).
    c. A behind the meter generator for which curtailment is not an obligation during Emergency events declared by the Transmission Provider will not qualify to participate in the PRA as a DRR – Type I or qualify as an LMR.

A Market Participant that submits an Offer in the Day-Ahead Market and/or Real-Time Energy and Operating Reserve Markets for a BTMG is still subject to the requirement to be available during an Emergency pursuant to the Transmission Provider Emergency Operating Procedures, regardless of the projected or actual Real-Time Energy Market LMP.

d. A Market Participant shall demonstrate GVTC capability for applicable Season in each Planning Year on an annual basis as established in the BPM for Resource Adequacy, and by submitting the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year for existing accredited BTMG unless the Transmission Provider has granted an extension pursuant to Section 69A.3.6.1.j. All new BTMGs or an existing accredited BTMG that has an increased installed capacity shall submit their GVTC to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA as established in the BPM for Resource Adequacy.

e. A Market Participant shall submit generator availability data (including, but not limited to, NERC GADS information) into a database provided by the Transmission Provider and as established in the BPM for Resource Adequacy. A Market Participant is not required to report generator availability data based on GVTC for a BTMG less than 10 MW if the Market Participant has never provided such data for such BTMG. A Market Participant that begins reporting generator availability data based upon GVTC for a BTMG that is less than 10 MW must continue to report such data.

f. A BTMG must be available to provide Energy with a notification time requirement: (i) of six (6) hours or less notice if registering in the PRA as a DRR – Type I or an LMR – Type I; or (ii) with thirty (30) minutes or less notice if registering as an LMR – Type II in the applicable Seasons.

g. A Market Participant shall demonstrate that the BTMG is able to sustain energy production at the MW level being registered for at least four (4) continuous Hours;

h. Unless unavailable due to Force Majeure:

(i) A BTMG participating as a DRR – Type I or LMR – Type I that is unavailable to respond to all Setpoint Instructions or Scheduling Instructions shall be subject to the penalties set forth in Section 69A.3.9; and

(ii) A BTMG participating as an LMR – Type II that is unavailable to respond to any Scheduling Instruction shall be subject to the penalties set forth in Section 69A.3.9.

This obligation only applies during Seasons which the BTMG clears the Planning Resource Auction.

i. A BTMG shall submit Metered data at regular intervals as set forth in Attachment TT.

j. A Market Participant registering a BTMG may not register as a DRR – Type II or Non-Emergency BTMG for three years (3) Planning Years. After three (3) Planning Years, a Market Participant may commit to participate as a BTMG for

an additional three (3) Planning Years or may elect to participate as a DRR – Type II or Non-Emergency BTMG. A BTMG may opt to participate as a DRR – Type I or LMR at any time by satisfying the requirement of such participation option.

k. A Market Participant for a BTMG required to submit GVTC results must use Reasonable Efforts to submit GVTC by October 31 prior to the upcoming Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the BTMG by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extent the GVTC deadline. Denial of an extension will not preclude the Market Participant for the BTMG from utilizing the ICAP Deferral process as described in Section 69A.7.9.

2. Installed Capacity (ICAP) Deferral

If a Market Participant for a BTMG has not completed GVTC testing by the deadlines provided in 69A.3.6.1.d, is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used the PRA, in a FRAP (including through bilateral ZRC transactions) or in an RBDC Opt Out, subject to the notification, credit, and non-compliance

provisions of Section 69A.7.9.

Transmission Provider Initiated Testing of Demand Resources

1. A Demand Resource participating as a DRR or a LMR that is registered in the PRA shall be subject to a Transmission Provider initiated test according to the following requirements:

   a. Test frequency:

      i. A Demand Resource using an Attachment TT defined Statistical Measurement and Verification methodology shall be tested once per Planning Year;

      ii. A Demand Resource participating as a DRR or LMR – Type I shall be tested once per three (3) Planning Years;

      iii. A Demand Resource participating as an LMR – Type II shall be tested once per Planning Year. A Market Participant representing a Demand Resource participating as an LMR – Type II may request a Transmission Provider initiated test opt out as set forth in Section 69A.3.8.2; or

      iv. Notwithstanding the provisions above, the Transmission Provider may test a resource at any time due to its non-performance.

   b. A Demand Resource that has successfully deployed in response to a Setpoint Instruction or Scheduling Instruction issued during an Emergency in either the past one (1) or three (3) Planning Years as applicable pursuant to sub-section a. above, shall count as a successful Transmission Provider initiated test. Provided there are no deployment failures for a Demand Resource participating as an LMR during the 2025/2026, 2026/2027, and 2027/2028 Planning Years, full

response to Setpoint Instructions or Scheduling Instructions issued during an Emergency shall count as a successful Transmission Provider initiated test for the first one (1) or three (3) Planning Year cycle, as applicable, beginning with the 2028/2029 Planning Year.

c. A new Demand Resource participating as a DRR or an LMR shall undergo a Transmission Provider initiated test during the first Planning Year it is registered for the PRA.

d. A Market Participant shall receive at least 24 hours notification prior to the initiation of a Transmission Provider initiated test. Additional requirements regarding the Transmission Provider initiated test shall be set forth in the BPM for Resource Adequacy.

2. A Demand Resource participating as an LMR – Type II may opt out of the annual Transmission Provider initiated test requirement if it has responded to all Scheduling Instructions and successfully passed all Transmission Provider initiated tests, within the past three (3) Planning Years.

a. If opting out of a test, a Demand Resource opting out of the test shall be subject to increased real-time penalties equal to the product of Pricing VOLL and the amount of specified Demand reduction, measured in MWh, not achieved in response to a Setpoint Instruction or Scheduling Instruction issued during an Emergency, in addition to any other penalty provisions set forth in 69A.3.9.

3. A Demand Resource will be deemed to have fully satisfied the Transmission Provider initiated test if the resource has met its performance obligations, as set forth in

Attachment TT, within the registered notification time, and maintained the Demand reduction or Firm Service Level as applicable for four (4) continuous hours.

4. A Demand Resource will have partially failed the Transmission Provider initiated test if the Demand Resource fully deploys outside of the registered notification time and within six (6) hours of initiating the test for participating as DRR – Type I or LMR – Type I, within thirty (30) minutes of initiating the test for participating as LMR – Type II, and within the Offered Shut-Down time for participating as a DRR – Type II. A partial failure of a Transmission Provider initiated test will result in:

   a. The Demand Resource being charged the product of the amount of the Demand shortfall, measured in MW at the Hour equal to the initiation of the Transmission Provider test plus the registered response time, and the Auction Clearing Price, for the lesser of:

      i. The remainder of the Season; or

      ii. Such time as the Demand Resource fully deploys in response to a Setpoint Instruction or Scheduling Instruction during a Transmission Provider declared Emergency.

   b. The Transmission Provider will adjust the resource's registered response time to reflect its tested response. A Market Participant must provide evidence to the Transmission Provider to register such resource with a response time less than the response time achieved during the Transmission Provider initiated test during subsequent Planning Years.

   c. The Demand Resource may be tested in subsequent Seasons during the same

Planning Year.

d. The Demand Resource shall be tested in the subsequent Planning Year.

5. A Transmission Provider initiated test shall be deemed to be fully failed if the Demand Resource failed to achieve its required Demand reduction, as measured per the applicable Attachment TT Measurement and Verification identified during the registration of the resource, within six (6) hours of initiating the test for participating as DRR – Type I or LMR – Type I, within thirty (30) minutes of initiating the test for participating as LMR – Type II, and within the Offered Shut-Down time for participating as a DRR – Type II.

a. A Demand Resource experiencing a complete test failure will be subject to penalties equal to the product of the cleared ZRCs and the ACP for the entire Season in which the test was performed.

b. The Transmission Provider shall perform a test in the subsequent Season the resource has cleared ZRCs.

c. A resource failing two (2) tests during a single Planning Year shall be fully disqualified for the remainder of the Planning Year and shall pay 2.748 times the applicable LRZ's CONE multiplied by the amount of cleared ZRCs for each Season.

Penalty Provisions for LMRs

Unless an LMR is unavailable as a result of maintenance requirements, for reasons of Force Majeure, or because the number of required deployments based on the registered number has been reached, the Market Participant representing the entity that had ZRCs from LMRs that cleared in the PRA, were used in a FRAP, or were used in an RBDC Opt Out will be subject to the following penalties in the event the LMR is called upon during an Emergency as declared by the Transmission Provider and the LMR fails to perform in accordance with its Market Participant's response to such Market Participant's Scheduling Instructions. The penalties defined below will only apply to the portion of the Market Participant's response to such Market Participant's Scheduling Instruction that is not followed during the Emergency declaration and will only be assessed by the Transmission Provider after giving the operator of the LMR an opportunity to provide documentation of the specific circumstances that would justify exemption from such penalties. There will not be an LMR penalty assessed for any portion of the Scheduling Instruction which had already been accomplished by an LMR for other reasons (*e.g.*, for economic considerations, self-scheduling at or above the credited amount of BTMG or local reliability concerns in accordance with instructions from the Local Balancing Authority) at the time the request for interruption is made by the Transmission Provider. Likewise, for certain Demand Resources that are temperature dependent (*e.g.*, a Demand Resource program involving air conditioning load), the specified Demand reduction may be adjusted in a manner defined in the measurement and verification procedures developed by the Transmission Provider to reflect the circumstances at the time a Demand Resource is called upon to reduce Demand.

a. The Transmission Provider shall assess the responsible Market Participant the costs that were otherwise incurred to replace the deficient Planning Resource at the time the Market Participant's LMR is called upon by the Transmission Provider and does not respond in full or in part consistent with the Market Participant's response to MISO's Scheduling Instructions. These costs will be the product of the amount of specified Demand reduction not achieved and the Hourly Real-Time Ex Post LMP at the Load CPNode, plus any applicable Revenue Sufficiency Guarantee charges. The Transmission Provider shall allocate any such penalty revenues only to the Market Participants representing the LSEs in the Local Balancing Authority Area(s) that experienced the Emergency that required the use of an LMR. Such revenues shall be distributed on a Load Ratio Share basis. For any situation where either an LMR does not respond to an interruption request, including those circumstances where the LMR is claimed to be unavailable as a result of maintenance requirements or for reasons of Force Majeure, the Transmission Provider shall initiate an investigation with the Market Participant which has registered the Demand Resource or BTMG and was qualified as an LMR into the cause of the LMR not being available when called upon to reduce Demand. If deemed appropriate by the Transmission Provider, the Transmission Provider will disqualify the Demand Resource or BTMG from further use as an LMR for the remainder of the current Planning Year, and will discontinue payment of the applicable ACP for the remainder of the current Planning Year when the LMR was unavailable. If such

LMR was used in a FRAP or cleared in the PRA or used in an RBDC Opt Out, then the Market Participant will be charged the applicable ACP for the remainder of the current Planning Year for the Unforced Capacity of the LMR. The revenues collected will be distributed on a *pro rata* basis in such LRZ based upon an LSE's Final PRMR.

b. In the event the same LMR is unavailable on a second occasion (with at least a separation period of 24 hours) when called upon to respond to Scheduling Instructions, except for a validated circumstance of maintenance requirements or for reasons of Force Majeure, the Market Participant taking credit for that LMR shall make the same penalty payment as indicated in Section 69A.3.9.a above, and the Demand Resource or BTMG will no longer qualify as an LMR and will not receive the applicable ACP for the remainder of the current Planning Year and will not be eligible for LMR status for the next Planning Year. If such LMR was used in a FRAP or cleared in the PRA or used in an RBDC Opt Out, then the Market Participant will be charged the applicable ACP for the remainder of the current planning year for the Unforced Capacity of the LMR. The revenues collected will be distributed on a *pro rata* basis in such LRZ based upon an LSE's Final PRMR.

Non-Emergency Behind the Meter Generation Eligibility

1. A Market Participant that possesses ownership or equivalent contractual rights in a behind the meter generator can register such behind the meter generator as a Non-Emergency BTMG to participate in the Planning Resource Auction as documented in the BPM for Resource Adequacy. The Market Participant registering the Non-Emergency BTMG must include the contracts with each behind the meter generator indicating rights behind the Non-Emergency BTMG to generate behind-the-meter generation. Notwithstanding, a copy of a contract with a behind the meter generator will not be required if the Market Participant is, or has non-contractual legal rights to control, the behind the meter generator. In addition, the Market Participant must meet the following requirements:

    a. A Market Participant shall be prohibited from registering into the PRA any Non-Emergency BTMG that is concurrently registered, in whole or in part, whether by the same or a different Market Participant.

    b. The Non-Emergency BTMG must be equal to or greater than 100 kW (a grouping of smaller resources aggregated together as a single Non-Emergency Behind the Meter Generation resource may qualify in meeting this standard).

    c. At registration, a Market Participant registering a Non-Emergency BTMG must commit to participate as a Non-Emergency BTMG for three (3) Planning Years. After three (3) Planning Years, a Market Participant may commit to participate as a Non-Emergency BTMG for an additional three (3) Planning Years or may elect to participate as a DRR – Type I or an LMR. A resource participating as a Non-

Emergency BTMG may opt to participate as a DRR – Type II Resource at any time by satisfying the requirements of a DRR – Type II.

d. A Non-Emergency BTMG has no obligation to respond to a Transmission Provider Setpoint Instruction or Scheduling Instruction.

e. A Market Participant registering a Non-Emergency BTMG shall demonstrate GVTC capability for the applicable Season in each Planning Year on an annual basis as established in the Business Practices Manual for Resource Adequacy. A Market Participant of an existing Non-Emergency BTMG must submit the GVTC results to the Transmission Provider no later than October 31 prior to such Planning Year. If circumstances prevent the Market Participant from submitting the GVTC results for the Non-Emergency BTMG by October 31, the Market Participant must notify the Transmission Provider no later than five (5) Business Days after October 31 and request an extension. The extension request must include a reasonable explanation and justification for missing the deadline and an expected completion date prior to the upcoming Planning Year. The Transmission Provider will review each extension request on a case by case basis to determine whether or not to approve or deny the request to extend the GVTC deadline. Denial of an extension will not preclude the Market Participant for the Non-Emergency BTMG from utilizing the ICAP Deferral process as described in Section 69A.7.9.

A Market Participant of all new Non-Emergency BTMGs, or an existing accredited Non-Emergency BTMG that have increased installed capacity, shall

submit their GVTC to the Transmission Provider prior to qualification, but no later than March 1 prior to the PRA.

