

EXHIBIT 24

PUBLIC VERSION



April 11, 2017

The Honorable James Richard Perry
Secretary of Energy
United States Department of Energy
U.S. Department of Energy
1000 Independence Ave, SW
Washington, DC 20585

Re: Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act

Dear Secretary Perry:

The Grand River Dam Authority (“GRDA”), an agency of the State of Oklahoma, hereby notifies the Department of Energy (“DOE” or “Department”) of an imminent shortage of generation resources in its service area that constitutes an emergency within the meaning of Section 202(c) of the Federal Power Act (“FPA”)¹ and requests that the Department invoke its emergency authority pursuant to Section 202(c) to alleviate such emergency.

This spring, because of a confluence of events that will result in the unavailability of all generation at GRDA’s principal generating facility, the Grand River Energy Center (“GREC”), GRDA will face an unexpected shortage of electric generation resources to address the reactive power needs of its service area. Specifically, from April 16, 2017 to July 15, 2017 (referred to herein as the “Emergency Period”), none of the GREC’s three generating units will be online due to: (i) the required closure of Unit No. 1 on April 15, 2017, pursuant to an Administrative Order issued by the Environmental Protection Agency (“EPA”); (ii) a lightning strike that seriously damaged Unit No. 2 on July 1, 2016, rendering it inoperable until August 2017; and (iii) unforeseen delays in the construction of a new generating unit (Unit No. 3) because of key supplier delays in the fabrication of essential project materials due to the August 2016 floods in Louisiana.

Without at least one of these three generating units available to generate electricity to provide reactive power needed for grid reliability during the Emergency Period, GRDA will be unable to meet the reactive power needs of its service area during any low-load, high voltage conditions that occur (hereinafter, GRDA refers to this shortage of available reactive power resources during the Emergency Period as the “Emergency”). This Emergency will require Southwest Power Pool, Inc. (“SPP”), the Reliability Coordinator for GRDA’s service area, to reconfigure the transmission system to mitigate the high voltage conditions by opening high voltage transmission lines. This method to address high voltage conditions on the transmission system is not as robust an engineering solution as the ability to operate a generator to provide

¹ 16 U.S.C. § 824a(c).



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☐ **COAL-FIRED COMPLEX**
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☐ **PENSACOLA DAM**, PO Box 70, Langley
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☐ **SALINA PUMPED STORAGE PROJECT**
PO Box 609, Salina OK 74365
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☐ **TRANSMISSION HEADQUARTERS**
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dynamic reactive power control; opening a transmission line offers only a static solution that poses more reliability risk to the system and does not follow good utility practice to keep the system intact.

Accordingly, GRDA hereby submits this application pursuant to FPA § 202(c) and Subpart W of Part 205 of the Department's regulations² for an emergency order to provide reactive power from Unit No. 1 of the GREC from April 16, 2017 to July 15, 2017 consistent with the conditions herein, in the event that Southwest Power Pool, Inc. ("SPP") determines that such generation is needed to maintain grid reliability. As explained below, GRDA is requesting that SPP have the ability to call on Unit No. 1, which would otherwise be offline but available (using natural gas igniters if necessary), only if SPP sees a need for Unit No. 1 to run to address reliability concerns relating to overvoltage conditions.

I. BACKGROUND

GRDA is an agency of the State of Oklahoma, primarily serving public power communities in Oklahoma. Approximately 70 percent of GRDA's total electric energy is generated by the Grand River Energy Center, which is located near Chouteau, Oklahoma. GREC Units No. 1 and 2 are coal-fired generating units (with natural gas-fired igniters), with generating capacities of 490 and 520 megawatts (MW), respectively.

Due in part to EPA's Mercury and Air Toxics Standards (MATS) requirements, which would have required substantial upgrades for Unit No. 1, GRDA determined to retire Unit No. 1 and to construct a new, lower-emitting, natural gas-fired generation unit (Unit No. 3). GRDA is currently in the process of constructing Unit No. 3, which is a highly efficient 495 MW natural gas combined cycle unit. When GRDA commenced construction of Unit No. 3, it was projected to come online in May 2017. To maintain grid reliability during Unit No. 3's construction, EPA issued an Administrative Order ("AO") granting GRDA a one-year extension of the compliance deadline for Unit No. 1 to comply with EPA's MATS requirements. The AO, attached hereto as Attachment A, requires Unit No. 1 to cease operation as a coal-fired unit on April 15, 2017.³ The AO, issued under Section 113(a)(4) of the Clean Air Act, is nonrenewable.

As GRDA's principal electric generating station, the GREC plays a critical role in meeting all aspects of GRDA's electric load and in providing ancillary services, including reactive power. In particular, Unit No. 1 has traditionally played a key role in generating reactive power to provide local voltage support in GRDA's service area, particularly when Unit No. 2 has been out of service.

In 2014, SPP on six occasions requested either additional capacitive or reactive voltage support from Unit No. 1 to address voltage problems on the transmission system. During a planned maintenance outage of GREC Unit No. 2 for the period October 15, 2014 through November 4, 2014, SPP created a Temporary Operating Guide for Unit No. 1 requiring it to be

² 10 C.F.R. Part 205, Subpart W (2016).

³ Attachment A also includes an Amendment to the AO to account for increased reliance on Unit No. 1 after the lightning strike at Unit No. 2.

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available for dispatch during instances of low load and high voltage. The Operating Guide, attached as Attachment B, stated that “[d]ue to the low load and high voltage in the GRDA area, GRDA Unit #1 generation will be needed. Generation needs to be online in order to ensure voltage stability until GRDA Unit #2 returns from outage.”⁴ Unit No. 1 was in fact called upon by SPP to provide reactive support during a substantial portion of the period Unit No. 2 was on outage. GRDA’s transmission system, along with the conditions that give rise to the need to maintain the availability of Unit No. 1 to address low load, high voltage conditions, have not changed materially since SPP issued the Temporary Operating Guide.

II. APPLICATION FOR EMERGENCY ORDER

As explained below, GRDA requests that DOE determine that an emergency exists within the meaning of FPA § 202(c) with respect to the unavailability of Unit No. 1 during the Emergency Period, and order GRDA to run Unit No. 1 for the purpose of providing reactive power during the Emergency Period in the event that neither Unit No. 2 nor Unit No. 3 is online, and SPP determines that reactive power from Unit No. 1 is needed for purposes of grid reliability.

A. An Emergency Exists Because a Lightning Strike at Unit No. 2, and Unforeseeable Construction Delays at Unit No. 3, Will Leave GRDA Without the Ability to Generate Electricity for Reactive Power During the Emergency Period.

FPA § 202(c) provides that if “an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes” DOE may issue an order requiring the temporary connections of facilities, and such generation, delivery, interchange, or transmission of electric energy as it deems appropriate to best meet the emergency and serve the public interest. DOE’s regulations provide additional detail about what constitutes an “emergency” for purposes of Section 202(c) at 10 C.F.R. § 205.371:

“Emergency” . . . is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected “entity” to prevent. An emergency also can result from . . . a regulatory action which prohibits the use of certain electric power supply facilities. Actions under this authority are envisioned as meeting a specific inadequate power supply situation. Extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations. . . .

⁴ See SPP Temporary Operating Guide, “GRDA Unit #1 Manual Commitment,” Attachment B.

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The unavailability of Units No. 1, 2, and 3 at the GREC during the Emergency Period constitutes an emergency within the meaning of Section 202(c) and DOE's regulations. First, without the availability of at least one of these three generating units at the GREC, GRDA will be unable to provide reactive power for local voltage support to maintain grid stability in GRDA's service area in low load, high voltage conditions. In the past, Unit Nos. 1 and 2 have traditionally met GRDA's needs for reactive power. However, these generating units will be offline during the Emergency Period, and Unit No. 3 will still be under construction and therefore not yet online. GRDA has no other means to procure or provide adequate reactive power for local voltage support in its service area during the Emergency Period. GRDA does not own, or have control over, other resources that can provide sufficient reactive power in GRDA's service area to provide adequate voltage support under low load, high voltage conditions. GRDA cannot rely on temporary generation to produce the needed reactive power because of the quantity of potential reactive power that might be needed under low load, high voltage conditions. (For instance, SPP called upon Unit No. 1 to provide more than 100 MVars of reactive power in 2016 under low load, high voltage conditions.)

Further, SPP's ability to address the reactive power needs of GRDA's service area without Unit No. 1 is limited and inadequate. SPP has the ability to reduce reactive power needs during the Emergency Period through reconfiguring its transmission system by opening transmission lines. However, this is not an optimal solution, because it would not allow SPP to maintain its system in an intact state consistent with good utility practice. Opening transmission lines is a less reliable means of addressing reactive power needs than through dynamic reactive power generation resources because of the relative reliability risk it poses; reactive power cannot be controlled as easily through system configuration as it can through dynamic resources to respond to unexpected events, and the system is more vulnerable to outages because the system is not intact. Thus, SPP's ability to address reactive power needs in GRDA's service area without Unit No. 1 is a limited and less robust method to ensure reliability.

Second, this shortage of resources to generate reactive power during the Emergency Period was unexpected and unforeseeable by GRDA, which originally expected to have Unit No. 2 available, and Unit No. 3 coming online, during the Emergency Period. However, Unit No. 2 sustained extensive damage on July 1, 2016 from a fire caused by a lightning strike, which took Unit No. 2 offline. Repairs to Unit No. 2 are ongoing and will not be completed until August 2017. This lightning strike causing the fire at Unit No. 2 was an unforeseeable act of God, the effects of which were not within the power of GRDA to prevent.⁵ Likewise, Unit No. 3's commercial operation date has been delayed because of another unforeseeable act of God – the Louisiana floods of August 2016 – which delayed the ability of a key supplier to meet contractual commitments for critical materials for Unit No. 3's construction. Although GRDA planned for the shutdown of Unit No. 1 due to EPA's AO, DOE's regulations note that an emergency can result from "a regulatory action which prohibits the use of certain electric power supply facilities."⁶ Collectively, the unavailability of the GREC's three generating units, each for different reasons, over the Emergency Period gives rise to a "shortage of facilities for

⁵ 10 C.F.R. § 205.371.

⁶ 10 C.F.R. § 205.371.

generating electric energy” within the meaning of Section 202(c) of the FPA for GRDA’s service area.

B. GRDA’s Shortage of Reactive Power Resources During the Emergency Period Will Imperil Grid Reliability

During low load, high voltage conditions, an inability to provide sufficient reactive power for voltage support can imperil grid reliability by allowing the grid to exceed the range of acceptable system voltage.⁷ The inability to schedule sufficient reactive power can constitute a reliability standards violation, because under NERC Reliability Standard VAR-001-4.1 (Voltage and Reactive Control), transmission operators “shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions.”⁸ A deficiency of reactive power can lead to disruption of service, because transmission facilities operating at voltages in excess of system voltage limits must be disconnected from other elements of the grid.⁹ If transmission facilities operating at excessive voltages are not disconnected, the overvoltages can cause electric arcing due to insulation “flash overs,” which can in turn result in physical damage to transmission facilities.¹⁰

GRDA’s impending shortage of reactive power resources increases the risk of service disruption to GRDA’s customers due to overvoltage, because the only means SPP will have to address reactive power needs is through reconfiguring the transmission system by opening a transmission line – a step that will mean the system is no longer intact. Good utility practice calls for the system to be maintained intact if possible. Without an intact system, GRDA’s system will be more vulnerable to disruption of service or outages as a result of unexpected events. SPP recognized the risks presented by a lack of reactive power resources at the GREC in 2014 when Unit No. 2 was on outage by issuing its Temporary Operating Guide for Unit No. 1. SPP has reaffirmed the importance of maintaining Unit No. 1 beyond April 15, 2017 for mitigation of system voltage issues and local grid reliability in a letter of support for this request, attached hereto as Attachment C.

C. GRDA Provides Power to Significant Regions in Oklahoma, Including Customers of National Significance

⁷ At low levels of electric system load, energized transmission lines may act as a capacitive load that increases system voltage.

⁸ NERC Reliability Standard VAR-001-4.1 (Voltage and Reactive Control), R1 (“Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load.”).

⁹ See Reliability Standard TOP-008-1 (Response to Transmission Limit Violations), R3 (“The Transmission Operator shall disconnect [an] affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered.”).

¹⁰ FERC Reliability Primer at 25 (“[H]igh voltages can exceed the insulation capabilities of equipment and cause dangerous electric arcs known as “flashovers.” These conditions can occur when there is light loading on the system (e.g., less customer demand), causing an excess of reactive power that elevates the voltage beyond safe operating limits.”).

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GRDA provides electric power on its transmission system to both retail and wholesale customers. GRDA provides retail electric service to 80 industrial and commercial customers, most of which are located in the MidAmerica Industrial Park (MAIP) near Pryor. [REDACTED]

[REDACTED] The 9,000 acre MAIP is home to over 80 companies employing over 4,500 people. There are also urgent care, emergency and life flight services within the MAIP boundaries. On the wholesale side, GRDA's largest customer is Western Farmers Electric Cooperative (WFEC) which is responsible for supplying power to [REDACTED] 18 member Oklahoma distribution cooperatives. GRDA provides power directly to over 16 municipalities, including [REDACTED] Coffeyville, Kansas, which has a strong industrial base, and the City of Stillwater, which is primarily residential and commercial service. There are 15 hospitals with a combined 1000+ bed-capacity in these cities. GRDA also provides electricity to the Oklahoma Municipal Power Authority (OMPA). Through support of OMPA, GRDA's generation provides a portion of the electric power to an additional 35 participating cities in Oklahoma. Directly and indirectly, GRDA provides electric power support to some portion of 75 of the Oklahoma's 77 counties.

D. Information Required By Section 205.373

Herein, GRDA sets forth the information required under Section 205.373 of DOE's regulations.¹¹ To ensure that DOE has the information it needs to evaluate GRDA's application, GRDA is providing certain additional information that GRDA deems salient to its application.

- (a) Legal Name of Applicant. The applicant is Grand River Dam Authority.
- (b) Person to Whom Correspondence Should Be Addressed. Correspondence with respect to this application should be directed to:

Daniel S. Sullivan
Chief Executive Officer
Grand River Dam Authority
P.O. Box 409
Vinita OK 74301-0409
(918)256-5545
dsullivan@grda.com

¹¹ Certain elements of Section 205.373 address the circumstances of an applicant facing a shortage of real power and the prospect of firm customer curtailment, but do not address GRDA's emergency circumstances, which involve a shortage of reactive power generation during light load conditions. GRDA has indicated where these requirements are Section 205.373 are not applicable to GRDA's circumstances.

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(c) Political Subdivision in Which GRDA Operates and Business Conducted. GRDA operates in 24 counties in Northeast Oklahoma. GRDA sells electricity to three customer classes in its service area: municipals, electric cooperatives and industries.

(d) Baseline Data.

(1) Daily peak load and energy requirements for each of the past 30 days, and projections for each day of the Emergency Period: These requirements are not applicable to GRDA's request, which contemplates relief in light load conditions. GRDA is providing information about the reactive power provided by Unit No. 1 in February 2017, the most recent month for which data is available, in Attachment D. GRDA provided reactive power pursuant to an SPP Temporary Operating Guide in the fall of 2014 period to maintain grid reliability. GRDA is providing data on the reactive power provided by Unit No. 1 during this time frame in Attachment E.

(2) All capacity and energy receipts or deliveries to other electric utilities for each of the past 30 days: Not applicable.

(3) The status of all interruptible customers for each of the past 30 days, and anticipated status during the Emergency Period: GRDA does not expect to interrupt any customers during the Emergency Period due to a lack of available energy. Interrupting load during the Emergency Period would exacerbate, rather than remedy, the low load, high voltage conditions that present an emergency for GRDA.

(4) All scheduled capacity and energy receipts or deliveries to other electric utilities during the Emergency Period. Not applicable.

(e) **A description of the emergency situation, any contingency plan of GRDA, and the current level of implementation.** The emergency situation GRDA faces is described above in Section II.A of this Application. Until GRDA can bring GREC Unit No. 2 or No. 3 online, GRDA does not have any contingency plan to provide reactive power for voltage support without Unit No. 1. As explained above in Section II.B, SPP's ability to address GRDA reactive power needs in low-load, high voltage conditions without Unit No. 1 is limited and poses increased reliability risks for GRDA's service area compared to operating Unit No. 1 for voltage support.

(f) **A showing that adequate electric service to firm customers cannot be maintained without additional power transfers.** Not applicable.

(g) **A description of any conservation or load reduction actions that have been implemented.** Not applicable. Reducing load via conservation or other load reduction actions under low load, high voltage circumstances would exacerbate, rather than mitigate, emergency overvoltage conditions.

(h) **A description of efforts made to obtain additional power through voluntary means and the results of such efforts.** GRDA does not have the ability to provide additional

reactive power resources to alleviate the Emergency. GRDA is required to cease operation of Unit No. 1 as a coal-fired unit after April 15, 2017 pursuant to an Administrative Order under Section 113(a)(4) of the Clean Air Act. An order issued under Section 113(a)(4) is nonrenewable, and therefore, EPA does not have authority to extend the compliance deadline in the AO and further delay compliance with MATS for Unit No. 1. Unit No. 2 is undergoing repairs as quickly as possible, but the unit will not be available during the Emergency Period. Construction on Unit No. 3 is not expected to be completed until sometime in June 2017, at the earliest, and may not be available at all during the Emergency Period.

- (i) **A listing of proposed sources and amounts of power necessary from each source to alleviate the emergency and a listing of any other “entities” that may be directly affected by the requested order.** The only generation source that GRDA proposes to alleviate the Emergency is Unit No. 1 of the GREC. Based on historical data, GRDA expects that it could be called upon to absorb up to 120 MVar or more from the grid if called on by SPP for local voltage support in low load, high voltage conditions.

Two entities would be directly affected by GRDA’s requested order. First, SPP manages grid operations for GRDA’s transmission assets, and thus would be directly responsible for addressing any grid instability resulting from the Emergency. If DOE grants GRDA’s request for relief herein, SPP would be able to dispatch Unit No. 1 to absorb reactive power if it determines that such generation is necessary to maintain grid reliability. Second, EPA would be directly affected, because running Unit No. 1 after April 15, 2017, would contravene the terms of EPA’s AO and the Clean Air Act, which require GRDA to cease coal-fired operations at Unit No. 1 after April 15, 2017.

- (j) **Specific proposals to compensate the supplying “entities” for the emergency services requested and to compensate any transmitting “entities” for services necessary to deliver such power.** GRDA proposes that, during the Emergency Period, it be compensated for any generation from Unit No. 1 directed by SPP pursuant to a DOE Section 202(c) Order consistent with the terms of the SPP Tariff.
- (k) **A showing that, to the best of the applicant's knowledge, the requested relief will not unreasonably impair the reliability of any “entity” directly affected by the requested order to render adequate service to its customers.** To GRDA’s knowledge, ordering reactive power generation from Unit No. 1, which is currently an SPP generating resource, will not impair the reliability of any entity.
- (l) **Description of the facilities to be used to transfer the requested emergency service to the applicant's system.** Not applicable.
- (m) **A general or key map on a scale not greater than 100 kilometers to the centimeter showing, in separate colors, the territory serviced by each “entity” named in the application; the location of the facilities to be used for the generation and transmission of the requested emergency service; and all connection points between systems.** This information is attached as Attachment F.

(n) An estimate of the construction costs of any proposed temporary facilities and a statement estimating the expected operation and maintenance costs on an annualized basis. Not applicable

(o) Supplemental Information. A letter from SPP in support of GRDA's request for action under FPA Section 202(c) is attached as Attachment C.

E. Compliance with Applicable Environmental Laws Under Section 202(c)(2).

Section 202(c)(2) of the FPA provides that when DOE issues an order under Section 202(c) that results in a conflict with Federal, State, or local environmental law, DOE is required to ensure that the order requires generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, is consistent with applicable Federal, State, or local environmental law and minimizes any adverse environmental impacts.¹² Herein, GRDA is requesting authorization to generate electricity to provide reactive power support from Unit No. 1 of the GREC after April 15, 2017, which would contravene EPA's Administrative Order on MATS Compliance for Unit No. 1.¹³

To ensure compliance with the AO to the maximum extent possible and minimize environmental impacts pursuant to Section 202(c)(2), GRDA commits that, in the event DOE issues a Section 202(c) order directing the generation of reactive power from Unit No. 1 of the GREC, GRDA will generate from Unit No. 1 only when called upon by SPP pursuant to DOE's order, and will otherwise keep Unit No. 1 offline. Although Unit No. 1 must burn coal to generate reactive power, GRDA Unit No. 1 has natural gas igniters available to keep Unit No. 1 in a ready state, if necessary. This will ensure compliance with EPA's AO to the maximum extent possible given that the AO does not prohibit the use of natural gas at Unit No. 1. Because GRDA can keep Unit No. 1 ready, Unit No. 1 does not need to maintain a minimum generation level or be synchronized to the grid to be ready to respond if called upon by SPP to provide reactive power. Unit No. 1 can be brought online to generate reactive power from an offline state within 24 hours, which is within the window of notice that SPP would give GRDA to generate reactive power.

Additionally, GRDA commits to cease all generation from Unit No. 1 as soon as GREC Unit No. 3 or Unit No. 2 is brought online, in which case either unit would be able to act as a reactive power resource for GRDA.

F. Request for Designation of Critical Electrical Infrastructure Information

Pursuant to Section 215A of the FPA, GRDA requests that the Department designate the bracketed information in Section II.C as critical electrical infrastructure information protected

¹² 16 U.S.C. § 824a(c)(2).

¹³ See Attachment A at P 31.

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from disclosure under the Freedom of Information Act and other public disclosure laws.¹⁴ The bracketed information includes information relating to the production, generation, and transmission of energy that could be useful to a person in planning an attack on critical infrastructure.¹⁵

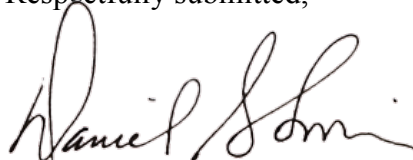
G. Requested Order

As explained herein, GRDA respectfully requests that DOE issue an emergency order directing the generation of electricity to provide reactive power from Unit No. 1 of the GREC from April 16, 2017 to (i) July 15, 2017, or (ii) the date on which GREC No. 3 or No. 2 is brought online, whichever is earlier, in the event that Southwest Power Pool, Inc. (“SPP”) determines that generation from Unit No. 1 is needed to maintain grid reliability, subject to the requirements that Unit No. 1 remain offline unless requested to generate by SPP pursuant to a DOE Section 202(c) order.

III. CONCLUSION

GRDA respectfully requests that DOE take the emergency action requested herein as soon as possible to address the imminent shortage of reactive power that GRDA faces in its service area. GRDA stands ready to answer any questions that DOE may have, and to provide any additional information that DOE requires.

Respectfully submitted,



Daniel S. Sullivan
Chief Executive Officer
Grand River Dam Authority

Cc: Patricia A. Hoffman, Principal Deputy Assistant Secretary and Acting Assistant Secretary, DOE Office of Electricity Delivery & Energy Reliability

Attachments

¹⁴ 16 U.S.C. § 824a(c)(2).

¹⁵ See 18 C.F.R. § 388.113(d)(1)(i). GRDA requests the bracketed information be designated critical electric infrastructure information for as long as permissible. See 18 C.F.R. § 388.113(d)(1)(ii).

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CERTIFICATE OF SERVICE

I hereby certify that I have this 11th day of April, 2017, caused copies of the foregoing documents to be served on the parties listed below by causing copies of the same to be sent via overnight delivery.

Michael Bardee
Director, Office of Electric Reliability
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Administrator Scott Pruitt
U.S. Environmental Protection Agency
Mail code 1101A
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Southwest Power Pool, Inc.
c/o Lanny Nickell, Vice President, Engineering
415 North McKinley Street, Suite 140
Little Rock, AR 72205

Ronald W. Ciesiel
General Manager
Southwest Power Pool Regional Entity
201 Worthen Drive
Little Rock, AR 72223

/s/ Nathan Reese

Nathan Reese
Assistant General Counsel
Grand River Dam Authority

Attachment A

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR ENFORCEMENT DIVISION, OFFICE OF ENFORCEMENT AND COMPLIANCE ASSURANCE
BEFORE THE ADMINISTRATOR

In the Matter of:

Grand River Dam Authority,

Respondent.

Administrative Compliance Order on Consent
AED-CAA-113(a)-2016-0002

ADMINISTRATIVE COMPLIANCE ORDER

A. PRELIMINARY STATEMENT

1. This Administrative Compliance Order (“Order”) is issued under the authority vested in the Administrator of the U.S. Environmental Protection Agency (“EPA”) by Section 113(a) of the Clean Air Act (the “CAA” or “Act”), 42 U.S.C. § 7413(a)(3) and (4).
2. On the EPA’s behalf, Phillip A. Brooks, Division Director of the Air Enforcement Division, Office of Civil Enforcement, Office of Enforcement and Compliance Assurance, U.S. Environmental Protection Agency, is delegated the authority to issue this Order under Section 113(a) of the Act.
3. Respondent is Grand River Dam Authority, an agency of the state of Oklahoma. Respondent is a “person” as defined in Section 302(e) of the Act, 42 U.S.C. § 7602(e). Respondent owns and/or operates the Grand River Energy Center (hereafter, the “Facility”), located in the state of Oklahoma.
4. Respondent signs this Order on consent.

B. STATUTORY AND REGULATORY BACKGROUND

5. Section 112 of the CAA, 42 U.S.C. § 7412, authorizes the Administrator of EPA to regulate hazardous air pollutants (“HAPs”) which may have an adverse effect on health or the environment.

6. Pursuant to Section 112 of the CAA, the EPA finalized National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Subpart UUUUU on December 16, 2011, 77 FR 9304 (Feb. 16, 2012) (40 C.F.R. Part 63 Subpart UUUUU), commonly known as the “Mercury and Air Toxics Standards.” *Id.* (hereafter, “MATS”). The MATS adopt emission limits on mercury, acid gases and other toxic pollutants for affected coal and oil-fired electric generating utility units (“EGUs”).
7. Pursuant to 40 C.F.R. § 63.9981, the MATS applies to owners or operators of coal-fired EGUs or oil-fired EGUs as defined in 40 C.F.R. § 63.10042.
8. Pursuant to 40 C.F.R. § 63.2, “owner or operator” is defined as “any person who owns, leases, operates, controls, or supervises a stationary source.”
9. Section 111(a)(3) of the Act, 42 U.S.C. § 7411(a)(3), and 40 C.F.R. § 63.2 defines a “stationary source” as “any building, structure, facility, or installation which emits or may emit any air pollutant.”
10. Pursuant to 40 C.F.R. § 63.2, “affected source” is defined as “the collection of equipment, activities, or both within a single contiguous area and under common control that is included in a Section 112(c) source category or subcategory for which a Section 112(d) standard or other relevant standard is established pursuant to Section 112 of the Act.”
11. Pursuant to 40 C.F.R. § 63.9982, the affected source to which the provisions of the MATS, 40 C.F.R. Part 63, Subpart UUUUU, applies is the collection of all existing coal- or oil-fired EGUs, as defined in 40 C.F.R. § 63.10042, within a subcategory, [and] ... each new or reconstructed coal- or oil-fired EGU, as defined in 40 C.F.R. § 63.10042.
12. On December 16, 2011, in parallel with finalizing the MATS, the Office of Enforcement and Compliance Assurance issued a policy memorandum describing its intended approach regarding issuance of Section 113(a) administrative orders (“Orders”) to sources that are unable to comply

with the MATS but that may need to operate for up to a year to address a specific and documented reliability concern. See The Environmental Protection Agency's Enforcement Response Policy For Use Of Clean Air Act Section 113(a) Administrative Orders In Relation To Electric Reliability And The Mercury and Air Toxics Standard (hereafter, "2011 MATS Enforcement Policy"). The 2011 MATS Enforcement Policy is limited in application to units that are critical for reliability purposes.

13. In issuing the 2011 MATS Enforcement Policy, the EPA believed that there would be few, if any, cases in which affected sources would not be able to comply with the MATS within the compliance period specified by Section 112(i)(3) of the CAA (including, as applicable, any extensions permitted under Section 112(i)(3)(B)), which has proven to be the case. Nonetheless, the EPA acknowledged that there may be isolated instances in which the deactivation or retirement of a unit or a delay in installation of controls due to factors beyond the owner's/operator's control could have an adverse, localized impact on electric reliability that could not be timely predicted or planned for with specificity. In such instances, sources could find themselves in the position of either operating in noncompliance with the MATS or halting operations and thereby potentially impacting electric reliability. Thus, although the EPA generally does not speak publicly to the intended scope of its enforcement efforts in advance of the date when a violation may occur, the Agency issued the 2011 MATS Enforcement Policy to describe the EPA's intended enforcement response in such instances and to provide confidence with respect to electric reliability. The policy is informed, as are EPA's enforcement actions in general, by the need to find an appropriate balance between critical public interests, bearing in mind the resources and process time required for any enforcement response.
14. The 2011 MATS Enforcement Policy specifies that to qualify for an Order in connection with it, an owner/operator must, in summary, provide early written notice of its compliance plans to

the Planning Authority¹ for the area in which the source is located, timely request an Order and provide notice of such request to the EPA, FERC, its Planning Authority, any state public utility or service commission, and any state, tribal or local environmental agencies, with jurisdiction over the area in which the EGU is located, and submit a complete request for an Order.

15. A complete request pursuant to the 2011 MATS Enforcement Policy must include the following elements: copies of the early notice provided to the Planning Authority; written analysis of the reliability risk, which demonstrates that operation of the unit after the MATS Compliance Date is critical to maintaining electric reliability; written concurrence with the reliability analysis by the relevant Planning Authority (or a written explanation of why such concurrence cannot be provided); copies of any written comments received from third parties in favor of, or opposed to, operation of the unit after the MATS Compliance Date; a plan to achieve compliance with the MATS no later than one year after the MATS Compliance Date; and identification of the level of operation required to avoid the reliability risk and proposed operational limits and/or work practices to minimize or mitigate emissions to the extent practicable during non-compliant operation.
16. With respect to the demonstration of reliability risk, the 2011 MATS Enforcement Policy states that the analysis provided in an Order request should demonstrate that operation of the unit after the MATS Compliance Date is critical to maintaining electric reliability, and that failure to operate the unit would: (a) result in the violation of at least one of the reliability criteria required to be filed with the Commission, and, in the case of the Electric Reliability Council of

¹ Planning Authorities are the entities tasked, under NERC reliability standards, with addressing electric reliability through grid planning. In the 2011 MATS Enforcement Policy, Planning Authority was defined as “the entity defined as such in the “Glossary of Terms Used in NERC Reliability Standards,” available at: http://www.nerc.com/docs/standards/rs/Reliability_Standards_Complete_Set.pdf, or any successor term thereto approved by FERC, and includes, in relevant jurisdictions, RTOs and ISOs.”

Texas, with the Texas Public Utility Commission; or (b) cause reserves to fall below the required system reserve margin.

17. Although the EPA's issuance of an Order is not conditioned upon the approval or concurrence of any entity, in light of the complexity of the electric system and the local nature of many reliability issues, for purposes of using its Section 113(a) Order authority in connection with the 2011 MATS Enforcement Policy, the EPA has sought advice in the identification and/or analysis of reliability risks, as necessary and on a case-by-case basis from reliability experts, including, but not limited to, the Federal Energy Regulatory Commission ("FERC"), Regional Transmission Operators ("RTOs"), Independent System Operators and other Planning Authorities, as EPA indicated it would do in the 2011 MATS Enforcement Policy.
18. The 2011 MATS Enforcement Policy specifically stated that an owner/operator interested in receiving a Section 113(a) administrative order pursuant to the policy should provide FERC with a copy of its complete and timely written request to the EPA.
19. On May 17, 2012, FERC issued a policy statement explaining how it intended to provide advice to the EPA on requests for an administrative order pursuant to the 2011 MATS Enforcement Policy. See Policy Statement of the Commission's Role Regarding the Environmental Protection Agency's Mercury and Air Toxics Standards, 139 FERC ¶ 61,131 (2012) ("FERC Policy Statement"). The FERC Policy Statement provided that the Commission will advise the EPA by submitting written Commission comments to the EPA based on the Commission's review of the information provided in an informational filing containing the copy of the request for the administrative order provided to the Commission in an AD docket. *Id.* at Paragraph 21. Further, the FERC Policy Statement indicated that the Commission's comments would provide advice to the EPA on whether, based on the Commission's review of the informational filing, there might be a violation of a Commission-approved Reliability Standard, and may also identify issues

within its jurisdiction other than a potential violation of a Commission-approved Reliability Standard. *Id.*

C. FINDINGS

20. Respondent owns and/or operates an existing coal-fired electric utility steam generating unit, as defined in 40 C.F.R. § 63.10042.
21. Respondent's operation at the Facility is subject to the MATS.
22. On November 28, 2012, Respondent received a one year extension pursuant to 40 C.F.R. 63.6(i)(4)(i)(A) from its permitting authority, extending the date by which it must comply with the MATS to April 15, 2016. *See* November 28, 2012 Letter from Steven A. Thompson, Oklahoma Department of Environmental Quality to Grand River Dam Authority.
23. On February 19, 2015, Respondent submitted a timely and complete request for an Order pursuant to the 2011 MATS Enforcement Policy to the EPA, with a copy to FERC. That request can be found in the FERC AD docket, AD15-6-000 (hereafter "Order Request").
24. Pursuant to the Order Request, Respondent seeks an Order from April 16, 2016 through April 15, 2017, on the grounds that it will not be able to comply with the MATS at Unit No. 1 of the Grand River Energy Center located near Chouteau, Oklahoma, without violating its system reserve margin of 12%, until the construction of a new, highly efficient natural gas-fired combined cycle combustion turbine (Unit No. 3) is completed as a replacement for Unit No. 1. Unit No. 3 will not be operational until shortly after April 16, 2017. *See id.*
25. More specifically, the Order Request states that Respondent, "a load serving member of the Southwest Power Pool (SPP) [Respondent's Planning Authority], states that it will be unable to meet its required reserve margin of 12 percent capacity if Unit No. 1 is retired before new Unit No. 3 becomes operational. Order Request at 6; *see also*, Southwest Power Pool, Criteria 2.1.9 (Minimum Required Capacity Margin) (revised July 29, 2014), available at

<http://www.spp.org/publications/SPP%20Criteria%20&%20Appendices%20July%2029,%202014.pdf>. Respondent indicates that the untimely loss of Unit No. 1 would prevent it from meeting its basic load obligations by 245 MW. *Id.* Additionally, Respondent states that Unit No. 1 has been used for local voltage support, noting that “there were six instances in 2014 where the GRDA System Operator requested either additional capacitive or reactive voltage support from Unit No. 1 to address voltage problems on the transmission system.” Order Request at 7. Respondent further claims that it has “experienced problems under certain conditions obtaining firm or non-firm transmission service to deliver power purchases from outside of the GRDA balancing area” when one or both of its existing units are offline, and without an administrative order, it “is concerned that transmission constraints will make importing sufficient replacement capacity and energy very difficult.” *Id.*

26. In a memorandum attached to Respondent’s submission, SPP concurred with Respondent’s reserve margin assessment. See Order Request, Attachment C (SPP January 27, 2014 Memorandum) at 2 (“[a] review of GRDA’s supply adequacy without GRDA unit 15-1 indicates that the firm resources available to GRDA fall below their 12% minimum capacity margin requirement in 2016”). Additionally, SPP concurred that SPP “has observed, over the last year, the need to commit GRDA Unit 1 for relief from high voltages ... [and that] SPP concurs with GRDA’s assessment regarding GRDA Unit 1’s criticality for reliability absent other system changes.” Order Request, Attachment E (SPP February 6, 2015 Letter) at 1.
27. FERC reviewed the reliability risk presented in the request in accordance with the FERC Policy Statement and on April 16, 2015 found that “the loss of GRDA’s Unit No. 1 would result in GRDA falling below the 12 percent capacity reserve requirement stipulated in SPP Criteria 2.1.9 unless GRDA is able to procure replacement capacity for the unit and associated firm transmission service,” and “[a]bsent a significant change in future circumstances, [FERC’s] view is that GRDA’s

Unit No. 1 is needed as requested by GRDA to maintain electric reliability.” See Commission Comments On Grand River Dam Authority’s Request For EPA Administrative Order (April 16, 2015), p. 4, Docket No. AD15-6-000. Additionally, FERC notes that “the reliability of the Bulk-Power System depends in part on whether utilities meet an appropriate planning reserve margin.” *Id.*

28. Respondent proposes to minimize emissions by implementing a bidding approach with SPP, in a manner consistent with the SPP Tariff and market rules, to limit the total electricity generated by Unit No. 1 while maintaining its reserve margin. See Order Request at 12-13. Specifically, Respondent shall bid Unit No. 1 to achieve a total annual capacity factor of not more than 50% during the period from April 16, 2016 up to April 16, 2017, which is lower than its historical operation as a base load facility of approximately 70% annual capacity. *Id.* Although the monthly capacity factor of Unit No. 1 would vary to allow Respondent to meet its reserve margin requirements throughout the period covered by this Order, Respondent states that reducing the annual capacity factor to 50% will result in approximately 30% lower total emissions during the period from April 16, 2016 up to April 16, 2017. *Id.*

D. ORDER

29. Respondent is ordered to take the actions described in this section of this Order.
30. From April 16, 2016 through April 15, 2017, Respondent shall implement a bidding approach with SPP, while maintaining Respondent’s reserve margin, in a manner consistent with the SPP Tariff and market rules, to limit the total electricity generated by Unit No. 1 to achieve a total annual capacity factor of not more than 50% during the period from April 16, 2016 through April 15, 2017.
31. By 11:59 pm April 15, 2017, Respondent shall achieve full compliance with the MATS at Unit No. 1 at the Facility by permanently ceasing operation as a coal-fired unit.

32. Within 30 days of achieving full compliance with the MATS at the Facility, Respondent shall provide written notice to the EPA indicating that compliance has been achieved and the date by which it was achieved, pursuant to the process specified in paragraph 39 of this Order.

E. OTHER TERMS AND CONDITIONS

33. Respondent admits the jurisdictional allegations contained in Sections A (Preliminary Statement) and B (Statutory and Regulatory Background) of this Order.
34. Respondent neither admits nor denies the findings in Section C (Findings) of this Order.

F. GENERAL PROVISIONS

35. Any violation of this Order may result in a civil administrative or judicial action for an injunction or civil penalties of up to \$37,500 per day per violation, or both, as provided in Sections 113(b)(2) and 113(d)(1) of the Act, 42 U.S.C. §§ 7413(b)(2) and 7413(d)(1), as well as criminal sanctions as provided in Section 113(c) of the Act, 42 U.S.C. § 7413(c). The EPA may use any information submitted under this Order in an administrative, civil judicial, or criminal action.
36. Nothing in this Order shall relieve Respondent of the duty of achieving and maintaining compliance with all applicable provisions of the Act or other federal, state or local laws or statutes, nor shall it restrict the EPA's authority to seek compliance with any applicable laws or regulations, nor shall it be construed to be a ruling on, or determination of, any issue related to any federal, state, or local permit.
37. Nothing herein shall be construed to limit the power of the EPA to undertake any action against Respondent or any person in response to conditions that may present an imminent and substantial endangerment to the public health, welfare, or the environment.
38. The provisions of this Order shall apply to and be binding upon Respondent and its officers, directors, employees, agents, trustees, servants, authorized representatives, successors, and assigns. From the Effective Date of this Order until the Termination Date as set out in paragraph

44 below, Respondent must give written notice and a copy of this Order to any successors in interest prior to any transfer of ownership or control of any portion of or interest in the Facility. Simultaneously with such notice, Respondent shall provide written notice of such transfer, assignment, or delegation to the EPA. In the event of any such transfer, assignment, or delegation, Respondent shall not be released from the obligations or liabilities of this Order unless the EPA has provided written approval of the release of said obligations or liabilities.

39. Unless this Order states otherwise, whenever, under the terms of this Order, written notice or other documentation is required to be given, it shall be directed to the individuals specified at the addresses below unless those individuals or their successors give notice of a change of address to the other party in writing:

Phillip A. Brooks
Division Director of the Air Enforcement Division, Office of Civil Enforcement, Office of Enforcement and Compliance Assurance, US Environmental Protection Agency
Mail Code 2242A, Room 1119
1200 Pennsylvania Ave, NW
Washington, DC 20460 mail or 20004 courier (note Room 1119 on courier packages)

Anupa Ahuja
Air Enforcement Section
Mail Code 6EN-AA
US EPA Region 6
1445 Ross Ave
Dallas, TX 75202
Phone: (214)665-2701

Daniel S. Sullivan
Grand River Dam Authority
P.O. Box 409
226 West Dwain Willis Avenue
Vinita, OK 74301
Phone: (918)256-5545

Britt S. Fleming
Van Ness Feldman, LLP
1050 Thomas Jefferson Street, NW
Washington, DC 20007
Phone: (202)298-1863

All notices and submissions shall be considered effective upon receipt.

40. To the extent this Order requires Respondent to submit any information to the EPA, Respondent may assert a business confidentiality claim covering part or all of that information, but only to the extent and only in the manner described in 40 C.F.R. Part 2, Subpart B. The EPA will disclose information submitted under a confidentiality claim only as provided in 40 C.F.R. Part 2, Subpart B. If Respondent does not assert a confidentiality claim, the EPA may make the submitted information available to the public without further notice to Respondent.
41. Each undersigned representative of the Parties certifies that he or she is authorized to enter into the terms and conditions of this Order to execute and bind legally the Parties to this document.

G. EFFECTIVE DATE AND OPPORTUNITY FOR A CONFERENCE

42. Pursuant to Section 113(a)(4) of the Act, an Order does not take effect until the person to whom it has been issued has had an opportunity to confer with the EPA concerning the alleged violations. By signing this Order, Respondent acknowledges and agrees that it has been provided an opportunity to confer with the EPA prior to issuance of this Order. Accordingly, this Order will take effect immediately upon signature by the latter of Respondent or the EPA.

H. JUDICIAL REVIEW

43. Respondent waives any and all remedies, claims for relief and otherwise available rights to judicial or administrative review that Respondent may have with respect to any issue of fact or law set forth in this Order, including any right of judicial review under Section 307(b)(1) of the Clean Air Act, 42 U.S.C. § 7607(b)(1).

I. TERMINATION

44. This Order shall terminate on the earlier of the following (the “Termination Date”) at which point Respondent shall operate in compliance with the Act:

- a. 11:59 pm April 15, 2017;
- b. The effective date of any determination by the EPA that Respondent has achieved compliance with all terms of this Order; or
- c. Immediately upon receipt by Respondent of notice from the EPA finding that an imminent and substantial endangerment to public health, welfare, or the environment has occurred.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR ENFORCEMENT DIVISION, OFFICE OF ENFORCEMENT AND COMPLIANCE ASSURANCE
BEFORE THE ADMINISTRATOR

In the Matter of:

Grand River Dam Authority,

Respondent.

Administrative Compliance Order on Consent
AED-CAA-113(a)-2016-0002

For United States Environmental Protection Agency, Air Enforcement Division, Office of Enforcement and Compliance Assurance:

4/16/2016
Date



Phillip A. Brooks
Division Director of the Air Enforcement Division, Office of Civil
Enforcement, Office of Enforcement and Compliance Assurance,
US Environmental Protection Agency
Mail Code 2242A, Room 1119
1200 Pennsylvania Ave, NW
Washington, DC 20460 mail or 20004 courier (note Room 1119
on courier packages)

For Grand River Dam Authority:



Signature

April 7, 2016
Date

Printed Name: Daniel S. Sullivan
Title: General Manager/CEO
Address: P.O. Box 409, 226 West Dwain Willis Avenue, Vinita, OK 74301

CERTIFICATE OF SERVICE

I certify that the foregoing "Administrative Compliance Order" in the Matter of Grand River Dam Authority, Order AED-CAA-113(a)-2016-0002, was filed and copies of the same were mailed to the parties as indicated below.

Certified Mail

Daniel S. Sullivan
Grand River Dam Authority
P.O. Box 409
226 West Dwain Willis Avenue
Vinita, OK 74301
Phone: (918)256-5545

Britt S. Fleming
Van Ness Feldman, LLP
1050 Thomas Jefferson Street, NW
Washington, DC 20007
Phone: (202)298-1863

Eddie Terrill
Director, Air Quality Division Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, OK 73101-1677

4/18/16
Date


Tawanna Cathey

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR ENFORCEMENT DIVISION, OFFICE OF ENFORCEMENT AND COMPLIANCE ASSURANCE
BEFORE THE ADMINISTRATOR

In the Matter of:

Grand River Dam Authority,

Respondent.

Amendment
Administrative Compliance Order on Consent
AED-CAA-113(a)-2016-0002

AMENDMENT – ADMINISTRATIVE COMPLIANCE ORDER

A. PRELIMINARY STATEMENT

1. This is an amendment (the “Amendment”) to the Administrative Compliance Order on Consent, AED-CAA-113(a)-2016-0002, (“Order”) issued on April 16, 2016 by the U.S. Environmental Protection Agency (“EPA”) to the Grand River Dam Authority (“Respondent”). A copy of the Order is attached to this Amendment as Attachment A. Unless otherwise indicated, defined terms in this Amendment have the same meaning as in the Order.

B. FINDINGS

2. From July 1, 2016 to July 2, 2016, a series of events arose from causes beyond the control of Respondent that require amendment to the terms of the Order. Specifically, during a storm, there was a lightning strike at the Facility, which resulted in a significant fire that severely damaged Unit 2 and moderately damaged Unit 1. Unit 1 returned to service on July 20, 2016. Unit 2 is not expected to return to service until after Unit 1 permanently ceases operation as a coal-fired unit on April 15, 2017.
3. As a result of Unit 2, a 520 MW unit, being out of service during the period covered by the Order, Respondent will not be able to meet the terms of operation of Unit 1 detailed in the Order without violating the reliability risks described in paragraphs 24 – 28 of the Order. To address those reliability risks, it is necessary to amend the Order to allow for increased

operation of Unit 1. During the period in July when both units were out of service, voltage support was not required and Respondent was able to make other short term power purchases to meet basic load requirements.

C. ORDER

4. Paragraph 30 of the Order is replaced with the following requirement: From April 16, 2016 through April 15, 2017, Respondent shall implement a bidding approach with SPP, while maintaining Respondent's reserve margin, in a manner consistent with the SPP Tariff and market rules, to limit the total electricity generated by Unit No. 1 to achieve a total annual capacity factor of not more than 80% during the period from April 16, 2016 through April 15, 2017.

D. GENERAL PROVISIONS

5. Unless explicitly modified in this Amendment, all provisions of the Order remain in effect.
6. Each undersigned representative of the Parties certifies that he or she is authorized to enter into the terms and conditions of this Amendment to execute and bind legally the Parties to this document.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
AIR ENFORCEMENT DIVISION, OFFICE OF ENFORCEMENT AND COMPLIANCE ASSURANCE
BEFORE THE ADMINISTRATOR

In the Matter of:

Grand River Dam Authority,

Respondent.

Amendment
Administrative Compliance Order on Consent
AED-CAA-113(a)-2016-0002

For United States Environmental Protection Agency, Air Enforcement Division, Office of Enforcement and Compliance Assurance:

9/14/2016
Date


Phillip A. Brooks
Division Director of the Air Enforcement Division, Office of Civil Enforcement, Office of Enforcement and Compliance Assurance, US Environmental Protection Agency
Mail Code 2242A, Room 1119
1200 Pennsylvania Ave, NW
Washington, DC 20460 mail or 20004 courier (note Room 1119 on courier packages)

For Grand River Dam Authority:


Signature

Sept. 8, 2016
Date

Printed Name: Daniel S. Sullivan
Title: General Manager/CEO
Address: P.O. Box 409, 226 West Dwain Willis Avenue, Vinita, OK 74301

CERTIFICATE OF SERVICE

I certify that the foregoing "Amendment" to the Administrative Compliance Order in the Matter of Grand River Dam Authority, Amendment AED-CAA-113(a)-2016-0002, was filed and copies of the same were mailed to the parties as indicated below.

Certified Mail

Daniel S. Sullivan
Grand River Dam Authority
P.O. Box 409
226 West Dwain Willis Avenue
Vinita, OK 74301
Phone: (918)256-5545

Britt S. Fleming
Van Ness Feldman, LLP
1050 Thomas Jefferson Street, NW
Washington, DC 20007
Phone: (202)298-1863

Eddie Terrill
Director, Air Quality Division Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, OK 73101-1677

Date

Tawanna Cathey

Attachment B

Temporary Operating Guide

Title: GRDA Unit #1 Manual Commitment

System Conditions: Intact

Written by: Patrick deLassus (SPP)

Reviewed by: Kevin Sanson (SPP), Jason Smith (SPP), Terry Oxandale (SPP), Will Tootle (SPP), Jeff Wells (GRDA), Mike Stafford (GRDA)

Op-Guide: Effective on: 10/15/2014

Expires on: 11/04/2014

I. Purpose/Background

Due to the low load and high voltage in the GRDA area, GRDA Unit #1 generation will be needed. Generation needs to be online in order to ensure voltage stability until GRDA Unit #2 returns from outage.

II. Monitoring

IDC FG #	Monitored Element	Contingent Element	Owner	Rating (MVA)
xxxxx	GRDA area (Voltage)	System Intact	GRDA	xxx

III. Mitigation

SPP BA will manually commit the GRDA Unit #1 (GRDA_UNIT_1) in order to provide relief from high voltage. Low load and high voltage are also contributing factors to this commitment. This requirement will be terminated once load levels permit.

If the generation from GRDA Unit #1 is unavailable, or otherwise unable to supply voltage support, reconfiguration plans may be needed. If reconfiguration is deemed necessary, GRDA will determine where to reconfiguration will be effective.

IV. Unit Commitment Details

RESOURCE NAME: GRDA_UNIT_1

Unit Start Time: 10/16/2014 00:00

Unit Online Time (Dispatchable):): ***** Extension – Unit is Already Online *****

Unit Release Time (Shutdown): 11/04/2014 00:00 (This will be re-evaluated once GRDA_UNIT_2 returns to service.)

Commit Reason: SPP: LOCAL

The SPP RCs are not obligated to use the directions given above in the recommended order. Depending on the circumstances, the SPP RCs will make the decision on the best and most efficient option that would provide relief adequately.

Attachment C

March 1, 2017

United States Department of Energy
1000 Independence Ave, SW
Washington, DC 20585

Re: Contribution of GRDA Unit 1 to local grid reliability as demonstrated by recent operating experience in SPP

Dear Sir/Madam:

The Southwest Power Pool, Inc. (SPP) Reliability Coordinator (RC) has observed, historically, the need to commit GRDA Unit 1 for relief from high voltages. In fact, the RC created a Temporary Operating Guide for the period October 15 through November 4 of 2014 stating that during a planned maintenance outage of GRDA Unit 2, GRDA Unit 1 must be available for dispatch during instances of low load and high voltage. GRDA Unit 1 was called upon to provide reactive support during the entire period of the Operating Guide. Although SPP no longer requires the Temporary Operating Guide, it nevertheless continues to believe that during future light load conditions when GRDA Unit 2 is unavailable, the commitment and dispatch of GRDA Unit 1 will be a critical resource in maintaining proper system voltage. Moreover, in the absence of GRDA Unit 2 and until GRDA Unit 3 comes online, SPP believes GRDA Unit 1 provides a valuable contribution to the local area's overall grid reliability. Based on the above, SPP concurs with GRDA's assessment regarding GRDA Unit 1's importance for reliability absent other system changes or until GRDA's Unit 2 and Unit 3 are in service.

Please do not hesitate to contact me should you have questions or would like to request additional information.

Respectfully submitted,

A handwritten signature in black ink that reads 'Lanny Nickell'.

Lanny Nickell
Vice President, Engineering
(501) 614-3232 • Fax: (501) 482-2022 • lnickell@spp.org

Attachment D

GRDA Unit No. 1 - Reactive Power Production in February 2017

Sum of 2:6832:MVAR CFP #1:O:GRDA #1



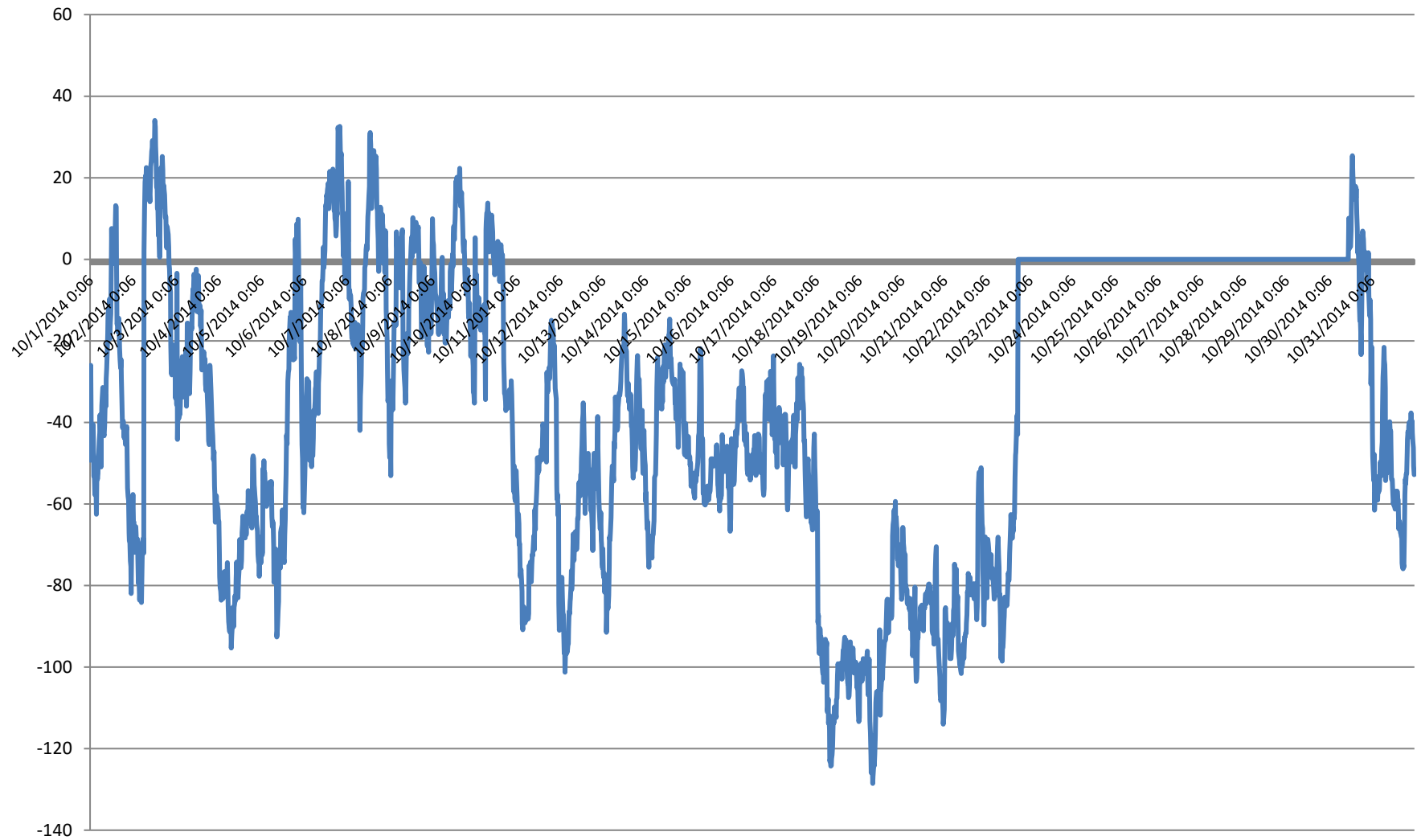
Attachment E

GRDA Unit No. 1 Reactive Power Production in October and November 2014

Sum of 2:6832:MVAR CFP #1

Total

— Total



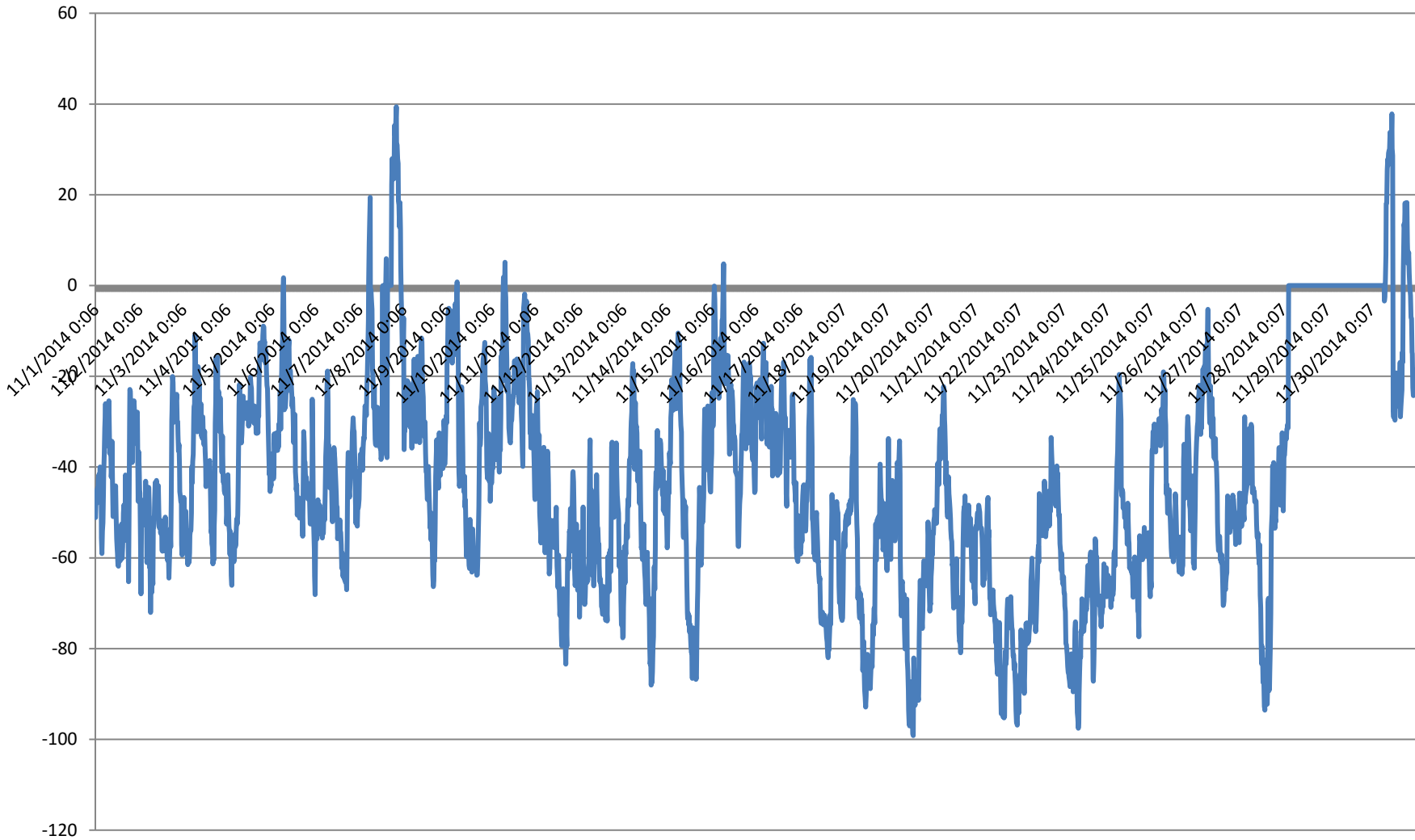
Time

GRDA Unit No. 1 Reactive Power Production in October and November 2014

Sum of 2:6832:MVAR CFP #1

Total

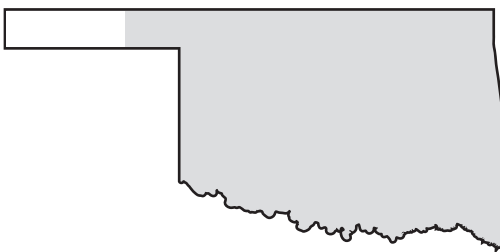
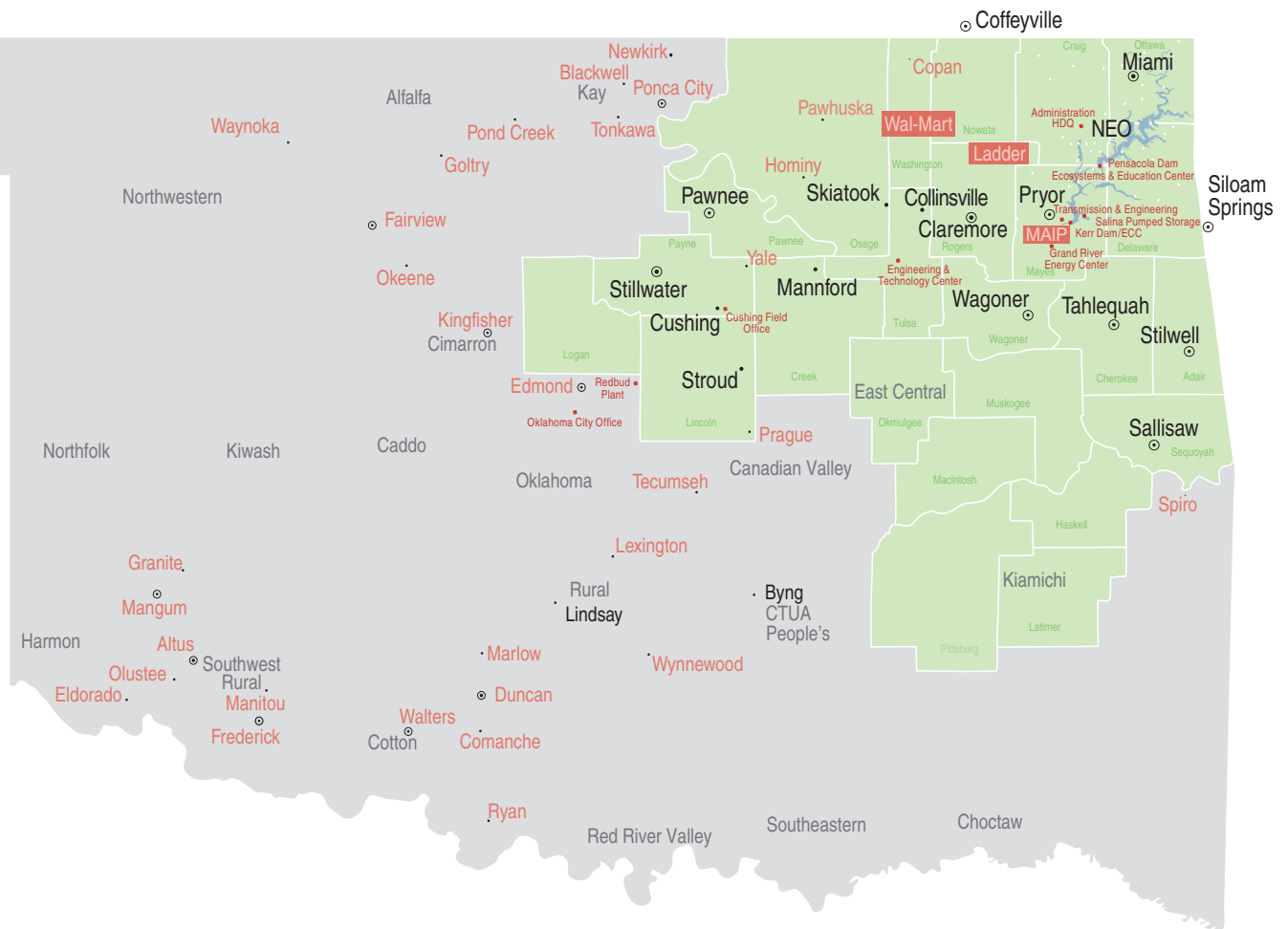
— Total



Time

Attachment F

MAP OF CUSTOMERS AND GRDA FACILITIES



GRDA directly or indirectly provides electricity to some portion of all counties in Oklahoma except for two counties in the panhandle.

Municipal Customers - Served by GRDA in BLACK lettering; many served since 1940s.

Northeast Electric Cooperative - Represented by WHITE DOTs, served since 1946.

Industrial Customers - Represented by ORANGE BOX, Majority located in MidAmerica Industrial Park (MAIP).

Oklahoma Municipal Power Authority - Served since 1985. OMPA's customers in LIGHT ORANGE lettering.

Western Farmers Electric Cooperative - Served since 1983. WFEC's customers in GRAY lettering.

GRDA Facilities - Shown in RED lettering.

See Notes to Financial Statements, Utility Plant for additional information on capital assets.

Source: Grand River Dam Authority

EXHIBIT 25



Department of Energy
Washington, DC 20585

Order No. 202-25-6

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

Emergency Situation

On July 21, 2025, PJM, the Regional Transmission Organization for 65 million people in thirteen states and the District of Columbia, filed a *Request for Emergency Order Under Federal Power Act, Section 202(c)* (Application) with the United States Department of Energy to preserve the reliability of the bulk electric power system.

H.A. Wagner Generating Station Unit 4 (Wagner Unit 4), a 397 MW unit located in Maryland, is constrained by an operating limit of no more than 438 hours of operation per calendar year when burning fuel oil (Operating Limit).³ The Operating Limit is contained in a Consent Order entered into by Raven Power Ft. Smallwood, LLC, a subsidiary of Talen Energy Corporation (Talen), and the Maryland Department of the Environment (MDE), which was submitted to the Environmental Protection Agency (EPA) on January 31, 2020.⁴ PJM is seeking an emergency order pursuant to section 202(c) to allow for the dispatch and operation of the unit in exceedance of its operating limit, if and when needed, over the next 90 days.⁵

As of July 21, 2025, Wagner Unit 4 has only 80 fuel burning hours remaining to operate for the duration of calendar year 2025.⁶ The inability to run Wagner Unit 4 could result in adverse reliability impacts to service in the Baltimore Gas and Electric (BG&E) territory, and within PJM's service territory more broadly.⁷ For the remainder of 2025, PJM anticipates the continued need to schedule Wagner Unit 4 in order to maintain reliable system operations during projected peak demand and/or increased flows on transmission facilities that are

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ Application at 2.

⁴ *Id.*

⁵ *Id.* at 5.

⁶ *Id.* at 8.

⁷ *Id.* at 4.

required to serve the BG&E Zone.⁸ PJM anticipates that it will need to dispatch Wagner Unit 4 when forecast temperatures are high, approximately around 92 degrees in the Mid-Atlantic region and forecast loads in the PJM territory are around 151,000 MW.⁹ PJM assesses that if another heatwave similar to that which occurred in late June 2025 were to occur, there are insufficient run hours remaining because of the Operating Limit on Wagner Unit 4.¹⁰ Additional circumstances that could cause the need for increased scheduling of Wagner Unit 4 include high system demand, additional transmission facility outages, and generation outages or a combination of these factors.¹¹

PJM's operations in 2025 continue to rely upon Wagner Unit 4 at a rate that exceeds its 2024 rate.¹² There were, for example, 11 instances where Wagner Unit 4 ran in January to support high loads, including the new all-time PJM winter peak.¹³ PJM also ran the unit once in early June and ran the unit again for 100 hours over the 5-day extreme heat event during the week of June 23, 2025.¹⁴

PJM has indicated that the electricity output from Wagner Unit 4, when generated beyond its Operating Limit, would be needed to avoid firm load shedding that may be required under certain system conditions or transmission limitations impacting the BG&E Zone.¹⁵ Additionally, absent this order, in the limited circumstances when PJM is operating pursuant to its emergency procedures, PJM anticipates that residences, as well as numerous critical facilities, may lose electric service to all or parts of their facilities due to the lack of adequate generation or transmission.¹⁶ Lastly, PJM has indicated that Talen "does not oppose" its request for relief under section 202(c) and will operate Wagner Unit 4 in accordance with this Order.¹⁷

Description of Mitigation Measures

PJM has indicated that it sought to modify the Operating Limit for Wagner Unit 4, but was unable to do so. The MDE and EPA have informed PJM that the process to modify a condition of the Maryland State Implementation Plan, on which the Consent Order is based, is a lengthy process that will not result in any relief in 2025.¹⁸ PJM has thus sought to minimize the runtime of Wagner Unit 4 to date and is seeking to continue to take actions to minimize the need to call upon Wagner Unit 4 to operate in excess of its Operating Limit.¹⁹ Specifically, PJM has updated operating procedures for committing generation in the BG&E Zone to take

⁸ *Id.* at 9.

⁹ *Id.* at 10.

¹⁰ *Id.* at 9.

¹¹ *Id.* at 9.

¹² *Id.* at 8.

¹³ *Id.* at 8.

¹⁴ *Id.* at 8.

¹⁵ *Id.* at 5.

¹⁶ *Id.* at 10.

¹⁷ *Id.* at 1-2.

¹⁸ *Id.* at 11.

¹⁹ *Id.* at 4.

into account unit limitations and environmental permit limits.²⁰ PJM is also coordinating generator and transmission outages at appropriate forecasted load levels to minimize the need to run Wagner Unit 4 to mitigate transmission limitations impacting the BG&E Zone that could result in firm load shed.²¹

PJM has provided that even with the grant of this Order pursuant to section 202(c), Wagner Unit 4 will “continue to be operated in compliance with permitted emissions limits.”²² However, as operating Wagner Unit 4 beyond its Operating Limit would violate the aforementioned Consent Order, relief under section 202(c) is still needed.

REQUEST FOR ORDER

PJM requests that the Secretary issue an Order immediately, effective July 28, 2025, for a period of 90 days authorizing Wagner Unit 4 to operate in exceedance of its Operating Limit only if certain conditions as described in PJM’s application are met.²³

ORDER

Given the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of Wagner Unit 4 is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on the expected electricity demand, the shortage of electric energy, the shortage of facilities for the generation of electric energy, and other causes.

Since the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below. Therefore, to minimize adverse environmental impacts, this Order limits operation of Wagner Unit 4 to the times and within the parameters determined by PJM for reliability purposes. Based on my determination of an emergency set forth above, I hereby order:

- A. In the event that PJM determines that generation from Wagner Unit 4 is necessary to meet the anticipated electricity demand, I direct PJM to dispatch such unit and to order its operation only as needed to maintain the necessary generation. Specifically, this Order authorizes the operation of Wagner Unit 4 beyond its Operating Limit of 438 hours for calendar year 2025 when PJM:

- (i) Declares or anticipates declaring based on system conditions, a Maximum Generation Alert and/or Transmission Security Emergency (to include

²⁰ *Id.* at 11.

²¹ *Id.* at 11.

²² *Id.* at 4.

²³ *Id.* at 4, 9-10.

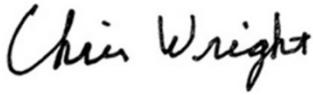
conditions impacting the reliability of transmission facilities that are required to serve the load in the BG&E Zone, or to prevent potential load shed due to transmission limitations); or

- (ii) To the extent not otherwise covered by the above, schedules and dispatches Wagner Unit 4 in a manner consistent with the Settlement Agreement accepted by the Federal Energy Regulatory Commission in Docket No. ER24-1787.²⁴
- B. Once PJM declares that the emergency event has ended, and the respective Maximum Generation Alert has been discontinued and/or Transmission Security Emergency has ended, Wagner Unit 4 must cease operations above its Operating Limit in a manner consistent with its operating parameters.
- C. If Wagner Unit 4 has been dispatched and operated in reliance on this Order, PJM shall provide the business day following the dispatch and operation, notification to the Department of Energy via AskCR@hq.doe.gov. Such notification shall include information on levels of exceedance of the annual Operating Limit.
- D. While operating Wagner Unit 4 under the emergency conditions, PJM shall comply, to the maximum extent practicable, with applicable laws and regulations including the applicable orders for Wagner Unit 4. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.
- E. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
- F. This Order shall not preclude the need for Wagner Unit 4 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- G. This Order expects PJM to comply with its commitments made regarding notifications as detailed in the “Public and Media Notifications” section on page 6 of its Application.

²⁴ *Id.* at 10 (specifically, Section 3.3(a) of the Settlement Agreement).

- H. This Order shall be effective upon its issuance, and shall expire at 12:45 PM EDT on October 26, 2025, with the exception of the reporting requirements in paragraphs C and E and applicable compliance obligations in paragraph F. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 12:45 PM EDT on this 28 day of July 2025.

A handwritten signature in black ink that reads "Chris Wright". The signature is written in a cursive, slightly slanted style.

Chris Wright
Secretary of Energy

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

EXHIBIT 26

Order No. 202-25-1

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 Puerto Rico 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.

The Puerto Rican electrical grid remains in a fragile state due to decades of deferred maintenance, insufficient investment, and the bankruptcy of the system owner and operator. Further, the devastating effects of Hurricanes Irma and Maria (both Category 5) in 2017, Fiona (Category 2) in 2022, and earthquakes in 2020, have significantly contributed to the grid's deterioration. Recent investments in the Puerto Rico grid have provided insignificant improvement towards augmenting reliability and security of the grid.

The result is that Puerto Rico continues to experience frequent partial or total blackouts,¹ with the latest partial blackout occurring on May 15, impacting 134,000 customers and island-wide blackout occurring on April 16, 2025, impacting all 1.4 million electric customers. Furthermore, the power quality metrics in Puerto Rico remain poor:² (voltage and frequency regulation), affecting not only residential customers, but also industry, commerce, telecommunications, healthcare, public safety and other essential critical services.³

The resource adequacy issues in Puerto Rico have been exacerbated by, among other factors, the unexpected long-term outage on February 14, 2025, of Unit 1 (450 MW) at the Aguirre power plant. The number and frequency of forced outages continues to adversely affect grid operations, continuing to delay much needed planned maintenance outages. These outages are likely to lead to insufficient generation capacity to meet customer demand starting in May 2025.⁴ The majority of the conventional generation fleet requires urgent maintenance and fuel conversion initiatives that cannot currently be efficiently

¹ See, e.g., Puerto Rico Public Service Regulatory Board (PSRB), Consolidated Investigation Report, PSRB Case Nos. NEPR-IN-2024-002, NEPR-IN-2024-003 (Apr. 4, 2025) (outlining findings regarding significant power outages in Puerto Rico and highlighting that “Puerto Rico’s electrical grid continues to face significant vulnerabilities, largely due to outdated infrastructure and insufficient maintenance practices.”).

² A. Nassif, “Managing distribution resources: the LUMA perspective” (23PESGM4426), IEEE PES General Meeting 2023.

³ On March 24–26, 2025, Department of Energy staff engaged with stakeholders in Puerto Rico who raised concerns regarding these issues.

⁴ *Id.*

implemented, as taking the units offline for these activities would likely result in negative impacts to grid reliability.

According to the Puerto Rico Electricity System Resource Adequacy Interim Update for Summer 2025 (2025 Resource Adequacy Summer Update), without any action Puerto Rico can be expected to experience severe inadequate capacity reserves from May 2025 and extending through October 2025.⁵ Any loss of a major unit in Puerto Rico is beyond the ability of the system to manage without resorting to load shedding,⁶ as demonstrated on May 13, 2025, when the forced outage of the Costa Sur Unit 5 caused a load shedding event which affected 200,000 customers.⁷ This also means that if “another baseload unit fails, the impact would be catastrophic: up to 135 days and 1,102 hours of load shedding.”⁸

On April 2, 2025, the Governor of Puerto Rico issued an Executive Order, EO-2025-016, which declared a state of emergency with respect to Puerto Rico’s electricity system.

“I hereby declare a modification and expansion of the state of emergency concerning Puerto Rico’s electric system, including—but not limited to—the transmission and distribution system, as well as the generation system and the auxiliary infrastructure required to operate Puerto Rico’s electric system in a reliable and affordable manner and in compliance with applicable laws, including environmental regulations. This declaration also seeks to modernize and strengthen the system in line with our current times and circumstances.”

According to the 2025 Resource Adequacy Summer Update, the restoration of at least 800MW will reduce the mean probability of Loss of Load Events from 90 to 5 and this will significantly reduce the likelihood of widespread blackouts and will make the system more resilient to generation outage events.

Given the emergency nature of the expected load stress, the responsibility of the Puerto Rico Electric Power Authority (PREPA) to ensure maximum reliability on its system, and the ability of PREPA to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Specified Generators, as described in the attachment “Order No. 202-25-1

⁵ 2025 Resource Adequacy Summer Update at 20.

⁶ *Id.* at 27.

⁷ Yaritza Rivera Clemente, “Falla en la Unidad 5 de Costa Sur provocó que cerca de 200,000 clientes se quedaran sin servicio de energía eléctrica - El Nuevo Día,” <https://www.elnuevodia.com/noticias/locales/notas/falla-en-la-unidad-5-de-costa-sur-provoco-que-cerca-de-200000-clientes-se-quedaran-sin-servicio-de-energia-electrica> (accessed on May 14, 2025).

⁸ *Supra* note 15.

Specified Generation Resources,” is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c).

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

To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PREPA for maintaining grid reliability.

Order

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

From May 16, 2025 to August 14, 2025, I order PREPA, or its agents, to dispatch such units from the Specified Resources as necessary to maintain grid reliability.⁹

PREPA is directed to provide the parameters described above to the Department upon implementation, and to report all dates on which the Specified Resources are operated by August 15, 2025, or the date upon which a renewal request is submitted, whichever occurs first.

The Specified Resources must operate only during hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation and minimizes any adverse environmental impacts.

Renewal of this Order, should it be needed, must be requested prior to its expiration. If the conditions creating the emergency remain substantially unchanged, a renewal request should be submitted at least 14 calendar days before this Order expires.

Issued in Washington, D.C. at 2:24pm Eastern Daylight Time on this 16th day of May 2025.

⁹ The private operations of (a) the transmission and distribution infrastructure; and (b) the legacy generation assets are both agents of PREPA under the corresponding Operation & Maintenance Agreements each signed with the government of Puerto Rico in 2020 and 2023, respectively.