A Market Participant may request an extension of these deadlines pursuant to Section 69A.3.10.2.

f. A Market Participant shall submit generator availability data (including, but not limited to, NERC GADS information) into a database provided by the Transmission Provider and as established in the Business Practices Manual for Resource Adequacy. A Market Participant is not required to report generator availability data based on GVTC for a Non-Emergency BTMG less than 10 MW if the Market Participant has never provided such data for such Non-Emergency BTMG. A Market Participant that begins reporting generator availability data based upon GVTC for a Non-Emergency BTMG that is less than 10 MW must continue to report such data.

g. A Market Participant for Non-Emergency BMTG shall submit Meter data at regular intervals as set forth in Attachment TT.

2. Installed Capacity (ICAP) Deferral

If a Market Participant for a Non-Emergency BTMG has not completed GVTC testing by the deadlines provided in 69A.3.10(e), is not expected to demonstrate deliverability, or is otherwise not expected to demonstrate commercial operation prior to March 1, ZRCs from such capacity may be used the PRA, in a FRAP (including through bilateral ZRC transactions), or in an RBDC Opt Out, subject to the notification, credit, and non-compliance provisions of Section 69A.7.9.

Planning Resource Capacity Values

In order for the Transmission Provider to account for resource performance and availability, Capacity Resources, Demand Response Resources – Type I, Load Modifying Resources, and Non-Emergency Behind the Meter Generation will be given a capacity value for each applicable Season based on the Seasonal Accredited Capacity calculation applicable to its Resource type; and EE Resources will be given capacity values based on the measurement and verification data provided for such resources, as provided in the BPM for Resource Adequacy.

Seasonal Accredited Capacity of Capacity Resources

The Transmission Provider will determine the Seasonal Accredited Capacity for each Capacity Resource.

a. The Seasonal Accredited Capacity for a Capacity Resource that is a Generation Resource, but not a Dispatchable Intermittent Resource, Intermittent Generation, Electric Storage Resource, External Resource, or Use Limited Resource, is based on an evaluation of the type and volume of interconnection service, GVTC value, and Real-Time offered availability of such Generation Resource or Electric Storage Resource for each Season as set forth in Schedule 53.

b. The Seasonal Accredited Capacity for a Capacity Resource that is an External Resource, but not a Dispatchable Intermittent Resource, Intermittent Generation or Use Limited Resource, is based on the GVTC value and $XEFOR_d$ values of such External Resource for each Season. External Resources that are not required to report generator availability data will have a forced outage rate based on the class average forced outage rate of the resource type.

c. The Transmission Provider will determine the Seasonal Accredited Capacity for a DRR – Type II that qualifies as a Capacity Resource, for each Season, as set forth in Schedule 53B.

d. The Seasonal Accredited Capacity for a Capacity Resource that is a Dispatchable Intermittent Resource or Intermittent Generation will be determined by the Transmission Provider based on historical performance, availability, and type and volume of interconnection service, for each Season in accordance with the BPM

for Resource Adequacy.

e. The Seasonal Accredited Capacity value for a Capacity Resource that is a Hybrid Resource will be established by the Transmission Provider based on the sum of the Seasonal Accredited Capacity values of its respective Electric Facilities for the production and/or storage for later injection of electricity, up to the level of firm interconnection service, prior to a minimum amount of operating data becoming available. Once sufficient operation data is available, as defined in the BPM, the Seasonal Accredited Capacity value for a Hybrid Resource will be determined by the Transmission Provider based on historical performance, availability, and type and volume of interconnection service, for each Season in accordance with the BPM.

f. The Seasonal Accredited Capacity of a Capacity Resource that is an Electric Storage Resource will be established by the Transmission Provider based on an evaluation of the type and volume of interconnection service, a GVTC value based upon a power and energy test, and an $XEFOR_d$. Electric Storage Resources that are not required to report generator availability data will have an $XEFOR_d$ rate based on their class average forced outage rate.

g. The Seasonal Accredited Capacity for a Capacity Resource that is a Use Limited Resource will be determined by the Transmission Provider based on the type and volume of interconnection service, the GVTC and $XEFOR_d$ values of such Use Limited Resource in accordance with the BPM for Resource Adequacy.

Seasonal Accredited Capacity of Demand Resources

The Transmission Provider will determine the appropriate Seasonal Accredited Capacity value for Demand Resources that qualify as a Planning Resource as established in Schedule 53B.

Seasonal Accredited Capacity of Behind the Meter Generation and Non-Emergency Behind the Meter Generation

The Transmission Provider will determine the Seasonal Accredited Capacity for each BTMG and Non-Emergency BTMG as set forth in Schedule 53B. If such BTMG or Non-Emergency BTMG is interconnected to the Transmission System, the Transmission Provider will consider the type and volume of interconnection service when determining the Seasonal Accredited Capacity.

EE Resources

The Seasonal Accredited Capacity for a qualified EE Resource will be determined by the Transmission Provider based upon submitted measurement and verification documents, as provided in the BPM for Resource Adequacy.

Attributes of ZRCs

A Market Participant that owns or possesses equivalent contractual rights to a qualified Planning Resource can convert the convertible Seasonal Accredited Capacity of the Resource (Seasonal Accredited Capacity MW) as determined in section 69.A.3.1.g into ZRCs through the MECT in order to offer such ZRCs into a PRA. Market Participants also can unconvert and/or transfer ZRCs through the MECT to another Market Participant, as described in the BPM for Resource Adequacy.

A. Eligibility for Zonal Resource Credits for a Capacity Resource that is a Planning Resource that is not Intermittent Generation or Dispatchable Intermittent Resource.

For a Capacity Resource that is not Intermittent Generation or Dispatchable Intermittent Resource the amount of Capacity that is eligible to be converted to Zonal Resource Credits shall be the convertible Seasonal Accredited Capacity value of the Capacity Resource. The convertible Seasonal Accredited Capacity shall be determined by:

i. Determining the Installed Capacity;

ii. Determining the Seasonal Accredited Capacity of the Capacity Resource;

iii. Allocating the Capacity Resource's Seasonal Accredited Capacity value where:

a. If the Capacity Resource has only Energy Resource Interconnection Service, the Seasonal Accredited Capacity will be allocated to the Capacity Resource's Energy Resource Interconnection Service Seasonal Accredited Capacity value, which will be calculated by multiplying the lesser of the Capacity Resource's ICAP or Energy Resource Interconnection Service by SAC divided by ICAP;

b. If the Capacity Resource has both Network Resource Interconnection Service and Energy Resource Interconnection Service, the Seasonal Accredited Capacity will be allocated first to the Capacity Resource's Network Resource Interconnection Service Seasonal Accredited Capacity value, which will be calculated by multiplying the lesser of the Capacity Resource's ICAP or Network Resource Interconnection Service by SAC divided by ICAP, as provided below:

NRIS SAC = MIN (NRIS, ICAP) × (SAC/ICAP)

c. Any remaining total Seasonal Accredited Capacity value will then be allocated to Energy Resource Interconnection Service Seasonal Accredited Capacity as provided below:

ERIS SAC = MAX (0, (ICAP-NRIS)) × (SAC/ICAP)

d. The resulting Network Resource Interconnection Service Seasonal Accredited Capacity value shall be eligible to be converted into Zonal Resource Credits; and

e. The resulting Energy Resource Interconnection Service Seasonal Accredited Capacity value that is coupled with firm Transmission Service shall be eligible to be converted into Zonal Resource Credits up to the Energy Resource Interconnection Service Unforced Capacity value of the Capacity Resource, by multiplying the firm Transmission Service amount by SAC divided by ICAP.

B. Eligibility for Zonal Resource Credits for a Capacity Resource that is an Intermittent Generation or Dispatchable Intermittent Resource

For Intermittent Generation and Dispatchable Intermittent Resources that are Capacity Resources, the amount of Capacity eligible to be converted to Zonal Resource Credits shall be the convertible Seasonal Accredited Capacity value of the Intermittent Generation or Dispatchable Intermittent Resource, which is equal to the total Seasonal Accredited Capacity value multiplied by the quotient of the deliverability adjusted Capacity factor divided by the peak performance Capacity factor of the Capacity Resource where:

a. the deliverability-adjusted capacity factor is the average of the actual Energy output capped at the demonstrated deliverability of the Intermittent Generation or Dispatchable Intermittent Resource determined in Section 69A.3.1.g during the highest system peak load observances for each Season that the Capacity Resource was in service divided by the Installed Capacity of the Capacity Resource; and,

b. the existing peak performance Capacity factor is the average of the actual Energy output during the highest system peak load observances for each Season that the Capacity Resource was in service divided by the Installed Capacity of the Capacity Resource.

C. Eligibility for Zonal Resource Credits for a Capacity Resource that is a Distributed Energy Aggregated Resource

For Distributed Energy Aggregated Resources that are Capacity Resources, the amount of Capacity eligible to be converted to Zonal Resource Credits shall be the convertible Seasonal

Accredited Capacity value of the Distributed Energy Resources within the aggregation according to their resource type as determined in section 69A.3.1.g.

Capacity Resource Must Offer and Performance Requirements

a. Market Participants that convert Seasonal Accredited Capacity from Capacity Resources into ZRCs that clear in a Season in the PRA or are used in a FRAP (and that do not replace such ZRCs in accordance with Section 69A.3.1.h) or used in an RBDC Opt Out, including Capacity Resources that are the subject of Diversity Contracts, must submit Self-Schedules or Offers for Energy, and Contingency Reserve if qualified, and offers for Short-Term Reserve if qualified, for the Installed Capacity value of the Capacity Resources converted to ZRCs and clear in a Season in the PRA or used in a FRAP or used in an RBDC Opt Out for each Hour of each Day during the applicable Season in the Planning Year, in the Day-Ahead Energy Market and all pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment process. This must offer obligation does not apply to the extent that the Capacity Resource is unavailable due to a full or partial forced or scheduled outage, in accordance with the BPM for Resource Adequacy and the BPM for Outage Operations. Additionally, this must offer obligation is modified to the extent the Capacity Resource is provided an operating limitation, such as thermal, voltage, or stability limits referenced in the BPM for Outage Operations, by the Transmission Provider or Transmission Operator to preserve the reliability of the Transmission System, that is lower than the must offer obligation described above, for the duration of such limitation.

Any such Capacity Resource with full or partial Generator Planned Outages that exceeds thirty-one (31) Days during any Season will be deemed not to have met its performance requirement for any Days greater than thirty-one (31) Days and must replace ZRCs in

accordance with Section 69A.3.1.h, provided that Capacity Resources subject to Diversity Contracts that are unavailable for greater than thirty-one (31) Days in total during any Season, will be deemed not to have met its performance requirement and will be subject to the ZRC replacement provisions set forth in Section 69A.3.1.h. Self-Schedules or Offers for Energy must be made consistent with requirements specified in Sections 39 and 40 of this Tariff as well as in the BPM for Resource Adequacy and the Business Practices Manual for Energy and Operating Reserves Markets. Partial or full forced or scheduled outages or derates of Capacity Resources must be reported in the Transmission Provider's Outage Scheduler, as described in further detail in the Business Practices Manual for Outage Operations. Must offer requirements specified in the BPM for Resource Adequacy will reflect resource operational limitations, including those related to Use Limited Resources, fuel limited, energy output limited or Intermittent Generation and including all state regulations and laws, including but not limited to, state safety standards, planning reserve margins, or the enforcement thereof. The Transmission Provider will monitor compliance with must offer requirements in accordance with the BPM for Resource Adequacy.

b. If a Capacity Resource that has ZRCs cleared in the PRA during any Season or is used in a FRAP during any Season or used in an RBDC Opt Out is capable of performing but fails to perform when called upon by the Transmission Provider for an Emergency, the Transmission Provider shall assess the owner of such Capacity Resource the costs that were otherwise incurred to replace the energy from the deficient Capacity Resource at the time that the Capacity Resource is called upon by the Transmission Provider and does not

respond in full or in part, for each day of non-performance of such Capacity Resource, provided that the planned or forced outage of the Capacity Resource is not properly reported in the Transmission Provider's Outage Scheduler, as set forth in the Business Practices Manual for Outage Operations. These costs will be the product of the amount of qualified ZRCs not achieved and the real-time LMP at the Capacity Resource's CPNode, plus any applicable related Revenue Sufficiency Guarantee charges. The Transmission Provider shall allocate any such revenues to the Market Participants representing the LSEs in the Local Balancing Authority Area(s) that experienced the Emergency. Such revenues shall be distributed on a Load Ratio Share basis.

c. Market Participants must input all Energy Efficiency Resource and Load Modifying Resource information into the MECT at least seven (7) Business Days prior to the Planning Resource Auction.

State RAR Standards

The Transmission Provider will assist states in meeting any state resource adequacy standards by providing relevant MECT information as available and as may be requested by states, subject to the data confidentiality provisions in Section 38.9 of this Tariff. Nothing in the RAR shall prohibit any state from requesting data relating to state safety standards, planning reserve margins, or the enforcement thereof.

Information regarding RAR Obligations

The Transmission Provider will maintain databases and will report to states and the affected LSEs, upon request, aggregated, non-confidential information regarding jurisdictional LSEs' RAR obligations during relevant time periods. Confidential Data regarding RAR status will be provided to states only in accordance with the data confidentiality provisions in Section 38.9 of this Tariff.

Facilitation of a Bilateral Capacity Bulletin Board

The Transmission Provider shall maintain an electronic bulletin board platform that may be used by Market Participants to facilitate voluntary bilateral ZRC transactions and to monitor the conversion of Seasonal Accredited Capacity to ZRCs.

Facilitation of LSE’s RAR Information

The Transmission Provider shall, upon request, submit RAR information to the applicable RE, Electric Reliability Organization, state (in the case of an LSE subject to regulation or using delivery services rates, terms or conditions established by such State Regulatory Authority) or to the Commission, subject to the provisions of Section 38.9 of this Tariff.

Reliability Based Demand Curve Procedures

A. Translation of MRI Curves to RBDCs

The following process will be utilized to determine the RBDC for the Transmission Provider Region for each Season of the upcoming Planning Year. The MRI Curves for the Transmission Provider Region as described in Section 68A.9 will be multiplied by a scaling factor measured in $/MWh. The scaling factor for an RBDC is calculated to support ACPs that achieve annual Net CONE when the Transmission Provider Region is at the reliability requirement established by the LOLE analysis for each Season. LOLE risk across the Seasons is modeled as described in Section 68A.2.1. The scaling factors shall be determined as set forth in the Business Practices Manual for Resource Adequacy.

The process used to determine the RBDCs for each of the First Planning Area and the Second Planning Area for each Season in the Planning Year is similar to the process used for developing the RBDC curve for the Transmission Provider Region.

B. Monte Carlo Analysis

Every three Planning Years, the Transmission Provider will evaluate the ability of RBDCs, through probabilistic analysis, to reliably serve the Transmission Provider Region's Demand while supporting ACPs that achieve annual Net CONE when the Transmission Provider Region is at the reliability requirement established by the LOLE analysis for each Season. The probabilistic analysis shall use a Monte Carlo study that assumes there are no internal transmission limitations within the Transmission Provider Region.

The Monte Carlo analysis will model both in-market supply and demand based on historic supply and demand variability, respectively, observed through a minimum of the three

most recent PRAs. The Monte Carlo model will produce seasonal clearing prices and quantities with each draw. Overall model results will be assessed by comparing the average of seasonal prices from the study against the estimate of Net CONE described in section 69A.8. The scaling factor is adjusted in each successive Monte Carlo simulation so that long run equilibrium conditions are ultimately achieved, indicated by the average of seasonal prices from the study equal to the estimate of Net CONE. Net CONE values used for the Monte Carlo analysis will be the simple arithmetic average of all LRZ Net CONE values.

A separate Monte Carlo analysis will be performed to evaluate the RBDCs for the First Planning Area and the Second Planning Area. Separate scaling factors will be used in the Monte Carlo analysis for each of the First Planning Area and the Second Planning Area that supports achievement of Net CONE values for the corresponding Planning Area, indicated by the average of seasonal capacity prices under long run equilibrium conditions. Net CONE values used in the Monte Carlo analysis for the RBDCs for the First Planning Area and the Second Planning Area will be the simple arithmetic average of LRZ Net CONE values for the specific LRZs in the corresponding Planning Area.

Planning Resource Auction

Within twenty (20) Business Days after the last Business Day in March, the Transmission Provider will conduct a PRA to determine the ACP in each LRZ and ERZ for the upcoming Planning Year which begins on June 1st. The Transmission Provider will post the results of the PRA on its website, consistent with the standards and procedures set forth in the BPM for Resource Adequacy. The Transmission Provider shall ensure that each Market Participant submitting a ZRC Offer is qualified to submit such an offer consistent with the Transmission Provider's creditworthiness provisions. The Transmission Provider will ensure that the LCR, the CEL and CIL are respected for each LRZ, the CEL is respected for each ERZ, and the SREC and the SRIC are respected for each SRRZ, if applicable, when conducting the PRA.

PRA Procedures

a. **Participating ZRCs in the PRA:** All Market Participants that own or have contractual rights to the Planning Resources that are represented within an LRZ or ERZ and have converted Seasonal Accredited Capacity to ZRCs, will have an option to (consistent with withholding provisions) submit offers into the PRA for such ZRCs, to the extent that the Market Participant has not submitted a FRAP, or RBDC Opt Out, as described in Section 69A.9. Owners of jointly-owned facilities can individually offer their share of any such resources into the PRA, either as self-schedule price takers or with specific offers, or use their share of such resources as part of their FRAPs, or RBDC Opt Outs. These ZRC Offers must be submitted in price/quantity pairs on a monotonically increasing basis expressed as MW-day and must consist of a stepped ZRC Offer curve of up to five (5) segments for each Planning Resource. ZRC Offers shall be submitted to the Transmission Provider via the MECT during the PRA offer window. Only ZRCs that are not otherwise committed for the remainder of the Planning Year are permitted to participate in the PRA. The PRA offer window shall begin at 8:00 am EPT three (3) Business Days before the last Business Day in March and shall end at 6:00 pm EPT on the last Business Day in March. The Transmission Provider may extend or reopen the PRA offer window based on unanticipated events that: (i) interfere with the Transmission Provider's ability to receive and/or process accurate and complete ZRC Offers or (ii) are otherwise likely to have a widespread negative impact on the results of the PRA. The Transmission Provider shall notify Market Participants and post such notice of any extension or reopening of the PRA on its website. The notice shall state the extension or

reopening's circumstances, rationale, and duration. The price associated with these ZRC Offers cannot exceed the annual CONE value divided by the number of days in the Season for the LRZ where the ZRC is represented. ZRC Offers from External Resources represented in ERZs, which are connected to single SRRZ, cannot exceed the greatest CONE value of all LRZs in respective SRRZ. ZRC Offers from External Resources represented in ERZs, which are connected to multiple SRRZs or are not connected to any SRRZs, cannot exceed the greatest CONE value of all LRZs in those connected SRRZs. Owners of ZRCs may bilaterally sell or buy ZRCs; however if a ZRC has cleared in the auction, the Market Participant that registered the Planning Resource that is the subject of such ZRC shall be responsible for complying with all Tariff requirements. The Independent Market Monitor will review the actions of owners/operators of all qualified Seasonal Accredited Capacity from Planning Resources and conversion to ZRCs to evaluate potential withholding of Planning Resources from the PRA, consistent with Module D. External Resources, including Generation Resources pseudo-tied into the MISO Balancing Authority Area, will be granted ZRCs in the applicable External Resource Zone. Notwithstanding the above, External Resources located within a Coordinating Owner that (i) borders the Transmission Provider Region; (ii) whose external ties are predominantly to the Transmission System; and (iii) has Seams Operating Agreements that allow for coordinated operations, will be granted ZRCs in the LRZ where their firm transmission service crosses the border of the Transmission Provider Region, and Border External Resources will be granted ZRCs in the LRZ where the Transmission System connects to the substation with its interconnection facilities.

Generation Resources, Intermittent Generation, Electric Storage Resources, and Dispatchable Intermittent Resources will have to meet the terms of Section 69A.3.1.g.

To the extent a Capacity Resource is located on the border of two or more LRZs (e.g., has transmission lines from two or more LRZs terminating at the substation containing the Capacity Resource's interconnection facilities), the Capacity Resource will be assigned to an LRZ as follows:

(i) if the Capacity Resource is located within the MISO BA, MISO will assign that Capacity Resource to the LRZ that contains the Local Balancing Authority in which the Capacity Resource is physically located; or

(ii) if the Capacity Resource is a Border External Resource, MISO will assign that Capacity Resource to the LRZ with which it has the greatest electrical connection. This connection will be determined by the impacts of the Resource on the system, including (i) the electrical loading of transmission facilities within and tying to the Zone and (ii) the transmission constraints which define the CIL and CEL for the Zone.

Once assigned, Capacity Resources which border two or more LRZs will not be reassigned unless significant changes occur in the Transmission Provider Region, including but not limited to, significant changes in LRZ boundaries, membership, the Transmission System, and/or Resources.

b. Participating Demand: All LSEs will be required to meet their Final PRMR through the PRA process, unless they have decided to pay the Capacity Deficiency Charge. LSEs can Self-Schedule ZRCs to meet their PRMR, consistent with the Self-

Scheduling Option in Section 69A.7.8. The Transmission Provider will conduct the PRA based upon the PRMR for the Transmission Provider Region minus the amount of PRMR associated with the Capacity Deficiency Charge, expressed as a variable reliability target through RBDCs for all of the LSEs located within the Transmission Provider Region.

c. Conducting the PRA: The Transmission Provider will conduct the PRA for each Season using the following auction procedures to determine the ACP for each LRZ and ERZ. The PRA shall be designed to commit resources equal to the Final PRMR determined by application of the RBDC for each LSE, minus the amount of PRMR associated with the Capacity Deficiency Charge but including resources used in a FRAP and an RBDC Opt Out, in each LRZ up to the total volume of offered ZRCs. All ZRCs offered at zero price will clear the PRA. The PRA shall clear for each LRZ and ERZ of the Transmission Provider Region. A multi-zone optimization methodology shall be employed to simultaneously perform the following tasks: (1) conduct the PRA to meet the supply and demand balance both for the Transmission Provider Region and for each of the First Planning Area and the Second Planning Area by clearing ZRC Offers and establishing the Final PRMR, as determined by application of the RBDCs, minus the amount of PRMR associated with the Capacity Deficiency Charge for each LRZ of the Transmission Provider Region to yield cleared ZRCs; (2) meet the LCR for each LRZ; (3) efficiently use transmission transfer capability between LRZs and from ERZs; and (4) respect the SREC and SRIC for each SRRZ, if applicable.

(i) **Objective Function:** The objective of the multi-zone optimization methodology shall be to maximize social surplus, using the as-offered overall

costs of capacity procurement and the as-bid overall benefits of capacity procurement reflected in the RBDCs over the time horizon, subject to LCR, network constraints, and SRICs and SRECs, if applicable. The overall costs will include the ZRC Offers of all Planning Resources selected for cleared ZRCs. CILs of each LRZ are simultaneous to the extent that imports into the LRZ are concurrently simulated; and CELs of each LRZ and ERZ are simultaneous to the extent that exports out of the relevant LRZ or ERZ are concurrently simulated. Network constraints will be represented by an initial set of zonal CELs and CILs, driven by the dispatch from planning models. The CELs and CILs will be reviewed by the Transmission Provider to determine if there are network loading violations when based on the geographical dispatch derived from the initial auction clearing. If no network violation is indicated, then the auction results are final. If a network violation is indicated, then reductions will be made to the affected export and import capabilities to avoid network violations and the auction will be cleared again with the new set of export and import capabilities. After a maximum of two (2) successive iterations per Season to address network violations, the auction clearing iteration with the fewest megawatts of network violations will be deemed as the final auction result.

(ii) **Time Horizon:** For purposes of clearing the system-wide PRMR the time horizon is an hour, representing the projected maximum Coincident Peak Demand. For a Local Resource Zone, the time horizon is the hour representing the Local Resource Zone Peak Demand, over each Season for the next Planning

Year for the Transmission Provider Region. Coincident Peak Demand is used to establish an LSE's Initial PRMR while Local Resource Zone Peak Demand is used to establish an LRZ's LRR.

(iii) **Capacity Market and Congestion Management:** The multi-zone optimization methodology will perform congestion management simultaneously with the scheduling of capacity for each Season in the Planning Year. Congestion management is the process where ZRCs are cleared to eliminate network constraint violations and to maximize the social surplus of procuring PRMR to meet applicable reliability standards.

(iv) **Model of Transmission Provider Transmission System:** The multi-zone optimization methodology will enforce network constraints represented by CILs, CELs and LCRs that are obtained by using a model of the transmission system including Planning Resources and Demand which will be updated annually to reflect existing and planned transmission and generation projects. Transmission and Planning Resources shall be modeled as part of the multi-zone optimization methodology to reflect their expected state during the peak Hour of each Season in the Transmission Provider Region. The model is of zonal form, which shall include all Planning Resources, Demand, and a representation of systems external to the Transmission Provider Region, and which will be consistent with seams agreements with neighboring regions.

Network Constraints. The multi-zone optimization methodology shall enforce constraints on transmission lines, transformers, and groups of

transmission branches that compose transmission interfaces represented by LCR, CIL, and CEL. Most of these constraints shall represent thermal limits on the power flow through transmission facilities. Certain constraints may impose more restrictive limits on power flow, taking into account contingencies and typically represented through operating guides.

Transmission Losses. The multi-zone optimization methodology will clear ZRCs to cover transmission losses; the PRMR will include estimates of transmission losses in its calculation for each Season.

(v) **LRZ ACP Calculation:** The Auction Clearing Price (ACP) for an LRZ is the marginal cost of serving the Demand in that LRZ. The ACP is composed of the system marginal cost of capacity, the regional marginal cost of capacity, the marginal cost of financially binding LCR, CEL, and CIL for a LRZ, (*i.e.*, network constraints that are active at the optimal solution prohibiting a lower cost outcome), and the marginal cost of financially binding SRECs and SRICs for SRRZs, if applicable. The ACP is calculated by considering the next increment or decrement to Demand for each LRZ. The Transmission Provider will calculate ACPs for each LRZ. For accounting purposes, ACP will be expressed in dollars per megawatt-day ($/MW-day).

(vi) **External Resource Zone (ERZ) ACP:** The ACP for an ERZ is comprised of the system marginal cost of capacity, marginal cost of financially binding CEL for the ERZ, the marginal cost of financially binding SRECs and SRICs for SRRZ with which the ERZ interconnects. For ERZs which connect with more than one

SRRZ, or which do not directly connect to a single SRRZ, a weighted average of the marginal cost of financially binding SREC and SRIC will be applied, with weights derived from the distribution of annual energy flows into the SRRZs from the ERZ. For accounting purposes, ACP will be expressed in dollars per megawatt-day ($/MW-day).

(vii) **ACP Inputs:** Primary inputs to the ACP calculation are network constraints represented by CIL, CEL, LCR, and other constraints established by the Transmission Provider associated with SRECs and SRICs for SRRZs in accordance with applicable seams agreements, coordination agreements, or transmission service agreements and the set of valid ZRC Offers and the Final PRMR for the Transmission Provider Region minus the amount of Initial PRMR associated with the Capacity Deficiency Charge for each LRZ. Valid ZRC Offers may include offers from ZRCs converted from confirmed Seasonal Accredited Capacity from Planning Resources. ZRC Offers can be submitted as Self-Schedules, in accordance with Section 69A.7.8.

(viii) **ACP Outputs:** For non-zero ACPs, Resources that set the ACP in a LRZ or ERZ will be cleared in proportion to the amount of ZRCs necessary to meet the Final PRMR. When more than one resource is marginal and offered at the ACP, then all resources offered at the ACP are cleared *pro rata* up to the amount required to meet the reliability requirement. This may result in a portion of multiple Resources clearing as the marginal resources that set the ACP.

(ix) **Eligibility Rules:** ACPs can be set by any ZRC Offers.

(x) **ACP for multiple Seasons with ZRC Shortage Conditions or ZRC Near-Shortage Conditions to meet Local Clearing Requirements:**

When an LRZ has more than one Season in any combination of ZRC Shortage Conditions and/or ZRC Near-Shortage Conditions the final Auction Clearing Price (ACP) for the LRZ will be set as the minimum of: (a) the original ACP as determined in Section 69A.7.1.c.(v) reflecting the effective financial binding of an LCR constraint; or (b) the summation of: (i) the amount composed of the system marginal cost of capacity, the regional marginal cost of capacity, and the marginal cost of financially binding SRECs and SRICs for SRRZs, if applicable; and (ii) the LCR price adder. The LCR price adder will be set as the amount obtained by dividing the applicable LRZ's annual CONE value by the summation of the number of days in Seasons in each Season of the Planning Year in which the LRZ was in ZRC Shortage Conditions in the Planning Resource Auction and the number of days in each Seasons of the Planning Year in which the LRZ was in ZRC Near-Shortage Conditions in the Planning Resource Auction.