Chris Wright
Secretary of Energy

Attachment:

Order No. 202-25-1 Specified Generation Resources

Order No. 202-25-1 Specified Generation Resources

Owner	Entity ID	Plant ID	Plant Name	Generator/Unit
Puerto Rico Electric Power Authority	15497	61146	Aguirre Plant	1
Puerto Rico Electric Power Authority	15497	61146	Aguirre Plant	2
Puerto Rico Electric Power Authority	15497	61147	Costa Sur Plant	5
Puerto Rico Electric Power Authority	15497	61147	Costa Sur Plant	6
Puerto Rico Electric Power Authority	15497	61148	Central San Juan Plant	7
Puerto Rico Electric Power Authority	15497	61148	Central San Juan Plant	9
Puerto Rico Electric Power Authority	15497	61148	Central San Juan Plant	CC5
Puerto Rico Electric Power Authority	15497	61148	Central San Juan Plant	CC6
Puerto Rico Electric Power Authority	15497	61149	Palo Seco Plant	3
Puerto Rico Electric Power Authority	15497	61149	Palo Seco Plant	4
Puerto Rico Electric Power Authority	15497	61150	Cambalache Plant	GT-1
Puerto Rico Electric Power Authority	15497	61150	Cambalache Plant	GT-2
Puerto Rico Electric Power Authority	15497	61150	Cambalache Plant	GT-3
Puerto Rico Electric Power Authority	15497	61151	Mayaguez Plant	GT-1
Puerto Rico Electric Power Authority	15497	61151	Mayaguez Plant	GT-2
Puerto Rico Electric Power Authority	15497	61151	Mayaguez Plant	GT-3
Puerto Rico Electric Power Authority	15497	61151	Mayaguez Plant	GT-4
Puerto Rico Electric Power Authority	15497	61171	Jobos	GT-1
Puerto Rico Electric Power Authority	15497	61171	Jobos	GT-2
Puerto Rico Electric Power Authority	15497	61227	Daguao	GT-1
Puerto Rico Electric Power Authority	15497	61227	Daguao	GT-2
Puerto Rico Electric Power Authority	N/A	N/A	FEMA Temporary Power Generation San Juan	General Electric TM2500 Emergency Generators - Unit 1

Puerto Rico Electric Power Authority	N/A	N/A	FEMA Temporary Power Generation San Juan	General Electric TM2500 Emergency Generators - Unit 2
Puerto Rico Electric Power Authority	N/A	N/A	FEMA Temporary Power Generation San Juan	General Electric TM2500 Emergency Generators - Unit 3
Puerto Rico Electric Power Authority	N/A	N/A	FEMA Temporary Power Generation San Juan	General Electric TM2500 Emergency Generators - Unit 4
Puerto Rico Electric Power Authority	N/A	N/A	FEMA Temporary Power Generation San Juan	General Electric TM2500 Emergency Generators - Unit 5
Puerto Rico Electric Power Authority	N/A	N/A	FEMA Temporary Power Generation San Juan	General Electric TM2500 Emergency Generators - Unit 6
Puerto Rico Electric Power Authority	N/A	N/A	FEMA Temporary Power Generation San Juan	General Electric TM2500 Emergency Generators - Unit 7
Puerto Rico Electric Power Authority	N/A	N/A	FEMA Temporary Power Generation San Juan	General Electric TM2500 Emergency Generators - Unit 8
Puerto Rico Electric Power Authority	N/A	N/A	FEMA Temporary Power Generation San Juan	General Electric TM2500 Emergency Generators - Unit 9
Puerto Rico Electric Power Authority	N/A	N/A	FEMA Temporary Power Generation San Juan	General Electric TM2500 Emergency Generators - Unit 10
Puerto Rico Electric Power Authority	N/A	N/A	FEMA Temporary Power Generation Palo Seco	20MW - Unit 1
Puerto Rico Electric Power Authority	N/A	N/A	FEMA Temporary Power Generation Palo Seco	20MW - Unit 2
Puerto Rico Electric Power Authority	N/A	N/A	FEMA Temporary Power Generation Palo Seco	25MW - Unit 1
Puerto Rico Electric Power Authority	N/A	N/A	FEMA Temporary Power Generation Palo Seco	25MW - Unit 2

EXHIBIT 27

Order No. 202-25-3

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

Emergency Situation

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

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

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

¹ 2025 summer reliability assessment. (May 14, 2025).

https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf

² *Id.*

³ U.S. Energy Information Administration, Michigan State Energy Profile, Oct. 17, 2024, *available at*: <https://www.eia.gov/state/print.php?sid=mi>.

⁴ *Id.*

⁵ <https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation>

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

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

ORDER

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

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

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

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

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

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

- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.
- C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.
- D. By June 15, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability and economic dispatch of the Campbell Plant consistent with the public interest. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
- E. The extent to which MISO's current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.
- F. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- G. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on August 21, 2025, with the exception of the reporting requirements in paragraph D and applicable compliance obligations in paragraph E.
- I. Issued in Washington, D.C. at 3:15:pm Eastern Daylight Time on this 23rd day of May 2025.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**

Chairman Mark Christie

Commissioner David Rosner

Commissioner Lindsay S. See

Commissioner Judy W. Chang

Michigan Public Service Commissioners

Chairman Dan Cripps

Commissioner Katherine Peretick

Commissioner Alessandra Carreon

EXHIBIT 28

Order No. 202-25-4

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

Emergency Situation

PJM has recently stated its system faces “growing resource adequacy concern” due to load growth, the retirement of dispatchable resources, and other factors.¹ Upcoming retirements, including the planned retirement of Unit 3 and Unit 4 of the Eddystone Generating Station in Eddystone, Pennsylvania, will exacerbate these resource adequacy issues.

PJM indicates that resource constraints could exist within the service territory under peak load conditions, stating that “available generation capacity may fall short of required reserves in an extreme planning scenario.”² In its February 2023 assessment “*Energy Transition in PJM: Resource Retirements, Replacements & Risks*,” PJM highlights the increasing risk of reliability risk in the coming years due to the “potential timing mismatch between resource retirements, load growth and the pace of new generation entry” under “low new entry” scenarios for renewable generation.³

In December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found “the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry.”⁴ In March 2025 congressional testimony, PJM found “a growing resource adequacy concern” due to a combination of load growth, the retirement of dispatchable resources, and other factors.⁵ Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM’s interconnection queue.⁶

¹ <https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf>

² <https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/>

³ <https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx>

⁴ https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250211-3120

⁵ <https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf>

⁶ Ibid.

Constellation Energy owns the Eddystone Generating Station, which includes Unit 3 and Unit 4, each of which has a nameplate capacity of 380 MW. Units 3 and 4 have a planned retirement date of May 31, 2025. The retirement of these units would further decrease available dispatchable generation within PJM's service territory.

Pursuant to Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid* (EO 14262), DOE is developing a methodology to identify current and anticipated reserve margins for all regions of the bulk-power system regulated by the Federal Energy Regulatory Commission. EO 14262 requires this methodology to be published by July 7, 2025, and be used to establish a protocol to identify which generation resources within a region are critical to system reliability and prevent identified generation resources from leaving the bulk-power system. DOE plans to use this methodology to further evaluate Eddystone Units 3 and 4.

ORDER

Given the emergency nature of resource adequacy concerns, the declared state of national energy emergency, the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, operational availability and economic dispatch of the aforementioned Eddystone Units 3 and 4 (Eddystone Units) is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the potential load stress due to aforementioned resource adequacy concerns, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The potential shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the region support the need for the Eddystone Units to contribute to system reliability.
- PJM's responsibility to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Eddystone Units, necessary to meet the load demands.

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

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse

environmental impacts. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes.

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

- A. From the time this Order is issued on May 30, 2025, PJM and Constellation Energy shall take all measures necessary to ensure that Eddystone Units are available to operate. For the duration of this order, PJM is directed to take every step to employ economic dispatch of the units to minimize cost to ratepayers. Following conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.
- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units through the expiration of the Order. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units have operated in compliance with the allowances contained in this Order.
- C. All operation of the Eddystone Units must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.
- D. By June 15, 2025, PJM is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with the public interest. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
- E. In addition, PJM and Constellation Energy are directed to file with the Federal Energy Regulatory Commission any tariff revisions or waivers necessary to effectuate this order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. This Order shall not preclude the need for the Eddystone Units to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- G. This Order shall be effective upon its issuance, and shall expire at 5:03 PM EDT on August 28, 2025, with the exception of the reporting requirements in paragraph D.

H. Issued in Simi Valley, California, at 5:03 PM Eastern Daylight Time on this 30th day of May 2025.



Chris Wright
Secretary of Energy

EXHIBIT 29

CLIMATE • 5 MIN READ

The Trump admin ordered a coal power plant to stay on past retirement. Customers in 15 states will foot the bill

JUN 6, 2025



By Ella Nilsen



An aerial image of Consumer Energy's J.H. Campbell Generating Complex in Ottawa County, ...



An aging coal power plant that was supposed to shutter last week will run throughout the summer at the order of President Donald Trump's Energy Sec. Chris Wright, a

decision that could cost Midwest energy customers tens of millions of dollars.

The last-minute federal order to keep the J.H. Campbell plant operating came as a surprise to Michigan officials, including the head of the state's Public Service Commission, given it was at the tail end of a multi-year retirement process that was approved in 2022.

"The grid operator hadn't asked for this, the utility hadn't asked for this, we as the state hadn't asked for this," said Dan Scripps, chair of the Michigan Public Service Commission. "We certainly didn't have any conversations with the (Energy Department) in advance of the order, or since."

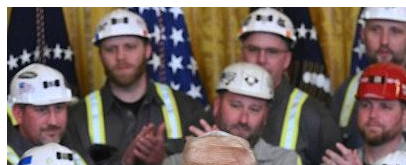
Wright's May 23 emergency order cited concerns the Midwest could face a summer electricity shortage due to a lack of available coal, gas and nuclear plants that can provide stable baseload power. But Consumers Energy, the utility that owns the coal plant, told CNN in an email it already purchased another natural gas-fired power plant to carry the load when the coal plant went offline.

Advertisement

Scripps said the cost to keep the over-60-year-old plant operating, even for 90 days, will be high, and customers in 15 states will foot the bill.

"I can say with a pretty high degree of confidence that we're looking at multiple tens of millions of dollars at the low end," Scripps said. "I think there's a range between

there and the high end of getting close to \$100 million.”



CNN One Thing

How Trump's Coal Cuts Are Hitting His D...

≡ CNN Climate

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It's unclear so far what that will mean for individual electricity bills, Scripps added, given the uncertainty about final cost.

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“For years, American grid operators have warned decommissioning baseload power sources such as coal plants would jeopardize the reliability of our grid systems, which has raised alarm bells,” Energy Department spokesperson Ben Dietderich said in a statement.

Dietderich didn't say whether the Energy Department had conducted a cost analysis before issuing the emergency order. It's unclear whether the department realized the company already had a plan to maintain baseload power after its closure.

Wright issued another emergency order last week to keep a Pennsylvania power plant that runs on natural gas and oil open past its May 31 retirement date.

Coal is the dirtiest fuel large plants still burn for electricity, and it's now the most expensive as renewable energy sources like solar have become increasingly cost-effective. Although natural gas is a fossil fuel and contributes significantly to warming the planet, it is still considered a cheaper and less-polluting option. Gas **generates** **43%** of the country's electricity.

Advertisement

Michigan Attorney General Dana Nessel said she is considering legal action against the federal government. Nessel and energy experts said such an emergency order from the federal government is extremely rare and usually reserved for the aftermath of severe storms or natural disasters.

"This is a novel case for us," Nessel said. "We've not had to do this before."

She reiterated keeping the plant open would "significantly" raise electricity rates, saying, "The whole point of closing this plant down was to save money."



US Energy Secretary Chris Wright looks on during a House subcommittee hearing on the department's budget on Capitol Hill in Washington, DC, on May 7, 2025. *(Brendan Smialowski/AFP/Getty Images)*

More electric utilities are retiring their coal plants because they are old and especially expensive to run. In 2021, the average coal-fired power plant was 45 years old, according to a report from the Energy Information Administration.

The Energy Department's order didn't specify exactly how much the Michigan coal plant should run, saying it was requiring the utility to "take all measures necessary to ensure that the Campbell Plant is available to operate."

Scripps and energy experts said that means the coal plant would likely run continuously at a lower level throughout the summer, or until Wright's order ends. Unlike gas plants, coal plants can't be easily turned on and off with the flip of a switch and take time to ramp up and come online. The Campbell plant is so old — it has been operating since 1962 — that Michigan energy regulators feared it could not physically turn back on once it was powered off.

The utility will also have to buy more coal to keep it going. Consumers Energy said it has “arranged for new shipments of coal to keep the plant operating.”

A new report from think tank Energy Innovation found the cost of coal-fired power has grown faster than inflation in the last few years — collectively costing US consumers \$6.2 billion more in 2024 than it would have cost in 2021.

“Even existing coal where it has fully depreciated and been paid off, the cost of coal is more than solar and storage at this point,” said Doug Lewin, a Texas based energy expert who authors the Texas Energy and Power Newsletter and host of the Energy Capital Podcast.

Lewin covers the energy transition in deep red Texas, where power companies are building wind, solar and battery storage at an incredible pace. Of the significant amount of new electricity added to the Texas grid in the last four years, 92% has been wind, solar and storage, Lewin said.

That has paid dividends, keeping energy prices relatively low and meeting the state's exploding power demand from air conditioning, data centers and big industry.

"All throughout the summer months, you're getting maximum solar output," Lewin said. "It's very well correlated to peak demand. For a place with massive AC load like Texas, it's fantastic."

Texas has also invested a lot in big batteries that can keep power flowing to the grid after the sun stops shining and the wind stops blowing.

Advertisement

Energy Sec. Wright, however, has panned renewables, saying they are not a reliable replacement for fossil fuels.

"There is simply no physical way that wind, solar and batteries could replace the myriad uses of natural gas," he said at Houston energy conference CERAWeek in March. "I haven't even mentioned oil or coal yet."

Read more

• [Trump EPA drafting a rule that would undo decades of progress on limiting pollution from power plants](#)

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• [The jobs and tax credits that could disappear if the ‘big, beautiful’ bill passes the Senate](#)

• [A polluting, coal-fired power plant found the key to solving America’s biggest clean energy challenge](#)



Up next



The Trump administration just ordered another retiring coal plant to stay open. It could cost ratepayers millions

3 MIN READ



The best solar generators in 2026, tested by editors

21 MIN READ



Exclusive: DHS begins slashing FEMA disaster response staff as 2026 begins

4 MIN READ

EXHIBIT 30

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the quarterly period ended June 30, 2025

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from _____ to _____

Commission File No.	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification No.
1-9513	 CMS ENERGY CORPORATION (A Michigan Corporation) One Energy Plaza, Jackson, Michigan 49201 (517) 788-0550	38-2726431
1-5611	 CONSUMERS ENERGY COMPANY (A Michigan Corporation) One Energy Plaza, Jackson, Michigan 49201 (517) 788-0550	38-0442310

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
CMS Energy Corporation Common Stock, \$0.01 par value	CMS	New York Stock Exchange
CMS Energy Corporation 5.625% Junior Subordinated Notes due 2078	CMSA	New York Stock Exchange
CMS Energy Corporation 5.875% Junior Subordinated Notes due 2078	CMSC	New York Stock Exchange
CMS Energy Corporation 5.875% Junior Subordinated Notes due 2079	CMSD	New York Stock Exchange
CMS Energy Corporation Depositary Shares, each representing a 1/1,000th interest in a share of 4.200% Cumulative Redeemable Perpetual Preferred Stock, Series C	CMS PRC	New York Stock Exchange
Consumers Energy Company Cumulative Preferred Stock, \$100 par value: \$4.50 Series	CMS-PB	New York Stock Exchange

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

CMS Energy Corporation: Yes ☒ No ☐ **Consumers Energy Company:** Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

CMS Energy Corporation: Yes ☒ No ☐ **Consumers Energy Company:** Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

CMS Energy Corporation:		Consumers Energy Company:	
Large accelerated filer	☒	Large accelerated filer	☐
Non-accelerated filer	☐	Non-accelerated filer	☒
Accelerated filer	☐	Accelerated filer	☐
Smaller reporting company	☐	Smaller reporting company	☐
Emerging growth company	☐	Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

CMS Energy Corporation: ☐ **Consumers Energy Company:** ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

CMS Energy Corporation: Yes ☐ No ☒ **Consumers Energy Company:** Yes ☐ No ☒

Indicate the number of shares outstanding of each of the issuer's classes of common stock at July 14, 2025:

CMS Energy Corporation:	
CMS Energy Corporation Common Stock, \$0.01 par value	299,335,461
Consumers Energy Company:	
Consumers Common Stock, \$10 par value, privately held by CMS Energy Corporation	84,108,789

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CMS Energy Corporation

Consumers Energy Company

Quarterly Reports on Form 10-Q to the Securities and Exchange Commission for the Period Ended June 30, 2025

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Glossary

Certain terms used in the text and financial statements are defined below.

2024 Form 10-K

Each of CMS Energy's and Consumers' Annual Report on Form 10-K for the year ended December 31, 2024

2023 Energy Law

Michigan's Public Acts 229, 230, 231, 233, 234, and 235 of 2023

ABATE

Association of Businesses Advocating Tariff Equity

ASP

Appliance Service Plan

Aviator Wind

Aviator Wind Holdings, LLC, a VIE in which Aviator Wind Equity Holdings holds a Class B membership interest

Aviator Wind Equity Holdings

Aviator Wind Equity Holdings, LLC, a VIE in which Grand River Wind, LLC, a wholly owned subsidiary of NorthStar Clean Energy, has a 51-percent interest

Bay Harbor

A residential/commercial real estate area located near Petoskey, Michigan, in which CMS Energy sold its interest in 2002

Bcf

Billion cubic feet

CCR

Coal combustion residual

CEO

Chief Executive Officer

CERCLA

Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended

CFO

Chief Financial Officer

[Table of Contents](#)**Clean Air Act**

Federal Clean Air Act of 1963, as amended

Clean Energy Plan

Consumers' long-term strategy for delivering clean, reliable, resilient, and affordable energy to its customers; this plan was originally outlined and approved in Consumers' 2018 integrated resource plan and subsequently updated and approved through its 2021 integrated resource plan

Clean Water Act

Federal Water Pollution Control Act of 1972, as amended

CMS Energy

CMS Energy Corporation and its consolidated subsidiaries, unless otherwise noted; the parent of Consumers and NorthStar Clean Energy

CMS Land

CMS Land Company, a wholly owned subsidiary of CMS Capital, L.L.C., a wholly owned subsidiary of CMS Energy

Consumers

Consumers Energy Company and its consolidated subsidiaries, unless otherwise noted; a wholly owned subsidiary of CMS Energy

Consumers 2014 Securitization Funding

Consumers 2014 Securitization Funding LLC, a wholly owned consolidated bankruptcy-remote subsidiary of Consumers and special-purpose entity organized for the sole purpose of purchasing and owning securitization property, issuing securitization bonds, and pledging its interest in securitization property to a trustee to collateralize the securitization bonds

Consumers 2023 Securitization Funding

Consumers 2023 Securitization Funding LLC, a wholly owned consolidated bankruptcy-remote subsidiary of Consumers and special-purpose entity organized for the sole purpose of purchasing and owning securitization property, issuing securitization bonds, and pledging its interest in securitization property to a trustee to collateralize the securitization bonds

Covert Generating Station

A 1,200-MW natural gas-fueled generation station that was acquired by Consumers in 2023 from New Covert Generating Company, LLC, a non-affiliated company

Craven

Craven County Wood Energy Limited Partnership, a VIE in which HYDRA-CO Enterprises, Inc., a wholly owned subsidiary of NorthStar Clean Energy, has a 50-percent interest

[Table of Contents](#)**CSAPR**

Cross-State Air Pollution Rule of 2011, as amended

DB Pension Plans

Defined benefit pension plans of CMS Energy and Consumers, including certain present and former affiliates and subsidiaries

DB SERP

Defined Benefit Supplemental Executive Retirement Plan

Delta Solar Equity Holdings

Delta Solar Equity Holdings, LLC, a VIE in which Grand River Solar, LLC, a wholly owned subsidiary of NorthStar Clean Energy, has a 50-percent interest

DIG

Dearborn Industrial Generation, L.L.C., a wholly owned subsidiary of Dearborn Industrial Energy, L.L.C., a wholly owned subsidiary of NorthStar Clean Energy

Dodd-Frank Act

Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010

DTE Electric

DTE Electric Company, a non-affiliated company

EGLE

Michigan Department of Environment, Great Lakes, and Energy

Endangered Species Act

Federal Endangered Species Act of 1973, as amended

energy waste reduction

The reduction of energy consumption through energy efficiency and demand-side energy conservation, as established under Michigan law

EPA

U.S. Environmental Protection Agency

EPS

Earnings per share

ERP

Enterprise Resource Planning software

[Table of Contents](#)**Exchange Act**

Securities Exchange Act of 1934

Federal Power Act

Federal Power Act of 1920

FERC

Federal Energy Regulatory Commission

FTR

Financial transmission right

GAAP

U.S. Generally Accepted Accounting Principles

Genesee

Genesee Power Station Limited Partnership, a VIE in which HYDRA-CO Enterprises, Inc., a wholly owned subsidiary of NorthStar Clean Energy, has a 50-percent interest

Good Neighbor Plan

A plan issued by the EPA which secures significant reductions in ozone-forming emissions of NOx from power plants and industrial facilities

Grayling

Grayling Generating Station Limited Partnership, a VIE in which HYDRA-CO Enterprises, Inc., a wholly owned subsidiary of NorthStar Clean Energy, has a 50-percent interest

IRS

Internal Revenue Service

IT

Information technology

J.H. Campbell

J.H. Campbell Generating Complex, a three-unit coal-fueled electric generating facility comprised of Units 1 and 2, which are wholly owned by Consumers, and Unit 3, which Consumers jointly owns with the Michigan Public Power Agency, holding a 4.80-percent interest, and Wolverine Power Supply Cooperative, Inc., holding a 1.89-percent interest, each a non-affiliated company

kWh

Kilowatt-hour, a unit of energy equal to one thousand watt-hours

[Table of Contents](#)**Ludington**

Ludington pumped-storage plant, jointly owned by Consumers and DTE Electric

MATS

Mercury and Air Toxics Standards, which limit mercury, acid gases, and other toxic pollution from coal-fueled and oil-fueled power plants

MD&A

Management's Discussion and Analysis of Financial Condition and Results of Operations

METC

Michigan Electric Transmission Company, LLC, a non-affiliated company

MGP

Manufactured gas plant

Migratory Bird Treaty Act

Migratory Bird Treaty Act of 1918, as amended

MISO

Midcontinent Independent System Operator, Inc.

MISO Tariff

MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff

mothball

To place a generating unit into a state of extended reserve shutdown in which the unit is inactive and unavailable for service for a specified period, during which the unit can be brought back into service after receiving appropriate notification and completing any necessary maintenance or other work; generation owners in MISO must request approval to mothball a unit, and MISO then evaluates the request for reliability impacts

MPSC

Michigan Public Service Commission

MW

Megawatt, a unit of power equal to one million watts

NAAQS

National Ambient Air Quality Standards

Natural Gas Act

Natural Gas Act of 1938

[Table of Contents](#)**Newport Solar Holdings**

Newport Solar Holdings III, LLC, a VIE in which Newport Solar Equity Holdings LLC, a wholly owned subsidiary of Grand River Solar, LLC, a wholly owned subsidiary of NorthStar Clean Energy, holds a Class B membership interest

NorthStar Clean Energy

NorthStar Clean Energy Company, a wholly owned subsidiary of CMS Energy, formerly known as CMS Enterprises Company

NO_x

Nitrogen oxides

NPDES

National Pollutant Discharge Elimination System, a permit system for regulating point sources of pollution under the Clean Water Act

NREPA

Part 201 of Michigan's Natural Resources and Environmental Protection Act of 1994, as amended

NWO Holdco

NWO Holdco, L.L.C., a VIE in which NWO Holdco I, LLC, a wholly owned subsidiary of NWO Wind Equity Holdings, LLC, holds a Class B membership interest

NWO Wind Equity Holdings

NWO Wind Equity Holdings, LLC, a VIE in which Grand River Wind, LLC, a wholly owned subsidiary of NorthStar Clean Energy, has a 50-percent interest

OBBBA

Federal One Big Beautiful Bill Act of 2025

OPEB

Other post-employment benefits

OPEB Plan

Postretirement health care and life insurance plans of CMS Energy and Consumers, including certain present and former affiliates and subsidiaries

PCB

Polychlorinated biphenyl

PPA

Power purchase agreement

[Table of Contents](#)**RCRA**

Federal Resource Conservation and Recovery Act of 1976

Reliability Roadmap

Consumers' five-year strategy to improve its electric distribution system and the reliability of the grid; this plan was filed with the MPSC in 2023, and is an update to Consumers' previous Electric Distribution Infrastructure Investment Plan filed in 2021

ROA

Retail Open Access, which allows electric generation customers to choose alternative electric suppliers pursuant to Michigan's Public Acts 141 and 142 of 2000, as amended

SEC

U.S. Securities and Exchange Commission

securitization

A financing method authorized by statute and approved by the MPSC which allows a utility to sell its right to receive a portion of the rate payments received from its customers for the repayment of securitization bonds issued by a special-purpose entity affiliated with such utility

SOFR

Secured overnight financing rate calculated and published by the Federal Reserve Bank of New York

TAES

Toshiba America Energy Systems Corporation, a non-affiliated company

TBJH

TBJH Inc., a non-affiliated company

TCJA

Tax Cuts and Jobs Act of 2017

Term SOFR

The rate per annum that is a forward-looking term rate based on SOFR

T.E.S. Filer City

T.E.S. Filer City Station Limited Partnership, a VIE in which HYDRA-CO Enterprises, Inc., a wholly owned subsidiary of NorthStar Clean Energy, has a 50-percent interest

Toshiba

Toshiba Corporation, a non-affiliated company

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Toshiba International

Toshiba International Corporation, a non-affiliated company

UWUA

Utility Workers Union of America, AFL-CIO

VIE

Variable interest entity

Filing Format

This combined Form 10-Q is separately filed by CMS Energy and Consumers. Information in this combined Form 10-Q relating to each individual registrant is filed by such registrant on its own behalf. Consumers makes no representation regarding information relating to any other companies affiliated with CMS Energy other than its own subsidiaries.

CMS Energy is the parent holding company of several subsidiaries, including Consumers and NorthStar Clean Energy. None of CMS Energy, NorthStar Clean Energy, nor any of CMS Energy's other subsidiaries (other than Consumers) has any obligation in respect of Consumers' debt securities or preferred stock and holders of such securities should not consider the financial resources or results of operations of CMS Energy, NorthStar Clean Energy, nor any of CMS Energy's other subsidiaries (other than Consumers and its own subsidiaries (in relevant circumstances)) in making a decision with respect to Consumers' debt securities or preferred stock. Similarly, neither Consumers nor any other subsidiary of CMS Energy has any obligation in respect of securities of CMS Energy.

This report should be read in its entirety. No one section of this report deals with all aspects of the subject matter of this report. This report should be read in conjunction with the consolidated financial statements and related notes and with MD&A included in the 2024 Form 10-K.

Available Information

CMS Energy's internet address is www.cmsenergy.com. CMS Energy routinely posts important information on its website and considers the Investor Relations section, www.cmsenergy.com/investor-relations, a channel of distribution for material information. Information contained on CMS Energy's website is not incorporated herein.

Forward-looking Statements and Information

This Form 10-Q and other CMS Energy and Consumers disclosures may contain forward-looking statements as defined by the Private Securities Litigation Reform Act of 1995. The use of "anticipates," "assumes," "believes," "could," "estimates," "expects," "forecasts," "goals," "guidance," "intends," "may," "might," "objectives," "plans," "possible," "potential," "predicts," "projects," "seeks," "should," "targets," "will," and other similar words is intended to identify forward-looking statements that involve risk and uncertainty. This discussion of potential risks and uncertainties is designed to highlight important factors that may impact CMS Energy's and Consumers' businesses and financial outlook. CMS Energy and Consumers have no obligation to update or revise forward-looking statements regardless of whether new information, future events, or any other factors affect the information contained in the statements. These forward-looking statements are subject to various factors that could cause CMS Energy's and Consumers' actual results to differ materially from the results anticipated in these statements. These factors include, but are not limited to, the following, all of which are potentially significant:

- the impact and effect of recent events, such as worsening trade relations, geopolitical tensions, war, acts of terrorism, and the responses to these events, and related economic disruptions including, but not limited to, inflation, energy price volatility, tariffs, and supply chain disruptions
- the impact of new or modified regulation by the MPSC, FERC, and other applicable governmental proceedings and regulations, including any associated impact on electric or gas rates or rate structures

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- potentially adverse regulatory treatment, effects of a failure to receive timely regulatory orders that are or could come before the MPSC, FERC, or other governmental authorities, or effects of a government shutdown
- changes in the performance of or regulations applicable to MISO, METC, pipelines, railroads, vessels, or other service providers that CMS Energy, Consumers, or any of their affiliates rely on to serve their customers
- federal or executive actions, the adoption of or challenges to federal or state laws or regulations or changes in applicable laws, rules, regulations, principles, or practices, or in their interpretation, such as those related to energy policy, ROA, the Public Utility Regulatory Policies Act of 1978, infrastructure integrity or security, cybersecurity, gas pipeline safety, gas pipeline capacity, energy waste reduction, the financial compensation mechanism, the environment, regulation or deregulation, reliability, health care reforms, taxes, tax credits, accounting matters, tariffs, climate change, air emissions, renewable energy, the Dodd-Frank Act, and other business issues that could have an impact on CMS Energy's, Consumers', or any of their affiliates' businesses or financial results
- factors affecting, disrupting, interrupting, or otherwise impacting CMS Energy's or Consumers' facilities, utility infrastructure, operations, or backup systems, such as costs and availability of personnel, equipment, and materials; weather and climate, including catastrophic weather-related damage and extreme temperatures; natural disasters; fires; smoke; scheduled or unscheduled equipment outages; maintenance or repairs; contractor performance; environmental incidents; failures of equipment or materials; electric transmission and distribution or gas pipeline system constraints; interconnection requirements; political and social unrest; general strikes; the government and/or paramilitary response to political or social events; changes in trade policies, regulations, or tariffs; accidents; explosions; physical disasters; global pandemics; cyber incidents; physical or cyber attacks; vandalism; war or terrorism; and the ability to obtain or maintain insurance coverage for these events
- the ability of CMS Energy and Consumers to execute cost-reduction strategies and/or convert economic development opportunities
- potentially adverse regulatory or legal interpretations or decisions regarding environmental matters, or delayed regulatory treatment or permitting decisions that are or could come before agencies such as EGLE, the EPA, FERC, and/or the U.S. Army Corps of Engineers, and potential environmental remediation costs associated with these interpretations or decisions, including those that may affect Consumers' coal ash management or routine maintenance, repair, and replacement classification under New Source Review, a construction-permitting program under the Clean Air Act
- changes in energy markets, including availability, price, and seasonality of electric capacity and energy and the timing and extent of changes in commodity prices and availability and deliverability of coal, natural gas, natural gas liquids, electricity, oil, gasoline, diesel fuel, and certain related products
- the price of CMS Energy common stock, the credit ratings of CMS Energy and Consumers, capital and financial market conditions, and the effect of these market conditions on CMS Energy's and Consumers' interest costs and access to the capital markets, including availability of financing to CMS Energy, Consumers, or any of their affiliates

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- the ability of CMS Energy and Consumers to execute their financing strategies
- the investment performance of the assets of CMS Energy's and Consumers' pension and benefit plans, the discount rates, mortality assumptions, and future medical costs used in calculating the plans' obligations, and the resulting impact on future funding requirements
- the impact of the economy, particularly in Michigan, and potential future volatility in the financial and credit markets on CMS Energy's, Consumers', or any of their affiliates' revenues, ability to collect accounts receivable from customers, or cost and availability of capital
- changes in the economic and financial viability of CMS Energy's and Consumers' suppliers, customers, and other counterparties and the continued ability of these third parties, including those in bankruptcy, to meet their obligations to CMS Energy and Consumers
- population changes in the geographic areas where CMS Energy and Consumers conduct business
- national, regional, and local economic, competitive, and regulatory policies, conditions, and developments
- loss of customer demand for electric generation supply to alternative electric suppliers, the creation of municipal utilities, increased use of self-generation including distributed generation, energy waste reduction, or energy storage
- loss of customer demand for natural gas due to alternative technologies or fuels or electrification
- the ability of Consumers to meet increased renewable energy demand due to customers seeking to meet their own sustainability goals in a timely and cost-efficient manner
- the reputational or other impact on CMS Energy and Consumers of the failure to meet the renewable or clean energy standards required by the 2023 Energy Law or to achieve or make timely progress on their greenhouse gas reduction goals related to reducing their impact on climate change
- adverse consequences of employee, director, or third-party fraud or non-compliance with codes of conduct or with laws or regulations
- federal regulation of electric sales, including periodic re-examination by federal regulators of CMS Energy's and Consumers' market-based sales authorizations
- any event, change, development, occurrence, or circumstance that could impact the implementation of the Clean Energy Plan, including any action by a regulatory authority or other third party to prohibit, delay, or impair the implementation of the Clean Energy Plan
- the ability to meet increases in electric demand associated with data centers
- the availability, cost, coverage, and terms of insurance, the stability of insurance providers, and the ability of Consumers to recover the costs of any insurance from customers
- the effectiveness of CMS Energy's and Consumers' risk management policies, procedures, and strategies, including strategies to hedge risk related to interest rates and future prices of electricity, natural gas, and other energy-related commodities
- factors affecting development of electric generation projects, gas transmission, and gas and electric distribution infrastructure replacement, conversion, and expansion projects, including

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factors related to project site identification, construction material availability, quality, and pricing, tariffs, embargoes on equipment, supply chain disruptions, schedule delays, interconnection delays, availability of qualified construction personnel, permitting, acquisition of property rights, community opposition, environmental regulations, performance of contractors and counterparties, and government actions

- changes or disruption in fuel supply, including but not limited to supplier bankruptcy and delivery disruptions
- potential costs, lost revenues, reputational harm, or other consequences resulting from misappropriation of assets or sensitive information, corruption of data, or operational disruption in connection with a cyberattack or other cyber incident
- potential disruption to, interruption or failure of, or other impacts on IT backup or disaster recovery systems
- technological developments in energy production, storage, delivery, usage, and metering
- the ability to implement and integrate technology successfully, including artificial intelligence
- the impact of CMS Energy's and Consumers' integrated business software system and its effects on their operations, including utility customer billing and collections
- adverse consequences resulting from any past, present, or future assertion of indemnity or warranty claims associated with assets and businesses previously owned by CMS Energy or Consumers, including claims resulting from attempts by foreign or domestic governments to assess taxes on or to impose environmental liability associated with past operations or transactions
- the outcome, cost, and other effects of any legal or administrative claims, proceedings, investigations, or settlements
- the reputational impact on CMS Energy and Consumers of operational incidents, violations of corporate policies, regulatory violations, inappropriate use of social media, and other events
- restrictions imposed by various financing arrangements and regulatory requirements on the ability of Consumers and other subsidiaries of CMS Energy to transfer funds to CMS Energy in the form of cash dividends, loans, or advances
- earnings volatility resulting from the application of fair value accounting to certain energy commodity contracts or interest rate contracts
- changes in financial or regulatory accounting principles or policies or interpretation of principles or policies
- other matters that may be disclosed from time to time in CMS Energy's and Consumers' SEC filings, or in other public documents

All forward-looking statements should be considered in the context of the risk and other factors described above and as detailed from time to time in CMS Energy's and Consumers' SEC filings. For additional details regarding these and other uncertainties, see Part I—Item 1. Financial Statements—MD&A—Outlook and Notes to the Unaudited Consolidated Financial Statements—Note 1, Regulatory Matters and Note 2, Contingencies and Commitments; and Part I—Item 1A. Risk Factors in the 2024 Form 10-K.

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Part I—Financial Information

Item 1. Financial Statements

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CMS Energy Corporation

Consumers Energy Company

Management's Discussion and Analysis of Financial Condition and Results of Operations

This MD&A is a combined report of CMS Energy and Consumers.

Executive Overview

CMS Energy is an energy company operating primarily in Michigan. It is the parent holding company of several subsidiaries, including Consumers, an electric and gas utility, and NorthStar Clean Energy, primarily a domestic independent power producer and marketer. Consumers' electric utility operations include the generation, purchase, distribution, and sale of electricity, and Consumers' gas utility operations include the purchase, transmission, storage, distribution, and sale of natural gas. Consumers' customer base consists of a mix of primarily residential, commercial, and diversified industrial customers. NorthStar Clean Energy, through its subsidiaries and equity investments, is engaged in domestic independent power production, including the development and operation of renewable generation, and the marketing of independent power production.

CMS Energy and Consumers manage their businesses by the nature of services each provides. CMS Energy operates principally in three business segments: electric utility; gas utility; and NorthStar Clean Energy, its non-utility operations and investments. Consumers operates principally in two business segments: electric utility and gas utility. CMS Energy's and Consumers' businesses are affected primarily by:

- regulation and regulatory matters
- state and federal legislation
- economic conditions
- weather
- energy commodity prices
- interest rates
- their securities' credit ratings

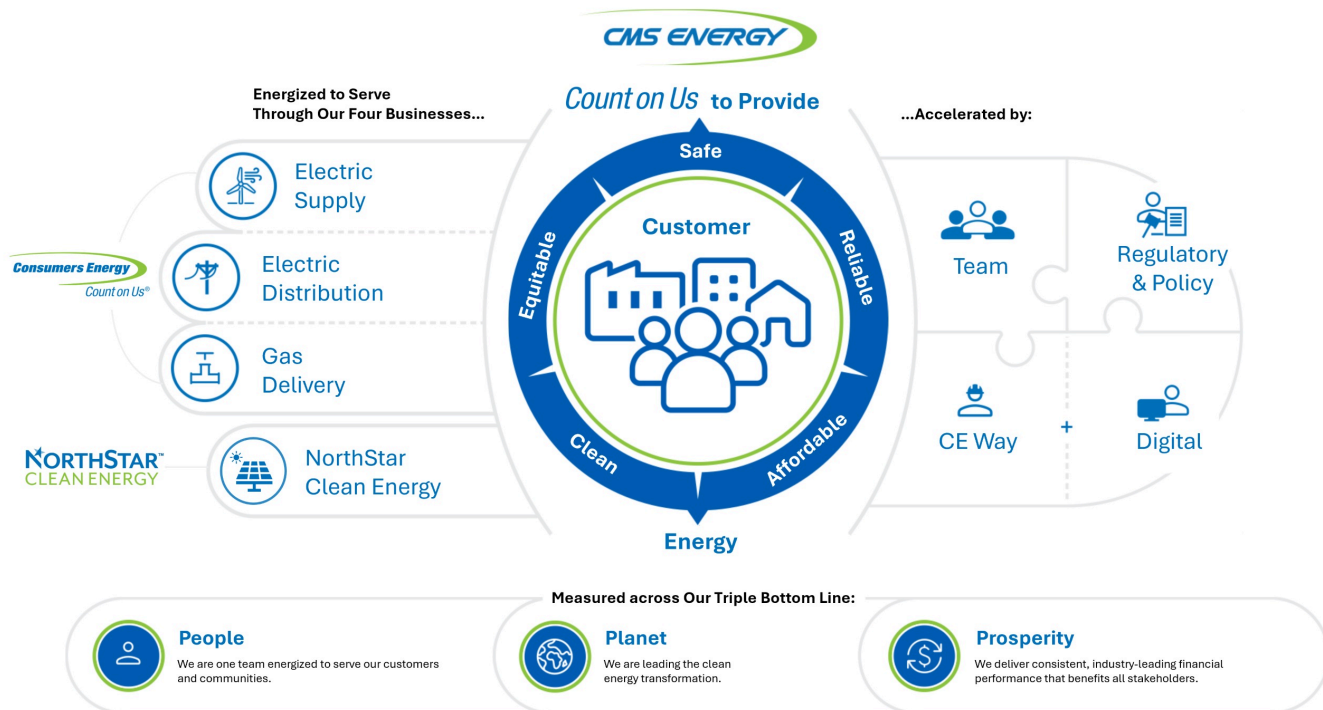
The Triple Bottom Line

CMS Energy's and Consumers' purpose is to provide safe, reliable, affordable, clean, and equitable energy in service of their customers. In support of this purpose, CMS Energy and Consumers couple digital transformation with the "CE Way," a lean operating system designed to improve safety, quality, cost, delivery, and employee morale.

CMS Energy and Consumers measure their progress toward the purpose by considering their impact on the "triple bottom line" of people, planet, and prosperity; this consideration takes into account not only the economic value that CMS Energy and Consumers create for customers and investors, but also their responsibility to social and environmental goals. The triple bottom line balances the interests of employees, customers, suppliers, regulators, creditors, Michigan's residents, the investment community,

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and other stakeholders, and it reflects the broader societal impacts of CMS Energy's and Consumers' activities.



CMS Energy's Sustainability Report, which is available to the public, describes CMS Energy's and Consumers' progress toward world class performance measured in the areas of people, planet, and prosperity.

People: The people element of the triple bottom line represents CMS Energy's and Consumers' commitment to their employees, their customers, the residents of local communities in which they do business, and other stakeholders.

The safety of co-workers, customers, and the general public is a priority of CMS Energy and Consumers. Accordingly, CMS Energy and Consumers have worked to integrate a set of safety principles into their business operations and culture. These principles include complying with applicable safety, health, and security regulations and implementing programs and processes aimed at continually improving safety and security conditions.

CMS Energy and Consumers also place a high priority on customer value and on providing reliable, affordable, and equitable energy in service of their customers. Consumers' customer-driven investment program is aimed at improving safety and increasing electric and gas reliability.

In the electric rate case it filed with the MPSC in June 2025, Consumers updated its Reliability Roadmap, a five-year strategy to improve Consumers' electric distribution system and the reliability of the grid. The plan proposes spending through 2029 for projects designed to reduce the number and duration of power outages to customers through investment in infrastructure upgrades, vegetation management, and grid

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modernization. Consumers has requested rate recovery of the investments needed to achieve the Reliability Roadmap's key objectives in its electric rate cases.

Central to Consumers' commitment to its customers are the initiatives it has undertaken to keep electricity and natural gas affordable, including:

- replacement of coal-fueled generation and PPAs with a cost-efficient and reliable mix of renewable energy, less-costly dispatchable generation sources, and energy waste reduction and demand response programs
- targeted infrastructure investment to reduce maintenance costs and improve reliability and safety
- supply chain optimization
- economic development to increase sales and reduce overall rates
- information and control system efficiencies
- employee and retiree health care cost sharing
- tax planning
- cost-effective financing
- workforce productivity enhancements

While inflationary pressures and tariffs could impact supply chain availability and pricing, CMS Energy and Consumers are taking steps to help mitigate the impact on their ability to provide safe, reliable, affordable, clean, and equitable energy in service of their customers.

Planet: The planet element of the triple bottom line represents CMS Energy's and Consumers' commitment to protect the environment. This commitment extends beyond compliance with various state and federal environmental, health, and safety laws and regulations. Management considers climate change and other environmental risks in strategy development, business planning, and enterprise risk management processes.

CMS Energy and Consumers continue to focus on opportunities to protect the environment and reduce their carbon footprint from owned generation. CMS Energy, including Consumers, has decreased its combined percentage of electric supply (self-generated and purchased) from coal by 23 percentage points since 2015. Additionally, as a result of actions already taken through 2024, Consumers has:

- reduced carbon dioxide emissions from owned generation by more than 30 percent since 2005
- reduced methane emissions by nearly 30 percent since 2012
- reduced the volume of water used to generate electricity by more than 50 percent since 2012
- reduced landfill waste disposal by more than two million tons since 1992
- enhanced, restored, or protected more than 11,700 acres of land since 2017
- reduced sulfur dioxide and particulate matter emissions by nearly 95 percent since 2005
- reduced NOx emissions by more than 86 percent since 2005
- reduced mercury emissions by more than 92 percent since 2007

In 2023, Michigan enacted the 2023 Energy Law, which among other things:

- raised the renewable energy standard from the present 15-percent requirement to 50 percent by 2030 and 60 percent by 2035; renewable energy generated anywhere within MISO can be applied to meeting this standard, with certain limitations
- set a clean energy standard of 80 percent by 2035 and 100 percent by 2040; low- or zero-carbon emitting resources, such as nuclear generation and natural gas generation coupled with carbon capture, are considered clean energy sources under this standard

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- enhanced existing incentives for energy efficiency programs and returns earned on new clean or renewable PPAs
- created a new energy storage standard that requires electric utilities to file plans by 2029 to obtain new energy storage that will contribute to a Michigan target of 2,500 MW based on their pro rata share
- expanded the statutory cap on distributed generation resources to 10 percent of utility sales

Consumers filed updates to its renewable energy plan in November 2024 and plans to file updates to its Clean Energy Plan in 2026. Together, these updated plans will serve as Consumers' blueprint to meeting the requirements of the 2023 Energy Law by focusing on increasing the generation of renewable energy, deploying energy storage, helping customers use less energy, and offering demand response programs to reduce demand during critical peak times.

Consumers' Clean Energy Plan details its strategy to meet customers' long-term energy needs and was most recently revised and approved by the MPSC in 2022 under Michigan's integrated resource planning process. The Clean Energy Plan outlines Consumers' long-term strategy for delivering safe, reliable, affordable, clean, and equitable energy to its customers. This strategy includes:

- ending the use of coal in owned generation in 2025, 15 years sooner than initially planned
- purchasing the Covert Generating Station, a natural gas-fueled generating facility with 1,200 MW of nameplate capacity, allowing Consumers to continue to provide controllable sources of electricity to customers; this purchase was completed in 2023
- soliciting capacity from sources able to deliver to Michigan's Lower Peninsula, including battery storage facilities

In May 2025, before the planned closure of J.H. Campbell, the U.S. Secretary of Energy issued an emergency order under section 202(c) of the Federal Power Act requiring J.H. Campbell to continue operating for 90 days, through August 20, 2025. The order stated that continued operation of J.H. Campbell was required to meet an energy emergency across MISO's North and Central regions. Consistent with the Federal Power Act and the U.S. Department of Energy regulations, the order authorizes Consumers to obtain cost recovery at FERC. Consumers has continued to make J.H. Campbell available in the MISO market, consistent with the order, and has filed a complaint at FERC seeking a modification of the MISO Tariff to establish a mechanism for recovery and allocation of the cost to comply with this order. The U.S. Department of Energy may issue one or more subsequent orders to require the operation of J.H. Campbell past August 20, 2025. At this time Consumers cannot predict the long-term impact of this order, or similar orders and governmental actions, on the Clean Energy Plan.

Consumers' proposed updates to its renewable energy plan include:

- up to 9,000 MW of both purchased and owned solar energy resources
- the addition of up to 2,800 MW of new, competitively bid wind energy resources
- the co-location of battery energy storage with its renewable energy assets to optimize those assets

Coupled with updates to the Clean Energy Plan, these actions will enable Consumers to achieve 60-percent renewable energy by 2035 and 100-percent clean energy by 2040, and will also contribute to Consumers' achievement of the net-zero emissions goals discussed below.

Net-zero methane emissions from natural gas delivery system by 2030: Under its Methane Reduction Plan, Consumers plans to reduce methane emissions from its system by about 80 percent, from 2012 baseline levels, by accelerating the replacement of aging pipe, rehabilitating or retiring outdated infrastructure, and adopting new technologies and practices. The remaining emissions will likely be offset

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by purchasing and/or producing renewable natural gas. To date, Consumers has reduced methane emissions by nearly 30 percent.

Net-zero greenhouse gas emissions target for the entire business by 2050: This goal incorporates greenhouse gas emissions from Consumers' natural gas delivery system, including suppliers and customers, and has an interim goal of reducing customer emissions by 25 percent by 2035. Consumers expects to meet this goal through carbon offset measures, renewable natural gas, energy efficiency and demand response programs, and the adoption of cost-effective emerging technologies once proven and commercially available.

Additionally, to advance its environmental stewardship in Michigan and to minimize the impact of future regulations, Consumers set the following goals for the five-year period 2023 through 2027:

- to enhance, restore, or protect 6,500 acres of land through 2027; Consumers had enhanced, restored, or protected more than 5,000 acres of land towards this goal through 2024
- to reduce water usage by 1.7 billion gallons through 2027; Consumers had reduced water usage by more than 1.3 billion gallons towards this goal through 2024
- to annually divert a minimum of 90 percent of waste from landfills (through waste reduction, recycling, and reuse); during 2024, Consumers' rate of waste diverted from landfills was 92 percent

CMS Energy and Consumers are monitoring numerous legislative, policy, and regulatory initiatives, including those related to regulation and reporting of greenhouse gases, and related litigation. While CMS Energy and Consumers cannot predict the outcome of these matters, which could affect them materially, they intend to continue to move forward with a triple-bottom-line approach that focuses on people, planet, and prosperity.

Prosperity: The prosperity element of the triple bottom line represents CMS Energy's and Consumers' commitment to meeting their financial objectives and providing economic development opportunities and benefits in the communities in which they do business. CMS Energy's and Consumers' financial strength allows them to maintain solid investment-grade credit ratings and thereby reduce funding costs for the benefit of customers and investors, to attract and retain talent, and to reinvest in the communities they serve.

For the six months ended June 30, 2025, CMS Energy's net income available to common stockholders was \$500 million, and diluted EPS were \$1.67. This compares with net income available to common stockholders of \$480 million and diluted EPS of \$1.61 for the six months ended June 30, 2024. In 2025, higher gas sales due primarily to favorable weather and electric and gas rate increases were offset partially by lower earnings at NorthStar Clean Energy and increased depreciation and property taxes, reflecting higher capital spending. A more detailed discussion of the factors affecting CMS Energy's and Consumers' performance can be found in the Results of Operations section that follows this Executive Overview.

Over the next five years, Consumers expects weather-normalized electric deliveries to increase compared to 2024. This outlook reflects strong growth in electric demand, offset partially by the effects of energy waste reduction programs. Weather-normalized gas deliveries are expected to remain stable relative to 2024, reflecting modest growth in gas demand, offset by the effects of energy waste reduction programs.

Performance: Impacting the Triple Bottom Line

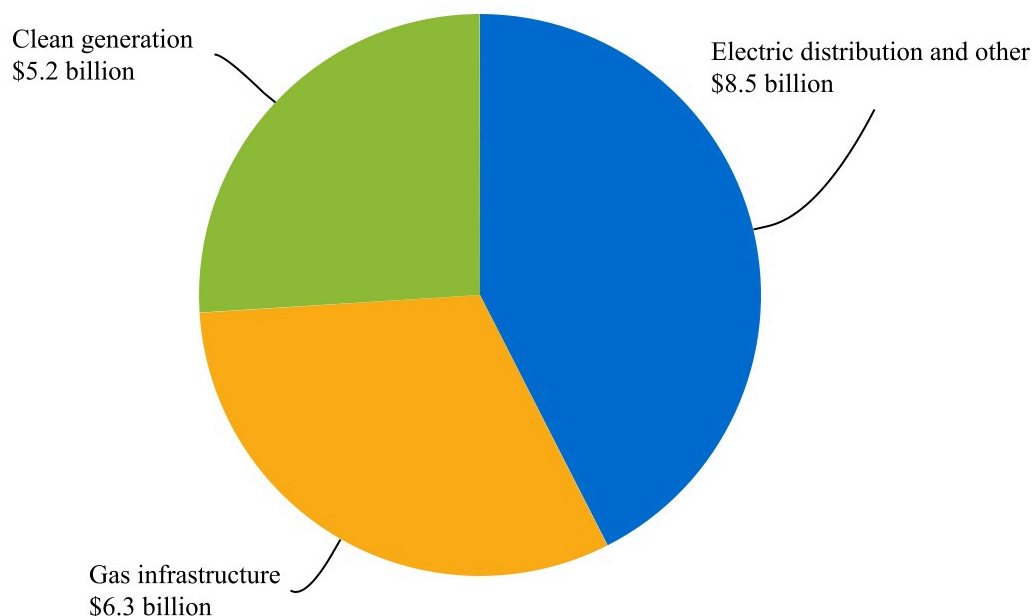
CMS Energy and Consumers remain committed to delivering safe, reliable, affordable, clean, and equitable energy in service of their customers and positively impacting the triple bottom line of people, planet, and prosperity. During the first half of 2025, CMS Energy and Consumers:

- announced the launch of “Green Giving,” a program enabling the general public to contribute to renewable energy while offering financial benefits to low-income customers, along with a new Residential Renewable Energy Program, which allows customers of all income levels to subscribe and match their energy usage with renewable energy sources, supporting clean energy initiatives
- moved forward with an aggressive plan to enhance grid reliability for nearly two million homes and businesses by clearing trees along 8,000 miles of power lines and creating a modern, stronger, and more resilient power grid through infrastructure upgrades and technology investments
- announced deployment of eight state-of-the-art vehicles that will survey the company’s nearly 30,000-mile gas distribution system to find methane emissions, enhancing safety and reliability for Consumers’ natural gas customers
- experienced early success with the underground power line pilot program in early 2025, with pilot areas seeing 100-percent reduction in storm-related outages and improved customer satisfaction

CMS Energy and Consumers will continue to utilize the CE Way to enable them to achieve world class performance and positively impact the triple bottom line. Consumers’ investment plan and the regulatory environment in which it operates also drive its ability to impact the triple bottom line.

Investment Plan: Over the next five years, Consumers expects to make significant expenditures on infrastructure upgrades, replacements, and clean generation. While it has a large number of potential investment opportunities that would add customer value, Consumers has prioritized its spending based on the criteria of enhancing public safety, increasing reliability, maintaining affordability for its customers, and advancing its environmental stewardship. Consumers’ investment program, which is subject to approval through general rate case and other MPSC proceedings, is expected to result in annual rate-base growth of more than 8 percent. This rate-base growth, together with cost-control measures, should allow Consumers to maintain affordable customer prices.

Presented in the following illustration are Consumers' planned capital expenditures through 2029 of \$20.0 billion:



Of this amount, Consumers plans to spend \$14.8 billion over the next five years primarily to maintain and upgrade its electric distribution systems and gas infrastructure in order to enhance safety and reliability, improve customer satisfaction, reduce energy waste on those systems, and facilitate its clean energy transformation. Electric distribution and other projects comprise \$8.5 billion primarily to strengthen circuits and substations, replace poles, and interconnect clean energy resources. The gas infrastructure projects comprise \$6.3 billion to sustain deliverability, enhance pipeline integrity and safety, and reduce methane emissions. Consumers also expects to spend \$5.2 billion on clean generation, which includes investments in wind, solar, and hydroelectric generation resources.

Regulation: Regulatory matters are a key aspect of Consumers' business, particularly rate cases and regulatory proceedings before the MPSC, which permit recovery of new investments while helping to ensure that customer rates are fair and affordable. Important regulatory events and developments not already discussed are summarized below.

2024 Electric Rate Case: In March 2025, the MPSC issued an order authorizing an annual rate increase of \$176 million, which is inclusive of a \$22 million surcharge for the recovery of distribution investments made in 2023 that exceeded the rate amounts authorized in accordance with previous electric rate orders. The approved rate increase is based on a 9.90-percent authorized return on equity. The new rates became effective in April 2025.

2025 Electric Rate Case: In June 2025, Consumers filed an application with the MPSC seeking a rate increase of \$460 million, made up of two components. First, Consumers requested a \$436 million annual rate increase, based on a 10.25-percent authorized return on equity for the projected 12-month period ending April 30, 2027. The filing requested authority to recover costs related to new infrastructure investment primarily in distribution system reliability. Second, Consumers requested approval of a \$24 million surcharge for the recovery of distribution investments made during the 12 months ended

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February 28, 2025 that exceeded the rate amounts authorized in accordance with previous electric rate orders. The MPSC must issue a final order in this case before or in April 2026.

2024 Gas Rate Case: In December 2024, Consumers filed an application with the MPSC seeking an annual rate increase of \$248 million based on a 10.25-percent authorized return on equity for the projected 12-month period ending October 31, 2026. In July 2025, Consumers revised its requested increase to \$217 million. The MPSC must issue a final order in this case before or in October 2025.

Looking Forward

CMS Energy and Consumers will continue to consider the impact on the triple bottom line of people, planet, and prosperity in their daily operations as well as in their long-term strategic decisions. Consumers will continue to seek fair and timely regulatory treatment that will support its customer-driven investment plan, while pursuing cost-control measures that will allow it to maintain sustainable customer base rates. The CE Way is an important means of realizing CMS Energy's and Consumers' purpose of providing safe, reliable, affordable, clean, and equitable energy in service of their customers.

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Results of Operations

CMS Energy Consolidated Results of Operations

In Millions, Except Per Share Amounts

June 30	Three Months Ended			Six Months Ended		
	2025	2024	Change	2025	2024	Change
Net Income Available to Common						
Stockholders	\$ 198	\$ 195	\$ 3	\$ 500	\$ 480	\$ 20
Basic Earnings Per Average Common Share	\$ 0.67	\$ 0.65	\$ 0.02	\$ 1.68	\$ 1.61	\$ 0.07
Diluted Earnings Per Average Common Share	\$ 0.66	\$ 0.65	\$ 0.01	\$ 1.67	\$ 1.61	\$ 0.06

In Millions

June 30	Three Months Ended			Six Months Ended		
	2025	2024	Change	2025	2024	Change
Electric utility	\$ 167	\$ 170	\$ (3)	\$ 291	\$ 267	\$ 24
Gas utility	25	15	10	238	184	54
NorthStar Clean Energy	22	16	6	4	47	(43)
Corporate interest and other	(16)	(6)	(10)	(33)	(18)	(15)
Net Income Available to Common						
Stockholders	\$ 198	\$ 195	\$ 3	\$ 500	\$ 480	\$ 20

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Presented in the following table is a summary of changes to net income available to common stockholders for the three and six months ended June 30, 2025 versus 2024:

	<i>In Millions</i>	
	Three Months Ended	Six Months Ended
June 30, 2024	\$ 195	\$ 480
<i>Reasons for the change</i>		
<i>Consumers electric utility and gas utility</i>		
Electric sales	\$ (3)	\$ 15
Gas sales	20	80
Electric rate increase	35	80
Gas rate increase, including gain amortization in lieu of rate relief	13	35
Lower service restoration costs, net of 2025 deferred storm expense ¹	23	23
Higher income tax expense	(19)	(38)
Higher depreciation and amortization	(16)	(35)
Higher interest charges	(15)	(16)
Higher property taxes, reflecting higher capital spending	(7)	(14)
Higher vegetation management cost	(4)	(13)
Higher other maintenance and operating expenses	(13)	(13)
Higher IT expenses, including early-phase ERP implementation costs	(6)	(10)
Lower other income, net of expenses	—	(10)
Absence of ASP revenue, net of expense, due to sale in 2024	(1)	(6)
	\$ 7	\$ 78
NorthStar Clean Energy (see below for additional detail)	6	(43)
Corporate interest and other	(10)	(15)
June 30, 2025	\$ 198	\$ 500

¹ See Notes to the Unaudited Consolidated Financial Statements—Note 1, Regulatory Matters.

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Consumers Electric Utility Results of Operations

Presented in the following table are the detailed changes to the electric utility's net income available to common stockholders for the three and six months ended June 30, 2025 versus 2024:

	<i>In Millions</i>	
	Three Months Ended	Six Months Ended
June 30, 2024	\$ 170	\$ 267
<i>Reasons for the change</i>		
<i>Electric deliveries¹ and rate increases</i>		
Rate increase, including return on higher renewable capital spending	\$ 35	\$ 80
Lower revenue due primarily to lower sales volume, offset partially by sales mix	(15)	—
Higher energy waste reduction program revenues	8	15
Higher other revenues	12	15
	\$ 40	\$ 110
<i>Maintenance and other operating expenses</i>		
Lower service restoration costs, net of 2025 deferred storm expense ²	23	23
Higher vegetation management cost	(4)	(13)
Higher energy waste reduction program costs	(8)	(15)
Higher IT expenses, including early-phase ERP implementation costs	(4)	(7)
Higher other maintenance and operating expenses	(10)	(10)
	(3)	(22)
<i>Depreciation and amortization</i>		
Increased plant in service, reflecting higher capital spending	(13)	(21)
<i>General taxes</i>		
Higher property taxes, reflecting higher capital spending	(5)	(7)
<i>Other income, net of expenses</i>		
	—	(7)
<i>Interest charges</i>		
	(10)	(11)
<i>Income taxes</i>		
Higher electric utility pre-tax earnings	(3)	(12)
State deferred tax remeasurement ³	(8)	(8)
Lower (higher) other income taxes	(1)	2
	(12)	(18)
June 30, 2025	\$ 167	\$ 291

¹ For the three months ended June 30, deliveries to end-use customers were 8.9 billion kWh in 2025 and 9.0 billion kWh in 2024. For the six months ended June 30, deliveries to end-use customers were 18.0 billion kWh in 2025 and 17.9 billion kWh in 2024.

² See Notes to the Unaudited Consolidated Financial Statements—Note 1, Regulatory Matters.

³ See Notes to the Unaudited Consolidated Financial Statements—Note 7, Income Taxes.

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Consumers Gas Utility Results of Operations

Presented in the following table are the detailed changes to the gas utility's net income available to common stockholders for the three and six months ended June 30, 2025 versus 2024:

	<i>In Millions</i>	
	Three Months Ended	Six Months Ended
June 30, 2024	\$ 15	\$ 184
<i>Reasons for the change</i>		
<i>Gas deliveries¹ and rate increases</i>		
Rate increase	\$ 8	\$ 18
Higher revenue due primarily to the absence of 2024 unfavorable weather	21	82
Higher energy waste reduction program revenues	2	12
Absence of ASP business revenue ²	(3)	(19)
ASP gain customer bill credit ²	(4)	(18)
Lower other revenues	(1)	—
	\$ 23	\$ 75
<i>Maintenance and other operating expenses</i>		
Amortization of ASP gain ²	9	33
Absence of 2024 ASP business expense ²	2	13
Higher IT expenses, including early-phase ERP implementation costs	(2)	(3)
Higher energy waste reduction program costs	(2)	(12)
Higher maintenance and other operating expenses	(3)	(3)
	4	28
<i>Depreciation and amortization</i>		
Increased plant in service, reflecting higher capital spending	(3)	(14)
<i>General taxes</i>		
Higher property taxes, reflecting higher capital spending	(2)	(7)
<i>Other income, net of expenses</i>		
	—	(3)
<i>Interest charges</i>		
	(5)	(5)
<i>Income taxes</i>		
Higher gas utility pre-tax earnings	(5)	(19)
State deferred tax remeasurement ³	(4)	(4)
Lower other income taxes	2	3
	(7)	(20)
June 30, 2025	\$ 25	\$ 238

¹ For the three months ended June 30, deliveries to end-use customers were 49 Bcf in 2025 and 41 Bcf in 2024. For the six months ended June 30, deliveries to end-use customers were 184 Bcf in 2025 and 158 Bcf in 2024.

² In April 2024, Consumers sold its unregulated ASP business to a non-affiliated company, resulting in a \$110 million gain. In July 2024, the MPSC approved the utilization of \$27.5 million, or one-fourth, of the gain on the sale as an offset to the revenue deficiency in lieu of additional rate relief during the 12-month period beginning October 1, 2024, with the remaining three-fourths of the gain, or \$82.5 million, to be credited to customers as a bill credit over a three-year period beginning October 1, 2024.

³ See Notes to the Unaudited Consolidated Financial Statements—Note 7, Income Taxes.

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NorthStar Clean Energy Results of Operations

Presented in the following table are the detailed changes to NorthStar Clean Energy's net income available to common stockholders for the three and six months ended June 30, 2025 versus 2024:

	<i>In Millions</i>	
	Three Months Ended	Six Months Ended
June 30, 2024	\$ 16	\$ 47
<i>Reason for the change</i>		
Lower earnings from renewable projects, reflecting timing of achieving commercial operation	\$ (9)	\$ (27)
Lower operating earnings, primarily due to a planned major outage at DIG	(7)	(23)
Lower (higher) other expense	2	(3)
Lower tax expense	20	10
June 30, 2025	\$ 22	\$ 4

Corporate Interest and Other Results of Operations

Presented in the following table are the detailed changes to corporate interest and other results for the three and six months ended June 30, 2025 versus 2024:

	<i>In Millions</i>	
	Three Months Ended	Six Months Ended
June 30, 2024	\$ (6)	\$ (18)
<i>Reasons for the change</i>		
Higher interest charges	\$ (17)	\$ (28)
Lower other expense	5	9
Higher gain on extinguishment of debt	24	2
Lower (higher) tax expense	(22)	2
June 30, 2025	\$ (16)	\$ (33)

Cash Position, Investing, and Financing

At June 30, 2025, CMS Energy had \$925 million of consolidated cash and cash equivalents, which included \$81 million of restricted cash and cash equivalents. At June 30, 2025, Consumers had \$680 million of consolidated cash and cash equivalents, which included \$81 million of restricted cash and cash equivalents.

Operating Activities

Presented in the following table are specific components of net cash provided by operating activities for the six months ended June 30, 2025 versus 2024:

	<i>In Millions</i>
CMS Energy, including Consumers	
Six Months Ended June 30, 2024	\$ 1,663
<i>Reasons for the change</i>	
Higher net income	\$ 43
Non-cash transactions ¹	43
Unfavorable impact of changes in core working capital, ² due primarily to fluctuations in gas prices	(171)
Unfavorable impact of changes in other assets and liabilities, due primarily to higher service restoration expenditures ³ and higher deposits for electric margins	(164)
Six Months Ended June 30, 2025	\$ 1,414
Consumers	
Six Months Ended June 30, 2024	\$ 1,691
<i>Reasons for the change</i>	
Higher net income	\$ 81
Non-cash transactions ¹	(18)
Unfavorable impact of changes in core working capital, ² due primarily to fluctuations in gas prices	(127)
Unfavorable impact of changes in other assets and liabilities, due primarily to higher service restoration expenditures ³ and higher deposits for electric margins	(148)
Six Months Ended June 30, 2025	\$ 1,479

- ¹ Non-cash transactions comprise depreciation and amortization, changes in deferred income taxes and investment tax credits, and other non-cash operating activities and reconciling adjustments.
- ² Core working capital comprises accounts receivable, accrued revenue, inventories, accounts payable, and accrued rate refunds.
- ³ See Notes to the Unaudited Consolidated Financial Statements—Note 1, Regulatory Matters.

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Investing Activities

Presented in the following table are specific components of net cash used in investing activities for the six months ended June 30, 2025 versus 2024:

	<i>In Millions</i>
CMS Energy, including Consumers	
Six Months Ended June 30, 2024	\$ (1,246)
<i>Reasons for the change</i>	
Higher capital expenditures	\$ (478)
Absence of proceeds from sale of ASP business in 2024	(124)
Other investing activities, primarily higher cost to retire property	(32)
Six Months Ended June 30, 2025	\$ (1,880)
Consumers	
Six Months Ended June 30, 2024	\$ (1,176)
<i>Reasons for the change</i>	
Higher capital expenditures	\$ (291)
Absence of proceeds from sale of ASP business in 2024	(124)
Other investing activities, primarily higher cost to retire property	(41)
Six Months Ended June 30, 2025	\$ (1,632)

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Financing Activities

Presented in the following table are specific components of net cash provided by financing activities for the six months ended June 30, 2025 versus 2024:

	<i>In Millions</i>
CMS Energy, including Consumers	
Six Months Ended June 30, 2024	\$ 124
<i>Reasons for the change</i>	
Higher debt issuances	\$ 1,745
Higher debt retirements	(408)
Lower repayments of notes payable	28
Lower issuances of common stock	(262)
Higher payments of dividends on common stock	(17)
Proceeds from sale of membership interests in VIEs	44
Other financing activities, primarily higher debt issuance costs	(41)
Six Months Ended June 30, 2025	\$ 1,213
Consumers	
Six Months Ended June 30, 2024	\$ 125
<i>Reasons for the change</i>	
Higher debt issuances	\$ 524
Higher debt retirements	(42)
Lower repayments of notes payable	28
Lower stockholder contribution from CMS Energy	(170)
Absence of return of stockholder contribution to CMS Energy in 2024	320
Higher payments of dividends on common stock	(57)
Other financing activities	(14)
Six Months Ended June 30, 2025	\$ 714

Capital Resources and Liquidity

CMS Energy and Consumers expect to have sufficient liquidity to fund their present and future commitments. CMS Energy uses dividends and tax-sharing payments from its subsidiaries and external financing and capital transactions to invest in its utility and non-utility businesses, retire debt, pay dividends, and fund its other obligations. The ability of CMS Energy's subsidiaries, including Consumers, to pay dividends to CMS Energy depends upon each subsidiary's revenues, earnings, cash needs, and other factors. In addition, Consumers' ability to pay dividends is restricted by certain terms included in its articles of incorporation and potentially by FERC requirements and provisions under the Federal Power Act and the Natural Gas Act. For additional details on Consumers' dividend restrictions, see Notes to the Unaudited Consolidated Financial Statements—Note 3, Financings and Capitalization—Dividend Restrictions. During the six months ended June 30, 2025, Consumers paid \$416 million in dividends on its common stock to CMS Energy.

Consumers uses cash flows generated from operations, external financing transactions, and the monetization of tax credits, along with stockholder contributions from CMS Energy, to fund capital expenditures, retire debt, pay dividends, and fund its other obligations. Consumers also uses these sources of funding to contribute to its employee benefit plans.

Financing and Capital Resources: CMS Energy and Consumers rely on the capital markets to fund their robust capital plan. Barring any sustained market dislocations or disruptions, CMS Energy and Consumers expect to continue to have ready access to the financial and capital markets and will continue to explore possibilities to take advantage of market opportunities as they arise with respect to future funding needs. If access to these markets were to diminish or otherwise become restricted, CMS Energy and Consumers would implement contingency plans to address debt maturities, which could include reduced capital spending.

In 2023, CMS Energy entered into an equity offering program under which it may sell shares of its common stock having an aggregate sales price of up to \$1 billion in privately negotiated transactions, in "at the market" offerings, or through forward sales transactions. As of June 30, 2025, these contracts had an aggregate sales price of \$350 million, maturing through September 2026.

CMS Energy, NorthStar Clean Energy, and Consumers use revolving credit facilities for general working capital purposes and to issue letters of credit. At June 30, 2025, CMS Energy had \$512 million of its revolving credit facility available, NorthStar Clean Energy had \$90 million available under its revolving credit facility, and Consumers had \$1.3 billion available under its revolving credit facilities.

An additional source of liquidity is Consumers' commercial paper program, which allows Consumers to issue, in one or more placements, up to \$500 million in aggregate principal amount of commercial paper notes with maturities of up to 365 days at market interest rates. These issuances are supported by Consumers' revolving credit facilities. While the amount of outstanding commercial paper does not reduce the available capacity of the revolving credit facilities, Consumers does not intend to issue commercial paper in an amount exceeding the available capacity of the facilities. At June 30, 2025, there were no commercial paper notes outstanding under this program.

For additional details about these programs and facilities, see Notes to the Unaudited Consolidated Financial Statements—Note 3, Financings and Capitalization.

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Certain of CMS Energy's, NorthStar Clean Energy's, and Consumers' credit agreements contain covenants that require each entity to maintain certain financial ratios, as defined therein. At June 30, 2025, no default had occurred with respect to any of the financial covenants contained in these credit agreements. Each of the entities was in compliance with the covenants contained in their respective credit agreements as of June 30, 2025, as presented in the following table:

	Limit	Actual
CMS Energy, parent only		
Debt to capital ¹	≤ 0.70 to 1.0	0.56 to 1.0
NorthStar Clean Energy, including subsidiaries		
Debt to capital ²	≤ 0.50 to 1.0	0.11 to 1.0
Debt service coverage ²	≥ 2.00 to 1.0	3.35 to 1.0
Pledged equity interests to aggregate commitment ^{2,3}	≥ 2.00 to 1.0	2.02 to 1.0
Consumers		
Debt to capital ⁴	≤ 0.65 to 1.0	0.52 to 1.0

¹ Applies to CMS Energy's revolving credit agreement and letter of credit reimbursement agreement.

² Applies to NorthStar Clean Energy's revolving credit agreement.

³ The aggregate book value of the pledged equity interests under the revolving credit agreement was at least two-times the aggregate commitment under the revolving credit agreement at June 30, 2025.

⁴ Applies to Consumers' revolving credit agreements and letter of credit reimbursement agreement.

Outlook

Several business trends and uncertainties may affect CMS Energy's and Consumers' financial condition and results of operations. These trends and uncertainties could have a material impact on CMS Energy's and Consumers' consolidated income, cash flows, or financial position.

During 2025, the federal government has taken numerous executive actions related to tariffs and trade, alleviating regulatory burdens, and environmental regulations and enforcement, among other areas of potential impact. Many of these actions require further implementation by federal agencies and departments, and some of these actions will likely be subject to further judicial review. CMS Energy and Consumers continue to monitor these executive actions, and will continue taking steps to deliver consistently on the triple bottom line, but cannot at this time predict specific material impacts of the actions.

For additional details regarding these and other uncertainties, see Forward-looking Statements and Information; Notes to the Unaudited Consolidated Financial Statements—Note 1, Regulatory Matters and Note 2, Contingencies and Commitments; and Item 1A. Risk Factors in the 2024 Form 10-K.

Consumers Electric Utility Outlook and Uncertainties

Energy Transformation: Consumers' Clean Energy Plan details its long-term strategy for delivering safe, reliable, affordable, clean, and equitable energy to its customers. Coupled with Consumers' renewable energy plan, the Clean Energy Plan will be Consumers' blueprint to meeting the requirements of the 2023 Energy Law. Among other things, this law:

- raised the renewable energy standard from the present 15-percent requirement to 50 percent by 2030 and 60 percent by 2035
- set a clean energy standard of 80 percent by 2035 and 100 percent by 2040; low- or zero-carbon emitting resources, such as nuclear generation and natural gas generation coupled with carbon capture, are considered clean energy sources under this standard
- created a new energy storage standard that requires electric utilities to file plans by 2029 to obtain new energy storage that will contribute to a Michigan target of 2,500 MW based on their pro rata share

While Consumers' existing Clean Energy Plan, established under Michigan's integrated resource planning process, provides a path towards meeting these requirements, Consumers will file updates to the plan in 2026 to expand and solidify that path. Additionally, Consumers filed updates to its renewable energy plan in November 2024 to propose plans to meet the increased renewable energy standard. Together, these plans will enable Consumers to achieve 60-percent renewable energy by 2035 and 100-percent clean energy by 2040. Also through its Clean Energy Plan, Consumers continues to make progress on expanding its customer programs, namely its demand response, energy efficiency, and conservation voltage reduction programs, as well as increasing its renewable energy generation.

The strategy outlined in Consumers' Clean Energy Plan includes ending the use of coal in owned generation in 2025. In 2023, Consumers retired the D.E. Karn coal-fueled generating units, totaling 515 MW of nameplate capacity, and as authorized by the MPSC, issued securitization bonds to finance the recovery of and return on those units. Additionally, Consumers had planned to retire J.H. Campbell, totaling 1,407 MW of nameplate capacity, in May 2025. The MPSC authorized regulatory asset treatment for Consumers to recover the remaining book value of these units, as well as a 9.0-percent return on equity, commencing upon their planned retirement.

In May 2025, before the planned closure of J.H. Campbell, the U.S. Secretary of Energy issued an emergency order under section 202(c) of the Federal Power Act requiring J.H. Campbell to continue operating for 90 days, through August 20, 2025. The order stated that continued operation of J.H. Campbell was required to meet an energy emergency across MISO's North and Central regions. Consistent with the Federal Power Act and the U.S. Department of Energy regulations, the order authorizes Consumers to obtain cost recovery at FERC. Consumers has continued to make J.H. Campbell available in the MISO market, consistent with the order, and has filed a complaint at FERC seeking a modification of the MISO Tariff to establish a mechanism for recovery and allocation of the cost to comply with this order.

In June 2025, several third-party stakeholders, including the Michigan Attorney General, the Organization of MISO States, and a group of environmental and public interest groups, asked the U.S. Department of Energy to reconsider the emergency order. In July 2025, after the U.S. Department of Energy took no action on those requests, several parties filed petitions for review of the emergency order in federal court. The U.S. Department of Energy may issue one or more subsequent orders to require the operation of J.H. Campbell past August 20, 2025. Consumers cannot predict the likelihood or content of future orders, the result of third-party legal challenges to the order or orders, or the manner by which rate recovery will be allocated. For additional details on the emergency order, see Notes to the Unaudited Consolidated Financial Statements—Note 1, Regulatory Matters.

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In order to continue providing controllable sources of electricity to customers while expanding its investment in renewable energy, Consumers purchased the Covert Generating Station, a natural gas-fueled generating facility with 1,200 MW of nameplate capacity, in 2023. Consumers has also contracted to purchase 700 MW of capacity from battery storage facilities, which will be located in Michigan's Lower Peninsula and are expected to be operational by 2028. In an April 2025 report, the MPSC Staff indicated that Consumers' share of the 2,500-MW statewide energy storage target established by the 2023 Energy Law is 817 MW.

Under its Clean Energy Plan, Consumers bids new capacity and energy competitively and proposed to own and operate all new wind capacity and approximately 50 percent of new solar capacity, with the remainder being built and owned by third parties. The actual composition of Consumers' future portfolio will reflect the results of the competitive bid process. Additionally, Consumers earns a return equal to its pre-tax weighted-average cost of capital on permanent capital structure on payments made under new clean, renewable, or energy storage PPAs with non-affiliated entities.

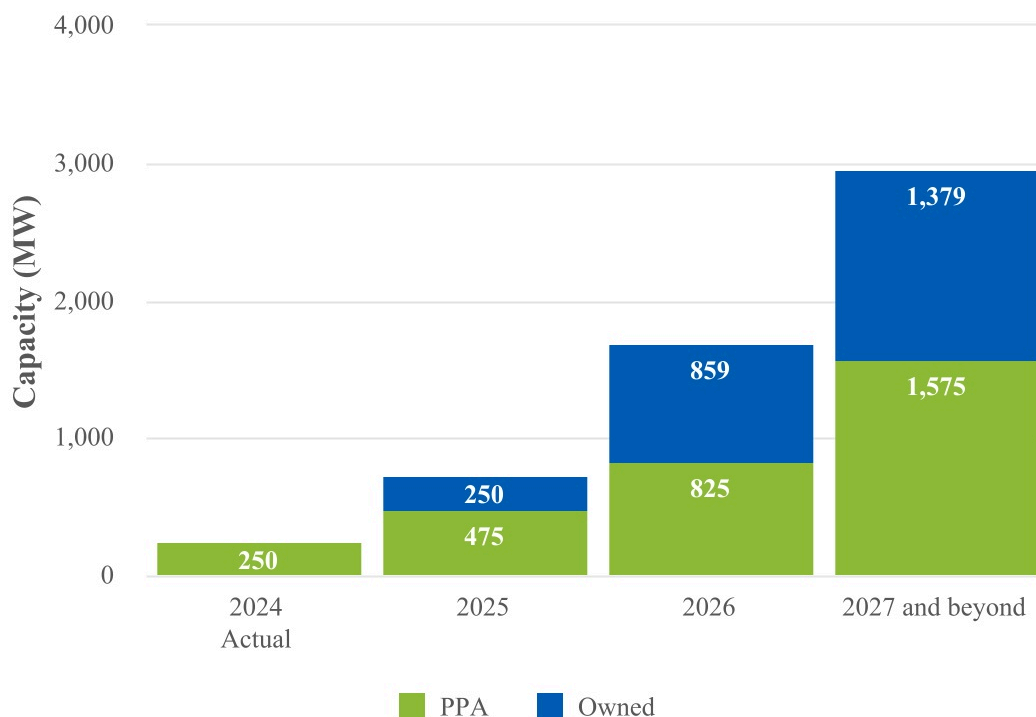
Under Consumers' existing renewable energy plan, most recently amended and approved by the MPSC in August 2024, 15 percent of the electricity supplied to customers comes from renewable energy sources. In accordance with this plan, Consumers has acquired three wind generation projects, totaling 517 MW of nameplate capacity, since 2020; the last of these projects became operational in 2023. The MPSC authorized Consumers to earn a 10.7-percent return on equity on these projects. The MPSC also approved the execution of a 20-year PPA under which Consumers will purchase 100 MW of renewable capacity, energy, and renewable energy credits from a solar generating facility that began operations in October 2024.

In November 2024, Consumers filed updates to its renewable energy plan, proposing up to 9,000 MW of both purchased and owned solar energy resources. Of this amount, 1,060 MW of projects would support Consumers' voluntary green program that provides full-service electric customers with the opportunity to advance the development of renewable energy beyond the present 15-percent requirement. Under this program, Consumers competitively solicits additional renewable energy assets based on customer applications.

In the updates to its renewable energy plan, Consumers also proposed the addition of up to 2,800 MW of new, competitively bid wind energy resources and the co-location of battery energy storage with its renewable energy assets to optimize those assets.

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Presented in the following illustration is the aggregate renewable capacity that Consumers expects to add to its portfolio through PPAs and owned generation proposed in its existing Clean Energy Plan and the updates to its renewable energy plan:



Consumers continues to evaluate the acquisition of additional capacity from intermittent resources and dispatchable, non-intermittent clean capacity resources (including battery storage resources). Any resulting contracts are subject to MPSC approval.

Electric Customer Deliveries and Revenue: Consumers' electric customer deliveries are seasonal and largely dependent on Michigan's economy. The consumption of electric energy typically increases in the summer months, due primarily to the use of air conditioners and other cooling equipment. In addition, Consumers' electric rates, which follow a seasonal rate design, are higher in the summer months than in the remaining months of the year. Each year in June, electric residential customers transition to a summer peak time-of-use rate that allows them to take advantage of lower-cost energy during off-peak times during the summer months. Thus, customers can reduce their electric bills by shifting their consumption from on-peak to off-peak times.