(xi) **Notification:** ACPs and total summarized cleared ZRC Offers determined as described above shall be calculated and published by the Transmission Provider by 11:59 pm EST on the twentieth Business Day following the last Business Day in March. The Transmission Provider may extend the publishing deadline based on unanticipated events that: (i) interfered with the Transmission Provider's ability to receive and/or process accurate and complete ZRC Offers or (ii) were

otherwise likely to have a widespread negative impact on the results of the PRA. The Transmission Provider shall notify Market Participants and post such notice of any extension of publishing the results of the PRA on its website. The notice shall state the extension's circumstances, rationale, and duration.

Consequences of PRA

All PRA transactions will be financially binding. Market Participants with cleared ZRC Offers must comply with all of the ZRC requirements for all ZRCs that clear in the PRA.

Uncleared ZRCs

Once the PRA has concluded, a Market Participant may convert back to Seasonal Accredited Capacity any ZRCs that do not clear in the PRA.

PRA Reporting

The Transmission Provider will not reveal the ZRC Offers submitted by any Market Participant in a PRA until one (1) month following the completion of the PRA, except as required pursuant to the provisions of Section 38.9 of the Tariff. When the ZRC Offers are posted, price/quantity pairs will be made public, however the names of the Market Participants submitting such offers and the names of the Planning Resources offered shall not be publicly revealed.

Market Monitoring

All actions of Market Participants participating or failing to participate in the PRA shall be subject to the provisions of Module D, except to the extent that a Market Participant has opted out of the PRA as described in Section 69A.9. The Transmission Provider will report any known attempt to exercise market power by LSEs or by Market Participants in the PRA procedures to the Independent Market Monitor.

PRA Settlement

a. Cleared ZRC Offers will be settled at the ACP for the LRZ or ERZ where the ZRC is represented on a daily basis and the Market Participants submitting cleared ZRC Offers will be credited on a weekly basis by the Transmission Provider. The Transmission Provider will settle the LSEs cost of their Final PRMR minus the amount of PRMR associated with the Capacity Deficiency Charge at the ACP for the LRZ where the Demand is located on a daily basis and will debit LSEs weekly, to the extent that an LSE has not opted out of the PRA pursuant to Section 69A.9 or submitted an RBDC Opt Out pursuant to Section 69A.9.1. For LSEs not selecting RBDC Opt Out, the Final PRMR will be established based on the financial binding of RBDCs representing the Transmission Provider Region and applicable planning area (i.e., the First Planning Area or the Second Planning Area).

Final PRMRs will be determined as follows:

i. LSEs using the RBDC Opt Out will have Final PRMRs calculated by multiplying the LSE's forecasted Coincident Peak Demand for each Season, including transmission losses, by (1 + Transmission Provider Region PRM + RBDC Opt Out Adder).

ii. LSEs not using the RBDC Opt Out will have Final PRMRs calculated using the formula below:

$$\textit{Final PRMR for a LSE not using the RBDC Opt Out}$$
$$= \left(\textit{PRA Cleared Capacity} - \sum \textit{Final PRMR for LSEs using the RBDC Opt Out}\right) \times \frac{\textit{Initial PRMR of the LSE not using the RBDC Opt Out}}{\sum \textit{Initial PRMR of all LSEs not using the RBDC Opt Out}}$$

iii. LSEs under state jurisdiction where the State Regulatory Authority has overridden the PRM established by the Transmission Provider will have Final PRMRs for each Season calculated by multiplying the LSE's forecasted Coincident Peak Demand for each Season, including transmission losses, by (1 + the planning reserve margin established by the State Regulatory Authority).

The Transmission Provider will financially net the ZRC credits and LSE debits for Market Participants. Market Participants with cleared ZRCs sourced from Diversity Contracts will receive reduced credit for any ZRC volumes cleared above their PRMR up to the cleared volume of ZRCs from Diversity Contracts. The reduced compensation will be based on the total number of days the capacity from the Diversity Contract is dedicated to Demand in the Transmission Provider Region in each Season divided by the total number of days in the Season.

b. An LSE that submits a FRAP or an RBDC Opt Out with PRMR in an LRZ and ZRCs in an ERZ or a separate LRZ may be subject to a ZDC, as described below:

(i) The Zonal Deliverability Charge will be the maximum of: (a) the difference between the ACP for the LSE's PRMR within an LRZ where an LSE has Demand

that is not met by ZRCs from Planning Resources that are represented in such LRZ and the ACP in the LRZ or ERZ where the LSE's ZRCs are represented; or (b) zero. The Transmission Provider will multiply the ZDC by the ZRCs to obtain the deliverability charge that the Transmission Provider will assess the LSE. The Zonal Deliverability Charge will only be assessed to an LSE's Load that is part of a FRAP or for LSEs submitting ZRCs for an RBDC Opt Out.

c. Any portion of an LSE's PRMR not covered by the FRAP, minus the amount of PRMR associated with the Capacity Deficiency Charge, shall be purchased through the PRA. An LSE will be charged the applicable ACP for any PRMR that is not recovered by ZRCs in a FRAP.

d. For instances where a LRZ clears under ZRC Shortage Conditions or ZRC Near-Shortage Conditions to meet Local Clearing Requirement in more than one Season in a Planning Resource Auction and final ACPs are adjusted per Section 69A.7.1.c.(x), certain cleared ZRC Offers may exceed the final ACPs. In this case, such cleared ZRCs may be eligible for a ZRC Offer Revenue Sufficiency Credit, to the extent that settlement amounts credited in paragraph 69A.7.6.a above for a Planning Year are insufficient to cover Allowable ZRC Offer Costs, needed to be incurred by the Planning Resource to be available for cleared Seasons.

ZRC Offer Revenue Sufficiency Credit will be calculated as the greater of: (i) zero; or, (ii) the difference between Allowable ZRC Offer Costs, and the total settlement amounts credited per paragraph 69A.7.6.a for the associated cleared

ZRC Offers for all Seasons in a Planning Year.

Where Allowable ZRC Offer Costs shall equal the minimum of: (i) the sum of all cleared ZRC Offer segment volumes multiplied by the ZRC Offer segment price, multiplied by the number of Days in the Season, calculated for all Seasons for which the ZRCs clear in the Planning Resource Auction; or, (ii) the annual CONE for the LRZ where the ZRCs are represented; or, (iii) the applicable facility-specific Reference Level costs for the Planning Resource, if a Market Participant received a facility-specific Reference Level per Section 64.1.4.

ZRC Offer Revenue Sufficiency Credits will be allocated pro-rata across the Seasons where the ZRC Offer cleared for settlement and distribution.

e. ZRC Offer Revenue Sufficiency Charges will be assessed as the sum of all ZRC Offer Revenue Sufficiency Credits for a Season distributed to Market Participants representing LSEs in an LRZ clearing under ZRC Shortage Conditions or ZRC Near-Shortage Conditions on a pro rata basis, based upon their respective LSE's share of Final PRMR minus the Initial PRMR associated with the Capacity Deficiency Charge in the appropriate LRZ.

Distribution of Excess Auction Revenue

The following provisions address situations where LSEs will be entitled to receive financial benefits on contractual commitments and/or use of the Transmission System. These benefits will provide LSEs with financial hedges for ACP separation between LRZs and/or ERZs based on excess revenue from the Planning Resource Auction.

The Transmission Provider will distribute any such excess revenues in two stages:

(i) in the first stage, the Transmission Provider shall distribute such excess revenues to LSEs qualifying for Historic Unit Considerations (HUCs) as described in Section 69A.7.7(a) and ZDC Hedges as described in Section 69A.7.7.(b), then

(ii) any remaining excess revenue will be distributed in accordance with the Zonal Deliverability Benefit provisions of Section 69A.7.7(c).

The LSE will only receive excess PRA revenue if the ACP paid by the LSE is higher than the ACP received for such Planning Resources. If there are not sufficient excess revenues to fully fund all Historic Unit Considerations and ZDC Hedges, the revenues will be allocated on a pro rata basis to all HUCs and ZDC Hedges.

Historic Unit Considerations (HUCs)

The Transmission Provider will allocate excess PRA revenue to LSEs with ownership or contractual arrangements, limited to a) Grandfathered Agreements, b) arrangements that predate July 20th, 2011, or c) arrangements that predate March 26, 2018 and pertain to External Resource represented in External Resource Zones in which:

i. The LSE has Initial PRMR obligations equal to or greater than the amount of the Planning Resource designated in the arrangement;

ii. The Planning Resource designated in the arrangement and Initial PRMR obligation span multiple LRZs and/or ERZs;

iii. The LSE has long-term (five years or more) contracts for or ownership of the Planning Resource and has maintained continuous firm Transmission Service or firm Network Resource Interconnection Service, and in the case of External Resources, firm transmission service on the applicable external Balancing Authority transmission system, for that Planning Resource to the LRZ containing the LSE's associated Initial PRMR obligation; and

iv. LSEs must note qualification for HUCs and submit information supporting HUC eligibility to the Transmission Provider by January 15th prior to the upcoming Planning Year.

A combination of arrangements that require the delivery of capacity throughout the Planning Year will qualify to receive excess PRA revenue through a HUC, provided that the arrangements satisfy the criteria herein. The volume of MW eligible to receive excess PRA revenue will be the lesser of the cleared ZRCs from the Planning Resource(s) or the amount of Initial PRMR that are

associated with the qualified arrangement. A qualified arrangement shall remain eligible to receive excess PRA revenue for the current term of the executed contract, excluding any evergreen contract extension, or for two Planning Years, whichever is longer. In the event that the owned resource status is changed to retired, the transmission service is not maintained, or the arrangement is terminated or otherwise expires, the arrangement shall no longer be eligible to receive excess PRA revenue.

ZDC Hedges

An LSE will also be able to receive excess Planning Resource Auction revenue if the LSE qualifies for a ZDC Hedge. A ZDC Hedge can result from approved firm Transmission Service Request where the source and sink are in separate LRZs or between an LRZ and an ERZ that result in required Network Upgrades. The Market Participant that funds the Transmission System upgrades that result in an increase in the CIL, as determined by the Transmission Provider, for an LRZ where the sink is located, will receive a ZDC Hedge. The Market Participant submitting the Transmission Service Request will receive one hundred percent(100%) of the MW volume of the CIL increase. ZDC Hedges will be granted based upon the order that the Transmission Provider receives Transmission Service Requests. Market Participants must submit information supporting ZDC Hedges to the Transmission Provider by November 1st prior to a Planning Year. The volume of a ZDC Hedge will be the incremental increase in the CIL that resulted from the Network Upgrades identified in the approved firm Transmission Service Request. ZDC Hedges will be effective for thirty (30) years or the service life of the Transmission System facility or Network Upgrade, whichever is less.

Zonal Deliverability Benefit

If there are any remaining excess PRA revenues, the Transmission Provider will distribute the remaining amounts to Deliverability Benefit Zones.

First, the Transmission Provider will subtract PRMR and ZRCs associated with HUCs and ZDC Hedges to derive an adjusted PRMR (Adjusted PRMR) and ZRC (Adjusted ZRC). Second, the Transmission Provider shall create a DBZ for each group of LRZs that have equal ACPs which result from the same auction constraint. Third, the Transmission Provider, for each DBZ, will subtract the sum of Adjusted PRMR for each LRZ within the DBZ from the sum of Adjusted ZRCs for each LRZ within the DBZ. A DBZ will be considered a net importing DBZ if the sum of the Adjusted PRMR is greater than the sum of Adjusted ZRCs. A DBZ will be considered a net exporting DBZ if the sum of the Adjusted PRMR is less than the sum of Adjusted ZRCs. A net exporting DBZ shall not receive any ZDB credit. A net importing DBZ shall receive a ZDB credit allocation based upon a weighted average approach. Fourth, the Transmission Provider will calculate the weighted average ACP of all net exporting DBZs (Weighted Average Export ACP) to determine a financial value of export capacity within the Transmission Provider region per the formula below:

$$Weighted\ Average\ Export\ ACP = \frac{\sum(Net\ Export_j \times ACP_j)}{\sum Net\ Export_j}$$

Where j = Each net exporting DBZ

Fifth, the Transmission Provider will calculate the ZDB credit allocation, in dollars, for each net importing DBZ:

$$ZDB\ Credit_k = Net\ Import_k \times (ACP_k - Weighted\ Average\ Export\ ACP)$$

Where k = Each net importing DBZ

Finally, the Transmission Provider will distribute the ZDB credit in each DBZk by dividing the ZDB credit by the sum of Adjusted PRMR of the LRZs within each DBZk. This distribution is a credit to the initial ACP calculated for each LRZ from the PRA.

The Transmission Provider will receive FRAP and RBDC Opt Out related revenue from Zonal Deliverability Charges. The Transmission Provider will allocate such revenue to the DBZ where the PRMR associated with the ZDC is physically located. This revenue will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ to develop an ACP credit adjustment.

The Transmission Provider will also receive FRAP and RBDC Opt Out related revenues derived from ZRCs that would have received payments greater than the charges to the associated FRAP or RBDC Opt Out PRMR. The Transmission Provider will allocate such revenue to the DBZ where the ZRC associated with the FRAP or RBDC Opt Out is represented. This revenue will be allocated on a *pro rata* basis by Adjusted PRMR to all LSEs within the DBZ to develop an ACP credit adjustment. After calculating the ZDB rate(s), if there exists any remaining excess revenue (i.e. surplus), the surplus will be allocated back to the Deliverability Benefiting Zone(s) on a PRMR *pro-rata* basis.

Whenever an LRZ has an ACP that exceeds the System ACP because the LCR for that LRZ exceeds the sum of PRMR for LSEs within that LRZ, payments made to ZRCs in that LRZ will exceed the sum of receipts from LSEs within that LRZ plus any receipts from other LRZs related to such ZRCs. The revenue shortfall within such LRZ will be recovered from all LSEs within that LRZ on a PRMR pro-rata basis. PRMR covered by FRAPs and RBDC Opt Outs will be included in the pro-rata calculation, and the related amounts charged to the LSEs that use FRAPs and RBDC Opt Outs through this Local Clearing Requirement Charge.

Self-Scheduling Option:

LSEs with sufficient ZRCs within an LRZ where the LSE has forecasted Demand will be able to avoid the financial impact of that LRZ's ACP for the Final PRMR by Self-Scheduling such ZRCs into the PRA (*i.e.*, by Offering ZRCs into the PRA at a zero price so that the ZRCs will clear). For Planning Resources associated with ZRCs represented outside the LRZ where the LSE has PRMR, an LSE would also need to use the financial hedges described in Section 69A.7.7 to avoid the financial effects of potential price differences between LRZs or between an LRZ and an ERZ.

Installed Capacity (ICAP) Deferral Requirements and Charges

a. ICAP Deferral Notice. Market Participants that request ICAP deferral as provided in Sections 69A.3.1.a.2, 69A.3.1.b.2, 69A.3.1.c.2, and/or 69A.3.6.2. must provide an ICAP Deferral Notice to the Transmission Provider in writing by an officer of the company no later than February 15th prior to the Planning Year: (1) the expected ICAP value (in megawatts) from such Planning Resource and if the Planning Resource is new, the LBA or external BA where it is represented for any Season for which it wants to be eligible to offer ZRCs, (2) appropriate information validating that ICAP will be submitted to the Transmission Provider by the last business day of the Month prior to the start of any Season in which it wants to be eligible.

b. ICAP Deferral Credit Requirements. A Market Participant that provides ICAP Deferral Notice must satisfy credit requirements by March 1st prior to the Planning Year totaling the ICAP value provided in the ICAP Deferral Notice, multiplied by ninety (90) days of daily CONE values (i.e., 90/365 times CONE) for the LRZ where the Planning Resource is represented. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in respective SRRZ. For External Resources represented in ERZs which are connected to multiple SRRZs, or which are not directly connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs. If the Market Participant: (1) submits GVTC results, demonstrates deliverability, and demonstrates commercial operation, or (2) registers replacement ZRCs in accordance with Section 69A.3.1.h, then the Transmission Provider will adjust the Market

Participant's credit requirement to account for these changes within ten (10) Business Days after ICAP is submitted or replacement ZRCs have been provided to the Transmission Provider. In the event ZRCs associated with a Planning Resource for which ICAP has been deferred are unconverted in accordance with 69A.7.3, the Market Participant may provide notice to the Transmission Provider that it wishes to forfeit the deferred ICAP value. Then the Transmission Provider will adjust the Market Participant's ICAP value and credit requirement within ten (10) Business Days.

c. ICAP Deferral Non-Compliance Charges.

i. A Market Participant that provides ICAP Deferral Notice and that either (1) has not submitted ICAP for such Planning Resources by the last business day of the Month prior to the start of any Season for which it has deferred, or (2) has submitted an ICAP value demonstrating fewer megawatts are available than the ICAP value submitted in the ICAP Deferral Notice, shall be assessed ICAP Deferral Non-Compliance Charges unless it completes ZRC replacement in accordance with Section 69A.3.1.h. Assessment of ICAP Deferral Non-Compliance Charges will commence on the first day of the any Season for which a Market Participant has an ICAP deferral and continue until ICAP is submitted and verified by the Transmission Provider, replacement ZRCs are registered per the BPM for Resource Adequacy, the ICAP value is forfeited, or the end of any deferred Season, whichever is earlier. Market Participants with Planning Resources subject to ICAP Deferral Non-Compliance Charges do not have to meet the applicable performance requirement as described in Sections 69A.3.9

and 69A.5 for such Resources, until such time that they are no longer subject to these charges.

ii. ICAP Deferral Non-Compliance Charges will be calculated as follows: the amount of ICAP that has not been submitted to the Transmission Provider multiplied by the sum of the ACP and the daily CONE value (i.e., 1/365 times CONE). The ACP and the CONE values will be based on the LRZ where the Planning Resource is represented. If the Planning Resource is represented in an ERZ connected to a single SRRZ, the applicable CONE value will be the greatest CONE value of all LRZs in respective SRRZ. For External Resources represented in ERZs which are connected to multiple SRRZs or which are not connected to any SRRZs, the applicable CONE value will be the greatest CONE value of all LRZs in those connected SRRZs.

iii. Distribution of ICAP Deferral Non-Compliance Charges: ICAP Deferral Non-Compliance Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs on a *pro rata* basis, based upon the LSE's share of Final PRMR minus the Initial PRMR associated with the Capacity Deficiency Charge for the Transmission Provider Region during the applicable Season.

Calculation of CONE and Net CONE

a. The CONE value shall initially be the rate proposed by the Transmission Provider in a 2012 Federal Energy Regulatory Commission filing and approved by the Commission for the Planning Year commencing on June 1, 2013. The Transmission Provider and the IMM shall consider factors, including, but not limited to: (1) physical factors (such as, the type of Generation Resource that could reasonably be constructed to provide Planning Resources, costs associated with locating the Generation Resource within the Transmission Provider Region, the estimated costs of fuel for the Generation Resource); (2) financial factors (such as, the hypothetical debt/equity ratio for the Generation Resource, the cost of capital, a reasonable return on equity, applicable taxes, interest, insurance); and (3) other costs (such as, costs related to permitting, environmental compliance, operating and maintenance expenses). In calculating the CONE, the Transmission Provider and the IMM shall not consider the anticipated net revenue from the sale of capacity, Energy or Ancillary Services. CONE values will be calculated for each LRZ. The Transmission Provider shall arrange for CONE values to be calculated in concert with the IMM no later than September 1 beginning on September 1, 2012. The recalculated CONE values shall be filed with the Commission annually thereafter.

b. The Transmission Provider shall calculate Net CONE values for each LRZ. Net CONE represents the difference between CONE values and Inframarginal Rents, for the Generation Resource type used in the CONE value calculation (the Reference Resource Type) . The following process will be used to estimate Net CONE:

To determine Inframarginal Rents, the most recent three Planning Years of historic data will be compiled for each Generation Resource of the Reference Resource Type operating in the Transmission Provider Region consisting of all revenues for the Generation Resource from the Transmission Provider's Energy and Operating Reserve Markets, on a per MW or MWh basis, whichever is applicable, calculated hourly, and Production Costs calculated hourly. The greater of the market revenues minus Production Costs, or zero, shall be calculated hourly, and summed across all Hours for each Planning Year, for each resource of the Reference Resource Type. Inframarginal Rents outside of two standard deviations from the sample mean are removed. The Generation Resources are then grouped into LRZs based on their location. An average Inframarginal Rents is calculated for each LRZ and then scaled using a capacity factor for each LRZ. The capacity factor is the ratio of the commitment hours of the Generation Resource of the Reference Resource Type that is committed for the maximum number of hours in the Planning Year amongst all Generation Resources of the Reference Resource Type to the average commitment hours of all Generation Resources of the Reference Resource Type that were committed in the LRZ in the Planning Year. This results in Inframarginal Rents values for each LRZ for each Planning Year, which will be averaged over a three-year period to determine an initial Inframarginal Rents for each LRZ.

To determine the final Inframarginal Rents values to be used for the upcoming Planning Year, the Transmission Provider will apply a scaling factor to the initial Inframarginal Rents. The scaling factor will be based on statistical models between: a) LMPs to gas, and; b) LMPs to Inframarginal Rents. Readily available settled futures gas prices for the

upcoming Planning Year will be applied to the statistical models to calculate the scaling factor.

Each LRZ's final Inframarginal Rents are then grouped and averaged into values in the First Planning Area and Second Planning Area. The values from the First Planning Area and Second Planning Area are then subtracted from the LRZ-specific CONE values to get an estimate of Net CONE for each LRZ. For use in the PRA, Net CONE values are sorted into values in the First Planning Area and Second Planning Area.

The Transmission Provider shall arrange for Net CONE values to be calculated no later than September 1 prior to the subsequent Planning Year beginning on September 1, 2024. The recalculated Net CONE values shall be filed with the Commission annually thereafter.

Use of FRAP in the Planning Resource Auction

An LSE electing to use a Fixed Resource Adequacy Plan (FRAP) in the PRA for any Season can continue to use its existing resource planning processes to meet all or any portion of its Initial PRMR by providing the Transmission Provider with a FRAP, as described below:

a. An LSE electing to use a FRAP for any Season must submit a FRAP for each LRZ to the Transmission Provider by the 7th Business Day of March prior to a Planning Year in order for the LSE to demonstrate that the LSE has designated ZRCs in order to meet all or any portion of the LSE's Initial PRMR for such LRZ. Market Participants submitting registrations for new and existing Load Modifying Resources can be included in the Module E Capacity Tracking Tool beginning as early as December prior to the Planning Year. Load Modifying Resources registrations submitted to the Transmission Provider will be evaluated to determine if Load Modifying Resources meet the qualification requirements. Market Participants that submit registrations by February 1 prior to the Planning Year will be evaluated by the Transmission Provider and will be notified of the outcome on or before February 21 that precedes the Planning Year.

Market Participants that submit registrations between February 2 and February 15 prior to the Planning Year will be evaluated by the Transmission Provider and will be notified of the outcome at least two Business Days prior to the FRAP deadline. The Transmission Provider will make a good faith effort to notify Market Participants that submit registrations after February 15 but not later than March 1 of the outcomes of such registrations no later than the FRAP deadline. The FRAP must include the LSE's forecasted Coincident Peak Demand for each LRZ for each Season and also identify the

ZRCs that the LSE owns, or has contractual rights to, in order to provide Planning Resources to meet the FRAP designated portion of its Initial PRMR and also its load ratio share of the LCR for each LRZ for each Season. The Transmission Provider will evaluate each LSE's FRAP to determine if it meets the designated portion of the LSE's Initial PRMR and the LSE's share of LCR and the Transmission Provider will notify the LSE via the MECT prior to March 15th before a Planning Year of the extent that the portion of an LSE's Initial PRMR or share of LCR for each LRZ is not covered by a submitted FRAP. The LSE will have until the PRA offer window opens to remedy any deficiencies in their FRAP for each Season.

b. To the extent that the LSE's ZRCs satisfy the portion of the LSE's Initial PRMR for the applicable Season(s) submitted through a FRAP, (1) the LSE will not have an obligation to make ZRC Offers for the ZRCs included in the FRAP into the PRA, or otherwise participate in the PRA for such Season; and (2) the LSE will not have an obligation to pay the applicable ACP for the LSE's Initial PRMR within such LRZ that is covered by the FRAP. The Transmission Provider will consider all PRMR and ZRCs, including PRMR and ZRCs in FRAPs, as part of the Transmission Provider's reliability assessment when conducting the PRA.

c. Any portion of an LSE's Initial PRMR not covered by the FRAP may be purchased through the PRA. An LSE will be charged the applicable ACP for any PRMR that is procured through the PRA.

d. If an LSE owns or controls ZRCs that are not included in the LSE's FRAP, then such LSE may submit ZRC Offers into the PRA for all such excess ZRCs, subject to Module D.

e. To the extent that an LSE designates ZRCs in a FRAP that are represented in the same LRZ as the LSE's Demand to meet the LSE's Initial PRMR for such LRZ, then the LSE will not be subject to a Zonal Deliverability Charge for such ZRCs.

f. An LSE that contains ZRCs from Planning Resources that are not represented in the same LRZ where the LSE has Demand may be subject to a Zonal Deliverability Charge, which will be calculated as described in Section 69A.7.6(b).

Use of RBDC Opt Out in the Planning Resource Auction

An LSE electing to use the RBDC Opt Out can continue to use its existing resource planning processes to meet its Final PRMR by providing the Transmission Provider with an RBDC Opt Out, as described below:

a. The RBDC Opt Out Lock-In Period will be three consecutive Planning Years for all Seasons. If an LSE fails to submit an RBDC Opt Out then the LSE will be required to participate in the PRA through any combination of the other Tariff-defined options, or pay the Capacity Deficiency Charge, for each Planning Year in which the LSE does not submit an RBDC Opt Out.

b. An LSE under state jurisdiction where the State Regulatory Authority has overridden the PRM established by the Transmission Provider is not eligible to select the RBDC Opt Out.

c. An LSE selecting the RBDC Opt Out will be required to meet its Final PRMR for the entirety of its load and losses, and its entire share of LCR for each LRZ, for each Season.

d. An LSE must provide an initial notification of its intent to elect the RBDC Opt Out no later than January 15th prior to the upcoming Planning Year. An LSE electing the RBDC Opt Out must submit its final plan for each LRZ to the Transmission Provider by the 7th Business Day of March prior to each Planning Year during the RBDC Opt Out Lock-In Period in order for the LSE to demonstrate that the LSE has designated ZRCs in order to meet the LSE's Final PRMR, and share of LCR for each LRZ, for each Season. Market Participants

using the RBDC Opt Out must submit all registrations for new and existing resources to be used in the RBDC Opt Out through the MECT consistent with the timelines established in the Business Practices Manual for Resource Adequacy. The RBDC Opt Out must include the LSE's seasonal forecasted Coincident Peak Demand for each LRZ and also identify the ZRCs that the LSE owns, or has contractual rights to, in order to provide Planning Resources to meet its Final PRMR, and also its share of the LCR for each LRZ for each Season. The Transmission Provider will evaluate each LSE's RBDC Opt Out on an annual basis to determine if it meets the LSE's Final PRMR and the LSE's share of LCR requirements for all Seasons. The Transmission Provider will notify the LSE prior to March 15th before the applicable Planning Year whether the submitted RBDC Opt Out meets the LSE's Final PRMR, and share of LCR for each LRZ, requirement for each Season during the applicable Planning Year. The LSE must remedy any deficiencies in its RBDC Opt Out for each Season before the PRA offer window opens.

e. The Transmission Provider will notify the RERRA(s) following the submission of an initial intent to elect the RBDC Opt Out by an LSE. RERRA(s) may elect to notify the Transmission Provider within twenty (20) Business Days whether the LSE's load subject to the RERRA's respective jurisdiction is authorized to select the RBDC Opt Out. Upon receipt of such a notification from the RERRA(s) that the LSE is not authorized to elect the RBDC Opt Out for the LSE's load subject to the RERRA's respective jurisdiction, the Transmission Provider will reject the

LSE's RBDC Opt Out for such load. If the Transmission Provider receives no notification from the RERRA(s) within the twenty (20) Business Day period, and an LSE has demonstrated that it has designated ZRCs in order to meet its Final PRMR, and share of LCR for each LRZ, for each Season, then the proposed RBDC Opt Out by the LSE will be deemed accepted by the Transmission Provider.