Over the next five years, Consumers expects weather-normalized electric deliveries to increase compared to 2024. This outlook reflects strong growth in electric demand, offset partially by the effects of energy waste reduction programs. Actual delivery levels will depend on:

- energy conservation measures and results of energy waste reduction programs
- weather fluctuations
- Michigan's economic conditions, including data center expansion; utilization, expansion, or contraction of large commercial and industrial facilities; economic development; population trends; electric vehicle adoption; and housing activity

Electric ROA: Michigan law allows electric customers in Consumers' service territory to buy electric generation service from alternative electric suppliers in an aggregate amount capped at 10 percent of

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Consumers' sales, with certain exceptions. At June 30, 2025, electric deliveries under the ROA program were at the 10-percent limit. Fewer than 300 of Consumers' electric customers purchased electric generation service under the ROA program.

In 2016, Michigan law established a path to ensure that forward capacity is secured for all electric customers in Michigan, including customers served by alternative electric suppliers under ROA. The law also authorized the MPSC to ensure that alternative electric suppliers have procured enough capacity to cover their anticipated capacity requirements for the four-year forward period. In 2017, the MPSC issued an order establishing a state reliability mechanism for Consumers. Under this mechanism, if an alternative electric supplier does not demonstrate that it has procured its capacity requirements for the four-year forward period, its customers will pay a set charge to the utility for capacity that is not provided by the alternative electric supplier.

During 2017, the MPSC issued orders finding that it has statutory authority to determine and implement a local clearing requirement, which requires all electric suppliers to demonstrate that a portion of the capacity used to serve customers is located in the MISO footprint in Michigan's Lower Peninsula. In 2020, the Michigan Supreme Court affirmed the MPSC's statutory authority to implement a local clearing requirement on individual electric providers.

In 2020, ABATE and another intervenor filed a complaint against the MPSC in the U.S. District Court for the Eastern District of Michigan challenging the constitutionality of a local clearing requirement. The complaint requests the federal court to issue a permanent injunction prohibiting the MPSC from implementing a local clearing requirement on individual electric providers. In 2023, the U.S. District Court for the Eastern District of Michigan dismissed the complaint. ABATE and the other intervenor filed a claim of appeal of the Eastern District Court's decision with the U.S. Court of Appeals for the Sixth Circuit.

In January 2025, the Sixth Circuit Court of Appeals issued an opinion finding that the MPSC's imposition of a local clearing requirement on individual electric suppliers would discriminate against interstate commerce. The Court of Appeals remanded to the District Court for a determination of whether the local clearing requirement discriminated against interstate commerce and whether the MPSC's regulation survives a strict scrutiny standard, which depends on a determination of whether the local clearing requirement is the only means of achieving the state's goal of securing reliable energy supply. In January 2025, Consumers filed a petition for rehearing and en banc review with the Sixth Circuit Court of Appeals, requesting the Court to reconsider and reverse the panel's opinion. In February 2025, the Sixth Circuit Court of Appeals issued an order denying Consumers' petition for rehearing and en banc review. The case has therefore been remanded to the District Court for the Eastern District of Michigan for consideration of whether the MPSC's local clearing requirement meets the strict scrutiny standard pursuant to the Court of Appeals' decision. The remanded proceeding has begun at the Eastern District Court; there is no deadline for decision.

Hydroelectric Facilities: In February 2024, Consumers issued a request for proposals to explore the possibility of selling its 13 river hydroelectric dams located throughout Michigan. Consumers has solicited community feedback on the dams' futures, as federal operating licenses for the dams begin to expire in 2034. Consumers continues to evaluate each dam's future, options for which include, but are not limited to, renewing operating licenses, transferring ownership, or removing the facilities. In Consumers' most recent electric rate case, the MPSC approved deferred accounting treatment for costs associated with the hydroelectric dams pending resolution of this evaluation.

Electric Rate Matters: Rate matters are critical to Consumers' electric utility business. For additional details on rate matters, see Notes to the Unaudited Consolidated Financial Statements—Note 1, Regulatory Matters and Note 2, Contingencies and Commitments.

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MPSC Distribution System Audit: In 2022, the MPSC ordered the state's two largest electric utilities, including Consumers, to report on their compliance with regulations and past MPSC orders governing the utilities' response to outages and downed lines. Consumers responded to the MPSC's order as directed.

Additionally, as directed by the MPSC, the MPSC Staff engaged a third-party auditor to review all equipment and operations of the two utilities' distribution systems. In September 2024, the MPSC Staff released the third-party auditor's final report on its audit of Consumers' distribution system. The report included several recommendations to improve Consumers' distribution system and associated processes and procedures. Consumers filed a response to the audit report in November 2024. In June 2025, the MPSC issued an order adopting the audit's findings and recommendations. Consumers is committed to working with the MPSC to continue improving electric reliability and safety in Michigan.

Performance-based Financial Incentives/Disincentives Mechanism: In February 2025, the MPSC issued an order establishing a mechanism through which the state's largest electric utilities, including Consumers, could realize up to \$10 million each in incentives or penalties annually for meeting or failing to meet reliability benchmarks, beginning in 2026. As directed, Consumers filed proposed company-specific baseline metrics for the performance mechanism in April 2025.

2025 Electric Rate Case: In June 2025, Consumers filed an application with the MPSC seeking a rate increase of \$460 million, made up of two components. First, Consumers requested a \$436 million annual rate increase, based on a 10.25-percent authorized return on equity for the projected 12-month period ending April 30, 2027. The filing requested authority to recover costs related to new infrastructure investment primarily in distribution system reliability. Second, Consumers requested approval of a \$24 million surcharge for the recovery of distribution investments made during the 12 months ended February 28, 2025 that exceeded the rate amounts authorized in accordance with previous electric rate orders.

Presented in the following table are the components of the requested increase in revenue:

	<i>In Millions</i>	
Projected 12-Month Period Ending April 30		2027
Investment in rate base	\$	194
Operating and maintenance costs		158
Cost of capital		77
Sales and other revenue		7
Subtotal	\$	436
Surcharge		24
Total	\$	460

The MPSC must issue a final order in this case before or in April 2026.

FERC Proceeding for J.H. Campbell Cost Recovery: In June 2025, Consumers filed a complaint at FERC seeking a modification of the MISO Tariff that would enable Consumers to recover the costs of complying with the U.S. Department of Energy's May 2025 emergency order requiring continued operation of J.H. Campbell. Consumers' complaint seeks a mechanism in the MISO Tariff that would allow allocation of those compliance costs across the MISO North and Central regions, consistent with the nature of the energy emergency declared in the U.S. Department of Energy order. FERC has not yet issued an order on this request. If FERC approves the request, Consumers will subsequently file a request for approval of its specific compliance costs under the approved MISO Tariff recovery mechanism.

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Retention Incentive Program: In accordance with its Clean Energy Plan, and absent an extension of the May 2025 emergency order or other government order, Consumers plans to retire J.H. Campbell in 2025. In order to ensure necessary staffing at J.H. Campbell through retirement, Consumers has implemented a retention incentive program. The aggregate cost of the J.H. Campbell program through 2025 is estimated to be less than \$50 million; Consumers expects to recognize \$5 million of retention benefit costs in 2025. The MPSC has approved deferred accounting treatment for these costs; these expenses are deferred as a regulatory asset. For additional details on this program, see Notes to the Unaudited Consolidated Financial Statements—Note 12, Exit Activities.

Electric Environmental Outlook: Consumers' electric operations are subject to various federal, state, and local environmental laws and regulations. Consumers estimates that it will incur capital expenditures of \$240 million from 2025 through 2029 to continue to comply with RCRA, the Clean Air Act, and numerous other environmental regulations. Consumers expects to recover these costs in customer rates, but cannot guarantee this result. Multiple environmental laws and regulations are subject to litigation. Consumers' primary environmental compliance focus includes, but is not limited to, the following matters.

Air Quality: Multiple air quality regulations apply, or may apply, to Consumers' electric utility.

MATS, emission standards for electric generating units published by the EPA based on Section 112 of the Clean Air Act, continue to apply to Consumers. In June 2025, the EPA issued a proposed rule to repeal changes made to the MATS rule in 2024. The company has complied, and continues to comply, with the MATS regulation and both the 2024 and 2025 versions of MATS have minimal impacts on Consumers' electric generating units. Consumers does not expect MATS to materially impact its environmental strategy.

CSAPR requires Michigan and many other states to improve air quality by reducing power plant emissions that, according to EPA modeling, contribute to ground-level ozone in other downwind states. Since its 2015 effective date, CSAPR has been revised several times. In 2023, the EPA published the Good Neighbor Plan, a revision to CSAPR. This regulation tightens emission allowance budgets for electric generating units in Michigan between 2023 and 2029 and changes the mechanism for allocating such allowances on a year-over-year basis beginning in 2026. In June 2024, the U.S. Supreme Court stayed the Good Neighbor Plan pending judicial review and, as a result, the allowance requirements for Michigan reverted back to the prior effective CSAPR ozone season rule. Regardless of the outcome of this litigation and which version of the rule applies, Consumers expects this regulation will have minimal financial and operational impact in the near and/or long term.

In 2015, the EPA lowered the NAAQS for ozone and made it more difficult to construct or modify power plants and other emission sources in areas of the country that do not meet the ozone standard. As of 2023, three counties in western Michigan have been designated as not meeting the ozone standard. Based on recent data, the EPA reclassified these counties from "moderate" to "serious" nonattainment. None of Consumers' fossil-fuel-fired generating units are located in these areas.

In March 2024, the EPA published a lower fine particulate matter NAAQS, which will likely result in newly designated nonattainment areas in Michigan starting in 2026. EGLE has proposed nonattainment areas for Kalamazoo and Wayne counties. Consumers does not have any fossil-fuel-fired generating assets in these counties and therefore does not expect this rule to have significant impacts on its existing assets or its clean energy strategy. Consumers will continue to monitor NAAQS rulemakings and litigation to evaluate potential impacts to its generating assets.

In December 2024, the EPA published a proposal to amend new source performance standards for new, modified, and reconstructed stationary combustion turbines to lower emission limits for NOx. This may

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impact future gas-fueled, simple-cycle turbine projects. Consumers, in conjunction with industry stakeholder groups, submitted comments on the proposed rule and will continue monitoring this rulemaking.

Consumers continues to evaluate these rules in conjunction with other EPA and EGLE rulemakings, litigation, executive orders, treaties, and congressional actions. This evaluation could result in:

- a change in Consumers' fuel mix
- changes in the types of generating units Consumers may purchase or build in the future
- changes in how certain units are operated, including the installation of additional emission control equipment
- the retirement, mothballing, extended operation, or repowering with an alternative fuel of some of Consumers' generating units
- changes in Consumers' environmental compliance costs
- the purchase or sale of allowances

Greenhouse Gases: There have been numerous legislative, executive, and regulatory initiatives at the state, regional, national, and international levels that involve the potential regulation and reporting of greenhouse gases. Consumers continues to monitor and comment on these initiatives, as appropriate.

In April 2024, the EPA finalized its rule under Section 111 of the Clean Air Act to address greenhouse gas emissions from new combustion turbine electric generating units and existing coal-, gas-, and oil-fueled steam electric generating units. These rules do not address existing combustion turbine electric generating units. In June 2025, the EPA issued a proposed rule containing two different pathways to rescind these requirements. Consumers does not expect these proposed changes will have a significant impact on its existing gas- and oil-fueled steam electric generating assets. Consumers will continue to follow the EPA rules that address greenhouse gas emissions and will continue to evaluate potential impacts to its operations.

In 2020, Michigan's Governor signed an executive order creating the Michigan Healthy Climate Plan, which outlines goals for Michigan to achieve economy-wide net-zero greenhouse gas emissions and to be carbon neutral by 2050. The executive order aims for a 28-percent reduction below 2005 levels of greenhouse gas emissions by 2025. Consumers has already surpassed the 28-percent reduction milestone for its owned electric generation. The 2023 Energy Law codifies much of the Governor's goals. For additional details on the 2023 Energy Law, see the Planet section of the Executive Overview.

Increased frequency or intensity of severe or extreme weather events, including those due to climate change, could materially impact Consumers' facilities, energy sales, and results of operations. Consumers is unable to predict these events; however, Consumers evaluates the potential physical impacts of climate change on its operations, including increased frequency or intensity of storm activity; increased precipitation; increased temperature; and changes in lake and river levels. Consumers released a report addressing the physical risks of climate change on its infrastructure in 2022. Consumers is taking steps to mitigate these risks as appropriate.

While Consumers cannot predict the outcome of changes in U.S. policy or of other legislative, executive, or regulatory initiatives involving the potential regulation or reporting of greenhouse gases, it intends to move forward with its Clean Energy Plan, its present net-zero goals, and its emphasis on reliable and resilient electric supply. Litigation, international treaties, executive orders, federal laws and regulations

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(including regulations by the EPA), and state laws and regulations, if enacted or ratified, could ultimately impact Consumers. Consumers may be required to:

- replace equipment
- install additional emission control equipment
- purchase emission allowances or credits (including potential greenhouse gas offset credits)
- curtail operations or modify existing facility retirement schedules
- arrange for alternative sources of supply
- purchase or build facilities that generate fewer emissions
- mothball, sell, or retire facilities that generate certain emissions
- pursue energy efficiency or demand response measures more swiftly
- take other steps to manage, sequester, or lower the emission of greenhouse gases

Although associated capital or operating costs relating to greenhouse gas regulation or legislation could be material and cost recovery cannot be assured, Consumers expects to recover these costs in rates consistent with the recovery of other reasonable costs of complying with environmental laws and regulations.

CCRs: In 2015, the EPA published a rule regulating CCRs under RCRA. This rule adopts minimum standards for the disposal of non-hazardous CCRs in CCR landfills and surface impoundments and criteria for the beneficial use of CCRs. The rule also sets out conditions under which some CCR units would be forced to cease receiving CCRs and related process water and to initiate closure. Due to continued litigation, many aspects of the rule have been remanded to the EPA, resulting in more proposed and final rules.

In May 2024, the EPA finalized a rule regulating legacy CCR surface impoundments and CCR management units in response to litigation that exempted inactive impoundments at inactive facilities from the 2015 CCR rule. The new rule adopts minimum standards for impoundments at electric generating facilities that became inactive before the 2015 CCR rule's effective date. During 2024, owners and operators were required to assess whether an inactive facility contains a legacy surface impoundment and then, for identified locations, proceed with the compliance schedule. Additionally, the EPA established groundwater monitoring, corrective action, closure, and post-closure care requirements for CCR surface impoundments and landfills closed prior to the effective date of the 2015 CCR rule, but that do not meet the closure technical and performance standards of the May 2024 rule. These include inactive CCR landfills that were previously exempted from regulation but that are now considered CCR management units. Owners are required to conduct an evaluation at active facilities and any inactive facilities with at least one legacy impoundment to identify CCR management units and determine an appropriate course of action (closure, groundwater treatment, etc.) for each identified unit according to established compliance milestone schedules. A direct final rule extending the compliance milestone schedule was issued by EPA. This extension does not have a material impact on Consumers' compliance strategy.

Separately, Congress passed legislation in 2016 allowing participating states to develop permitting programs for CCRs under RCRA Subtitle D. The EPA was granted authority to review these permitting programs to determine if permits issued under the proposed program would be as protective as the federal rule. Once approved, permits issued from an authorized state would serve as the basis for compliance, replacing the requirement to self-certify each aspect of the 2015 CCR rule.

Consumers, with agreement from EGLE, completed the work necessary to initiate closure by excavating CCRs or placing a final cover over each of its relevant CCR units prior to the closure initiation deadline set forth in the 2015 CCR rule. Consumers has historically been authorized to recover in electric rates costs related to coal ash disposal sites that supported power generation. Consumers has completed an

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assessment of inactive facilities as required by the 2024 CCR rule, and did not identify any legacy impoundments. Consumers is continuing with evaluations related to CCR management units and 2024 CCR rule impacts on the state permit program.

Water: Multiple water-related regulations apply, or may apply, to Consumers.

The EPA regulates cooling water intake systems of existing electric generating plants under Section 316(b) of the Clean Water Act. The rules seek to reduce alleged harmful impacts on aquatic organisms, such as fish. In 2018, Consumers submitted to EGLE studies and recommended plans to comply with Section 316(b) for its coal-fueled units but has not yet received final approval.

The EPA also regulates the discharge of wastewater through its effluent limitation guidelines for steam electric generating plants. In 2020, the EPA revised previous guidelines related to the discharge of certain wastewater, but allowed for extension of the compliance deadline from the end of 2023 to the end of 2025, upon approval by EGLE through the NPDES permitting process. Consumers received such an extension for J.H. Campbell, which it plans to retire in 2025. In April 2024, the EPA released a final rule updating its effluent limitation guidelines for existing coal-fueled units. This rule regulates additional wastewater streams previously not regulated, including combustion residual leachate and legacy wastewater. Consumers has submitted timely NPDES permit applications and will be working with EGLE to incorporate applicable provisions during the permit renewal process.

Many of Consumers' facilities maintain NPDES permits, which are vital to the facilities' operations. Consumers applies for renewal of these permits every five years. Failure of EGLE to renew any NPDES permit, a successful appeal against a permit, a change in the interpretation or scope of NPDES permitting, or onerous terms contained in a permit could have a significant detrimental effect on the operations of a facility.

Protected Wildlife: Multiple regulations apply, or may apply, to Consumers relating to protected species and habitats.

Statutes like the federal Endangered Species Act, the Migratory Bird Treaty Act, and the Bald and Golden Eagle Protection Act of 1940 and changes to permitting may impact operations at Consumers' facilities. In February 2024, the U.S. Fish and Wildlife Service published a final rule providing for bald eagle general permits for qualifying wind farms and electric distribution systems. Consumers has received, or is pursuing, bald eagle general permits for all its wind farms. While any resulting permitting and monitoring fees and/or restrictions on operations could impact Consumers' existing and future operations, Consumers does not expect any material changes to its environmental strategy or Clean Energy Plan as a result of this rule.

Additionally, Consumers regularly monitors proposed changes to the listing status of several species within its operational area. A change in species listed under the Endangered Species Act, or under Michigan's equivalent law, may impact Consumers' costs to mitigate its impact on protected species and habitats at certain existing facilities as well as siting choices for new facilities.

Other Matters: Other electric environmental matters could have a material impact on Consumers' outlook. For additional details on other electric environmental matters, see Notes to the Unaudited Consolidated Financial Statements—Note 2, Contingencies and Commitments—Consumers Electric Utility Contingencies—Electric Environmental Matters.

Consumers Gas Utility Outlook and Uncertainties

Gas Deliveries: Consumers' gas customer deliveries are seasonal. The peak demand for natural gas occurs in the winter due to colder temperatures and the resulting use of natural gas as heating fuel.

Over the next five years, Consumers expects weather-normalized gas deliveries to remain stable relative to 2024. This outlook reflects modest growth in gas demand, offset by the effects of energy waste reduction programs. Actual delivery levels will depend on:

- weather fluctuations
- use by power producers
- availability and development of renewable energy sources
- gas price changes
- Michigan's economic conditions, including population trends and housing activity
- the price or demand of competing energy sources or fuels
- energy efficiency and conservation impacts

Gas Rate Matters: Rate matters are critical to Consumers' gas utility business. For additional details on rate matters, see Notes to the Unaudited Consolidated Financial Statements—Note 1, Regulatory Matters and Note 2, Contingencies and Commitments.

2024 Gas Rate Case: In December 2024, Consumers filed an application with the MPSC seeking an annual rate increase of \$248 million based on a 10.25-percent authorized return on equity for the projected 12-month period ending October 31, 2026. In July 2025, Consumers revised its requested increase to \$217 million.

Presented in the following table are the components of the revised requested increase in revenue:

	<i>In Millions</i>
Projected 12-Month Period Ending October 31	2026
Investment in rate base	\$ 104
Operating and maintenance costs	43
Cost of capital	44
Sales/gross margin	26
Total	\$ 217

The MPSC must issue a final order in this case before or in October 2025.

Gas Pipeline and Storage Integrity and Safety: Consumers' gas operations are governed by federal and state pipeline safety rules, and there are robust processes and procedures in place to maintain compliance with these regulations. The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration has published various rules that revise federal safety standards for gas transmission pipelines and underground storage facilities. Consumers has implemented measures to achieve compliance with the revised rules. There are also proposed rules expanding requirements for gas distribution systems and leak detection and repair, although these rules are subject to reconsideration by the current administration. Under the proposed rules, Consumers will incur increased capital and increased operating and maintenance costs to install and remediate pipelines and to expand inspections, maintenance, and monitoring of existing pipelines and storage facilities.

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Although associated capital or operating and maintenance costs relating to these regulations could be material and cost recovery cannot be assured, Consumers expects to recover such costs in rates consistent with the recovery of other reasonable costs of complying with laws and regulations.

Gas Environmental Outlook: Consumers expects to incur response activity costs at a number of sites, including 23 former MGP sites. For additional details, see Notes to the Unaudited Consolidated Financial Statements—Note 2, Contingencies and Commitments—Consumers Gas Utility Contingencies.

Consumers' gas operations are subject to various federal, state, and local environmental laws and regulations. Multiple environmental laws and regulations are subject to litigation. Consumers' primary environmental compliance focus includes, but is not limited to, the following matters.

Air Quality: Multiple air quality regulations apply, or may apply, to Consumers' gas utility.

In 2015, the EPA lowered the NAAQS for ozone and made it more difficult to construct or modify natural gas compressor stations and other emission sources in areas of the country that do not meet the ozone standard. As of 2023, three counties in western Michigan have been designated as not meeting the ozone standard. Based on recent data, the EPA reclassified these counties from "moderate" to "serious" nonattainment, which has more stringent requirements. One of Consumers' compressor stations is in a serious ozone nonattainment area. Consequently, Consumers has initiated plans to retrofit equipment at this compressor station to lower NOx emissions. Consumers will continue to monitor NAAQS rulemakings and evaluate potential impacts to its compressor stations and other applicable natural gas storage and delivery assets.

In March 2024, the EPA published a lower fine particulate matter NAAQS, which will likely result in newly designated nonattainment areas in Michigan starting in 2026. EGLE has proposed nonattainment areas for Kalamazoo and Wayne counties. Consumers has one compressor station located in Wayne County and thus will continue to monitor NAAQS rulemakings and litigation to evaluate potential impacts to the natural gas compressor station assets.

Greenhouse Gases: Some interest exists at the various levels of government in regulating greenhouse gases or their sources. Future regulations, if adopted, may involve requirements to reduce methane emissions from Consumers' gas utility operations and carbon dioxide emissions from customer use of natural gas. Consumers will continue to monitor such potential rules for impacts.

In 2020, Michigan's Governor signed an executive order creating the Michigan Healthy Climate Plan, which outlines goals for Michigan to achieve economy-wide net-zero greenhouse gas emissions and to be carbon neutral by 2050. The executive order aims for a 28-percent reduction below 2005 levels of greenhouse gas emissions by 2025. For additional details on the executive order, see Outlook—Consumers Electric Utility Outlook and Uncertainties.

Consumers is making voluntary efforts to reduce its gas utility's methane emissions. Under its Methane Reduction Plan, Consumers has set a goal of net-zero methane emissions from its natural gas delivery system by 2030. Consumers plans to reduce methane emissions from its system by about 80 percent, from 2012 baseline levels, by accelerating the replacement of aging pipe, rehabilitating or retiring outdated infrastructure, and adopting new technologies and practices. The remaining emissions will likely be offset by purchasing and/or producing renewable natural gas. To date, Consumers has reduced methane emissions by nearly 30 percent.

In 2022, Consumers also announced a net-zero greenhouse gas emissions target for its entire natural gas system by 2050. This includes suppliers and customers, and has an interim goal of reducing customer emissions by 25 percent by 2035. Consumers' Natural Gas Delivery Plan, a rolling ten-year investment

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plan to deliver safe, reliable, clean, and affordable natural gas to customers, outlines ways in which Consumers can make early progress toward these goals in a cost-effective manner, including energy waste reduction, carbon offsets, and renewable natural gas supply.

Consumers has already initiated work in these key areas by continuing to expand its energy waste reduction targets and by offering gas customers the ability to offset their carbon footprint associated with natural gas use by purchasing renewable natural gas and/or carbon credits associated with Michigan forest preservation. Consumers has two renewable natural gas facilities under construction scheduled for commercial operation in late 2025. Consumers is evaluating and monitoring newer technologies to determine their role in achieving Consumers' interim and long-term net-zero goals, including biofuels, geothermal, synthetic methane, carbon capture sequestration systems, and other innovative technologies.

NorthStar Clean Energy Outlook and Uncertainties

CMS Energy's primary focus with respect to its NorthStar Clean Energy businesses is to maximize the value of generating assets representing 1,655 MW of capacity, and to pursue opportunities for the development of renewable generation projects.

Trends, uncertainties, and other matters related to NorthStar Clean Energy that could have a material impact on CMS Energy's consolidated income, cash flows, or financial position include:

- investment in and financial benefits received from renewable energy and energy storage projects, including changes to tax and trade policy
- changes in energy, capacity, and other commodity prices
- severe weather events and climate change associated with increasing levels of greenhouse gases
- changes in various environmental laws, regulations, principles, or practices, or in their interpretation
- indemnity obligations assumed in connection with ownership interests in facilities that involve tax equity financing
- representations, warranties, and indemnities provided in connection with sales of assets
- delays or difficulties in obtaining environmental permits or in constructing and developing projects, including those arising from the performance of contractors, suppliers, or other counterparties.

For additional details regarding NorthStar Clean Energy's uncertainties, see Notes to the Unaudited Consolidated Financial Statements—Note 2, Contingencies and Commitments—Guarantees.

NorthStar Clean Energy Environmental Outlook: NorthStar Clean Energy's operations are subject to various federal, state, and local environmental laws and regulations. Multiple environmental laws and regulations are subject to litigation. NorthStar Clean Energy's primary environmental compliance focus includes, but is not limited to, the following matters.

CSAPR requires Michigan and many other states to improve air quality by reducing power plant emissions that, according to EPA modeling, contribute to ground-level ozone in other downwind states. Since its 2015 effective date, CSAPR has been revised several times. In 2023, the EPA published the Good Neighbor Plan, a revision to CSAPR. This regulation tightens emission allowance budgets for electric generating units in Michigan between 2023 and 2029 and changes the mechanism for allocating such allowances on a year-over-year basis beginning in 2026. In June 2024, the U.S. Supreme Court stayed the Good Neighbor Plan pending judicial review and, as a result, the allowance requirements for Michigan reverted back to the prior effective CSAPR ozone season rule. Under the 2023 revision, NorthStar Clean Energy could incur increased costs to purchase allowances or retrofit equipment.

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In March 2024, the EPA published a lower fine particulate matter NAAQS, which will likely result in newly designated nonattainment areas in Michigan starting in 2026. EGLE has proposed nonattainment areas for Kalamazoo and Wayne counties. NorthStar Clean Energy has two fossil-fuel-fired generating stations in these counties and therefore will continue to monitor NAAQS rulemaking and litigation to evaluate potential impacts to its generating assets.

In December 2024, the EPA published a proposal to amend new source performance standards for new, modified, and reconstructed stationary combustion turbines to lower emission limits for NOx. This may impact future gas-fueled, simple-cycle turbine projects. NorthStar Clean Energy will monitor this rulemaking.

For additional details regarding the ozone NAAQS, see Consumers Electric Utility Outlook and Uncertainties—Electric Environmental Outlook.

In April 2024, the EPA finalized its rule under Section 111 of the Clean Air Act to address greenhouse gas emissions from new combustion turbine electric generating units and existing coal-, gas-, and oil-fueled steam electric generating units. These rules do not address existing combustion turbine electric generating units. In June 2025, the EPA issued a proposed rule containing two different pathways to rescind these requirements. Neither pathway impacts NorthStar Clean Energy's existing facilities. NorthStar Clean Energy will continue to follow the EPA rules that address greenhouse gas emissions and will continue to evaluate potential impacts to its operations.

Many of NorthStar Clean Energy's facilities maintain NPDES permits, which are vital to the facilities' operations. NorthStar Clean Energy applies for renewal of these permits every five years. Failure of EGLE to renew any NPDES permit, a successful appeal against a permit, a change in the interpretation or scope of NPDES permitting, or onerous terms contained in a permit could have a significant detrimental effect on the operations of a facility.

Other Outlook and Uncertainties

Union Contract: The UWUA represents Consumers' operating, maintenance, construction, and customer contact center employees. In May 2025, Consumers and the UWUA ratified a new five-year contract for its operating, maintenance, and construction bargaining unit. In July 2025, Consumers and the UWUA ratified a new five-year contract with customer contact center employees. Consumers and the United Steelworkers labor union will commence negotiations for a new five-year contract for its Zeeland plant bargaining unit in August 2025. The existing contract expires on October 1, 2025.

Tax Legislation: CMS Energy and Consumers are subject to changing tax laws. In July 2025, President Trump signed into law the OBBBA. The legislation allows for the immediate expensing of domestic research and development costs and includes changes to clean energy tax credits enacted by the Inflation Reduction Act of 2022. While the OBBBA restores, and makes permanent, the 100-percent bonus depreciation deduction, it also retains a provision that allows utilities to take a full deduction of interest expense in lieu of 100-percent bonus depreciation. CMS Energy and Consumers are still evaluating the potential impacts of the OBBBA and related executive actions; however, CMS Energy and Consumers do not anticipate a material impact on their respective financial statements.

Litigation: CMS Energy, Consumers, and certain of their subsidiaries are named as parties in various litigation matters, as well as in administrative proceedings before various courts and governmental agencies, arising in the ordinary course of business. For additional details regarding certain legal matters, see Notes to the Unaudited Consolidated Financial Statements—Note 1, Regulatory Matters and Note 2, Contingencies and Commitments.

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New Accounting Standards

There are no new accounting standards issued but not yet effective that are expected to have a material impact on CMS Energy's or Consumers' consolidated financial statements.

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CMS Energy Corporation

Consolidated Statements of Income (Unaudited)

In Millions, Except Per Share Amounts

	Three Months Ended		Six Months Ended	
June 30	2025	2024	2025	2024
Operating Revenue	\$ 1,838	\$ 1,607	\$ 4,285	\$ 3,783
Operating Expenses				
Fuel for electric generation	134	114	351	270
Purchased and interchange power	439	349	819	663
Purchased power – related parties	30	16	48	34
Cost of gas sold	124	66	507	417
Maintenance and other operating expenses	397	404	802	806
Depreciation and amortization	288	273	676	641
General taxes	109	102	271	257
Total operating expenses	1,521	1,324	3,474	3,088
Operating Income	317	283	811	695
Other Income (Expense)				
Non-operating retirement benefits, net	47	41	89	85
Other income	95	77	109	121
Other expense	(5)	(5)	(11)	(7)
Total other income	137	113	187	199
Interest Charges				
Interest on long-term debt	199	171	386	343
Interest expense – related parties	3	3	6	6
Other interest expense	—	5	(1)	7
Allowance for borrowed funds used during construction	(3)	(6)	(6)	(6)
Total interest charges	199	173	385	350
Income Before Income Taxes	255	223	613	544
Income Tax Expense	62	41	125	99
Net Income	193	182	488	445
Loss Attributable to Noncontrolling Interests	(8)	(16)	(17)	(40)
Net Income Attributable to CMS Energy	201	198	505	485
Preferred Stock Dividends	3	3	5	5
Net Income Available to Common Stockholders	\$ 198	\$ 195	\$ 500	\$ 480
Basic Earnings Per Average Common Share	\$ 0.67	\$ 0.65	\$ 1.68	\$ 1.61
Diluted Earnings Per Average Common Share	\$ 0.66	\$ 0.65	\$ 1.67	\$ 1.61

The accompanying notes are an integral part of these statements.

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CMS Energy Corporation

Consolidated Statements of Comprehensive Income (Unaudited)

In Millions

June 30	Three Months Ended		Six Months Ended	
	2025	2024	2025	2024
Net Income	\$ 193	\$ 182	\$ 488	\$ 445
Retirement Benefits Liability				
Amortization of net actuarial loss, net of tax of \$— for all periods	—	—	—	1
Other Comprehensive Income	—	—	—	1
Comprehensive Income	193	182	488	446
Comprehensive Loss Attributable to Noncontrolling Interests	(8)	(16)	(17)	(40)
Comprehensive Income Attributable to CMS Energy	\$ 201	\$ 198	\$ 505	\$ 486

The accompanying notes are an integral part of these statements.

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CMS Energy Corporation

Consolidated Statements of Cash Flows (Unaudited)

	<i>In Millions</i>	
Six Months Ended June 30	2025	2024
Cash Flows from Operating Activities		
Net income	\$ 488	\$ 445
<i>Adjustments to reconcile net income to net cash provided by operating activities</i>		
Depreciation and amortization	676	641
Deferred income taxes and investment tax credits	124	79
Other non-cash operating activities and reconciling adjustments	(144)	(107)
<i>Changes in assets and liabilities</i>		
Accounts receivable and accrued revenue	80	153
Inventories	34	158
Accounts payable and accrued rate refunds	24	(2)
Other current assets and liabilities	117	129
Other non-current assets and liabilities	15	167
Net cash provided by operating activities	1,414	1,663
Cash Flows from Investing Activities		
Capital expenditures (excludes assets placed under finance lease)	(1,772)	(1,294)
Proceeds from sale of ASP business	—	124
Cost to retire property and other investing activities	(108)	(76)
Net cash used in investing activities	(1,880)	(1,246)
Cash Flows from Financing Activities		
Proceeds from issuance of debt	2,449	704
Retirement of debt	(841)	(433)
Decrease in notes payable	(65)	(93)
Issuance of common stock	17	279
Payment of dividends on common and preferred stock	(331)	(314)
Proceeds from the sale of membership interests in VIEs	44	—
Other financing costs	(60)	(19)
Net cash provided by financing activities	1,213	124
Net Increase in Cash and Cash Equivalents, Including Restricted Amounts	747	541
Cash and Cash Equivalents, Including Restricted Amounts, Beginning of Period	178	248
Cash and Cash Equivalents, Including Restricted Amounts, End of Period	\$ 925	\$ 789
Other Cash Flow Activities and Non-cash Investing and Financing Activities		
<i>Non-cash transactions</i>		
Capital expenditures not paid	\$ 537	\$ 259

The accompanying notes are an integral part of these statements.

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CMS Energy Corporation

Consolidated Balance Sheets (Unaudited)

ASSETS

	<i>In Millions</i>	
	June 30 2025	December 31 2024
Current Assets		
Cash and cash equivalents	\$ 844	\$ 103
Restricted cash and cash equivalents	81	75
Accounts receivable and accrued revenue, less allowance of \$30 in 2025 and \$23 in 2024	924	1,049
Accounts receivable – related parties	12	14
<i>Inventories at average cost</i>		
Gas in underground storage	402	435
Materials and supplies	305	299
Generating plant fuel stock	29	35
Deferred property taxes	324	448
Regulatory assets	132	229
Prepayments and other current assets	140	103
Total current assets	3,193	2,790
Plant, Property, and Equipment		
Plant, property, and equipment, gross	35,962	34,932
Less accumulated depreciation and amortization	9,865	9,569
Plant, property, and equipment, net	26,097	25,363
Construction work in progress	2,750	2,098
Total plant, property, and equipment	28,847	27,461
Other Non-current Assets		
Regulatory assets	3,570	3,569
Accounts receivable	68	20
Investments	62	69
Postretirement benefits	1,705	1,627
Other	254	384
Total other non-current assets	5,659	5,669
Total Assets	\$ 37,699	\$ 35,920

[Table of Contents](#)**LIABILITIES AND EQUITY**

	<i>In Millions</i>	
	June 30 2025	December 31 2024
Current Liabilities		
Current portion of long-term debt and finance leases	\$ 1,125	\$ 1,195
Notes payable	—	65
Accounts payable	1,139	1,085
Accounts payable – related parties	7	8
Accrued rate refunds	4	38
Accrued interest	170	156
Accrued taxes	461	654
Regulatory liabilities	93	111
Other current liabilities	197	209
Total current liabilities	3,196	3,521
Non-current Liabilities		
Long-term debt	16,781	15,194
Non-current portion of finance leases	139	112
Regulatory liabilities	4,164	4,067
Postretirement benefits	93	96
Asset retirement obligations	747	728
Deferred investment tax credit	120	122
Deferred income taxes	3,079	2,925
Other non-current liabilities	409	407
Total non-current liabilities	25,532	23,651
Commitments and Contingencies (Notes 1 and 2)		
Equity		
<i>Common stockholders' equity</i>		
Common stock, authorized 350.0 shares in both periods; outstanding 299.3 shares in 2025 and 298.8 shares in 2024	3	3
Other paid-in capital	5,998	6,009
Accumulated other comprehensive loss	(41)	(41)
Retained earnings	2,210	2,035
Total common stockholders' equity	8,170	8,006
Cumulative redeemable perpetual preferred stock, Series C, authorized 9.2 depositary shares; outstanding 9.2 depositary shares in both periods	224	224
Total stockholders' equity	8,394	8,230
Noncontrolling interests	577	518
Total equity	8,971	8,748
Total Liabilities and Equity	\$ 37,699	\$ 35,920

The accompanying notes are an integral part of these statements.

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CMS Energy Corporation

Consolidated Statements of Changes in Equity (Unaudited)

	<i>In Millions, Except Per Share Amounts</i>			
	Three Months Ended		Six Months Ended	
June 30	2025	2024	2025	2024
Total Equity at Beginning of Period	\$ 8,923	\$ 8,506	\$ 8,748	\$ 8,125
Common Stock				
At beginning and end of period	3	3	3	3
Other Paid-in Capital				
At beginning of period	5,975	5,975	6,009	5,705
Common stock issued	23	16	35	297
Common stock repurchased	—	—	(12)	(11)
Adjustment for sale of membership interests in VIEs	—	—	(34)	—
At end of period	5,998	5,991	5,998	5,991
Accumulated Other Comprehensive Loss				
<i>Retirement benefits liability</i>				
At beginning of period	(41)	(45)	(41)	(46)
Amortization of net actuarial loss	—	—	—	1
At end of period	(41)	(45)	(41)	(45)
Retained Earnings				
At beginning of period	2,174	1,789	2,035	1,658
Net income attributable to CMS Energy	201	198	505	485
Dividends declared on common stock	(162)	(154)	(325)	(308)
Dividends declared on preferred stock	(3)	(3)	(5)	(5)
At end of period	2,210	1,830	2,210	1,830
Cumulative Redeemable Perpetual Preferred Stock, Series C				
At beginning and end of period	224	224	224	224
Noncontrolling Interests				
At beginning of period	588	560	518	581
Sale of membership interests in VIEs	—	—	78	—
Loss attributable to noncontrolling interests	(8)	(16)	(17)	(40)
Other changes in noncontrolling interests	(3)	(6)	(2)	(3)
At end of period	577	538	577	538
Total Equity at End of Period	\$ 8,971	\$ 8,541	\$ 8,971	\$ 8,541
Dividends declared per common share	\$ 0.5425	\$ 0.5150	\$ 1.0850	\$ 1.0300
Dividends declared per preferred stock Series C depositary share	\$ 0.2625	\$ 0.2625	\$ 0.5250	\$ 0.5250

The accompanying notes are an integral part of these statements.

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Consumers Energy Company

Consolidated Statements of Income (Unaudited)

In Millions

	Three Months Ended		Six Months Ended	
June 30	2025	2024	2025	2024
Operating Revenue	\$ 1,746	\$ 1,533	\$ 4,094	\$ 3,630
Operating Expenses				
Fuel for electric generation	113	91	306	216
Purchased and interchange power	394	337	729	643
Purchased power – related parties	30	16	48	34
Cost of gas sold	123	66	505	416
Maintenance and other operating expenses	376	377	749	755
Depreciation and amortization	276	261	651	617
General taxes	106	99	265	251
Total operating expenses	1,418	1,247	3,253	2,932
Operating Income	328	286	841	698
Other Income (Expense)				
Non-operating retirement benefits, net	45	38	84	79
Other income	19	26	29	43
Other expense	(4)	(5)	(7)	(7)
Total other income	60	59	106	115
Interest Charges				
Interest on long-term debt	131	120	253	241
Interest expense – related parties	10	7	20	13
Other interest expense	3	3	3	5
Allowance for borrowed funds used during construction	(3)	(4)	(5)	(4)
Total interest charges	141	126	271	255
Income Before Income Taxes	247	219	676	558
Income Tax Expense	59	41	142	105
Net Income	188	178	534	453
Preferred Stock Dividends	1	1	1	1
Net Income Available to Common Stockholder	\$ 187	\$ 177	\$ 533	\$ 452

The accompanying notes are an integral part of these statements.

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Consumers Energy Company

Consolidated Statements of Comprehensive Income (Unaudited)

In Millions

	Three Months Ended		Six Months Ended	
June 30	2025	2024	2025	2024
Net Income	\$ 188	\$ 178	\$ 534	\$ 453
Other Comprehensive Income	—	—	—	—
Comprehensive Income	\$ 188	\$ 178	\$ 534	\$ 453

The accompanying notes are an integral part of these statements.

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Consumers Energy Company

Consolidated Statements of Cash Flows (Unaudited)

	<i>In Millions</i>	
Six Months Ended June 30	2025	2024
Cash Flows from Operating Activities		
Net income	\$ 534	\$ 453
<i>Adjustments to reconcile net income to net cash provided by operating activities</i>		
Depreciation and amortization	651	617
Deferred income taxes and investment tax credits	66	76
Other non-cash operating activities and reconciling adjustments	(80)	(38)
<i>Changes in assets and liabilities</i>		
Accounts and notes receivable and accrued revenue	95	151
Inventories	33	158
Accounts payable and accrued rate refunds	59	5
Other current assets and liabilities	125	114
Other non-current assets and liabilities	(4)	155
Net cash provided by operating activities	1,479	1,691
Cash Flows from Investing Activities		
Capital expenditures (excludes assets placed under finance lease)	(1,519)	(1,228)
Proceeds from sale of ASP business	—	124
Cost to retire property and other investing activities	(113)	(72)
Net cash used in investing activities	(1,632)	(1,176)
Cash Flows from Financing Activities		
Proceeds from issuance of debt	1,123	599
Retirement of debt	(57)	(15)
Decrease in notes payable	(65)	(93)
Stockholder contribution	150	320
Return of stockholder contribution	—	(320)
Payment of dividends on common and preferred stock	(417)	(360)
Other financing costs	(20)	(6)
Net cash provided by financing activities	714	125
Net Increase in Cash and Cash Equivalents, Including Restricted Amounts	561	640
Cash and Cash Equivalents, Including Restricted Amounts, Beginning of Period	119	56
Cash and Cash Equivalents, Including Restricted Amounts, End of Period	\$ 680	\$ 696
Other Cash Flow Activities and Non-cash Investing and Financing Activities		
<i>Non-cash transactions</i>		
Capital expenditures not paid	\$ 425	\$ 255

The accompanying notes are an integral part of these statements.

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Consumers Energy Company

Consolidated Balance Sheets (Unaudited)

ASSETS

	<i>In Millions</i>	
	June 30 2025	December 31 2024
Current Assets		
Cash and cash equivalents	\$ 599	\$ 44
Restricted cash and cash equivalents	81	75
Accounts receivable and accrued revenue, less allowance of \$30 in 2025 and \$23 in 2024	884	1,019
Accounts and notes receivable – related parties	10	17
<i>Inventories at average cost</i>		
Gas in underground storage	402	435
Materials and supplies	296	291
Generating plant fuel stock	25	30
Deferred property taxes	324	448
Regulatory assets	132	229
Prepayments and other current assets	130	86
Total current assets	2,883	2,674
Plant, Property, and Equipment		
Plant, property, and equipment, gross	34,406	33,434
Less accumulated depreciation and amortization	9,600	9,310
Plant, property, and equipment, net	24,806	24,124
Construction work in progress	2,253	1,766
Total plant, property, and equipment	27,059	25,890
Other Non-current Assets		
Regulatory assets	3,570	3,569
Accounts receivable	74	26
Accounts and notes receivable – related parties	90	92
Postretirement benefits	1,586	1,514
Other	205	323
Total other non-current assets	5,525	5,524
Total Assets	\$ 35,467	\$ 34,088

[Table of Contents](#)**LIABILITIES AND EQUITY**

	<i>In Millions</i>	
	June 30 2025	December 31 2024
Current Liabilities		
Current portion of long-term debt and finance leases	\$ 576	\$ 456
Notes payable	—	65
Accounts payable	1,029	917
Accounts payable – related parties	15	12
Accrued rate refunds	4	38
Accrued interest	140	130
Accrued taxes	522	678
Regulatory liabilities	93	111
Other current liabilities	152	185
Total current liabilities	2,531	2,592
Non-current Liabilities		
Long-term debt	11,581	10,818
Long-term debt – related parties	1,004	823
Non-current portion of finance leases	86	69
Regulatory liabilities	4,164	4,067
Postretirement benefits	68	70
Asset retirement obligations	713	694
Deferred investment tax credit	120	122
Deferred income taxes	3,148	3,053
Other non-current liabilities	354	349
Total non-current liabilities	21,238	20,065
Commitments and Contingencies (Notes 1 and 2)		
Equity		
<i>Common stockholder's equity</i>		
Common stock, authorized 125.0 shares; outstanding 84.1 shares in both periods	841	841
Other paid-in capital	8,324	8,174
Accumulated other comprehensive loss	(11)	(11)
Retained earnings	2,507	2,390
Total common stockholder's equity	11,661	11,394
Cumulative preferred stock, \$4.50 series, authorized 7.5 shares; outstanding 0.4 shares in both periods	37	37
Total equity	11,698	11,431
Total Liabilities and Equity	\$ 35,467	\$ 34,088

The accompanying notes are an integral part of these statements.

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Consumers Energy Company

Consolidated Statements of Changes in Equity (Unaudited)

In Millions

June 30	Three Months Ended		Six Months Ended	
	2025	2024	2025	2024
Total Equity at Beginning of Period	\$ 11,656	\$ 10,810	\$ 11,431	\$ 10,800
Common Stock				
At beginning and end of period	841	841	841	841
Other Paid-in Capital				
At beginning of period	8,324	7,759	8,174	7,759
Stockholder contribution	—	—	150	320
Return of stockholder contribution	—	—	—	(320)
At end of period	8,324	7,759	8,324	7,759
Accumulated Other Comprehensive Loss				
Retirement benefits liability				
At beginning and end of period	(11)	(15)	(11)	(15)
Retained Earnings				
At beginning of period	2,465	2,188	2,390	2,178
Net income	188	178	534	453
Dividends declared on common stock	(145)	(94)	(416)	(359)
Dividends declared on preferred stock	(1)	(1)	(1)	(1)
At end of period	2,507	2,271	2,507	2,271
Cumulative Preferred Stock				
At beginning and end of period	37	37	37	37
Total Equity at End of Period	\$ 11,698	\$ 10,893	\$ 11,698	\$ 10,893

The accompanying notes are an integral part of these statements.

CMS Energy Corporation

Consumers Energy Company

Notes to the Unaudited Consolidated Financial Statements

These interim consolidated financial statements have been prepared by CMS Energy and Consumers in accordance with GAAP for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. As a result, CMS Energy and Consumers have condensed or omitted certain information and note disclosures normally included in consolidated financial statements prepared in accordance with GAAP. CMS Energy and Consumers have reclassified certain prior period amounts to conform to the presentation in the present period.

CMS Energy and Consumers are required to make estimates using assumptions that may affect reported amounts and disclosures; actual results could differ from these estimates. In management's opinion, the unaudited information contained in this report reflects all adjustments of a normal recurring nature necessary to ensure that CMS Energy's and Consumers' financial position, results of operations, and cash flows for the periods presented are fairly stated. The notes to the unaudited consolidated financial statements and the related unaudited consolidated financial statements should be read in conjunction with the consolidated financial statements and related notes contained in the 2024 Form 10-K. Due to the seasonal nature of CMS Energy's and Consumers' operations, the results presented for this interim period are not necessarily indicative of results to be achieved for the fiscal year.

1: Regulatory Matters

Regulatory matters are critical to Consumers. The Michigan Attorney General, ABATE, the MPSC Staff, residential customer advocacy groups, environmental organizations, and certain other parties typically participate in MPSC proceedings concerning Consumers, such as Consumers' rate cases and power supply cost recovery and gas cost recovery processes. Intervenor also participate in certain FERC matters, including FERC's regulation of certain wholesale rates that affect Consumers' power supply costs. These parties often challenge various aspects of those proceedings, including the prudence of Consumers' policies and practices, and seek cost disallowances and other relief. The parties also have appealed significant MPSC orders. Depending upon the specific issues, the outcomes of rate cases and proceedings, including judicial proceedings challenging MPSC and FERC orders or other actions, could negatively affect CMS Energy's and Consumers' liquidity, financial condition, and results of operations. Consumers cannot predict the outcome of these proceedings.

2024 Electric Rate Case: In May 2024, Consumers filed an application with the MPSC seeking a rate increase of \$325 million, made up of two components. First, Consumers requested a \$303 million annual rate increase, based on a 10.25-percent authorized return on equity for the projected 12-month period ending February 28, 2026. The filing requested authority to recover costs related to new infrastructure investment primarily in distribution system reliability and cleaner energy resources. Second, Consumers requested approval of a \$22 million surcharge for the recovery of distribution investments made in 2023 that exceeded the rates authorized in accordance with previous electric rate orders.

In October 2024, Consumers revised its requested increase to \$277 million, primarily to reflect the removal of projected capital investments associated with certain solar facilities that Consumers incorporated into its amended renewable energy plan.

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In March 2025, the MPSC issued an order authorizing an annual rate increase of \$176 million, which is inclusive of a \$22 million surcharge for the recovery of distribution investments made in 2023 that exceeded the rate amounts authorized in accordance with previous electric rate orders. The approved rate increase is based on a 9.90-percent authorized return on equity. The new rates became effective in April 2025.

J.H. Campbell Emergency Order: In May 2025, before the planned closure of J.H. Campbell, the U.S. Secretary of Energy issued an emergency order under section 202(c) of the Federal Power Act requiring J.H. Campbell to continue operating for 90 days, through August 20, 2025. The order stated that continued operation of J.H. Campbell was required to meet an energy emergency across MISO's North and Central regions. Consistent with the Federal Power Act and the U.S. Department of Energy regulations, the order authorizes Consumers to obtain cost recovery at FERC. Consumers has continued to make J.H. Campbell available in the MISO market, consistent with the order, and has filed a complaint at FERC seeking a modification of the MISO Tariff to establish a mechanism for recovery and allocation of the cost to comply with this order. Between the start of the emergency order and June 30, 2025, the net financial impact of complying with the order was \$29 million, for which recovery will be sought through FERC in a subsequent proceeding after a modification to the MISO Tariff is established.

Service Restoration Cost Deferral Application: As a result of catastrophic storms in Consumers' electric service territory, Consumers incurred significant service restoration costs during March and April 2025. In April 2025, Consumers filed with the MPSC an ex parte application requesting approval to defer, as a regulatory asset, operating and maintenance expenses associated with the storms. In June 2025, the MPSC approved the application, authorizing the deferral of these expenses for accounting purposes. At June 30, 2025, Consumers had deferred \$54 million of these costs as a regulatory asset, recovery for which will be requested in a future rate case.

2: Contingencies and Commitments

CMS Energy and Consumers are involved in various matters that give rise to contingent liabilities. Depending on the specific issues, the resolution of these contingencies could negatively affect CMS Energy's and Consumers' liquidity, financial condition, and results of operations. In their disclosures of these matters, CMS Energy and Consumers provide an estimate of the possible loss or range of loss when such an estimate can be made. Disclosures stating that CMS Energy or Consumers cannot predict the outcome of a matter indicate that they are unable to estimate a possible loss or range of loss for the matter.

CMS Energy Contingencies

CMS Land retained environmental remediation obligations for the collection and treatment of leachate at Bay Harbor after selling its interests in the development in 2002. Leachate is produced when water enters into cement kiln dust piles left over from former cement plant operations at the site. In 2012, CMS Land and EGLE finalized an agreement establishing the final remedies and the future water quality criteria at the site. CMS Land completed all construction necessary to implement the remedies required by the agreement and will continue to maintain and operate a system to discharge treated leachate into Little Traverse Bay under an NPDES permit, which is valid through 2025. CMS Land submitted a renewal request in March 2025, and will continue to operate under the existing permit until a renewal is issued.

At June 30, 2025, CMS Energy had a recorded liability of \$47 million for its remaining obligations for environmental remediation. CMS Energy calculated this liability based on discounted projected costs, using a discount rate of 4.34 percent and an inflation rate of 1 percent on annual operating and maintenance costs. The undiscounted amount of the remaining obligation is \$59 million. CMS Energy

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expects to pay the following amounts for long-term leachate disposal and operating and maintenance costs during the remainder of 2025 and in each of the next five years:

	<i>In Millions</i>					
	2025	2026	2027	2028	2029	2030
Long-term leachate disposal and operating and maintenance costs	\$ 2	\$ 4	\$ 4	\$ 4	\$ 4	\$ 4

CMS Energy's estimate of response activity costs and the timing of expenditures could change if there are changes in circumstances or assumptions used in calculating the liability. Although a liability for its present estimate of remaining response activity costs has been recorded, CMS Energy cannot predict the ultimate financial impact or outcome of this matter.

Consumers Electric Utility Contingencies

Electric Environmental Matters: Consumers' operations are subject to environmental laws and regulations. Historically, Consumers has generally been able to recover, in customer rates, the costs to operate its facilities in compliance with these laws and regulations.

Cleanup and Solid Waste: Consumers expects to incur remediation and other response activity costs at a number of sites under NREPA. Consumers believes that these costs should be recoverable in rates, but cannot guarantee that outcome. Consumers estimates its liability for NREPA sites for which it can estimate a range of loss to be between \$4 million and \$5 million. At June 30, 2025, Consumers had a recorded liability of \$4 million, the minimum amount in the range of its estimated probable NREPA liability, as no amount in the range was considered a better estimate than any other amount.

Consumers is a potentially responsible party at a number of contaminated sites administered under CERCLA. CERCLA liability is joint and several. In 2010, Consumers received official notification from the EPA that identified Consumers as a potentially responsible party for cleanup of PCBs at the Kalamazoo River CERCLA site. The notification claimed that the EPA had reason to believe that Consumers disposed of PCBs and arranged for the disposal and treatment of PCB-containing materials at portions of the site. In 2011, Consumers received a follow-up letter from the EPA requesting that Consumers agree to participate in a removal action plan along with several other companies for an area of lower Portage Creek, which is connected to the Kalamazoo River. All parties asked to participate in the removal action plan, including Consumers, declined to accept liability. Until further information is received from the EPA, Consumers is unable to estimate a range of potential liability for cleanup of the river.

Based on its experience, Consumers estimates its share of the total liability for known CERCLA sites to be between \$3 million and \$8 million. Various factors, including the number and creditworthiness of potentially responsible parties involved with each site, affect Consumers' share of the total liability. At June 30, 2025, Consumers had a recorded liability of \$3 million for its share of the total liability at these sites, the minimum amount in the range of its estimated probable CERCLA liability, as no amount in the range was considered a better estimate than any other amount.

The timing of payments related to Consumers' remediation and other response activities at its CERCLA and NREPA sites is uncertain. Consumers periodically reviews these cost estimates. A change in the underlying assumptions, such as an increase in the number of sites, different remediation techniques, the nature and extent of contamination, and legal and regulatory requirements, could affect its estimates of NREPA and CERCLA liability.

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Ludington Overhaul Contract Dispute: Consumers and DTE Electric, co-owners of Ludington, entered into a 2010 engineering, procurement, and construction agreement with Toshiba International, under which Toshiba International contracted to perform a major overhaul and upgrade of Ludington. Toshiba International later assigned the contract and all of its obligations to TAES. TAES' work under the contract was incomplete, defective, and non-conforming. Consumers and DTE Electric repeatedly documented TAES' failure to perform under the contract and demanded that TAES provide a comprehensive plan to resolve those matters, including adherence to its warranty commitments and other contractual obligations. Consumers and DTE Electric engaged in extensive efforts to resolve these issues with TAES, including a formal demand to TAES' parent, Toshiba, under a parent guaranty it provided. TAES did not provide a comprehensive plan or otherwise meet its performance obligations. As a result of TAES' defaults, Consumers and DTE Electric terminated the contract.

In order to enforce their rights under the contract and parent guaranty, and to pursue appropriate damages, Consumers and DTE Electric filed a complaint against TAES and Toshiba in the U.S. District Court for the Eastern District of Michigan in 2022. TAES and Toshiba filed a motion to dismiss the complaint, along with an answer and counterclaims seeking approximately \$15 million in damages related to payments allegedly owed under the parties' contract. As a co-owner of Ludington, Consumers would be liable for 51 percent of any such damages, if liability and damages were proven. The court denied the motion to dismiss filed by TAES and Toshiba. The parties are engaged in ongoing litigation pursuant to a court-ordered schedule. Consumers believes the counterclaims filed by TAES and Toshiba are without merit, but cannot predict the financial impact or outcome of this matter. An unfavorable outcome could have a material adverse effect on CMS Energy's and Consumers' financial condition, results of operations, or liquidity.

In 2023, Toshiba announced that TBJH became the majority shareholder and new parent company of Toshiba through a common stock purchase. TBJH is a subsidiary of a Japanese private equity firm. Consumers and DTE Electric continue to monitor this development, but do not believe that this affects their rights under the parent guaranty provided by Toshiba.

In 2023, the MPSC approved Consumers' and DTE Electric's jointly-filed request for authority to defer as a regulatory asset the costs associated with repairing or replacing the defective work performed by TAES while the litigation with TAES and Toshiba moves forward. Although litigation is ongoing, Consumers currently estimates that its share of repair, replacement, and other damages resulting from TAES' defective work is approximately \$350 million, which may be offset in part or entirely by any potential future litigation proceeds received from TAES or Toshiba. Consumers and DTE Electric will have the opportunity to seek appropriate recovery and ratemaking treatment for amounts recorded as a regulatory asset following resolution of the litigation, including any amounts not recovered from TAES or Toshiba, but cannot predict the financial impact or outcome of such proceedings.

Consumers Gas Utility Contingencies

Consumers expects to incur remediation and other response activity costs at a number of sites under NREPA. These sites include 23 former MGP facilities. Consumers operated the facilities on these sites for some part of their operating lives. For some of these sites, Consumers has no present ownership interest or may own only a portion of the original site.

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At June 30, 2025, Consumers had a recorded liability of \$59 million for its remaining obligations for these sites. Consumers expects to pay the following amounts for remediation and other response activity costs during the remainder of 2025 and in each of the next five years:

	<i>In Millions</i>					
	2025	2026	2027	2028	2029	2030
Remediation and other response activity costs	\$ 2	\$ 7	\$ 9	\$ 24	\$ 7	\$ 1

Consumers periodically reviews these cost estimates. Any significant change in the underlying assumptions, such as an increase in the number of sites, changes in remediation techniques, or legal and regulatory requirements, could affect Consumers' estimates of annual response activity costs and the MGP liability.

Pursuant to orders issued by the MPSC, Consumers defers its MGP-related remediation costs and recovers them from its customers over a ten-year period. At June 30, 2025, Consumers had a regulatory asset of \$86 million related to the MGP sites.

Guarantees

Presented in the following table are CMS Energy's and Consumers' guarantees at June 30, 2025:

<i>In Millions</i>					
Guarantee Description	Issue Date	Expiration Date	Maximum Obligation	Carrying Amount	
CMS Energy, including Consumers					
Indemnity obligations from sale of membership interests in VIEs ¹	various	various	\$ 238	\$	—
Indemnity obligations from stock and asset sale agreements ²	various	indefinite	152		—
Guarantee ³	2011	indefinite	30		—
Consumers					
Guarantee ³	2011	indefinite	\$ 30	\$	—

¹ These obligations arose from the sale of membership interests in Aviator Wind, Newport Solar Holdings, and NWO Holdco to tax equity investors. NorthStar Clean Energy provided certain indemnity obligations that protect the tax equity investors against losses incurred as a result of breaches of representations and warranties under the associated limited liability company agreements. These obligations are generally capped at an amount equal to the tax equity investor's capital contributions plus a specified return, less any distributions and tax benefits it receives, in connection with its membership interest. For any indemnity obligations related to Aviator Wind, NorthStar Clean Energy would recover 49 percent of any amounts paid to the tax equity investor from the other owner of Aviator Wind Equity Holdings. Additionally, Aviator Wind holds insurance coverage that would partially protect against losses incurred as a result of certain failures to qualify for production tax credits. For further details on NorthStar Clean Energy's ownership interest in Aviator Wind, Newport Solar Holdings, and NWO Holdco, see Note 11, Variable Interest Entities.

² These obligations arose from stock and asset sale agreements under which CMS Energy or a subsidiary of CMS Energy indemnified the purchaser for losses resulting from various matters, including claims related to taxes. The maximum obligation amount is mostly related to an Equatorial Guinea tax claim.

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- ³ This obligation comprises a guarantee provided by Consumers to the U.S. Department of Energy in connection with a settlement agreement regarding damages resulting from the department's failure to accept spent nuclear fuel from nuclear power plants formerly owned by Consumers.

Additionally, in the normal course of business, CMS Energy, Consumers, and certain other subsidiaries of CMS Energy have entered into various agreements containing tax and other indemnity provisions for which they are unable to estimate the maximum potential obligation. CMS Energy and Consumers consider the likelihood that they would be required to perform or incur substantial losses related to these indemnities and those disclosed in the table to be remote.

Other Contingencies

In addition to the matters disclosed in this Note and Note 1, Regulatory Matters, there are certain other lawsuits and administrative proceedings before various courts and governmental agencies, as well as unasserted claims that may result in such proceedings, arising in the ordinary course of business to which CMS Energy, Consumers, and certain other subsidiaries of CMS Energy are parties. These other lawsuits, proceedings, and unasserted claims may involve personal injury, property damage, contracts, environmental matters, federal and state taxes, rates, licensing, employment, and other matters. Certain of these matters, while potentially substantial, are covered by insurance and the insurer or insurers are involved in the relevant proceedings. Further, CMS Energy and Consumers occasionally self-report certain regulatory non-compliance matters that may or may not eventually result in administrative proceedings. CMS Energy and Consumers believe that the outcome of any one of these proceedings and potential claims will not have a material negative effect on their consolidated results of operations, financial condition, or liquidity.

3: Financings and Capitalization

Financings: Presented in the following table is a summary of major long-term debt issuances during the six months ended June 30, 2025:

	Principal (In Millions)	Interest Rate (%)	Issuance Date	Maturity Date
CMS Energy, parent only				
Junior subordinated notes ¹	\$ 1,000	6.500	February 2025	June 2055
Term loan credit agreement	110	variable	February 2025	December 2025
Total CMS Energy, parent only	\$ 1,110			
NorthStar Clean Energy, including subsidiaries				
Construction financing agreement ²	\$ 132	variable	February 2025	Five years after conversion date ²
Total NorthStar Clean Energy, including subsidiaries	\$ 132			
Consumers				
First mortgage bonds	\$ 500	4.500	May 2025	January 2031
First mortgage bonds	625	5.050	May 2025	May 2035
Total Consumers	\$ 1,125			
Total CMS Energy	\$ 2,367			

- ¹ These unsecured obligations rank subordinate and junior in right of payment to all of CMS Energy's existing and future senior indebtedness. On June 1, 2035, and every five years thereafter, the notes will reset to an interest rate equal to the five-year treasury rate plus 1.961 percent.

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- ² At completion of project construction, scheduled for the first half of 2026, these financings will convert into a term loan that will mature five years after the conversion date.

Retirements: Presented in the following table is a summary of major long-term debt retirements during the six months ended June 30, 2025:

	Principal (In Millions)	Interest Rate (%)	Retirement Date	Maturity Date
CMS Energy, parent only				
Term loan credit agreement	\$ 400	variable	February 2025	September 2025
Term loan credit agreement	200	variable	February 2025	December 2025
Total CMS Energy, parent only	\$ 600			
Total CMS Energy	\$ 600			

CMS Energy's Purchase of Consumers' First Mortgage Bonds: CMS Energy purchased Consumers' first mortgage bonds with a principal balance of \$184 million during the three and six months ended June 30, 2025 in exchange for cash of \$109 million. On a consolidated basis, CMS Energy's repurchase of Consumers' first mortgage bonds was accounted for as a debt extinguishment and resulted in a pre-tax gain of \$72 million for the three and six months ended June 30, 2025, which was recorded in other income on CMS Energy's consolidated statements of income. Interest expense related to the repurchased bonds was \$7 million for the three months ended June 30, 2025 and \$13 million for the six months ended June 30, 2025, which was recorded in interest expense - related parties on Consumers' consolidated statements of income.

CMS Energy purchased Consumers' first mortgage bonds with a principal balance of \$151 million during the three months ended June 30, 2024 and \$242 million during the six months ended June 30, 2024, in exchange for cash of \$100 million and \$169 million, respectively. On a consolidated basis, CMS Energy's repurchase of Consumers' first mortgage bonds was accounted for as a debt extinguishment and resulted in a pre-tax gain of \$48 million for the three months ended June 30, 2024 and a pre-tax gain of \$70 million for the six months ended June 30, 2024, which was recorded in other income on its consolidated statements of income. Interest expense related to the repurchased bonds was \$4 million for the three months ended June 30, 2024 and \$8 million for the six months ended June 30, 2024, which was recorded in interest expense - related parties on Consumers' consolidated statements of income.

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Credit Facilities: The following credit facilities with banks were available at June 30, 2025:

<i>In Millions</i>					
Expiration Date	Amount of Facility Amount Borrowed		Letters of Credit Outstanding		Amount Available
CMS Energy, parent only					
December 14, 2027 ¹	\$	550	\$	—	\$ 38 512
September 30, 2025		50		—	50 —
NorthStar Clean Energy, including subsidiaries					
May 30, 2028 ²	\$	250	\$	160	\$ — 90
September 25, 2025 ³		37		—	37 —
Upon completion of construction project ⁴		19		—	12 7
Consumers⁵					
December 14, 2027	\$	1,100	\$	—	\$ 10 1,090
November 18, 2025		250		—	72 178
March 31, 2028		50		—	24 26

¹ There were no borrowings under this facility during the six months ended June 30, 2025.

² Obligations under this facility are secured by certain pledged equity interests in subsidiaries of NorthStar Clean Energy; under the terms of this facility, the interests may not be sold by NorthStar Clean Energy unless there is an agreed-upon substitution for the pledged equity interests. At June 30, 2025, the net book value of the pledged equity interests was \$505 million. Also under the terms of this facility, NorthStar Clean Energy may be restricted from remitting cash dividends to CMS Energy in the event of default.

³ This letter of credit facility is available to Aviator Wind Equity Holdings. For more information regarding Aviator Wind Equity Holdings, see Note 11, Variable Interest Entities.

⁴ The letter of credit facility is available to certain subsidiaries of NorthStar Clean Energy. The letter of credit facility will expire upon completion of project construction scheduled for the first half of 2026.

⁵ Obligations under these facilities are secured by first mortgage bonds of Consumers. There were no borrowings under these facilities during the six months ended June 30, 2025.

Regulatory Authorization for Financings: Consumers is required to maintain FERC authorization for financings. Any long-term issuances during the authorization period are exempt from FERC's competitive bidding and negotiated placement requirements. Its short-term authorization ends on May 2, 2026. In February 2025, FERC approved Consumers' application for authority to issue long-term debt securities. The authorization is effective February 21, 2025 through February 20, 2027.

Short-term Borrowings: Under Consumers' commercial paper program, Consumers may issue, in one or more placements, investment-grade commercial paper notes with maturities of up to 365 days at market interest rates. These issuances are supported by Consumers' revolving credit facilities and may have an aggregate principal amount outstanding of up to \$500 million. While the amount of outstanding commercial paper does not reduce the available capacity of the revolving credit facilities, Consumers does not intend to issue commercial paper in an amount exceeding the available capacity of the facilities. At June 30, 2025, there were no commercial paper notes outstanding under this program.

In December 2024, Consumers renewed a short-term credit agreement with CMS Energy, permitting Consumers to borrow up to \$500 million at an interest rate of the prior month's average one-month Term SOFR minus 0.100 percent. At June 30, 2025, there were no outstanding borrowings under the agreement.

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NorthStar Clean Energy's Supplier Financing Program: Under a supplier financing program, NorthStar Clean Energy agrees to pay a bank that is acting as its payment agent the stated amount of confirmed invoices from participating suppliers on the original maturity dates of the invoices. The bank is required to pay the supplier invoices that have been confirmed as valid under the program in full within 135 days of the invoice date. NorthStar Clean Energy does not provide collateral or a guarantee to the bank in support of its payment obligations under the agreement, nor does it pay a fee for the service. NorthStar Clean Energy or the bank may terminate the supplier financing program agreement upon 30 days prior written notice to the other party. At June 30, 2025, obligations under this program accounted for as accounts payable on CMS Energy's consolidated balance sheets were \$43 million.

Dividend Restrictions: At June 30, 2025, payment of dividends by CMS Energy on its common stock was limited to \$8.2 billion under provisions of the Michigan Business Corporation Act of 1972.

Under the provisions of its articles of incorporation, at June 30, 2025, Consumers had \$2.4 billion of unrestricted retained earnings available to pay dividends on its common stock to CMS Energy. Provisions of the Federal Power Act and the Natural Gas Act appear to restrict dividends payable by Consumers to the amount of Consumers' retained earnings. Several decisions from FERC suggest that, under a variety of circumstances, dividends from Consumers on its common stock would not be limited to amounts in Consumers' retained earnings. Any decision by Consumers to pay dividends on its common stock in excess of retained earnings would be based on specific facts and circumstances and would be subject to a formal regulatory filing process.

During the six months ended June 30, 2025, Consumers paid \$416 million in dividends on its common stock to CMS Energy.

Issuance of Common Stock: In 2023, CMS Energy entered into an equity offering program under which it may sell shares of its common stock having an aggregate sales price of up to \$1 billion in privately negotiated transactions, in "at the market" offerings, or through forward sales transactions.

Presented in the following table are details of CMS Energy's forward sales contracts under its current equity offering program at June 30, 2025:

Contract Date	Maturity Date	Number of Shares	Forward Price Per Share	
			Initial	June 30, 2025
December 16, 2024	November 27, 2025	400,581	\$ 69.43	\$ 69.76
February 25, 2025	May 11, 2026	757,686	70.11	70.48
March 14, 2025	June 15, 2026	551,166	72.99	73.25
June 13, 2025	April 28, 2026	1,094,643	71.70	71.80
June 16, 2025	September 16, 2026	2,150,000	69.30	69.39

Under these contracts, CMS Energy may either settle physically by issuing shares of its common stock at the then-applicable forward sale price specified by the agreement or settle net by delivering or receiving cash or shares. CMS Energy may settle the contracts at any time through their maturity dates, and presently intends to physically settle the contracts by delivering shares of its common stock.

The initial forward price in the forward equity sale contracts includes a deduction for commissions and will be adjusted on a daily basis over the term based on an interest rate factor and decreased on certain dates by certain predetermined amounts to reflect expected dividend payments. No amounts are recorded on CMS Energy's consolidated balance sheets until settlements of the forward equity sale contracts occur. If CMS Energy had elected to net share settle or net cash settle the contracts as of June 30, 2025, it would not have been required to deliver shares or pay cash.

4: Fair Value Measurements

Accounting standards define fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. When measuring fair value, CMS Energy and Consumers are required to incorporate all assumptions that market participants would use in pricing an asset or liability, including assumptions about risk. A fair value hierarchy prioritizes inputs used to measure fair value according to their observability in the market. The three levels of the fair value hierarchy are as follows:

- Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities.
- Level 2 inputs are observable, market-based inputs, other than Level 1 prices. Level 2 inputs may include quoted prices for similar assets or liabilities in active markets, quoted prices in inactive markets, and inputs derived from or corroborated by observable market data.
- Level 3 inputs are unobservable inputs that reflect CMS Energy's or Consumers' own assumptions about how market participants would value their assets and liabilities.

CMS Energy and Consumers classify fair value measurements within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement in its entirety.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Presented in the following table are CMS Energy's and Consumers' assets and liabilities recorded at fair value on a recurring basis:

	<i>In Millions</i>			
	CMS Energy, including Consumers		Consumers	
	June 30 2025	December 31 2024	June 30 2025	December 31 2024
<i>Assets¹</i>				
Cash equivalents	\$ 87	\$ 27	\$ —	\$ —
Restricted cash equivalents	81	75	81	75
Nonqualified deferred compensation plan assets	34	34	26	25
Derivative instruments	4	2	4	2
Total assets	\$ 206	\$ 138	\$ 111	\$ 102
<i>Liabilities¹</i>				
Nonqualified deferred compensation plan liabilities	\$ 34	\$ 34	\$ 26	\$ 25
Derivative instruments	4	—	—	—
Total liabilities	\$ 38	\$ 34	\$ 26	\$ 25

¹ All assets and liabilities were classified as Level 1 with the exception of derivative contracts, which were classified as Level 2 and 3.

Cash Equivalents: Cash equivalents and restricted cash equivalents consist of money market funds with daily liquidity.

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Nonqualified Deferred Compensation Plan Assets and Liabilities: The nonqualified deferred compensation plan assets consist of mutual funds, which are bought and sold only at the discretion of plan participants. The assets are valued using the daily quoted net asset values. CMS Energy and Consumers value their nonqualified deferred compensation plan liabilities based on the fair values of the plan assets, as they reflect the amount owed to the plan participants in accordance with their investment elections. CMS Energy and Consumers report the assets in other non-current assets and the liabilities in other non-current liabilities on their consolidated balance sheets.

Derivative Instruments: CMS Energy and Consumers value their derivative instruments using either a market approach that incorporates information from market transactions, or an income approach that discounts future expected cash flows to a present value amount. CMS Energy's and Consumers' derivatives are classified as Level 2 and 3.

The derivatives classified as Level 2 are interest rate swaps at NorthStar Clean Energy, which are valued using market-based inputs.

In February 2025, a subsidiary of NorthStar Clean Energy entered into floating-to-fixed interest rate swaps to reduce the impact of interest rate fluctuations associated with interest payments on certain future long-term variable-rate debt. The interest rate swaps economically hedge the future variability of interest payments on debt with a notional amount of \$109 million. Gains or losses on these swaps are reported in other expense on CMS Energy's consolidated statements of income. The amount recorded in other expense was \$1 million for the three months ended June 30, 2025 and \$4 million for the six months ended June 30, 2025. The fair value of these swaps recorded in other non-current liabilities on CMS Energy's consolidated balance sheets totaled \$4 million at June 30, 2025.

The majority of derivatives classified as Level 3 are FTRs held by Consumers. Due to the lack of quoted pricing information, Consumers determines the fair value of its FTRs based on Consumers' average historical settlements. Consumers reports derivatives associated with FTRs in other current assets on its consolidated balance sheets. There was no material activity within the Level 3 category of derivatives during the periods presented.

5: Financial Instruments

Presented in the following table are the carrying amounts and fair values, by level within the fair value hierarchy, of CMS Energy's and Consumers' financial instruments that are not recorded at fair value. The table excludes cash, cash equivalents, short-term financial instruments, and trade accounts receivable and payable whose carrying amounts approximate their fair values. For information about assets and liabilities recorded at fair value and for additional details regarding the fair value hierarchy, see Note 4, Fair Value Measurements.

<i>In Millions</i>															
	June 30, 2025									December 31, 2024					
	Carrying Amount	Total	Fair Value				Carrying Amount	Total	Fair Value						
			Level	1	2	3			Level	1	2	3			
CMS Energy, including Consumers															
<i>Assets</i>															
Long-term receivables ¹	\$ 7	\$ 7	\$ —	\$ —	\$ 7	\$ 9	\$ 8	\$ —	\$ —	\$ 8					
<i>Liabilities</i>															
Long-term debt ²	17,901	16,678	1,981	12,768	1,929	16,386	14,876	1,018	11,952	1,906					
Long-term payables ³	8	8	—	—	8	9	9	—	—	9					
Consumers															
<i>Assets</i>															
Long-term receivables ¹	\$ 7	\$ 7	\$ —	\$ —	\$ 7	\$ 9	\$ 8	\$ —	\$ —	\$ 8					
Notes receivable – related party ⁴	92	92	—	—	92	94	94	—	—	94					
<i>Liabilities</i>															
Long-term debt ⁵	12,151	11,067	—	9,138	1,929	11,270	9,940	—	8,034	1,906					
Long-term debt – related party ⁶	1,004	662	—	662	—	823	549	—	549	—					
Long-term payables	3	3	—	—	3	4	4	—	—	4					

¹ Includes current portion of long-term accounts receivable and notes receivable of \$3 million at June 30, 2025 and \$4 million at December 31, 2024.

² Includes current portion of long-term debt of \$1.1 billion at June 30, 2025 and \$1.2 billion at December 31, 2024.

³ Includes current portion of long-term payables of \$1 million at June 30, 2025 and \$2 million at December 31, 2024.

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- ⁴ Includes current portion of notes receivable – related party of \$7 million at June 30, 2025 and December 31, 2024.
- ⁵ Includes current portion of long-term debt of \$570 million at June 30, 2025 and \$452 million at December 31, 2024.
- ⁶ For more information on CMS Energy’s repurchases of Consumers’ first mortgage bonds, see Note 3, Financings and Capitalization—CMS Energy’s Purchase of Consumers’ First Mortgage Bonds.

Notes receivable – related party represents Consumers’ portion of the DB SERP demand note payable issued by CMS Energy to the DB SERP rabbi trust. The demand note bears interest at an annual rate of 4.10 percent and has a maturity date of 2028.

6: Retirement Benefits

CMS Energy and Consumers provide pension, OPEB, and other retirement benefits to eligible employees under a number of different plans.

Costs: Presented in the following table are the costs (credits) and other changes in plan assets and benefit obligations incurred in CMS Energy’s and Consumers’ retirement benefit plans:

<i>In Millions</i>									
June 30	DB Pension Plans				OPEB Plan				
	Three Months Ended		Six Months Ended		Three Months Ended		Six Months Ended		
	2025	2024	2025	2024	2025	2024	2025	2024	
CMS Energy, including Consumers									
<i>Net periodic credit</i>									
Service cost	\$ 7	\$ 7	\$ 13	\$ 14	\$ 2	\$ 3	\$ 4	\$ 6	
Interest cost	27	26	54	52	11	11	22	22	
Expected return on plan assets	(57)	(59)	(114)	(118)	(28)	(29)	(56)	(58)	
<i>Amortization of:</i>									
Net loss	2	3	5	6	1	1	2	2	
Prior service cost (credit)	1	1	2	2	(8)	(8)	(17)	(16)	
Settlement loss	2	2	5	5	—	—	—	—	
Net periodic credit	\$ (18)	\$ (20)	\$ (35)	\$ (39)	\$ (22)	\$ (22)	\$ (45)	\$ (44)	
Consumers									
<i>Net periodic credit</i>									
Service cost	\$ 6	\$ 6	\$ 12	\$ 13	\$ 2	\$ 3	\$ 4	\$ 6	
Interest cost	25	25	51	49	11	10	21	20	
Expected return on plan assets	(54)	(55)	(108)	(110)	(26)	(27)	(52)	(54)	
<i>Amortization of:</i>									
Net loss	3	2	5	5	1	1	2	2	
Prior service cost (credit)	1	1	2	2	(9)	(8)	(17)	(15)	
Settlement loss	2	2	5	5	—	—	—	—	
Net periodic credit	\$ (17)	\$ (19)	\$ (33)	\$ (36)	\$ (21)	\$ (21)	\$ (42)	\$ (41)	

In Consumers’ electric and gas rate cases, the MPSC approved a mechanism allowing Consumers to defer for future recovery or refund pension and OPEB expenses above or below the amounts used to set

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existing rates. Amounts deferred will be collected from or refunded to customers over ten years. At June 30, 2025, CMS Energy, including Consumers, had deferred less than \$1 million of pension credits and \$5 million of OPEB credits under this mechanism related to 2025 expense. At June 30, 2024, CMS Energy, including Consumers, had deferred \$9 million of pension credits and \$4 million of OPEB credits under this mechanism related to 2024 expense.