f. To the extent that the LSE's ZRCs satisfy the LSE's Final PRMR for the applicable Season(s) submitted through an RBDC Opt Out, (1) the LSE will not have an obligation to make ZRC Offers for the ZRCs included in the RBDC Opt Out into the PRA, or otherwise participate in the PRA for such Season; and (2) the LSE will not have an obligation to pay the applicable ACP for the LSE's Final PRMR within such LRZ. The Transmission Provider will consider all PRMR and ZRCs, including PRMR and ZRCs in RBDC Opt Outs, as part of the Transmission Provider's reliability assessment when conducting the PRA.

g. If an LSE owns or controls ZRCs that are not included in the LSE's RBDC Opt Out, then such LSE may submit ZRC Offers into the PRA for all such excess ZRCs, subject to Module D.

h. To the extent that an LSE designates ZRCs in an RBDC Opt Out that are represented in the same LRZ as the LSE's Demand to meet the LSE's Final PRMR for such LRZ, then the LSE will not be subject to a Zonal Deliverability Charge for such ZRCs.

i. An LSE that designates ZRCs from Planning Resources that are not represented in

the same LRZ where the LSE has Demand may be subject to a Zonal Deliverability Charge, which will be calculated as described in Section 69A.7.6(b).

j. LSEs that submit an RBDC Opt Out may not use any of the other options to satisfy their Final PRMR including: (i) submitting a Fixed Resource Adequacy Plan; (ii) Self-Scheduling ZRCs; (iii) purchasing ZRCs through the Planning Resource Auction process, and/or (iv) paying the Capacity Deficiency Charge to meet all or a portion of their Initial PRMR.

k. LSEs that elect the RBDC Opt Out that do not meet their Final PRMR shall pay the RBDC Opt Out Deficiency Charge, which is 2.748 times applicable LRZ's CONE multiplied by the difference in ZRCs between the LSEs Final PRMR and the amount of ZRCs submitted as the LSEs RBDC Opt Out for each Season in which the LSE fails to meet its Final PRMR.

l. RBDC Opt Out Deficiency Charge revenues will be distributed to Market Participants representing LSEs on a pro rata basis, based upon their respective LSE's share of Final PRMR for the Transmission Provider Region minus the Final PRMR associated with the RBDC Opt Out Deficiency Charge. If the LRZ where LSEs incurred RBDC Opt Out Deficiency Charges failed to meet its Local Clearing Requirement ("LCR"), then RBDC Opt Out Deficiency Charge revenues will be distributed to Market Participants representing LSEs on a pro rata basis, based upon their respective LSE's share of Final PRMR minus the Final PRMR associated with the RBDC Opt Out Deficiency Charge in such LRZ.

m. The Transmission Provider will determine the RBDC Opt Out Adder that will be applicable for the upcoming Planning Year every year on or before December 15. The RBDC Adder applicable during the first Planning Year in which an LSE elects to use the RBDC Opt Out will apply for such LSE's entire RBDC Opt Out Lock-In Period.

n. The Transmission Provider will determine the RBDC Opt Out Adder based on a Seasonal average of the RBDC based PRA clearing for the prior three Planning Years. If the prior year RBDC based PRA clearing is not available, simulated RBDC based PRA clearing will be used to determine the RBDC Opt Out Adder.

Capacity Deficiency Charge

a. The Transmission Provider will impose a Capacity Deficiency Charge on an LSE that has provided notification prior to the Planning Resource Auction that they will meet their Initial PRMR in part or in whole by removing Initial PRMR from the Transmission Provider's capacity construct for one or more Seasons by paying the Capacity Deficiency Charge. The Capacity Deficiency Charge will be calculated as follows: The CONE value for the LRZ(s) where the LSE has provided notice it will be meeting its Initial PRMR by paying the Capacity Deficiency Charge for each Season of the Planning Year will be multiplied by 2.748 times the Initial PRMR volume indicated by the LSE. The Capacity Deficiency Charge will be assessed to Market Participants representing their respective LSE paying the Capacity Deficiency Charge on the first Business Day after the results of the Planning Resource Auction have been published.

b. Distribution of Capacity Deficiency Charge Revenues: A Market Participant representing an LSE that provided notice it will be meeting all or part of its Initial PRMR by paying the Capacity Deficiency Charge will not be distributed any Capacity Deficiency Charge revenues for that LSE's Initial PRMR that was met by paying the Capacity Deficiency Charge. Capacity Deficiency Charge revenues received by the Transmission Provider will be distributed to Market Participants representing LSEs on a *pro rata* basis, based upon their respective LSE's share of Initial PRMR for the Transmission Provider Region minus the Initial PRMR associated with the Capacity Deficiency Charge. If the LRZ where LSEs incurred Capacity Deficiency Charges failed to meet its Local Clearing Requirement ("LCR"), then Capacity Deficiency Charge revenues will be distributed to Market Participants representing LSEs on a *pro rata* basis,

based upon their respective LSE's share of Initial PRMR minus the Initial PRMR associated with the Capacity Deficiency Charge in such LRZ.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 60
MISO Tariff Section 38.2.7

38.2.7 Generation Suspension, Generation Retirement, and System Support Resources

a. Generator or SCU Notification of Change in Status.

(i) Notification Procedures for Units.

An owner of a Generation Resource, Synchronous Condenser Unit (SCU), or a Generator that is directly interconnected to the Transmission System but is Pseudo-tied out of the Transmission Provider's Balancing Authority Area that is planning to Suspend operations of all or any portion of that resource must notify the Transmission Provider of such a plan by submitting a completed Attachment Y Notice to the Transmission Provider. This notification provision also applies to a Generation Resource connected to the underlying lower voltage facilities within Transmission Provider region and to Generation Resources that are not directly interconnected to the Transmission System, but are External Resources that are Pseudo-tied into the Transmission Provider's Balancing Authority Area. The Transmission Provider shall coordinate with the entity to which the External Resource is directly connected to determine whether the External Resource is necessary for reliability of the Transmission System, in accordance with applicable coordinated planning provisions between the Transmission Provider and the regional planning entity to which the External Resource is interconnected.

The owner of a Generation Resource or SCU shall submit an Attachment Y Notice to the Transmission Provider at least four full Quarterly Study Periods prior to changing to Suspend status, unless the Generation Resource or SCU is inoperable due to Forced Outage in which case Attachment Y Notice must be submitted to the Transmission Provider at least thirty (30) days prior to changing to Suspend status. A Generation Resource that has undergone a Reliability Assessment Study that performs an Attachment Y equivalent study as part of the Generating

Facility Replacement process and all reliability violations identified through such study have been mitigated must submit an Attachment Y Notice to the Transmission Provider at least thirty (30) days prior to changing to Suspend status. The owner of a Pseudo-tied out Generator shall submit an Attachment Y Notice to the Transmission Provider at least thirty (30) days prior to the anticipated effective date of change of status.

A Generation Resource or SCU that is inoperable due to Forced Outage or a Pseudo-tied out Generator shall not be designated as an SSR Unit. The provisions for time limitations on suspension within Section 38.2.7 shall apply to a Generation Resource or SCU that is inoperable due to Forced Outage and a Pseudo-tied out Generator.

A Generation Resource that is designated as a Blackstart Unit by a Transmission Operator in its System Restoration Plans shall not be designated as an SSR Unit to solely provide Blackstart Service. However, the Transmission Provider may determine that SSR Unit status is justified if such Generation Resource is required to maintain the reliability of the Transmission System based on its Attachment Y Reliability Study. Section 38.2.7 shall not modify or alter a Transmission Operator’s obligations under the Tariff to identify Blackstart Units that are included in its System Restoration Plans, or a Blackstart Unit Owner's obligations to comply with the terms of any Blackstart Service agreement, in accordance with Schedule 33, or the requirements of Commission approved reliability standards.

The following exception applies to the Generation Suspension, Generation Retirement and System Support Resource (SSR) provisions in Section 38.2.7: The owner of a Generation Resource or SCU that requests a Generator Planned Outage or submits a Generator Forced Outage through the Transmission Provider’s outage scheduling system (Control Room

Operations Window – CROW or its successor) does not need to submit an Attachment Y Notice to the Transmission Provider if the request does not involve a change of status to Suspend.

An owner of a Generation Resource, SCU, or a Pseudo-tied out Generator certifies by submitting an Attachment Y Notice that it has elected to Suspend such resource and the Attachment Y Notice shall be executed by an officer of such owner attesting to that claim. The decision to Suspend may be modified by rescission as specifically provided in this Section 38.2.7.

An owner may not submit a new Attachment Y Notice to Suspend that supersedes a prior notification unless the prior Attachment Y Notice is rescinded. The new Attachment Y Notice shall be submitted to the Transmission Provider at least four full Quarterly Study Periods prior to changing to Suspend status.

(ii) Confidentiality of Attachment Y Notice.

The Transmission Provider shall treat all Attachment Y Notices as Confidential Information unless the Attachment Y Reliability Study is complete and any of the following occurs: 1) the owner has elected to waive its rescission rights; 2) the resource fails to return to operation before the period for rescission has lapsed; 3) public release is required under Section 38.2.7.b in order to evaluate the need for an SSR Agreement; or 4) the information is otherwise publicly disclosed by the owner of a Generation Resource, SCU, or a Pseudo-tied out Generator. The Transmission Provider shall promptly post on OASIS that an Attachment Y Notice was submitted, along with the effective date of retirement, under the first three of these circumstances.

(iii) Notification of the Outage Scheduler After Submittal of Attachment Y Notice.

After receipt of an Attachment Y Notice, the Transmission Provider shall schedule such outage notification through the Transmission Provider's Control Room Operations Window ("CROW") outage scheduling system, or successor system, to coordinate the outage planning of a Generation Resource or SCU through CROW, on behalf of the owner.

b. SSR Unit Procedures.

System Support Resource (SSR) procedures provide a mechanism for the Transmission Provider to enter into agreements with Market Participants that own or operate Generation Resources or Synchronous Condenser Units (SCUs) that are required by the Transmission Provider to maintain reliability of the Transmission System, if all or a specified portion of the capacity of such Generation Resources or SCUs would otherwise either Retire or Suspend. SSR Agreements are a last-resort measure to address a reliability issue on the Transmission System facilities under the functional control of the Transmission Provider and shall only be entered into once all potential SSR Agreement alternatives have been examined.

An owner of a Generation Resource or SCU must submit all necessary information to enable the Transmission Provider to evaluate whether SSR Unit status is appropriate for such Generation Resource or SCU. If, after completing a reliability study (Attachment Y Reliability Study) and analyzing potential alternatives (Attachment Y Alternatives Study), the Transmission Provider determines that SSR Unit status is justified for a Generation Resource or SCU, that is not subject to an exception under Section 38.2.7.a, then the Transmission Provider and Market Participant of such Generation Resource or SCU shall enter into an SSR Agreement, in

accordance with the Attachment Y-1 form of agreement. The SSR Unit will be operated in accordance with the terms of the SSR Agreement, which contains detailed terms and conditions regarding operation and compensation of such Generation Resource or SCU. The Transmission Provider shall periodically review the reliability requirements of the Transmission Provider Region and shall determine which, if any, SSR Agreements should be extended.

The Transmission Provider shall use reasonable efforts to respond to the owner within 150 Calendar Days after the start of the individual Attachment Y Reliability Study, regarding whether the subject of an Attachment Y Notice appears to be required for transmission system reliability, unless an alternative date is agreed to by the owner and the Transmission Provider.

If the Attachment Y Reliability Study determines that a reliability concern exists, and a response is provided by the Transmission Provider to the owner, the Transmission Provider shall promptly post on OASIS: (1) that an Attachment Y Notice was submitted; (2) that the Transmission Provider's Attachment Y Reliability Study concluded that the Generation Resource or SCU was required for the reliability of the Transmission System; (3) the draft report on the Attachment Y Reliability Study with the CEII information redacted from the report; and (4) how the associated SSR Unit costs would be allocated in the event that the Generation Resource or SCU is required to provide service under an SSR designation.

The Transmission Provider shall discontinue Confidential treatment of an Attachment Y Notice and Attachment Y Reliability Study in the event that the Attachment Y Reliability Study results determine that the Generation Resource or SCU is required to maintain system reliability and would be eligible for treatment as an SSR Unit. The Transmission Provider may use information related to Retire or Suspend status in its Transmission Planning processes (pursuant

to Attachment FF and the Transmission Planning BPM) and in its Generator Interconnection process (pursuant to Attachment X and the Generation Interconnection BPM), provided that recipients of the information have signed appropriate Non-Disclosure Agreements with the Transmission Provider.

c. Evaluation of Need for the SSR Designation.

The Transmission Provider will perform an Attachment Y Reliability Study to determine whether the Generation Resource or SCU is necessary for the reliability of the Transmission System based on the analyses described in this section and the criteria set forth in the Business Practices Manuals, but will not determine in this initial analysis the available alternatives to designating the Generation Resource or SCU as an SSR Unit. The Transmission Provider will start the study process at the beginning of the Quarterly Study Period. A request to Suspend operations submitted in an Attachment Y Notice received during a quarter will be studied individually, beginning in the subsequent Quarterly Study Period.

In collaboration with the affected Transmission Owners, the Transmission Provider will cause an evaluation to be performed of transmission system conditions (an Attachment Y Reliability Study) that result from the change in status of the unit(s) subject to Attachment Y notification requirements. The evaluation will consider the performance of the transmission system to determine if thermal or voltage violations of applicable NERC Standards and Transmission Owner planning criteria occur when the unit is offline compared to conditions when the unit is online. The scope of this evaluation will include a steady state analysis, and may require analyses of stability and import limitations for the particular study area. Study cases will be derived from approved MTEP models that are representative of the period of time for

which the suspension of the unit(s) is requested, and will include models that represent near-term and/or longer-term scenarios as appropriate for the study period. Models that are developed to reflect both the online and offline status of the unit being evaluated will be analyzed to compare the differences in results to determine the impact of the unit on the transmission system. The results of the evaluation will be reviewed with the participating Transmission Owners to verify the Transmission Provider's findings and to evaluate proposed solutions that should be considered to address the reliability issues. The need to retain a unit(s) as a System Support Resource, absent implementation of a feasible alternative, shall be determined by the presence of unresolved reliability violations on the Transmission System that is under the functional control of the Transmission Provider.