7: Income Taxes

Presented in the following table is a reconciliation of the statutory U.S. federal income tax rate to the effective income tax rate from continuing operations:

Six Months Ended June 30	2025	2024
CMS Energy, including Consumers		
U.S. federal income tax rate	21.0 %	21.0 %
<i>Increase (decrease) in income taxes from:</i>		
State and local income taxes, net of federal effect ¹	7.4	5.3
Renewable energy tax credits	(5.8)	(5.7)
TCJA excess deferred taxes	(3.5)	(3.6)
Taxes attributable to noncontrolling interests	1.3	1.0
Other, net	—	0.2
Effective tax rate	20.4 %	18.2 %
Consumers		
U.S. federal income tax rate	21.0 %	21.0 %
<i>Increase (decrease) in income taxes from:</i>		
State and local income taxes, net of federal effect ¹	6.7	4.8
Renewable energy tax credits	(3.5)	(3.8)
TCJA excess deferred taxes	(2.9)	(3.2)
Other, net	(0.3)	—
Effective tax rate	21.0 %	18.8 %

¹ In June 2025, state deferred tax balances were increased by \$12 million to reflect a change in Illinois tax policy that establishes nexus for Consumers. The policy change is effective for tax years beginning January 1, 2026.

State Income Tax Claim: In February 2025, CMS Energy received an adverse ruling from the Michigan Tax Tribunal in regards to the methodology of state apportionment for Consumers' electricity sales to MISO. In March 2025, CMS Energy filed an appeal with the Michigan Court of Appeals and a final decision is not expected until 2026. CMS Energy and Consumers have evaluated and concluded their uncertain tax positions associated with this matter to be sufficient as of June 30, 2025. While CMS Energy and Consumers expect the appeal to prevail, if it were to fail, the companies would be required to revise the estimated value of their state deferred tax liabilities, which could result in a material impact to their results of operations.

Tax Legislation: CMS Energy and Consumers are subject to changing tax laws. In July 2025, President Trump signed into law the OBBBA. The legislation allows for the immediate expensing of domestic research and development costs and includes changes to clean energy tax credits enacted by the Inflation Reduction Act of 2022. While the OBBBA restores, and makes permanent, the 100-percent bonus depreciation deduction, it also retains a provision that allows utilities to take a full deduction of interest expense in lieu of 100-percent bonus depreciation. CMS Energy and Consumers are still

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evaluating the potential impacts of the OBBBA and related executive actions; however, CMS Energy and Consumers do not anticipate a material impact on their respective financial statements.

8: Earnings Per Share—CMS Energy

Presented in the following table are CMS Energy's basic and diluted EPS computations based on income from continuing operations:

June 30	<i>In Millions, Except Per Share Amounts</i>			
	Three Months Ended		Six Months Ended	
	2025	2024	2025	2024
<i>Income available to common stockholders</i>				
Income from continuing operations	\$ 193	\$ 182	\$ 488	\$ 445
Less loss attributable to noncontrolling interests	(8)	(16)	(17)	(40)
Less preferred stock dividends	3	3	5	5
Income from continuing operations available to common stockholders – basic and diluted	\$ 198	\$ 195	\$ 500	\$ 480
<i>Average common shares outstanding</i>				
Weighted-average shares – basic	298.5	297.9	298.4	297.2
Add dilutive nonvested stock awards	0.6	0.6	0.6	0.7
Weighted-average shares – diluted	299.1	298.5	299.0	297.9
<i>Income from continuing operations per average common share available to common stockholders</i>				
Basic	\$ 0.67	\$ 0.65	\$ 1.68	\$ 1.61
Diluted	0.66	0.65	1.67	1.61

Nonvested Stock Awards

CMS Energy's nonvested stock awards are composed of participating and non-participating securities. The participating securities accrue cash dividends when common stockholders receive dividends. Since the recipient is not required to return the dividends to CMS Energy if the recipient forfeits the award, the nonvested stock awards are considered participating securities. As such, the participating nonvested stock awards were included in the computation of basic EPS. The non-participating securities accrue stock dividends that vest concurrently with the stock award. If the recipient forfeits the award, the stock dividends accrued on the non-participating securities are also forfeited. Accordingly, the non-participating awards and stock dividends were included in the computation of diluted EPS, but not in the computation of basic EPS.

Forward Equity Sale Contracts

CMS Energy has entered into forward equity sale contracts. These forward equity sale contracts are non-participating securities. While the forward sale price in the forward equity sale contract is decreased on certain dates by certain predetermined amounts to reflect expected dividend payments, these price adjustments were set upon inception of the agreement and the forward contract does not give the owner the right to participate in undistributed earnings. Accordingly, the forward equity sale contracts were included in the computation of diluted EPS, but not in the computation of basic EPS. The impact to diluted EPS was de minimis.

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The potentially dilutive impact from these forward equity sale contracts is reflected in diluted EPS using the treasury stock method. There will be a dilutive effect on EPS when the average market price of common stock shares is above the applicable adjusted forward sale price. Additionally, any physical settlement or net share settlement of the agreements would dilute EPS. For further details on the forward equity sale contracts, see Note 3, Financings and Capitalization.

Convertible Securities

In 2023, CMS Energy issued convertible senior notes. Potentially dilutive common shares issuable upon conversion of the convertible senior notes are determined using the if-converted method for calculating diluted EPS. Upon conversion, the convertible senior notes are required to be paid in cash with only amounts exceeding the principal permitted to be settled in shares. Accordingly, the convertible senior notes were included in the computation of diluted EPS, but not in the computation of basic EPS. The impact to diluted EPS was de minimis.

9: Revenue

Presented in the following tables are the components of operating revenue:

	<i>In Millions</i>				
Three Months Ended June 30, 2025	Electric Utility	Gas Utility	NorthStar Clean Energy ¹	Consolidated	
CMS Energy, including Consumers					
Consumers utility revenue	\$ 1,355	\$ 385	\$ —	\$ 1,740	
Other	—	—	58	58	
Revenue recognized from contracts with customers	\$ 1,355	\$ 385	\$ 58	\$ 1,798	
Leasing income	—	—	34	34	
Financing income	2	2	—	4	
Consumers alternative-revenue programs	2	—	—	2	
Total operating revenue – CMS Energy	\$ 1,359	\$ 387	\$ 92	\$ 1,838	
Consumers					
<i>Consumers utility revenue</i>					
Residential	\$ 619	\$ 276		\$ 895	
Commercial	473	90		563	
Industrial	199	10		209	
Other	64	9		73	
Revenue recognized from contracts with customers	\$ 1,355	\$ 385		\$ 1,740	
Financing income	2	2		4	
Alternative-revenue programs	2	—		2	
Total operating revenue – Consumers	\$ 1,359	\$ 387		\$ 1,746	

¹ Amounts represent NorthStar Clean Energy's operating revenue from independent power production and its sales of energy commodities. Certain of NorthStar Clean Energy's power sales agreements are accounted for as operating leases. In addition to fixed payments, these agreements have variable payments based on energy delivered. NorthStar Clean Energy's leasing income included variable lease payments of \$23 million for the three months ended June 30, 2025.

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Three Months Ended June 30, 2024	Electric Utility	Gas Utility	NorthStar Clean Energy ¹	Consolidated
CMS Energy, including Consumers				
Consumers utility revenue	\$ 1,221	\$ 305	\$ —	\$ 1,526
Other	—	—	50	50
Revenue recognized from contracts with customers	\$ 1,221	\$ 305	\$ 50	\$ 1,576
Leasing income	—	—	24	24
Financing income	2	2	—	4
Consumers alternative-revenue programs	3	—	—	3
Total operating revenue – CMS Energy	\$ 1,226	\$ 307	\$ 74	\$ 1,607
Consumers				
<i>Consumers utility revenue</i>				
Residential	\$ 547	\$ 206		\$ 753
Commercial	433	64		497
Industrial	174	8		182
Other	67	27		94
Revenue recognized from contracts with customers	\$ 1,221	\$ 305		\$ 1,526
Financing income	2	2		4
Alternative-revenue programs	3	—		3
Total operating revenue – Consumers	\$ 1,226	\$ 307		\$ 1,533

¹ Amounts represent NorthStar Clean Energy's operating revenue from independent power production and its sales of energy commodities. Certain of NorthStar Clean Energy's power sales agreements are accounted for as operating leases. In addition to fixed payments, these agreements have variable payments based on energy delivered. NorthStar Clean Energy's leasing income included variable lease payments of \$13 million for the three months ended June 30, 2024.

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Six Months Ended June 30, 2025	Electric Utility	Gas Utility	NorthStar Clean Energy ¹	Consolidated
CMS Energy, including Consumers				
Consumers utility revenue	\$ 2,649	\$ 1,432	\$ —	\$ 4,081
Other	—	—	115	115
Revenue recognized from contracts with customers	\$ 2,649	\$ 1,432	\$ 115	\$ 4,196
Leasing income	—	—	76	76
Financing income	5	4	—	9
Consumers alternative-revenue programs	4	—	—	4
Total operating revenue – CMS Energy	\$ 2,658	\$ 1,436	\$ 191	\$ 4,285
Consumers				
<i>Consumers utility revenue</i>				
Residential	\$ 1,213	\$ 1,007		\$ 2,220
Commercial	891	329		1,220
Industrial	372	40		412
Other	173	56		229
Revenue recognized from contracts with customers	\$ 2,649	\$ 1,432		\$ 4,081
Financing income	5	4		9
Alternative-revenue programs	4	—		4
Total operating revenue – Consumers	\$ 2,658	\$ 1,436		\$ 4,094

¹ Amounts represent NorthStar Clean Energy's operating revenue from independent power production and its sales of energy commodities. Certain of NorthStar Clean Energy's power sales agreements are accounted for as operating leases. In addition to fixed payments, these agreements have variable payments based on energy delivered. NorthStar Clean Energy's leasing income included variable lease payments of \$54 million for the six months ended June 30, 2025.

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Six Months Ended June 30, 2024	Electric Utility	Gas Utility	NorthStar Clean Energy ¹	Consolidated
CMS Energy, including Consumers				
Consumers utility revenue	\$ 2,350	\$ 1,268	\$ —	\$ 3,618
Other	—	—	102	102
Revenue recognized from contracts with customers	\$ 2,350	\$ 1,268	\$ 102	\$ 3,720
Leasing income	—	—	51	51
Financing income	4	4	—	8
Consumers alternative-revenue programs	4	—	—	4
Total operating revenue – CMS Energy	\$ 2,358	\$ 1,272	\$ 153	\$ 3,783
Consumers				
<i>Consumers utility revenue</i>				
Residential	\$ 1,072	\$ 871		\$ 1,943
Commercial	793	271		1,064
Industrial	330	32		362
Other	155	94		249
Revenue recognized from contracts with customers	\$ 2,350	\$ 1,268		\$ 3,618
Financing income	4	4		8
Alternative-revenue programs	4	—		4
Total operating revenue – Consumers	\$ 2,358	\$ 1,272		\$ 3,630

¹ Amounts represent NorthStar Clean Energy's operating revenue from independent power production and its sales of energy commodities. Certain of NorthStar Clean Energy's power sales agreements are accounted for as operating leases. In addition to fixed payments, these agreements have variable payments based on energy delivered. NorthStar Clean Energy's leasing income included variable lease payments of \$29 million for the six months ended June 30, 2024.

Electric and Gas Utilities

Consumers Utility Revenue: Consumers recognizes revenue primarily from the sale of electric and gas utility services at tariff-based rates regulated by the MPSC. Consumers' customer base consists of a mix of residential, commercial, and diversified industrial customers. Consumers' tariff-based sales performance obligations are described below.

- Consumers has performance obligations for the service of standing ready to deliver electricity or natural gas to customers, and it satisfies these performance obligations over time. Consumers recognizes revenue at a fixed rate as it provides these services. These arrangements generally do not have fixed terms and remain in effect as long as the customer consumes the utility service. The rates are set by the MPSC through the rate-making process and represent the stand-alone selling price of Consumers' service to stand ready to deliver.
- Consumers has performance obligations for the service of delivering the commodity of electricity or natural gas to customers, and it satisfies these performance obligations upon delivery. Consumers recognizes revenue at a price per unit of electricity or natural gas delivered, based on the tariffs established by the MPSC. These arrangements generally do not have fixed terms and remain in effect as long as the customer consumes the utility service. The rates are set by the MPSC through the rate-making process and represent the stand-alone selling price of a bundled

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product comprising the commodity, electricity or natural gas, and the service of delivering such commodity.

In some instances, Consumers has specific fixed-term contracts with large commercial and industrial customers to provide electricity or gas at certain tariff rates or to provide gas transportation services at contracted rates. The amount of electricity and gas to be delivered under these contracts and the associated future revenue to be received are generally dependent on the customers' needs. Accordingly, Consumers recognizes revenues at the tariff or contracted rate as electricity or gas is delivered to the customer. Consumers also has other miscellaneous contracts with customers related to pole and other property rentals and utility contract work. Generally, these contracts are short term or evergreen in nature.

Accounts Receivable and Unbilled Revenues: Accounts receivable comprise trade receivables and unbilled receivables. CMS Energy and Consumers record their accounts receivable at cost less an allowance for uncollectible accounts. The allowance is increased for uncollectible accounts expense and decreased for account write-offs net of recoveries. CMS Energy and Consumers establish the allowance based on historical losses, management's assessment of existing economic conditions, customer payment trends, and reasonable and supported forecast information. CMS Energy and Consumers assess late payment fees on trade receivables based on contractual past-due terms established with customers. Accounts are written off when deemed uncollectible, which is generally when they become six months past due.

CMS Energy and Consumers recorded uncollectible accounts expense of \$8 million for the three months ended June 30, 2025 and \$7 million for the three months ended June 30, 2024. CMS Energy and Consumers recorded uncollectible accounts expense of \$20 million for the six months ended June 30, 2025 and \$17 million for the six months ended June 30, 2024.

Consumers' customers are billed monthly in cycles having billing dates that do not generally coincide with the end of a calendar month. This results in customers having received electricity or natural gas that they have not been billed for as of the month-end. Consumers estimates its unbilled revenues by applying an average billed rate to total unbilled deliveries for each customer class. Unbilled revenues, which are recorded as accounts receivable and accrued revenue on CMS Energy's and Consumers' consolidated balance sheets, were \$464 million at June 30, 2025 and \$584 million at December 31, 2024.

Alternative-revenue Program: Under a demand response incentive mechanism, Consumers earns a financial incentive when it meets demand response targets set by the MPSC. Consumers recognizes revenue related to this program once demand response incentive objectives are complete, the incentive amount is calculable, and the incentive revenue will be collected within a 24-month period.

Consumers also accounts for its financial compensation mechanism as an alternative-revenue program. Consumers recognizes revenue related to the financial compensation mechanism as payments are made on MPSC-approved PPAs.

Consumers does not reclassify revenue from its alternative-revenue program to revenue from contracts with customers at the time the amounts are collected from customers.

10: Reportable Segments

Reportable segments consist of business units defined by the products and services they offer. CMS Energy's and Consumers' chief operating decision-maker is the CEO. The chief operating decision-maker evaluates segment performance and profitability using net income available to CMS Energy's common stockholders. This metric provides a clear, consistent basis for analyzing the financial results of each segment and supports decision-making regarding the allocation of resources.

Resource allocation to CMS Energy's and Consumers' segments begins with the annual budgeting process, which establishes initial funding and resource levels for each segment. The budget incorporates key financial and operational inputs, including anticipated revenues, expenses, and capital requirements, aligning with CMS Energy's and Consumers' strategic objectives and regulatory obligations. The chief operating decision-maker reviews budget-to-actual variances on a monthly basis and makes interim decisions to reallocate resources among segments as needed, ensuring a timely and effective response to changing conditions. For the electric utility and gas utility segments, the chief operating decision-maker uses this assessment to determine whether the segments are achieving their regulatory authorized return on equity.

CMS Energy

The segments reported for CMS Energy are:

- electric utility, consisting of regulated activities associated with the generation, purchase, distribution, and sale of electricity in Michigan
- gas utility, consisting of regulated activities associated with the purchase, transmission, storage, distribution, and sale of natural gas in Michigan
- NorthStar Clean Energy, consisting of various subsidiaries engaging in domestic independent power production, including the development and operation of renewable generation, and the marketing of independent power production

CMS Energy presents corporate interest and other expenses, discontinued operations, and Consumers' other consolidated entities within other reconciling items.

Consumers

The segments reported for Consumers are:

- electric utility, consisting of regulated activities associated with the generation, purchase, distribution, and sale of electricity in Michigan
- gas utility, consisting of regulated activities associated with the purchase, transmission, storage, distribution, and sale of natural gas in Michigan

Consumers' other consolidated entities are presented within other reconciling items.

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Three Months Ended June 30, 2025	Electric Utility	Gas Utility	NorthStar Clean Energy	Segments Total	Other Reconciling Items	Consolidated
CMS Energy, including Consumers						
Operating revenue	\$ 1,359	\$ 387	\$ 92	\$ 1,838	\$ —	\$ 1,838
<i>Operating expenses</i>						
Power supply cost ¹	537	—	66	603	—	603
Cost of gas sold	—	123	1	124	—	124
Maintenance and other operating expenses	264	112	18	394	3	397
Depreciation and amortization	222	54	12	288	—	288
General taxes	73	33	3	109	—	109
Total operating expenses	1,096	322	100	1,518	3	1,521
Operating Income (Loss)	263	65	(8)	320	(3)	317
Other income	36	23	2	61	76	137
Interest charges	89	51	(1)	139	60	199
Income (Loss) Before Income Taxes	210	37	(5)	242	13	255
Income tax expense (benefit)	42	12	(18)	36	26	62
Income (Loss) From Continuing Operations	168	25	13	206	(13)	193
Other segment items ²	(1)	—	9	8	(3)	5
Net Income (Loss) Available to Common Stockholders	\$ 167	\$ 25	\$ 22	\$ 214	\$ (16)	\$ 198
Property, plant, and equipment, gross	\$ 20,761 ³	\$ 13,609 ³	\$ 1,562	\$ 35,932	\$ 30	\$ 35,962
Total assets	21,942 ³	13,388 ³	2,105	37,435	264	37,699

¹ Power supply costs comprise of fuel for electric generation, purchased and interchange power, and purchased power – related parties.

² Other segment items comprise of loss attributable to noncontrolling interests and preferred stock dividends.

³ Amounts include a portion of Consumers' other common assets attributable to both the electric and gas utility businesses.

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Three Months Ended June 30, 2025	Electric Utility	Gas Utility	Segments Total	Other Reconciling Items	Consolidated
Consumers					
Operating revenue	\$ 1,359	\$ 387	\$ 1,746	\$ —	\$ 1,746
<i>Operating expenses</i>					
Power supply cost ¹	537	—	537	—	537
Cost of gas sold	—	123	123	—	123
Maintenance and other operating expenses	264	112	376	—	376
Depreciation and amortization	222	54	276	—	276
General taxes	73	33	106	—	106
Total operating expenses	1,096	322	1,418	—	1,418
Operating Income	263	65	328	—	328
Other income	36	23	59	1	60
Interest charges	89	51	140	1	141
Income Before Income Taxes	210	37	247	—	247
Income tax expense	42	12	54	5	59
Net Income (Loss)	168	25	193	(5)	188
Other segment items ²	(1)	—	(1)	—	(1)
Net Income (Loss) Available to Common Stockholder	\$ 167	\$ 25	\$ 192	\$ (5)	\$ 187
Property, plant, and equipment, gross	\$ 20,761 ³	\$ 13,609 ³	\$ 34,370	\$ 36	\$ 34,406
Total assets	21,997 ³	13,430 ³	35,427	40	35,467

¹ Power supply costs comprise of fuel for electric generation, purchased and interchange power, and purchased power – related parties.

² Other segment items comprise of preferred stock dividends.

³ Amounts include a portion of Consumers' other common assets attributable to both the electric and gas utility businesses.

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Three Months Ended June 30, 2024	Electric Utility	Gas Utility	NorthStar Clean Energy	Segments Total	Other Reconciling Items	Consolidated
CMS Energy, including Consumers						
Operating revenue	\$ 1,226	\$ 307	\$ 74	\$ 1,607	\$ —	\$ 1,607
<i>Operating expenses</i>						
Power supply cost ¹	444	—	35	479	—	479
Cost of gas sold	—	66	—	66	—	66
Maintenance and other operating expenses	261	116	24	401	3	404
Depreciation and amortization	209	51	13	273	—	273
General taxes	68	31	3	102	—	102
Total operating expenses	982	264	75	1,321	3	1,324
Operating Income (Loss)	244	43	(1)	286	(3)	283
Other income	36	23	2	61	52	113
Interest charges	79	46	—	125	48	173
Income Before Income Taxes	201	20	1	222	1	223
Income tax expense	30	5	2	37	4	41
Income (Loss) From Continuing Operations	171	15	(1)	185	(3)	182
Other segment items ²	(1)	—	17	16	(3)	13
Net Income (Loss) Available to Common Stockholders	\$ 170	\$ 15	\$ 16	\$ 201	\$ (6)	\$ 195
Property, plant, and equipment, gross	\$ 19,557 ³	\$ 12,638 ³	\$ 1,464	\$ 33,659	\$ 21	\$ 33,680
Total assets	20,122 ³	12,469 ³	1,659	34,250	105	34,355

¹ Power supply costs comprise of fuel for electric generation, purchased and interchange power, and purchased power – related parties.

² Other segment items comprise of income from discontinued operations, net of tax, loss attributable to noncontrolling interests, and preferred stock dividends.

³ Amounts include a portion of Consumers' other common assets attributable to both the electric and gas utility businesses.

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Three Months Ended June 30, 2024	Electric Utility		Gas Utility Segments Total		Other Reconciling Items	Consolidated
Consumers						
Operating revenue	\$ 1,226	\$ 307	\$ 1,533	\$ —	\$ 1,533	
<i>Operating expenses</i>						
Power supply cost ¹	444	—	444	—	444	
Cost of gas sold	—	66	66	—	66	
Maintenance and other operating expenses	261	116	377	—	377	
Depreciation and amortization	209	51	260	1	261	
General taxes	68	31	99	—	99	
Total operating expenses	982	264	1,246	1	1,247	
Operating Income (Loss)	244	43	287	(1)	286	
Other income	36	23	59	—	59	
Interest charges	79	46	125	1	126	
Income (Loss) Before Income Taxes	201	20	221	(2)	219	
Income tax expense	30	5	35	6	41	
Net Income (Loss)	171	15	186	(8)	178	
Other segment items ²	(1)	—	(1)	—	(1)	
Net Income (Loss) Available to Common Stockholder	\$ 170	\$ 15	\$ 185	\$ (8)	\$ 177	
Property, plant, and equipment, gross	\$ 19,557	\$ 12,638	\$ 32,195	\$ 29	\$ 32,224	
Total assets	20,180	12,512	32,692	26	32,718	

¹ Power supply costs comprise of fuel for electric generation, purchased and interchange power, and purchased power – related parties.

² Other segment items comprise of preferred stock dividends.

³ Amounts include a portion of Consumers' other common assets attributable to both the electric and gas utility businesses.

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Presented in the following tables is financial information by segment:

<i>In Millions</i>												
Six Months Ended June 30, 2025	Electric Utility		Gas Utility	NorthStar Clean Energy Segments Total		Other Reconciling Items		Consolidated				
CMS Energy, including Consumers												
Operating revenue	\$	2,658	\$	1,436	\$	191	\$	4,285	\$	—	\$	4,285
<i>Operating expenses</i>												
Power supply cost ¹		1,083		—		135		1,218		—		1,218
Cost of gas sold		—		505		2		507		—		507
Maintenance and other operating expenses		521		228		48		797		5		802
Depreciation and amortization		443		208		25		676		—		676
General taxes		146		119		6		271		—		271
Total operating expenses		2,193		1,060		216		3,469		5		3,474
Operating Income (Loss)		465		376		(25)		816		(5)		811
Other income		63		42		3		108		79		187
Interest charges		171		99		(1)		269		116		385
Income (Loss) Before Income Taxes		357		319		(21)		655		(42)		613
Income tax expense (benefit)		65		81		(7)		139		(14)		125
Income (Loss) From Continuing Operations		292		238		(14)		516		(28)		488
Other segment items ²		(1)		—		18		17		(5)		12
Net Income (Loss) Available to Common Stockholders	\$	291	\$	238	\$	4	\$	533	\$	(33)	\$	500

¹ Power supply costs comprise of fuel for electric generation, purchased and interchange power, and purchased power – related parties.

² Other segment items comprise of loss attributable to noncontrolling interests and preferred stock dividends.

[Table of Contents](#)*In Millions*

Six Months Ended June 30, 2025	Electric Utility	Gas Utility	Segments Total	Other Reconciling Items	Consolidated
Consumers					
Operating revenue	\$ 2,658	\$ 1,436	\$ 4,094	\$ —	\$ 4,094
<i>Operating expenses</i>					
Power supply cost ¹	1,083	—	1,083	—	1,083
Cost of gas sold	—	505	505	—	505
Maintenance and other operating expenses	521	228	749	—	749
Depreciation and amortization	443	208	651	—	651
General taxes	146	119	265	—	265
Total operating expenses	2,193	1,060	3,253	—	3,253
Operating Income	465	376	841	—	841
Other income	63	42	105	1	106
Interest charges	171	99	270	1	271
Income Before Income Taxes	357	319	676	—	676
Income tax expense (benefit)	65	81	146	(4)	142
Net Income	292	238	530	4	534
Other segment items ²	(1)	—	(1)	—	(1)
Net Income Available to Common Stockholder	\$ 291	\$ 238	\$ 529	\$ 4	\$ 533

¹ Power supply costs comprise of fuel for electric generation, purchased and interchange power, and purchased power – related parties.

² Other segment items comprise of preferred stock dividends.

[Table of Contents](#)*In Millions*

Six Months Ended June 30, 2024	Electric Utility	Gas Utility	NorthStar Clean Energy	Segments	Total	Other Reconciling Items	Consolidated
CMS Energy, including Consumers							
Operating revenue	\$ 2,358	\$ 1,272	\$ 153	\$ 3,783	\$ —	\$ 3,783	
<i>Operating expenses</i>							
Power supply cost ¹	893	—	74	967	—	967	
Cost of gas sold	—	416	1	417	—	417	
Maintenance and other operating expenses	499	256	46	801	5	806	
Depreciation and amortization	422	194	24	640	1	641	
General taxes	139	112	6	257	—	257	
Total operating expenses	1,953	978	151	3,082	6	3,088	
Operating Income (Loss)	405	294	2	701	(6)	695	
Other income	70	45	8	123	76	199	
Interest charges	160	94	1	255	95	350	
Income (Loss) Before Income Taxes	315	245	9	569	(25)	544	
Income tax expense (benefit)	47	61	3	111	(12)	99	
Income (Loss) From Continuing Operations	268	184	6	458	(13)	445	
Other segment items ²	(1)	—	41	40	(5)	35	
Net Income (Loss) Available to Common Stockholders	\$ 267	\$ 184	\$ 47	\$ 498	\$ (18)	\$ 480	

¹ Power supply costs comprise of fuel for electric generation, purchased and interchange power, and purchased power – related parties.

² Other segment items comprise of loss attributable to noncontrolling interests and preferred stock dividends.

[Table of Contents](#)*In Millions*

Six Months Ended June 30, 2024	Electric Utility		Gas Utility Segments Total		Other Reconciling Items		Consolidated			
Consumers										
Operating revenue	\$	2,358	\$	1,272	\$	3,630	\$	—	\$	3,630
<i>Operating expenses</i>										
Power supply cost ¹		893		—		893		—		893
Cost of gas sold		—		416		416		—		416
Maintenance and other operating expenses		499		256		755		—		755
Depreciation and amortization		422		194		616		1		617
General taxes		139		112		251		—		251
Total operating expenses		1,953		978		2,931		1		2,932
Operating Income (Loss)		405		294		699		(1)		698
Other income		70		45		115		—		115
Interest charges		160		94		254		1		255
Income (Loss) Before Income Taxes		315		245		560		(2)		558
Income tax expense (benefit)		47		61		108		(3)		105
Net Income		268		184		452		1		453
Other segment items ²		(1)		—		(1)		—		(1)
Net Income Available to Common Stockholder	\$	267	\$	184	\$	451	\$	1	\$	452

¹ Power supply costs comprise of fuel for electric generation, purchased and interchange power, and purchased power – related parties.

² Other segment items comprise of preferred stock dividends.

11: Variable Interest Entities

Consolidated VIEs: In March 2025, NorthStar Clean Energy sold a 50-percent interest in NWO Wind Equity Holdings for net proceeds of \$36 million. NWO Wind Equity Holdings holds the Class B membership interest in NWO Holdco, the holding company of a 100-MW wind project located in Paulding County, Ohio. Additionally in March 2025, NorthStar Clean Energy sold a 50-percent interest in Delta Solar Equity Holdings for net proceeds of \$8 million. Delta Solar Equity Holdings is the holding company of a 24-MW solar project located in Delta Township, Michigan.

NorthStar Clean Energy consolidates these and other entities that it does not wholly own, but for which it manages and controls the entities' operating activities. NorthStar Clean Energy is the primary beneficiary of these entities because it has the power to direct the activities that most significantly impact the economic performance of the companies, as well as the obligation to absorb losses or the right to receive

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benefits from the companies. Presented in the following table is information about the VIEs NorthStar Clean Energy consolidates:

Consolidated VIE	NorthStar Clean Energy's ownership interest	Description of VIE
Aviator Wind Equity Holdings	51-percent ownership interest ¹	Holds a Class B membership interest in Aviator Wind Holding company of a 525-MW wind generation project in Coke County, Texas
Aviator Wind	Class B membership interest ²	Holding company of a 24-MW solar generation project in Delta Township, Michigan
Delta Solar Equity Holdings	50-percent ownership interest ¹	Holding company of a 180-MW solar generation project in Jackson County, Arkansas
Newport Solar Holdings	Class B membership interest ²	Holds a Class B membership interest in NWO Holdco Holding company of a 100-MW wind generation project in Paulding County, Ohio
NWO Wind Equity Holdings	50-percent ownership interest ¹	
NWO Holdco	Class B membership interest ²	

¹ The remaining ownership interest is presented as noncontrolling interest on CMS Energy's consolidated balance sheets.

² The Class A membership interest in the entity is held by a tax equity investor and is presented as noncontrolling interest on CMS Energy's consolidated balance sheets. Under the associated limited liability company agreement, the tax equity investor is guaranteed preferred returns from the entity.

Earnings, tax attributes, and cash flows generated by the entities in which NorthStar Clean Energy holds a Class B membership are allocated among and distributed to the membership classes in accordance with the ratios specified in the associated limited liability company agreements; these ratios change over time and are not representative of the ownership interest percentages of each membership class. Since these entities' income and cash flows are not distributed among their investors based on ownership interest percentages, NorthStar Clean Energy allocates the entities' income (loss) among the investors by applying the hypothetical liquidation at book value method. This method calculates each investor's earnings based on a hypothetical liquidation of the entities at the net book value of underlying assets as of the balance sheet date. The liquidation tax gain (loss) is allocated to each investor's capital account, resulting in income (loss) equal to the period change in the investor's capital account balance.

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Presented in the following table are the carrying values of the VIEs' assets and liabilities included on CMS Energy's consolidated balance sheets:

	<i>In Millions</i>	
	June 30, 2025	December 31, 2024
<i>Current</i>		
Cash and cash equivalents	\$ 16	\$ 18
Accounts receivable	7	4
Prepayments and other current assets	4	3
<i>Non-current</i>		
Plant, property, and equipment, net	993	1,024
Other non-current assets	6	3
Total assets ¹	\$ 1,026	\$ 1,052
<i>Current</i>		
Accounts payable	\$ 10	\$ 8
Accrued taxes	1	—
<i>Non-current</i>		
Non-current portion of finance leases	23	23
Asset retirement obligations	34	33
Other non-current liabilities	3	—
Total liabilities	\$ 71	\$ 64

¹ Assets may be used only to meet VIEs' obligations and commitments.

NorthStar Clean Energy is obligated under certain indemnities that protect the tax equity investors against losses incurred as a result of breaches of representations and warranties under the associated limited liability company agreements. For additional details on these indemnity obligations, see Note 2, Contingencies and Commitments—Guarantees.

Consumers' wholly-owned subsidiaries, Consumers 2014 Securitization Funding and Consumers 2023 Securitization Funding, are VIEs designed to collateralize Consumers' securitization bonds. These entities are considered VIEs primarily because their equity capitalization is insufficient to support their operations. Consumers is the primary beneficiary of and consolidates these VIEs, as it has the power to direct the activities that most significantly impact the economic performance of the companies, as well as the obligation to absorb losses or the right to receive benefits from the companies. The VIEs' primary assets and liabilities comprise non-current regulatory assets and long-term debt. The carrying value of the regulatory assets on Consumers' consolidated balance sheets was \$609 million at June 30, 2025 and \$666 million at December 31, 2024. The carrying value of securitization bonds on Consumers' consolidated balance sheets was \$643 million at June 30, 2025 and \$700 million at December 31, 2024.

Non-consolidated VIEs: NorthStar Clean Energy has variable interests in T.E.S. Filer City, Grayling, Genesee, and Craven. While NorthStar Clean Energy owns 50 percent of each partnership, it is not the primary beneficiary of any of these partnerships because decision making is shared among unrelated parties, and no one party has the ability to direct the activities that most significantly impact the entities' economic performance, such as operations and maintenance, plant dispatch, and fuel strategy. The partners must agree on all major decisions for each of the partnerships.

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Presented in the following table is information about these partnerships:

Name	Nature of the Entity	Nature of NorthStar Clean Energy's Involvement
T.E.S. Filer City	Coal-fueled power generator	Long-term PPA between partnership and Consumers Employee assignment agreement
Grayling	Wood waste-fueled power generator	Long-term PPA between partnership and Consumers Reduced dispatch agreement with Consumers ¹ Operating and management contract
Genesee	Wood waste-fueled power generator	Long-term PPA between partnership and Consumers Reduced dispatch agreement with Consumers ¹ Operating and management contract
Craven	Wood waste-fueled power generator	Operating and management contract

- ¹ Reduced dispatch agreements allow the facilities to be dispatched based on the market price of power compared with the cost of production of the plants. This results in fuel cost savings that each partnership shares with Consumers' customers.

The creditors of these partnerships do not have recourse to the general credit of CMS Energy, NorthStar Clean Energy, or Consumers. NorthStar Clean Energy's maximum risk exposure to these partnerships is generally limited to its investment in the partnerships, which is included in investments on CMS Energy's consolidated balance sheets in the amount of \$57 million at June 30, 2025 and \$64 million at December 31, 2024.

12: Exit Activities

In accordance with its Clean Energy Plan, and absent an extension of the May 2025 emergency order or other government order, Consumers plans to retire J.H. Campbell in 2025. In order to ensure necessary staffing at J.H. Campbell through retirement, Consumers has implemented a retention incentive program. The terms of and Consumers' obligations under this program have not been modified. The aggregate cost of the J.H. Campbell program through 2025 is estimated to be less than \$50 million. The MPSC has approved deferred accounting treatment for these costs; these expenses are deferred as a regulatory asset. For information on the emergency order associated with J.H. Campbell, see Note 1, Regulatory Matters.

As of June 30, 2025, the cumulative cost incurred and deferred as a regulatory asset related to the J.H. Campbell retention incentive program was \$46 million. Amounts deferred under the program are subsequently collected from customers over three years.

Presented in the following table is a reconciliation of the retention benefit liability recorded in other liabilities on Consumers' consolidated balance sheets:

	<i>In Millions</i>	
Six Months Ended June 30	2025	2024
Retention benefit liability at beginning of period	\$ 14	\$ 16
Costs deferred as a regulatory asset ¹	3	3
Retention benefit liability at the end of the period ²	\$ 17	\$ 19

- ¹ Includes \$1 million for the three months ended June 30, 2025 and less than \$1 million for the three months ended June 30, 2024.

- ² Includes current portion of other liabilities of \$17 million at June 30, 2025 and \$8 million at June 30, 2024.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's discussion and analysis of financial condition and results of operations for CMS Energy and Consumers is contained in Part I—Item 1. Financial Statements—MD&A, which is incorporated by reference herein.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

There have been no material changes to market risk as previously disclosed in Part II—Item 7A. Quantitative and Qualitative Disclosures About Market Risk, in the 2024 Form 10-K.

Item 4. Controls and Procedures

CMS Energy

Disclosure Controls and Procedures: CMS Energy's management, with the participation of its CEO and CFO, has evaluated the effectiveness of its disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Based on such evaluation, CMS Energy's CEO and CFO have concluded that, as of the end of such period, its disclosure controls and procedures are effective.

Internal Control Over Financial Reporting: There have not been any changes in CMS Energy's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the last fiscal quarter that have materially affected, or are reasonably likely to affect materially, its internal control over financial reporting.

Consumers

Disclosure Controls and Procedures: Consumers' management, with the participation of its CEO and CFO, has evaluated the effectiveness of its disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Based on such evaluation, Consumers' CEO and CFO have concluded that, as of the end of such period, its disclosure controls and procedures are effective.

Internal Control Over Financial Reporting: There have not been any changes in Consumers' internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the last fiscal quarter that have materially affected, or are reasonably likely to affect materially, its internal control over financial reporting.

Part II—Other Information

Item 1. Legal Proceedings

CMS Energy, Consumers, and certain of their affiliates are parties to various lawsuits and regulatory matters in the ordinary course of business. For information regarding material legal proceedings, including updates to information reported under Part I—Item 3. Legal Proceedings of the 2024 Form 10-K, see Part I—Item 1. Financial Statements—Notes to the Unaudited Consolidated Financial Statements—Note 1, Regulatory Matters and Note 2, Contingencies and Commitments.

Item 1A. Risk Factors

There have been no material changes to the Risk Factors as previously disclosed in Part I—Item 1A. Risk Factors in the 2024 Form 10-K, which Risk Factors are incorporated herein by reference.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Unregistered Sales of Equity Securities

None.

Issuer Repurchases of Equity Securities

Presented in the following table are CMS Energy's repurchases of common stock for the three months ended June 30, 2025:

Period	Total Number of Shares Purchased ¹	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under Publicly Announced Plans or Programs
April 1, 2025 to April 30, 2025	126	\$ 73.63	—	—
May 1, 2025 to May 31, 2025	882	72.29	—	—
June 1, 2025 to June 30, 2025	68	69.54	—	—
Total	1,076	\$ 72.27	—	—

¹ All of the common shares were repurchased to satisfy the minimum statutory income tax withholding obligation for common shares that have vested under the Performance Incentive Stock Plan. The value of shares repurchased is based on the market price on the vesting date.

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Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

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Item 6. Exhibits

CMS Energy's and Consumers' Exhibit Index

The agreements included as exhibits to this Form 10-Q filing are included solely to provide information regarding the terms of the agreements and are not intended to provide any other factual or disclosure information about CMS Energy, Consumers, or other parties to the agreements. The agreements may contain representations and warranties made by each of the parties to each of the agreements that were made exclusively for the benefit of the parties involved in each of the agreements and should not be treated as statements of fact. The representations and warranties were made as a way to allocate risk if one or more of those statements prove to be incorrect. The statements were qualified by disclosures of the parties to each of the agreements that may not be reflected in each of the agreements. The agreements may apply standards of materiality that are different than standards applied to other investors. Additionally, the statements were made as of the date of the agreements or as specified in the agreements and have not been updated. The representations and warranties may not describe the actual state of affairs of the parties to each agreement.

Additional information about CMS Energy and Consumers may be found in this filing, at www.cmsenergy.com, at www.consumersenergy.com, and through the SEC's website at www.sec.gov.

<u>Exhibits</u>	<u>Description</u>
4.1	— 153rd Supplemental Indenture dated as of May 2, 2025 between Consumers and The Bank of New York Mellon, as Trustee (Exhibit 4.1 to Form 8-K filed May 2, 2025 and incorporated herein by reference)
10.1 ^{1, 2}	— Annual NorthStar Clean Energy Employee Incentive Compensation Plan, as amended, effective as of May 1, 2025
31.1	— CMS Energy's certification of the CEO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	— CMS Energy's certification of the CFO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.3	— Consumers' certification of the CEO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.4	— Consumers' certification of the CFO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	— CMS Energy's certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	— Consumers' certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	— Inline XBRL Instance Document
101.SCH	— Inline XBRL Taxonomy Extension Schema
101.CAL	— Inline XBRL Taxonomy Extension Calculation Linkbase
101.DEF	— Inline XBRL Taxonomy Extension Definition Linkbase
101.LAB	— Inline XBRL Taxonomy Extension Labels Linkbase
101.PRE	— Inline XBRL Taxonomy Extension Presentation Linkbase
104	— Cover Page Interactive Data File (the cover page XBRL tags are embedded in the Inline XBRL document)

¹ Obligations of CMS Energy or its subsidiaries, but not of Consumers.

² Management contract or compensatory plan or arrangement.

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Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, each registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature for each undersigned company shall be deemed to relate only to matters having reference to such company or its subsidiary.

CMS ENERGY CORPORATION

Dated: July 31, 2025

By:

/s/ Rejji P. Hayes

Rejji P. Hayes

Executive Vice President and Chief Financial Officer

CONSUMERS ENERGY COMPANY

Dated: July 31, 2025

By:

/s/ Rejji P. Hayes

Rejji P. Hayes

Executive Vice President and Chief Financial Officer

EXHIBIT 31



Expert Blog

Trump Administration's DOE Is Forcing Coal Plants to Stay Open. Michigan Is the First Target.

People in Michigan and across the Midwest will be stuck paying the cost of a nonexistent "emergency" with their health and their electric bills.

June 16, 2025



Consumer Energy's coal-fired J.H. Campbell Generating Complex in Ottawa County, Michigan |
Joel Bissell/Kalamazoo Gazette via AP

Derrell E. Slaughter

Michigan Policy Director, Climate & Energy

Casey Roberts

Director, RTO Advocacy, Climate & Energy

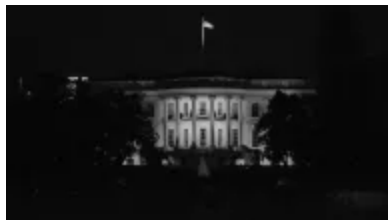
The Trump administration has vowed to revive the long declining U.S. coal-fired power industry, which has become economically uncompetitive relative to proliferating cheaper, cleaner energy sources. On May 23, the U.S. Department of Energy (DOE) followed through on that vow by issuing what it termed an "emergency" order that forces Michigan's J.H. Campbell Complex plant to continue operating through the summer, despite being set to retire on June 1.

The result? Higher electricity bills for consumers and dirtier air that our families must breathe.

LEARN MORE



Why Strong Climate Action Needs a Strong Energy Department



White House Watch: Tracking Attacks on Our Environment & Health

The Campbell coal plant, which began operating on the shores of Lake Michigan in 1962, is woefully out of date, costs more to operate than other electricity generation options, and is one of the worst polluters in Michigan. That's why Consumers Energy, the Michigan utility that operates Campbell, agreed to a settlement with NRDC and other stakeholders in 2022 to shut down the plant by June 1, 2025, and replace it with newer, cheaper electric generation. It then took all the steps needed to secure that energy and shut down Campbell in an orderly fashion—all with the approval of state utility regulators and grid operators, which agreed that the plant was no longer needed on the electrical grid for adequate energy supply and reliability.

Now the DOE's unexpected order has thrown a costly and dangerous monkey wrench into this carefully planned process. The agency invoked a rarely used section of the Federal Power Act—Section 202(c)—to assert that there is a potential reliability "emergency" but offered only specious evidence for this proposition. This unprecedented decision will force Midwest customers to pay to operate an aging, inefficient plant, driving up

costs at a time when families and businesses are already struggling with high energy prices. Using federal emergency powers where no emergency exists sets a dangerous and expensive national precedent.

As Michigan Public Service Commission Chair Dan Scripps stated just days after the order, "We currently produce more energy in Michigan than needed. The unnecessary recent order from the U.S. Department of Energy will increase the cost of power for homes and businesses across the Midwest."

The Campbell order will harm Michigan ratepayers and public health

The DOE's decision to force the Campbell coal plant to remain online will not address a real problem. Instead, it will impose real costs on customers and communities in Michigan and throughout the Midwest.

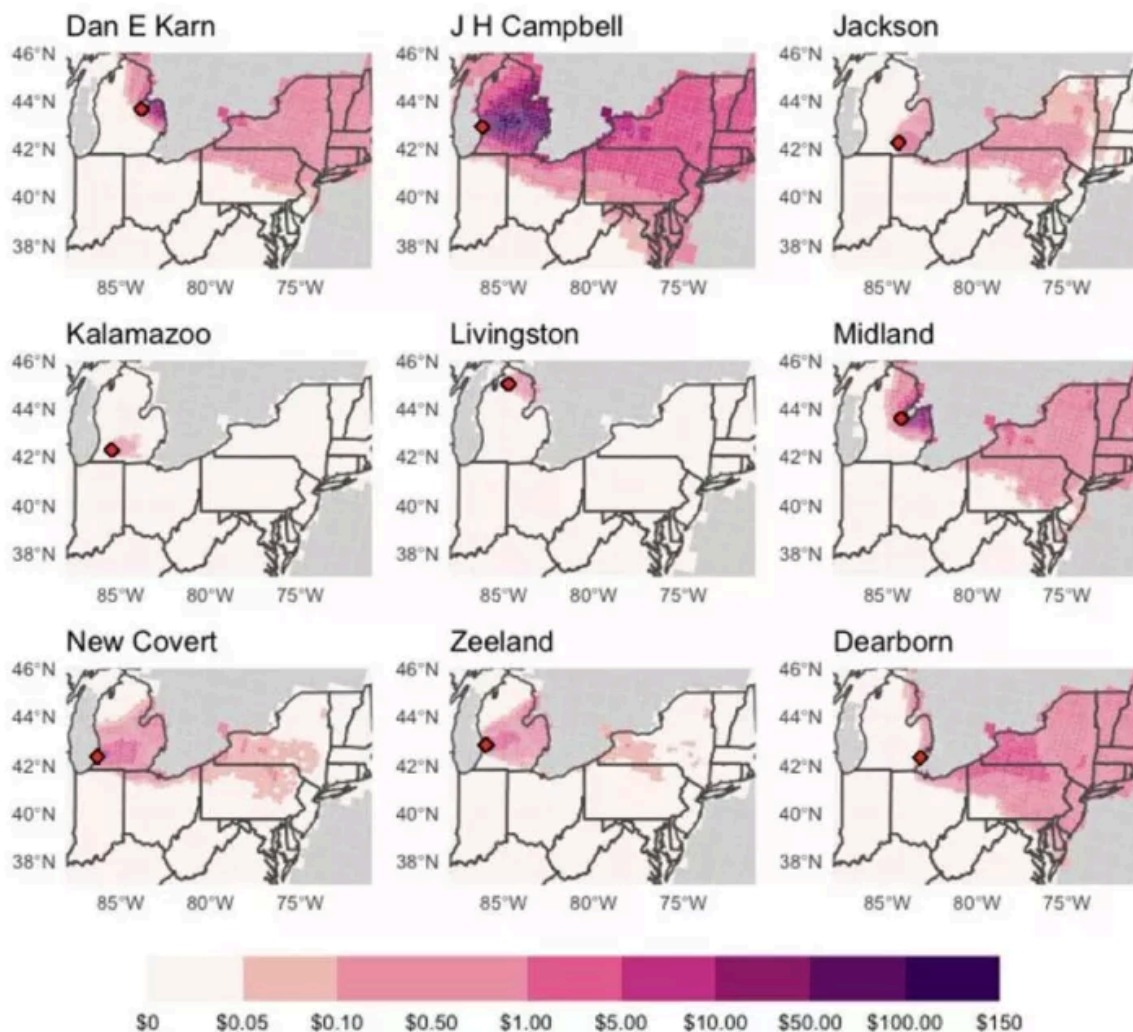
To comply with the DOE's order, Consumers Energy must now:

- Pay premium prices to purchase coal on short notice.
- Perform unplanned repairs and maintenance on a plant that was preparing for closure.
- Find and pay for adequate staffing to run the plant, after many employees already moved to other facilities or retired.

These unbudgeted costs will be passed along to Midwest electric customers. While the costs of the Campbell Section 202(c) order won't be clear until Consumers Energy files with the Federal Energy Regulatory Commission, S&P Global Market Intelligence estimates of the fixed operation and maintenance costs for the plant suggest that keeping it online just for the 90-day order could cost more than \$7 million, even without accounting for the extra expenses associated with last-minute coal procurement and emergency maintenance repairs. If the plant is not dispatched economically—i.e., if it's kept running when it is more expensive than cheaper sources on the grid—the costs could be much higher. These costs come as families and businesses are already struggling with high energy prices.

Scripps has warned that the DOE order will increase costs and erase much of the savings that customers were expecting from Campbell's retirement. There is no sound reason to ask Michigan or other Midwest ratepayers to subsidize an inefficient and polluting coal plant that the state has already moved beyond.

Campbell is also one of the most polluting coal plants in the Midwest. It emits millions of tons of carbon dioxide annually, along with thousands of tons of sulfur dioxide and nitrogen oxides. These pollutants contribute to climate change and cause severe public health impacts, including asthma attacks and other respiratory illnesses. The communities surrounding Campbell will bear the brunt of this pollution, a burden they were promised would end with the plant's retirement.



Public health damages from pollution from Consumers Energy coal plants, including the J.H. Campbell Complex plant. This analysis, prepared by Dr. Kelsey Bilsback, expert witness for the Clean Energy Organizations coalition, shows per capita health impacts in dollars per 100 people, with plant locations marked in red. The coalition partners—The Environmental Law & Policy Center, Ecology Center, Union of Concerned Scientists, and Vote Solar—submitted health testimony that informed this proceeding (view testimony, PDF page 122, testimony page 18). | *Environmental Law & Policy Center*

Michigan's clean energy planning was robust and responsible

The notion that Michigan faces a reliability emergency this summer is simply false. The state, its utilities, and its regulators have spent years preparing for the Campbell plant's retirement through a deliberate, transparent, and collaborative process.

Consumers Energy's 2021 Integrated Resource Plan resulted in a landmark 2022 settlement, which NRDC and a broad coalition of Michigan stakeholders helped negotiate. The settlement committed Consumers to retire all of its coal plants by 2025, with Campbell as the largest and last. The settlement was specifically designed to maintain grid reliability while accelerating Michigan's shift to clean energy.

As part of the agreement:

- Consumers Energy purchased a 1,200 megawatt (MW) natural gas plant.
- Consumers Energy preserved its plan to add thousands of megawatts of new solar capacity through competitive solicitations.
- Consumers Energy committed to new battery storage and clean energy through an all-source solicitation.

These combined investments ensure that Michigan has sufficient, reliable, and affordable electricity without Campbell.

Challenging DOE overreach: Flimsy justifications and smarter national solutions

The DOE's order requires Consumers Energy and the Midcontinent Independent System Operator (MISO) to continue operating the Campbell plant through the summer, based on assertions that the state of Michigan lacks sufficient generation and that the MISO region faces shortages of electricity during that time. Section 202(c) of the Federal Power Act permits the department to order electricity generation if an emergency exists "by reason of a shortage of electric energy or of facilities for the generation or transmission of electric energy."

However, no credible evidence supports the claim that an energy emergency exists in Michigan or the broader MISO region.

MISO's latest Summer Readiness Assessment indicates that the region has nearly 2,400 MW of capacity above its required reserve margin, a cushion designed to ensure reliability even under extreme conditions. The DOE's order takes out of context comments from MISO that encourage the development of new generating capacity to falsely suggest an imminent state of shortfall.

Even more troubling, the order is not an isolated case. Just a week after the Campbell order, the DOE issued another Section 202(c) order at Constellation's Eddystone power plant that burns oil and gas outside of Philadelphia. That order similarly lacked evidence of a genuine emergency. These two orders are an ominous beginning of a broader Trump

administration effort to prop up fossil fuel plants under an executive order issued April 8. The DOE's quick orders—based on flimsy evidence—portend a wave of unjustified, costly emergency orders this summer.

Federal energy policy should not be manufacturing emergencies to prop up outdated fossil fuel infrastructure. The DOE has many better tools to support a reliable grid and an abundant energy supply, such as supporting the development of new transmission projects to improve regional power sharing and to interconnect new generators and energy storage resources faster. The federal government should also work to address supply chain issues that delay clean energy deployments, expand demand flexibility to reduce peak demand and enhance grid stability, and encourage large new loads, such as data centers, to build their own clean generation and avoid stressing local grids.

These are the solutions that serve the public interest—not artificially prolonging the life of aging coal plants at great public cost.

Michigan must stay the course and push back

Michigan must stand firm and continue pursuing a clean, affordable, and reliable grid that protects both ratepayers and public health. Our energy future should not be dictated by political decisions from Washington, D.C., that ignore the state's careful planning and progress.

State officials must remain focused on achieving least-cost reliability through renewables, battery storage, and transmission upgrades. These investments not only lower costs for families and businesses, but they also

reduce the pollution that disproportionately impacts low-income communities and communities of color.

Michigan leaders must also be prepared to fight back against the DOE's order:

- State agencies, the attorney general's office, and legislative leaders should continue to oppose this federal intrusion, which threatens the health of Michiganders and will raise their electricity costs.
- Michigan must make clear that decisions about its energy future belong to Michigan—not to Washington.
- The state should vigorously defend its clean energy progress and prevent Michigan ratepayers from being forced to subsidize an unnecessary and costly coal plant this summer.

Conclusion: A moment for Michigan leadership

This is a pivotal moment for Michigan to stand strong. The state has demonstrated leadership in planning a clean, reliable energy future. It must not allow federal political interference to derail this progress.

The Campbell order is a bad solution to a nonexistent problem. It imposes real financial and public health harms on Michigan residents. The order undermines state authority over electricity generation resources and sets a dangerous precedent for manufactured emergencies that disregard careful

planning by states and utilities for an affordable energy transition. The DOE should reverse this misguided order and refocus its efforts on real solutions that enhance reliability and affordability for all Americans.

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RELATED BLOGS



EPA Declines to Limit Deadly Soot Air Pollution

December 8, 2020 • Expert Blog • United States, Washington, D.C. • Emily Davis, John Walke, Dr. Vijay Limaye

On its way out the door, the Trump Administration undermines the Clean Air Act and public health in a profound way.

EXHIBIT 32

The Department Of Energy's Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid

THE NEW REPORT REVEALS, PLANT CLOSURES AND OVERRELIANCE ON INTERMITTENT ENERGY SOURCES DRIVEN BY A RADICAL GREEN AGENDA, AND INCREASING ARTIFICIAL INTELLIGENCE DEMAND, COULD LEAD TO A SIGNIFICANT INCREASE IN U.S. POWER OUTAGES

- On July 7, 2025, the Department of Energy (DOE) released its Resource Adequacy Report, in fulfillment of a directive under President Trump's Executive Order 14262 of April 8, 2025, "Strengthening the Reliability and Security of the United States Electric Grid."
- According to DOE's findings, which are based on similar work completed by the North American Electric Reliability Corporation (NERC), the U.S. energy grid will not be able to sustain the combined impact of coal and other plant closures, an overreliance on intermittent energy sources like wind and solar, and data center growth, highlighting the urgency of increasing dispatchable energy output, which the Trump Administration has already taken steps to accomplish.
- The analysis clearly demonstrates that in the absence of robust and rapid energy policy reform that prioritizes use of America's abundant natural resources and fast infrastructure buildout, resource inadequacy will prevent development of new manufacturing in America, prohibit the re-industrialization of the US economy, drive up the cost of living for all Americans, and eliminate the potential to sustain enough data centers to win the artificial intelligence (AI) arms race.
- According to the report, the Nation's power grid is not prepared to meet the energy demand of AI, putting U.S. national security at risk by compromising both our grid stability and our ability to innovate.
 - The report estimates an additional 100 GW of new peak hour supply is needed by 2030. Of this, 50 GW of this is directly attributable to data centers.
 - Data centers can be built in 18 months, but it takes more than three times as long to add new generation required to service those data centers to the grid.
 - Load growth is accelerating at a rate not seen in decades. The energy infrastructure industry, which is accustomed to moderate to zero load growth, needs to innovate to keep up with the demand.
 - Intermittent energy sources like wind and solar will not meet reliability demands, and the planned closures of firm, reliable power sources like coal are dramatically greater than expected additions.
 - The DOE report assumes 104 GW of announced plant closures by 2030 will be met with 210 GW of new generation; however, only 22 GW of that new generation will be firm, reliable, dispatchable generation that is available 24/7.
 - According to the report, capacity is not being replaced on a one-to-one basis and this loss of capacity will lead to shortfalls during periods of low intermittent renewable power generation.
 - With current projections of generation retirements and additions, grid reliability deteriorates in all regions.

AI INNOVATION IS ACCELERATING ENERGY DEMANDS AND THE NEED FOR RELIABLE, FIRM GENERATION SOURCES

- U.S. grid operators have raised a unified alarm about an impending capacity crunch, warning about the pace and scale of explosive energy demand from data centers, increased manufacturing, and electrification.
 - At a March 25th hearing before the House Energy and Commerce Subcommittee on Energy, the Nation's top grid officials testified that the U.S. power system is under mounting strain—and without urgent reform, their ability to maintain reliable electric service will fail.
 - At the June 5th FERC technical conference on resource adequacy, NERC leadership testified that mounting resource adequacy challenges are elevating the outage risk profile across a broad swath of North America, leaving few areas untouched.
- Renewables have been subsidized while dispatchable energy sources such as coal, oil and gas, and nuclear have been minimized by environmental activism that hinders American energy production, and renewables cannot power a 24/7 AI infrastructure.
 - These sources are intermittent and cannot always match real-time demand, especially when split-second latency and uptime are critical.
 - Baseload, dispatchable power, such as from coal, oil and gas, and nuclear, is essential in grid planning.
 - According to these operators, without urgent structural reforms such as those underway under the Trump Administration, the ability to maintain reliable electric service could falter.
 - Several utilities have fast-tracked proposals for new natural gas peaker plants, while others are evaluating small modular nuclear reactors as potential solutions for delivering steady, baseload power.
 - Firm, reliable energy sources like coal, oil and gas, which the Trump Administration has already taken decisive action to support, and a rapid energy infrastructure buildout, for which the Trump Administration has already undertaken historic permitting reform to enable, are needed to ensure we can continue to supply adequate energy to meet the demands of our re-industrialization, manufacturing centers, and innovators while keeping the cost of living low for all Americans.

PRESIDENT TRUMP AND THE DEPARTMENT OF ENERGY ARE WORKING TO SECURE GRID RELIABILITY

- In April 2025, President Trump issued Executive Order 14262, “Strengthening the Reliability and Security of the United States Electric Grid,” in order to address the surge in electricity demand.
 - The order called on the Secretary of Energy to expedite the DOE's processes for issuing 202(c) orders of the Federal Power Act, during periods of emergency grid operations.
 - The order called on the Secretary of Energy to develop a uniform methodology within 30 days, analyzing current and anticipated reserve margins for all regions of bulk power

regulated by the Federal Energy Regulatory Commission (FERC) and publish the methodology, along with any analysis it produces, on the DOE's website.

- The order called on the Secretary of Energy to use this methodology to identify which generation resources within a region are critical to system reliability and prevent those identified generation resources from leaving the bulk-power system
- The Trump administration has already issued several 202(c) emergency orders in order to secure the U.S. power grid and prevent unnecessary power outages.
 - In May 2025, the DOE issued an emergency 202(c) order of the Federal Power Act, to the Midcontinent Independent System Operator (MISO).
 - The emergency order directed MISO, in coordination with Consumers Energy, to keep the J.H. Campbell Power Plant in West Olive, Michigan, active for operation to prevent potential power outages.
 - In June, MISO issued an Energy Emergency Alert¹ (EEA1) as a result of high expected load and low wind conditions. It was able to avoid black-outs but only after running the J.H. Campbell unit and after significant imports from other RTOs.
 - In May 2025, the DOE issued a 202(c) emergency order of the Federal Power Act, to the Puerto Rico Electric Power Authority (PREPA).
 - The order directed PREPA to dispatch generation units necessary to expand baseload generation on the island to maintain grid reliability and avoid a gap in generation shortfall.
 - In May 2025, the DOE issued an emergency 202(c) order of the Federal Power Act, ordering PJM Interconnection (PJM) to operate specified generation units at the Eddystone, Pennsylvania Generation Station past their planned retirement.
 - The order followed statements from PJM warning that their systems faced a “growing resource adequacy concern” due to load growth,” the retirement of dispatchable resources, and other factors.
 - In June issued an Energy Emergency Alert 1 (EEA1) alert and called on the Eddystone units to run.
 - In June 2025, the DOE issued an emergency 202(c) order of the Federal Power Act to address potential power grid shortages in the Southeast U.S.
 - The order authorized Duke Energy Carolina to use specific electric generating units within the Duke Energy Carolina area to operate at their maximum generating capacity, in response to ongoing extreme weather conditions.

EXHIBIT 33

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

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

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July 7, 2025

 4 min

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

WASHINGTON— The U.S. Department of Energy (DOE) today released its [Report on Evaluating U.S. Grid Reliability and Security](#). The report

fulfills Section 3(b) of President Trump's Executive Order, [*Strengthening The Reliability And Security Of The United States Electric Grid*](#), by delivering a uniform methodology to identify at-risk regions and guide Federal reliability interventions.

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

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

Highlights of the Report:

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

undermine U.S. economic growth, national security, and leadership in emerging technologies.

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

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

Click [here](#) for a fact sheet on the report.

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STRENGTHEN GRID RELIABILITY AND SECURITY

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EXHIBIT 34

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY

Order No. 202-25-3B
ORDER ADDRESSING ARGUMENTS RAISED ON REHEARING

(Issued September 8, 2025)

1. On May 23, 2025, pursuant to section 202(c) of the Federal Power Act (FPA),¹ and section 301(b) of the Department of Energy Organization Act,² the Secretary of Energy (Secretary) issued an order (Emergency Order) determining that “an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes”³ In the Emergency Order, the Secretary determined that “additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c).”⁴ Requests for rehearing were filed by Public Interest Organizations (PIOs);⁵ Michigan Attorney General Dana Nessel (Michigan AG); the States of Minnesota and Illinois (Minnesota and Illinois); and the Organization of MISO States (OMS).⁶ Comments were filed by the Michigan Public Power Agency (MPPA) and the Maryland Office of People’s Counsel (Maryland OPC).

2. On July 28, 2025, the Department of Energy (DOE) issued a notice of denial of rehearing by operation of law and providing for further consideration (DOE Notice). However, as provided in sections 202(c) and 313(a) of the FPA,⁷ we are modifying the discussion in the Emergency Order and continue to reach the same result in this Order, as discussed below.⁸

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b)

³ Department of Energy Order No. 202-25-3 (May 23, 2025) (Emergency Order).

⁴ *Id.* at 2.

⁵ Sierra Club, Natural Resources Defense Council, Michigan Environmental Council, Environmental Defense Fund, Environmental Law and Policy Center, Vote Solar, Public Citizen, Union of Concerned Scientists, the Ecology Center, and Urban Core Collective refer to themselves collectively as Public Interest Organizations.

⁶ OMS also filed a notice of clarification to identify which of its members voted in support of filing only a petition to intervene and which of its members voted in support of filing a petition to intervene and a request for rehearing.

⁷ 16 U.S.C. § 824a(c); 16 U.S.C. § 825l(a). In the context of FPA section 202(c) orders, the DOE interprets FPA section 313’s references to “the Commission” to mean the DOE.

⁸ *See Allegheny Def. Project v. FERC*, 964 F.3d 1, 16-17 (D.C. Cir. 2020). The Department is not

I. Background

3. In the Emergency Order, the Secretary determined that “an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.”⁹

4. The Emergency Order provided substantial support for the Secretary’s emergency determination. The Emergency Order explained that, in its 2025 Summer Reliability Assessment, the North American Electric Reliability Corporation (NERC) indicated that “[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.”¹⁰ The Emergency Order observed that multiple generation facilities in Michigan have retired in recent years, specifically identifying the closures of two nuclear plants—Big Rock Point and Palisades. The Emergency Order explained that the retirement of the Campbell Plant would further decrease the amount of available dispatchable generation in the Midcontinent Independent System Operator, Inc. (MISO) service territory, noting that a combined 1,575 MW of natural gas and coal-fired generation had retired since the summer of 2024.¹¹ The Emergency Order stated that MISO’s 2025/2026 Planning Resource Auction results indicated that, for the North/Central sub-regions, “new capacity additions were insufficient to offset the negative impacts of accreditation, suspensions/retirements and external resources” and that, while the results “demonstrated sufficient capacity,” the summer months reflected the “highest risk and a tighter supply-demand balance[;]” and the results “reinforce the need to increase capacity.”¹²

5. In the Emergency Order, the Secretary determined that continued operation of the Campbell Plant is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination was based on the insufficiency of dispatchable capacity

changing the outcome of the Emergency Order. *See Smith Lake Improvement & Stakeholders Ass’n v. FERC*, 809 F.3d 55, 56-57 (D.C. Cir. 2015).

⁹ Emergency Order at 1.

¹⁰ *Id.* (quoting *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, at 16 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf (NERC 2025 Summer Reliability Assessment)). The Emergency Order stated that NERC anticipates “elevated risk of operating shortfalls” notwithstanding Consumers Energy’s acquisition of a 1,200 MW natural gas power plant in Covert, Michigan. *Id.* at 1-2.

¹¹ *Id.*

¹² *Id.* (citing MISO, *Planning Resource Auction Results for Planning Year 2025-26* (Apr. 2025)). After the Emergency Order was issued, on May 29, 2025, MISO posted a corrected version of the presentation, which is available here: https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

and an anticipated increase in demand during the summer months, resulting in a risk to public health and safety caused by the potential loss of power to homes and local businesses in areas that may be affected by curtailments or outages. The Emergency Order was limited in duration to align with the emergency circumstances. In recognition of potential conflict with environmental standards and requirements and consistent with FPA section 202(c), the Secretary placed specific conditions on the operation of this necessary additional generation.¹³

II. Discussion

1. The Secretary's Authority to Require the Campbell Plant to Continue to Operate

6. Michigan AG, PIOs, Minnesota and Illinois, and OMS argue that the Emergency Order impermissibly exceeds the Secretary's statutory authority under FPA section 202(c) in various respects.¹⁴ For instance, Michigan AG and PIOs argue that the Emergency Order, in effect, impermissibly asserts the authority to further its policy decisions by managing issues unrelated to addressing emergencies but rather concerning resource adequacy and electric generation facilities—issues which are reserved for the states and the Federal Energy Regulatory Commission (FERC), pursuant to other provisions in the FPA.¹⁵ Minnesota and Illinois additionally contend that the Emergency Order impermissibly intrudes on the states' authority to make plant retirement decisions.¹⁶

7. Minnesota and Illinois also assert that section 202(c) has been used sparingly to address retirements like the Campbell Plant, and “only when requested by the operator or local government” in the context of an emergency.¹⁷

8. In a related argument, OMS asserts that the Emergency Order did not adequately consult with or incorporate the findings of MISO and other relevant state regulatory bodies, which they claim have primary jurisdiction over resource planning, siting, and cost recovery for utilities operating in their states.¹⁸

¹³ Emergency Order at 2-3.

¹⁴ Michigan AG Pet. § IV.B; PIO Pet. § IV.C; Minnesota and Illinois Pet. § V.E; OMS Pet. § B.

¹⁵ See Michigan AG Pet. § IV.B.i (citing 16 U.S.C. § 824(b)(1) and 16 U.S.C. §§ 824d, 824e); PIO Pet. at 44 (citing 16 U.S.C. § 824(a)); *id.* at 45 (citing *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 281 (2016)).

¹⁶ Minnesota and Illinois Pet. at 27.

¹⁷ *Id.* at 24.

¹⁸ *Id.* at 30-31.

9. Minnesota and Illinois also assert that the Emergency Order, subparagraph E, impermissibly calls for state governments to assist in its execution.¹⁹ In particular, Minnesota and Illinois claim that the Emergency Order's directive that "the relevant governmental authorities are directed to take such action"—*i.e.*, effectuate the dispatch and operation of the Campbell Plant's units—unlawfully violates the Tenth Amendment of the United States Constitution.²⁰

The DOE's Determination

10. There is no dispute that the Secretary has the statutory authority under FPA section 202(c) to (1) determine that an emergency exists, and then (2) exercise his judgment to address that emergency. Rather, Petitioners claim that the Secretary exceeded that authority in directing MISO and Consumers Energy to undertake specific actions to keep the Campbell Plant in operation. As explained below, these claims have no merit.

11. Section 201(b)(1) of the FPA specifically reserves authority over "facilities used for the generation of electric energy" for the states "*except as specifically provided in this subchapter.*"²¹ Section 202(c) constitutes one such carve out. It grants the Secretary the "authority, either upon [the Secretary's] own motion or upon complaint, with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in [the Secretary's] judgment will best meet the emergency and serve the public interest." Congress thus purposely provided discretion in section 202(c) to require changes to the operation of the U.S. electricity system on a temporary basis, including changes to the operations of electric generation facilities.

12. Michigan AG and PIOs attempt to avoid this clear grant of authority by arguing that the Emergency Order addresses issues unrelated to emergencies but rather concern resource adequacy.²² But placing a different label on the Secretary's action cannot change the fact that actions taken in the Emergency Order fall squarely within the authority granted by section 202(c). By its terms, that section specifically applies to the potential "shortage of electric energy or of facilities for the generation or transmission of electric energy," which is exactly the situation that led to the issuance of the Emergency Order. And section 202(c) specifically authorizes the Secretary to "require by order . . . such generation . . . of electric energy as in [the Secretary's] judgment will best meet the emergency and serve the public interest," which is exactly the action the Emergency Order requires.

¹⁹ *Id.* at 31.

²⁰ *Id.*

²¹ 16 U.S.C. § 824(b)(1) (emphasis added).

²² See Michigan AG Pet. § IV.B.i (citing 16 U.S.C. § 824(b)(1) and 16 U.S.C. §§ 824d, 824e); PIO Pet. at 44 (citing 16 U.S.C. § 824(a)); *id.* at 45 (citing *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 281 (2016)).

13. Nor is there any requirement under section 202(c), as Minnesota and Illinois and OMS suggest,²³ for the Secretary to consult with the impacted states prior to issuing a section 202(c) order. Section 103 of the DOE Organization Act requires consultation with states “where practicable.”²⁴ In an emergency situation, it is often not practicable to consult with the states and relevant state agencies prior to taking emergency action. This point is further supported by the plain language of section 202(c), which specifically authorizes DOE to issue an emergency order “with or *without notice*.”²⁵

14. Finally, the argument that the Emergency Order violates the Tenth Amendment²⁶ is incorrect. The Emergency Order provides that “[t]he extent to which MISO’s current Tariff provisions are inapposite to effectuate the dispatch and operation of the units for the reasons specified herein, the relevant governmental authorities are directed to take such action and make accommodations as may be necessary to do so.”²⁷ Had the Emergency Order directed State governments or their instruments to take such an action, there would, of course, be a constitutional issue, grounded perhaps in regards to the 10th Amendment, but even more directly in the anti-commandeering clause. But that was not the intended endpoint, however, for the avoidance of doubt, we provide clarification that the Order does not direct State governments or their instrumentalities to take such actions.

15. Here, there is no state tariff provision which governs wholesale energy sales. DOE clarifies that the relevant authorities to which the Emergency Order refers are MISO and FERC. DOE is not requiring state governmental authorities to take any action with respect to the Emergency Order.

2. The Secretary’s Authority to Determine the Existence of an Emergency

16. Michigan AG, PIOs, Minnesota and Illinois, and OMS each raise similar arguments that the Emergency Order failed to meet the legal definition of an “emergency” within the meaning of FPA section 202(c).²⁸ For instance, Michigan AG argues that, while section 202(c) “permits some measure of flexibility with respect to what type of events may cause the emergency, allowing for ‘other causes’ beyond those enumerated,” it only authorizes action during extraordinary

²³ See, e.g., Minnesota and Illinois Pet. § V.E; OMS Pet. at 4.

²⁴ 42 U.S.C. § 7113.

²⁵ 16 U.S.C. § 824a(c)(1) (emphasis added).

²⁶ Minnesota and Illinois Pet. at 31-32.

²⁷ Emergency Order at 3.

²⁸ Michigan AG Pet. § IV.A; PIO Pet. § IV.A.1; Minnesota and Illinois Pet. § V.B; OMS Pet. §§ II.A, D.

circumstances.²⁹ Michigan AG,³⁰ PIOs,³¹ and Minnesota and Illinois³² cite to the definition of “emergency” in DOE’s regulations at 10 C.F.R. § 205.371 and argue that the Emergency Order exceeded the scope of that definition. Michigan AG³³ and PIOs³⁴ also cite to various dictionary definitions of “emergency” to assert the same point.

17. Further, Michigan AG,³⁵ PIOs,³⁶ and Minnesota and Illinois³⁷ each rely on *Richmond Power and Light v. FERC*, 574 F.2d 610 (D.C. Cir. 1978), and *Otter Tail Power Co. v. Federal Power Commission*, 429 F.2d 232 (8th Cir. 1970), for the proposition that courts have interpreted section 202(c) narrowly to apply only to temporary emergencies requiring an imminent response.

The DOE’s Determination

18. In enumerating emergency powers in section 202(c), Congress accorded the Secretary discretion to determine the existence of an emergency. The statute’s plain text grants the Secretary authority to respond, in certain circumstances, to emergencies posing dire threats to the Nation’s electric infrastructure. Specifically, the Secretary “*shall* have authority” to act “*whenever* the [Secretary] determines that an emergency exists.”³⁸ Next, the statute sets forth three different categories of emergencies where section 202(c) action is permissible. An emergency may exist “by reason of [1] a sudden increase in the demand for electric energy, or [2] a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or [3] other causes.”³⁹

19. Section 202(c)(1) delegates a wide degree of latitude for the Secretary to determine the existence of an emergency, “either upon its own motion or upon complaint, with or without notice,

²⁹ Michigan AG Pet. at 24.

³⁰ Michigan AG Pet. at 26.

³¹ PIO Pet. at 28-29.

³² Minnesota and Illinois Pet. at 22-23.

³³ Michigan AG Pet. at 25.

³⁴ PIO Pet. at 26.

³⁵ Michigan AG Pet. at 25-26.

³⁶ PIO Pet. 26-27.

³⁷ Minnesota and Illinois Pet. at 24.

³⁸ 16 U.S.C. § 824a(c)(1) (emphases added).

³⁹ *Id.* (brackets added).

hearing, or report.” Beyond providing exemplar categories of where an “emergency exists,” the statute is silent on any additional requirements that must be satisfied. Here, as is evident from the face of the Emergency Order, and as is consistent with section 202(c)’s text and prior DOE practice, the Secretary exercised his authority under section 202(c) and determined, in his statutory discretion and substantive expertise, that “an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes.”⁴⁰

20. The argument that the Secretary can act only when a shortage of electricity is “imminent” makes no sense in the context of his statutory authority under section 202(c) to act to address a “shortage of . . . facilities for the generation . . . of electric energy.” As a general matter, some retired generation facilities generally cannot be brought back online in a matter of days. If the Secretary was required to wait until a blackout is “imminent” before addressing a shortage of generation facilities, he will be unable to take any meaningful action to address the blackout. Determining to take action before the retirement of the Campbell Plant, which was necessary to ensure that it would be available to produce electric energy to prevent blackouts in summer peak load periods, falls well within the Secretary’s statutory discretion.

21. The definition of “emergency” contained in DOE’s regulations at 10 C.F.R. § 205.371 does not supersede the discretion section 202(c) affords to the Secretary to “determine[] that an emergency exists.” In any event, those regulations specifically provide that “[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations.” Accordingly, the Secretary’s emergency determination is entirely consistent with the governing statutory requirements in section 202(c) and the DOE’s regulations.

22. Similarly, the dictionary definitions cited by Michigan AG⁴¹ and PIOs⁴² are not persuasive. Those definitions cannot limit the discretion Congress expressly delegated to the Secretary in section 202(c).

23. The arguments made by Michigan AG,⁴³ PIOs,⁴⁴ and Minnesota and Illinois⁴⁵ based on the *Otter Tail Power* and *Richmond Power and Light* decisions likewise are misguided. *Otter Tail Power* did not limit the Secretary’s section 202(c) discretion or the meaning of “emergency” because the court held that section 202(c) *did not apply* to the case. Instead, *Otter Tail Power*

⁴⁰ See Emergency Order at 1.

⁴¹ Michigan AG Pet. at 25.

⁴² PIO Pet. at 26.

⁴³ Michigan AG Pet. at 25-26.

⁴⁴ PIO Pet. 26-27.

⁴⁵ Minnesota and Illinois Pet. at 24.

involved section 202(b) of the FPA dealing with permanent interconnection (and not an “emergency” within the meaning of section 202(c)).⁴⁶ In *Richmond Power and Light*, the Court of Appeals for the D.C. Circuit held that the Federal Power Commission (FPC) did not abuse its discretion in *declining* to invoke its emergency powers under section 202(c).⁴⁷ The court determined that the FPC had discretion to choose a temporary, voluntary program rather than issue an order pursuant to section 202(c), as the circumstance, in the FPC’s discretion, did not warrant the use of emergency authority.⁴⁸

24. A more relevant decision is *Board of Trade of the City of Chicago v. Commodity Futures Trading Commission*.⁴⁹ In that case, the Court of Appeals for the Seventh Circuit recognized the broad powers of the Commodity Futures Trading Commission (CFTC) to issue emergency actions under section 8a(9) of the Commodity Exchange Act (7 U.S.C. § 12a(9)). Through section 8a(9), the CFTC issued an emergency order for the Board of Trade to suspend trading in a certain wheat futures contracts, citing transportation and warehouse shortages and potential market manipulation.⁵⁰ In response, the Board of Trade sought an injunction against the order, arguing that no emergency existed. The district court granted a preliminary injunction, and the CFTC appealed.⁵¹ In its decision to vacate and remand the district court’s preliminary injunction, the Seventh Circuit concluded that Congress intended to grant the CFTC discretion in making emergency determinations under the Commodity Exchange Act.⁵² The court reasoned: “Congress recognized that regulation of the volatile futures markets could be accomplished effectively only through the use of an expert Commission, that situations could occur suddenly for which the traditional enforcement powers would be an inadequate response, and that therefore the Commission should have emergency powers, the exercise of which is committed to the expertise and discretion of the Commission.”⁵³ In addition, “[t]he fact that the Commission is authorized by Congress to take emergency action is, in itself, a suggestion of Congressional intent to commit

⁴⁶ See *Otter Tail Power Co. v. Federal Power Commission*, 429 F.2d 232 (8th Cir. 1970) (*Otter Tail Power*) (rejecting petitioner’s contention that “any proceedings in the instant case must be dealt with in compliance with § 202(c)”).

⁴⁷ See *Richmond Power and Light v. FERC*, 574 F.2d 610 (D.C. Cir. 1978) (*Richmond Power and Light*) at 615.

⁴⁸ *Id.* at 614-15.

⁴⁹ *Board of Trade of the City of Chicago v. Commodity Futures Trading Commission*, 605 F.2d 1016, 1025 (7th Cir. 1979)

⁵⁰ See *Board of Trade of the City of Chicago v. Commodity Futures Trading Commission*, 605 F.2d 1016, 1025 (7th Cir. 1979) at 1018.

⁵¹ *Id.* at 1019-20.

⁵² *Id.* at 1023-25.

⁵³ *Id.* at 1025.

such actions to the Commission's discretion."⁵⁴ Given the similarities between FPA section 202(c) and section 8a(9) of the Commodity Exchange Act, the *Board of Trade* decision confirms the conclusion that Congress intended to grant the Secretary broad discretion to determine when his emergency powers should be applied to protect the public interest.⁵⁵

25. Finally, the assertion of Minnesota and Illinois that the Emergency Order is "novel" and contravenes prior practice wherein section 202(c) was used to address retirements "only when requested" has no merit.⁵⁶ On its face, section 202(c)(1) authorizes the Secretary to act "*either upon its own motion or upon complaint.*" It is undisputed that section 202(c) has been used in the past to address generation retirements. Under the statute, it is irrelevant whether a utility requested that the Secretary take this action.

26. In sum, the Secretary acted within his authority to determine the existence of an emergency and the statutory meaning of "emergency" has been satisfied here. In its 90-year history, no court has questioned the Secretary's (or, prior to its dissolution in 1977, the FPC's)⁵⁷ discretion in this respect, much less overturned the Secretary's determination that an emergency exists. The absence of such circumstances underscores the Secretary's authority as expressly delegated in the statute.

3. The Factual Basis to Support the Secretary's Emergency Determination

27. Michigan AG, PIOs, Minnesota and Illinois, and OMS also raise similar objections that there is no factual basis to support the Emergency Order, and that the Secretary is required to submit substantial evidence in support of his emergency determination.⁵⁸

28. *First*, Michigan AG, PIOs, Minnesota and Illinois, and OMS criticize the Emergency Order's references to the 2025 NERC Summer Reliability Assessment.⁵⁹ For instance, Michigan AG claims that the Emergency Order fails to explain (1) how NERC's assessment supports an emergency finding, as NERC did not put MISO in the high-risk category; (2) why NERC's designation of "elevated" risk represents a sudden or unexpected circumstance, as MISO has been

⁵⁴ *Id.* at 1023.

⁵⁵ *See id.* at 1023-25.

⁵⁶ *See* Minnesota and Illinois Pet. at 24.

⁵⁷ The FPC was dissolved in 1977, and the FPC's functions were split between FERC and the Department, with the Secretary retaining FPA section 202(c) power.

⁵⁸ Michigan AG Pet. §§ IV.A(ii), IV.C; PIO Pet. § IV.A.2; Minnesota and Illinois Pet. § V.A; OMS Pet. § II.A.

⁵⁹ Michigan AG Pet. at 27-29, 37; PIO Pet. 32-35; Minnesota and Illinois Pet. at 19-20; OMS Pet. at 2-3. OMS also contends that NERC's long-term and seasonal assessments are unreliable and inconsistent. OMS Pet. at 3.

at this risk level or higher for years; and (3) why the “potential tight reserve margins” identified by NERC constitute an emergency, as MISO exceeded the NERC reference margin level in the 2020-2025 period.⁶⁰

29. *Second*, Michigan AG and PIOs contend that the retirement of the Campbell Plant was not unexpected or sudden, and that generation retirement does not constitute an emergency.⁶¹ Michigan AG further states that MISO approved the retirement of the Campbell Plant after an extensive process.⁶²

30. *Third*, Michigan AG, PIOs, and Minnesota and Illinois also assert that the April 2025 MISO Planning Resource Auction does not demonstrate the existence of an emergency.⁶³ For example, according to Michigan AG, the Emergency Order ignored MISO’s conclusion that the 2025/2026 Planning Resource Auction “demonstrated sufficient capacity at the regional, subregional and zonal levels.”⁶⁴

31. Minnesota and Illinois also contend that the Emergency Order failed to consider MISO’s purported history of performance in several extreme weather events and, according to Minnesota and Illinois, MISO currently is not afflicted by any unexpected outage or extreme weather event.⁶⁵

The DOE’s Determination

32. The exigencies that Section 202(c) is designed to address necessarily require that the Secretary’s determination is informed by the facts available at the time and by his sound expert judgment as to what situations constitute an emergency. The statute’s express exclusion of any notice, hearing, or report requirements prior to issuance of a section 202(c) order confirms the commonsense fact that the Secretary must exercise his section 202(c) authority expeditiously and with broad discretion in responding to emergency situations.

33. In any event, the Secretary’s determination that an emergency exists is supported by the factual evidence and the exercise of the Secretary’s judgment. The Emergency Order identified the ongoing emergency “in portions of the Midwest region of the United States due to a shortage

⁶⁰ Michigan AG Pet. at 37.

⁶¹ *Id.* at 30, 37; PIO Pet. 29-30.

⁶² Michigan AG Pet. at 39

⁶³ *Id.* at 30-32, 38; PIO Pet. at 30-32; Minnesota and Illinois Pet. at 20-21.

⁶⁴ Michigan AG Pet. at 39 (citing Attachment B, MISO, Planning Resource Auction, Results for Planning Year 2025 – 2026 (April 2025) at 12).

⁶⁵ Minnesota and Illinois Pet. at 22.

of electric energy, a shortage of facilities for the generation of electric energy, and other causes.”⁶⁶ Consistent with this determination, the Emergency Order explains the need to increase capacity to meet the increasingly high demands and decreasing generation output.⁶⁷

34. In 2021, Consumers Energy announced that it planned a “speed closure” of the Campbell Plant in 2025, years before the end of its scheduled design life.⁶⁸ Specifically, the Campbell Plant was scheduled to retire on May 31, 2025, and thus would not be operational in August, the month the Secretary anticipated heightened demand on the grid.⁶⁹ In the Emergency Order, the Secretary noted that the Campbell Plant’s retirement was part of an ongoing trend, which has seen 1,575 MW of natural gas and coal-fired generation retired since the summer of 2024, further decreasing the amount of dispatchable generation within MISO’s service territory.⁷⁰ Although MISO and Consumers Energy have incorporated the Campbell Plant’s planned retirement into their supply forecasts, as well as Consumers Energy’s acquisition of an existing 1,200 MW natural gas power plant in Covert, Michigan, NERC’s 2025 Summer Reliability Assessment still anticipated “elevated risk of operating reserve shortfalls.”⁷¹

35. Michigan AG, PIOs, Minnesota and Illinois, and OMS mischaracterize the 2025 NERC Summer Reliability Assessment’s designation of “elevated risk” for the MISO region. This assessment reflects NERC’s determination that “resources will not be sufficient to meet operating reserves” in the event of “extreme peak-day demand with normal resource scenarios” or “normal peak-day demand with reduced resources.”⁷² The NERC assessment of “elevated risk” suggests that there will be significant strain on the grid in the MISO service area even in normal operating conditions. If the Secretary had waited to act until the conditions identified by NERC arose, it would have been too late for him to take any effective action.

36. Petitioners note that MISO and Consumers Energy have incorporated the Campbell Plant’s planned retirement into their supply forecasts and acquired a 1,200 MW natural gas power plant in Covert, Michigan. However, NERC’s 2025 Summer Reliability Assessment anticipated

⁶⁶ See Emergency Order at 1.

⁶⁷ See *id.* (noting recent closures of generation facilities in Michigan and uncertain near-term future of generation from the Palisades nuclear power plant).

⁶⁸ See *Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan’s Clean Energy Transformation*, Consumers Energy (June 23, 2021), <https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation>.

⁶⁹ Emergency Order at 1.

⁷⁰ *Id.*

⁷¹ *Id.* (citing NERC 2025 Assessment).

⁷² NERC 2025 Assessment at 10.

“elevated risk of operating reserve shortfalls” even including the Covert Plant’s capacity.⁷³ The fact that Consumers Energy acquired this existing plant to replace the Campbell Plant did not forestall the emergency.

37. Similarly, MISO’s approval of the retirement of the Campbell Plant came before NERC’s 2025 Summer Reliability Assessment, which took into account increased demand projections.

38. Michigan AG, PIOs, and Minnesota and Illinois’ respective criticisms⁷⁴ of the Secretary’s reliance on the April 2025 MISO Planning Resource Auction ignore that MISO stated that the summer months reflected the “highest risk and a tighter supply-demand balance” and the results of the auction “reinforce the need to increase capacity.”⁷⁵ In addition, the May 2025 NERC assessment referenced a Seasonal Outlook issued by the National Oceanic and Atmospheric Administration (NOAA) on April 17, 2025, which estimated that much of the Midwest had a 33%-40% chance to experience above-normal temperatures in the summer.⁷⁶ DOE also notes that a Seasonal Outlook released by the NOAA on June 19, 2025 increased this estimate to a 40%-50% chance of above-normal temperatures.⁷⁷

39. Similarly, the argument of Minnesota and Illinois that the MISO region does not face current “extreme” weather events misses the mark.⁷⁸ The Emergency Order was based on the facts known at the time it was issued in May 2025, including the projected potential for a shortage of capacity in the summer identified by NERC. In other words, the Secretary was required to act before the shortage actually occurred. Moreover, contrary to the contentions of Minnesota and Illinois, the conditions that actually existed in the summer following issuance of the Emergency Order further confirm the ongoing emergency and sudden increased threats to energy reliability. In June 2025, MISO issued alerts affecting the Central Region on 18 days. For instance, on June 23, 2025, MISO issued an Energy Emergency Alert 1 for the North and Central Regions “[d]ue to the hot weather and high demand” during a heat dome over the eastern portion of the United States.⁷⁹ In fact, between June 11 and August 18, MISO issued dozens of alerts to manage grid

⁷³ Emergency Order at 1 (citing to NERC 2025 Assessment).

⁷⁴ Michigan AG Pet. at 30-32, 38; PIO Pet. at 30-32; Minnesota and Illinois Pet. at 20-21.

⁷⁵ *Planning Resource Auction Results for Planning Year 2025-26*, MISO (Apr. 2025). (Corrected and reissued on 05/29/25) available at https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

⁷⁶ NERC 2025 Assessment at 9.

⁷⁷ *Seasonal Outlook*, NOAA Climate Prediction Ctr., (July 17, 2025), https://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=1.

⁷⁸ Minnesota and Illinois Pet. at 22.

⁷⁹ See MISO Energy Emergency Alert 1 (June 23, 2025),

reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits. MISO issued alerts for the Central Region on at least 40 of the 69 days between June 11 and August 18.

40. In addition, the Secretary took section 202(c) action in the context of a National Energy Emergency declared by the President in the months prior to the Emergency Order. In executive orders dated January 20, 2025, and April 8, 2025, the President underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. The President recognized, in Executive Order 14156, “Declaring a National Energy Emergency,” that the “United States’ insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation’s economy, national security, and foreign policy.”⁸⁰ In view of the National Energy Emergency, in Executive Order 14262, “Strengthening the Reliability and Security of the United States Electric Grid,” the President explained that “the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and an increase in domestic manufacturing.”⁸¹ Significantly, Executive Order 14262 specifically ordered the Secretary to draw upon “all mechanisms available under applicable law, *including section 202(c) of the Federal Power Act*, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region.”⁸² The executive orders informed the Secretary’s decision and action, in addition to the other factors outlined in the Emergency Order and this Order.

41. Grid operators, including MISO itself, have likewise acknowledged the Nation’s current energy crisis. For instance, during a March 25, 2025 hearing before the House Committee on Energy and Commerce, Jennifer Curran, the Senior Vice President of Planning and Operations for MISO, testified that “the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth.”⁸³ Ms. Curran also described “much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers

https://x.com/MISO_energy/status/1937172353118548150.

⁸⁰ Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025).

⁸¹ Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025).

⁸² *Id.* (emphasis added).

⁸³ Keeping the Lights On: Examining the State of Regional Grid Reliability Hearing Before the House Committee on Energy and Commerce, Subcommittee on Energy, 119th Cong. (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), at 5, [witness-testimony curran eng_gridoperators 03.25.2025.pdf](#).

to support artificial intelligence.”⁸⁴ She added, “[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them.”⁸⁵

42. Finally, DOE’s assessment reveals that, if current retirement schedules and incremental additions remain unchanged, most regions—including the MISO region relevant to the Emergency Order—will face unacceptable reliability risks within five years. The action taken in the Emergency Order requiring the Campbell Plant to continue to operate before its planned retirement on May 31, 2025 addresses that risk.⁸⁶

43. In sum, the Secretary’s determination in the Emergency Order that continued operations of the Campbell Plant fully complies with section 202(c).

4. Potential Environmental Impacts

44. Michigan AG and Minnesota and Illinois raise similar arguments that the Emergency Order fails to comply with section 202(c)’s requirement to ensure that any order “to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation and minimizes any adverse environmental impacts.”⁸⁷ In particular, Michigan AG and PIOs argue that the Emergency Order fails to identify any specific criteria or conditions for ensuring compliance with environmental regulations or limiting environmental impact.⁸⁸

The DOE’s Determination

45. Section 202(c)(2) requires the Secretary to ensure that any section 202(c) order that may result in a conflict with a requirement of any environmental law or regulation to the “maximum extent practicable, [be] consistent with any applicable . . . environmental law or regulation and minimize[] any adverse environmental impacts.” Contrary to Michigan AG and Minnesota and Illinois’ contentions, the Emergency Order contains certain limitations to minimize the hours of operation and adverse environmental impacts. Specifically, the Emergency Order requires that “[a]ll operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible,”⁸⁹ and requires daily reporting from MISO on “whether the Campbell

⁸⁴ *Id.* at 6.

⁸⁵ *Id.* at 7.

⁸⁶ NERC 2025 Summer Reliability Assessment

⁸⁷ Michigan AG Pet. at 52 (citing 16 U.S.C. § 824a(c)(2)); Minnesota and Illinois Pet. at 13 (citing 16 U.S.C. § 824a(c)(2)).

⁸⁸ Michigan AG Pet. at 54-55; PIO Pet. at 47.

⁸⁹ Emergency Order at 3, Ordering Paragraph C.

Plant has operated in compliance with the allowances contained in this Order.”⁹⁰ These reporting requirements provide a mechanism for the DOE to obtain information concerning any adverse environmental impacts of the Emergency Order, and DOE may modify the Emergency Order to require additional actions as the Secretary deems appropriate.

46. Michigan AG and Minnesota and Illinois argue that the Emergency Order is not tailored to respect environmental considerations, of particular concern to Michigan AG and Minnesota and Illinois are the potential environmental impacts that may be produced by the Campbell Plant.⁹¹ Michigan AG and Minnesota and Illinois provide examples of certain conditions that in their view would, presumably, satisfy the requirements of the statute (*e.g.*, direction to optimize use of pollution control equipment or avoid operations during air quality episodes).⁹² These conditions, however, are not required by statute. Congress did not prescribe in section 202(c) how the Department was to fulfill its obligations concerning consistency with environmental laws and minimization of adverse effects. Moreover, Congress recognized, by including the phrase “to the maximum extent practicable,” that emergency circumstances would at times make compliance with all Federal, state, and local environmental requirements and minimization of all potential adverse environmental impacts infeasible. This phrase provides the Secretary with discretion in fulfilling its obligations under section 202(c). Accordingly, the Emergency Order’s limits on duration and the conditions that authorize only the additional generation necessary and require the operation of the plant to comply with environmental laws to the maximum extent feasible, as well as the reporting requirements that allow DOE to monitor MISO’s compliance with the Emergency Order and the environmental impacts such that DOE could take additional action as the Secretary deems appropriate, were sufficient to satisfy its obligation under section 202(c)(2) to ensure that the Emergency Order, to the maximum extent practicable, is consistent with applicable environmental laws and minimizes adverse environmental impacts.

5. Authority to Order Economic Dispatch

47. Michigan AG and Minnesota and Illinois assert that DOE does not have the authority under 202(c)(1) to order the utilization of economic dispatch of the Campbell Plant as a response to an emergency, and that economic dispatch is not an effective or rational measure to address resource shortages.⁹³ Accordingly, Michigan AG and Minnesota and Illinois contend that economic dispatch is not in the “public interest,” as required under section 202(c).⁹⁴ In addition, PIOs contend that the Emergency Order’s economic dispatch requirement is ambiguous and vague.⁹⁵

⁹⁰ *Id.*, Ordering Paragraph B.

⁹¹ Michigan AG Pet. at 54-55; Minnesota and Illinois Mot. at 26-27.

⁹² Michigan AG Pet. at 54; Minnesota and Illinois Mot. at 26-27.

⁹³ Michigan AG Pet. § IV.D; Minnesota and Illinois Pet. § V.G.

⁹⁴ Michigan AG Pet. At

⁹⁵ PIO Pet. at 42-43.

Michigan AG asserts that Consumers Energy can subvert the economic dispatch requirement by offering the Campbell Plant on a “must run” status.⁹⁶ Michigan AG asserts that, if this happens, the costs to ratepayers will not have been minimized.⁹⁷

The DOE’s Determination

48. As noted, section 202(c)(1) affords the Secretary discretion as to what remedy “will best meet the emergency and serve the public interest.” The statute expressly delegates the decision on the appropriate remedy to the Secretary’s “judgment” (similar to the express delegation to “determine[] that an emergency exists”). In the Emergency Order, the Secretary soundly exercised his judgment in directing “additional dispatch of the Campbell Plant [] necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c).”⁹⁸ “This determination [was] based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety,” as discussed above.⁹⁹

49. The Emergency Order directs MISO and Consumers Energy to “take all measures necessary to ensure that the Campbell Plant is available to operate.”¹⁰⁰ The Emergency Order then directs MISO “to take every step to employ economic dispatch of the [facility] to minimize [the] cost to ratepayers.”¹⁰¹ The DOE disagrees with arguments that economic dispatch is not effective or rational in this case. The directive regarding economic dispatch ensures that the Campbell Plant can be dispatched instead of more costly generation (if available), reducing electricity costs and serving the public interest. The directive recognizes the fact that MISO uses “a production cost modeling software that produces a unit commitment and security-constrained economic dispatch while optimizing production costs.”¹⁰² DOE clarifies, however, that to the extent operational (including safety) limitations prevent the Campbell Plant from being economically dispatched, offering the Campbell Plant on a must run basis may be necessary to ensure the units are available to operate. Under those circumstances, such operation would be consistent with

⁹⁶ Michigan AG Pet. at 49.

⁹⁷ *Id.*

⁹⁸ Emergency Order at 2.

⁹⁹ *Id.*

¹⁰⁰ *Id.*, Ordering Paragraph A.

¹⁰¹ *Id.*

¹⁰² *MISO Economic Planning Whitepaper* (Oct. 3, 2024), at 3, <https://cdn.misoenergy.org/MISO%20Economic%20Planning%20Whitepaper651689.pdf>

minimizing the cost to ratepayers because a price taker can decrease (but cannot increase) the market price.

6. Best and Appropriate Means for Addressing the Emergency

50. The Michigan AG and PIOs raise similar arguments that the Campbell Plant is neither the best nor an appropriate means of alleviating the capacity shortfall addressed by the Emergency Order.¹⁰³ In particular, Michigan AG and PIOs argue that DOE was required to consider alternatives and evaluate other possible methods for addressing the emergency, which they argue the Emergency Order failed to do.¹⁰⁴ They further argue that there are alternative means by which DOE could have addressed the emergency.¹⁰⁵

51. PIOs additionally argue that the Emergency Order fails to consider the various policies of the FPA.¹⁰⁶ Specifically, PIO's argue that the Emergency Order fails to provide a reasoned basis for its determination that additional dispatch of the Campbell Plant is necessary to best meet the emergency.¹⁰⁷ PIOs further contend that the Emergency Order does not examine the expense or environmental impact of running the Campbell Plant, or address how the Campbell Plant can meet the emergency.¹⁰⁸

The DOE's Determination

52. The Secretary, in issuing the Emergency Order, adhered to the process established in FPA section 202(c) in exercising his judgment in directing MISO and Consumers Energy to undertake specific actions as to the Campbell Plant.¹⁰⁹ There is no dispute that the Secretary, as the presidentially-appointed and Senate-confirmed head of the Department (*see* 42 U.S.C. § 7131), is the appropriate individual to determine the existence of an emergency within the meaning of section 202(c) and exercise "[the Secretary's] judgment" as to what Department actions "best meet the emergency and serve the public interest."¹¹⁰ As discussed above, the Secretary exercised his discretion in responding to an emergency pursuant to an express delegation of authority under

¹⁰³ Michigan AG Pet. at 41; PIO Pet. at 36-37.

¹⁰⁴ Michigan AG Pet. at 41; PIO Pet. at 36-37.

¹⁰⁵ Michigan AG Pet. at 41; PIO Pet. at 41.

¹⁰⁶ PIO Pet. at 37.

¹⁰⁷ *Id.* at 37-41.

¹⁰⁸ *Id.*

¹⁰⁹ *See generally* Emergency Order.

¹¹⁰ 16 U.S.C. § 824a(c)(1).

section 202(c). Further, as explained below, there is no basis to grant rehearing to review the Secretary's exercise of his judgment in prescribing the required response to the emergency.

53. As noted above, section 202(c)(1) affords the Secretary discretion as to what remedy "will best meet the emergency and serve the public interest." The statute expressly delegates the decision on the appropriate remedy to the Secretary's "judgment" (similar to the express delegation to "determine[] that an emergency exists"). Here, the Secretary soundly exercised his judgment in directing "additional dispatch of the Campbell Plant [] necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c)."¹¹¹ "This determination [was] based on the insufficiency of dispatchable capacity and anticipated demand during the summer months, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety."¹¹²

54. That Petitioners have now, after the fact, identified alternatives they deem to be better and more appropriate solutions to the emergency is irrelevant. Section 202(c)(1) delegates a wide degree of latitude for the Secretary to determine the existence of an emergency and to order the means to address such emergency. It does not require the Secretary to engage in a lengthy weighing of options or explanation of the Secretary's actions prior to issuing an emergency order. Indeed, such a process would defeat the very purpose of the emergency power.

7. NEPA Concerns

55. Michigan AG claims that the Emergency Order violates the National Environmental Policy Act (NEPA), as any orders issued under section 202(c) that affect the quality of the environment are considered "major federal actions"¹¹³ that require compliance with NEPA standards and requirements.¹¹⁴ According to the Michigan AG, these requirements include the "issuance of an environmental impact statement, environmental assessment, categorical exclusion, or special environmental analysis."¹¹⁵

56. Michigan AG further asserts that in other section 202(c) orders, DOE has previously sought to comply with NEPA through categorical exclusions, such as categorical exclusion B4.4 for "power management activities," or special environmental assessments—neither of which has been undertaken nor would apply in this instance.¹¹⁶ Lastly, Michigan AG argues that DOE would not be justified in seeking an extension of the Emergency Order beyond 90 days under section

¹¹¹ Emergency Order at 2.

¹¹² *Id.*

¹¹³ Michigan AG Pet. at 55-56 (citing 42 U.S.C. § 4336e(10)).

¹¹⁴ *Id.* at 55-56.

¹¹⁵ *Id.* at 56 (citing 10 C.F.R. § 1021.102(b)).

¹¹⁶ *See id.*

202(c)(3), considering “[a]ny justification that NEPA can be sidestepped to address an emergency need fades as DOE’s orders extend beyond the initial 90-day period.”¹¹⁷

The DOE’s Determination

57. We disagree with Michigan AG’s contention that the DOE “is acting contrary to its own NEPA regulations and to its obligations under NEPA.”¹¹⁸ Although DOE has previously followed the procedures provided in the Department’s NEPA regulations governing emergency actions, as described in 10 C.F.R. § 1021.343 (for example, by preparing a special environmental analysis after the issuance of a section 202(c) order), recent amendments to NEPA clarify that agencies are “not required to prepare an environmental document with respect to a proposed agency action if... the preparation of such document would clearly and fundamentally conflict with the requirements of another provision of law.”¹¹⁹ As DOE recently explained in its NEPA Implementing Procedures, “NEPA does not apply to DOE’s issuance of emergency Orders pursuant to section 202(c) of the Federal Power Act (16 U.S.C. 824a(c)) because preparing an environmental document under NEPA’s generally applicable provisions would clearly and fundamentally conflict with the emergency provisions in the Federal Power Act.”¹²⁰

58. As discussed above, under FPA section 202(c), Congress explicitly authorized the Secretary to “with or without . . . report” exercise certain emergency authorities. Requiring compliance with the analytic and procedural demands of preparing an environmental document under NEPA prior to issuing a section 202(c) emergency order fundamentally conflicts with the authorization for emergency action contemplated by FPA section 202(c) and the Congressional authorization to exercise such authorities without report. Accordingly, DOE has determined, in consultation with the Council on Environmental Quality, that “NEPA does not apply to DOE’s issuance of emergency orders pursuant to section 202(c) . . . because preparing an environmental document under NEPA’s generally applicable provisions would clearly and fundamentally conflict with the emergency provisions in the Federal Power Act.”¹²¹

59. Furthermore, as stated above, section 202(c) specifically provides alternative measures for affording environmental protection by requiring the Secretary to ensure that any such order “to the maximum extent practicable, is consistent with any applicable Federal, state, or local

¹¹⁷ *Id.* at 57-58.

¹¹⁸ *Id.* at 56.

¹¹⁹ See 42 U.S.C. § 4336(a)(3); see also Fiscal Responsibility Act of 2023, Pub. L. No. 188-5, § 321(b), 137 Stat. 10, 39 (2023).

¹²⁰ *National Environmental Policy Act (NEPA) Implementing Procedures*, U.S. Department of Energy, 6 (June 30, 2025), <https://www.energy.gov/sites/default/files/2025-06/2025-06-30-DOE-NEPA-Procedures.pdf>.

¹²¹ See *id.*

environmental law or regulation and minimizes any adverse environmental impacts.”¹²² Again, those environmental obligations were met through the conditions imposed via the Emergency Order’s limitation on the duration of the emergency operations, authorization of only the additional generation necessary, requirement that the operation of the plant to comply with environmental laws to the maximum extent feasible, and the requirement that MISO reports to the Department on MISO’s compliance with the Emergency Order and corresponding environmental impacts, if any.

8. Deprivation of Fair Notice and Adequate Record

60. PIOs claim that DOE failed to comply with its own procedures to post filings on DOE’s 202(c) website within twenty-four hours of receipt, depriving the public of fair notice and a meaningful opportunity to comment.¹²³ According to PIOs, DOE has not posted materials related to the Emergency Order that it has received, such as “a letter from counsel for Consumers Energy, which stated that MISO and Consumers Energy have not been able to reach agreement on the rate issues relating to the May 23, 2025 Order,” among other things.¹²⁴ PIOs also argue that DOE’s failure to follow these procedures “deprives the public and Public Interest Organizations of fair notice and an adequate record.”¹²⁵

The DOE’s Determination

61. The subject of the letter PIOs reference was certain rate issues relating to the Emergency Order, as Consumers Energy and MISO have not been able to agree on appropriate rate issues relating to Emergency Order. Because the letter pertained to rate issues, DOE referred the issues to FERC pursuant to 10 C.F.R. § 205.376, by its own letter dated June 13, 2025.¹²⁶ Moreover, the letter and other materials identified by PIOs were submitted to the Department after the Emergency Order was issued and, as a result, had no bearing on the issuance of the Emergency Order.

9. Lack of Cost Allocation and Cost Recovery Framework

62. OMS claims that the Emergency Order disclaims responsibility for cost recovery to the FERC, while directly incurring costs through the continued operation of the Campbell Plant. OMS argues that this creates legal, jurisdictional, and equity concerns, by assigning costs to those not

¹²² 16 U.S.C. § 824a(c)(2).

¹²³ PIO Pet. at 50.

¹²⁴ *Id.*

¹²⁵ *Id.* (citing *United States v. Nova Scotia Food Prods. Corp.*, 568 F.2d 240, 249 (2d Cir. 1977)).

¹²⁶ See Ltr. from DOE to FERC, *Consumers Energy Company et al. v. Midcontinent Independent System Operator, Inc.*, FERC Docket. No. EL25-90 (June 13, 2025). In its letter, DOE described the contents of the prior letter from Consumers Energy, explaining that, “[o]n June 10, 2025, DOE received a letter from counsel for Consumers which stated that MISO and Consumers have not been able to reach agreement on the rate issues relating to the [Emergency Order].” *Id.* at 2.

causing the costs or receiving the benefits.¹²⁷ Further, OMS alleges the Emergency Order violates FPA sections 205 and 206, which OMS characterizes as requiring rates to be “just and reasonable and not unduly discriminatory or preferential.”¹²⁸ Lastly, OMS alleges the Emergency Order violates “Cost Causation Principles” as held by courts.¹²⁹

63. MPPA similarly claims it must be able to recover costs incurred due to compliance with the Emergency Order and operating the Campbell Plant beyond the retirement date of May 31, 2025, considering MPPA owns 4.80% of Unit No. 3 of the Campbell Plant and is therefore responsible for a portion of its operating and maintenance costs.¹³⁰

64. According to MPPA, any alterations to the original directive could impact its financial recovery.¹³¹ Additionally, MPPA is an intervenor in a related FERC complaint seeking cost recovery for the Campbell Plant owners and actively supports that complaint.¹³² As such, MPPA’s interests are unique and not adequately represented by other parties, and it requests party status in this DOE proceeding to ensure its concerns are addressed.¹³³

The DOE’s Determination

65. Petitioners’ arguments are misguided. FPA section 202(c) does not impose any obligation on the Secretary to address cost allocation issues on the face of an emergency order. In any event, MISO’s existing tariff already establishes how the costs of all generators dispatched by MISO ordinarily are to be allocated. Nothing in the Emergency Order held otherwise.

66. To the extent that the owners of the Campbell Plant desired additional compensation beyond what MISO’s existing tariff provides, FPA section 202(c)(1) provides that: “[i]f the parties affected by [an emergency order issued pursuant to section 202(c)] fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party.”

¹²⁷ OMS Pet. at 4.

¹²⁸ *Id.* at 5.

¹²⁹ *Id.*

¹³⁰ MPPA Comments at 1-2.

¹³¹ *Id.* at 2.

¹³² *Id.*

¹³³ *Id.*

67. Consistent with this statutory provision, DOE’s regulations concerning generation of electricity to alleviate an emergency shortage of electric power address the procedures that DOE will follow when relevant entities are not able to agree on the rate issues arising from an order issued by DOE pursuant to section 202(c):

The applicant and the generating or transmitting systems from which emergency service is requested are encouraged to utilize the rates and charges contained in approved existing rate schedules or to negotiate mutually satisfactory rates for the proposed transactions. In the event that the DOE determines that an emergency exists under section 202(c), and the “entities” are unable to agree on the rates to be charged, the DOE shall prescribe the conditions of service and refer the rate issues to the [FERC] for determination by that agency in accordance with its standards and procedures.¹³⁴

68. On June 6, 2025, Consumers Energy filed a complaint (Complaint) pursuant to sections 202(c), 306, and 309 of the FPA and Rule 206 of FERC’s Rule of Practice and Procedure, proposing revisions to the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) to add a provision (Proposed Tariff Provision) to allocate the costs of keeping the Campbell Plant in operation, in response to the Emergency Order.¹³⁵ On June 13, 2025, DOE promptly issued a referral on cost allocation to FERC, pursuant to 10 C.F.R. § 205.376, in Docket Nos. EL25-90 and AD25-14.¹³⁶ The referral letter specified that “DOE is not referring to the Commission any other matters, including, but not limited to, DOE’s finding of an emergency, the prescription of conditions of service, or any other matter arising from DOE’s exercise of its authority under section 202(c). In an order issued August 15, 2025, in Docket Nos. EL25-90 and AD25-14, FERC granted the Complaint and determined that the Proposed Tariff Provision is just and reasonable.¹³⁷ FERC directed MISO to make a compliance filing, within 30 days of the date of the order, and to adopt the Proposed Tariff Provision.¹³⁸

69. Thus, the cost allocation process established in the Emergency Order worked exactly as contemplated by section 202(c) and DOE’s implementing regulations.

¹³⁴ 10 C.F.R. § 205.376.

¹³⁵ *Consumers Energy Company et al. v. Midcontinent Independent System Operator, Inc.*, FERC Docket No. EL25-90 (June 6, 2025) (citing 16 U.S.C. §§ 824a(c), 825e, 825h, and 18 C.F.R. § 385.206 (2024) (Consumers Energy argued FPA sections 202(c) and 309 provide ample support for their request but moved for Section 206 relief in the alternative)).

¹³⁶ See Ltr. from DOE to FERC, *Consumers Energy Company et al. v. Midcontinent Independent System Operator, Inc.*, FERC Docket Nos. EL25-90 and AD25-14 (June 13, 2025).

¹³⁷ See *Consumers Energy Co. v. Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,158 (2025).

¹³⁸ *Id.* at 18.

III. Procedural Issues

1. PIOs' Request for a Stay

70. PIOs move for a stay of the Emergency Order pending resolution of judicial review. In support of their request, PIOs contend that (i) absent a stay, they will be irreparably harmed by the Emergency Order, (ii) a stay will not harm any other interested parties, and (iii) the public interest favors a stay.¹³⁹

The DOE's Determination

71. In considering a request for a stay, agencies consider (1) whether the party requesting the stay will suffer irreparable injury without a stay; (2) whether issuing a stay may substantially harm other parties; and (3) whether a stay is in the public interest.¹⁴⁰

72. By its terms, the Emergency Order terminated on August 21, 2025. Consequently, the stay request is now moot.

73. In any case, DOE finds that a stay is not warranted here because issuing a stay will substantially harm other parties and therefore is not within the public interest. Specifically, the Emergency Order was issued to address a shortage of electric energy, a shortage of facilities for the generation of electric energy in the Midwest region of the United States. As discussed above, this determination is based on the insufficiency of dispatchable capacity and anticipated demand, and the risk to public health and safety presented by the potential loss of power to homes and local businesses in areas that may be affected by curtailments or outages. Imposition of a stay undoubtedly may harm those citizens residing in the Midwest region of the United States who would face potentially critical electric energy shortages, and therefore the stay is contrary to the public interest.

2. Motions to Intervene

74. Michigan AG, PIOs, Minnesota and Illinois, MPPA, and Maryland OPC each moved to intervene in this proceeding, citing various alleged interests which may be affected by the outcome of this proceeding.¹⁴¹

The DOE's Determination

75. The motions to intervene are hereby granted for Michigan AG, PIOs, Minnesota and Illinois, and MPPA, but DOE takes no position on whether they are “aggrieved” parties for

¹³⁹ PIO Pet. at 51-53.

¹⁴⁰ *Nken v. Holder*, 556 U.S. 418, 434, 436 (2010); *Ohio v. EPA*, 603 U.S. 279, 291 (2024).

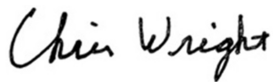
¹⁴¹ See Michigan AG Pet. at 2-3; PIO Pet. at 5-11; Minnesota & Illinois Pet. at 3-8; OMS Pet. at 1-2; Maryland OPC Comments at 1-3; MPPA Comments at 1-2.

purposes of FPA section 313.¹⁴² The motion to intervene by Maryland OPC is denied as DOE maintains that Maryland OPC is not an “aggrieved” party for purposes of FPA section 313.¹⁴³

* * * * *

The Emergency Order is hereby modified upon the issuance of this Order and the result sustained, as discussed in the body of this Order.

Issued at 6:40pm Eastern Daylight Time on this 8th day of September 2025.



Chris Wright

Secretary of Energy

¹⁴² See 16 U.S.C. § 825l(b) (“Any party to a proceeding under this chapter aggrieved by an order issued by the Commission in such proceeding may obtain a review of such order in the United States court of appeals for any circuit wherein the licensee or public utility to which the order relates is located or has its principal place of business, or in the United States Court of Appeals for the District of Columbia, by filing in such court, within sixty days after the order of the Commission upon the application for rehearing, a written petition praying that the order of the Commission be modified or set aside in whole or in part.”).

¹⁴³ See, Resp. in Opp’n to Maryland Office of People’s Counsel Mot. to Intervene. *People of the State of Michigan v. U.S. Department of Energy*, No. 25-1162 (D.C. Cir. Sept. 4, 2025).

EXHIBIT 35

BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

In re: Resource Adequacy Report: Evaluating
the Reliability and Security of the United
States Electric Grid, July 2025

Submitted via e-mail to:
AskCR@hq.doe.gov
August 6, 2025

**Motion to Intervene and Protective Request for Rehearing by the Attorneys General of
Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut,
and New York**

The Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York (“the States”) make this filing to raise our concerns with the Department of Energy’s (“Department” or “DOE”) report titled *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, published July 7, 2025 (“Report”),¹ and request rehearing of the same.

Given that DOE has not yet applied the report to issue future emergency orders, the States do not concede that the Federal Power Act requires the States to request rehearing at this time.² Still, the States acknowledge that President Trump instructed DOE to use the methodology in this report as part of a “protocol” to issue orders pursuant to Section 202(c) of the Federal Power Act preventing the retirement of power plants identified as critical to reliability in DOE’s report.³ DOE has indicated that it intends to comply with that mandate and use this Report to “guide reliability interventions” and issue Section 202(c) emergency orders.⁴ The States reserve all rights to present these objections, or any other objection or legal challenge to the Report or DOE’s reliance on this report going forward. However, out of an abundance of caution and to preserve their arguments, the States also formally request rehearing of the methodology,

¹ Available at https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29_0.pdf [https://perma.cc/J2XU-2RRJ].

² See 16 U.S.C. § 825l.

³ See Exec. Order No. 14,262, 90 Fed. Reg. 15,521 (Apr. 14, 2025).

⁴ See U.S. DEP’T OF ENERGY, *Fact Sheet: The Department of Energy’s Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid* (2025), https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf [https://perma.cc/YLX7-8G7T] (explaining that DOE’s methodology will be used, pursuant to the executive order, “prevent [] generation resources from leaving the bulk-power system”); Press Release, U.S. Dep’t of Energy, Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security (July 7, 2025), <https://www.energy.gov/articles/departments-energy-releases-report-evaluating-us-grid-reliability-and-security> [https://perma.cc/8TEJ-AGH6]. (stating that its “methodology also informs the potential use of DOE’s emergency authority under Section 202(c) of the Federal Power Act”); Report at vi (explaining that DOE’s standard will be used to “guide reliability interventions”), 1 (emphasizing the need for DOE’s “decisive intervention” in energy markets), 10 (analyzing ERCOT because “FPA Section 202(c) allows DOE to issue emergency orders to ERCOT”).

standards, and protocol identified in this Report under Section 313l of the Federal Power Act, 16 U.S.C. § 825l.

This filing details the ways in which the Report is arbitrary and why it would be unlawful to rely on it to justify future Section 202(c) orders. The States also request DOE review the Report independently before it is used in any capacity in order to address the serious errors in the analysis highlighted here.

I. Motion to Intervene

The Attorneys General of Maryland, Washington, Illinois, Michigan, Minnesota, Arizona, Colorado, Connecticut, and New York move to intervene in this proceeding pursuant to Section 313l of the Federal Power Act, 16 U.S.C. § 825l, and request that the Department of Energy grant rehearing of its July 7, 2025 report titled *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*.

Executive Order 14262 and DOE's own statements alongside the Report's publication indicate that it will be used to "guide reliability interventions" and justify issuance of emergency orders under Section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c). The Report is deeply flawed and, if DOE is taken at its word, it will inflict significant harm on our states.

Many of the retiring resources targeted by this report are located in our states. In Washington, for example, the Transalta Centralia coal-fired power plant is scheduled to retire in December 2025. In Colorado, the Craig and Comanche coal-fired power plants are scheduled to retire by the end of the year as well and the state's remaining coal fired power plants are scheduled to retire by 2031. These retirements have been thoroughly vetted by state and regional authorities and approved only following an extensive examination of cost considerations and reliability impacts.

And even when a source is not located directly in one of our states, the ratepayer impacts of overriding a planned retirement based on the DOE Report will often be felt by our residents. That is because many of these resources operate within regional transmission systems that spread costs across all, or a portion of, their footprint. In MISO, for example, ratepayers across the ISO's north and central regions are being asked to foot the bill for the continued operation of the J.H. Campbell coal-fired power plant in Michigan pursuant to a Section 202(c) order issued by DOE in May. In just five weeks, complying with that Order has cost the plant's owner \$29 million.⁵ The order is expected to cost consumers close to \$100 million if it expires on August 21 and is not renewed.⁶

⁵ See CMS Energy Corp., Quarterly Report (Form 10-Q) (Jul. 31, 2025), <https://www.sec.gov/ix?doc=/Archives/edgar/data/0000201533/000081115625000071/cms-20250630.htm>.

⁶ Brian Dabbs, *Coal Plant Ordered to Stay Open Cost \$29M to Run in 5 Weeks*, POLITICO ENERGYWIRE (Aug. 1, 2025), <https://subscriber.politicopro.com/article/eenews/2025/08/01/coal-plant-ordered-to-stay-open-cost-29m-to-run-in-5-weeks-00487542>.

Our states are also harmed when Section 202(c) is used to keep polluting facilities from retiring in upwind locations. Fossil-fuel power plants are large sources of ozone-forming pollution and toxic emissions that contribute to nonattainment of air quality standards in downwind states like Connecticut, New York, and Maryland. Planned retirements have the benefit of reducing this pollution and overriding those state and regional determinations based on the DOE Report will further the harm that downwind states face from upwind sources.

Moreover, the report unlawfully intrudes on the states' authority to regulate generation resources within their borders. Section 201 of the Federal Power Act clearly reserves to the states their traditional authority "over facilities used for the generation of electric energy."⁷ That authority "is a matter that has traditionally rested with the states, and it should continue to rest there."⁸

Both EO 14262 and subsequent statements by DOE make clear that the report will be used to justify Section 202(c) orders going forward.⁹ The States are aggrieved by the report which paints an unrealistic picture of resource adequacy to justify use of DOE emergency authority. Exercising that authority in non-emergency situations will harm ratepayers and the environment and unlawfully infringe on an area of state sovereign authority. Moreover, our states are also purchasers of retail electricity and are directly harmed by the rate impacts from these decisions.

II. Background

a. Resource adequacy is highly regulated at the state and regional levels.

Existing regulatory mechanisms govern both federal requirements for reserve margins and state resource adequacy determinations. Resource adequacy is an integral part of prudent, least-cost, utility planning in every state and region of the country.¹⁰ DOE plays no role in the complex proceedings to determine either reserve margins or specific resource adequacy conclusions. The Report fails to grapple with the complicated task of resource adequacy planning undertaken by state utility offices and regional grid planners across the country, yet these existing procedures are a key part of the alleged resource adequacy conundrum which the DOE Report claims to address.

⁷ 16 U.S.C. § 824(b)(1).

⁸ *Devon Power LLC et al.*, 109 FERC ¶ 61,154, para. 47 (Nov. 8, 2004).

⁹ See U.S. Dep't of Energy, Order No. 202-25-4 (May 30, 2025) [<https://perma.cc/PS3M-6CJA>] [*hereinafter* "Eddystone Order"] (The methodology "will be used to establish a protocol to identify which generation resources within a region are critical to system reliability and prevent identified generation resources from leaving the bulk power system. . . . DOE plans to use [the July 7] methodology to further evaluate Eddystone Units 3 and 4.").

¹⁰ See SYNAPSE ENERGY ECONOMICS & LAWRENCE BERKELEY NATIONAL LABORATORY, BEST PRACTICES IN INTEGRATED RESOURCE PLANNING 1-2 (Nov. 2024), https://www.synapse-energy.com/sites/default/files/IRP_Best_Practices_2024_Synapse_LBNL_24-061_1.pdf [<https://perma.cc/D68F-WHWQ>].

i. States directly regulate resources to ensure an adequate supply of electricity.

Most states rely on resource planning processes to ensure that adequate generation is available to meet projected demand. While some states have largely delegated this authority to the regional grid operators and rely on market-based mechanisms to ensure future demand is met, it is ultimately the state that retains regulatory authority over generation resources.¹¹ These state processes are transparent and iterative, relying on technical and expert analysis to ensure that adequate resources are procured in a prudent manner. The States describe just a few of the mechanisms at play in our jurisdictions as relevant examples below.

1. Arizona

Arizona, like other states, regulates the power generation, transmission, and distribution needs of the electric grid to ensure resource adequacy and reliability. This regulatory authority is established in the State's constitution. The Arizona Constitution grants the Arizona Corporation Commission ("ACC") broad authority to regulate public service corporations, including electric utilities.¹² The Arizona Constitution also empowers the ACC to set just and reasonable classifications, rates, and charges, as well as to make and enforce rules, regulations, and orders for the governance of utilities. This constitutional authority underpins the ACC's ability to establish requirements for resource planning and grid reliability.¹³

The ACC has reliability requirements in its Resource Planning and Procurement ("RPP") rules.¹⁴ The ACC's RPP rules require load-serving entities to file and seek acknowledgement of their prospective, 15-year resource plans every three years, which include projected data for generating units and power supply systems, capital costs, environmental impacts, and cost analyses.

The most recent version of Integrated Resource Plans was authorized by the ACC on October 21, 2024,¹⁵ which approved the power generation, transmission, and distribution acquisition plans that were submitted by Arizona Public Service,¹⁶ Tucson Electric Power,¹⁷ and UNS Electric.¹⁸ The ACC requires similar data from its electric cooperatives in order to improve

¹¹ 16 U.S.C. § 824(b)(1).

¹² ARIZ. CONST. art. 15, § 3.

¹³ *Id.*

¹⁴ A.A.C. R14-2-701.

¹⁵ ACC Decision No. 79589, <https://docket.images.azcc.gov/0000212120.pdf?i=1754080707112>.

¹⁶ ARIZONA PUBLIC SERVICE, *2023 Integrated Resource Plan* (Nov. 1, 2023), <https://docket.images.azcc.gov/E000031965.pdf?i=1754080707112>.

¹⁷ TUCSON ELECTRIC POWER, *Tucson Electric Power 2024 Integrated Resource Plan* (Nov. 1, 2023), <https://docket.images.azcc.gov/E000031960.pdf?i=1754080707112>.

¹⁸ UNS ELECTRIC, *UNS Electric 2023 Integrated Resource Plan* (Nov. 1, 2023), <https://docket.images.azcc.gov/E000031961.pdf?i=1754080707112>.

grid performance and reliability in rural areas of the state.¹⁹ The decision requires technology-neutral portfolio methodologies, annual load forecast accuracy reports, and analysis of coal-fired power plant retirement timelines to enhance reliability, building on existing triannual utility analyses. It also requires sharing modeling data with stakeholders.

While one major utility in Arizona, the Salt River Project, is not subject to the ACC's jurisdiction, it has adopted its own planning and goal-setting requirements, referred to as the Integrated System Plan.²⁰

2. New York

The New York Independent System Operator ("NYISO") plays a significant role in safeguarding electric grid reliability while supporting the clean energy transition.²¹ As part of its biennial reliability planning process, NYISO first conducts a Reliability Needs Assessment, which examines whether New York's power grid will have enough generation, storage, and transmission capacity to meet demand over the next ten years.²² Specifically, the Assessment uses probabilistic simulations to evaluate whether New York meets the Loss of Load Expectation (LOLE) criterion of not more than 0.1 event-days/year (equivalent to one day in ten years), which is the standard reliability criterion used by the New York State Reliability Council and the Northeast Power Coordinating Council.²³ The Assessment also evaluates how New York's environmental and energy laws—such as the Climate Leadership and Community Protection Act, which requires 100% zero-emission electricity by 2040—will affect grid reliability, especially as fossil fuel-fired power plants retire, and electricity demand increases due to building electrification and the continued growth of the electric vehicle market.²⁴

Following the Reliability Needs Assessment, NYISO completes the biennial planning process by issuing a Comprehensive Reliability Plan that documents the plans for a reliable electric grid over the same ten years.²⁵ The Comprehensive Reliability Plan provides solutions to any shortfalls identified in the Reliability Needs Assessment, such as accelerating battery deployment, deferring certain retirements, upgrading transmission lines, or increasing demand-side participation.²⁶ While the 2022 Reliability Needs Assessment did not identify any actionable

¹⁹ ARIZONA ELECTRIC POWER COOPERATIVE, *Demand-and Supply-Side Data Filing* (Apr. 1, 2025), <https://docket.images.azcc.gov/E000042810.pdf?i=1753996193952>.

²⁰ SALT RIVER PROJECT, *Integrated System Plan* (Apr. 1, 2025), <https://www.srpnet.com/grid-water-management/future-planning/integrated-system-plan>.

²¹ See *About Us*, NYISO, <https://www.nyiso.com/about-us>.

²² See NYISO, 2024 RELIABILITY NEEDS ASSESSMENT (Nov. 19, 2024), <https://www.nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf>.

²³ *Id.* at 41.

²⁴ *Id.* at 23-24 fig. 13.

²⁵ See NYISO, 2023–2032 COMPREHENSIVE RELIABILITY PLAN (Nov. 28, 2023), <https://www.nyiso.com/documents/20142/2248481/2023-2032-Comprehensive-Reliability-Plan.pdf> (following the 2022 RNA and incorporating finding and solutions from the quarterly short term reliability process).

²⁶ See *id.*

reliability shortfalls, the 2023–2032 Comprehensive Reliability Plan nonetheless provided a forward-looking analysis that evaluated key risk factors related to reliability, including delays in major transmission projects, winter peaking and gas shortage risks, and extreme weather.²⁷

In parallel with the biennial reliability planning process, as of 2019, NYISO also conducts a quarterly short-term reliability (“STAR”) process to identify reliability needs that may arise over the next five years due to various changes in the grid, such as generator deactivations, revised transmission plans, or updated electricity demand.²⁸ For example, NYISO’s Quarter 2 2023 STAR report, published on July 14, 2023, identified the potential for electricity supply shortfalls in New York City beginning in the summer 2025 as a result of the New York State Department of Environmental Conservation’s “Peaker Rule,” which seeks to reduce nitrogen oxide (NO_x) emissions from simple-cycle combustion turbines that supply backup generation during peak demand.²⁹ Following this STAR report, NYISO sought proposed solutions from market participants and ultimately exercised its authority under the Peaker Rule to require specific peaker units to remain operational until long-term solutions—such as the Champlain Hudson Power Express line, scheduled to enter service in spring 2026, bringing 1,250 MW of hydropower to New York City—could come online.³⁰ NYISO incorporates any needs or shortfalls identified in the STAR process into its biennial reliability planning process.³¹

3. Connecticut

Connecticut General Statutes § 16a-3a requires that the Department of Energy and Environmental Protection (“DEEP”) prepare an Integrated Resource Plan (“IRP”). An IRP is composed of an assessment of the future electric needs and a plan to meet those future needs. It is “integrated” in that it looks at both demand side (conservation, energy efficiency, etc.) resources as well as the more traditional supply side (generation/power plants, transmission lines, etc.) resources in making its recommendations on how best to meet future electric energy needs in the state. Connecticut’s current IRP was completed in 2020 and updated in 2022. DEEP is currently developing the 2025 IRP, which involves planning for the next ten years.

²⁷ *Id.* at 48-67.

²⁸ See *Short-Term Reliability Process*, NYISO, <https://www.nyiso.com/short-term-reliability-process> (last visited July 28, 2025); *Reliability Planning Process and Declaring a Reliability Need: Next Steps*, NYISO (July 14, 2023), <https://www.nyiso.com/-/reliability-planning-process-and-declaring-a-reliability-need-next-steps>.

²⁹ NYISO, *Short-Term Assessment of Reliability: 2023 Quarter 2* (July 14, 2023), <https://www.nyiso.com/documents/20142/16004172/2023-Q2-STAR-Report-Final.pdf/5671e9f7-e996-653a-6a0e-9e12d2e41740>.

³⁰ Press Release, NYISO, *NYISO Identifies Solution to Solve New York City Reliability Need* (Nov. 20, 2023), <https://www.nyiso.com/-/press-release-%7C-nyiso-identifies-solution-to-solve-new-york-city-reliability-need>.

³¹ See NYISO, 2023–2032 COMPREHENSIVE RELIABILITY PLAN, *supra* note 25, at 30–32.

4. Colorado

Colorado regulations require every investor-owned retail electric utility and wholesale electric generation and transmission cooperative operating in the state to file an energy resource plan (“ERP”) with the Public Utilities Commission (“PUC”) every four years.³² ERPs must contain electric demand and energy forecasts, evaluation of existing resources, an assessment of planning reserve margins and contingency plans for the acquisition of additional resources.³³ If an ERP includes retirement of an existing coal-fired generating facility, detailed workforce transition and community assistance plans must be filed.³⁴

The planning process includes a reserve margin to meet a 0.1 days per year loss of load expectation standard.³⁵ Utilities use this reserve margin to propose additional generation for the planning period, where necessary. Those proposals are vetted through extensive stakeholder input and consideration by the Colorado PUC and the additional generation must satisfy availability and dispatchability criteria.³⁶ And where generation needs arise outside of the four-year ERP process, interim ERPs and applications for certificates of public convenience and necessity can be filed to meet those needs.³⁷ These proceedings are transparent and iterative and conducted with technical and expert analysis of grid conditions and ratepayer impacts.

5. Illinois

Illinois ratepayers are served by two Regional Transmission Organizations (“RTO”), Midcontinent Independent System Operator, Inc. (“MISO”) and PJM Interconnection, L.L.C. (“PJM”). Central and Southern Illinois are encompassed by MISO Local Resource Zone 4 and a small portion of Northwest Illinois is included in MISO Local Resource Zone 1.³⁸ The service area of Commonwealth Edison Company, the load serving entity for Illinois electricity customers in Northern Illinois, is encompassed by PJM’s ComEd Zone.³⁹ The Illinois Attorney General’s office represents Illinois ratepayers who have a significant interest in resource adequacy and maintaining reliable service at least possible cost that is materially affected by the outcome of this proceeding.

³² 4 COLO. CODE REGS. § 723-3-3603(a).

³³ 4 COLO. CODE REGS. § 723-3-3604(b-f).

³⁴ COLO. REV. STAT. § 40-2-125.5(4)(a)(VII).

³⁵ See Colo. Pub. Utils. Comm’n Proceeding No. 24A-0422E, HE 109 and HE 109 ZM-1; Colo. Pub. Utils. Comm’n Proceeding No. 21A-0141E, Hrg. Exh. 115, pp. 8-10.

³⁶ COLO. REV. STAT. § 40-2-125.5 (4)(d)(II).

³⁷ *Id.*

³⁸ See MISO Tariff, Attachment VV, Map of Local Resource Zone Boundaries, https://docs.misoenergy.org/miso12-legalcontent/Attachment_VV_-_MAP_of_Local_Resource_Zone_Boundaries.pdf.

³⁹ See MISO Tariff, Attachment VV, Map of Local Resource Zone Boundaries, https://docs.misoenergy.org/miso12-legalcontent/Attachment_VV_-_MAP_of_Local_Resource_Zone_Boundaries.pdf.

6. Washington

Washington electric utilities file clean energy implementation plans to the Washington Utilities and Transportation Commission once every four years with a biennial update filing at the midway point of every plan.⁴⁰ They also file long term integrated resource plans every four years.⁴¹ For investor-owned utilities, if an integrated resource plan identifies a resource need within the next four years, the utility must file a request for proposal with the Commission for approval.⁴²

7. Michigan

In Michigan, ratepayers are served primarily by MISO, with a smaller portion included within PJM. In MISO, the regulation of resource adequacy planning has both a state and federal aspect. MISO member states have a capacity obligation under the MISO tariff. MISO's resource adequacy requirements, however, are designed to be complementary to the primary role of the states in ensuring resource adequacy.⁴³ In Michigan, the investment decisions of utilities are regulated by the Michigan Public Service Commission ("MI PSC"). Through Michigan's state Integrated Resource Planning process, the MI PSC exercises regulatory authority over utilities in order to ensure that the utilities obtain the amounts of capacity they need to meet their obligations under the MISO tariff, and that they do so at the best value to ratepayers, and with a composition of resources that otherwise complies with state law, including environmental requirements.

Michigan's IRP statute requires electric utilities whose rates are regulated by the MI PSC to periodically file an integrated resource plan. The IRP is a projection of the utility's load obligations and a plan to meet those obligations.⁴⁴ The IRP statute directs the MI PSC to approve

⁴⁰ See WASH. REV. CODE § 19.405.060; WASH. ADMIN. CODE § 480-100-640, -645; *see also* WASH. UTILS. AND TRANSP. COMM'N, *Clean Energy Implementation Plans*, <https://www.utc.wa.gov/regulated-industries/utilities/energy/conservation-and-renewable-energy-overview/clean-energy-transformation-act/clean-energy-implementation-plans-ceips>.

⁴¹ See WASH. REV. CODE § 19.280.040 to 050; WASH. ADMIN. CODE § 480-100-620, -625; *see also* WASH. UTILS. AND TRANSP. COMM'N, *Integrated Resource Plans*, <https://www.utc.wa.gov/integrated-resource-plans-irps>.

⁴² See WASH. ADMIN. CODE § 480-107-009(2), -017.

⁴³ *Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,215, 62,606 at P 13 (2020) ("approximately 90% of the load in MISO is served by vertically integrated LSEs, the vast majority of which are subject to state integrated resource planning processes. To accommodate the make-up of the MISO's footprint, MISO's proposed Tariff provisions accepted in the February 2018 Order provide that its resource adequacy requirements "are complementary to the reliability mechanisms of the states and the Regional Entities ... within the [MISO] region."); *see also id.* ("MISO's proposed Tariff language explains that the resource adequacy requirements 'are not intended to and shall not in any way affect state actions over entities under the states' jurisdiction.' In other words, unlike the centralized capacity constructs used in the Eastern RTOs/ISOs, MISO's Auction is not—and has never been—the primary mechanism for its [Load Serving Entities] to procure capacity."); *Midwest Indep. Transmission Sys. Operator, Inc.*, 119 FERC ¶ 61,311, 62,722 at P 75 (2007) ("From the beginning . . . the Commission has recognized the role that state resource planning plays in managing the resource adequacy of [MISO]").

⁴⁴ MICH. COMP. LAWS § 460.6t(3).

a plan if the MI PSC determines that it “represents the most reasonable and prudent means of meeting the electric utility’s energy and capacity needs.”⁴⁵ To make that decision, the statute instructs the MI PSC to consider whether the IRP appropriately balances seven statutory factors: (i) resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement; (ii) compliance with applicable state and federal environmental regulations; (iii) competitive pricing; (iv) reliability; (v) commodity price risks; (vi) diversity of generation supply; and (vii) whether proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective.⁴⁶

The IRP statute also directs the MI PSC to establish – among other things – computer modeling scenarios that must be used to analyze the costs of possible plans in an IRP, including costs associated with plant retirement dates.⁴⁷ In Consumers Energy’s 2021 IRP, for example, the company conducted modeling that compared other possible retirement dates of its J.H. Campbell coal-fired power plant to a 2025 retirement and concluded that the most cost-effective retirement date was 2025.

8. Minnesota

Since 1991, Minnesota law has required each public utility to propose a set of resource options that the utility could use to meet the electricity service needs of its customers over a forecast period of 15 years.⁴⁸ The resource options include using, refurbishing and constructing utility plant and equipment, buying power generated by other entities, controlling customer loads, and implementing customer energy conservation. The Minnesota Public Utilities Commission (“Minnesota Commission”) evaluates the plan’s ability to ensure reliability of utility service, keep customer’s bills and utility rates as low as practicable, minimize adverse socioeconomic effects and adverse effects on the environment, and limit risk.⁴⁹ The Commission uses an extensive notice and comment process in which the utilities and stakeholders evaluate detailed modeling of demand and various resource costs. The Minnesota Commission may approve, reject or modify utility resource plans.⁵⁰ In the most recent resource plan for Minnesota’s largest utility, the Minnesota Commission approved including in the resource plan a new natural-gas fired 420 MW combustion turbine plant to address peak load.⁵¹

⁴⁵ MICH. COMP. LAWS § 460.6t(8)(a).

⁴⁶ *Id.*

⁴⁷ MICH. COMP. LAWS § 460.6t(1).

⁴⁸ MINN. STAT. § 216B.2422; MINN. R. ch. 7843; *see also Electric Integrated Resource Planning (IRP)*, MINN. PUB. UTILS. COMM’N, <https://mn.gov/puc/activities/economic-analysis/planning/irp/> (last accessed Aug. 6, 2025).

⁴⁹ MINN. R. 7843.0600, subp. 3.

⁵⁰ MINN. STAT. § 216B.2422.

⁵¹ MINN. PUB. UTILS. COMM’N, Dkt. No. E-002/RP-24-67; E-002/CN-23-212, Order Approving Settlement Agreement With Modifications (Apr. 21, 2025), <https://www.edockets.state.mn.us/documents/%7B30F45996-0000-CF1F-80E3-5E41B2F16918%7D/download?contentSequence=0&rowIndex=3>.

ii. Regional operators establish mechanisms to ensure resource adequacy and grid stability.

State primacy over resource adequacy is further complemented by the regional transmission operators. For example, MISO and PJM both have extensive processes for obtaining resource adequacy and reliability. MISO works collaboratively with its member states to ensure resource adequacy throughout its service area.⁵² MISO ensures there is sufficient generation capacity through forecasting demand growth, assessing existing generation assets, and planning for new generation resources.⁵³ MISO accounts for state Integrated Resource Planning and also operates a capacity auction where utilities and other load-serving entities can procure the necessary generation capacity to meet projected demand. MISO's capacity market is intended to incentivize the development and maintenance of adequate generation resources.⁵⁴ MISO's annual Planning Resource Auction ("PRA") procures sufficient resources and allows market participants to buy and sell capacity via the auction.⁵⁵

Resource adequacy within the PJM footprint is subject to an established, extensive, layered, framework of oversight and regulation. The resource adequacy contribution of each PJM electric generating plant operating is subject to ongoing, technical reviews by PJM, pursuant to its tariff, and in conformity with rules promulgated and periodic grid reliability reviews conducted by Reliability First Corporation and NERC, respectively.⁵⁶ PJM also conducts an auction, its base residual auction ("BRA"), for the procurement of capacity from generating resources.

b. Historic use of 202(c) is limited.

Section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c), grants the Secretary of Energy the authority to issue orders that require the "temporary connection[]" of power plants and the "generation, delivery, interchange, or transmission of electric energy" in order to address certain emergencies "and serve the public interest."⁵⁷ The law also effectively waives compliance with "any Federal, State, or local environmental law or regulation" that would conflict with any

⁵² *System Planning*, MISO, https://www.misoenergy.org/meet-miso/about-miso/industry-foundations/grid_planning_basics/ (last visited July 30, 2025).

⁵³ *Id.*

⁵⁴ *Id.*

⁵⁵ *Resource Adequacy*, MISO, <https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc> (last visited July 30, 2025).

⁵⁶ *See, e.g., North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009); Order No. 748, Final Rule, 134 FERC ¶ 61,213 (2011). FERC approved regional reliability standards applicable to PJM, developed by RFC and submitted to FERC by NERC. *Notice of Proposed Rulemaking on Plan. Res. Adequacy Assessment Reliability Standard*, 133 FERC ¶ 61,066 (2010) (proposed rule for RFC); *Plan. Res. Adequacy Assessment Reliability Standard*, Order No. 747, 134 FERC ¶ 61,212 (2011) (final approval of RFC's Resource Adequacy Reliability Standard).

⁵⁷ 16 U.S.C. § 824a(c)(1).

party's obligations under such an order, but limits the length of any order that conflicts with a pollution control requirement to 90-days, with extension possible.⁵⁸

That authority originated principally as a wartime power of what was then the Federal Power Commission. Section 202(c) was enacted in 1935, in the leadup to World War II, with the same “emergency” language that exists in the statute today, specifically to guard against energy related shortages that were viewed as hampering national security during World War I.⁵⁹ It was initially used largely to issue “interconnection” orders specifically between utilities at a time when America’s electric grid was more fragmented, monopolized, and less diversified than it is today.⁶⁰ Interconnection was seen as a powerful means to increase grid reliability, but the federal government largely lacked regulatory power over the electric sector at the time.⁶¹ The then-Federal Power Commission did not invoke its emergency authority until the United States entered World War II.⁶² Section 202(c) orders were issued repeatedly during the war, primarily to order interconnection between utilities, but the provision was rarely invoked once the war ended. A number of organizational changes ensued in the decades following the War and the provision’s authority eventually came to rest with the Secretary of Energy.⁶³

From 2000, when the authority of Section 202(c) was “rediscovered” in response to the California Energy Crisis, through 2024, the provision was sparingly invoked to respond to true emergencies to avoid imminent widespread blackouts.⁶⁴ Most 202(c) orders issued during this period involved natural disasters or other acute power outages.⁶⁵ These emergencies included one high-profile incident near the nation’s capital that led to the statute’s 2015 amendment, adding the provisions explicitly waiving environmental liability due to compliance with a Section 202(c) order, leading the statute to read as it does today.⁶⁶ Orders issued during this period were typically of limited duration, lasting for a period of days to weeks.⁶⁷

The typical process for issuing a Section 202(c) order is outlined by DOE implementing regulations at 10 C.F.R. §§ 205.370-379. In the normal course, requests for Section 202(c) orders originate with a grid operator or utility facing an acute and unforeseen emergency that normal processes and demand response mechanisms are incapable of addressing, though they may be issued by the Department unprompted as well.⁶⁸ Applications for Section 202(c) orders made by

⁵⁸ *Id.* at § 824a(c)(3)-(4).

⁵⁹ For a deeper discussion of the history of Section 202(c), see Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. 789 (2025). *See also id.* at 798-802.

⁶⁰ *Id.* at 802-804.

⁶¹ *Id.* at 801-802.

⁶² *See id.* at 803 n.82 and accompanying text.

⁶³ *Id.* at 803-04; 42 U.S.C. § 7151(b).

⁶⁴ *Id.* at 805-509.

⁶⁵ Rolsma, *supra* note 59, at 805-09, 839-42 tbl.1.

⁶⁶ *Id.* at 806-08 (citing DEP’T OF ENERGY, ORDER NO. 202-05-3 (Dec. 20, 2005)); 16 U.S.C. § 824a(c)(3)-(5).

⁶⁷ *See* Rolsma, *supra* note [x], at 839-42 tbl.1 (chronicling all Section 202(c) orders issued “after dissolution of the Federal Power Commission”).

⁶⁸ *See* 10 C.F.R. § 205.370.

outside entities are to include specific details to “be considered by the DOE in determining that an emergency exists” and the appropriate intervention.⁶⁹ This information is supposed to include “[d]aily peak load and energy requirements for each of the past 30 days and projections for each day of the expected duration of the emergency,” “[a] description of the situation and a discussion of why this is an emergency, ... includ[ing] any contingency plan of the applicant and the current level of implementation,” and “[a] description of efforts made to obtain additional power through voluntary means and the results of such efforts.”⁷⁰ Section 202(c) orders bypass environmental review under NEPA and can waive pollution control requirements that would otherwise apply to the facilities.⁷¹

c. President Trump Declares a National Energy Emergency on his first day in office and subsequently issues EO 14262.

On January 20, 2025, his first day in office, President Trump issued Executive Order 14156 titled “Declaring a National Energy Emergency”.⁷² That unilateral declaration did not provide any factual support for its assertion that emergency conditions had overtaken the electricity grid.⁷³

On April 8, 2025, President Trump issued Executive Order 14262, “Strengthening the Reliability and Security of the United States Electric Grid.”⁷⁴ Section 3(b) of the executive order directs the Secretary of Energy (Secretary) to:

develop a uniform methodology for analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy.⁷⁵

It further requires that the methodology in the Report (Methodology) “be published, along with any analysis it produces, on the Department of Energy’s website within 90 days of the date of this order,” or July 7, 2025.⁷⁶

The Executive Order describes the featured role that the Report will play in future DOE actions. EO 14262 § 3 is titled “Addressing Energy Reliability and Security with Emergency Authority” and § 3(c) directs the Secretary to “establish a process by which the [Methodology],

⁶⁹ 10 C.F.R. § 205.373.

⁷⁰ 10 C.F.R. §§ 205.373(a)-(o).

⁷¹ *See, e.g., Environmental Integrity Project v. DOE*, 471 F. Supp. 3d 132 (D.D.C. 2023).

⁷² 90 Fed. Reg. 8433.

⁷³ *See Id.* (providing no factual support for claimed emergency). Many of the States have since joined litigation challenging that declaration. *See Complaint, Washington v. Trump*, NO. 2:25-cv-00869 (W.D. Wa. May 9, 2025).

⁷⁴ The EO was signed alongside Exec. Order No. 14261, Reinvigorating America’s Beautiful Clean Coal Industry and Amending Executive Order 14241, 90 Fed. Reg. 15517 (Apr. 8, 2025), at a White House event with members of the coal industry.

⁷⁵ Exec. Order No. 14262, 90 Fed. Reg. 15521, 15521 (Apr. 8, 2025).

⁷⁶ Exec. Order No. 14262, 90 Fed. Reg. 15521, 15521 (Apr. 8, 2025) (referring to § 3(b)(iii)).

and any analysis and results it produces, are assessed on a regular basis, and a protocol to identify which generation resources within a region are critical to system reliability.”⁷⁷ It indicates the protocol shall “include all mechanisms available under applicable law, including Section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region.”⁷⁸ In short, Executive Order 14262 instructs DOE to publish a methodology by July 7, 2025 that will form the basis for future exercises of its Section 202(c) authority.

d. DOE’s 2025 Emergency Orders Preventing the Retirement of Fossil Fuel Power Plants.

Since January 20, 2025, the U.S. Department of Energy (DOE) has issued five emergency orders under Section 202(c) of the Federal Power Act (FPA), a sharp uptick from the less than one order per year issued on average from 2017-2024.⁷⁹ Three of these orders were largely in line with DOE’s historic Section 202(c) practice – allowing units to modify their operations in response to acute risks to the grid.⁸⁰ However, in late May 2025 DOE issued a pair of Section 202(c) orders requiring facilities that were slated to retire the very next business day to remain on-line. These orders represent a marked shift in how Section 202(c) has historically been used.⁸¹

For example, the orders for the J.H. Campbell Generating Station in Michigan and the Eddystone Plant in Pennsylvania, both previously slated for retirement, cited general concerns about resource adequacy and not any acute emergency. In Michigan, regulators warned that the Campbell order would place upward pressure on ratepayers, particularly in Consumers Energy’s service territory, where decommissioning costs were already being recovered through base rates. One Michigan regulator estimated that the costs of complying with DOE’s order for 90 days would approach \$100 million.⁸² Consumers Energy has since disclosed that continued operation

⁷⁷ Exec. Order No. 14262, 90 Fed. Reg. 15521, 15522 (Apr. 8, 2025) (referring to § 3).

⁷⁸ Exec. Order No. 14262, 90 Fed. Reg. 15521, 15522 (Apr. 8, 2025) (referring to § 3) (emphasis added).

⁷⁹ U.S. DEP’T OF ENERGY, *DOE Issues 202(c) Orders to PREPA for Grid Stability*, <https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority>.

⁸⁰ See Duke Energy Carolinas (Order No. 202-25-5) (allowing increased operations to support grid stability); H.A. Wagner (Order No. 202-25-6) (allowing exceedance of operational limit – but maintained compliance with pollution control requirements – to allow units to respond to demand); PREPA (Order No. 202-25-1) (requiring measures to mitigate outage risks during high load conditions)

⁸¹ U.S. Dep’t of Energy, Order No. 202-25-3 (May 23, 2025), https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf [<https://perma.cc/Q7P7-TDTX>] [hereinafter “Campbell Order”]; Eddystone Order, *supra* note 9.

⁸² See, e.g., Ella Nilsen, *The Trump Admin Ordered a Coal Power Plant to Stay On Past Retirement. Customers in 15 States Will Foot the Bill*, CNN (June 6, 2025), <https://www.cnn.com/2025/06/06/climate/michigan-coal-plant-energy-cost-wright>.

of the plant in the first five weeks since the Order was issued has resulted in a net financial impact of \$29 million.⁸³

e. DOE Publishes its Methodology and Reliability Standard to Guide Future Section 202(c) “Reliability Interventions.”

On July 7, 2025, DOE published a “Report on Evaluating U.S. Grid Reliability and Security,” which set forth the methodology and reliability standard that the Executive Order had mandated. *See* Report at *vi* (hereinafter, “the Report”). DOE stated the methodology “will be assessed on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States.” *Id.* Despite this statement, DOE has not explained how or when it will re-assess the methodology and, to date, has not involved the public in the creation of the methodology or offered an opportunity for public comment on the methodology.

i. DOE did not provide public notice or an opportunity for comment on the Report.

Before publishing the Report, DOE provided no public notice or request for comment on methods or reliability standards that DOE was considering. DOE did not consult with the undersigned States or, to the States’ knowledge and belief, consult with any grid operator or other State on appropriate mechanisms to ensure grid reliability and grid reliability issues around the country.⁸⁴ Other than the statements in the Report, DOE has not made the underlying data or models available to allow the public to reproduce or test DOE’s analysis. DOE has not requested public comment on the Report, opened any administrative proceeding to otherwise involve the public in DOE’s methodology, or published the Report in the Federal Register.

DOE has confirmed, consistent with the Executive Order’s mandate, that it will rely on the Report to justify future Section 202(c) orders.⁸⁵ DOE explained in the June 2025 Eddystone Order that it would use the forthcoming Report “to establish a protocol to identify which generation resources within a region are critical to system reliability and prevent identified generation resources from leaving the bulk power system[,]” including potential Section 202(c) orders extending DOE’s Eddystone Order.⁸⁶ DOE also issued the Report with a “Fact Sheet,”

⁸³ *See supra* notes 5-6 and accompanying text; NRDC, *Trump Administration’s DOE Is Forcing Coal Plants to Stay Open. Michigan Is the First Target* (June 16, 2025), <https://www.nrdc.org/bio/derrell-e-slaughter/trump-administrations-doe-forcing-coal-plants-stay-open-michigan-first>.

⁸⁴ *See* Report at *i* (acknowledging lack of data from regional and utility levels).

⁸⁵ *See* Report at *vi* (explaining that DOE’s standard will be used to “guide reliability interventions”), 1 (emphasizing the need for DOE’s “decisive intervention” in energy markets), 10 (analyzing ERCOT because “FPA Section 202(c) allows DOE to issue emergency orders to ERCOT”).

⁸⁶ Eddystone Order, *supra* note 9.

wherein DOE explained that the methodology will be used to “prevent [] generation resources from leaving the bulk-power system.”⁸⁷

ii. DOE’s analysis rests on key assumptions about load growth, retirements, and capacity additions.

The Report’s analysis rests on assumptions about future electricity demand (referred to as “load growth”), anticipated retirements of existing facilities (“retirements”), and future electricity generation sources (referred to as “capacity additions”). DOE made additional assumptions, some explicit and others implicit, which the States have not yet been able to fully analyze or comment on here.⁸⁸

Regarding load growth, DOE assumes 101 Gigawatts (“GW”) of new load will be added to the grid by 2030.⁸⁹ DOE projects that data centers, especially for developing Artificial Intelligence (“AI”), will add 50 GW of that new load, and other demand growth will add 51 GW. DOE appears to assume that data-center load will be “firm,” meaning electricity to meet that demand must be guaranteed at all times.⁹⁰ That is in contrast to “interruptible” load for which supply can be reduced during peak periods.⁹¹ DOE also appears to assume that all the new data centers will connect to the grid, rather than rely on “behind-the-meter” generation and that regulators and grid operators will allow every MW of new load to connect to the grid on a firm basis, even if doing so threatens the grid’s reliability.⁹² Based on these assumptions, DOE projects a 15% increase in load by 2030.⁹³

The Report assumes 51 GW of non-data-center load, purportedly based on the NERC’s 2024 ITCS projections.⁹⁴ DOE does not explain why using projections from a NERC report on inter-regional transmission is reasonable or why those projections are reliable for DOE’s purposes. Additionally, NERC’s 2024 projections likely already include some data center load expectations, as well as policies to encourage the electrification of transportation, heating and cooling, and other energy uses that the Trump Administration has rescinded or is planning to

⁸⁷ U.S. DEP’T OF ENERGY, *Fact Sheet: The Department of Energy’s Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid* (2025), https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf [<https://perma.cc/YLX7-8G7T>]; *see also* Press Release, U.S. Dep’t of Energy, Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security (July 7, 2025), <https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security> [<https://perma.cc/8TEJ-AGH6>] (stating that its “methodology also informs the potential use of DOE’s emergency authority under Section 202(c) of the Federal Power Act”).

⁸⁸ *See generally* Report at 10-19.

⁸⁹ Report at 2-3.

⁹⁰ Report at 18.

⁹¹ *Id.*

⁹² *See id.* at 2-3, 15-18.

⁹³ *See* Ric O’Connell, *GridLab Analysis: Department of Energy Resource Adequacy Report* (July 11, 2025), <https://gridlab.org/gridlab-analysis-department-of-energy-resource-adequacy-report/> [<https://perma.cc/GN56-VLNA>].

⁹⁴ *See* Report at 11.

rescind.⁹⁵ DOE apparently did not account for shifting electrification policies in its load projections.

Regarding retirements, DOE assumed 104 GW of “firm capacity” retirements by 2030, roughly three-quarters from coal-fired power plants and one-quarter gas plants.⁹⁶ *Id.* at 5; see also Report at 3, 12-13, A1-A8. DOE included approximately 50 GW of “confirmed retirements,” retirements that have been formally recognized by system operators as having started the official retirement process and are assumed to retire on their expected date.⁹⁷ DOE also included approximately 50 GW of “announced retirements,” which are generators that have publicly stated retirement plans but not formally notified system operators or initiated the retirement process.⁹⁸

Regarding capacity additions, DOE took a more conservative approach. Rather than including all announced projects, DOE assumed “that only projects considered very mature in the development pipeline—such as those with signed interconnection agreements—will be built.” Report at A-5. These projects, known as Tier 1 resources, are by their very nature likely to be built in the short term. As a result, DOE assumed “minimal capacity additions beyond 2026.” *Id.* In addition, DOE does not appear to have modeled new transmission projects, despite their grid reliability benefits.

The Report’s assumptions about load growth and electricity supply differ significantly from other forecasts.⁹⁹ As one grid reliability expert commented, DOE’s report “used aggressive assumptions regarding load growth and retirements, but conservative assumptions about how much new generation capacity will be added, even assuming no new resources after 2026.”¹⁰⁰ For example, DOE assumed 15% load growth by 2030, but the U.S. Energy Information Agency recently assumed just 6% in their “high” growth” case.¹⁰¹ Other differences with the Energy

⁹⁵ See NERC, 2024 Long Term Reliability Assessment Report 8 (July 15, 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf [https://perma.cc/NMP4-KRN5] (discussing how “the continued adoption of electric vehicles and heat pumps is a substantial driver for demand around North America”).

⁹⁶ Report at 5.

⁹⁷ *Id.* at 12; see also O’Connell, *supra* note 93.

⁹⁸ Report at 12.

⁹⁹ Report at 2 (noting that demand forecasts vary widely).

¹⁰⁰ O’Connell, *supra* note 93.

¹⁰¹ U.S. Energy Information Administration, Form EIA-860 (June 11, 2025) <https://www.eia.gov/electricity/data/eia860/>.

Information Agency forecasts are described in the chart below:¹⁰²

DOE Report Assumptions vs. U.S. Energy Information Administration Data:

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

The Report also does not address actions already being taken by states, utilities, and regional grid operators to meet increased load growth or how markets are already responding to increasing demand. As GridLab explained in its analysis:

Markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that could add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.¹⁰³

iii. Based on these assumptions and DOE's resource adequacy standard, DOE concluded intervention in electricity markets is needed to prevent outages.

DOE then adopted a novel "resource adequacy standard," using a combination of non-traditional and non-standardized metrics ("Loss of Load Hours" and "Normalized Unserved Energy").¹⁰⁴ DOE selected the target to be achieved with each metric.¹⁰⁵

DOE did not define what energy sources it considered "firm" capacity or why only those sources provide the necessary attributes for grid reliability. DOE's usage of the term in the report suggests that only coal or gas power plants count as "firm" capacity and excluded other sources that could provide similar, greater, or different levels of reliability (like batteries or transmission) from its analysis.¹⁰⁶

¹⁰² O'Connell, *supra* note 93.

¹⁰³ *Id.*

¹⁰⁴ Report at 3-4.

¹⁰⁵ *Id.*

¹⁰⁶ *See, e.g., id.* at 1, 32, 37.