The Transmission Provider shall post the determination of reliability need on the Transmission Provider's OASIS and shall: (1) begin negotiations of a potential SSR Agreement with the Market Participant owning or operating the Generation Resource or SCU; and (2) use reasonable efforts to hold a stakeholder meeting pursuant to Attachment FF within thirty (30) Calendar Days to review alternatives to the potential SSR Unit designation or designations (if multiple Attachment Y Notices apply). The Transmission Provider will schedule subsequent stakeholder meetings as needed. The Transmission Provider shall complete the Attachment Y Alternatives Study within four full Quarterly Study Periods after receipt of an Attachment Y Notice, if the Attachment Y Notice provides only four full Quarterly Study Periods of advance notification, unless otherwise agreed to by the owner of the potential SSR Unit. If no alternative is identified as available by the Attachment Y Notice date to Suspend, then the Transmission

Provider shall file the SSR Agreement with an effective date as of the Attachment Y Notice date to Suspend.

Before entering into an SSR Agreement with any Generation Resource or SCU, the Transmission Provider shall assess, in an open and transparent planning process in accordance with the provisions of the Transmission Expansion Planning Protocol Attachment FF to the Tariff, feasible alternatives to the proposed SSR Agreement. The list of alternatives to SSR Unit status that the Transmission Provider shall consider and expeditiously approve as applicable include (depending upon the type of reliability concern identified): (i) redispatch/reconfiguration through operator instruction; (ii) remedial action plans; (iii) special protection schemes initiated upon Generation Resource trips or unplanned Transmission Outages; (iv) contracted demand response or Generator alternatives; and (v) transmission expansions. Consistent with Section B.1.b of Attachment FF, the Transmission Provider will review and evaluate alternatives to an SSR Agreement on a comparable basis and select the most appropriate solution. Comparability includes the ability of the Transmission Provider to require contractual assurances that the party who provides the alternative solution will implement the solution before the Generation Resource or SCU with the Attachment Y Notice is permitted to Retire or Suspend. The executed contractual arrangements must provide a binding arrangement that obligates the Market Participant who provides the alternative solution to complete any required infrastructure changes that are needed to avoid the reliability issues that would otherwise be addressed by transmission upgrades. While the contractual arrangements will vary based on the particular solution, the terms of the contractual arrangements must further obligate the party who provides the alternative solution to implement actions when required by the Transmission Provider to provide

necessary relief. A Generator alternative may be a new Generator, an existing Generator that is made available after the Attachment Y Reliability Study is completed, or an increase to existing Generator capacity that has an executed Generator Interconnection Agreement pursuant to Attachment X for a Commercial Operation Date that is prior to the commencement of the change of status date of the Generation Resource or SCU that has submitted an Attachment Y Notice and must be registered as a Generation Resource that is obligated to offer into the market and respond to instructions from the Transmission Provider. Contractual commitments associated with demand-side resource alternative solutions shall require demonstration to the Transmission Provider of an executed contract between LSE or ARC and Energy Consumers as well as necessary procedures and protocols for responding to Transmission Provider instructions. Such demand-side contracts must be in place by the time that the SSR Agreement alternative solution would otherwise need to be committed in order to ensure a timely solution to the identified planning need, and must be of a sufficient duration such that a reliable alternative solution can be assured. In assessing applicability for SSR status, the Transmission Provider will not require continued operation when the continued operation of a portion or all of Generation Resources or SCUs would be contrary to applicable law, regulations, or court or agency orders (such as a settlement with an environmental agency or a consent decree approved by a court). In performing the Attachment Y Reliability Study and the Attachment Y Alternatives Study to an SSR Agreement, the Transmission Provider shall collaborate with the affected Transmission Owners and NERC-registered Transmission Planners, and if appropriate, may consult with a retained consultant. The Transmission Provider will appropriately identify any Confidential Information regarding a decision to Suspend before the Transmission Provider transfers such

information to any entity. An entity that receives Confidential Information must agree in writing to maintain such confidentiality, to comply with any confidentiality obligations owed to Transmission Provider under the Tariff or pursuant to a related non-disclosure agreement, and to comply with applicable Standards of Conduct found in 18 C.F.R. § 358. The owner of the Generation Resource or SCU subject to review under this section shall make good faith efforts to minimize the costs to be incurred by seeking any available waivers or exemptions from environmental or other regulatory requirements that would necessitate improvements to the potential SSR Unit. The Transmission Provider will reasonably assist the owner of a potential SSR Unit in working with regulatory agencies to obtain environmental or other waivers or exemptions to the extent necessary to maintain the reliability of the Transmission System. For purposes of determining whether a Generation Resource or SCU qualifies as an SSR Unit, the Transmission Provider will process multiple Attachment Y Notices in the order in which the Attachment Y Notices are received. If a subsequent Attachment Y Notice is received before a determination is made for a Generation Resource or SCU that is the subject of a prior Attachment Y Notice, the Generation Resource or SCU that is the subject of a prior Attachment Y Notice will not be the subject of an SSR Agreement to avoid reliability issues caused by the subsequently noticed suspension of another Generation Resource or SCU.

The filing of a SSR Agreement with FERC shall be accompanied by a corresponding report on the Attachment Y Reliability Study and the Attachment Y Alternatives Study that details the methodologies used, study assumptions, Transmission Owner planning criteria used (including when the criteria became effective and the approving regulatory body, if any), analysis results, an evaluation of alternatives and the conclusion of the study (including a short

explanation of the proposed solution to any reliability issue identified and estimated timetables for implementing the preferred solution). An affirmation that the results, in whole or in part, from a previously filed report remain applicable may substitute for filing an entirely new report on the Attachment Y Reliability Study and the Attachment Y Alternatives Study.

d. Modification or Rescission of an Attachment Y Notice.

(i) Rescission of an Attachment Y Notice Prior to the Transmission Provider's Reliability Study Response.

The Transmission Provider shall notify the owner prior to publicizing the Attachment Y Notice and Attachment Y Reliability Study results that the Attachment Y Reliability Study is complete. However, the Transmission Provider shall not provide any information related to the Attachment Y Reliability Study results to the owner at that time. The owner may rescind its Attachment Y Notice by submitting an amended Attachment Y Notice to the Transmission Provider stating its intention, not more than fifteen (15) Business Days after receiving notice from the Transmission Provider that the Attachment Y Reliability Study is complete. In the event of such rescission, the confidentiality of the Attachment Y Notice shall be preserved.

(ii) Modification or Rescission of an Attachment Y Notice After the Owner of Generation Resource or SCU Receives the Results of Attachment Y Reliability Study, but Prior to Commencing Suspension, Retirement, or an SSR Agreement.

(1) An owner of a Generation Resource or SCU that notifies the Transmission Provider in writing of a decision to Suspend, and for which the Transmission Provider has determined that the Generation Resource or SCU is not necessary for the reliability of the

Transmission System, may rescind its decision to Suspend any time prior to the end of the period for rescission following the effective date or may modify the start of the suspension any time prior to the original effective date by submitting an amended Attachment Y Notice to the Transmission Provider stating its intention. If the revised date for suspension is prior to the original date specified in the Attachment Y Notice, a new Attachment Y Notice shall be submitted to the Transmission Provider at least four full Quarterly Study Periods prior to the effective date of suspension.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is not necessary for the reliability of the Transmission System, may elect to convert the Attachment Y Notice to retirement by notifying the Transmission Provider of its intent to waive the right to both rescind and modify the Attachment Y Notice. After the owner has waived the right to both rescind and modify the Attachment Y Notice, the requested status of the Generation Resource will change to Retire, and the interconnection service will be terminated in accordance with Section 38.2.7.k. The Attachment Y Notice will no longer be treated as Confidential Information once the owner has elected to waive its right to both rescind and modify the Attachment Y Notice and committed to retirement of the Generation Resource or SCU.

(2) An owner of a Generation Resource or SCU that notifies the Transmission Provider in writing of a decision to Suspend, and for which the Transmission Provider has determined that the Generation Resource or SCU is required as an SSR Unit may rescind its decision to Retire or Suspend or modify the date of suspension at any time while designated as

an SSR Unit by submitting an amended Attachment Y Notice specifying the modified effective date or stating its decision to rescind.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is required as an SSR Unit may elect to convert the Attachment Y Notice to retirement by notifying the Transmission Provider of its intent to waive the right to both rescind and modify the Attachment Y Notice for the initial rescission period of the Attachment Y Notice. The owner that provides such notification will retain rescission rights (*i.e.* those additionally acquired by virtue of operating as an SSR Unit) only while designated as an SSR Unit after which time the Generation Resource or SCU will have a Retire status and the interconnection service will be terminated in accordance with Section 38.2.7.k.

(iii) Modification or Rescission of an Attachment Y Notice After Commencing a Suspension, Retirement, or an SSR Agreement.

(1) An owner of a Generation Resource or SCU that notifies the Transmission Provider in writing of a decision to Suspend, and for which the resource has not been designated as an SSR Unit or is not continuing to operate pursuant to an SSR Agreement, may rescind its decision to Suspend by submitting an amended Attachment Y Notice to the Transmission Provider stating its intention to rescind any time during the period for rescission following the effective date.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is not necessary for the reliability of the Transmission System, may elect to convert the Attachment Y Notice to

retirement by notifying the Transmission Provider of its intent to waive the right to rescind and modify the Attachment Y Notice. After the owner has waived the right to rescind, the Generation Resource will have a Retire status, and the interconnection service will be terminated in accordance with Section 38.2.7.k. The Attachment Y Notice will no longer be treated as Confidential Information once the owner has elected to waive their right to rescind and committed to retirement of the Generation Resource or SCU.

(2) An owner of an SSR Unit may rescind its decision to Suspend or to Retire or modify the effective date prior to the termination date of the SSR Agreement by submitting an amended Attachment Y Notice specifying the modified effective date or stating its intention to rescind. After receiving an amended Attachment Y Notice from an owner of an SSR Unit to rescind or modify its decision to Suspend or to Retire, the Transmission Provider will then exercise the termination provisions of the SSR Agreement.

At any time during the Attachment Y Conversion Period, the owner of the Generation Resource or SCU for which the Transmission Provider has determined is required as an SSR Unit may elect to convert the Attachment Y Notice to retirement by notifying the Transmission Provider of its intent to waive the right to both rescind and modify the Attachment Y Notice for the initial rescission period of the Attachment Y Notice. The owner that provides such notification will retain rescission rights (*i.e.* those additionally acquired by virtue of operating as an SSR Unit) only while designated as an SSR Unit after which time the Generation Resource or SCU will have a Retire status and the interconnection service will be terminated in accordance with Section 38.2.7.k.

e. Refund of Costs.

(i) If the owner of a Generation Resource or SCU that notifies the Transmission Provider of a decision to Suspend and for which the Transmission Provider has not determined the Generation Resource or SCU is needed for reliability rescinds an Attachment Y Notice prior to commencing suspension, then such owner shall pay the Transmission Provider all of the costs that the Transmission Provider incurred in conducting an Attachment Y Reliability Study.

(ii) The Market Participant that owns or operates an SSR Unit must refund to the Transmission Provider with interest at the FERC-approved rate, all costs, less depreciation, for repairs and capital expenditures that were needed to continue operation of the Generation Resource or SCU and to meet applicable regulations and other requirements (including environmental) while the Generation Resource or SCU was subject to an SSR Agreement if the owner: (1) rescinds its decision to Suspend or to Retire the unit while it is designated a SSR; (2) rescinds its decision to Suspend following its previous designation as an SSR Unit; or **(**3**)** returns a unit to service following its previous designation as an SSR Unit and later retirement of the unit.

(iii) An owner of a Generation Resource or SCU that returns the unit to service upon failure to Retire or Suspend according to an Attachment Y Notice (*i.e*. returns from retirement or rescinds the Attachment Y Notice, including a Generation Resource or SCU that was not a SSR Unit, a former SSR Unit that no longer operates pursuant to an SSR Agreement, or an SSR Unit) will be allocated the total costs of Network Upgrades incurred or financially committed to as of the date of the notification of modification of the decision to Retire or Suspend if all the following apply:

- the rescission obviates the need for such Network Upgrades that were identified by the Transmission Provider in an Attachment Y Reliability Study;
- such Network Upgrades were necessitated solely by the Attachment Y Notice to Suspend; and
- such Network Upgrades were approved by the Transmission Provider's Board of Directors as Attachment FF Appendix A projects.

The total costs will include all pre-construction costs and interest at the FERC-approved rate. Such an owner will also be allocated the costs of expedited construction of such Network Upgrades that were approved for purposes other than dealing with needs identified in an Attachment Y Reliability Study to the extent that such expedited construction was necessitated by the Attachment Y Notice to Suspend.

In the event that multiple Attachment Y studies identified reliability issues that required the Network Upgrades and the owners of the units subject to the studies return their units to operation upon failure to Retire or Suspend (*i.e*. return from retirement or rescind the Attachment Y Notices, including Generation Resources and/or SCUs that were not SSR Units, former SSR Units that no longer operate pursuant to an SSR Agreement, or SSR Units), the owners will be allocated the total costs of such Network Upgrades incurred or financially committed to as of the date of notification of the last modification of a decision to Retire or Suspend if all the following apply:

- the rescission obviates the need for such Network Upgrades that were identified by the Transmission Provider in the Attachment Y Reliability Study;

- such Network Upgrades were necessitated solely by the Attachment Y Notice to Suspend; and
- such Network Upgrades were approved by the Transmission Provider's Board of Directors as Attachment FF Appendix A projects.

The total costs will include all pre-construction costs and interest at the FERC-approved rate. Such owners will also be allocated the costs of expedited construction of such Network Upgrades that were approved for purposes other than dealing with needs identified in an Attachment Y Reliability Study to the extent that such expedited construction was necessitated by an Attachment Y Notice to Suspend.

Except as provided in this Section, cost responsibility is assigned only for Network Upgrades that are identified to fully alleviate the violations identified in the Attachment Y Reliability Study in connection with a change in a plan to Retire or Suspend a Generation Resource or SCU. Costs of Network Upgrades that have been identified in the MTEP to address Transmission issues other than the issues identified in the Attachment Y Reliability Study of a unit that requests suspension will not be allocated to the owner of that unit if such costs of construction were not expedited as the result of an Attachment Y Notice to Suspend. In accordance with Attachment FF of the Tariff, the estimated costs of such Network Upgrades are included in the MTEP when it is approved by the Board of Directors of the Transmission Provider for inclusion in the MTEP. The Transmission Provider will solicit from the constructing Transmission Owner the actual costs (including the costs of expediting construction, and pre-construction costs, if any) incurred or committed to as of the date of notification for the last modification of a decision to Retire or Suspend. Each owner shall pay its pro rata share of

the incurred or committed Network Upgrade costs, based on the relative Generation Verification Test Capacity of each resource whose operation causes the assignment of Network Upgrade costs to its owner. The Transmission Provider will promptly notify the responsible owner of their share of the total costs once actual costs are determined.

f. Execution and Filing of SSR Agreement.