DOE portrayed three scenarios in an attempt to assess the impact of planned retirements on resource adequacy in 2030.¹⁰⁷ The first scenario is “Plant Closures,” which assumes that announced retirements and capacity additions “in the final stages for connection” that are “either under construction or ha[ve] received approved planning requirements” will occur.¹⁰⁸ The second scenario is “No Plant Closures,” which has the same assumption about additions as the “Plant Closures” scenario but assumes no retirements.¹⁰⁹ The third scenario is “Required Build” which uses the “Plant Closures” scenario’s assumptions about retirements and then artificially adds enough hypothetical perfect capacity to the system to meet DOE’s new reliability standard.¹¹⁰ Perfect capacity is hypothetical capacity that experiences no outages and is used in the modeling “to avoid the complex decision of selecting specific generation technologies, as that is ultimately an optimization of reliability against cost considerations.”¹¹¹

DOE then concluded, based on the above assumptions, the risk of power outages in 2030 would be 100 times higher in 2030 than it is today.¹¹² DOE concluded that “decisive intervention” and “robust and rapid reforms” are necessary to avoid this result and to accommodate “projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”¹¹³ Numerous grid experts have commented on the shortcomings of this approach.¹¹⁴

III. Statement of Issues and Specification of Errors.

1. The Report is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure Act and Federal Power Act because it suffers from numerous analytical, mathematical, and empirical flaws, including but not limited to the following:
 - a. DOE relies on key assumptions about load growth, retirements, and capacity additions that are unreasonable and unsupported by evidence or logic.

¹⁰⁷ *Id.* at 3, 5.

¹⁰⁸ *Id.* at 4-5.

¹⁰⁹ *Id.*

¹¹⁰ *Id.*

¹¹¹ *Id.* at 5.

¹¹² *Id.* at 1.

¹¹³ *Id.*

¹¹⁴ See, e.g., Jeff St. John, *Critics Fear Trump Will Use Flawed DOE Report to Push Pro-Coal Agenda*, CANARY MEDIA (July 14, 2025), <https://www.canarymedia.com/articles/fossil-fuels/trump-doe-report-open-coal-plants> [https://perma.cc/2T7L-3FWX]; Matthias Fripp & Brendan Pierpont, *Energy Department’s Flawed Grid Study Props Up Expensive, Zombie Power Plants*, UTILITYDIVE (July 24, 2025), <https://www.utilitydive.com/news/doe-grid-reliability-study-zombie-power-plants/753596/> [https://perma.cc/QH3V-KM5R]; INST. FOR POL’Y INTEGRITY, *ENOUGH ENERGY: A REVIEW OF DOE’S RESOURCE ADEQUACY METHODOLOGY* (July 2025), https://policyintegrity.org/files/publications/IPI_EnoughEnergy_FinalReport.pdf [https://perma.cc/WN39-K9LE].

- b. DOE assumes the transmission grid will remain static over the next five years and fails to consider how new transmission projects in development will impact reliability.
- c. DOE fails to define “firm power capacity” or reasonably explain why DOE apparently considers only coal and gas to be “firm power capacity” when other generation sources, energy storage, or transmission could provide similar or greater reliability attributes.
- d. DOE’s assumptions unreasonably presume that the market, grid operators, and state regulators will take no action in the next five years to address load growth or reliability issues, and that no alternative other than preserving aging coal and gas power plants will ensure grid reliability.
- e. DOE’s analysis suffers from mathematical errors, analytical flaws, and lacks sufficient data or regional input. Those flaws are amply described in the attached analysis by the Institute for Policy Integrity and are incorporated and adopted here. *See* IPI Report (attached as Ex. XX).
- f. Although DOE acknowledged that data and input from states and regional entities could improve the analysis, DOE chose not to consult with those entities or seek to obtain that data.
- g. DOE selected non-traditional and non-standardized resource adequacy metrics and targets to be achieved without providing a reasoned explanation for its choices, including why it selected Normalized Unserved Energy (“NUSE”) and Loss of Load Hours (“LOLH”) instead of other possible metrics that would provide different data, an explanation of the costs and benefits of its choices and the target to be achieved, and why a nationwide target is appropriate despite regional differences in the costs and benefits with regard to resource adequacy.
- h. DOE offers no reasonable explanation how the Report could be used to identify “at-risk region[s] and guide reliability interventions” when it arbitrarily relies on geographic groupings that do not match boundaries used by utilities, balancing authority areas, transmission planning regions, regional wholesale markets, NERC regional entities, or NERC reliability coordinators to reliably operate the nation’s electric grid.

These assumptions and omissions work together to arbitrarily tip the scales in favor of finding a resource adequacy risk. *See Motor Vehicles Mfrs. Ass’n v. State Farm*, 463 U.S. 29, 43 (1983); *WildEarth Guardians v. U.S. Bureau of Land Mgmt.*, 870 F.3d 1222, 1237 (10th Cir. 2017); *Nat. Res. Def. Council, Inc. v. Herrington*, 768 F.2d 1355, 1391 (D.C. Cir. 1985); *see also infra* Section 4.a.

- 2. The Report is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure and Federal Power Acts because it pursues an extra-statutory motive of preserving aging and uneconomic fossil fuel

power plants at consumer expense, which contradicts the Federal Power Act’s express goal of preserving just and reasonable rates and preventing undue discrimination or preference. The Administration’s energy actions, when viewed collectively, also demonstrate that DOE has prejudged the outcome of this proceeding and intended its analysis to reach only one result: preventing the retirement of fossil-fueled power plants. *See Dep’t of Com. v. New York*, 588 U.S. 752, 785 (2019); *Gresham v. Azar*, 950 F.3d 93, 104 (D.C. Cir. 2020), *vacated as moot*, *Becerra v. Gresham*, 142 S. Ct. 1665 (2022). *See also infra* Section 4.a.iii-iv.

3. The Report is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure and Federal Power Acts because it purports to guide emergency action under Section 202(c) of the Federal Power Act but does not describe an “emergency” within the meaning of the Federal Power Act or DOE’s implementing regulations. *See* 16 U.S.C. § 824a(c)(1); 10 C.F.R. § 205.371; *Otter Tail Power Co. v. Federal Power Com.*, 429 F.2d 232, 234 (8th Cir. 1970). *See also infra* Section 4.b.
4. The Report is arbitrary, capricious, contrary to law, and unsupported by substantial evidence in violation of the Administrative Procedure and Federal Power Acts because it “fails to consider an important aspect of the problem” and fails to consider reasonable alternatives. Specifically, the Report ignores alternatives, or in some cases actively prevents viable alternatives with no explanation, such as expanding interregional transmission, batteries, renewable energy, incorporating data centers flexibly into load, and the existing resource adequacy mechanisms that are used by states and regional grid operators to assess reliability and respond to resource adequacy needs. *See State Farm*, 463 U.S. at 43. *See also infra* Section 4.a. (arbitrary and capricious) and section 4.c. (existing resource adequacy mechanisms)].
5. The Report is *ultra vires* and contrary to law in violation of the Administrative Procedure and Federal Power Acts because it intrudes upon matters reserved for the States and the Federal Energy Regulatory Commission. DOE does not possess authority to set nationwide resource adequacy standards or regulate sources of electricity generation. *See* 16 U.S.C. § 824b(1); *Whitman v. Am. Trucking Ass’n, Inc.*, 531 U.S. 457, 468 (2001). *See also infra* Section 4.d.
6. The Report violates the Administrative Procedure Act, 5 U.S.C. 553, because it establishes a legislative rule without first providing public notice and comment. *See Shalala v. Guernsey Mem’l Hosp.*, 514 U.S. 87, 99–100 (1995); *Nat’l Min. Ass’n v. McCarthy*, 758 F.3d 243 (D.C. Cir. 2014); *Children’s Health Care v. Centers for Medicare & Medicaid Servs.*, 900 F.3d 1022 (8th Cir. 2018). *See infra* Section 4.e.

7. The Report is arbitrary, capricious, and contrary to law in violation of the Administrative Procedure Act because it allegedly supports issuing Section 202(c) emergency orders based on factors and procedures that conflict and are inconsistent with DOE's existing regulations. *See Emergency Interconnection of Electric Facilities*, 46 Fed. Reg. 39,984 – 39,989 (Aug. 6, 1981); 10 C.F.R. §§ 205.371 *et seq.* *See infra* Section 4.e.ii.
8. The Report is arbitrary and capricious in violation of the Administrative Procedure Act because DOE failed to acknowledge that its methodology and protocol for issuing Section 202(c) orders is inconsistent with the factors for determining when an emergency exists that DOE's regulations already set out. *See Emergency Interconnection of Electric Facilities*, 46 Fed. Reg. at 39,985; 10 C.F.R. §§ 205.371, 205.373. It is also inconsistent with DOE's previous position that emergency orders are inappropriate for long-term reliability issues and a "utility must solve long-term problems itself." 46 Fed. Reg. at 39,985; *see also* 10 C.F.R. § 205.371. Agencies act arbitrarily when they fail to display awareness that they are changing position and offer good reasons for the change in policy. *See Food & Drug Administration v. Wages & White Lion Invs.*, 604 U.S. ---, 145 S. Ct. 898, 918 (2025); *see also infra* Section 4.e.

IV. Request for Rehearing

a. DOE's Report is Based on Flawed and Arbitrary Assumptions and is Unsupported by Substantial Evidence.

The Report's conclusions rest on critical assumptions about load growth, retirements, and capacity additions, but DOE did not reasonably explain how it arrived at those assumptions or support its choices with substantial evidence. At times, DOE's assumptions are internally inconsistent and arbitrarily tip the scales in favor of finding a need to prevent scheduled retirements. The Report also seems to adopt a definition of "firm capacity" that includes only fossil-fuel power plants, but does not explain why other generation sources or batteries are not also "firm capacity." DOE has also failed to make the data it relied on publicly available – rendering it impossible to fully test DOE's analysis.¹¹⁵

¹¹⁵ Due to the lack of public notice or any consultation or opportunity for involvement in the DOE's development of this report, the States have not had an opportunity to fully analyze DOE's methodology. DOE also has not made the data or models it used publicly available, which would allow the States to critically assess or replicate DOE's analysis and uncover additional flaws in DOE's approach. As such, the States reserve the right to raise additional flaws with DOE's analysis and conclusions at a later date, as they continue to analyze the Report.

Agencies act arbitrarily when they base decisions on key assumptions that are irrational or unsupported.¹¹⁶ Moreover, when agencies use complex models, they must publicly reveal the assumptions and data incorporated into their models and “provide a full analytical defense” of their model.¹¹⁷

i. DOE fails to reasonably explain or support its load growth assumptions

DOE assumes 15% load growth by 2030, half of which DOE assumes will serve new data centers.¹¹⁸ In doing so, DOE presumes – without evidence or a rational explanation – that data center load is firm (i.e., it cannot be interrupted at peak times). That assumption is arbitrary and directly undermined by recent advances in both policy and technology.

Some policymakers are already requiring data centers to be flexible, interruptible load.¹¹⁹ In Texas, for example, a new law grants ERCOT more flexibility to curtail certain data center loads in the event of a grid emergency.¹²⁰ DOE did not grapple with the impact of this law on its underlying assumptions despite the fact that curtailing such load during peak hours “could go a long way towards avoiding the DOE-identified resource adequacy problem” in ERCOT.¹²¹

DOE also ignores the possibility of industry reducing its demand for electricity either as a matter of policy or innovation in this rapidly developing field. NVIDIA, the foremost supplier of hardware for AI data centers, recently announced a new power supply unit that can reduce peak grid demand by up to 30%.¹²² In another recent example, Google agreed to a demand response framework with two utilities that would reduce how much electricity is used by its data centers during peak hours.¹²³

DOE’s reliance on an inflexible assumption for data center load reflects a failure to consider how this rapidly developing industry may adapt to address its significant energy

¹¹⁶ *WildEarth Guardians v. U.S. Bureau of Land Mgmt.*, 870 F.3d 1222, 1237 (10th Cir. 2017); *Hisp. Affs. Project v. Acosta*, 901 F.3d 378, 389 (D.C. Cir. 2018) (noting agencies’ affirmative duty to examine key assumptions underlying their policies).

¹¹⁷ *Nat. Res. Def. Council, Inc. v. Herrington*, 768 F.2d 1355, 1385 (D.C. Cir. 1985); *see also Columbia Falls Aluminum Co. v. EPA*, 139 F.3d 914, 923 (D.C. Cir. 1998).

¹¹⁸ Report at 18.

¹¹⁹ *See* Ex. D, Nicholas Institute Report at 25; *see also* Ex. C, IPI Report at 24

¹²⁰ S.B. No. 6 § 4, 89th Legislature (Tex. 2025) (to be enacted at Tex. Util. Code § 39.170); *See also* Ex. C, IPI Report at 26.

¹²¹ Ex. C., IPI Report at 26.

¹²² Meris Lutz, *NVIDIA addresses AI peak power demand, spikes in new rack-scale systems*, UtilityDive (July 30, 2025), <https://www.utilitydive.com/news/nvidia-rack-scale-system-smooth-ai-power/756279/>.

¹²³ Laila Kearney, *Google agrees to curb power use for AI data centers to ease strain on US grid when demand surges*, Reuters (Aug. 4, 2025), <https://www.reuters.com/sustainability/boards-policy-regulation/google-agrees-curb-power-use-ai-data-centers-ease-strain-us-grid-when-demand-2025-08-04/>.

demand. This renders DOE’s blunt conclusions regarding resource adequacy arbitrary and capricious.¹²⁴

The Report also adopts an unreasonably high estimate of future data center load, arbitrarily claiming it is simply adopting a “midpoint assumption.” Report at 15. DOE admits that there are “wide variations” in estimates of future data center load growth, yet the agency does not appear to have conducted any actual evaluation of those estimates to determine their respective accuracy. DOE must explain why its adoption of an estimated 50 GW load growth is more reliable or likely than other projections. It cannot just pick what it calls a “midpoint” from available studies and move forward. A rational approach would involve projecting future growth under a number of scenarios. Indeed, DOE did not account for a number of factors that temper against aggressive assumptions for future data center load growth. Those factors include the fact that data center developers often make duplicative requests for service; that data center deployment is limited by the availability of chips and processing systems; that data center efficiency may increase in the future as technology develops; and that utilities are incentivized to adopt aggressive load forecasts.¹²⁵

The Report also assumes an additional 51 GW of non-data center load growth. DOE states that it adopted this assumption from NERC’s 2024 ITCS Report. But NERC’s 2024 ITCS Final Report does not contain its own load growth projections.¹²⁶ DOE has not cited which NERC projections it is relying on, what data underlie those projections, or why DOE considers it reliable for purposes of setting a uniform resource adequacy standard and guiding reliability interventions. Moreover, NERC’s forecasts already contain data center load expectations meaning the Report may be double counting projected future demand from data centers.¹²⁷ NERC’s forecasts may also contain other assumptions that are no longer appropriate, such as demand forecasts based on federal incentives to electrify transportation that no longer exist. Additionally, as the Institute for Policy Integrity explains in its report, DOE’s method for distributing load growth across the country is questionable and does not necessarily reflect actual market decisions.¹²⁸

ii. DOE arbitrarily assumes 104 GW of retiring capacity by 2030 but only 22 GW of additions in the same time period.

The Report also assumes the retirement of 104 GW of generating capacity by 2030, an extremely aggressive estimate that cannot withstand any level of scrutiny.¹²⁹ That assumption is inconsistent with the U.S. Energy Information Administration’s data from June 2025 showing

¹²⁴ See Report at 17, 40; *see also* Ex. C, IPI Report at 26 (“DOE should have considered the possibility that some of the projected data center load would be flexible, especially in ERCOT”).

¹²⁵ See *generally* Ex. E, London Economics International Report.

¹²⁶ Ex. A, NERC ITCS Report.

¹²⁷ Report at 17.

¹²⁸ See Ex. C, IPI report at 24; *see also* Ex. E, LEI Report at 10-14 (noting that data centers have many choices where to locate).

¹²⁹ See Report at 5, A-5.

only half of that capacity is actually set for retirement.¹³⁰ This projection is also flawed because it arbitrarily includes announced retirements even though those generators have not formally provided notice of their retirement or initiated the retirement process.¹³¹ Many of these resources have, however, pushed back their actual retirement dates due to changing market conditions and the policies of the current administration.¹³²

At the same time that the Report overestimates the amount of load growth and retirements by 2030, it underestimates capacity additions that can be reasonably expected to come online in that same timeframe. DOE assumes only Tier 1 projects will be built by 2030. Because Tier 1 additions are projects that are either under construction or received approved planning requirements, nearly all will be in service by 2026.¹³³ DOE acknowledged that the Tier 1 assumption “results in minimal capacity additions beyond 2026,” Report at A-5, yet DOE did not explain why that assumption was nonetheless reasonable when forecasting conditions to 2030.

By focusing solely on Tier 1 projects, DOE excludes announced capacity additions or even capacity additions that are seeking approval to interconnect to the grid (NERC “Tier 2” projects).¹³⁴ Excluding capacity that has been requested but has not yet received approval for planning requirements does not make sense for predictions stretching out five years from now. Both common sense and history suggest that at least some of these additions will receive approval in that time.¹³⁵ DOE has thus adopted a view of generator additions that is completely at odds with its projection of generator retirements and together the approach arbitrarily tips the scales in favor of finding a resource adequacy risk.

These assumptions seem to ignore a fundamental property of market dynamics: that supply will respond to rising demand. DOE assumes that generators who have not initiated the retirement process will retire even if remaining in the market would still be economic for them. And DOE assumes that developers will refrain from building any new energy projects from 2027-2030 despite market signals that additional capacity is needed. Those assumptions are unreasonable and render the Report arbitrary and capricious.¹³⁶

¹³⁰ U.S. Energy Information Administration, Form EIA-860 (June 11, 2025)

<https://www.eia.gov/electricity/data/eia860/>.

¹³¹ See Report at 5, A-5.

¹³² Kevin Clark, *Where coal plant retirements are happening – And what could delay them*, Power Engineering (July 14, 2025), <https://www.power-eng.com/coal/plant-decommissioning/where-coal-plants-are-closing-and-what-could-delay-them/>. See also, Joe Schulz, *We Energies will delay Oak Creek coal plant retirement by one year to 2026*, Wisconsin Public Radio (June 26, 2025), <https://www.wpr.org/news/we-energies-delay-oak-creek-coal-plant-retirement-2026>. See also Ex. C, IPI Report at 23-24 (explaining why DOE’s retirement figure likely overstates retirements).

¹³³ NERC, *2024 Long-Term Reliability Assessment* at 22, 136-37 (2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

¹³⁴ *Id.*

¹³⁵ See also Ex. C, IPI Report at 21-22 (applying historical statistics and data to demonstrate why DOE’s exclusion of Tier 2 additions is unreasonable).

¹³⁶ See Report at 1 (concluding that, based on its model, intervention is needed to ensure a reliable power grid and meet the AI growth requirements).

DOE also arbitrarily excludes new transmission projects from its analysis altogether. Interregional transmission improvements are known to be one of the most cost-effective ways of improving grid reliability.¹³⁷ DOE apparently assumes that the nation's transmission will remain static over the next five years, despite ongoing planning processes and reforms to increase transmission projects and the well-documented reliability benefits that more transmission can provide.¹³⁸ DOE also appears to undercount the reliability benefit of existing transmission systems in its analysis.¹³⁹ It is nonsensical to ignore the benefits of new transmission when DOE is purportedly seeking to improve the reliability of the electric grid and keep costs affordable for consumers.

iii. DOE's analysis lacks sufficient regional granularity and suffers from other analytical flaws.

DOE's analysis also suffers from mathematical errors, analytical flaws, and lacks sufficient data or regional input further highlighting the importance of leaving resource adequacy to the states. DOE itself recognized that the Report's lack of regional data was a shortcoming that undercut its conclusions. As DOE acknowledges, "[e]ntities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience."¹⁴⁰ Despite this admission, DOE made no attempt to consult with States or grid operators on reliability issues or to obtain this data. An agency "may not tolerate needless uncertainties in its central assumptions when the evidence fairly allows investigation and solution of those uncertainties."¹⁴¹

This lack of state and regional granularity contributes to the report's unreasonable assumptions and overstated conclusions. Rather than focus on a region-specific analysis, DOE engaged in broad approximations to allocate nationwide projections to the various regions. For example, DOE started with a nationwide estimate of 50 GW of incremental data center load, allocated it across regions using state-level growth ratios from S&P's forecast, then mapped these state-level projections to the regions used for its analysis, the NERC Transmission Planning Regions (TPRs).⁵⁴ It is also unclear how DOE accomplished this mapping, given that the referenced NERC TPRs do not perfectly map to states.⁵⁶

Further, the Report's conclusions regarding resource adequacy are contradictory at times, even within a single region, rendering DOE's characterization of certain regions' resource adequacy arbitrary and capricious. To guide its assessments, DOE set reliability standards of "[n]o more than 2.4 hours of lost load in an individual year" and "[n]o more than an NUSE [Normalized Unserved Energy] of 0.002%."¹⁴² In its analysis of the PJM region, the Report highlights PJM's average loss of load figure of 2.4 hours under the current system analysis, apparently to indicate resource inadequacy despite clearly not *exceeding* the threshold DOE set,

¹³⁷ See generally Ex. A, NERC ITCS Report; see also Ex. F, GridStrategies Report at 1.

¹³⁸ See generally Ex. A, NERC ITCS 2024 Report (identifying areas where new transmission can significantly improve reliability); Ex. F, GridStrategies, Resource Adequacy Value of Interregional Transmission (June 2025)

¹³⁹ See Ex. C, IPI Report at 25.

¹⁴⁰ Report at i.

¹⁴¹ *Nat. Res. Def. Council, Inc. v. Herrington*, 768 F.2d 1355, 1391 (D.C. Cir. 1985).

¹⁴² Report at 4.

while also describing the region’s current system as “experienc[ing] shortfalls, but ... below the required threshold.”¹⁴³ At the same time, the Report notes that “[f]or the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM,” despite the Report’s summary of the PJM’s modeled NUSE metric in the current system clocking in at 0.0008%, again clearly meeting the reliability threshold that DOE itself selected.¹⁴⁴

The Report also fails to explain how it could be used to identify “at-risk region(s) and guide reliability interventions”¹⁴⁵ while relying on many geographic groupings that do not match the boundaries used by utilities, balancing authority areas, transmission planning regions, regional wholesale markets, NERC regional entities, or NERC reliability coordinators to reliably operate the nation’s electric grid.

For example, the “Front Range” region in the Report includes Colorado and portions of New Mexico and Wyoming but those boundaries are geographically different from regions analyzed in NERC’s reliability assessments. NERC’s 2025 Summer Reliability Assessment includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota in the “WECC-Rocky Mountain” region, and includes Arizona and New Mexico, most of Nevada, and small parts of California and Texas in the “WECC-Southwest” region.¹⁴⁶ The regional grouping used in the Report is arbitrary and inconsistent with these existing groupings.

The Report states its model is derived from NERC’s Interregional Transfer Capability Study (“ITCS”)¹⁴⁷ and asserts the subregions used in the Report, called Transmission Planning Regions (“TPRs”), “match the regional subdivisions in the NERC ITCS study, itself based on FERC’s transmission planning regions.”¹⁴⁸ However, the ITCS makes clear that FERC’s transmission planning regions were altered to create the TPRs for the ITCS,¹⁴⁹ which was focused on transfer capability between neighboring regions and not resource adequacy.¹⁵⁰ The ITCS Final Report does not explain how specific footprints were determined in any detail.¹⁵¹ In January 2025 comments filed with FERC in response to the ITCS report, DOE commented “[t]he subregion boundaries used in the ITCS are useful for evaluating interregional transfer capability given the chosen methodology, *but not for evaluating resource adequacy of those subregions.*”¹⁵² DOE explained the ITCS subregions do not reflect actual monitored transmission constraints, nor

¹⁴³ Report at 27 & Tbl. 8.

¹⁴⁴ Report at 9, 27 Tbl. 8. *See also* Ex. C, IPI Report at 20.

¹⁴⁵ Report at vi.

¹⁴⁶ NERC, *2025 Summer Reliability Assessment* at 36, 38 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.

¹⁴⁷ Report at 2.

¹⁴⁸ Report at 10 n.14.

¹⁴⁹ Ex. A, NERC ITCS Report at 7.

¹⁵⁰ Fiscal Responsibility Act of 2023, H.R. 3746, 118th Congress (2023–2024) (directing NERC to study the total transfer capability between transmission planning regions).

¹⁵¹ *See* Ex. A, NERC ITCS Report at 7.

¹⁵² Comments of the U.S. Dep’t of Energy, FERC Docket No. AD25-4-000, at 6 (Jan. 17, 2025) (emphasis added).

do they accurately capture the service territories or balancing authority areas that are the footprints on which resource adequacy decisions are made.¹⁵³

Despite DOE's earlier comments, the DOE Report fails to explain why the TPR subregions, many of which have no similarities to the regions actually used by NERC to assess reliability nor the planning regions used by entities with resource adequacy obligations, are now appropriate geographic boundaries for running resource adequacy scenarios and guiding reliability interventions. Returning to the example of the Front Range region, neither the ITCS Final Report nor the DOE Report explain why resource adequacy analysis should be done collectively for Colorado and portions of New Mexico and Wyoming, in which the load serving entities and balancing authorities plan their systems, acquire generating resources, and decide to interconnect to neighboring systems under completely separate processes. Because many of the Report's subregions are divorced from how the grid is actually planned and operated, they risk inaccurate groupings of load and available generating resources and incomplete understandings of how transmission capacity may be used in times of peak demand.

The Report suffers from other analytical shortcomings, which are amply described in the Institute for Policy Integrity's report and are expressly incorporated and adopted here.¹⁵⁴ As the Institute for Policy Integrity explained, DOE fails to offer a reasonable explanation for its choice of resource adequacy metrics and targets, outage thresholds, or the use of a deterministic model instead of a more accurate probabilistic model. By relying solely on weather data from recent years in a deterministic model, rather than a more statistically accurate probabilistic model, the Report "does not sufficiently account for uncertainty," weakening the strength of its modeled findings for 2030.¹⁵⁵

Given the abundant shortcomings in DOE's methodology, it is unreasonable to rely on the data and analysis contained in the Report to draw any firm conclusions about the resource adequacy of any region of the United States electrical grid now or in 2030, and DOE's various findings of resource inadequacy despite these flaws is arbitrary and capricious.

iv. DOE's flawed analysis establishes an arbitrary and unlawful preference for fossil fuel plants over other methods to preserve grid reliability, contrary to the Federal Power Act.

The flawed assumptions discussed above lead to an obvious conclusion: that DOE designed the Report to satisfy the White House's goal of bailing out uneconomic and environmentally harmful power plants. DOE's report is not addressing an emergency, but seeking to prop up a coal industry that is unable to compete with cheaper and cleaner modern energy sources like wind, solar, and batteries.

¹⁵³ See *id.* at 6-7.

¹⁵⁴ See Ex. C, IPI Report at 18-26

¹⁵⁵ *Id.* at 21.

Executive Order 14262 was signed alongside EO 14261 *Reinvigorating America's Beautiful Clean Coal Industry and Amending Executive Order 14241*. EO 14261 claims to “encourage and support our Nation’s coal industry to increase our energy supply, lower electricity costs, stabilize our grid, create high-paying jobs, support burgeoning industries, and assist our allies.” And President Trump’s statements at the signing ceremony make clear that the two orders are intended to serve a complementary purpose. As the President said, with coal workers lining the stage behind him for a photo-op, “we’re bringing back an industry that was abandoned” and “all those plants that have been closed are going to be opened.”¹⁵⁶

The President’s Grid Reliability Order references his earlier Declaration of an Energy Emergency, *see* EO 14156 “Declaring a National Energy Emergency,” which created an energy emergency based on an alleged shortage of affordable and domestic energy sources. In all orders, the President narrowly focuses on fossil fuels and specifically excludes wind, solar, or batteries from the definition of “energy.” And the Administration has simultaneously taken steps to derail the wind and solar industries, revoking previously issued permits for offshore wind projects, pausing the issuance of approvals, permits, and loans for wind projects nationwide, and adding bureaucratic hurdles to the permitting process for wind and solar.¹⁵⁷

To the extent that the Report advances the Administration’s policy of discriminating against renewable energy, batteries, and transmission to advance the extra-statutory motive of preserving aging fossil fuel power plants at consumer expense, it is contrary to express goals of the Federal Power Act.¹⁵⁸ Sections 205 and 206 of the Federal Power Act require rates to be just and reasonable and not unduly discriminatory or preferential.¹⁵⁹ Purporting to justify Section 202(c) orders for fossil fuel plants that are not needed and ignoring other viable methods to preserve grid reliability at a lower cost for consumers is likely to result in unjust and unreasonable rates. While 202(c) permits deferral of this issue to FERC in a rate proceeding, DOE must – at minimum – consider how a streamlined and uniform methodology may impact rates and cost recovery.

Significantly, when DOE proposed in 2017 that FERC adjust its rates to compensate generation that could store 90 days of fuel on-site (i.e., coal and nuclear generation), FERC unanimously rejected that proposal.¹⁶⁰ FERC concluded that DOE failed to demonstrate that allowing all eligible resources to receive a special rate regardless of the specific reliability needs of that region would be a just and reasonable outcome.¹⁶¹ DOE also failed to show that such a remedy “would not be unduly discriminatory or preferential” since only “certain resources [could] be eligible for the rate, thereby excluding other resources that may have resilience

¹⁵⁶ Adam Burke, *Trump orders coal revival, but market favors natural gas*, NPR (April 17, 2025)

<https://www.npr.org/2025/04/16/nx-s1-5359013/trump-orders-coal-revival-market-favors-natural-gas>.

¹⁵⁷ *See generally*, Complaint, New York, et al. v. Trump, et al., No. 25-cv-11221 (D. Mass., filed May 5, 2025) (describing Administration’s assault on wind energy). *See also e.g.*, Department of the Interior, Secretarial Order 3437, <https://www.doi.gov/document-library/secretary-order/so-3437-ending-preferential-treatment-unreliable-foreign>; Department of the Interior, Secretarial Order 3438, <https://www.doi.gov/document-library/secretary-order/so-3438-managing-federal-energy-resources-and-protecting>.

¹⁵⁸ *See* FPA Sections 205 and 206; 16 U.S.C. §§ 824d, 824e.

¹⁵⁹ *Id.*

¹⁶⁰ *See* Order Terminating Rulemaking, 162 FERC ¶ 61,012, ¶ 16 (Jan. 8, 2018).

¹⁶¹ *Id.*

attributes.”¹⁶² DOE’s second attempt to manipulate the energy markets in favor of its preferred energy sources suffers from the same fatal flaws and its motives are contrary to the goals of the Federal Power Act.

b. The Report does not describe an “emergency” and cannot be used to justify future grid reliability interventions by DOE.

i. Common usage and regulation define “emergency” narrowly.

Section 202(c) is limited, by its own terms, to either “the continuance of any war in which the United States is engaged,” or “whenever the Commission determines that an emergency exists *by reason of*” certain enumerated causes.¹⁶³ Those causes include: (1) “a *sudden* increase in the demand for electric energy,” (2) “a shortage of electric energy or of facilities for the generation or transmission of electric energy,” (3) a shortage of “fuel or water for generating facilities,” and (4) “other causes.”¹⁶⁴

The relevant focus is therefore on the definition of “emergency.” In 1930, just a few years before the Act’s passage, Webster’s New International Dictionary of the English Language defined “emergency” as a “sudden or unexpected appearance or occurrence... an unforeseen occurrence or combination of circumstances which calls for immediate action or remedy; pressing necessity; exigency.” The year before the statute was last amended, Merriam-Webster’s Dictionary and Thesaurus (2014) defined “emergency” as “an *unforeseen* event or condition requiring prompt action.” Thus, at all relevant times “emergency” was defined as being unexpected or unforeseen and requiring some form of exigent response.

That limited reading of Section 202(c) is bolstered by the emergency provision’s immediate statutory context. Section 202(c) is preceded by Section 202(b), which grants what is now the Federal Energy Regulatory Commission the authority to issue similar interconnection orders “*after* opportunity for hearing,” indicating that Congress intended to place a temporal constraint upon the emergency authority in Section 202(c), limiting it to situations not amenable to public notice and hearing.¹⁶⁵

DOE’s regulations implementing Section 202(c) also suggest the provision’s narrow applicability to only true emergencies.¹⁶⁶ DOE has provided that “actions under this authority are envisioned as meeting a specific inadequate power supply situation.”¹⁶⁷ The regulations

¹⁶² *Id.*

¹⁶³ 16 U.S.C. § 824a(c)(1) (emphasis added).

¹⁶⁴ *Id.* (emphasis added). The catchall “other causes” must still be the “reason” that an emergency exists. *Id.* See also Rolsma, *The New Reliability Override*, 57 U. Conn. L. Rev. at 810-13.

¹⁶⁵ 16 U.S.C. § 824a(b); 42 U.S.C. § 7172(a)(1)(B).

¹⁶⁶ See also 46 Fed. Reg. 39987 (Aug. 6, 1981).

¹⁶⁷ 10 C.F.R. § 205.371.

further define applicable emergencies to include “an *unexpected* inadequate supply of electric energy,” “*unforeseen* occurrences,” or “a *sudden* increase in customer demand,” echoing the.¹⁶⁸

In guidelines for defining “inadequate utility system fuel inventory or energy supply,” the regulations further specify that the threshold for such an emergency may be met “when, combined with other conditions, the projected energy deficiency upon the applicant’s system *without emergency action by the DOE*, will equal or exceed 10 percent of the applicant’s then normal daily net energy for load, or will cause the applicant to be unable to meet its normal peak load requirements *based upon use of all of its otherwise available resources* so that it is unable to supply adequate electric service to its ultimate customers.”¹⁶⁹ This definition again narrows the circumstances in which DOE may exercise its 202(c) authority to those not redressable by other means, implicating only acute or imminent power shortages where no other recourse is available.¹⁷⁰

ii. The report does not point to any sudden or unforeseen circumstances.

. DOE’s report does not identify any region, except ERCOT, that currently fails to meet DOE’s reliability targets.¹⁷¹ DOE’s flawed analysis points to a failure to meet reliability targets only in 2030. An expected increase in demand that can be projected over the next five years is not an energy emergency. Those shortfalls are not “unexpected” or “imminent” so as to justify a departure from normal planning procedures. The Report is squarely focused on 2030 and does not assess resource adequacy in any of the intervening years. According to the standard set out in *Otter Tail Power Co. v. Federal Power Com.*, 429 F.2d 232, 234 (8th Cir. 1970), the shortfalls predicted by the Report are at best policy crises “which [are] likely to develop in the foreseeable future but which [do] not necessitate immediate action.” In other words, the concerns may be addressable using FPA § 202(b), but certainly not FPA § 202(c).

Significantly, DOE has never before issued a 202(c) order based on such a broad and speculative increase in load demand. On the contrary, prior to 2025, DOE had only used 202(c) to delay the retirement of generation facilities on three narrow occasions, as requested by the system operator or government body, and only for as long as necessary to address the imminent emergency.¹⁷²

¹⁶⁸ *Id.* (emphasis added).

¹⁶⁹ 10 C.F.R. § 205.375 (emphasis added).

¹⁷⁰ While the regulations also state that “[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency ...,” the definition crucially does not allow for *projections* of such circumstances to qualify or include any qualifying terms indicating similar intent. On the face of the regulation, and consistent with reasonable interpretations of the statute, such an eligible power shortage must be sufficiently imminent to avoid reducing the inherent limitation of the word “emergency” to an absurdity. 10 C.F.R. § 205.371.

¹⁷¹ Report at 7.

¹⁷² See Benjamin Rolsma, *The New Reliability Override*, 57 U. Conn. L. Rev. 789, 843-46 (2025).

iii. Reliance on the Report to justify a Section 202(c) order would be contrary to law.

Based on EO 14262 and DOE's own statements, it is evident that the Department intends to rely upon the analysis and methodology in the Report to justify future Section 202(c) orders.¹⁷³ But the Report cannot lawfully be relied upon to justify the exercise of DOE's limited emergency authority. Doing so would be contrary to law.¹⁷⁴

As discussed above, the Secretary of Energy's authority under Section 202(c) of the Federal Power Act is statutorily limited to wartime or certain "emergency" situations; otherwise, similar proceedings fall under the jurisdiction of the Federal Energy Regulatory Commission through a process of notice and hearing.¹⁷⁵ Even taking the Report at face value, its own conclusions fail to describe anything resembling an emergency in any part of the country besides ERCOT.¹⁷⁶ Any conclusion that an emergency exists is undermined by the arbitrary nature of the Report's analysis.¹⁷⁷

Moreover, the Report's conclusions, on their face, fail to describe an "emergency". Conclusions about resource adequacy five years in the future, in 2030, fall outside of the temporal limits of an "emergency" and are exactly the type of concern that should be dealt with through usual planning processes.¹⁷⁸ Any attempt by DOE to bootstrap future Section 202(c) orders to the Report would be in direct contradiction to its statutory authority to issue such orders and its own regulations implementing that authority.¹⁷⁹

c. DOE failed to consider an important aspect of the problem: existing reliability mechanisms.

Agency action is arbitrary and capricious under the APA if it "fails to consider an important aspect of the problem." *Motor Vehicle Mfrs. Assn. of United States, Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983). Here, DOE has acted as if the Report exists on a blank slate of resource adequacy and reliability planning yet that could not be farther from the

¹⁷³ See Report at vi; EO 14262 Sec. 3(c). In at least one Section 202(c) order issued after the publication of EO 14262 but before the release of the Report, the Department stated that it "plans to use this methodology to further evaluate" the generation units subject to that order. Order No. 202-25-4 ("Eddystone 202(c) Order") at 2 (May 30, 2025).

¹⁷⁴ See 16 U.S.C. § 824a(c); 10 C.F.R. §§ 205.370-371, 375.

¹⁷⁵ 16 U.S.C. §§ 824a(b)-(c); 42 U.S.C. §§ 7151(b), 7172(a)(1)(B).

¹⁷⁶ Report at 7 ("Analysis of the current system shows all regions except ERCOT have less than 2.4 hours of average load loss per year and less than 0.002% NUSE. This indicates relative reliability for most regions based on the average indicators of risk used in this study."); see also Ex. C, IPI Report at 29-31 ("Despite DOE's press statement asserting that the study's methodology can help guide [sic] 'guide Federal reliability interventions,' presumably to address the EO's [EO 14262] mandate that DOE find a way to routinize further 202(c) emergency orders, the study reports a fundamental limitation for doing so: It does not find any near-term reliability risk from current levels of resource adequacy." (footnotes omitted)).

¹⁷⁷ See *supra* Section 4.a.

¹⁷⁸ See Report at 8-9.

¹⁷⁹ 16 U.S.C. § 824a(c); 10 C.F.R. §§ 205.370-371, 375.

truth. As described above, a multilayered system of resource planning involving states and regional grid operators ensures adequate supplies and grid stability.¹⁸⁰

The Report’s conclusion that “absent intervention, it is impossible for the nation’s bulk power system to meet the AI growth requirements while maintaining a reliable power grid and keeping energy costs low for our citizens,” is undermined by this failure.¹⁸¹ States across the nation are grappling with how to meet increased demand from AI data centers while maintaining grid reliability and distributing the costs of those changes in an equitable manner. Without an analysis of the existing framework for making such determinations, and ongoing efforts to adjust those systems to meet new challenges, there is no basis for DOE’s conclusion that “intervention” – likely through 202(c) orders – is the only way to possibly reach those goals.¹⁸²

d. As described in the EO, the report intrudes upon state authority.

EO 14262 directs the Secretary of Energy to rely upon the methodology disclosed in the Report to “identify current and anticipated regions with reserve margins below acceptable thresholds” and “identify which generation resources within a region are critical to system reliability.”¹⁸³ The Executive Order also directs DOE to further develop a “protocol” for applying this analysis to “include all mechanisms available under applicable law, including section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource.”¹⁸⁴ The Report is therefore foundational to the “protocol” that EO 14262 intends will direct emergency orders to override planned retirements. The Report thus directly intrudes on the States’ lawful resource adequacy planning processes.

With respect to regulatory oversight for resource adequacy, section 201 of FPA, 16 U.S.C. § 824(b)(1), reserves authority over generation facilities to the states. It states in pertinent part: “The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, *but shall not have jurisdiction*, except as specifically provided in this subchapter and subchapter III of this chapter, *over facilities used for the generation of electric energy* or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.”¹⁸⁵

The Federal Power Act is likewise clear that federal regulatory jurisdiction over the power sector “extend[s] only to those matters which are not subject to regulation by the States.”¹⁸⁶ With the few and specific exceptions outlined elsewhere in the statute, this jurisdiction

¹⁸⁰ See *Supra*, Section 2.a.

¹⁸¹ Report at 1.

¹⁸² *Id.*

¹⁸³ Executive Order 14262, §§ 3(b)-(c).

¹⁸⁴ *Id.* at § 3(c).

¹⁸⁵ *Id.* (emphasis added).

¹⁸⁶ 16 U.S.C. § 824(a).

does *not* extend to “facilities used for the generation of electric energy”¹⁸⁷ This statutory language places the regulation of generation resource adequacy squarely in the ambit of the states, not the federal government.¹⁸⁸

States have typically exercised this authority through a combination of individual state legislative and regulatory functions as well as engaging in multistate RTOs and ISOs. Some states have retained this authority over resource adequacy in its entirety,¹⁸⁹ while others have directed their utilities to join RTOs/ISOs that, through their tariffs, impose resource adequacy requirements. Those RTO/ISOs also generally establish markets that allow market participants to buy and sell capacity and thereby to facilitate market entry and exit decisions based on price signals. Resource adequacy requirements in RTO/ISO tariffs have been held to be practices affecting wholesale rates subject to the jurisdiction of FERC under sections 205 and 206 of the Federal Power Act, 16 U.S.C. §§ 824d & 824e.¹⁹⁰

Through these channels, states conduct the careful, calculated, long-term capacity planning that goes ignored in DOE’s Report.¹⁹¹ The Report utterly fails to recognize or properly account for the states’ traditional and statutory role in resource adequacy planning, and as forecasted by EO 14262, the Report constitutes a central component of the federal government’s proposed protocol to usurp the states’ authority over this issue.

The use of emergency orders to illegally override state resource adequacy planning has been challenged on the same grounds by the Organization of MISO States, Inc. (OMS), in its Petition for Rehearing of DOE Order No. 202-25-3 (ordering continued operation of the J.H. Campbell coal-fired power plant). In its Petition, OMS noted among other points that “[t]his is the first time the DOE has invoked Section 202(c) outside a severe weather event or emergency, and for the first time, uses the power to suspend a retirement and interfere with established and vetted state and regional planning processes.”¹⁹² OMS’ petition continues, “[t]his expansive use of emergency powers sets a troubling precedent, enabling interventions in routine, state-approved planning decisions without an actual crisis and risks establishing its use to circumvent normal utility, RTO, and states processes, and likely exposes ratepayers to costs that should not be borne.”¹⁹³ In DOE’s issuance of the Report pursuant to EO 14262, the federal government is

¹⁸⁷ *Id.* § 824(b)(1).

¹⁸⁸ See, e.g., Ashley J. Lawson, CONG. RESEARCH SERV., R47521, *Electricity: Overview and Issues for Congress*, at 7 (Feb. 14, 2025).

¹⁸⁹ See *Devon Power LLC et al.*, 109 FERC ¶61,154, P 47 (2004) (“Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.”).

¹⁹⁰ See *Conn. Dep’t of Pub. Util. Control v. FERC*, 569 F.3d 477, 483 (D.C. Cir. 2009).

¹⁹¹ E.g., Report at 2-3, 5, 12-13 (relying solely on federal, EIA, and NERC estimates and failing to mention nuanced state, RTO, or ISO figures and actions).

¹⁹² See Petition to Intervene and Request for Rehearing of the Organization of MISO States, Inc., Order No. 202-25-3 (filed June 23, 2025), <https://www.energy.gov/sites/default/files/2025-07/Petition%20to%20Intervene%20and%20Request%20for%20Rehearing%20of%20the%20Organization%20of%20MISO%20States.pdf>.

¹⁹³ See *id.* at 5; see also *id.* at 4 (challenging “Violation of the Federal Power Act and State Jurisdiction.”).

attempting to establish its own rule for resource adequacy planning from which it can routinely issue illegal orders under the same flawed premise that OMS challenges in its Petition.

Lastly, Section 202(c) does not serve as a widespread grant of DOE jurisdiction over resource adequacy and capacity planning. “Congress ... does not ... hide elephants in mouseholes.”¹⁹⁴ First, as described above in Part [3b], Congress assigned non-emergent questions of interconnection and transmission necessity amenable to public notice and hearing to FERC, not DOE.¹⁹⁵ Moreover, even this authority should not be seen as a substitute for the overarching reservation of regulatory jurisdiction over resource adequacy planning to the states.¹⁹⁶ No reasonable reading of the relevant statutory authorities could construe DOE’s authority in 16 U.S.C. § 824a(c) as intruding on the explicit and traditional role of the states in regulating electricity generation and resource adequacy. However, all available indicators in the Report and EO 14262 evince a flawed understanding contrary to DOE’s appropriate and limited role in this space, thus the Department should reconsider its findings and position on this authority.

e. DOE’s Failure to Provide Public Notice and Comment on its New Standard and Methodology Violated the Administrative Procedure Act, 5 U.S.C. § 553.

Before adopting a final rule, the Administrative Procedure Act requires agencies to publish in the Federal Register a notice of proposed rulemaking and accept public comment.¹⁹⁷ An agency action that imposes legally binding obligations or prohibitions on regulated parties, substantially removes the agency’s discretion, or would be the basis for an enforcement action for violations of those requirements, is a legislative rule that requires notice and comment.¹⁹⁸ Notice and comment is also required when agencies establish new standards that are not derived from an existing statute or regulation or when an agency relies on its statutorily delegated authority to establish policy.¹⁹⁹ Additionally, agency documents that adopt a “new position inconsistent with any of the [agency’s] existing regulations” are subject to notice and comment.²⁰⁰

DOE’s report creates a brand-new national standard and methodology for evaluating resource adequacy. This standard has concrete legal effects because DOE plans to enforce it via Section 202(c) emergency orders. It also is inconsistent with DOE’s existing regulations, which direct DOE to issue emergency orders in very different circumstances based on different criteria than what DOE now proposes. Significantly, DOE acknowledges that its conclusions lack sufficient input from the entities responsible for operating the grid, but DOE nonetheless refused to submit the Report to notice and comment where the public could have tested DOE’s assumptions and conclusions. Assuming DOE continues to comply with the Executive Order’s

¹⁹⁴ *Whitman v. Am. Trucking Ass’n, Inc.*, 531 U.S. 457, 468 (2001).

¹⁹⁵ 16 U.S.C. § 824a(b); 42 U.S.C. § 7172(a)(1)(B).

¹⁹⁶ 16 U.S.C. §§ 824(a)-(b).

¹⁹⁷ 5 U.S.C. § 553(b)-(c).

¹⁹⁸ *See Nat’l Min. Ass’n v. McCarthy*, 758 F.3d 243, 251–52 (D.C. Cir. 2014).

¹⁹⁹ *See Children’s Hosp. of the King’s Daughters, Inc. v. Azar*, 896 F.3d 615, 622 (4th Cir. 2018).

²⁰⁰ *Shalala v. Guernsey Mem’l Hosp.*, 514 U.S. 87, 99–100 (1995).

unlawful command to use this Report to support future Section 202(c) orders, the Report and any action relying on it must be set aside for failure to provide notice and comment.

i. DOE’s standard is an exercise of assumed legislative authority, and it has concrete legal effects.

Pursuant to the Executive Order, DOE established a “uniform methodology” for assessing resource adequacy across the country.²⁰¹ That methodology adopts a new “resource adequacy standard” to measure the desired level of adequacy needed for the bulk power system.²⁰² DOE acknowledges that it is not using the “traditional . . . criterion” for measuring resource adequacy and is relying on metrics that are “not standardized in the U.S. today.”²⁰³ Instead, DOE unilaterally adopts new metrics to evaluate resource adequacy and establishes the reliability targets that should be obtained.²⁰⁴ DOE’s choice of metrics and the targets to be achieved are value judgments and should be informed by economic tradeoffs and other policy considerations about what level of system reliability should be achieved and at what cost to consumers, areas where public input is essential to sound decision making.²⁰⁵

DOE also fills its methodology with value-laden policy choices around the data inputs and assumptions that determine when DOE’s reliability standard is achieved. As just one example, DOE includes projected future demand from potential new AI data centers as part of its calculation of future load.²⁰⁶ Those data centers have not yet been built and some may never be.²⁰⁷ And, as DOE recognized, grid operators are not likely to allow those large loads to connect if doing so threatens reliability.²⁰⁸ Including those potential loads in DOE’s determinations of system reliability thus inherently represents a policy choice: Should present-day consumers pay to keep retiring power plants online to ensure that potential data centers can be reliably served in the future?²⁰⁹

Even assuming *arguendo* that DOE has the statutory authority to set a uniform reliability standard, place risks of future large load growth on current consumers, or engage in long-term resource adequacy planning for the entire nation, it still must involve stakeholders through notice and comment in those legislative choices. “When an agency relies on expressly delegated authority to establish policy . . . courts generally treat the agency action as legislative [] rulemaking” and require notice and comment.²¹⁰ In other words, “when Congress leaves [] a policy choice to the agency, [courts] should lean toward finding that the agency’s making of that

²⁰¹ See Report at vi (explaining that the report is “delivering the required uniform methodology to identify at-risk region(s)”; Executive Order 14262 § 3(b)).

²⁰² Report at 3.

²⁰³ *Id.* 3-4.

²⁰⁴ See *id.*

²⁰⁵ See Ex. C, IPI Report at ii (criticizing DOE’s choice of targets as not “appropriately justified based on a cost-benefit framework, and the use of a one-size-fits-all target for the entire country ignores regional differences”).

²⁰⁶ See Report at 1-3.

²⁰⁷ See, e.g., Ex. E, London Economics International Report; Laila Kearney and Liz Hampton, *U.S. Power Stocks Plummet as DeepSeek Raises Data Center Demand Doubts*, Reuters (Jan. 27, 2025) <https://www.reuters.com/business/energy/us-power-stocks-plummet-deepseek-raises-data-center-demand-doubts-2025-01-27/>.

²⁰⁸ See Report at 14.

²⁰⁹ See also *supra* Section 4.a. (discussing other arbitrary assumptions in DOE’s analysis).

²¹⁰ *Children’s Hosp. of the King’s Daughters, Inc.*, 896 F.3d at 622.

choice requires notice and comment.²¹¹ “Otherwise, it would be difficult to imagine what regulations *would* require notice and comment procedures.”²¹²

DOE’s standard also has concrete legal effects because, consistent with the Executive Order, DOE will use Section 202(c) emergency orders (or the threat of Section 202(c) orders) to ensure regions meet the new standard. The Executive Order directs DOE to use this standard to “establish . . . a protocol” to identify generation resources that are critical to system reliability.²¹³ DOE’s “protocol shall additionally” use Section 202(c) of the Federal Power Act to “ensure” those resources are retained and prevent their retirement.²¹⁴ “Protocol” means “a set of rules to be followed . . .”²¹⁵ As DOE has made clear, DOE “plans to use” this new standard to evaluate retiring coal plants and potentially issue Section 202(c) emergency orders preventing their retirement.²¹⁶

DOE’s new standard, and protocol for enforcing it, removes DOE’s discretion and is intended to provide the basis for enforcement actions via Section 202(c) orders.²¹⁷ The new standard is not derived from the Federal Power Act or, as explained further below, from DOE’s existing regulations, but is an entirely new method of determining resource adequacy across the country. DOE must accordingly submit its new standard and methodology to public notice and comment.²¹⁸

ii. DOE must provide notice and comment because its standard allegedly supports issuing emergency orders based on factors that conflict with existing regulations.

DOE’s Report provides new bases for issuing emergency orders that conflict with DOE’s existing regulations, but DOE cannot amend those standards without first providing notice and comment.²¹⁹ DOE promulgated regulations detailing how and when it issues Section 202(c) emergency orders following public notice and comment in 1981.²²⁰ Under DOE’s current regulations, emergency orders “are envisioned as meeting a *specific* inadequate power supply situation,” occasioned by “acts of God[] or unforeseen occurrences not reasonably within the

²¹¹ *Id.*

²¹² *Id.* (quoting *N.H. Hosp. Ass’n v. Azar*, 887 F.3d 62, 70–71 (1st Cir. 2018)).

²¹³ Executive Order 14262 at § 3(c).

²¹⁴ *Id.*

²¹⁵ PROTOCOL, Black’s Law Dictionary (12th ed. 2024).

²¹⁶ Order No. 202-25-4 at 2 (Eddystone Order). *See also* U.S. DEP’T OF ENERGY, *Fact Sheet: The Department of Energy’s Resource Adequacy Report Affirms The Energy Emergency Facing The U.S. Power Grid* (2025), https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf [<https://perma.cc/YLX7-8G7T>] (explaining that DOE’s methodology will be used, pursuant to the executive order, “prevent [] generation resources from leaving the bulk-power system”); Press Release, U.S. Dep’t of Energy, Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security (July 7, 2025), <https://www.energy.gov/articles/departments-energy-releases-report-evaluating-us-grid-reliability-and-security> [<https://perma.cc/8TEJ-AGH6>]. (stating that its “methodology also informs the potential use of DOE’s emergency authority under Section 202(c) of the Federal Power Act”); Report at *vi* (explaining that DOE’s standard will be used to “guide reliability interventions”), 1 (emphasizing the need for DOE’s “decisive intervention” in energy markets), 10 (analyzing ERCOT because “FPA Section 202(c) allows DOE to issue emergency orders to ERCOT”).

²¹⁷ *See Nat’l Min. Ass’n v. McCarthy*, 758 F.3d 243, 251–52 (D.C. Cir. 2014).

²¹⁸ *See id.*; *Children’s Hosp. of the King’s Daughters, Inc. v. Azar*, 896 F.3d 615, 622 (4th Cir. 2018).

²¹⁹ *See Shalala*, 514 U.S. at 99–100.

²²⁰ *See Emergency Interconnection of Electric Facilities*, 46 Fed. Reg. 39,984 - 39,989 (Aug. 6, 1981).

power of the affected ‘entity’ to prevent.”²²¹ DOE did not intend its emergency authority to replace long-term planning by utilities: “while a utility may rely upon these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself.”²²²

As DOE stated then, “[t]he factors that DOE will consider in determining whether an emergency exists are specified in § 205.373.”²²³ Section 205.373 requires applicants to submit detailed information on “daily peak load and energy requirements for each of the past 30 days and projections for each day of the expected duration of the emergency” and make a “showing that adequate electric service cannot be maintained without additional power transfers.” Applicants must also describe what “conservation or load reduction actions have been implemented” before seeking emergency relief.²²⁴ In sum, DOE’s current regulations direct a case-by-case analysis of specific, temporary shortages in particular situations, based on detailed information from an applicant.

DOE’s new standard and methodology is an unprecedented expansion of the bases upon which DOE will justify Section 202(c) emergency orders, but DOE has not offered public comment on that expansion. Rather than focusing on specific showings of an imminent threat to grid stability, the report rests on DOE’s analysis of “the U.S. electric grid’s ability to meet future demand through 2030.”²²⁵ Rather than consider the “daily peak load and energy requirements of the past 30 days and projections for each day of the [] emergency,” 10 C.F.R. § 205.373, DOE now plans to base Section 202(c) decisions on speculation over the development of artificial intelligence, re-industrialization of the U.S. economy, and other uncertain developments over the next five years.²²⁶ Rather than consider the “scheduled . . . deliveries” during the emergency period and needs of existing firm customers, § 205.373(d),(f), DOE now proposes to find an emergency based on potential load growth for customers who do not currently, and may never, exist.²²⁷

Rather than allowing utilities and grid operators to solve long-term planning issues themselves, DOE now seeks to intervene in those state- and FERC-regulated processes based on its own assumptions about future load growth and electricity supply. But unlike DOE’s Report, the long-term resource adequacy plans developed by utilities and grid operators are transparent and publicly-accountable processes that involve relevant stakeholders and the public.²²⁸ DOE, on the other hand, published its analysis without critical data or insights from the entities who actually operate and maintain the electric grid.²²⁹

²²¹ 10 C.F.R. § 205.371 (emphasis added).

²²² 46 Fed. Reg. at 39,985; *see also* 10 C.F.R. § 205.371

²²³ 46 Fed. Reg. at 39,985.

²²⁴ *Id.*; *see also* 10 C.F.R. § 205.375 (defining an inadequate energy supply as when an applicant is “unable to meet its normal peak load requirements based upon use of all its otherwise available resources.”).

²²⁵ Report at 2.

²²⁶ Report at 2; *see also supra* Section 4.a.

²²⁷ *See, e.g.,* Ex. E London Economics International Report; Laila Kearney and Liz Hampton, *U.S. Power Stocks Plummet as DeepSeek Raises Data Center Demand Doubts*, Reuters (Jan. 27, 2025)

<https://www.reuters.com/business/energy/us-power-stocks-plummet-deepseek-raises-data-center-demand-doubts-2025-01-27/>.

²²⁸ *See supra* Section 2.a.

²²⁹ Report at *i*.

Rather than considering what other “conservation or load reduction actions have been implemented” before turning to emergency relief, 10 C.F.R. § 205.373, DOE’s standard ignores those possibilities altogether. Instead, DOE adopts aggressive and likely overstated assumptions of load growth and ignores whether any of that future demand could be flexibly integrated into the grid, what measures state and local regulators are taking to mitigate the impact of new data center demand on grid reliability, or other factors influencing grid reliability over the long-term.²³⁰ DOE appears to admit that its overstated potential load growth will not *actually* lead to any grid reliability emergency, as there is no “indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system.”²³¹

DOE appropriately involved the public when it initially set out the process and factors to consider for Section 202(c) orders in its 1981 rulemaking. Yet now, DOE seeks to expand the bases for Section 202(c) orders in ways that intrude on state-regulated processes and the free market, without any input from stakeholders or the public who will ultimately pay for DOE’s actions. Because the methodology and protocol effectively “expand[s] the footprint [of DOE’s emergency authority] by imposing new requirements, rather than simply interpreting the legal norms Congress or the agency itself has previously created” and is inconsistent with DOE’s existing regulations, it is a “rule” under the APA and notice and comment is required.²³²

iii. DOE acknowledges the importance of involving the States and other actors yet fails to provide public notice and comment to test DOE’s assumptions and conclusions.

DOE’s failure to provide public notice and comment is prejudicial error. DOE admittedly lacks the “range of data and insights” to make robust reliability decisions that entities responsible for the maintenance and operation of the grid have access to.²³³ Had the States been given adequate notice and an opportunity to comment, they could have provided more information to DOE on how existing mechanisms address grid reliability, issues with DOE’s assumptions, chosen metrics, and choice of data, identified gaps in DOE’s analysis and data, and other issues. Numerous grid experts have commented on shortfalls with DOE’s report.²³⁴ Given adequate notice and an opportunity to comment, the States could have obtained their own expert analysis and potentially raised even more issues with DOE’s proposed standard and methodology than what time permitted the States to raise here.

DOE has previously acknowledged the importance of involving States and the public in these questions. When DOE initially established regulations governing how and when it would

²³⁰ See, e.g., Ex. D, Nicholas Institute Report; Jason Plautz, *State lawmakers grapple with energy demand for data centers*, E&E News (Mar. 3, 2025) <https://www.eenews.net/articles/state-lawmakers-grapple-with-energy-demand-for-data-centers/>; Washington Office of the Governor, *Gov. Bob Ferguson Signs Executive Order Establishing a Data Center Workgroup* (Feb. 4, 2025) <https://governor.wa.gov/news/2025/governor-bob-ferguson-signs-executive-order-establishing-data-center-workgroup>.

²³¹ Report at 14.

²³² *Children’s Health Care v. Centers for Medicare & Medicaid Servs.*, 900 F.3d 1022, 1025 (8th Cir. 2018); see also *Shalala*, 514 U.S. at 99–100.

²³³ Report at *i*

²³⁴ See, e.g., Jeff St. John, *Critics fear Trump will use flawed DOE report to push pro-coal agenda*, Canary Media (July 14, 2025), <https://www.canarymedia.com/articles/fossil-fuels/trump-doe-report-open-coal-plants>; Matthias Fripp and Brendan Pierpont, Opinion, *Energy Department’s flawed grid study props up expensive, zombie power plants*, UtilityDive, <https://www.utilitydive.com/news/doe-grid-reliability-study-zombie-power-plants/753596/>.

issue emergency orders, DOE consulted with the Federal Energy Regulatory Commission and state officials.²³⁵ DOE also explained that “[t]he DOE intends to utilize any available State and local expertise in resolving an emergency.”²³⁶ Indeed, DOE’s organizational statute *requires* it to consult with States “[w]henever any proposed action by the Department conflicts with the energy plan of any State.”²³⁷ And States are already taking actions to address reliability issues and load growth in their jurisdictions.²³⁸ DOE’s refusal to collaborate with States or meaningfully involve other stakeholders here is inexplicable, conflicts with DOE’s organizational statute, and the APA.

V. Conclusion

The State’s request for rehearing should be granted and DOE should withdraw or otherwise amend the subject Report following public vetting through notice and comment proceedings. In the meantime, DOE cannot rely on the challenged report to support the exercise of its 202(c) authority. Doing so would be arbitrary and capricious and otherwise contrary to law and impose significant harm on our States.

Filed: August 6, 2025

²³⁵ 46 Fed. Reg. at 39,985.

²³⁶ *Id.*

²³⁷ 42 U.S.C. § 7113; *see also* 16 U.S. Code § 824h (encouraging federal-state collaboration).

²³⁸ Jason Plautz, *State lawmakers grapple with energy demand for data centers*, E&E News (Mar. 3, 2025) <https://www.eenews.net/articles/state-lawmakers-grapple-with-energy-demand-for-data-centers/>; Washington Office of the Governor, *Gov. Bob Ferguson Signs Executive Order Establishing a Data Center Workgroup* (Feb. 4, 2025) <https://governor.wa.gov/news/2025/governor-bob-ferguson-signs-executive-order-establishing-data-center-workgroup>.

Respectfully Submitted,

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EXHIBIT 36



Department of Energy
Washington, DC 20585

Order No. 202-25-9

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

Order Nos. 202-25-3 and 202-25-7

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

Order No. 202-25-3, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until August 21, 2025. Subsequently, Order No. 202-25-7, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until November 19, 2025. Those orders were based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO). Specifically, I determined that MISO likely faced tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. I determined that the continued operation of the Campbell Plant would provide additional generation capacity during these periods which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety. I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability. My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

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

Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that “[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output.”⁴ In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.⁵

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), “[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned.”⁶ Additionally, EIA stated, “[t]ypically, Michigan’s nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned.”⁷ The state’s Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. The Palisades plant remains unavailable, although according to a recent news report, “Holtec International expects the Palisades plant in Michigan to resume service early next year....”⁸

Third, the Campbell Plant’s retirement would have further decreased available dispatchable generation within MISO’s service territory, adding to the loss of the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts and Consumers acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates “elevated risk of operating reserve shortfalls.”⁹

Fourth, MISO’s Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which include Michigan, “new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources.”¹⁰ While the results “demonstrated sufficient

⁴ 2025 Summer Reliability Assessment, North American Electric Reliability Corporation, at 16 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf (NERC 2025 Summer Reliability Assessment).

⁵ *Id.*

⁶ *Michigan State Profile and Energy Estimates*, U.S. Energy Info. Admin. (Oct. 17, 2024), <https://www.eia.gov/state/print.php?sid=MI>.

⁷ *Id.*

⁸ *Nuclear plants face decadelong timeline to meet AI energy needs*, Los Angeles Times. (Nov. 13, 2025), <https://www.latimes.com/business/story/2025-11-13/despite-80-billion-commitment-nuclear-plants-face-decade-long-timeline-to-meet-ai-energy-needs>.

⁹ NERC 2025 Summer Reliability Assessment at 16.

¹⁰ *Planning Resource Auction—Results for Planning Year 2025–2026*, Midcontinent Independent System Operator, Inc., 13 (May 29, 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf. (MISO Planning Resource Auction – Results for Planning Year 2025-26).

capacity,” the summer months reflected the “highest risk and a tighter supply-demand balance” and these results “reinforce the need to increase capacity.”¹¹

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order Nos. 202-25-3 and 202-25-7 continue, both in the near and long term.¹² The production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO. According to the U.S. Environmental Protection Agency’s data, the plant has generated an average of approximately 509,000 MWh per month, from June 2025 through September 2025,¹³ providing vital generation capacity to the region. Additionally, between June 11 and November 5, MISO issued dozens of alerts to manage grid reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits.

MISO’s year-round resource adequacy concerns are well documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.¹⁴ MISO justified this revision by explaining that “Reliability risks associated with resource adequacy have shifted from ‘Summer only’ to a year-round concern.”¹⁵ MISO noted that over 60% of all “MaxGen” events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.¹⁶

In December of 2023, MISO released an “Attributes Roadmap,” in which it presented “an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape.”¹⁷ Among other things, this report described changes in the time of year during

¹¹ *Id.* at 2,12. For further information regarding the determination that emergency conditions existed, *see* Order No. 202-25-7.

¹² Further, as noted in Order No. 202-25-7, as a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Consumers were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

¹³ *See, Custom Data Download, EPA CAMPD (Clean Air Markets Program Data), <https://campd.epa.gov/data/custom-data-download> (search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >>Apply >> “2025” and “June, July, August, September.” The data can then be filtered to only include the JH Campbell Plant.)*

¹⁴ *Midcontinent Independent System Operator, Inc.*, FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. *Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).

¹⁵ MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).

¹⁶ *Id.* at 3-4.

¹⁷ *Attributes Roadmap*, MISO (Dec. 2023), <https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf>

which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projects that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.¹⁸

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, “*MISO’s Response to the Reliability Imperative*.”¹⁹ In a section of that report entitled “Risks in Non-Summer Seasons,” MISO again stressed that it has resource reliability concerns outside of the summer season.

Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region’s highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.²⁰

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

While the 2025 – 2026 NERC Winter Reliability Assessment has not yet been released as of the date of this Order, two recent winter studies (2024 – 2025 NERC Winter Reliability Assessment²¹ and the 2023 – 2024 NERC Winter Reliability Assessment²²) have assessed the MISO assessment area as an elevated risk, with the “potential for insufficient operating reserves in above-normal conditions.” Specifically, the 2024 – 2025 Winter Reliability Assessment noted that “[ge]nerating capacity is 10 GW lower (-6.8%) compared to the prior winter as generators have retired, withdrawn from MISO’s capacity market, or received lower winter accredited capacity.”²³

The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that “new capacity additions were insufficient to offset the negative impacts of decreased

¹⁸ *Id.* at 11.

¹⁹ *MISO’s Response to the Reliability Imperative*, MISO (Updated Feb. 2024), <https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf>

²⁰ *Id.* at 12.

²¹ 2024 – 2025 NERC Winter Reliability Assessment at 5, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf

²² 2023 – 2024 NERC Winter Reliability Assessment at 5, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf

²³ 2024 – 2025 NERC Winter Reliability Assessment at 15, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf

accreditation, suspensions/retirements and external resources” in the northern and central zones, which include Michigan.²⁴

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.²⁵ The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.²⁶ The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.²⁷ Similar results were projected for MISO’s winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.²⁸

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.²⁹ Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.³⁰

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.³¹ The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.³² In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are

²⁴ MISO Planning Resource Auction – Results for Planning Year 2025-26 at 13.

²⁵ *OMS-MISO Survey Results*, OMS and MISO (Updated June 6, 2025) <https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf>

²⁶ *Id.* at 2.

²⁷ *Id.* at 7.

²⁸ *Id.* at 9

²⁹ *Id.* at 7, 9.

³⁰ *Id.*

³¹ *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

³² 192 FERC ¶ 61,064 at P 84.

likely to further hinder rapid construction and exacerbate reliability concerns.³³ Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order Nos. 202-25-3 and 202-25-7 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, “Strengthening the Reliability and Security of the United States Electric Grid,” President Trump emphasized that “the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing.”³⁴ President Trump likewise recognized, in Executive Order 14156, “Declaring a National Energy Emergency,” that the “United States’ insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation’s economy, national security, and foreign policy.”³⁵ The Executive Order adds: “Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets.”³⁶

The Department’s July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President’s directive in Executive Order 14262, details the myriad challenges affecting the Nation’s energy outlook. “Absent decisive intervention, the Nation’s power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”³⁷ The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.³⁸ In addition, as just one example,

³³ See generally, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P Global (May 2025), [US gas-fired turbine wait times as much as seven years; costs up sharply | S&P Global](#). “With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts.”

³⁴ Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/>.

³⁵ Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/>.

³⁶ *Id.*

³⁷ See also *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy (July 2025), at 1, <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

³⁸ Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan*, (last accessed Aug. 13, 2025), <https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan>.

Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and “continue[s] to see positive momentum with data centers within the 9 GW pipeline”³⁹

Grid operators — including MISO itself — have also acknowledged the Nation’s current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that “the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth.”⁴⁰ Ms. Curran also described “much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence.”⁴¹ She added, “[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them.”⁴²

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

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.”⁴³ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has

³⁹ See *Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center*, Data Center Dynamics (August 05, 2025), <https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-toprovide-1gw-of-power-to-new-hyperscale-data-center/> (quoting Consumers Energy CEO Garrick Rochow).

⁴⁰ Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce, Subcommittee on Energy, 119th Cong. (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), at 5, https://democratsenergycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-mediadocument/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf

⁴¹ *Id.* at 6.

⁴² *Id.* at 7.

⁴³ Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. See 42 U.S.C. § 7151(b).

determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

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

To ensure the Campbell Plant will be available if needed to address emergency conditions, the Campbell Plant shall remain in operation until February 17, 2026.⁴⁴

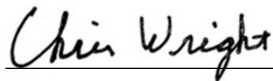
Based on my determination of an emergency set forth above, I hereby order:

- A. From November 19, 2025, MISO and Consumer Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.
- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.
- C. All operation of the Campbell Plant must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

⁴⁴ 16 U.S.C. § 824a(c)(4).

- D. By December 3, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
- E. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. This Order shall not preclude the need for the Campbell Plant to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Campbell Plant shall not be considered a capacity resource.
- H. This Order shall be effective from 00:00 Eastern Standard Time (EST) on November 19, 2025, and shall expire at 00:00 EST on February 17, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 5:58PM EST on this 18th day of November 2025.



Chris Wright
Secretary of Energy

cc:

FERC Commissioners

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

Michigan Public Service Commissioners

Chairman Dan Scripps

Commissioner Katherine Peretick

Commissioner Shaquila Myers

EXHIBIT 37



Department of Energy
Washington, DC 20585

Order No. 202-25-12

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

BACKGROUND

The R.M. Schahfer Generating Station (Schahfer) is an electric generating facility in Wheatfield, Indiana. Schahfer is owned and operated by Northern Indiana Public Service Company (NIPSCO), a division of NiSource Inc. Schahfer consists of two 129 MW natural-gas fired units and two coal-fired units, Unit 17 (423.5 MW) and Unit 18 (423.5 MW).³ Unit 17 and Unit 18 began operations in 1983 and 1986 respectively. Unit 17 and Unit 18 are both slated to cease operations in December 2025.⁴

EMERGENCY SITUATION

Midcontinent Independent System Operator, Inc.'s (MISO) year-round resource adequacy concerns are well documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.⁵ MISO justified this revision by explaining that "Reliability risks associated with Resource Adequacy have shifted from 'Summer only' to a year-round concern."⁶ MISO noted that over 60% of all

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ U.S. Energy Information Administration, Form EIA-860, Schedule 3: Generator Data (2024), <https://www.eia.gov/electricity/data/eia860/>.

⁴ As coal-fired facilities, it would be difficult for the Schahfer Units 17 and 18 to resume operations once they have been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Schahfer were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

⁵ *Midcontinent Independent System Operator, Inc.*, FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. See *Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).

⁶ MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).

“MaxGen” events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.⁷

In December of 2023, MISO released an “Attributes Roadmap,” in which it presented “an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape.”⁸ Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.⁹

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, “*MISO’s Response to the Reliability Imperative*.”¹⁰ In a section of that report entitled “Risks in Non-Summer Seasons,” MISO again stressed that it has resource reliability concerns outside of the summer season:

Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region’s historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.¹¹

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season. The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO.

In its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area is at an elevated risk “because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years.”¹²

When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that “new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources” in the northern and central zones, which include Indiana.¹³

⁷ *Id.* at 3-4.

⁸ MISO, *Attributes Roadmap*, at 3 (Dec. 2023), <https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf>.

⁹ *Id.* at 11.

¹⁰ MISO, *MISO’s Response to the Reliability Imperative* (Updated February 2024), <https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf>.

¹¹ *Id.* at 12.

¹² NERC 2024 Long-Term Reliability Assessment, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

¹³ MISO, *Planning Resource Auction: Results for Planning Year 2025-26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.¹⁴ The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.¹⁵ The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.¹⁶ Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.¹⁷

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large quantities of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.¹⁸ Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.¹⁹

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.²⁰ The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.²¹ In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.²² Consequently, it is not at all clear that the new ERAS process will result in the addition of new capacity in the next few years.

More broadly, executive orders issued by President Donald J. Trump on January 20, 2025 and April 8, 2025, underscored the dire energy challenges facing the Nation due to growing

¹⁴ OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025), <https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf>.

¹⁵ *Id.* at 2.

¹⁶ *Id.* at 7.

¹⁷ *Id.* at 9.

¹⁸ *Id.* at 7, 9.

¹⁹ *Id.*

²⁰ *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

²¹ *Id.* P 84.

²² See generally, S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025), ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), <https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply>.

resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, “Declaring a National Energy Emergency,” in which he determined that the “United States’ insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation’s economy, national security, and foreign policy.”²³ The Executive Order adds: “Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets.”²⁴ In a subsequent Executive Order 14262, “Strengthening the Reliability and Security of the United States Electric Grid,” President Trump emphasized that “the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing.”²⁵

Further, the Department detailed the myriad challenges affecting the Nation’s energy systems in its July 2025 “Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid,” issued pursuant to the President’s directive in Executive Order 14262. The Department concluded that “[a]bsent decisive intervention, the Nation’s power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”²⁶

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.”²⁷ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Schahfer Units 17 and 18 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety. Given the responsibility of MISO to

²³ Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency>.

²⁴ *Id.*

²⁵ Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid>.

²⁶ U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025_07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

²⁷ Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of Energy. *See* 42 U.S.C. § 7151(b).

identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of Schahfer Units 17 and 18 is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c).

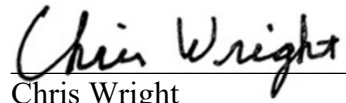
To ensure Schahfer Units 17 and 18 will be available if needed to address emergency conditions, Schahfer Units 17 and 18 shall remain in operation until March 23, 2026.

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

- A. From December 23, 2025, MISO and NIPSCO, shall take all measures necessary to ensure that Schahfer Units 17 and 18 are available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Schahfer Units 17 and 18 to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. NIPSCO is directed to comply with all orders from MISO related to the availability and dispatch of the Schahfer Units 17 and 18.
- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Schahfer Units 17 and 18 has operated in compliance with the allowances contained in this Order.
- C. All operation of Schahfer Units 17 and 18 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.
- D. By January 13, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Schahfer Units 17 and 18 consistent with this Order. MISO and NIPSCO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.
- E. NIPSCO is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. This Order shall not preclude the need for Schahfer Units 17 and 18 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.
- G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Schahfer Units 17 and 18 shall not be considered capacity resources.

H. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 23, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 23, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Denver, Colorado at 6:39 PM EST on this 23rd day of December 2025.

A handwritten signature in black ink that reads "Chris Wright". The signature is written in a cursive style and is positioned above a horizontal line.

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**

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

Indiana Utility Regulatory Commission

Chairman Jim Huston
Commissioner David Veleta
Commissioner David Ziegner

EXHIBIT 38



Department of Energy
Washington, DC 20585

Order No. 202-25-13

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

BACKGROUND

The F.B. Culley Generating Station (Culley) is an electric generating facility in Warrick County, Indiana. Culley is owned and operated by CenterPoint Energy and consists of two coal-fired generation units, Unit 2 (103.7 MW) and Unit 3 (265.2 MW), with a combined name plate capacity of 368.9 MW. Unit 2 and Unit 3 began operations in 1966 and 1973, respectively. Unit 2 is slated to cease operations in December 2025.³

EMERGENCY SITUATION

Midcontinent Independent System Operator, Inc.'s (MISO) year-round resource adequacy concerns are well documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.⁴ MISO justified this revision by explaining that "Reliability risks associated with Resource Adequacy have shifted from 'Summer only' to a year-round concern."⁵ MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.⁶

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

¹ 16 U.S.C. § 824a(c).

² 42 U.S.C. § 7151(b).

³ As a coal-fired facility, it would be difficult for Culley Unit 2 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Culley were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

⁴ *Midcontinent Independent System Operator, Inc.*, FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. See *Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).

⁵ MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).

⁶ *Id.* at 3-4.

transforming energy landscape.”⁷ Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.⁸

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, “*MISO’s Response to the Reliability Imperative*.”⁹ In a section of that report entitled “Risks in Non-Summer Seasons,” MISO again stressed that it has resource reliability concerns outside of the summer season:

Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region’s highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.¹⁰

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season. The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO.

In its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area is at an elevated risk “because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years.”¹¹

When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that “new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources” in the northern and central zones, which include Indiana.¹²

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to

⁷ MISO, *Attributes Roadmap*, at 3 (Dec. 2023), <https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf>.

⁸ *Id.* at 11.

⁹ MISO, *MISO’s Response to the Reliability Imperative* (Updated Feb. 2024), <https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf>.

¹⁰ *Id.* at 12.

¹¹ NERC 2024 Long-Term Reliability Assessment, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

¹² MISO, *Planning Resource Auction: Results for Planning Year 2025-26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

which expected capacity resources satisfy planning reserve margin requirements.¹³ The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.¹⁴ The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.¹⁵ Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.¹⁶

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large quantities of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.¹⁷ Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.¹⁸

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.¹⁹ The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.²⁰ In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.²¹ Consequently, it is not at all clear that the new ERAS process will result in the addition of new capacity in the next few years.

¹³ OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025), <https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf>.

¹⁴ *Id.* at 2.

¹⁵ *Id.* at 7.

¹⁶ *Id.* at 9.

¹⁷ *Id.* at 7, 9.

¹⁸ *Id.*

¹⁹ *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

²⁰ *Id.* P 84.

²¹ See generally, S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, (May 2025), ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), <https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply>.

More broadly, executive orders issued by President Donald J. Trump on January 20, 2025, and April 8, 2025, underscore the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump likewise declared a national energy emergency in Executive Order 14156, “Declaring a National Energy Emergency,” that the “United States’ insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation’s economy, national security, and foreign policy.”²² The Executive Order adds: “Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets.”²³ In a subsequent Executive Order 14262, “Strengthening the Reliability and Security of the United States Electric Grid,” President Trump emphasized that “the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing.”²⁴

Further, the Department detailed the myriad challenges affecting the Nation’s energy systems in its July 2025 “Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid,” issued pursuant to the President’s directive in Executive Order 14262. The Department concluded that “[a]bsent decisive intervention, the Nation’s power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation.”²⁵

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines “that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy,” then the Secretary has the authority “to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.”²⁶ This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Culley Unit 2 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

²² Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), <https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency>.

²³ *Id.*

²⁴ Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), <https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid>.

²⁵ U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>.

²⁶ Although the text of FPA section 202(c) grants this authority to “the Commission,” section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of Energy. See 42 U.S.C. § 7151(b).

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of Culley Unit 2 is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c).

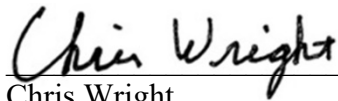
To ensure Culley Unit 2 will be available if needed to address emergency conditions, Culley Unit 2 shall remain in operation until March 23, 2026.

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

- A. From December 23, 2025, MISO and CenterPoint Energy shall take all measures necessary to ensure that Culley Unit 2 is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Culley Unit 2 to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. CenterPoint Energy is directed to comply with all orders from MISO related to the availability and dispatch of Culley Unit 2.
- B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Culley Unit 2 has operated in compliance with the allowances contained in this Order.
- C. All operations of Culley Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.
- D. By January 13, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Culley Unit 2 consistent with this Order. MISO and CenterPoint Energy shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

- E. CenterPoint Energy is directed to file with the Federal Energy Regulatory Commission tariff revisions or waivers to effectuate this Order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).
- F. This Order shall not preclude the need for Culley Unit 2 to comply with applicable state, local, or Federal laws or regulations following the expiration of this Order.
- G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Culley Unit 2 shall not be considered a capacity resource.
- H. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 23, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 23, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Denver, Colorado at 6:39 PM EST on this 23rd day of December 2025.



Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Indiana Utility Regulatory Commission
Chairman Jim Huston
Commissioner David Veleta
Commissioner David Ziegner

EXHIBIT 39

PJM Manual 18:

PJM Capacity Market

Revision: 61

Effective Date: July 23, 2025

Prepared By
Capacity Market & Demand Response
Operations

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Approval

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Peter Langbein, Manager

Capacity Market and Demand Response Operations

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Administrative Change (Pete Langbein approved 08/01/2025):

- Added missing changes from Revision 60 back into Revision 61

Revision 61 (07/23/2025):

- Conforming changes were made to the following sections to incorporate provisions of FERC orders (ER25-682) and (ER25-785) and (er24-2995-000).
- 2.4.5 Adjustments to RPM Auction Parameters for EE Resources
- 3.3 Parameters of the Variable Resource Requirement
 - 3.3.1 Cost of New Entry
- 3.4 Plotting the Variable Resource Requirement Curve
- 4.7.1 Resource Position for Generation Capacity Resources
- 5.1 Overview of RPM Auctions
 - 5.4.1 Resource-Specific Sell Offer Requirements
 - 5.4.8.4 Default MOPR Floor Offer Prices
- 8.4A Non-Performance Assessment

Introduction

Welcome to the ***PJM Manual for PJM Capacity Market***. In this Introduction you will find information about PJM Manuals in general, an overview of this PJM Manual in particular, and information on how to use this manual.

- What you can expect from the PJM Manuals (see “About PJM Manuals”).
- What you can expect from this PJM Manual (see “About This Manuals”).
- How to use this manual (see “Using This Manual”).

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by PJM for the operation, planning, and accounting requirements of PJM and the PJM Energy Market. The manuals are grouped under the following categories:

- Transmission
- Energy Market
- Regional Transmission Planning Process
- Reserve
- Accounting and Billing
- Administration
- Miscellaneous

For a complete list of all PJM manuals, go to the Library section on PJM.com.

About This Manual

The ***PJM Manual for PJM Capacity Market*** is one of the PJM reserve manuals. This manual focuses on the capacity markets, including the Reliability Pricing Model and the Fixed Resource Requirement Alternative, and the requirements for resource providers and Load Serving Entities (LSEs) to participate in these markets and their responsibilities as signatories to the Open Access Transmission Tariff, Reliability Assurance Agreement and Operating Agreement of PJM Interconnection, L.L.C.

This manual also refers to other PJM manuals, which define in detail the operating procedures, obligations, reporting requirements, and accounting procedures established to ensure reliable and efficient capacity market operation.

The ***PJM Manual for PJM Capacity Market*** consists of 11 sections and 4 attachments (labeled A through D). Both the sections and the attachments are listed in the table of contents beginning on page 2.

Intended Audience

The intended audiences for this PJM Manual for PJM Capacity Market are:

- Applicants to the RAA, OA and OATT Operating Agreement of PJM Interconnection, L.L.C.
- Resource providers and those interested in providing adequate Capacity Resources that will be made available to provide reliable service to loads within the PJM Region.
- Load Serving Entities (LSEs) for load served in the PJM Region.
- PJM Members
- PJM staff

References

There are other PJM documents that provide both background and detail on specific topics. These documents are the primary source for specific requirements and implementation details. This manual does not replace any of the information in those reference documents. The references for the PJM Manual for *PJM Capacity Market* are:

- [Control Center and Data Exchange Requirements \(M-01\)](#)
- [Pre-Scheduling Operations \(M-10\)](#)
- [Energy & Ancillary Services Market Operations \(M-11\)](#)
- [Balancing Operations \(M-12\)](#)
- [Regional Transmission Planning Process \(14B\)](#)
- [Generator Operational Requirements \(M-14D\)](#)
- [Energy Efficiency Measurement & Verification \(M-18B\)](#)
- [Load Forecasting & Analysis \(M-19\)](#)
- [Reserve Adequacy Analysis \(M-20\)](#)
- Reserve Adequacy Analysis (M-20A)
- [Rules and Procedures for Determination of Generating Capability \(M-21\)](#)
- Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis (M-21A)
- Rules and Procedures for Determination of Generating Capability (M-21B)
- [Generator Resource Performance Indices \(M-22\)](#)
- [Open Access Transmission Tariff Accounting \(M-27\)](#)
- [Billing \(M-29\)](#)

Using This Manual

We believe that explaining concepts is just as important as presenting procedures. This philosophy is reflected in the way we organize the material in this manual. We start each section with the “big picture.” Then we present details, procedures or references to procedures found in other PJM manuals.

What You Will Find In This Manual

- A table of contents that lists two levels of subheadings within each of the sections and attachments
- An approval page that lists the required approvals and a brief outline of the current revision
- Sections containing the specific guidelines, requirements, or procedures including PJM actions and PJM Member actions
- Attachments that include additional supporting documents, forms, or tables
- A section at the end detailing all previous revisions of this PJM Manual.

Note:

Prior to the Transition Date, the Interconnection Service Agreement (ISA) was the form agreement included in the Tariff used to facilitate interconnection to PJM’s transmission system, which used the term “Interconnection Customer” to refer to generation interconnection customers, similar to the Project Developer”. While the ISA is no longer used for interconnection to the transmission system, pre-existing ISAs remain active. On and after the Transition Date, the Generation Interconnection Agreement (GIA) is used as the form agreement included in the Tariff to facilitate interconnection to PJM’s transmission system.

The Tariff defines the Transition Date as the later of: (i) the effective date of PJM’s Docket No. ER22-2110 transition cycle filing seeking FERC acceptance of Tariff, Part VII (Which is January 3, 2023) or (ii) the date by which all AD2 and prior queue window Interconnection Service Agreements or wholesale market participation agreements have been executed or filed unexecuted. Because this section condition happened last, this date establishes the Transition Date.

Section 1: Overview of the PJM Capacity Market

Welcome to the *Overview of the PJM Capacity Market* section of the **PJM Manual for the PJM Capacity Market**. In this section, you will find the following information:

- An overview description of the PJM Capacity Market (see “Overview of the PJM Capacity Market”)
- The business rules for participation in the PJM Capacity Markets (see “Participation in the PJM Capacity Market”)
- A definition and purpose of the Reliability Pricing Model (see “Definition and Purpose of the Reliability Pricing Model”)
- The timeframe for implementation of the Reliability Pricing Model (see “Implementation of the Reliability Pricing Model”)
- A summary of the transition to Capacity Performance (see “Transition to Capacity Performance”)

1.1 Overview of the PJM Capacity Market

The PJM Capacity Market is designed to ensure the adequate availability of necessary resources that can be called upon to ensure the reliability of the grid. In PJM, the Capacity Market structure, through either the Reliability Pricing Model (RPM) consisting of a Base Residual Auction and three Incremental Auctions for a Delivery Year or the Fixed Resource Requirement (FRR) Alternative, provides transparent information to enable forward capacity market signals to support infrastructure investment. The capacity market design provides a forward mechanism to evaluate the ongoing reliability requirements in a transparent way to provide opportunity for generation, demand response, energy efficiency, price responsive demand, and transmission solutions.

In the PJM Region, the basis for the Capacity Market design is the Reliability Pricing Model (RPM). The goal of RPM is to align capacity pricing with system reliability requirements and to provide transparent information to all market participants far enough in advance for actionable response to the information. In RPM, the fundamental elements to achieve this are:

- Locational capacity pricing to recognize and quantify the locational value of capacity
- Variable Resource Requirement mechanism to adjust price based on the level of resources procured
- Forward commitment of supply by generation, demand resources, energy efficiency resources, and qualified transmission upgrades cleared in a multi-auction structure
- A Reliability Backstop mechanism to ensure that sufficient generation, transmission and demand response solutions will be available to preserve system reliability

The PJM Capacity Market also contains an alternative method of participation, known as the Fixed Resource Requirement (FRR) Alternative. The Fixed Resource Requirement Alternative provides a Load Serving Entity (LSE) with the option to submit a FRR Capacity Plan and meet a fixed capacity resource requirement as an alternative to the requirement to participate in the PJM Reliability Pricing Model (RPM), which includes a variable capacity resource requirement.

Effective with the 2018/2019 Delivery Year, the Capacity Market design was enhanced to recognize two product types for Capacity Resources, Capacity Performance Resources and Base Capacity Resources, to ensure that capacity resources committed to meet the PJM Region's reliability and resource adequacy needs will deliver the promised energy and reserves when called upon in emergencies. The Base Capacity Resource product-type was phased out such that all capacity resources used to meet the PJM Region's reliability and resource adequacy needs are the Capacity Performance Resource product-type effective with the 2020/2021 Delivery Year.

Effective with the 2020/2021 Delivery Year, the Capacity Market design includes the ability to offer Seasonal Capacity Performance Resources directly into the RPM Auction as an alternative to entering into a commercial arrangement to establish and offer an Aggregate Resource. Capacity Market Sellers may submit sell offers of either Summer-Period Capacity Performance Resources or Winter-Period Capacity Performance Resources and the auction clearing optimization algorithm will be designed to clear equal quantities of off-setting seasonal capacity sell offers thereby creating an annual capacity commitment by matching a Summer-Period Capacity Performance Resource with a Winter-Period Capacity Performance Resource.

Unless otherwise specified, the rules presented throughout this Manual are focused on the Reliability Pricing Model. Information on the Fixed Resource Requirement Alternative can be found in **Section 11 of this Manual** and on PJM.com.

1.2 Participation in the PJM Capacity Market

Participants in the PJM Capacity Market, both Load Serving Entities and resource providers, must comply with all applicable provisions of the PJM Open Access Transmission Tariff, PJM Operating Agreement, and the PJM Reliability Assurance Agreement. PJM Capacity Market participants must be signatories of the appropriate Agreements and Full Members of PJM. All participants must comply with the procedures and requirements as set forth by these agreements and in PJM Manuals.

1.2.1 Participation of Load Serving Entities

Participation by Load Serving Entities (LSEs) in the RPM for load served in the PJM region is mandatory, except for those LSEs that have elected the Fixed Resource Requirement (FRR) Alternative and submitted an approved FRR Capacity Plan for their load served in an FRR Service Area. Under RPM, each LSE that serves load in a PJM Zone during the Delivery Year shall be responsible for paying a Locational Reliability Charge equal to their Daily Unforced

Capacity Obligation in the Zone multiplied by the Final Zonal Capacity Price applicable to that Zone. LSEs may choose to hedge their Locational Reliability Charge obligations by directly offering and clearing resources in the Base Residual Auction and Incremental Auctions or by designating self-supplied resources (resources directly owned or resources contracted for through unit-specific bilateral purchases) as self-scheduled to cover their obligation in the Base Residual Auction. Such action may wholly or partially offset an LSE's Locational Reliability Charges during the Delivery Year depending upon how the clearing prices of the resources compare to the Final Zonal Capacity Prices that apply to their unforced capacity obligations.

Participants with Non-Zone Load, as defined in the PJM Agreements, may be included in the Reliability Pricing Model depending if the load that is located outside of the PJM Region is included in the PJM load forecasts and served by generation resources located within the PJM Region. The treatment of Non-Zone Load is described in **Section 7 of this Manual**.

1.2.2 Participation of Resource Providers

Resource providers with Existing Generation Capacity Resources, Planned Generation Capacity Resources, bilateral contracts for unit-specific Capacity Resources, existing Demand Resources, Planned Demand Resources, Energy Efficiency Resources, and Qualifying Transmission Upgrades may participate in PJM's Capacity Market, either in PJM's Reliability Pricing Model or the Fixed Resource Requirement Alternative, if these resources meet the requirements specified in this Manual. Existing generation that is located outside of the PJM market footprint may also be offered into PJM's Capacity Market, either in the Reliability Pricing Model or the Fixed Resource Requirement Alternative, if the external generation meets the requirements specified in the PJM Manuals and PJM Agreements.

Participation is mandatory for resource providers with:

- Available unforced capacity from Existing Generation Capacity Resources located within the PJM market footprint; or
- Bilateral contracts for available unit-specific Capacity Resources that are Existing Generation Capacity Resources located within the PJM market footprint.
- Generation is treated as existing for the purpose of must-offer requirement and mitigation provisions when the generation is (a) in service at the commencement of an RPM Auction or (b) not yet in service but has cleared an RPM Auction for any prior Delivery Year.
- External Generation Capacity Resource with an effective External Resource Must Offer Agreement
- Beginning with the 2025/2026 Delivery Year and subsequent Delivery Years, a Planned Generation Capacity Resource associated with a notice of intent to offer submitted pursuant to Tariff, Attachment DD, section 5.5 shall be required to be offered by the Capacity Market Seller of such resource in the relevant RPM Auction.

Resource providers do have the option to export available capacity outside the PJM market footprint if the generator is exporting per the requirements specified in PJM Manuals and PJM Agreements.

Participation is voluntary for resource providers with:

- External Generation Capacity Resource without an effective External Resource Must Offer Agreement
- Planned Generation Capacity Resource (which includes new Generation Capacity Resources and planned upgrades to Existing Generation Capacity Resources); however, effective with the 2025/2026 Delivery Year, a Planned Generation Capacity Resource must satisfy the requirements of the binding notice of intent in section 4.2.3.1 in order to submit a Sell Offer in an RPM Auction
- Planned External Generation Capacity Resources (which includes new Generation Capacity Resources and planned upgrades to Existing Generation Capacity Resources)
- Existing Demand Resources
- Planned Demand Resources
- Energy Efficiency Resources
- Qualifying Transmission Upgrades.

All participation by resource providers is subject to the market power mitigation rules described in ***Attachment DD, Section 6 of the PJM Open Access Transmission Tariff***.

1.2.3 Participation of PRD Providers

PRD Providers may participate in PJM's Capacity Market, either in PJM's Reliability Pricing Model or the Fixed Resource Requirement Alternative. A PRD Provider is a PJM Member that has entered contractual arrangements with end-use customers that satisfy the eligibility criteria for PRD as specified in this Manual.

1.3 Definition and Purpose of the Reliability Pricing Model

The Reliability Pricing Model is the PJM resource adequacy construct that ensures that adequate Capacity Resources, including planned and existing Generation Capacity Resources, Energy Efficiency Resources and planned and existing Demand Resources will be made available to provide reliable service to loads within the PJM Region.

The purpose of the RPM is to develop a long term pricing signal for Capacity Resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP). RPM is also designed to add stability and a locational nature to the pricing signal. The RPM is a multi-auction structure designed to procure resource and PRD

commitments to satisfy the region's unforced capacity obligation through the following market mechanisms: a Base Residual Auction, Incremental Auctions and a Bilateral Market.

- *Base Residual Auction* - The Base Residual Auction is held during the month of May three (3) years prior to the start of the Delivery Year. The Base Residual Auction (BRA) allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the Load Serving Entities (LSEs) through a Locational Reliability Charge.
- *Incremental Auctions* – At least three Incremental Auctions are conducted after the Base Residual Auction to procure additional resource commitments needed to satisfy potential changes in market dynamics that are known prior to the beginning of the Delivery Year.
 - The First, Second, and Third Incremental Auctions are conducted to allow for replacement resource procurement, increases and decreases in resource commitments due to reliability requirement adjustments.
 - A Conditional Incremental Auction may be conducted if a Backbone transmission line is delayed and results in the need for PJM to procure additional capacity in a Locational Deliverability Area to address the corresponding reliability problem.
- *The Bilateral Market* – The bilateral market provides resource providers an opportunity to cover any auction commitment shortages. The bilateral market also provides LSEs the opportunity to hedge against the Locational Reliability Charge. The bilateral market is facilitated through the Capacity Exchange system.

1.4 Implementation of the Reliability Pricing Model

The implementation of the Reliability Pricing Model began with the 2007/2008 Delivery Year. PJM's Planning Period is defined as an annual period from June 1 to May 31. The Delivery Year is the Planning Period for which resources are being committed and for which a constant load obligation for the entire PJM region exists. For example, the 2012/2013 Delivery Year corresponds to the June 1, 2012 - May 31, 2013 Planning Period.

The Transition Period of the RPM took place during the 2007/2008 through 2010/2011 Delivery Years.

The steady-state condition of the RPM began with the 2011/2012 Delivery Year. Unless otherwise specified, the rules and time frames presented throughout this Manual are for the steady-state condition of RPM.

1.5 Transition to Capacity Performance

Effective with the 2018/2019 Delivery Year¹, PJM introduced Capacity Performance requirement that requires Capacity Resources to meet their commitments to deliver electricity whenever PJM determines they are needed to meet power system emergencies and procured two capacity

product types through RPM Auctions: Capacity Performance Resources and Base Capacity Resources. The Base Capacity Resource product-type was phased out such that only resources that meet the requirements of the Capacity Performance Resource product-type are used to meet the PJM Region's reliability and resource adequacy needs effective with the 2020/2021 Delivery Year.

For a Capacity Resource to qualify as a Capacity Performance Resource product type, the resource must be capable of sustained, predictable operation that allows the resource to be available throughout the entire Delivery Year to provide energy and reserves whenever PJM determines an emergency condition exists. Internal and external Generation Capacity Resources, Capacity Storage Resources, and Aggregate Resources that can qualify as Capacity Performance Resource product type, Demand Resources that meet Capacity Performance DR product type requirements, Energy Efficiency resources that provide permanent, continuous load reduction during both summer and winter peak seasons in accordance with the Capacity Performance EE product type requirements, and Qualifying Transmission Upgrades are eligible to offer as the Capacity Performance product-type. Resources that clear and have a Capacity Performance Resource Commitment are subject to Non-Performance Assessment during the relevant Delivery Year in accordance with **Section 8.4A of this Manual**.

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¹ For FRR Entities, Capacity Performance and Base Capacity resources are effective for the 2019/2020 Delivery Year. Limited DR, Extended Summer DR, and Annual Resources remain effective for FRR Entities through the 2018/2019 Delivery Year. Capacity Performance Resources are solely effective for 2020/2021 Delivery Year.

Section 2: Resource Adequacy

Welcome to the *Resource Adequacy* section of the **PJM Manual for the PJM Capacity Market**. In this section, you will find the following information:

- An overview description of resource adequacy (see “Overview of Resource Adequacy”)
- The role of load deliverability in the Reliability Pricing Model (see “Role of Load Deliverability in the Reliability Pricing Model”)
- The business rules for Locational Constraints in the Reliability Pricing Model (“see Locational Constraints in the Reliability Pricing Model”)
- The definitions of Reliability Requirements (see “Reliability Requirements”)

2.1 Overview of Resource Adequacy

The purpose of PJM RTO resource adequacy is to determine the amount of Capacity Resources that can be required to serve the forecast load and satisfy the PJM reliability criterion. PJM performs an assessment of resource adequacy each year for an eleven-year future period. The analysis considers load forecast uncertainty, forced outages of Generation Capacity Resources, as well as planned and maintenance outages. In PJM, studies are performed using the installed capacity values of resources. The reliability value of a resource depends on two variables: the installed capacity of the resource and a measure of the probability that a resource will not be available due to forced outages or forced de-ratings. The reliability criterion is based on Loss of Load Expectation (LOLE) not exceeding one occurrence in ten years. The resource requirement to meet the reliability criterion is expressed as the Installed Reserve Margin (IRM) as a percentage of forecast peak load.

2.1.1 Installed Reserve Margin

The Installed Reserve Margin (IRM) for the Delivery Year is the measure calculated to establish the level of installed capacity resources that will provide an acceptable level of reliability consistent with the PJM Reliability Principles and Standards. The IRM is determined by PJM in accordance with the ***Resource Adequacy Analysis Manual (M-20) and (M-20A)***.

Note:

The Installed Reserve Margin (IRM) is approved by the PJM Board of Managers no later than 75 days in advance of Base Residual Auction for the Delivery Year and posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website. An Updated IRM is approved by the PJM Board of Managers and posted one month prior to its use in an Incremental Auction for the Delivery Year. The Updated IRM that is posted for the Third Incremental Auction for the Delivery Year is the final IRM for the Delivery Year.

2.1.2 Peak Load Forecasts

PJM produces peak load forecasts for use in the RPM auction clearing processes and for planning purposes. In RPM, the load forecasts will be used to determine the RTO Reliability Requirement. PJM will determine **annual peak load forecasts** for the RTO and zones for use in the RPM Auction clearing process.

The RTO Peak Load Forecast and the Zonal Peak Load Forecasts for the Delivery Year are determined by PJM in accordance with the ***Load Forecasting and Analysis Manual (M-19)***.

Note:

The Preliminary RTO and Zonal Peak Load Forecasts are determined and posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website .

Updated RTO and Zonal Peak Load Forecasts are posted no later than one month prior to the First and Second Incremental Auctions.

The ***Final RTO and Zonal Peak Load Forecasts*** are posted no later than one month prior to the Third Incremental Auction.

Load forecasts are also used in the determination of other planning and auction parameters such as Capacity Emergency Transfer Limit (CETL), Capacity Emergency Transfer Objective (CETO), Capacity Import Limits, and RPM Zonal Scaling Factors. These parameters are discussed in detail in later sections of this Manual.

2.1.3.1 Pool-wide Average EFORD (Through 2024/2025 Delivery Year)

To account for the forced outage rates of generation capacity resources, an Equivalent Forced Outage Rate (EFORD) for each generating unit in the PJM RTO is calculated. Equivalent Demand Forced Outage Rate (EFORD) is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate. See ***Generator Resource Performance Indices Manual (M-22)*** for equations and details.

The Pool-wide Average EFORD for the Delivery Year is the average of the EFORD values based on five years history, weighted for unit capability and expected time in service, attributable to all units that are expected to be in service during the Delivery Year. The Pool-Wide Average EFORD includes forced outage events that are outside management control (referred to as OMC events). The Pool-wide Average EFORD is determined by PJM in accordance with the ***Resource Adequacy Analysis Manual (M-20)***.

Note:

The **Pool-wide average EFORD** is posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website. An updated Pool-wide average EFORD is posted one month prior to its use in an Incremental Auction for the Delivery Year. The Pool-wide average EFORD that is posted for the Third Incremental Auction for the Delivery Year is the final pool-wide average EFORD for the Delivery Year.

2.1.3.2 Pool-wide average Accredited UCAP Factor (Starting 2025/2026 Delivery Year)

The Pool-wide average Accredited UCAP Factor for the Delivery Year is the ratio of the total Accredited UCAP to total installed capacity of all resources, as determined pursuant to RAA, Schedule 9.2, that are included in the determination of the Forecast Pool Requirement, stated in percent. The Pool-wide average Accredited UCAP Factor is determined by PJM in accordance with the Resource Adequacy Analysis Manual (M-20A).

Note: The **Pool-wide average Accredited UCAP Factor** is posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website. An updated Pool-wide average Accredited UCAP Factor is posted one month prior to its use in an Incremental Auction for the Delivery Year. The Pool-wide average Accredited UCAP Factor that is posted for the Third Incremental Auction for the Delivery Year is the final Pool-wide average Accredited UCAP Factor for the Delivery Year.

2.1.4 Forecast Pool Requirement

While IRM multiplied by peak load forecasts provides the installed capacity required to meet the reliability criterion, the Forecast Pool Requirement (FPR) multiplied by peak load forecasts provides unforced capacity values, required to meet the reliability criterion.

The Forecast Pool Requirement is the measure determined for the specified Delivery Year to establish the level of unforced capacity (UCAP) that will provide an acceptable level of reliability consistent with PJM Reliability Principles and Standards.

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For Delivery Years through the 2024/2025 Delivery Year, the Forecast Pool Requirement (FPR) for the Delivery Year is equal to (1 + Installed Reserve Margin) times (1-Pool-wide Average EFORD).²

$$\text{ForecastPoolRequirement}(FPR) = (1 + \text{InstalledReserveMargin}) * (1 - \text{PoolWideAverageEFORD})$$

² The terms in this equation are expressed in decimal form.

Starting with the 2025/2026 Delivery Year and for all subsequent Delivery Years, the Forecast Pool Requirement (FPR) for the Delivery Year is equal to (1 + Installed Reserve Margin) times (Pool-wide average Accredited UCAP Factor).

$$\text{ForecastPoolRequirement(FPR)} = (1 + \text{InstalledReserveMargin}) * (\text{Pool - wide average Accredited UCAP Factor})$$

Note:

The **Forecast Pool Requirement (FPR)** is approved by the PJM Board of Managers by no later than 75 days in advance of Base Residual Auction for the Delivery Year and posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website. An Updated FPR is approved by the PJM Board of Managers and posted one month prior to its use in an Incremental Auction for the Delivery Year. The Updated FPR that is posted for the Third Incremental Auction for the Delivery Year is the final FPR for the Delivery Year.

2.1.5 Effective Load Carrying Capability and ELCC Resources in Capacity Exchange

Effective Load Carrying Capability (ELCC) establishes the Accredited UCAP value for ELCC Resources. Through the 2024/2025 Delivery Year, an ELCC Resource is a Generation Capacity Resource that is a Variable Resource, a Limited Duration Resource, or a Combination Resource. Beginning with the 2025/2026 Delivery Year, an ELCC Resource includes all Generation Capacity Resources and Demand Resources. ELCC analyzes historical hourly weather and load shapes relative to hourly output of ELCC Resources in order to quantify the ability of such resources to satisfy the reliability criterion. The ELCC method is described in **Manual 20 and Manual 20A (PJM Resource Adequacy Analysis)**, and the calculation of Accredited UCAP for an ELCC Resource is described in **Manual 21A (Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis)** and **Manual 21B (Rules and Procedures for Determination of Generating Capability)**.

2.2 Role of Load Deliverability in the Reliability Pricing Model

The process of determining the Installed Reserve Margin (IRM) that meets the PJM reliability criterion assumes that the internal RTO transmission is adequate and any generation can be delivered to any load without transmission constraints. This process helps in determining the minimum possible IRM for the RTO. However, since transmission may have limitations, after IRM is determined, a Load Deliverability analysis is conducted. The RTO is divided into different sub-regions for this analysis. These sub-regions are referred to as Locational Deliverability Areas (LDAs) in the Reliability Pricing Model.

The first step in the Load Deliverability analysis is to determine the Capacity Emergency Transfer Objective (CETO) of each LDA which is used to determine the amount of generation required to meet the locational reliability standard. For more details regarding the CETO analysis, please see **Resource Adequacy Analysis Manual (M-20) and M20A**.

The second step in Load Deliverability analysis is to determine the transmission import capability limit for each LDA using the transmission analysis models. For this analysis, a Transmission Upgrade including transmission facilities at voltages of 500 kV or higher that is in an approved Regional Transmission Expansion Plan (“Backbone Transmission”) will be included in the system model only if it satisfies the project development milestones set forth in the tariff. This import capability limit is called Capacity Emergency Transfer Limit (CETL), expressed in megawatts and valued as unforced capacity. For more details regarding CETL analysis, please see **Manual 14B: Regional Transmission Planning Process, Attachment C: PJM Deliverability Testing Methods**.

If CETL value is less than CETO value, transmission upgrades are planned under the Regional Transmission Expansion Planning Process (RTEPP). However, higher than anticipated load growth and unanticipated retirements may result in the CETL value being less than CETO value with no lead time to build transmission upgrades to increase CETL value. These conditions could result in locational constraints in the RTO.

2.3 Locational Constraints in the Reliability Pricing Model

When a capacity market does not have the ability to price capacity on a locational basis, all the resources in the market are valued equally. When this occurs, it is possible to have excess reserves in the RTO and relatively low capacity prices. This market signal will result in generation capacity retirements. In some areas of the RTO these retirements will create reliability violations. These conditions will indicate that a higher value for resources is required to be recognized in constrained locations to incent existing generating capacity to remain in service, and new capability to be built in the form of generation resources, demand resources, energy efficiency resources, or merchant transmission upgrades. One of the key features of RPM is the recognition of locational value of capacity.

Locational Constraints are localized intra-PJM capacity import capability limitations (low CETL margin over CETO) that are caused by transmission facility limitations or voltage limitations that are identified for a Delivery Year in the PJM Regional Transmission Expansion Planning Process (RTEPP) prior to each Base Residual Auction. Such locational constraints are included in the RPM to recognize and to quantify the locational value of capacity within the PJM region.

Note:

CETOs and CETLs for the LDAs to be modeled in all RPM Auctions for the Delivery Year are posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website. Updated CETOs and CETLs for the modeled LDAs are posted one month prior to its use in an Incremental Auction for the Delivery Year.

2.3.1 Locational Deliverability Areas

In the development of the Reliability Pricing Model, the RTEP Process identified 27 sub-regions referred to as Locational Deliverability Areas for evaluating the locational constraints. LDAs include EDC zones, sub-zones, and combination of zones.

The 27 LDAs (highlighted in boldface) and an LDA's relationship to an immediate parent LDA are listed below:

- RTO=> **Western PJM**
- RTO => Western PJM => **ComEd**
- RTO => Western PJM => **AEP**
- RTO => Western PJM => **Dayton** (may be listed as DAY)
- RTO => Western PJM => **Duquesne** (may be listed as DLCO or DUQ)
- RTO => Western PJM => **APS**
- RTO => Western PJM => **ATSI**
- RTO => Western PJM => ATSI => **Cleveland** (may be listed as ATSI-Cleveland)
- RTO => Western PJM => **DEOK**
- RTO => Western PJM => **EKPC**
- RTO => Western PJM => OVEC
- RTO => **Dominion** (may be listed as DOM)
- RTO => **MAAC**³
- RTO => MAAC => **WMAAC**⁴
- RTO => MAAC => WMAAC => **MetEd**
- RTO => MAAC => WMAAC => **PPL** (may be listed as PL)
- RTO => MAAC => WMAAC => **Penelec** (may be listed as PENLC)
- RTO =>MAAC => **EMAAC**⁵
- RTO => MAAC => EMAAC => **AE** (may be listed as AECO)
- RTO => MAAC => EMAAC => **PSEG** (may be listed as PS)
- RTO => MAAC => EMAAC => PSEG => **PSEG northern region** (may be listed as PSEG N or PSNORTH)
- RTO => MAAC => EMAAC => **PECO**
- RTO => MAAC => EMAAC => **JCPL**

³ MAAC LDA represents the Mid-Atlantic Region (MAR).

⁴ WMAAC LDA represents the Western Mid-Atlantic Region (WMAR)

⁵ EMAAC LDA represents the Eastern Mid-Atlantic Region (EMAR)

- RTO => MAAC => EMAAC => **DPL**
- RTO => MAAC => EMAAC => DPL => **DPL southern region** (may be listed as DPL S or DPLSOUTH)
- RTO => MAAC => EMAAC => RECO
- RTO => MAAC => **SWMAAC**⁶
- RTO => MAAC => SWMAAC => **BGE**
- RTO => MAAC => SWMAAC => **PEPCO**

2.3.2 Constrained Locational Deliverability Areas (LDAs)

An LDA with Capacity Emergency Transfer Limit (CETL) less than 1.15 times Capacity Emergency Transfer Objective (CETO) will be modeled as a constrained LDA in RPM. In addition, an LDA will be modeled if (a) such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; (b) such LDA is determined by PJM to likely have a Locational Price Adder based on historic offer price levels; and (c) EMAAC, SWMAAC, and MAAC LDAs will be modeled as constrained LDAs regardless of the outcome of the above tests. PJM may decide to model the LDA as a constrained LDA regardless of the outcome of the above tests if there are other reliability concerns. A Reliability Requirement and a Variable Resource Requirement Curve will be established for each constrained LDA to be modeled in the RPM Base Residual Auction. See Section 2.4, 3, and 5 of this Manual for the details on Reliability Requirement, Variable Resource Requirement Curve, and RPM Auctions, respectively. The constrained Locational Deliverability Areas that will be modeled for a particular Delivery Year with their Reliability Requirements and the VRR Curves will be posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website.

If an LDA clears with a Locational Price Adder in any Base Residual Auction, PJM shall perform an analysis to determine if any new generation, new demand resource or Qualifying Transmission Upgrades were cleared in that LDA in such Base Residual Auction. New generation or new demand resources include incremental upgrades to existing resources beyond historic installed capacity levels or new resource installations. If any LDA has a Locational Price Adder and if no new generation, new demand resource or Qualifying Transmission Upgrades have cleared in the LDA for two consecutive Base Residual Auctions, then PJM shall evaluate a transmission upgrade as part of the RTEPP that would reduce the Locational Price Adder to zero.

The evaluation of such transmission upgrade shall include an evaluation of the cost of the upgrade as compared to the incremental benefit of reducing Locational Price Adder to zero in the LDA. If the transmission upgrade is feasible and cost beneficial over the next ten year period, then the transmission upgrade shall be included in the Regional Transmission

⁶ SWMAAC LDA represents the Southwest Mid-Atlantic Region (SWMAR).

Expansion Plan as soon as possible. The annual costs of such upgrade shall (1) be allocated across zones based on each zone's pro-rata share of load in such LDA and (2) within each zone to all LSEs serving load in the LDA, pro rata based on such loads.

2.3.3 Creation of New Locational Deliverability Areas (LDAs)

A prudent planning practice is to continuously monitor system performance and study transmission constraints as they develop. Triggers and criteria to consider a new LDA are specified in **Manual 14B:PJM Regional Transmission Planning Process, Attachment C, PJM Deliverability Testing Methods**, based on RTEP Market Efficiency Analysis and RTEP Long Term Planning. PJM will make a filing with FERC to amend RAA Schedule 10.1 to add a new LDA (including a new LDA that is an aggregate of Zones), if such new area is projected to have a CETL less than 1.15 times the CETO of the area, or if warranted by other reliability concern. In addition, any Party may propose, and PJM would evaluate, possible LDAs under such standards.

2.4 Reliability Requirements

In the PJM Capacity Market, reliability requirements, or reserve requirements, represent the target level of reserves required to meet PJM Reliability Standards and Principles. It is important to note that the Installed Reserve Margin (IRM) and the Forecast Pool Requirement (FPR) represent the level of reserves required, but are expressed in different capacity values. The IRM is expressed as the **installed capacity** reserve as a percent (e.g. 15%) of the forecast peak load, whereas the FPR (e.g., 1.079) when multiplied by forecast peak load provides the total **unforced capacity** required.

In the RPM clearing process, the Reliability Requirements for the RTO and the LDA are used to establish the target reserve levels, valued as unforced capacity that will be cleared in the RPM Auctions.

The final Reliability Requirements, used in the clearing of RPM Auctions, will be adjusted to account for entities that have elected the Fixed Resource Requirement Alternative and for EE Resources as described in Section 2.4.5 of this manual. Therefore, when known, the Unforced Capacity Obligations for FRR entities will be removed from the calculation of the Reliability Requirements for the RTO and any LDAs. Reliability Requirements for the region and for any affected LDA are further adjusted for PRD proposed in an approved PRD Plan or committed following an RPM Auction.

2.4.1 PJM Region Reliability Requirement

The PJM Region Reliability Requirement, valued in unforced capacity terms, is the RTO Peak Load Forecast, multiplied by the approved Forecast Pool Requirement for the PJM Region, less the sum of Preliminary Unforced Capacity Obligations of the FRR Entities in the PJM Region, plus any necessary adjustment for EE Resources per Section 2.4.5 of this manual, and less any

necessary adjustment for PRD proposed in an approved PRD Plan or committed following an RPM Auction.

$$RTORelReq = (RTOPeakLoadForecast * FPR) - \sum PrelimUCapOblig_{FRR\ Entity} + Adj_{EE} - Adj_{PRD}$$

2.4.2 Reliability Requirement in Locational Deliverability Areas

The Locational Deliverability Area Reliability Requirement is the projected internal capacity⁷ (in UCAP terms) in the LDA plus the Capacity Emergency Transfer Objective (CETO) for the Delivery Year, as determined by the RTEP process, less the minimum internal resources (in UCAP terms) required for the FRR Entities located in the LDA, plus any necessary adjustment for EE Resources per Section 2.4.5 of this manual, and less any necessary adjustment for PRD proposed in an approved PRD Plan or committed in any RPM Auction for PRD located in the LDA.

$$LDARelReq = (LDAInternalCapacity + LDACETO - MinInternalResources_{FRR\ Entity}) + Adj_{EE} - Adj_{PRD}$$

2.4.3 Deleted

2.4.3A Deleted

2.4.4 Adjustments to RPM Auction Parameters for PRD

After PRD Providers propose PRD commitments in their PRD Plans, and PJM reviews and accepts those commitments, PJM will use the resulting PRD values to reduce the reliability requirement to be satisfied for the region and for any affected Zones (or sub-Zonal LDAs). The reliability requirement will be reduced by the quantity of UCAP that would have been procured on behalf of the PRD load but that is now not needed due to the PRD loads' commitment to reduce consumption. The Reliability Requirement of the RTO and each affected LDA will be reduced by a quantity equal to the Nominal PRD Value multiplied by the FPR. These reliability requirement reductions will be considered in the development of the RTO/LDA Variable Resource Requirement Curves as explained in Section 3.4 of this manual.

⁷ See Manual 20: PJM Resource Adequacy Analysis and Manual 20A.

2.4.5 Adjustments to RPM Auction Parameters for EE Resources (through the 2025/2026 Delivery Year only)

An Energy Efficiency (EE) Resource is a project that involves the installation of more efficient devices/equipment, or the implementation of more efficient processes/systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a permanent, continuous reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the EE Resource is proposed. Because energy efficiency measures are reflected in the peak load forecast for a Delivery Year for which an auction is being conducted, the auction parameters must be adjusted as described below for the EE Resource(s) that are proposed for that auction in order to avoid double-counting of the energy efficiency measures.⁸

For each auction, the Reliability Requirement of the RTO and each affected LDA will be increased by the total UCAP Value of all EE Resource(s) for which PJM accepted an EE M&V Plan for that auction, and upon which PJM created an EE Resource to be offered into that upcoming auction.⁹ If a first-pass auction solution clears fewer EE Resource MW than the amount by which the Reliability Requirement of the RTO and each affected LDA was increased, the Reliability Requirement increase of the RTO and each affected LDA will be reduced such that it is set equal to the cleared EE MW quantity of the first-pass auction solution and the auction will be solved again. This step is repeated until the cleared EE Resource MW across the RTO equals the total EE Addback MW quantity of the RTO or until the sum of squares of the differences across all LDAs increases relative to the previous iteration. The RTO/LDA reliability requirement increases will be considered in the development of the RTO/LDA VRR Curves as explained in Section 3.4 of this manual.

⁸ Effective for RPM Auctions conducted after January 2016.

⁹ The increase in Reliability Requirement is accomplished in each BRA by shifting the VRR Curve of the RTO and each affected LDA to the right by the MW quantity of the increase. The increase in Reliability Requirement is accomplished in each IA by the submittal of a PJM Buy Bid in each affected LDA with the buy bid MW quantity set equal to the increase.

Section 3: Demand in the Reliability Pricing Model

Welcome to the *Demand in the Reliability Pricing Model* section of the **PJM Capacity Market Manual**. In this section, you will find the following information:

- An overview description of demand in the Reliability Pricing Model (see “Overview of Demand in the Reliability Pricing Model”)
- The definition and purpose of the Variable Resource Requirement (see “Definition and Purpose of the Variable Resource Requirement”)
- The parameters of the Variable Resource Requirement (see “Parameters of the Variable Resource Requirement”)
- The method for plotting the Variable Resource Requirement Curve (see “Plotting the Variable Resource Requirement Curve”)
- A description of the demand curves in the Incremental Auctions (see “Demand Curves in the Incremental Auction”)

3.1 Overview of Demand in the Reliability Pricing Model

In the Reliability Pricing Model, the demand for installed capacity reserve is met when supply is procured as a function of the clearing of the RPM Auctions. A demand curve is defined in advance of each RPM Auction.

In the Base Residual Auction, the demand curve is downward sloping and based on the variable resource requirement concept. In RPM, a variable resource requirement is defined as a function of price. The variable resource requirement is a family of price/quantity points that provide a specified price for various levels of resources procured relative to the Installed Reserve Margin. If the price exceeds the limit on the VRR, then the quantity of resources that is procured may be less than the IRM requirement. Alternatively, if the price is low, additional resources may be procured at a level greater than the IRM requirement. The cost of the supply that is procured at the clearing price will be allocated to the Load Serving Entities. Therefore, a variable resource requirement curve will reflect the reality that additional capacity above a target installed reserve margin nevertheless has value.

There are at least four sources of this value:

1. One source of value is that in the face of uncertain load growth, weather, and capacity availability, the probability of available capacity being less than what is required to meet load and operating reserves never reaches zero, even for large reserve margins. Thus, reserves beyond the target are valuable for reducing the risk of capacity shortfalls.
2. The second source of value is that the slope of the curve can lessen the risk of large suppliers being pivotal or otherwise able to exercise market power.

3. A third source of value is that excess resources can reduce the frequency and duration of scarcity energy prices in the system and provide energy savings to Load Serving Entities.
4. The fourth source of value is the reduction in capacity price volatility and the resulting investment risk to capacity resources, in particular to the generating resources. Lower investment costs would tend to reduce capacity prices

3.2 Definition and Purpose of the Variable Resource Requirement

As mentioned in the previous section, the Variable Resource Requirement Curve is a demand curve used in the clearing of the Base Residual Auction that defines the price for a given level of Capacity Resource commitment relative to the applicable reliability requirement. Variable Resource Requirement Curves are defined for the PJM Region and each of the constrained LDAs within the PJM region.

The purpose of the Variable Resource Requirement concept is to recognize the value of excess resources above the reliability requirement and provide revenue to resources. The price on the Variable Resource Requirement is higher when the resources are less than the reliability requirement and lower when the resources are in excess.

3.3 Parameters of the Variable Resource Requirement

Prior to the clearing of the Base Residual Auction, Variable Resource Requirement Curves are defined for the PJM Region and each of the constrained Locational Delivery Areas (LDAs) within the PJM region that are to be modeled in the auction. The Variable Resource Requirement Curves for the PJM Region and each Locational Delivery Area (LDA) are based on the following parameters defined prior to the RPM Auctions:

- A target level of reserve
- Cost of New Entry
- Net Energy & Ancillary Services (E&AS) Revenue Offset
- The Nominal PRD Value and PRD Reservation Prices that have been elected

The initial posting of the Variable Resource Requirement Curves will be based on no adjustments related to FRR Entities' Preliminary Unforced Capacity Obligations. A later posting of the Variable Resource Requirement Curves with the FRR adjustments will be made shortly after the approval of the FRR Capacity Plans for the RPM Auction Delivery Year considering any changes in the FRR elections for RPM Auction.

Note:

The parameters of the Variable Resource Requirement Curve (i.e., RTO and LDA Reliability Requirements, Cost of New Entry, and Net E&AS Revenue Offsets) will be posted with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website.

The Variable Resource Requirement Curve for the PJM Region is based on a target level (i.e., the PJM Region Reliability Requirement), Cost of New Entry, and Net Energy & Ancillary Services (E&AS) Revenue Offset.

For each LDA, the LDA Variable Resource Requirement Curve is based on a target level (i.e., the LDA Reliability Requirement), Cost of New Entry, and Net E&AS Revenue Offset.

Inclusion of Variable Resource Requirement Curves in the Base Residual Auction clearing may result in the level of resources being committed for a Delivery Year exceeding the applicable PJM Region Reliability Requirement or the LDA Reliability Requirement , if the total cost of resource procurement for the PJM Region or LDA is lower at the higher level of reliability than it would be at the target level and the associated Variable Resource Requirement Curve price.

3.3.1 Cost of New Entry

The value for Cost of New Entry (CONE) (in ICAP terms) is determined in accordance with Attachment DD of the Open Access Transmission Tariff (OATT), Section 5.10 (a) (iv). The Reference Resource is a combustion turbine (CT) generating station, configured with a single General Electric Frame 7HA turbine as defined in the OATT.

The gross Cost of New Entry values for the following four CONE Areas for the 2022/2023 Delivery Year are specified in the OATT, Attachment DD, Section 5.10 (a) (iv)(A). :

1. AE, DPL, JCPL, PECO, PSEG, RECO ("CONE Area 1");
2. BGE, PEPCO ("CONE Area 2");
3. AEP, APS, COMED, DAYTON, DLCo, ATSI, DEOK, EKPC, Dominion, OVEC ("CONE Area 3"); and
4. METED, PENELEC, PPL ("CONE Area 4").

For the 2023/2024 Delivery Year, the gross CONE values specified in the OATT for the 2022/2023 Delivery Year shall be adjusted to reflect changes in generating plant construction costs based on changes in the applicable United States Bureau of Labor Statistics (BLS) Composite Index, and then adjusted further by a factor of 1.022 to reflect the annual decline in bonus appreciation scheduled under federal tax law, to establish the CONE values used in the development of the Variable Resource Requirement Curves for the PJM Region and the modeled LDAs for all RPM Auctions for the 2023/2024 Delivery Year.

The applicable BLS Composite Index for a Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 20%), the BLS Producer Index for Construction Materials and Components (weighted 55%), and the BLS Producer Price Index for Turbines and Turbine Generator Sets (weighted 25%). The Quarterly Census of Employment and Wages for Utility System Construction will be based on the state of New Jersey for CONE Area 1, Maryland for CONE Area 2, Ohio for CONE Area 3, and Pennsylvania for CONE Area 4.

For subsequent Delivery Years, up to and including the 2025/2026 Delivery year, the Benchmark CONE values for all CONE areas except CONE area 5 will be the CONE values used in the development of the Variable Resource Requirement Curves for the prior Delivery Year. The applicable BLS Composite Index for the Delivery Year will be applied to the Benchmark CONE values, and then multiplying the result by 1.022, to establish the CONE values for such Delivery Year for CONE areas 1 through 4 listed above.

For the 2025/2026 Delivery Year, a new CONE Area 5 encompassing only the ComEd Zone shall be established and the ComEd Zone will be removed from CONE Area 3. For the 2025/2026 Delivery Year, the Cost of New Entry for CONE Area 5 will be equal to the product of the Cost of New Entry determined for CONE Area 3 for the 2025/2026 Delivery Year multiplied by an asset life factor of 1.0069.

Through the 2024/2025 Delivery Year, the gross Cost of New Entry value for the PJM Region shall be the average of the gross CONE values for the four CONE Areas listed above. For the 2025/2026 Delivery Year, the Cost of New Entry for the PJM Region shall be the average of the Cost of New Entry for all five CONE Areas.

The gross Cost of New Entry values for the following five CONE Areas for the 2026/2027 Delivery Year are specified in the OATT, Attachment DD, Section 5.10 (a) (iv)(C):

1. AE, DPL, JCPL, PECO, PSEG, RECO ("CONE Area 1");
2. BGE, PEPCO ("CONE Area 2");
3. AEP, APS, DAYTON, DLCo, ATSI, DEOK, EKPC, Dominion, OVEC ("CONE Area 3"); and
4. METED, PENELEC, PPL ("CONE Area 4").
5. COMED ("CONE Area 5")

For the 2026/2027 Delivery Year and subsequent Delivery Years, the gross Cost of New Entry value for the PJM Region shall be the average of the gross CONE values for the five CONE Areas. For the 2027/2028 Delivery Year, the gross CONE values specified in the OATT for the 2026/2027 Delivery Year for each CONE Area (except for CONE Area 5) shall be adjusted to

reflect changes in generating plant construction costs based on changes in the applicable United States Bureau of Labor Statistics (BLS) Composite Index to establish the CONE values used for the 2027/2028 Delivery Year for CONE Areas 1 through 4.

The applicable BLS Composite Index for a Delivery Year and CONE Area shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in a composite of the BLS Quarterly Census of Employment and Wages for Utility System Construction (weighted 40%), the BLS Producer Index for Construction Materials and Components (weighted 45%), and the BLS Producer Price Index for Turbines and Turbine Generator Sets (weighted 15%). The Quarterly Census of Employment and Wages for Utility System Construction will be based on the state of New Jersey for CONE Area 1, Maryland for CONE Area 2, Ohio for CONE Area 3, and Pennsylvania for CONE Area 4.

For subsequent Delivery Years, the Benchmark CONE values for all CONE areas except for CONE Area 5 will be the CONE values used in the development of the Variable Resource Requirement Curves for the prior Delivery Year. The applicable BLS Composite Index for the Delivery Year will be applied to the Benchmark CONE values to establish the CONE values used for such Delivery Year for CONE Areas 1 through 4.

For the 2027/2028 Delivery Year through and including the 2029/2030 Delivery Year, the CONE for CONE Area 5 for a given delivery year shall be set equal to the product of the CONE of CONE Area 3 as determined for the relevant Delivery Year, multiplied by the asset life factor applicable to that Delivery Year where such asset life factors are 1.0376 for the 2027/2028 Delivery Year, 1.0581 for the 2028/2029 Delivery Year, and 1.0818 for the 2029/2030 Delivery Year.

3.3.2 Net Energy and Ancillary Services Offset

Pursuant to Attachment DD, Section 5.10(a)(v and v-1) of the PJM Tariff, PJM determines a Net Energy and Ancillary Services (E&AS) Revenue Offset for the PJM Region and for each Zone.

For Delivery Years 2023/2024 through and including 2025/2026

The Net E&AS Revenue Offset for the PJM Region for a Delivery Year is (a) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the Base Residual Auction for such Delivery Year plus (b) an assumed value for ancillary services revenues (\$/MW-year) as set forth in Attachment DD, Section 5.10(a)(v) of the PJM Tariff.

The annual average of energy revenues for the PJM Region is based on (1) heat rate and other characteristics of such Reference Resource; (2) daily natural gas prices averaged across the fuel pricing points specified in the table below with a fuel transmission adder appropriate for the PJM region; (3) assumed variable operation and maintenance expenses for such Reference

Resource as set forth in Attachment DD, Section 5.10(a)(v) of the PJM Tariff; (4) actual PJM hourly average LMP prices recorded in the PJM Region during such period; and (5) an assumption that the Reference Resource would be dispatched for both Day-Ahead and Real-Time Energy Markets on Peak-Hour Dispatch basis.

The Net E&AS Revenue Offset for each Zone for a Delivery Year is determined using the same procedures and methods used to determine the Net E&AS Revenue Offset for the PJM Region; provided, however, that (1) actual hourly average LMPs for such Zone shall be used in place of the PJM Region hourly average LMPs; and (2) daily natural gas prices at the fuel pricing points specified in the table below in this section 3.3.2 with a fuel transmission adder appropriate to the zone.

Peak-Hour Dispatch means, for purposes of calculating the energy revenues in the Energy and Ancillary Services Revenue Offset, that the Reference Resource is committed in the Day-Ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate under the same conditions as described above for the Day-Ahead Energy Market.

For the 2026/2027 Delivery Year and subsequent Delivery Years

The Net E&AS Revenue Offset for the PJM Region for a Delivery Year is the annual average of the revenues that the Reference Resource is projected to receive from the PJM energy and ancillary service markets from three separate simulations, with each simulation using forward prices shaped using historical data from one of the three consecutive calendar years preceding the time of the determination for the RPM Auction to take account of year-to-year variability in such shapes. The projected Net E&AS Revenue Offset will be determined for the PJM Region and each Zone as specified in Attachment DD, Section 5.10(a)(v-1) of the PJM Tariff

The annual average of energy revenues for the PJM Region is based on (1) heat rate and other characteristics of such Reference Resource; (2) forward daily natural gas prices averaged across the fuel pricing points specified in the table above with a fuel transmission adder appropriate for the PJM region; (3) assumed variable operation and maintenance expenses for such Reference Resource; (4) Forward Hourly LMPs for the PJM Region; (4) Forward Hourly Ancillary Services Prices; and (5) an assumption that the Reference Resource would be dispatched on a Projected EAS Dispatch basis.

Projected EAS Dispatch means, for purposes of calculating the Net Energy and Ancillary Services Revenue Offset, a simulated dispatch with the objective of committing and dispatching a resource for the purpose of maximizing its net revenues. The calculation shall take inputs including Forward Hourly LMPs, Forward Hourly Ancillary Service Prices, and Forward Daily Natural Gas Prices or forecasted fuel prices, as applicable, in addition to the operating parameters and costs of the specific resource, including the cost emission allowances. Using operating parameters, forward or forecasted fuel prices, as applicable and other cost pricing inputs, a composite, cost-based energy offer is created for the resource such that its commitment and dispatch is co-optimized between energy and ancillary services in the Day-Ahead Energy Market and then the Real-Time Energy Market considering the electricity and ancillary service price inputs. In the Real-Time Energy Market co-optimization, the resource is assumed to be operating in the hours it was scheduled in the Day-Ahead Energy Market but is dispatched according to the real-time price inputs. In the hours where the resource was not committed in the Day-Ahead Market, the resource may be committed and dispatched in real-time only subject to the real-time electricity and ancillary service price inputs and the resource's offer and operating parameters.

The Net E&AS Revenue Offset for each Zone is determined using the same procedures and methods used to determine the Net E&AS Revenue Offset for the PJM Region; provided, however, that (1) Forward Hourly LMPs of each such Zone are used in place of the Forward Hourly LMPs of the PJM Region; and (2) forward daily natural gas prices are used for each such Zone based on the fuel price point to Zone mapping shown in the table below.

The Forward Hourly LMPs, Forward Hourly Ancillary Service Prices and Forward Daily Natural Gas Prices used in the calculation of the Net E&AS Revenue Offset are determined as defined in Attachment DD, Section 5.10(a)(v-1) of the PJM Tariff.

In the determination of Forward Hourly LMPs, the ComEd Zone is mapped to N. Illinois Hub, the AEP, ATSI, DAY, DEOK, DUQ, EKPC and OVEC Zones are mapped to the AEP-Dayton Hub, and all other Zones are mapped to the Western Hub. In addition, several of the fuel pricing points of the table below lack sufficient liquidity and are therefore mapped to more liquid hubs for the purposes of calculating Forward Daily Natural Gas Prices. For the purpose of calculating Forward Daily Natural Gas Prices, Transco-Z6 (non-NY) is used in place of Transco-Z5 Div and Transco-Z6 (NY)

Zone to Fuel Pricing Point Mapping

The fuel pricing point used for the purpose of establishing the Net E&AS Offset for each Zone is provided in the table below.

Zone	Fuel Pricing Point
AE, BGE, DPL, & JCPL	Transco-Z6 (non-NY)

Zone	Fuel Pricing Point
COMED	Chicago Citygates
DUQ, METED, PECO, & PPL	TETCO M3
PEPCO & DOM	Transco Z5 Dlv
AEP, OVEC	Columbia-Appalachia TCO
DAY, DEOK, ATSI, EKPC	Mich Con
APS & PENELEC	Dominion South
PSEG & RECO	Transco Z6 (NY)

3.3.3 Net Cost of New Entry

The Net Cost of New Entry (Net CONE) for the PJM Region is the gross Cost of New Entry for the PJM Region minus the Net E&AS Revenue Offset for the PJM Region.

PJM shall determine the Net Cost of New Entry for each Zone that comprises the modeled LDA. The Net Cost of New Entry for a Zone is the applicable gross Cost of Net Entry value for such Zone minus the Net E&AS Revenue Offset for such Zone. The Net Cost of New Entry for the Zone is used for a sub-zonal LDA. The Net Cost of New Entry for a modeled LDA shall be the average of the Net CONE values of all zones within the modeled LDA.

3.4 Plotting the Variable Resource Requirement Curve

For the 2022/2023 Delivery Year through and including the 2024/2025 Delivery Year, the Variable Resource Requirement Curve is plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis using the following three points a, b, and c:

a. The price is equal to the greater of [the Cost of New Entry or 1.5 times (the Cost of New Entry minus the Net E&AS Revenue Offset, referred to as “Net CONE”)] divided by (one minus Pool-Wide Average EFORD) and Unforced Capacity is equal to [PJM Region Reliability Requirement¹⁰ multiplied by (100% plus the approved IRM% minus 1.2%) divided by (100% plus approved IRM %)].

¹⁰ The Reliability Requirement used in the unforced capacity quantity equation for points (a), (b), and (c) excludes any adjustment for PRD or EE (through the 2025/2026 Delivery Year for EE only). The VRR Curve that results is adjusted leftward to reflect the impact of PRD and rightward to reflect the impact of EE through the 2025/2026 Delivery Year as explained in section 3.4.1 of this manual.

Basis for Price at Point a:

$$\frac{\text{Greaterof}[\text{CONEor}1.5(\text{CONE} - E \ \& \ AS)]}{\frac{\text{Greaterof}[\text{CONEor}1.5(\text{CONE} - E \ \& \ AS)]}{1 - \text{Pool Wide EFORDd}}}$$

Basis for Quantity at Point a:

$$\left[\frac{\text{RelReq} \frac{(100\% + \text{IRM} - 1.2\%)^*}{(100\% + \text{IRM})}}{\text{RelReq} \frac{(100\% + \text{IRM} - 1.2\%)^*}{(100\% + \text{IRM})}} \right]$$

b. The price is equal to 0.75 times Net CONE divided by (one minus Pool-Wide Average EFORDd) and Unforced Capacity equals [PJM Region Reliability Requirement multiplied by (100% plus the approved IRM% plus 1.9%) divided by (100% plus approved IRM%)].

Basis for Price at Point b:

$$\frac{[0.75(\text{CONE} - E \ \& \ AS)]}{\frac{[0.75(\text{CONE} - E \ \& \ AS)]}{1 - \text{Pool Wide EFORDd}}}$$

Basis for Quantity at Point b:

$$\left[\frac{\text{RelReq} \frac{(100\% + \text{IRM} + 1.9\%)^*}{(100\% + \text{IRM})}}{\text{RelReq} \frac{(100\% + \text{IRM} + 1.9\%)^*}{(100\% + \text{IRM})}} \right]$$

c. The price is equal to zero and Unforced Capacity equals [PJM Region Reliability Requirement multiplied by (100% plus the approved IRM% plus 7.8%) divided by (100% plus approved IRM %)].

Basis for Price at Point c:

$$\frac{\$0 / \text{MW} - \text{day}}{\$0 / \text{MW} - \text{day}}$$

Basis for Quantity at Point c:

$$\left[\frac{\text{RelReq} \frac{(100\% + \text{IRM} + 7.8\%)^*}{(100\% + \text{IRM})}}{\text{RelReq} \frac{(100\% + \text{IRM} + 7.8\%)^*}{(100\% + \text{IRM})}} \right]$$

For the 2025/2026 Delivery Year only, the Variable Resource Requirement Curve is plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis using the following three points a, b, and c:

a. The price is equal to the greater of [the Cost of New Entry or 1.5 times (the Cost of New Entry minus the Net E&AS Revenue Offset, referred to as "Net CONE")] divided by (the applicable

ELCC Class Rating of the Reference Resource) and Unforced Capacity is equal to (PJM Region Reliability Requirement multiplied by 98.9%).

b. The price is equal to 0.75 times Net CONE divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals (PJM Region Reliability Requirement multiplied by 101.6%).

c. The price is equal to zero and Unforced Capacity equals (PJM Region Reliability Requirement multiplied by 106.8%).

For the 2026/2027 and 2027/2028 Delivery Years, the Variable Resource Requirement Curve for the PJM Region shall be plotted by a horizontal line from the y-axis equal to \$256.75/MW-day ICAP divided by the applicable ELCC Class Rating for the Reference Resource until such line intersects the curve that is based on the following: (i) a straight line connecting points (1) and (2), and (ii) a straight line connecting points (2) and (3), where:

- For point (1), price equals: {the greater of [the Cost of New Entry] or [1.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 99%];
- For point (2), price equals: [0.75 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (the applicable ELCC Class Rating of the Reference Resource) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 101.5%]; and
- For point (3), price equals zero and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by 104.5%].

Once the horizontal line intersects above the curve, the Variable Resource Requirement Curve shall follow the curve that is based on the above points until the price reaches \$138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource, at which point it shall be extended as a horizontal line at \$138.25/MW-day ICAP divided by the applicable ELCC Class Rating of the Reference Resource to infinity.

3.4.1 Plotting the Variable Resource Requirement Curves

The graph below illustrates the process for plotting the Variable Resource Requirement curve. The VRR Curve is plotted by combining a horizontal line from the y-axis to point (a), a straight line connecting points (a) and (b), a straight line connecting points (b) and (c).

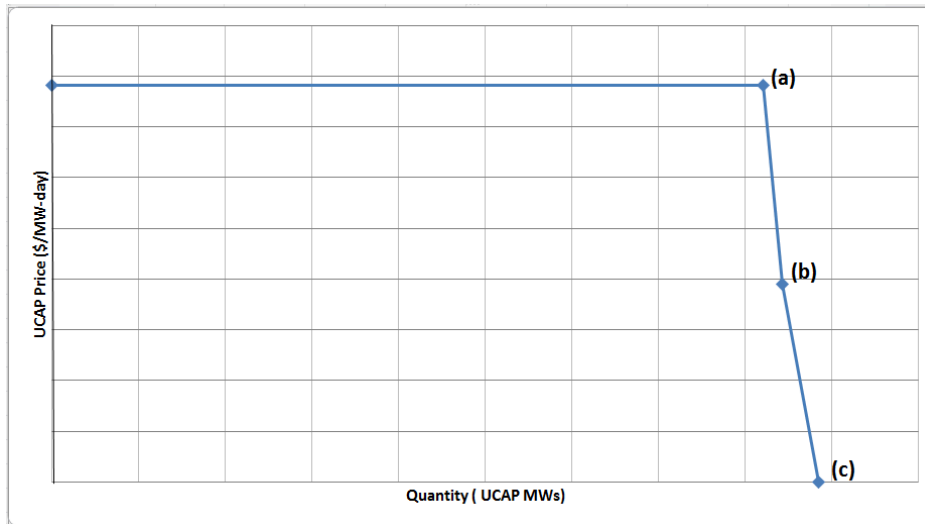


Exhibit 1: Illustrative Example of a Variable Resource Requirement Curve

The same process shall be used to establish the Variable Resource Requirement Curve for each LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement, and the FRR adjustments will be for the FRR Entities in the LDA.

Beginning with the 2018/2019 Delivery Year and continuing no later than for every fourth Delivery Year thereafter, PJM will perform a review of the shape of the Variable Resource Requirement Curve, CONE values, and Energy & Ancillary Services methodology, and any FERC approved changes resulting from this review will be incorporated into the appropriate BRA Auctions.

The Variable Resource Requirement Curve will be further adjusted to reflect the impact of any PRD that is proposed in a PRD Plan and that is reviewed and accepted by PJM. To reflect accepted PRD Plans, the Variable Resource Requirement Curve will be shifted leftward along the horizontal axis by a quantity equal to the Nominal PRD Value multiplied by the FPR. This quantity represents the quantity of Unforced Capacity that would have been procured in the RTO on behalf of the PRD load but that is now not needed due to the PRD loads' commitment to reduce consumption. The curve will be shifted leftward in this manner only for those portions of the curve that are at or above the PRD Reservation Price, since the PRD load can be excluded only if the auction clears at or above that price. The Variable Resource Requirement Curve for each LDA in which the PRD resides (including the RTO curve) will be shifted in the exact same manner.

The Variable Resource Requirement Curve will be further adjusted to reflect the impact of any EE addback through the 2025/2026 Delivery Year. The Variable Resource Requirement Curve

will be shifted rightward along the horizontal axis by a quantity equal to the EE addback MW quantity as explained in Section 2.4.5. The Variable Resource Requirement Curve for each LDA in which EE resides (including the RTO curve) will be shifted in the exact same manner.

3.5 Demand Curves in the Incremental Auctions

The First, Second and Third Incremental Auctions provide both a forum for capacity suppliers to purchase replacement capacity, and a means for PJM to adjust previously committed capacity levels due to reliability requirement increases or decreases. The demand curve in these auctions will be built based on a combination of buy bids submitted by market participants and buy bids, if any, submitted by PJM.

PJM will recalculate the RTO and each LDA Reliability Requirement prior to each of the First, Second, and Third Incremental Auctions based on an updated peak load forecast, updated Installed Reserve Margin, and an updated Capacity Emergency Transfer Objective. The recalculated Reliability Requirements are compared to the Reliability Requirements used in the prior auction for the same Delivery Year and a determination is made as to the need for the procurement and/or sale of capacity by PJM.

For the RTO and each LDA, PJM will sum the following component quantities to determine the total quantity that it will seek to procure or release in each Incremental Auction:

- The difference between the Updated Reliability Requirement minus the Reliability Requirement utilized in the most recent prior auction conducted for that Delivery Year. For a 1st or 2nd Incremental Auction, this difference is only considered if the change in Reliability Requirement is greater than the lesser of 500 MW or 1% of the prior auction's Reliability Requirement. Note that this quantity is negative if the Updated Reliability Requirement is less than the Reliability Requirement utilized in the most recent prior auction.
- Plus/minus the amount of committed capacity that PJM sought to procure/release that did not clear in the prior Incremental Auction for the same Delivery Year.
- Plus the amount of non-viable commitments associated with transition provision of OATT, Attachment DD, Section 5.5A(c)(i)(B) (i.e., Prior CIL Exception External Resources electing prior to Delivery Year Third Incremental Auction to be relieved of their capacity obligation for such Delivery Year) and RAA, Schedule 6, section L.9 (i.e., EE Resources electing prior to Delivery Year Third Incremental Auction to be relieved of their capacity obligation for such Delivery Year due to prohibition of EE participation by a Relevant Electric Retail Regulatory Authority).
- Minus any capacity PJM seeks to release in a parent LDA as a result of any Conditional Incremental Auction commitments for the same Delivery Year.

If the result of such summation is a positive quantity, PJM will seek to procure such quantity by employing a PJM buy bid represented by the portion of the Updated VRR Curve Increment extending right from the left-most portion on that curve in a MW amount equal to the positive

quantity. PJM will employ a PJM buy bid represented by the entire portion of the Updated VRR Curve if the prior auction's RTO/LDA Reliability Requirement exceeds the total capacity committed in all prior auction's by the threshold (lesser of 500 MW or 1% of prior auction's Reliability Requirement). The Updated VRR Curve Increment is the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year (adjusted, if applicable, by change in Unforced Capacity commitments associated with transition provision of OATT, Attachment DD, Section 5.5A(c)(i)(B) and RAA Schedule 6, section L.9).

If the result of such summation is a negative quantity, PJM will seek to release such quantity by employing a PJM sell offer represented by the portion of the Updated VRR Curve Decrement extending and ascending to the left from the right-most portion on that curve in a MW amount equal to the negative quantity. The Updated VRR Curve Decrement is the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year (adjusted, if applicable, by change in Unforced Capacity commitments associated with transition provision of OATT, Attachment DD Section 5.5A(c)(i)(B) and RAA, Schedule 6, section L.9).

In a Conditional Incremental Auction, the quantity at the appropriate location required to address the identified reliability violation will be procured using a Buy Bid equal to 1.5 times Net CONE.

Section 3A: Integration of Price Responsive Demand

Welcome to the *Integration of Price Responsive Demand* section of the **PJM Manual for the PJM Capacity Market**. In this section, you will find the following information:

- An overview of Price Responsive Demand in PJM Capacity Market (see “Overview of Price Responsive Demand in PJM Capacity Market”)
- The transition period for price responsive demand (see “Transition Period”)
- The eligibility requirements for price responsive demand participation in PJM Capacity Market (see “Eligibility Requirements for Price Responsive Demand”)
- The PRD Plan requirements (see “PRD Plan Requirements”)
- The registration requirements of price responsive demand (see “Registration of Price Responsive Demand”)
- The performance requirements of price responsive demand in the delivery year (see “Performance Requirements of Price Responsive Demand”)
- The bilateral transfer of a price responsive demand obligation (see “PRD Bilaterals”)

3A.1 Overview of Price Responsive Demand in PJM Capacity Market

The development and implementation of dynamic and time-differentiated retail rates, together with utility investment in advanced metering infrastructure (AMI) has lead an increasing quantity of load in PJM to be responsive to changing wholesale prices. Through enabling technology and behavioral changes, consumers modify their demand as prices change without being centrally dispatched by PJM or bidding demand reductions into the PJM markets. Given the linkage between dynamic retail rate structures and wholesale prices, this price responsiveness is predictable and needs to be accounted for in the wholesale market design and operations. This predictable reduction in consumption in response to changing wholesale prices is known as Price Responsive Demand (PRD).

Although Price Responsive Demand is not directly dispatchable by PJM, automated retail customer response to real time energy prices signals can produce a predictable demand curve as a function of real time energy price. Prices typically increase during capacity emergencies and as a consequence demand drops. Price Responsive Demand will therefore be able to reduce the installed capacity required to meet Loss of Load Expectation (LOLE) based reliability standards.

PRD is provided by a PJM Member that represents retail customers that have the capability to reduce load in response to price. PJM Member acting on behalf of such retail customers for the purpose of providing PRD is referred to as the PRD Provider. A PRD Provider for a given retail customer must meet all of the eligibility requirements for providing PRD.

In the PJM Capacity Market, a PRD Provider may voluntarily make a firm commitment of the quantity of Price Responsive Demand that will reduce its consumption in response to real time energy price during a Delivery Year.

In order to commit PRD for a Delivery Year, a PRD Provider must submit a PRD Plan in advance of the Base Residual Auction or Third Incremental Auction for such Delivery Year that demonstrates to PJM's satisfaction that the maximum nominated amount of price responsive demand will be available by the start of the Delivery Year. Additional PRD may participate in the Third Incremental Auction only in the event, and to the extent that the LDA final peak load forecast for the Delivery Year increases relative to the LDA preliminary peak load forecast used for the Base Residual Auction.

A PRD Provider that is committing PRD in Base Residual Auction or Third Incremental Auction must also submit a PRD election in the Capacity Exchange system which indicates the Nominal PRD Value in MWs that the PRD Provider is willing to commit at different reservation prices (\$/MW-day). The PRD election by PRD Providers will result in a change in the shape of the RTO/LDA VRR Curves used in the RPM Auctions. Based on the PRD elections and Resource Clearing Price in the RPM Auction, PJM will determine the Nominal PRD Value committed by each PRD Provider. Those PRD Providers that elected to provide PRD at reservation prices equal to or less than the Resource Clearing Price will have the corresponding value of PRD committed in the RPM Auction.

A PRD Provider that is committing PRD which is associated with load being served under the Fixed Resource Requirement Alternative is not required to submit a PRD election. The FRR Entity's Preliminary Daily Unforced Capacity Obligation to be satisfied in the FRR Entity's initial submittal of their FRR Capacity Plan for the Delivery Year will be reduced by the Nominal PRD Value associated with their FRR load that was approved by PJM in advance of the BRA, multiplied by the BRA Forecast Pool Requirement. The Final Daily Unforced Capacity Obligation of the FRR Entity that must be satisfied in the FRR Entity's FRR Capacity Plan for the Delivery Year will be reduced by the total Nominal PRD Value associated with their FRR load that was approved by PJM in advance of the Base Residual Auction and Third Incremental Auction for the Delivery Year, multiplied by the final Forecast Pool Requirement. The approval of the PRD Provider's PRD Plan associated with the FRR load shall establish a firm commitment of the PRD Provider to the PJM approved sub-zonal/zonal Nominal PRD Value.

Once committed in a Base Residual Auction, Third Incremental Auction or committed for load served under the FRR Alternative, Price Responsive Demand may not be uncommitted or replaced by available capacity resources or Excess Commitment Credits. However, a PRD Provider may transfer the PRD obligation to another PRD Provider bilaterally.

A PRD Provider with a committed sub-zonal/zonal Nominal PRD Value through an RPM Auction or through the FRR Alternative will be required to register sub-zonal/zonal PRD prior to the start of the Delivery Year to satisfy their PRD commitment. Failure to register enough price responsive loads to meet their sub-zonal/zonal PRD commitment prior to the start of the

Delivery Year or failure to maintain enough price responsive loads to meet their sub-zonal/zonal PRD commitment throughout the Delivery Year will result in a PRD Commitment Compliance Penalty.

A PRD Provider is subject to Non-Performance Assessment during the Delivery Year. Failure to comply during a Performance Assessment Interval will result in a Non-Performance Charge for such interval. If PJM does not have an Emergency Action that triggers a Non-Performance Assessment during the Delivery Year that requires a PRD registration to reduce to the Firm Service Level (FSL) in the registration, then PRD registrations in the zone that did not have compliance measured for a Performance Assessment Interval during the Delivery Year must demonstrate that such registrations were tested for a one-hour period during any hour from 10:00 AM EPT to 10:00 PM EPT during June through October or the following May of the relevant Delivery Year. Failure of such PRD registrations in the zone to reduce to the aggregate FSL levels of such registrations in a test will result in a PRD Test Failure Charge.

The PRD Provider will receive a Daily PRD Credit (\$/MW-day) during the Delivery Year. A PRD Provider under the FRR Alternative will not be eligible to receive a Daily PRD Credit (\$/MW-day) during the Delivery Year.

3A.2 Deleted

3A.3 Eligibility Requirements of Price Responsive Demand

In order for load to be eligible to be considered as Price Responsive Demand, the end-use customer load must be:

- served under a dynamic retail rate structure with an LSE or subject to a contractual arrangement with a PRD Provider where such rate or compensation arrangement can change on an hourly basis, is linked to or based upon a PJM real-time LMP trigger at a substation location within a transmission zone as electrically close as practical to the applicable load, and results in predictable response to varying wholesale electricity prices;
- subject to advanced metering capable of recording electricity consumption at an interval of one hour or less;
- subject to Supervisory Control as defined in the Reliability Assurance Agreement to curtail the demand should PJM declare an emergency condition; and
- Shall exclude Critical Natural Gas Infrastructure

Supervisory Control of customer load registered as Price Responsive Demand is required on the part of the PRD Provider consistent with any Relevant Electric Retail Regulatory Authority (RERRA) requirements. RERRA shall have the meaning specified in the PJM Operating Agreement. Prior to the 2022/2023 Delivery Year, to the extent load was not already reduced, the PRD Provider is required to have the remote capability to decrease the load at each location contained in the PRD Registration to the required service level when a PJM Maximum

Emergency event has been declared and the Real-time LMP at the applicable location has exceeded the level at which the load has committed to reduce. Effective with the 2022/2023 Delivery Year, to the extent load was not already reduced, the PRD Provider is required to have remote capability to decrease the load at each location contained in the PRD Registration to the required service level when an Emergency Action triggers a Performance Assessment Interval and the Real-time LMP at the applicable location has exceeded the level at which the load was committed to reduce. PRD Providers with committed PRD are required to have automation of PRD that is needed to respond to Real Time LMPs for the PRD Curves that are submitted in the PJM Energy Market. Automation of load response to LMP trigger without manual intervention is required to be PRD.

However, PRD Providers may request an exception to the automation requirement for end-use customers that are a single site, a single location and a single end-use customer with supervisory control over processes with which load reduction would be accomplished. In this case, the end use customer site is eligible for this specific exception from standard automation requirement, but the end-use customer is still required to respond within 15 minutes to Real Time LMPs for the PRD Curves that are submitted in the PJM Energy Market. Effective with 2022/2023 Delivery Year, PRD registrations with an approved exception to the automation requirement will not have compliance measured during the Performance Assessment Intervals that fall within the 15 minute response allowance.

The customer load must be on a dynamic retail rate structure with an LSE or subject to a contractual arrangement with a PRD Provider that results in retail charges or credits to the end use customer that are linked to or based on the Real Time LMP. Multiple retail rates or contractual arrangements could qualify for this requirement, such as a structure where the retail charge or credit to the end-use customer is greater than or equal to the Real-time LMP, or applies only when the Real Time LMP exceeds a preset threshold. Dynamic retail rate structures, based on PJM Real-time LMP, that qualify as Price Responsive Demand may include:

- Critical Peak Pricing that allows retail rates to rise when the wholesale market price exceeds a threshold level;
- Critical Peak Rebate pricing which provides bill credits to consumers who reduce their usage below a baseline quantity during periods when the wholesale market price exceeds a threshold level; or
- Real-Time Pricing based on LMP.

3A.4 PRD Plan Requirements

3A.4.1 PRD Plan Submission & Approval Process

A PRD Provider that wishes to nominate PRD load for a Delivery Year's Base Residual Auction or nominate PRD to reduce an FRR Entity's preliminary unforced capacity obligation must submit a PRD Plan by email via the RPM Hotline at rpm_hotline@pjm.com no later than

January 15 immediately prior to the Delivery Year's Base Residual Auction. Additional PRD may be nominated in an LDA in the Third Incremental Auction in the event and to the extent that the LDA final peak load forecast used in Third Incremental Auction increases relative to LDA preliminary peak load forecast used in the Base Residual Auction. Nomination of additional PRD load in an LDA for a Delivery Year's Third Incremental Auction when LDA peak load forecast increases may be made by submitting a PRD Plan by email via the RPM Hotline at rpm_hotline@pjm.com no later than January 15 immediately prior to the Delivery Year's Third Incremental Auction. Nomination of additional PRD for use in reducing an FRR Entity's final unforced capacity obligation for the Delivery Year may also be made by submitting a PRD Plan by email via the RPM Hotline at rpm_hotline@pjm.com no later than January 15 prior to the Delivery Year's Third Incremental Auction.

Once received by PJM, the PRD Provider will receive an email confirmation that their plan has been received and will be reviewed by PJM. PJM will review the content to ensure the PRD Plan contains all the necessary detail and information. PJM will notify the PRD Provider within 10 days of receipt of the PRD Plan and indicate whether or not the PRD Plan is approved or rejected. Any submitted plan that is incomplete or falls short of meeting the informational requirements of a PRD Plan by such January 15 deadline shall be rejected.

A PRD Provider must submit a PRD Plan no later than January 1, prior to a Base Residual Auction or Third Incremental Auction if the PRD Provider wants PJM to conduct an advance review of their PRD Plan. PJM will review the content of the PRD Plan and will notify the PRD Provider within 10 days of receipt of the PRD Plan if the submitted PRD Plan is approved or rejected. If the PRD Plan is rejected, PJM will provide to the PRD Provider a list of the areas in the PRD Plan that were not adequate. PRD Plans that are denied by PJM in an advance review may be corrected and resubmitted no later than January 15, prior to the Base Residual Auction or Third Incremental Auction. Alternately, PJM may approve a lower maximum Nominal PRD Value supported by the PRD Plan.

To help a PRD Provider prepare and submit a PRD Plan by the January 15 deadline, the following information will be made available:

- Prior year summer weather normalized zonal peak loads posted by PJM by October 31. The summer weather normalized zonal peak loads will be developed from hourly metered zonal loads that include add backs due to demand response and price responsive demand in accordance with ***PJM Manual 19, Load Forecasting and Analysis***.
- Customer PLCs developed and made available by EDCs based on prior year summer weather normalized Zonal peak loads by December 31.

3A.4.2 Required Components of a PRD Plan

The PRD Plan is a document submitted by the PRD Provider that defines and provides data to support a PRD Provider's maximum Nominal PRD Value in a Zone or sub-zone LDA (for example, if nominating PRD in DPL South or PS North). The PRD plan must identify any methods and techniques that will be used to determine and verify the quantity of load consumed

at varying wholesale price levels. A single PRD Plan may be submitted to cover multiple Sub-zone/Zone locations, provided that the price-demand curves are submitted on a Sub-zone/Zone level. All of the assumptions, procedures, and data for the PRD Plan should be clearly documented. The data included should be sufficient for a third party to audit the procedures and verify the PRD Provider's maximum Nominal PRD Value in a Sub-zone/Zone.

The PRD Plan must detail the price responsive characteristic of the customer load at a zonal or sub-zonal LDA (for example, if load is in PSEG-North or DPL-South) level. If known, the PRD Plan should detail the price responsive characteristics at a substation level. The price responsive characteristic of such customer loads must be provided in terms of the quantity of load that will continue to consume at various levels of price.