The Transmission Provider shall enter into an SSR Agreement with the Market Participant owning or operating a Generation Resource or SCU that is needed for SSR purposes based on the *pro forma* Attachment Y-1. The SSR Agreement shall state that it incorporates by reference the compensation authorized by the Commission. Resources that are ineligible to continue operating for legal or regulatory reasons, however, shall not be required to enter into an SSR Agreement. If a potential SSR Unit is ineligible or an existing SSR Unit becomes ineligible to continue operation, then the Transmission Provider shall seek to minimize the impact to Load by operating the Transmission System in the same manner as for any Resource that becomes ineligible to continue operation due to Forced Outage.

The Transmission Provider will file an SSR Agreement with the Commission for approval if the Transmission Provider's analysis determines that the Generation Resource or SCU is required for reliability of the Transmission System. All potentially affected parties will receive notification of such Commission filing. SSR service is a contracted service between the Market Participant that owns or operates an SSR Unit and the Transmission Provider and shall be for a term of twelve (12) months, unless the Transmission Provider requires a different term. The Transmission Provider must have available the entire capacity specified in the SSR Agreement of each SSR Unit.

g. Operation of SSR Unit.

Once the Transmission Provider has entered into an SSR Agreement with a Generation Resource or SCU, the Transmission Provider shall have the right to dispatch the SSR Unit at any time for reliability of the facilities within the Transmission Provider Region. The Transmission Provider shall make every attempt to minimize the use of an SSR Unit for reliability purposes. The Transmission Provider will commit the SSR Unit when conditions are identified that require the use of the SSR Unit and will make best efforts to minimize the uneconomic commitment of the SSR Unit. The SSR Agreement found in Attachment Y-1 to this Tariff shall provide for equitable compensation to an SSR Unit when it is dispatched by the Transmission Provider.

h. Scheduling Rules for SSR Units.

The Transmission Provider shall notify Market Participants with SSR Units as to the time period of Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve, and/or Other Ancillary Services required from each SSR Unit in accordance with Section 39.1.5 for the Day-Ahead Energy and Operating Reserve Markets, Section 40.1 for Reliability Assessment Commitment processes, and Section 40.1.A.3 Look Ahead Commitment processes.

i. SSR Unit Participation in Markets.

A Market Participant may offer Energy or Ancillary Services from SSR Units into the Day-Ahead Energy and Operating Reserve Market, RAC, or Real-Time Energy and Operating Reserve Market during times when the Transmission Provider has not requested the Market Participant to run the SSR Unit at full capacity unless this would impair the ability of the SSR

Unit to provide the Energy, Operating Reserve, Up Ramp Capability, Down Ramp Capability, Short-Term Reserve, or Other Ancillary Services when requested by the Transmission Provider.

Market Participants that own or operate an SSR Unit shall not use the SSR Unit to: (i) participate in Interchange Schedules; (ii) except for plant auxiliary Load obligations under the SSR Agreement, use the SSR Unit as a Self-Scheduled Resource to submit Self-Schedules for Energy and/or Operating Reserve; or (iii) submit Self-Schedules for Other Ancillary Services, if applicable, to the extent that Other Ancillary Services are required by the Transmission Provider under this Section.

j. SSR Unit Compensation.

(i) The Market Participant will be compensated for only costs incurred for the extended operation as an SSR Unit that do not exceed the full cost-of-service (including the fixed cost of existing plant). The hourly component of compensation will be provided as stated in this Tariff. For the determination of any additional compensation, the Market Participant shall submit a filing to the Commission under Section 205 of the FPA that states the additional compensation the Market Participant deems appropriate that is associated with the SSR Agreement filed by the Transmission Provider, but the Market Participant shall not separately file an SSR Agreement. The Market Participant shall provide the Transmission Provider and the Independent Market Monitor with a copy of all compensation-related filings regarding a SSR-designated unit.

(ii) Any compensation for the SSR Unit will be reduced by payments for operation of the SSR Unit, according to the provisions in this Tariff. Monthly compensation under Schedule 2 of this Tariff and payments under resource adequacy programs (a percentage of such payments

to a Market Participant whose generating unit designations are not made) shall be identified in the filing for compensation submitted by the Market Participant.

Hourly compensation will be provided for those hours in which the SSR Unit has Actual Energy Injections and the SSR Unit is committed by the Transmission Provider in the Day-Ahead Energy and Operating Reserve Market or committed by the Transmission Provider in any of the RAC processes, or in the Look Ahead Commitment ("LAC") process, including any Reliability Assessment Commitment ("RAC") process conducted prior to the Day-Ahead Energy and Operating Reserve Market, in which hours the Transmission Provider shall calculate the Market Participants' Production Cost and Operating Reserve Cost. For the purposes of this calculation, "Production Cost" means the Energy output cost pursuant to Section 39.3.2B Day-Ahead Revenue Sufficiency Guarantee Payments of the Tariff for commitments by the Transmission Provider in the Day-Ahead Energy and Operating Reserve Market or the Energy output cost pursuant to Section 40.2.19 Real-Time Sufficiency Guarantee of the Tariff for commitments by the Transmission Provider in any of the RAC processes, or in the LAC process, including any RAC process conducted prior to the Day-Ahead Energy and Operating Reserve Market, of each SSR Unit based upon Start Up, No Load, and Energy Offer cost components that reflect the actual costs of physically operating the SSR Unit(s). "Operating Reserve Cost" mean the actual cost to provide Operating Reserves. All Production Costs and Operating Reserve Costs will be subject to audit by the Transmission Provider, and will be subject to audit and enforcement by the Independent Market Monitor.

Through the Transmission Provider settlement process, the Transmission Provider will compare the "SSR Unit Compensation," which (for each SSR Unit) is equal to the sum of

Production Cost and Operating Reserve Cost, to the SSR Unit Energy, Operating Reserve Credit, and Short-Term Reserve. The SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit are those charges and credits calculated pursuant to Sections 39.3 Day-Ahead Energy and Operating Reserve Market, 40.3 Real Time Energy and Operating Reserve Market Settlement and 40.7 Determination of Inadvertent Energy of the Tariff, plus any revenues from Schedule 2 associated with the SSR Unit or from Planning Resource designation and any charges assessed through Schedule 17 and Schedule 24. In those hours where the SSR Unit Compensation is greater than the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit for that SSR Unit, the Transmission Provider will make the applicable make-whole payment to Market Participant (such make-whole payment to be equal to the difference between the SSR Unit Compensation and the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit). In those hours where the SSR Unit Compensation is less than the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit, the Transmission Provider will debit from Market Participant (such debit to be equal to the difference between the SSR Unit Energy, Operating Reserve, and Short-Term Reserve Credit and the SSR Unit Compensation). If the SSR Unit receives revenue pursuant to Sections 39.3 Day-Ahead Energy and Operating Reserve Market and 40.3 Real Time Energy and Operating Reserve Market Settlement of the Tariff in hours other than those described above, the Transmission Provider will debit those revenues from the Market Participant.

(iii) The Market Participant shall file with the Commission for a Monthly SSR Payment for compensation not covered by the hourly compensation stated in the previous sub-section. The Market Participant's filing shall state the requested Monthly SSR Payment along

with its sub-components (including amounts for monthly Schedule 2 payments for each SSR Unit) and applicable cost support, including an affidavit executed by an officer of the Market Participant attesting to the accuracy of the submitted cost information. The Market Participant shall provide the Monthly SSR Payment information for each SSR Agreement, including any renewals of an SSR Agreement, and may update the information in a Section 205 filing to revise such Monthly SSR Payment following any material, unforeseen circumstances affecting the SSR Unit that changes the costs incurred by the Market Participant. The Transmission Provider shall pay the Market Participant the Monthly SSR Payment as directed by the Commission, commencing on the effective date established by the Commission.

The filing for the additional compensation should evaluate, at a minimum, the following factors in negotiating compensation for an SSR Unit: (1) operations and maintenance labor expenses directly related to the SSR Unit; (2) administrative expenses directly related to employees at the SSR Unit, including employee expenses environmental fees, safety and operator training, office supplies, communications, and plant inspection/testing expenses; (3) non-labor maintenance expenses, including chemical and materials consumed during maintenance of the SSR Unit and rental expenses for maintenance equipment used to maintain the SSR Unit; (4) taxes, permit and licensing fees, site security expenses, and insurance; (5) carrying charges**,** including charges for maintaining reasonable levels of inventories of fuel and spare parts that result from short-term operating unit decisions based on Good Utility Practice; (6) corporate expenses, including those incurred for legal services, environmental reporting, and procurement; (7) costs associated with capitalized projects; (8) depreciation, and (9) return on the undepreciated plant costs for the SSR Unit.

k. Termination of Interconnection Service.

Except as provided in Attachment X, the Transmission Provider shall file with the Commission to terminate the interconnection service to the Transmission Provider's system held by an owner of a Generation Resource or SCU or Pseudo-tied out Generator, that certifies by submitting an Attachment Y Notice that it plans to Suspend a Generation Resource or SCU or Pseudo-tied out Generator, upon the latter of: (1) the termination of an SSR Agreement; (2) the effective date for which the owner has elected to convert the Attachment Y Notice to retirement by waiving the right to rescind the decision; or (3) the end of the period for rescission for which the owner has not waived the right to rescind. Such termination of interconnection service shall be contained in a filing with the Commission and also posted by the Transmission Provider on its OASIS to the extent that such interconnection service was filed with the Commission, and shall otherwise be terminated by the Transmission Provider by a posting on its OASIS. If the owner rescinds or modifies the Attachment Y Notice in accordance with Section 38.2.7.d, the owner of such resource may retain its interconnection service and continue to operate after the conclusion of an SSR Agreement or the date specified in the Attachment Y Notice.

l. Allocation of SSR Unit Costs.

The costs pursuant to the SSR Agreement shall be allocated to the LSE(s) which require(s) the operation of the SSR Unit for reliability purposes.

m. Annual Review of SSR Unit Status.

On at least an annual basis, the Transmission Provider will review Generation Resource or SCU characteristics to determine whether the Generation Resource or SCU is qualified to remain as an SSR Unit in coordination with a review of the Transmission Provider’s annual

regional transmission expansion plan in accordance with Attachment FF. If an SSR Unit continues to be required for reliability of the Transmission System, then the Transmission Provider will have the unilateral right to negotiate and enter into a subsequent SSR Agreement by providing the Market Participant at least ninety (90) days advance notice prior to the termination date of the existing SSR Agreement and by negotiating and filing a new SSR Agreement at the Commission. If not, the SSR Agreement will expire by its own terms and the Generation Resource or SCU will lose its SSR Unit status and will resume suspension in accordance with the Attachment Y Notice or Retire. Any subsequent SSR Agreement also shall be filed with the Commission.

n. Time Limitations on Suspension.

An owner of a Generation Resource or a SCU or a Pseudo-tied out Generator may request suspension pursuant to the provisions of this Section 38.2.7 and remain for a maximum of thirty-six (36) cumulative months during any five (5) year period under any combination of suspended and SSR-designated statuses. An owner of a Generation Resource or a SCU or a Pseudo-tied out Generator that had not exhausted its maximum period may request an additional suspension period by submitting a new Attachment Y Notice four full Quarterly Study Periods prior to the effective date of the extension period, provided that the combined period is not greater than thirty-six (36) months in a five (5) year period. If a Generation Resource or a SCU or a Pseudo-tied out Generator does not return to service at the end of the thirty-six (36) month maximum suspension period, the Transmission Provider will terminate interconnection service of the resource pursuant to Section 38.2.7.

o. Non-Binding Informational Studies.

An owner of a Generation Resource or a SCU may complete an Attachment Y-2 to request that the Transmission Provider conduct a study to determine whether it is likely that a portion or all of such Generation Resource of SCU would qualify as an SSR Unit. The Transmission Provider will collaborate with the affected Transmission Owners and NERC-registered Transmission Planners, and if appropriate, will consult with a retained consultant to evaluate whether the facility is required for the reliability of the Transmission System. The Transmission Provider will appropriately identify any Confidential Information regarding a decision to Suspend that the Transmission Provider transfers to any entity. An entity that receives Confidential Information must agree in writing to maintain such confidentiality, or to any confidentiality obligations owed to Transmission Provider under the Tariff or related non-disclosure agreement, and to comply with applicable Standards of Conduct found in 18 C.F.R. § 358. The owner will not be bound to the change of status indicated in an Attachment Y-2 request. Along with a completed Attachment Y-2, such owner shall submit a study deposit of $70,000 to the Transmission Provider for the reasonable costs and expenses of such study. The Transmission Provider shall invoice such owner for all costs and expenses incurred in addition to the deposit amount, or shall refund any unused portion of such deposit upon completion of the study.

The Transmission Provider will process multiple Attachment Y-2 requests in the order in which the Attachment Y-2 requests are received. The Transmission Provider shall use reasonable efforts to submit the results of such study to the owner upon its completion within 150 days of receipt of the deposit and completed Attachment Y-2, unless an alternative period is mutually agreed to. The Transmission Provider shall treat Attachment Y-2 as Confidential

Information. If an owner rescinds an Attachment Y-2 study request, then such owner shall not receive the results of the study and the owner shall pay the Transmission Provider all of the costs incurred in conducting the study up until the date of such rescission.

Once a response is provided by the Transmission Provider to the owner, the Transmission Provider shall promptly notify the Independent Market Monitor of any Resource that may qualify as an SSR Unit. The results of such study will provide the owner with the outcome if the owner elects to submit an Attachment Y Notice to request SSR status in the future and does so in accordance with Section 38.2.7.p.

The Transmission Provider shall maintain regional power flow models pursuant to Section I.C of Attachment FF, for use by the owner of a Generation Resource or a SCU choosing to conduct a study.

p. Submission of Attachment Y Notice Following Non-Binding Reliability Studies Under Y-2.

The Attachment Y Notice following a non-binding Y-2 request must be submitted at least four full Quarterly Study Periods prior to the date of the planned change of status. The Transmission Provider shall conduct the subsequent Attachment Y process consistent with timeline and milestones in Section 38.2.7.