Estimates of the substation/sub-zonal/zonal peak load contribution (PLC) values of such PRD Provider's price responsive load for the Delivery Year if such load were not to be reduced in response to price are to be provided in the PRD Plan. The substation/ sub-zonal/zonal PLC values will be aggregated to determine the Zonal/LDA PLC value for the PRD Provider in such Zone/LDA. In addition, an estimate of the representative loss factor for the Zone/LDA is to be provided. The Firm Service Level (FSL) is the level to which the price-responsive load will be reduced during the Delivery Year when an Emergency Action triggers a Performance Assessment Interval during the Delivery Year. The quantity of load that will be consumed at a price equal to the applicable energy market offer cap for the relevant Delivery Year represents the FSL. The locational FSL quantities (at substation/sub-zonal/zone) will be aggregated to determine the Zonal/LDA FSL quantity for the PRD Provider in such zone/LDA. For the purposes of the PRD Plan, the PRD Provider's Nominal PRD Value for a Zone/LDA is the Zonal/LDA PLC value minus (the Zonal/LDA FSL quantity times the loss factor).

A Price Responsive Demand (PRD) Plan submitted to PJM must include:

- Company name
- Submission date
- Company address and contact information
- Indication of whether price responsive demand is being nominated for an RPM Auction or for use in reducing an FRR Entity's unforced capacity obligation
- Location of Price Responsive Demand by applicable electrical location within a transmission zone (i.e., PNODE), if available at the time of submittal of PRD Plan, or by Sub-zone/Zone. At the time of the submittal of PRD Plan, the PRD Provider may provide data at the smallest LDA level, but the PRD Provider is required to provide final locational detail (i.e., PNODE) prior to Delivery Year.
- Peak Load Contribution Value of PRD by applicable electrical location, if available, or by Sub-zone/Zone Firm Service Level (FSL) of Price Responsive Demand by applicable electrical location, if available, or by Sub-zone/Zone Nominal PRD Value by applicable electrical location, if available, or by Sub-zone/Zone. The smallest increment that may be submitted for a Sub-zone/Zone is .1 MW.

- PRD Reservation Price, elected by PRD Provider as defined in section 3A.4.2.3
- Price-Demand curves at the applicable electrical location, (PNODE)/Sub-zone/Zone level, detailing the base electricity consumption level as well as the decreasing consumption levels (i.e., demand levels) at increasing wholesale energy prices (i.e., real-time LMPs).
- A description of the methodologies, analysis, or pilot programs used to determine the aggregate Zonal/LDA Peak Load Contribution value, aggregate Zonal/LDA FSL value, and Price-Demand Curves. Specifications of the equipment used to meet the advanced metering and supervisory control requirements, including a project plan and timeline with the milestones that demonstrates that the AMI and supervisory control will be available and operational for the start of the Delivery Year.
- Documentation conformation to Section 3A.4.2.3 below, verifying that the contractual arrangement with relevant end-use customers establishing a time-varying retail rate structure that conforms to any RERRA requirements and adheres to PRD implementation standards as specified in PJM RAA, PJM Operating Agreement, PJM OATT and PJM Manuals.
- AMI is required in support of the PRD installation:
 - In jurisdictions where the PRD program is under the jurisdiction of a RERRA, the PRD Provider shall use the AMI infrastructure in conformance with RERRA requirements. Furthermore, the AMI system shall be designed to allow for full implementation of PRD including metering reading requirements, supervisory control requirements, and all other requirements developed under the PJM RAA, PJM Operating Agreements, OATT and PJM Manuals.
 - In jurisdictions where PRD Provider is not required to obtain RERRA approval for the PRD program, the PRD Provider shall use an automated metering infrastructure that effects the needed operational requirements for PRD. Furthermore, the metering infrastructure shall be designed to allow for full implementation of PRD including meter reading requirements, supervisory control requirements, and all other requirements developed under the PJM RAA, PJM Operating Agreements, OATT and PJM Manuals.
 - The meter utilized to measure consumption for the purpose of retail billing shall also be the meter utilized to measure consumption for the purpose of PRD participation.

3A.4.2.1 Deleted

3A.4.2.2 Verification of Contractual Arrangement with PRD Provider

PJM will require the PRD Provider to provide documentation, within (10) business days of PJM's request, that verifies that their contractual arrangement with the relevant end-use customers establishing a time-varying retail rate structure that conforms any RERRA requirements and adheres to PRD implementation standards specified in the PJM RAA, PJM Operating Agreement, PJM OATT or PJM Manuals. The PRD Provider shall provide to PJM, within ten (10) business days of PJM's request, copies of their applicable contracts with end-use

customers capable of reducing load in response to price (including any proposed contracts). If the PRD Provider fails to provide any of the required documentation, including but not limited to end-use customer contracts within the ten business days, PJM shall reject the PRD Provider's PRD Plan.

In RERRA jurisdictions where a PRD Provider is not required by the RERRA to seek approval from the RERRA for its contractual arrangement for the referenced load, the PRD Provider shall provide to PJM, within ten (10) business days of PJM's request, an opinion of either the PRD Provider's legal counsel or the RERRA's legal counsel attesting that the PRD Provider does not need to obtain approval from the RERRA for the PRD Provider's contractual arrangement for the referenced load, and that the PRD Provider's contractual arrangement for the referenced load adheres to any guidelines established by the RERRA. If the PRD Provider fails to provide the required documentation within the ten business days, PJM shall reject the PRD Provider's PRD Plan.

3A.4.2.3 PRD Election Requirements

A PRD Provider that is nominating PRD for an RPM Auction must also submit a PRD election (indicating the Sub-zonal/Zonal Nominal PRD Value to be provided at different reservation prices) in the Capacity Exchange system by January 15, prior to the Base Residual Auction or Third Incremental Auction for the relevant Delivery Year.

A PRD election must include:

- Zonal/Sub-zonal Nominal PRD Value (MW) and Reservation Price (\$/MW-day) pair(s) that meet the following requirements.
 - Up to ten quantity(MW)-price(\$/MW-day) pair segments for a zone/sub-zone may be submitted
 - A minimum and maximum Nominal PRD Value quantity must be submitted for each segment
 - The smallest increment that may be submitted for a Nominal PRD Value MW quantity is 0.1 MW.
 - The sum of the maximum Nominal PRD Values in the segments must not exceed the sub-zonal/zonal Nominal PRD Value requested for approval by PJM in the PRD Provider's PRD Plan. If PJM approves a lower sub-zonal/zonal Nominal PRD Value than the requested value in their PRD Plan, the PRD Provider will be asked to resubmit their PRD election such that the maximum Nominal PRD Values in the segments does not exceed the final sub-zonal/zonal Nominal PRD Value approved by PJM.
 - A Reservation Price submitted in a segment must be equal to or greater than \$0/MW-day. If a PRD Provider does not submit a reservation price for a segment, the reservation price will default to \$0/MW-day. A PRD Provider is willing to commit the Nominal PRD level specified in a segment if the RPM Auction Resource Clearing

Price applicable to Annual Resources in the zone/sub-zone is equal to or greater than the Reservation Price specified in such segment.

- The PRD Provider is willing to accept the commitment of any amount of Nominal PRD Value equal to or greater than the minimum MW amount quantity specified in a segment and equal to or less than the maximum MW amount quantity specified in a segment.
- If a PRD Provider's PRD Plan is not approved by PJM, the PRD Provider's Election will be rejected by PJM and not considered in the RPM Auction clearing.

Upon posting of the RPM Auction Results, PJM will notify the PRD Provider via the Capacity Exchange system of their sub-zonal/zonal committed Nominal PRD Value. Upon notification by PJM, the PRD Provider has a binding commitment to provide sub-zonal/zonal PRD at the committed level during the relevant Delivery Year.

3A.5 Registration of Price Responsive Demand

A PRD Provider will be required to register price responsive load in DR Hub system prior to the start of the Delivery Year and maintain the registration of enough price responsive load in a zone/sub-zone throughout the Delivery Year to satisfy their zonal/sub-zonal PRD commitments.

Only load that meets all the eligibility requirements of PRD can be registered as PRD. The registration of price responsive load must be identified at the substation location within a transmission zone as electrically close as practical to the applicable load (i.e., PNODE).

If during the Delivery Year, the load no longer meets all the eligibility requirements of PRD, the PRD Provider must terminate the initial registration on the date the load no longer meets the eligibility requirements. The PRD Provider may also register new customers throughout the Delivery Year to cover loss of PRD load when customers drop out of the PRD Provider's program.

End-use customer loads identified in a PRD Plan or PRD registration for a Delivery Year as Price Responsive Demand may not, for such Delivery Year, (i) be registered as Economic Load Response or Emergency Load Response; (ii) be used as the basis of any Demand Resource Sell Offer or Energy Efficiency Sell Offer in any RPM Auction; (iii) be identified in a PRD Plan or PRD registration of any other PRD Provider.

An individual site registration must be submitted for each end-use customer site that is price responsive and has a peak load contribution equal to or greater than 10 KW. The site registration must identify the EDC, PLC, FSL, EDC-assigned loss factor, PNODE, and whether the load is being served under the RPM or the FRR Alternative. The FSL in the registration represents the load level that the site is committing to be at during a Performance Assessment Interval in the Delivery Year.

An aggregate registration may be submitted to aggregate end-use customer sites that have peak load contributions below 10 KW provided such aggregate registration must represent end-use customers located at the same PNODE.

The Nominal PRD Value calculated for a registration is equal to the PLC in the registration minus (the FSL in the registration times the EDC-assigned loss factor).

PJM will aggregate the Nominal PRD Values of effective, approved registrations in a zone/sub-zone to determine the PRD Provider's actual Daily Nominal PRD Value in zone/sub-zone for each day during the Delivery Year.

The deadline for the submittal of a PRD registration in the DR Hub system is one day before the tenth business day prior to the start date that a PRD registration is effective so that adequate time is provided for the EDC to confirm the registration data. During the Delivery Year, if the load identified in the approved PRD registration will no longer meet the PRD eligibility requirements, a request to terminate the PRD registration on the last day that such load meets the PRD eligibility requirements must be submitted in DR Hub within two business days prior to the date that the PRD registration is to terminate. A PRD registration must be in an approved status by the start date of the registration and be effective on the delivery day in order for such registration to be counted towards meeting the PRD Provider's committed sub-zonal/zonal Nominal PRD Value for the relevant delivery day.

For a PRD Provider, the MW amount of PRD that is currently registered by the PRD Provider at the time of PRD Plan submittal may be considered as Existing PRD and not be subject to a Price Responsive Demand Credit Requirement.

3A.6 Performance Requirements of Price Responsive Demand

Once a PRD Provider commits PRD for the Delivery Year, the PRD Provider will be subject to both daily commitment compliance during the Delivery Year Non-Performance Assessment during the Delivery Year in accordance with Section 8.4A. In the absence of a Performance Assessment Interval during the relevant Delivery Year that required the PRD registration to respond, such registration would be required to test during the Delivery Year

A PRD Provider cannot use replacement capacity to reduce a MW shortfall for PRD commitment compliance, failure to perform during a Performance Assessment Interval, or failure to perform during a test. However, a PRD provider may register additional price responsive demand throughout the Delivery Year to cure a daily commitment compliance shortfall or avoid additional Non-Performance Assessment shortfalls. In addition, a PRD Provider may transfer the obligation to provide PRD to another PRD provider through a bilateral transaction.

3A.6.1 PRD Commitment Compliance

A PRD Provider must register enough PRD prior to the start of the Delivery Year and maintain enough Price Responsive Demand registrations throughout the Delivery Year to satisfy their sub-zonal/zonal PRD commitment for RPM or FRR.

PRD commitment compliance will be evaluated on a daily basis throughout the Delivery Year. PJM will determine the actual Daily Nominal PRD Value of the PRD Provider in a Sub-Zone/Zone for RPM or FRR based on the registration information provided in the DR Hub system. If a PRD Provider's actual Daily Nominal PRD Value in a Sub-Zone/Zone for RPM is less than their committed Nominal PRD Value in Sub-Zone/Zone for RPM, the PRD Provider will be subject to a Daily PRD Commitment Compliance Penalty in the Sub-zone/Zone for the MW shortfall. If a PRD Provider's actual Daily Nominal PRD Value in a Sub-Zone/Zone for FRR is less than their committed Nominal PRD Value in Sub-Zone/Zone for FRR, the PRD Provider will be subject to a Daily PRD Commitment Compliance Penalty in the Sub-zone/Zone for the MW shortfall.

3A.6.2 Deleted

3A.6.2A Compliance during a Performance Assessment Interval

A PRD Provider is subject to a Non-Performance Assessment in accordance with Section 8.4A. Compliance is measured for a PRD registration upon declaration of a Performance Assessment Interval in same sub-zone/zone of such PRD registration and when the PRD Curve associated with such registration in the PJM Real-time Energy Market has a price point where demand reduction is expected at Real Time LMP recorded during the Performance Assessment Interval. A PRD registration shall not be considered in the calculation of a Performance Shortfall or Bonus Performance when the PRD Curve associated with such registration in the Real-time Energy Market indicates a price point where no demand reduction is expected at the real-time LMP recorded during the Performance Assessment Interval.

A PRD registration with an approved exception to the automation requirement will not have compliance measured during Performance Assessment Intervals that fall within the 15 minute response allowance. A PRD Provider will only be subject to Non-Performance Assessment and associated Non-Performance Charges/Bonus Performance Credits for those PRD registrations that were measured for compliance.

PRD Providers are responsible for the submittal to PJM of all meter information required to complete this measurement and verification for each Performance Assessment Interval during the Delivery Year that the PRD was required to respond. PJM requires that actual metered data at the end-use customer site for all hours during the day of a Performance Assessment Interval be submitted to PJM via DR Hub system within 45 days after the end of the month in which a Performance Assessment Interval occurs, with accountability for failure to do so. PJM verifies compliance on a registration basis by reviewing the data submitted by the PRD Provider through the DR Hub system.

The actual load reduction provided by the registration for the Performance Assessment Interval is calculated as the registration's Peak Load Contribution minus (the metered load multiplied by the loss factor). A load reduction will only be recognized if metered load multiplied by the loss factor is less than the Peak Load Contribution. When five minute revenue meter data is not available to determine compliance of a PRD registration for a Performance Assessment Interval, the actual load reduction for a Performance Assessment Interval is calculated as the actual hourly load reduction for the hour ending that includes the Performance Assessment Interval(s) multiplied by (twelve divided by the number of five minute intervals the PRD registration was to be measured for compliance). The actual load reduction for a registration for a Performance Assessment Interval is capped at the Peak Load Contribution of the registration. If the PRD Provider failed to submit actual metered data for the registration for all hours during the day of a Performance Assessment Interval, the actual load reduction for such registration will be equal to zero MWs.

For each registration in an Emergency Action Area, the Actual Performance is equal to the actual load reduction for such registration for the Performance Assessment Interval. The Actual Performance for a PRD Provider in the Emergency Action Area for the Performance Assessment Interval is equal to the sum of the Actual Performance of the PRD registrations that were measured for compliance for such Emergency Action Area and Performance Assessment Interval. If a PRD Provider registered PRD to satisfy RPM PRD commitments and PRD to satisfy FRR PRD commitments, an Actual Performance quantity will be calculated for registrations tied to RPM and a separate Actual Performance quantity will be calculated for registrations tied to FRR.

The Expected Performance for a PRD Provider for the Emergency Action Area and Performance Assessment Interval is equal to the Nominal PRD Value committed by PRD Provider in the Emergency Action Area, adjusted to account for any PRD registrations in the Emergency Action Area that were not subject to compliance measurement. If a PRD Provider committed PRD to RPM and committed PRD to FRR, an Expected Performance quantity will be calculated for RPM commitments and a separate Expected Performance quantity will be calculated for FRR commitments.

The Performance Shortfall for a PRD Provider is calculated as Expected Performance minus the Actual Performance. If the Performance Shortfall related to RPM commitments is negative number, the PRD Provider is subject to a Non-Performance Charge, in accordance with Section 8.4A. If the Performance Shortfall related to RPM commitments is a negative number, the PRD Provider may be eligible for a Bonus Performance Credit, in accordance with Section 8.4A. Performance Shortfalls related to FRR commitments are subject to Non-Performance Charge or Bonus Performance Credit if the FRR Entity elected the financial non-performance assessment as opposed to the physical non-performance option described in Section 11.8.7

3A.6.3 PRD Test Compliance (Effective for 2022/2023 Delivery Year)

If a PRD registration is not measured for compliance for a Performance Assessment Interval in a Delivery Year, then such registered PRD must demonstrate that it was tested for a one hour

period between 10:00 AM EPT to 10:00 PM EPT during June through October or May of the relevant Delivery Year. If a PRD registration is measured for compliance for a Performance Assessment Interval in a Delivery Year, then no PRD Test Failure Charges will be assessed for such PRD registration.

All PRD registrations in a zone must be tested simultaneously except that, when less than 25 percent (by megawatts) of a PRD Provider's total PRD registered in a Zone fails a test, the PRD Provider may conduct a re-test limited to all registered PRD that failed the prior test, provided that such re-test must be at the same time of day and under approximately the same weather conditions as the prior test, and provided further that all affiliated registered PRD must test simultaneously, where affiliated means registered PRD that has any ability to shift load and that is owned or controlled by the same entity. If less than 25 percent of a PRD Provider's total PRD registered in a Zone fails the test and the PRD Provider chooses to conduct a retest, the PRD Provider may elect to maintain the performance compliance result for registered PRD achieved during the test if the PRD Provider: (1) notifies PJM 48 hours prior to the re-test under this election; and (2) the PRD Provider retests affiliated registered PRD under this election.

Multiple tests may be conducted; however only one test result may be submitted for each end use customer site in DR Hub for test compliance evaluation. Test data must be submitted in DR Hub on or after June 1 and no later than July 14th after the Delivery Year. Actual load reduction for a PRD registration in a test is calculated in a manner similar to calculating actual hourly load reduction during an emergency action.

The MW testing shortfall for a PRD registration is equal to the nominal load reduction value of the registration, capped at daily Nominal PRD Value committed by such registration on the day of the test, minus the actual hourly load reduction for such registration.

The PRD Provider's daily committed Zonal (or Sub-Zonal LDA) Nominal PRD Value is allocated to the PRD Provider's registrations in the zone (or sub-zonal LDA) pro-rata based on the Nominal PRD Value of the registrations to determine the PRD commitment level for such registrations.

Positive MW shortfalls represent underperformance for a PRD registration. Negative MW shortfalls represent over performance for a PRD registration. The test compliance results of the PRD Provider's PRD registrations in a zone that were expected to test are aggregated to determine a PRD Provider's net zonal testing shortfall. If a PRD Provider committed PRD to RPM and committed PRD to FRR, a net zonal testing shortfall will be calculated for their PRD registrations linked to RPM and a separate net zonal testing shortfall will be calculated for their PRD registrations linked to FRR.

3A.6.3A PRD Test Compliance (Effective with 2023/2024 Delivery Year)

For the 2023/2024 Delivery Year and subsequent Delivery Years, if the registered PRD is not required to reduce the load for a Performance Assessment Interval during the relevant Delivery Year, then such registered PRD shall test for a two hour period between 11:00 EPT to 18:00

EPT on a weekday that is a non-NERC holiday during the relevant Delivery Year and in accordance with the following provisions. The date and time of such test shall be selected by the Office of the Interconnection and notice of such test shall be provided to the PRD Provider in accordance with the procedure described in sections (2) and (3) listed below. If a PRD registration is measured for compliance for a Performance Assessment Interval in a Delivery Year, then no PRD Test Failure Charges will be assessed for such PRD registration.

1. For the 2023/2024 Delivery Year and subsequent Delivery Years, all PRD registered in a zone will be tested simultaneously for two hours. Performance will be calculated as the two hour average reduction. The Office of the Interconnection may, at its discretion, cancel a test and retest to ensure system reliability.
 - a. If less than 25 percent (by megawatts) of a PRD Provider's total PRD registered in a Zone fails a test, the PRD Provider may conduct re-tests limited to all registered PRD that failed the prior test, provided that such re-test must be at the same time of day and under approximately the same weather conditions as the prior test, and provided further that all affiliated registered PRD must test simultaneously, where affiliated means registered PRD that has any ability to shift load and that is owned or controlled by the same entity. The PRD Provider may elect to maintain the performance compliance result for registered PRD achieved during the test if the PRD Provider: (1) notifies the Office of the Interconnection 48 hours prior to the re-test under this election; and (2) the PRD Provider retests affiliated registered PRD under this election as set forth in the PJM Manuals.
 - b. If 25 percent or more (by megawatts) of a PRD Provider's total PRD registered in a Zone fails the test the PRD Provider may request PJM to schedule a one-time retest limited to all registrations that failed the prior test, provided that all affiliated registrations must test simultaneously where affiliated means registered PRD that has any ability to shift load and that is owned or controlled by the same entity. The request must be made before the 46th day after the test. The Office of the Interconnection will select the date and time of the retest during the same season period (except if test was conducted in March in which case retest can be conducted in May) and notice is provided consistent with the following procedure.
2. Notification of the initial Office of the Interconnection scheduled test will be provided as follows:
 - a. On the first business day of a week, PJM will provide notice of all zones to be tested during the following two week test window. The test window opens the first business day of the week following the notice. By 10:00 EPT the day before the test, the Office of the Interconnection will post on its website the test date and zones. The Office of the Interconnection will also notify the PRD Providers the test date. On the test date, PRD Providers will receive the start time through web service communications with a 15 minute lead time and as defined in the PJM Manuals.

3. Notification of any scheduled retest by the Office of the Interconnection will be provided as follows:
 - a. By 10:00 EPT the day before the retest, the Office of the Interconnection will post the retest date on its website. PJM will also notify the PRD Providers the retest date. On retest date PRD Providers will receive start time through web service communications with a 15 minute lead time and as defined in the PJM Manuals.

The MW testing shortfall for a PRD registration is equal to the nominal load reduction value of the registration, capped at daily Nominal PRD Value committed by such registration on the day of the test, minus the actual load reduction for such registration.

The PRD Provider's daily committed Zonal (or Sub-Zonal LDA) Nominal PRD Value is allocated to the PRD Provider's registrations in the zone (or sub-zonal LDA) pro-rata based on the Nominal PRD Value of the registrations to determine the PRD commitment level for such registrations.

Positive MW shortfalls represent underperformance for a PRD registration. Negative MW shortfalls represent over performance for a PRD registration. The test compliance results of the PRD Provider's PRD registrations in a zone that were expected to test are aggregated to determine a PRD Provider's net zonal testing shortfall. If a PRD Provider committed PRD to RPM and committed PRD to FRR, a net zonal testing shortfall will be calculated for their PRD registrations linked to RPM and a separate net zonal testing shortfall will be calculated for their PRD registrations linked to FRR.

3A.7 PRD Bilaterals

A PRD Provider may transfer the obligation to provide PRD bilaterally to another PRD Provider during the Delivery Year.

The following are the business rules that apply to PRD bilateral transactions:

- PRD bilateral transactions must be reported in the Capacity Exchange system.
- Both parties of the PRD transaction must confirm the transfer of a PRD commitment from the seller (transferor) to the buyer (transferee) via the Capacity Exchange system prior to the start date of the transaction.
- PRD bilateral transactions must be in the "Approved" status by the start date of the transaction or the status of such transaction will be changed to "PJM Withdrawn".
- The smallest increment of committed Nominal PRD Value that may be transferred is 0.1 MW.
- PRD transactions must specify:
 - start and end data for the transaction
 - the amount of Nominal PRD Value (in MW) to be transferred

- the sub-zone/zone in which the Nominal PRD Value to be transferred was committed
- whether the Nominal PRD Value to be transferred was committed to RPM or the FRR Alternative
- the RPM Auction (BRA or Third IA) for which the Nominal PRD Value to be transferred was committed (if committed to RPM)
- The Capacity Exchange system will validate that the Seller has the committed Nominal PRD Value in the sub-zone/zone to transfer for the term of the transaction.
- To the extent that the Nominal PRD Value to be transferred has a Price Responsive Demand Credit Requirement, the Buyer must have sufficient credit in place prior to PJM approving the PRD transaction.
- As a result of an approved PRD transaction, the buyer that is assuming the seller's PRD commitment and obligations will be subject to PRD performance requirements to the extent of such transfer and for the term of the transaction.
- The seller shall be relieved of its PRD commitment and any Price Responsive Demand Credit Requirements for the Nominal PRD Value transferred for the term of the transaction.

Section 4: Supply Resources in the Reliability Pricing Model

Welcome to the *Supply Resources in RPM* section of the **PJM Manual for the PJM Capacity Market**. In this section, you will find the following information:

- An overview description of supply in the Reliability Pricing Model (see “Overview of Supply in the Reliability Pricing Model”)
- The business rules for generation resources (see “Generation Resources”)
- The business rules for load management products (see “Load Management Products”)
- The business rules for energy efficiency resources (see “Energy Efficiency Resources”)
- The business rules for qualified transmission upgrades (see “Qualified Transmission Upgrades”)
- The business rules for bilateral transactions (see “Bilateral Transactions”)
- The business rules for resource portfolios in RPM (see “Resource Portfolios”)
- The credit requirements in RPM (see “Credit Requirements”)
- The business rules for Aggregate Resources (see “Aggregate Resources”)
- The business rules for Seasonal Capacity Resources (see “Seasonal Capacity Resources”)

4.1 Overview of Supply in the Reliability Pricing Model

In the Reliability Pricing Model, the supply of installed capacity is procured to meet demand as a function of the clearing of the RPM Auctions. In each auction, a supply curve is defined based on the offers submitted by providers with installed capacity resources. Supply, valued as unforced capacity, which is procured in the RPM multi-auction clearing process, ensures that sufficient resources are committed to meet the PJM Reliability Principles and Standards.

A party's supply resource portfolio in Capacity Exchange may consist of:

- Generation Capacity Resources;
- Load Management Resources;
- Energy Efficiency Resources;
- Aggregate Resources
- Qualifying Transmission Upgrades.

Key qualifications and requirements for generation resources are presented in Existing Generation, Planned Generation, and Bilateral Unit-Specific Transaction sections of this Manual. Key qualifications and requirements for load management products are presented in the Load Management section of this Manual. Key qualifications and requirements for Energy Efficiency Resources are presented in the Energy Efficiency Resources section of this Manual.

Key qualifications and requirements for Aggregate Resources are presented in the Aggregate Resources section of this Manual. Key qualifications and requirements for Qualified Transmission Upgrades are presented in the Qualified Transmission Upgrade section of this Manual.

Note:

Prior to any RPM auction, RPM suppliers must confirm the modeling of each of their capacity resources. RPM suppliers must verify the following characteristics of generation units, demand resources, energy efficiency resources, and aggregate resources:

Zone assignment

LDA assignment

Unit Location by State (generation resources only)

Unit Type (generation resources only)

Product Type (Annual)

Fuel type (generation resources only)

Seasonal eligibility

4.2 Generation Resources

A party's Generation Capacity Resource portfolio may consist of Existing Generation Capacity Resources, Planned Generation Capacity Resources, and bilateral contracts for unit-specific Capacity Resources. Qualifications and requirements for Generation Capacity Resources are presented in the sections below. A Generation Capacity Resources that is being committed to the initial FRR Capacity Plan must satisfy the same qualification requirements as a Generation Capacity Resource offering into a Base Residual Auction; however, the qualification requirements must be satisfied in advance of the FRR Capacity Plan submittal deadline.

4.2.1 Existing Generation Capacity Resources - Internal

Existing Generation Capacity Resource located within the PJM region is eligible to be offered into RPM Auctions or traded bilaterally if it meets the following requirements:

- The unit is pre-certified by PJM as meeting the generation deliverability test. PJM's certification process for internal generating resources is described in the ***Open Access Transmission Tariff and the Operating Agreement***.
- The resource owner or operator submits the required operating and maintenance information into PJM's eDART and eGADs systems.

- The resource owner or operator performs winter and summer testing as described in **PJM's Rules and Procedures for Determination of Generating Capability (M-21) and M-21B** to verify the net capability of each unit.
- The unit resides in the Capacity Exchange resource portfolio of a signatory of the PJM Operating Agreement. This is accomplished by having an "Approved" Capacity Modification in the Capacity Exchange system.
- The relevant portion of the unit was not specified in any FRR Capacity Plan for the Delivery Year.
- Unoffered MWs for a unit as a result of not satisfying the RPM must offer requirement in the Base Residual Auction or an Incremental Auction for the Delivery Year, are ineligible to be offered in any subsequent Incremental Auctions for that Delivery Year and are ineligible to take on any RPM or FRR commitment for such Delivery Year.

4.2.2 Existing Generation Capacity Resources - External

Existing Generation Capacity Resources located outside the PJM region is eligible to be offered into an RPM Auction if it meets the following requirements:

- For an external Generation Capacity Resource offering as Capacity Performance, the external resource satisfies the requirements to offer as Capacity Performance or qualifies for an exception to such requirements as a Prior CIL Exception External Resource. A Prior CIL Exception External Resource is defined as an external Generation Capacity Resource for which (1) a Capacity Market Seller had, prior to May 9, 2017, cleared a Sell Offer in an RPM Auction under the exception provided to the definition of Capacity Import Limit as set forth in Article 1 of the Reliability Assurance Agreement or (2) an FRR Entity committed, prior to May 9, 2017, in an FRR Capacity Plan under the exception provided in the definition of Capacity Import Limit. In the event only a portion (in MW) of an external Generation Capacity Resource has a Pseudo-Tie into the PJM Region, that portion of the external Generation Capacity Resource, which can include up to the maximum megawatt amount cleared in any prior RPM auction or committed in an FRR Capacity Plan (and no other portion thereof), is eligible for treatment as a Prior CIL Exception External Resource if such portion satisfies the requirements of the first sentence of this definition.
- For a Capacity Market Seller to offer an external Generation Capacity Resource as Capacity Performance, the Capacity Market Seller must demonstrate to PJM, by no later than five (5) business days prior to the commencement of the offer period for the relevant RPM Auction, that such resource meets the following requirements:
 - The Capacity Market Seller has obtained a determination that the Pseudo-Tie required for its External Generation Capacity Resource is feasible, including (without limitation) that such Pseudo-Tie meets the requirements in **PJM Balancing Operations Manual (M-12)** and the Capacity Market Seller has committed in writing, via the submittal of an Officer Certification Form, that it will take all steps necessary to implement such Pseudo-Tie prior to the start of the relevant Delivery Year. A template for the Officer Certification Form is posted on the PJM website.

- The Capacity Market Seller has demonstrated that it has, for transmission outside PJM, obtained long-term firm point-to-point transmission service (evaluated for deliverability from the unit-specific physical location of the resource to PJM load pursuant to a study that is reviewed and approved by PJM in accordance with PJM deliverability criteria to ensure uniformity for internal and external resource deliverability requirements), with rollover rights for the term of the transmission service that is confirmed by the Balancing Authority where such external resource is geographically located.
- The Capacity Market Seller has demonstrated that it has, for transmission service within PJM, obtained Network External Designated Transmission Service.
- The Capacity Market Seller has demonstrated by written commitment via the Officer Certification Form that such external resource is subject to the same obligations to offer into RPM Auctions imposed on Generation Capacity Resources located in the PJM Region by section 6.6 of Attachment DD of OATT. A Capacity Market Seller that satisfies the requirements to offer as Capacity Performance with respect to an external Generation Capacity Resource Sell Offer submitted in an RPM Auction for a Delivery Year is required to demonstrate satisfaction of such requirements for any Sell Offer with respect to such external resource submitted in an RPM Auction for any subsequent Delivery Year, including without limitation, demonstration that the required external transmission service continues to satisfy PJM's deliverability standards.
- To qualify for an exception to satisfy the above requirements to offer as Capacity Performance for a Delivery Year RPM Auction, the Prior CIL Exception External Resource must demonstrate that the external resource is (1) owned by a Load Serving Entity and used to self-supply (under arrangements initiated before June 1, 2016, with a duration of at least ten years) such LSE's PJM Region load, for any Delivery Year during the life of such resource or (2) the subject of a contract for energy or capacity or equivalent written agreement entered into on or before June 1, 2016 for a term of ten years or longer with a purchaser that is an internal PJM load customer, for any Delivery Year that covers the term of the agreement.
- The Prior CIL Exception External Resource must continue to comply with all the conditions in place on the grant of its exception to the Capacity Import Limit, subject to the following additional conditions:
 - The Prior CIL Exception External Resource must be Operationally Deliverable, as defined in the Open Access Transmission Tariff. If PJM determines that a Prior CIL Exception Resource is not Operationally Deliverable for a Delivery Year and notifies the Capacity Market Seller of such a determination by no later October 1 immediately preceding such Delivery Year, the Capacity Market Seller may elect to:
 - Take the necessary actions to make the Prior CIL Exception External Resource Operationally Deliverable, in PJM's sole judgement, prior to the beginning of such Delivery Year. If transmission upgrades are required to make the external resource Operationally Deliverable, PJM will facilitate the performance of

transmission studies and otherwise cooperate with the external Transmission Provider of the system on which such upgrades are required to identify the upgrades required to meet PJM's deliverability standards;

- Be relieved of the external resource's capacity obligation for such Delivery Year by providing written notice of such election to the RPM Hotline at rpm_hotline@pjm.com no later than seven (7) days prior to the posting of planning parameters for the Third Incremental Auction for such Delivery Year. As a result of such election, the Capacity Market Seller will not receive any RPM Auction Credits for the external resource's cleared MWs for such Delivery Year, will be relieved of all commitments and any resource performance obligations for such Delivery Year, and will have no further must-offer obligation in RPM Auctions. PJM will consider all such elections from Capacity Market Sellers in the determination of the PJM Buy Bid/Sell Offer for the Third Incremental Auction.
- Procure and specify replacement capacity in a sufficient quantity to replace the entire commitment on the Prior CIL Exception External Resource for the Delivery Year.
 - A Capacity Market Seller's continued ability to offer as a Prior CIL Exception External Resource in RPM Auctions is conditioned on external Transmission Providers continuing to honor the firm status of the Capacity Market Seller's transmission service for all Delivery Years that such Capacity Market Seller offered as a Prior CIL Exception Resource.
 - A Capacity Market Seller offering and clearing a Prior CIL Exception Resource shall be relieved of its must offer obligation in future Delivery Year RPM Auctions after the last Delivery Year for which it qualifies for an exception to requirements to offer as a Capacity Performance Resource.
- The unit resides in the Capacity Exchange resource portfolio of a signatory of the PJM Operating Agreement. This is accomplished by having a "Provisionally Approved" or "Approved" unit-specific transaction with "External Party" (i.e., "EXT") as the "Seller" of the transaction in the Capacity Exchange system.
- At least twelve months of NERC/GADs unit performance data in PJM format is required to establish a unit's Accredited UCAP Factor.
- The resource owner or operator submits the required operating and maintenance information into PJM's eDART and eGADs systems.
- The resource owner or operator performs winter and summer testing as described in ***PJM's Rules and Procedures for Determination of Generating Capability (M-21 and M-21B)*** to verify the net capability of each unit.
- The external capacity without firm transmission service confirmed on the complete transmission path must establish an RPM Credit Limit prior to an RPM Auction.
- Credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction.

- The resource owner provides a letter of non-recallability assuring PJM that the energy and capacity from the unit is not recallable to any other control area.
- A communication path (acceptable to PJM Dispatching/Operations personnel) must be established between the PJM Dispatchers and the operator of the unit.
- The relevant portion of the unit was not specified in any FRR Capacity Plan for the Delivery Year.

An Existing Generation Capacity Resource located outside the PJM region is eligible to be traded bilaterally if the unit resides in the Capacity Exchange resource portfolio of a signatory of the PJM Operating Agreement through the accomplishment of an “Approved” unit-specific transaction with “External party” (i.e., “EXT”) as the “Seller” of the transaction in the Capacity Exchange system. For an external resource offering or committing as Capacity Performance, an “Approved” unit-specific transaction status will not be granted until the pseudo-tie for such resource is actually implemented and the external resource has satisfied PJM’s deliverability standards, which for CIL Exception External Resource may include completing the necessary actions to make such CIL Exception External Resource Operationally Deliverable for the relevant Delivery Year. Demonstrating deliverability may require transmission upgrades on an external Transmission Provider’s system or PJM’s system to be completed prior to June 1st of the delivery year. The study process for participant-funded upgrades is defined in Part VI of the PJM Open Access Transmission Tariff. The following requirements for existing external generation are still applicable for external resources traded bilaterally:

- At least twelve months of NERC/GADs unit performance data in PJM format is required to establish a unit’s Accredited UCAP Factor.
- The resource owner or operator submits the required operating and maintenance information into PJM’s eDART and eGADs systems.
- The resource owner or operator performs winter and summer testing as described in ***PJM’s Rules and Procedures for Determination of Generating Capability (M-21 and M-21B)*** to verify the net capability of each unit.
- The resource owner provides a letter of non-recallability assuring PJM that the energy and capacity from the unit is not recallable to any other control area.
- A communication path (acceptable to PJM Dispatching/Operations personnel) must be established between the PJM Dispatchers and the operator of the unit.
- The relevant portion of the unit was not specified in any FRR Capacity Plan for the Delivery Year.

If an existing Generation Capacity Resource located outside the PJM region cleared as Capacity Performance Resource in the Base Residual Auction, First Incremental, Second Incremental Auction, Third Incremental Auction, or Conditional Incremental Auction and does not have the pseudo-tie implemented and generation deliverability demonstrated by the start date of associated unit-specific transaction, the status of the associated unit-specific transaction

in the Capacity Exchange system will be changed from “Provisionally Approved” to “PJM Withdrawn”.

4.2.3 Planned Generation Capacity Resources - Internal

A Planned Generation Capacity Resource that is participating in PJM’s Regional Transmission Expansion Planning Process (RTEPP) is eligible to be offered into PJM’s RPM Auctions if it meets the following requirements:

- The planned unit’s start date of Interconnection Service is on or before the start of Delivery Year.
- At a minimum, planned generation resources greater than 20 MW must be in the Phase III System Impact Study and planned generation resources less than or equal to 20 MW must be in the Phase II System Impact Study, for the unit to participate in the Base Residual Auction.
- A Generation Interconnection Agreement (GIA) or Wholesale Market Participant Agreement (WMPA) has been executed for the unit to participate in an Incremental Auction.
- A Capacity Modification for the planned unit has been submitted and “Provisionally Approved” in Capacity Exchange.
- Planned Generation Capacity Resources must establish an RPM Credit Limit prior to an RPM Auction.
- Credit requests should be made to PJM’s Treasury Department at least two weeks prior to an RPM Auction.
- If the Planned Generation Capacity Resource was committed through the Base Residual Auction and the GIA is not received prior to opening of the bid window for the First Incremental Auction, the status of the Capacity Modification will be changed from “Provisionally Approved” to “Denied” so that the planned generation will no longer be included in a resource provider’s Capacity Exchange Generation Resource portfolio.
- If a GIA is eventually executed with a start date of Interconnection Service that is on or before the start of the Delivery Year, a new Capacity Modification will need to be submitted and “Provisionally Approved” in order to be re-included in a resource provider’s Capacity Exchange Generation Resource portfolio.
- If the Planned Generation Capacity Resource is delayed and has not commenced Interconnection Service by the start date of the Capacity Modification, the status of the Capacity Modification will be changed from “Provisionally Approved” to “Denied”. A new Capacity Modification will need to be submitted and approved with a start date that corresponds to the start date of Interconnection Service.
- Planned Generation Capacity Resources are required to submit an acceptance test to PJM Planning prior to the start date of the submitted CAPMOD in accordance with Manual 21 Section 1.3

- If PJM Planning determines a portion of a Planned Generation Capacity Resource has commenced Interconnection Service, or considered Partially In-Service, the status of the Capacity Modification may be changed from "Provisionally Approved" to "Approved" up to the amount of MWs deemed in-service by PJM Planning. A Capacity Modification for the remaining Planned MWs should be submitted and remain "Provisionally Approved" until PJM Planning confirms the MWs are in-service.
- Effective with the 2025/2026 Delivery Year, an internal Planned Generation Capacity Resource must satisfy the requirements of the binding notice of intent in section 4.2.3.1 in order for the internal Planned Generation Capacity Resource to be included in a Sell Offer for an RPM Auction.

4.2.3.1 Binding Notice of Intent to Offer (Effective with the 2025/2026 Delivery Year)

Any Planned Generation Capacity Resource, including planned Intermittent Resources, Capacity Storage Resources, and Hybrid Resources, will be required to provide a binding notice of intent to offer, in the format requested by PJM, in order to participate in the RPM Auction. A Capacity Market Seller must provide a binding notice of intent no later than (a) the immediately preceding December 1 for a Base Residual Auction (except that for the 2025/2026 auction the deadline was 12/12/23, and 2026/2027 and 2028/2029 Delivery Years, such notice shall be submitted by 180 days prior to the commencement of the offer period), or (b) ninety (90) days prior to the commencement of the offer period for an Incremental Auction. A notice of intent to offer should be made by the Capacity Market Seller that intends to offer the Planned Generation Capacity Resource/upgrade into the auction. The resource associated with a binding notice of intent is required to be offered into the auction even if a different Capacity Market Seller will offer the resource into the RPM Auction. Any bilateral unit-specific transaction involving the Planned Generation Capacity Resource prior to the auction will transfer the binding notice of intent to the new Capacity Market Seller. If a resource associated with a binding notice of intent is not offered in the auction, then the resource will not be permitted to offer into any subsequent auctions for the relevant Delivery Year or take on a RPM commitment through Locational UCAP or Replacement Capacity transaction during the relevant Delivery Year, or take on a FRR Commitment during the relevant Delivery Year.

4.2.4 Planned Generation Capacity Resources – External

A Planned External Generation Capacity Resource is eligible to be offered into PJM's RPM Auctions. Such resources will be treated in a manner comparable to planned internal generation resources and existing external generation resources. Prior to participation in any RPM Auction, the Resource Provider must demonstrate that it has executed an interconnection agreement (functionally equivalent to being in the Phase II or Phase III System Impact Study as outlined below for a Base Residual Auction and a Generation Interconnection Agreement for an Incremental Auction) with the transmission owner to whose transmission facilities or distribution facilities the resource is being connected, and if applicable with the transmission provider. A planned external generation resource must provide evidence to PJM it has been studied as a Network Resource, or such other similar interconnection product in the external Control Area. A

Planned External Generation Capacity Resource is eligible to be offered into RPM Auction if it meets the following requirements:

- A Planned External Generation Capacity Resource offering as Capacity Performance Resource must satisfy the same requirements for existing external generation capacity resources offering as a Capacity Performance Resource in Section 4.2.2 of this manual.
- The planned unit's start date of Interconnection Service is on or before the start of Delivery Year.
- At a minimum, planned generation resources greater than 20 MW must be in the Phase III System Impact Study and planned generation resources less than or equal to 20 MW must be in the Phase II System Impact Study, for the unit to participate in the Base Residual Auction. A functionally equivalent Generation Interconnection Agreement has been executed for the unit to participate in an Incremental Auction.
- The unit resides in the Capacity Exchange resource portfolio of a signatory of the PJM Operating Agreement. A Capacity Modification for the planned unit has been submitted by PJM and "Provisionally Approved" in Capacity Exchange in an External Party (i.e., EXT) account. A unit-specific transaction with External Party as the "Seller" has been submitted by the provider and "Provisionally Approved" in the Capacity Exchange system to represent the import of capacity into PJM.
- External Planned Generation Capacity Resources must establish an RPM Credit Limit prior to an RPM Auction.
- Credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction.
- If the Planned Generation Capacity Resource was committed through the Base Residual Auction and the GIA is not received prior to opening of the bid window for the First Incremental Auction, the status of the Capacity Modification and any unit-specific transaction(s) representing the capacity import will be changed from "Provisionally Approved" to "Denied" so that the planned generation will no longer be included in a resource provider's Capacity Exchange Generation Resource portfolio.
- If a GIA is eventually executed with a start date of Interconnection Service that is on or before the start of the Delivery Year, a new Capacity Modification and any unit-specific transaction(s) representing the import will need to be submitted and "Provisionally Approved" in order to be re-included in a resource provider's Capacity Exchange Generation Resource portfolio.
- If the Planned Generation Capacity Resource is delayed and has not commenced Interconnection Service by the start date of the Capacity Modification, the status of the Capacity Modification and any unit-specific transaction representing the import will be changed from "Provisionally Approved" to "Denied". A new Capacity Modification and unit-specific transaction representing the import will need to be submitted and approved with a start date that corresponds to the start date of Interconnection Service.
- Once operational, the resource owner or operator submits the required operating and maintenance information into PJM's eDART and eGADs systems.

- Once operational, the resource owner or operator performs winter and summer testing as described in **PJM's Rules and Procedures for Determination of Generating Capability (M-21 and M-21B)** to verify the net capability of each unit.
- The resource owner provides a letter of non-recallability assuring PJM that the energy and capacity from the unit is not recallable to any other control area.
- The relevant portion of the unit was not specified in any FRR Capacity Plan for the Delivery Year.
- Effective with the 2025/2026 Delivery Year, an external Planned Generation Capacity Resource must satisfy the requirements of the binding notice of intent in section 4.2.3.1 in order for the external Planned Generation Capacity Resource to be included in a Sell Offer for an RPM Auction.

4.2.5 Equivalent Demand Forced Outage Rate (EFORd) (Through 2024/2025 Delivery Year)

Equivalent Demand Forced Outage Rate (EFORd) is a measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate. See **Generator Resource Performance Indices Manual (M-22)** for the equations and derivations used in calculating a unit's EFORd.

The EFORd of a unit is based on forced outage data from an October through September period. If a unit does not have a full one-year history of forced outage data, the EFORd will be calculated using class average EFORd and the available history as described in the **Reliability Assurance Agreement, Schedule 5, Section B**.

The EFORd based on forced outage data from an October through September period prior to the Delivery Year is based on all forced outage data and does not exclude forced outage data for Outside Management Control events.

Since no forced outage data is collected for Variable Resources, an EFORd is not calculated for Variable Resources. The EFORd of Variable Resources is set to zero in the Capacity Exchange system.

New units are initially assigned a class average EFORd. The class average EFORds that are used by PJM to calculate a unit's EFORd are posted to the PJM website by November 30 prior to the Delivery Year.

The Effective EFORd is the EFORd that is effective for the delivery day in the Capacity Exchange system. Prior to the Delivery Year, the Effective EFORd is the most recently calculated EFORd that has been bridged to the Capacity Exchange system. During the Delivery Year, the Effective EFORd is based on forced outage data from the October through September period prior to the Delivery Year.

The EFORd that is effective for the Delivery Year is considered locked in the Capacity Exchange system by November 30 prior to the execution of the Third Incremental Auction.

Note: Through and including the 2024/2025 Delivery Year, the UCAP value of a Generation Capacity Resource (except for a Generation Capacity Resource that is a Variable Resource, a Limited Duration Resource or a Combination Resource) is based on the resource's EFORd. Effective with the 2025/2026 Delivery Year, the UCAP value of all Generation Capacity Resources is based on the Accredited UCAP Factor of each resource as determined by ELCC analysis (see Section 4.2.7 Accredited UCAP for ELCC Resources).

4.2.6 Capacity Modifications (CAP Mods)

Capacity Modifications (CAP MODs) are a type of Capacity Exchange transaction used by generation owners to request the addition of a new unit or the removal of an existing unit from their resource portfolio in Capacity Exchange, or to request a MW increase or decrease in the summer or winter installed capacity rating of an existing unit.

The purpose of a CAP MOD is to establish the installed capacity value of a generation resource in the Capacity Exchange system. CAP MOD transactions represent permanent changes to the installed capacity value of a generation unit.

CAP MODs are also used by a generation owner to establish the capacity value of an ELCC Resource to be offered into the PJM Capacity Market and by PJM to establish the Delivery Year capacity value of an ELCC Resource.

A CAP MOD may also be submitted by PJM to establish the capacity value of a Winter-Period Capacity Performance Resource for November through April of the Delivery Year.

The following are business rules that apply to Capacity Modifications (CAP Mods):

- CAP MODs with a start date that occurs on or before the start of the Delivery Year must be submitted and “Provisionally Approved” or “Approved” by PJM in the Capacity Exchange system prior to the opening of the Base Residual Auction’s or Incremental Auction’s bidding window in order for the CAP MODs to be considered in a party’s Generation Resource Position and the calculation of Available ICAP to offer for a Base Residual Auction, Incremental Auction or bilateral unit-specific transaction.
- All other CAP MODs must be submitted a minimum of 2 business days prior to the start date of the CAP MOD. The CAP MOD must be “Approved” by PJM in the Capacity Exchange system prior to the start date of the CAP MOD in order to be considered in a party’s final Daily Generation Resource Position.
- If the status of a “Provisionally Approved” CAP MOD changes to “Denied” or “PJM Withdrawn”, there will be no change to any party’s RPM Resource Commitments¹¹.
- CAP MODs cannot be created during an RPM Auction’s bidding window and clearing week.

- CAP MODs that are not in the “Approved” status by the start date of the CAP MOD will have their status changed to “PJM Withdrawn”.
- CAP MODs that would cause the summer rating of a generation resource or the capacity value of an ELCC Resource to exceed such unit’s Capacity Interconnection Rights plus transitional resource MWs will be “Denied” by PJM.

4.2.7 Accredited UCAP for ELCC Resources

Effective Load Carrying Capability (ELCC) establishes the Accredited UCAP value for ELCC Resources. Through the 2024/2025 Delivery Year, an ELCC Resource is a Variable Resource, a Limited Duration Resource, or a Combination Resource. Beginning with the 2025/2026 Delivery Year, an ELCC Resource is a Generation Capacity Resource or Demand Resources. Through the 2024/2025 Delivery Year, for the sole purpose of Manual 18 and the Capacity Exchange tool, the “ICAP” and “UCAP” for an ELCC Resource are set equal to the lesser of its Accredited UCAP or its Capacity Interconnection Rights plus transitional resource MW, and the EFORD of an ELCC Resource is shown as zero because the actual EFORD of an ELCC Resource, if applicable, has already been used in the determination of its Accredited UCAP.

Through the 2024/2025 Delivery Year, the Accredited UCAP Factor shall mean one minus the EFORD. For the 2025/2026 Delivery Year and subsequent Delivery Years, Accredited UCAP Factor is the ratio of the Capacity Resource's Accredited UCAP to the Capacity Resource's installed capacity.

The ELCC method is described in Manual 20 and Manual 20A (**PJM Resource Adequacy Analysis**), and the calculation of Accredited UCAP for an ELCC Resource is described in Manual 21A and Manual 21B (**Determination of Accredited UCAP Using Effective Load Carrying Capability Analysis**).

4.2.8 Interim Provisions for RMR Generation Resources

For Delivery Years up to and including the 2027/2028 Delivery Year (unless an extension of these provisions are proposed by PJM and approved by FERC), Reliability Must Run (RMR) Generation Capacity Resources that meet the criteria specified in Tariff, Attachment DD, section 5.3(b) will be included in the Base Residual Auction and to the extent there is an increase in Accredited UCAP, the additional MWs shall be included in the Third Incremental Auction with a Sell Offer of \$0/MW-day and settled in accordance with the provisions specified in Tariff, Attachment DD, sections 5.3, 5.4 and 5.14. To the extent there is a reduction in Accredited UCAP for such resources between the Base Residual Auction and Third Incremental Auction, PJM will adjust the quantity that it seeks to procure or release in the Third Incremental Auction in accordance with Tariff, Attachment DD, section 5.3 (b) (ii) and 5.4(c). Furthermore, such

¹¹ RPM Resource Commitments are placed on a resource when the resource clears or receives make-whole MWs through an RPM Auction, when the resource is specified as a replacement resource, or when the resource is used as the source of a Locational UCAP transaction.

resources shall not be subject to the rights and obligations of a committed Capacity Resource, and shall not be eligible for Non-Performance Charges or bonus payments. The performance and cleared Unforced Capacity of such Generation Capacity Resources shall also be excluded from the Balancing Ratio, as specified in Tariff, Attachment DD, section 10A.

4.3 Load Management Products

Load management is the ability to reduce metered load, either manually or automatically by the customer, after a request from the resource provider which holds the load management rights or its agent.

A load management program (e.g., Firm Service Level (FSL) or Guaranteed Load Drop (GLD) program) is eligible to (1) be offered by a resource provider as a Demand Resource (DR) into the Base Residual Auction or an Incremental Auction and is paid the applicable LDA product-specific Resource Clearing Price if such resource clears in the auction; or (2) be committed by an FRR Entity to an FRR Capacity Plan.

4.3.1 Requirements of Load Management Products in RPM

In order to offer a Demand Resource in an RPM Auction or commit a Demand Resource in an FRR Capacity Plan, a demand resource provider must submit no later than 30 days prior to the RPM Auction or prior to the deadline for submitting the FRR Capacity Plan a Demand Resource Sell Offer Plan (DR Sell Offer Plan) in accordance with Attachment C of this Manual. Actual deadline date for a DR Sell Offer Plan for an RPM Auction or FRR Capacity Plan is provided in the RPM Auction Schedule posted on the PJM website. A demand resource provider with a PJM approved DR Sell Offer Plan for the RPM Auction will be permitted to offer their Demand Resource(s) into such RPM Auction or commit such Demand Resource in an FRR Capacity Plan, provided the additional demand resource requirements in section 4.3.3 are met.

Demand resources that clear in an RPM Auction will have an RPM Resource Commitment for the relevant Delivery Year. Demand resources that are committed to an FRR Capacity Plan will have an FRR Capacity Plan Commitments for the relevant Delivery Year. A resource provider who has RPM Resource Commitments or FRR Capacity Plan Commitments for their demand resource must meet the following requirements:

- Must be registered in the Pre-Emergency or Emergency Load Response Program (see more detail below in the Pre-Emergency and Emergency Load Response Registration section) prior to the start of the relevant Delivery Year.
- Have the capability to retrieve electronic messages from PJM which notify curtailment service providers of a load management event in accordance with **PJM Manual 1: Control Center and Data Exchange Requirements**.
- Provide (or contract with another party to provide) customer-specific compliance and verification information within 45 days after the end of the month in which a Performance Assessment Interval occurred, in accordance with the Measuring Compliance during

Performance Assessment Interval section, Section 8.6 of this manual. Provide (or contract with another party to provide) customer-specific compliance and verification information in accordance with the timelines established in the Load Management Test Compliance section, Section 8.7 of this manual. Statistical sampling may be used instead of customer-specific compliance and verification information for residential customers without interval metering when approved by PJM in accordance with **PJM Manual 19: Load Forecasting & Analysis, Attachment D**.

- Provide load drop estimates for all Load Management events (whether initiated by PJM or the resource provider) and provider initiated test event, in accordance with **PJM Manual 19: Load Forecasting & Analysis**.
- Provide accurate estimates of the amount of energy that will be reduced in direct response to PJM dispatch of demand response during the Delivery Year (see more detail in the Load Reduction Reporting section).

These requirements are described in terms of the customer response and qualifications. The specifics of the customer contract and tariffs are the responsibility of the resource provider and the regulatory process. PJM does not have direct involvement with customers.

The entity requesting load management must verify that each customer's load management meets the following criteria:

- Availability for PJM-initiated interruptions in accordance with the availability requirements of the demand resource product type.
 - Capacity Performance DR – Capacity Performance DR is available for an unlimited number of interruptions during the Delivery Year, and will be capable of maintaining each such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time for the months of June through October and the following May, and 6:00AM through 9:00PM Eastern Prevailing Time for the months of November through April unless there is an Office of the Interconnection approved maintenance outage during October through April.
 - Summer-Period DR – Summer-Period DR is available for an unlimited number of interruptions during an extended summer period of June through October and the following May, and will be capable of maintaining such interruption between the hours of 10:00AM to 10:00PM Eastern Prevailing Time.
- Load management must be able to be implemented within two hours of notification to the resource provider of a PJM-initiated load management event. Load management is required to fully respond within 30 minutes of notification unless an exception request for 60 or 120 minutes notification time is approved by PJM. If qualified for one of the following exceptions, then CSP shall elect either 60 minute or 120 minute lead time based on the resources physical capability to provide the load reduction:
 - The manufacturing processes for the Demand Resource Registration require gradual reduction to avoid damaging major industrial equipment used in the manufacturing

- process, or damage to the product generated or feedstock used in the manufacturing process; or
- Transfer of load to back-up generation requires time-intensive manual process taking more than 30 minutes; or
- On-site safety concerns prevent location from implementing reduction plan in less than 30 minutes; or
- The Demand Resource Registration is comprised of mass market residential customers or similarly situated mass market small commercial customers which collectively cannot be notified of a Load Management event within a 30-minute timeframe due to unavoidable communications latency, in which case the requested notification time shall be no longer than 120 minutes.
- The intent of these exemptions is to accommodate Demand Resource Registrations with legitimate, physical reasons as to why the load reduction cannot be achieved in the default, 30 minute notification time period and require up to 120 minutes to fully provide the load reduction. CSP must provide additional data and information within three business days of PJM request to substantiate the request for a longer lead time (60 or 120 minutes). PJM will make its determination within ten business days of receiving such additional information regarding the appropriate lead time for the registration.
- Initiation of load interruptions upon request of PJM must be within the authority of the resource provider dispatcher without any additional approvals being required.

4.3.2 Types of Load Management Programs

PJM recognizes three types of Load Management programs:

- Firm Service Level (FSL) – Load management achieved by a customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the resource provider's market operations center or its agent.
- Guaranteed Load Drop (GLD) – Load management achieved by a customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the resource provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

For each type of recognized Load Management Program, there can be three notification periods:

- 30 Minute Lead Time – Load management which must be fully implemented in 30 minutes or less from the time the PJM dispatcher notifies the market operations center of a curtailment event.
- 60 Minute Lead Time – Load management which requires more than 30 minutes but no more than one hour, from the time the PJM dispatcher notifies the market operations center of a curtailment event, to be fully implemented.

- 120 Minute Lead Time - Load management which requires more than one hour but no more than two hours, from the time the PJM dispatcher notifies the market operations center of a curtailment event, to be fully implemented.

4.3.3 Demand Resources

Both Existing and Planned Demand Resources may participate in RPM Auctions or commit to FRR Capacity Plan if a demand resource provider has a PJM approved Demand Resource Sell Offer Plan.

Existing Demand Resources are those MWs on a demand resource identified in a pre-registration process in the Capacity Exchange system prior to the RPM Auction.¹² The Nominated DR Values (in MWs) associated with end-use customer sites that the Curtailment Service Provider (CSP) has under contract for the current Delivery Year (i.e., end-use customer sites registered in PJM DR Hub system for the current Delivery Year)¹³ and that the CSP intends to have under contract for the auction Delivery Year are considered Existing MWs. The summer Nominated DR Value of a Demand Resource Registration is used in the calculation of Existing MWs. A CSP may request an adjustment to the summer Nominated DR Value (in MWs) associated with an end-use customer site and used in the determination of a CSP's Existing MWs if the following three criteria are satisfied:

- The original Nominated DR Value for the end-use customer was determined based on one registration in DR Hub.
- The peak load contribution (PLC) reported in the DR Hub registration for the end-use customer is at least 2 MW lower than it should have been due to an anomaly. An anomaly is a condition at the end-use customer site that resulted in significantly low usage that is not expected to occur in the future, such as a lighting strike or a major mechanical failure to an end use device.
- The CSP provides supporting information including historical load data to support an adjustment to the Nominated DR Value for the end-use customer.

A CSP request for an adjustment to the summer Nominated DR Value of an end-use customer and supporting information must be submitted via email to rpm_hotline@pjm.com at least five business days prior to the opening of the pre-registration window in the Capacity Exchange system for an RPM Auction. PJM will notify the CSP of the approval or rejection of their request

¹² For an FRR Entity, a pre-registration process is performed manually through spreadsheets provided by PJM.

¹³ For a Base Residual Auction and a Third Incremental Auction, end-use customer sites registered in the PJM DR Hub system for the subsequent Delivery Year may also be considered as existing DR provided the registrations are in "Confirmed" status by specified deadlines established by PJM and communicated to CSPs in advance of the DR Sell Offer Plan submittal deadline.

prior to the opening of the pre-registration window in the Capacity Exchange system for an RPM Auction.

Planned Demand Resources are defined as resources that do not currently have the capability to provide reduction in demand or to otherwise control load in PJM, but that is scheduled to be capable of providing such reduction or control on or before the start of the Delivery Year. Planned Demand Resources are those MWs on a demand resource that the CSP intends to offer in the RPM Auction or commit to an FRR Capacity Plan in excess of the CSP's Existing MWs on such demand resource.

Note:

Planned Demand Resources must establish an RPM Credit Limit prior to an RPM Auction. Credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction.

A resource provider may offer Demand Resources (Planned or Existing) associated with Behind the Meter Generation for an entire Delivery Year into the Base Residual or Incremental Auctions. If the DR offer clears in an RPM auction for a given Delivery Year, the operating Behind the Meter Generation cannot be netted from load for the purposes of calculating the Peak Load Contributions for the subsequent Delivery Year in accordance with ***Generator Operational Requirements Manual (M-14D), Appendix A: Behind the Meter Generation Business Rules***.

If offering as a Demand Resource in the Base Residual Auction or Incremental Auction, a sell offer must be submitted in the Base Residual Auction or Incremental Auction. Demand Resources offered and cleared in a Base Residual or Incremental Auction will receive the corresponding LDA product-specific Resource Clearing Price determined by the optimization algorithm.

4.3.4 Demand Resource Modifications (DR Mods)

A Demand Resource Modification (DR MOD), a type of Capacity Exchange transaction, can be used to track an increase or decrease of the nominated value of a provider's DR Resource in the Capacity Exchange system. DR MODs are no longer submitted by DR Providers. PJM may submit a DR MOD for an FRR Entity to establish the Daily Nominated DR Value for an FRR Entity's Demand Resource based on PJM's approval of the FRR Entity's DR Sell Offer Plan. After the Delivery Year demand resource registration process begins in the DR Hub system, the Daily Nominated DR Value for a Demand Resource is established based on confirmed Demand Resource Registrations in "completed" status linked to the DR Resource in the DR Hub system. The Daily Nominated DR Value for a Capacity Performance Demand Resource during the summer period of June through October and May of the Delivery Year is based on the sum of the summer nominated DR values of the registrations linked to such Demand Resource. The Daily Nominated DR Value for a Demand Resource during the non-summer period of November through April is based on the lesser of (a) the sum of the summer nominated DR values of the

registrations linked to such Demand Resource or (b) the sum of the winter nominated DR values of the registrations linked to such Demand Resource.

4.3.5 Pre-Emergency and Emergency Load Response Registration

Pre-Emergency and Emergency Load Response Registration is the process of providing the following information through the submittal of a Pre-Emergency or Emergency Load Response registration into PJM's DR Hub system. As part of this process, resource providers will submit the following types of information:

- Customer-specific load management information for planning and verification purposes (i.e., EDC account number, Zone, etc.)
- Customer-specific information to establish nominated load management levels (i.e., Peak Load Contribution, Winter Peak Load, EDC Loss Factor, notification period, Firm Service Level data (summer and winter), Guaranteed Load Drop data (summer and winter). Winter Peak Load and winter Firm Service Levels are required for Capacity Performance DR registrations. However, Winter Peak Load and winter Firm Service Levels are not required if such registration indicates that it is a Summer-Period DR Only registration. Economic, Pre-Emergency, or Emergency Load Response registrations that would like to be eligible for Bonus Performance for a Performance Assessment Interval must have both customer-specific summer and winter based data provided in the registration.
- Demand Resource name to link the Demand Resource Registration to the appropriate Demand Resource modeled in the Capacity Exchange system.
- Load Management product type for customer site (Capacity Performance DR, Summer-Period DR¹⁴).
- A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process

A resource provider who has RPM or FRR Resource Commitments for their demand resource must register customers in the Full Program Option or as a Capacity Only Option of the Emergency Load Response or Pre-Emergency Load Response Program.

The Full Program and Capacity Only Option enable a resource provider that has approved registrations for the Delivery Year prior to the applicable registration deadline to receive capacity credits, in the form of RPM Auction Credits, if the resource provider cleared their demand resource in an RPM Auction, for that Delivery Year. Full Program Option resource providers

¹⁴ Summer-Period DR is included in Capacity Performance DR registration when a Nominated DR Value based on summer data is greater than Nominated DR Value based on winter data. If Summer-Period DR Only is checked on the registration, such registration is only required to provide Nominated DR Value based on summer capability when dispatched in the summer period. If Summer-Period DR Only is not checked on the registration, the registration is required to provide Nominated DR Value based on summer capability and Nominated DR Value based on non-summer capability.

may claim an energy settlement for a PJM-initiated Load Management Event. Capacity Only Option resource providers may not claim an energy settlement for a PJM-initiated Load Management Event for Capacity Only Option registrations.

Customer sites registered in the Energy Only Program are not eligible to receive capacity credits.

A provider with RPM or FRR Resource Commitments for their Demand Resource must register customer sites that are the Capacity Performance product-type.¹⁵

A completed Load Response registration in DR Hub for a DR resource must be submitted no later than one day before the tenth business day preceding the relevant Delivery Year. All registrations that have not been approved on or before May 31st preceding the relevant Delivery year shall be rejected by PJM.

Full details of the Pre-Emergency and Emergency Load Response registration and approval process may be found in ***Energy & Ancillary Services Market Operations Manual (M-11), Section 10.***

4.3.6 End-Use Customer Aggregation

A resource provider may aggregate multiple end-use customer sites to create a single Demand Resource for the purposes of submitting an offer in the RPM Auctions, if all the end-use customer sites have the same following characteristics:

- Curtailment Service Provider
- Electric Distribution Company (EDC)
- Transmission Zone (or sub-zonal LDA)

The mechanism for aggregating end-use customer sites to create a single Demand Resource is to select the same Demand Resource for multiple end-use customer sites during the registration process.

4.3.7 Determination of Nominated Values for Load Management

Once an end-use customer is registered in the Pre-Emergency or Emergency Load Response Program (Full Program Option or Capacity Only), a nominated load reduction value is calculated for that customer. A summer and winter nominated load reduction value may be calculated for a registration depending on the product-type registration and Delivery Year. The determination of the value of the load reduction is consistent with the process for determination of the capacity obligation for the customer. Nominated value of a load management resource is equivalent to the Installed Capacity value of a generation resource.

¹⁵ A Capacity Performance product-type registration includes Summer-Period DR when a Nominated DR Value based on summer data is greater than Nominated DR Value based on winter data.

For an end-use customer registration, the summer nominated DR value for the registration is based on the Peak Load Contribution in place at the time of the registration in the DR Hub system. The winter nominated DR value for a Capacity Performance registration is based on the Winter Peak Load at the time of the registration in the DR Hub system.

Nominated Value of Firm Service Level Resources

A registration for a Firm Service Level (FSL) customer includes a summer nominated DR value. Registrations of the Capacity Performance product-type also include a winter nominated DR value.

The summer nominated DR value for a Firm Service Level customer on Capacity Performance DR and Summer-Period DR Only product-type registrations is equal to the difference between its Peak Load Contribution (PLC) and its pre-determined summer firm service level load adjusted for system losses.

$$\text{Summer Nominated Value of FSL Customer} = \text{PLC} - (\text{SFSL} * \text{LossF})$$

Where:

PLC	the customer's EDC-assigned Peak Load Contribution;
SFSL	Summer Firm Service Load level;
LossF	the customer's EDC-assigned loss factor.

The winter nominated DR value for a Firm Service Level customer on a Capacity Performance product-type registration is calculated as (Winter Peak Load for customer multiplied by Zonal Winter Weather Adjustment Factor minus winter Firm Service Level) times the loss factor.

If a Capacity Performance product-type registration indicates that such registration is for Summer-Period DR Only, the winter nominated DR value for a Firm Service Level registration will be zero.

The Winter Peak Load is determined by the Curtailment Service Provider based on the average of the Demand Resource customer's specific peak hourly load between hours ending 7:00 EPT through 21:00 EPT on the PJM defined 5 coincident peak days from December through February two Delivery Years prior to the Delivery Year for which the registration is submitted. Notwithstanding, if the average use between hours ending 7:00 EPT through 21:00 EPT on a winter 5 coincident peak day is below 35% of the average hours ending 7:00 EPT through 21:00 EPT over all five of such peak days, then up to two such days and corresponding peak demand

values may be excluded from the calculation. If no hourly load data exists for December through February two Delivery Years prior to the Delivery Year, or if more than two days meet the exclusion criteria, then the CSP may use the most recent December through February hourly load data to calculate the Winter Peak Load, upon PJM verification. If no hourly load data for the customer exists for the last two December through February periods prior to the Deliver Year, or if more than two days meet the exclusion criteria for the last two December through February periods prior to the Delivery Year, the CSP may provide alternative data to support a Winter Peak Load subject to PJM's review and approval of the use of alternative data.

The Zonal Winter Weather Adjustment Factor is equal to the zonal winter weather normalized peak divided by the zonal average of five coincident peak loads in December through February. PJM posts the RTO winter 5 CP days on the PJM website. PJM calculates and posts the Zonal Winter Weather Adjustment Factors on the PJM website.

Nominated Value of Guaranteed Load Drop Resources

A registration for a Guaranteed Load Drop (GLD) customer includes a summer nominated DR value. Registrations of the Capacity Performance product-type also include a winter nominated DR value and an annual nominated DR value.

The summer nominated DR value for a Guaranteed Load Drop customer on a Capacity Performance DR and Summer-Period DR Only product-type registrations will be the summer guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the resource provider. The summer nominated value shall not exceed the customer's Peak Load Contribution.

$$\text{Summer Nominated Value of GLD} = \text{SGLD} (\text{LossF})$$

Where:

GLD	Customer's Summer Guaranteed Load Reduction;
LossF	the customer's EDC-assigned loss factor.

The winter nominated DR value for a GLD customer on a Capacity Performance product-type registration shall equal the winter guaranteed load drop amount multiplied by the loss factor, as established by the customer's contract with the resource provider. The winter nominated DR value shall not exceed the Winter Peak Load for customer multiplied by Zonal Winter Weather Adjustment Factor times the loss factor. If a Capacity Performance product-type registration indicates that such registration is for Summer-Period DR Only, the winter nominated DR value for the GLD customer on the registration will be zero.

4.3.8 Determination of the UCAP Value of Load Management

Prior to the 2025/2026 Delivery Year, unforced capacity (UCAP) value of a Load Management product is equal to the Nominated Value of that product multiplied by the Forecast Pool Requirement.

$$UCAPValue_{LM} = NominatedValue * FPR$$

Beginning with the 2025/2026 Delivery Year, the unforced capacity (UCAP) value of a Load Management product is equal to the Nominated Value of that product multiplied by the applicable ELCC Class Rating.

$$UCAPValue_{LM} = Nominated\ Value * applicable\ ELCC\ Class\ Rating$$

4.3.9 Load Reduction Reporting

PJM requires an accurate estimate of the amount of energy that will be reduced in direct response to PJM dispatch of Pre-Emergency and Emergency Demand Response capacity resources. This information will be used by PJM to determine the amount of DR resources to dispatch during a pre-emergency or emergency event. The Curtailment Service Provider will contact DR resources, as necessary, to determine a reasonably accurate load reduction capability. The CSP will analyze and review the load reduction capability on a periodic basis to ensure it is reasonably accurate before it is provided to PJM.

Load Reduction Capability

The Load Reduction Capability provided by the CSP should represent the expected future incremental load reduction of energy that will be provided by the DR resources if dispatched by PJM under pre-emergency or emergency conditions. The Load Reduction Capability should only include energy load reductions expected to occur if a pre-emergency or emergency DR event is declared. This is independent of the committed capacity MW on the registration(s) and represents the operational expectations regarding the ability to reduce load for the specific time period. The Load Reduction Capability should not include load reductions that have already occurred or are already planned such as the following:

- Planned or unplanned outages at the facility
- Load reductions based on high expected prices, peak shaving or existing contract provisions

PJM will adjust, downward, the reported Load Reduction Capability values to account for any real time or day ahead economic market dispatch that has been assigned to the registered

location(s) by PJM. The difference between the Load Reduction Capability and any economic dispatch reductions will indicate the estimated load reductions still available and able to respond to a PJM call for Pre-Emergency or Emergency DR.

Reporting

Curtailment Service Providers that have active Full Program Option or Capacity Only registrations shall provide PJM the Load Reduction Capability by zone, by lead time, and by product-type on a monthly basis, to be submitted by the last business day of a given month and effective on the first business day of the following month. During the months of June through September, CSPs will provide any updates to this information for each day by no later than 4 p.m. on the day prior to the operating day.

On days for which a Maximum Emergency Generation/Load Management Alert or Action has been issued as communicated through the PJM ALL CALL and/or published on Data Viewer emergency messages, the Curtailment Service Provider shall on an hourly basis provide any updates to their information for the remaining hours of the day beginning at 10 a.m. and continuing until 7 p.m.

The Curtailment Service Provider shall submit the information electronically to the appropriate PJM system.

4.3.10 Maintenance Outage Reporting for Annual Demand Resource

A Capacity Performance product Pre-Emergency or Emergency Load Response registration may request a maintenance outage during the months of October through April. The maintenance is defined as:

- maintenance to a device or generator used to reduce load at the end use customer location that cannot be reasonably scheduled outside of the annual product availability window, or
- maintenance of a CSP's system used to dispatch DR, but such maintenance shall be limited to no more than two times per quarter, shall not exceed one day in duration, and shall be on a Saturday or Sunday.

The outage request must be submitted at least four business days before the requested start date in the appropriate PJM system and will be evaluated on a first come first served basis. If a request is submitted less than four business days in advance, PJM may approve the request up to one day prior to operating day. The maintenance outage must be between one and thirty days and an extension may be requested during an approved outage at least four business days before the beginning of the extension period. PJM may deny a maintenance outage request if the outage is expected to create reliability issues. A maintenance outage denied by PJM may be resubmitted by the CSP to request another time period for the outage. CSPs should make a best effort not to request outages during weekday Capacity Performance product availability hours for the months of January and February. A CSP may cancel maintenance

outage at any time and the associated registration(s) will be required to respond to a PJM initiated Load Management Event and shall be measured for event compliance or Non-Performance Assessment if the event or Performance Assessment Interval starts after PJM receives the cancellation. PJM may cancel a previously approved maintenance outage one day prior to the start of the outage for reliability concerns.

A registration associated with an approved maintenance outage that is in effect during a Performance Assessment Interval will not be considered as dispatched for such Performance Assessment Interval.

4.4 Energy Efficiency Resources

An Energy Efficiency (EE) Resource is a project that involves the installation of more efficient devices/equipment, or the implementation of more efficient processes/systems, exceeding then current building codes, appliance standards, or other relevant standards, at the time of installation, as known at the time of commitment, and meets the requirements of **Schedule 6 (section L) of the Reliability Assurance Agreement**. The EE Resource must achieve a permanent, continuous reduction in electric energy consumption at the End Use Customer's retail site (during the defined EE Performance Hours and during winter performance period if such EE Resource is a Capacity Performance Resource) that is not reflected in the peak load forecast used for the Auction Delivery Year for which the EE Resource is proposed. The EE Resource must be fully implemented at all times during the Delivery Year, without any requirement of notice, dispatch, or operator intervention.

Because energy efficiency measures are reflected in the peak load forecast for a Delivery Year for which an auction is being conducted, the auction parameters must be adjusted through the 2025/2026 Delivery Year, as described in Section 2.4.5, for the EE Resource(s) that are proposed for that auction in order to avoid double-counting of the energy efficiency measures.

The EE Performance Hours are defined as the hours between the hour ending 15:00 Eastern Prevailing Time (EPT) and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year, that is not a weekend or federal holiday.

An EE installation is eligible to offer through the 2025/2026 Delivery Year into an RPM auction or commit to an FRR Capacity Plan if it meets the following criteria:

- EE installation must be scheduled for completion prior to DY;
- EE installation is not reflected in peak load forecast used for the auction for which the EE is offered (is not reflected in peak load forecast used as basis for FRR Capacity Plan requirements if committing to an FRR Capacity Plan);
- EE installation exceeds relevant standards at time of installation as known at time of commitment;
- EE installation achieves load reduction during defined EE Performance Hours; and

- EE installation is not dispatchable¹⁶.

An Existing EE Resource is defined as an EE Resource with a PJM approved Post-Installation Measurement & Verification (M&V) Report. A Planned EE Resource is defined as an EE Resource that does not have a PJM approved Post-Installation M&V Report.

If cleared in an RPM Auction, a Capacity Performance EE Resource will receive a Capacity Performance Resource Clearing Price for the LDA in which the EE Resource resides and a Summer-Period EE Resource will receive a Resource Clearing Price applicable to the EE Provider's cleared Seasonal Capacity Performance sell offer as described in Section 4.10 of this manual.

An EE Resource may participate in RPM Auctions or commit to FRR Capacity Plan for a maximum of up to four consecutive Delivery Years. The time period of an Energy Efficiency installation determines whether an installation is eligible to be a capacity resource for a Delivery Year. The time period of Energy Efficiency installations and their associated eligibility, in addition to the modeling of EE Resources in the PJM Capacity Market, is presented in ***PJM Manual 18B: Energy Efficiency Measurement & Verification***.

An EE Resource must meet the following minimum requirements:

- Submit Initial Measurement & Verification (M&V) Plan no later than 30 days prior to RPM Auction in which the EE Resource is initially offered or 30 days prior to the FRR Capacity Plan in which the EE Resource is initially offered;
- Submit Updated M&V Plan no later than 30 days prior to next RPM auction in which EE Resource is subsequently offered or no later than 30 days prior to next FRR Capacity Plan update in which the EE is subsequently committed;
- Submit a completed Nominated EE Value Template with the M&V Plan using the current Nominated EE Value Template posted on the PJM website;
- Establish credit with PJM Credit Department prior to RPM Auction or prior to committing EE Resource to FRR Capacity Plan (for Planned EE Resources);
- Submit Initial Post-Installation M&V Report no later than 15 business days prior to first Delivery Year that the EE Resource is committed;
- Submit Updated Post-Installation M&V Reports no later than 15 business days prior to each subsequent Delivery Year that the EE Resource is committed; and
- Permit Post- Installation M&V Audit(s) by PJM or Independent Third Party.

PJM Manual 18B: Energy Efficiency Measurement & Verification establishes the requirements for the Initial M&V Plan, Updated M&V Plans, Initial Post-Installation M&V Report, Updated Post-Installation M&V Reports, and the M&V Audit.

¹⁶ Dispatchable demand may be offered as a Demand Resource in the PJM Capacity Market.

The following rules apply for Energy Efficiency Resources to facilitate the implementation of any restrictions that may be imposed on Energy Efficiency Resources by a Relevant Electric Retail Regulatory Authority (RERRA) authorized by FERC to opt-out and restrict the sale of Energy Efficiency Resources into PJM Capacity Market (i.e., the Authorized RERRA).

- If a RERRA receives FERC authorization to qualify or prohibit Energy Efficiency Resource participation in a specific area(s) of PJM the following process applies:
 - PJM will publicly post a reference to the FERC authorization of a RERRA order, ordinance or resolution that qualifies or prohibits Energy Efficiency Resource participation, the applicable EDC(s), and applicable auction(s), and/or Delivery Years.
 - A Capacity Market Seller that intends to offer or certify Energy Efficiency Resources must identify and itemize all resources located in the jurisdiction of the Authorized RERRA within the Zone or LDA, as required, and those outside the area but within the Zone or LDA, as required, in the such Seller's Energy Efficiency M&V Plan for the Delivery Year RPM Auction or Seller's Delivery Year Post-Installation M&V Report.
 - PJM shall provide a list of Capacity Market Sellers to the relevant EDC for the specific area(s) to review compliance with the Authorized RERRA. PJM shall provide the list of Capacity Market Sellers within two business days after the deadline for submitting an EE M&V Plan for a DY Auction and within two business days of receipt of Delivery Year Post Installation M&V Report.
 - The relevant EDC shall review compliance with the rules from an Authorized RERRA and provide a response to PJM within five business days after receiving the list of Capacity Market Sellers offering or certifying EE Resources.
 - PJM shall not allow a Capacity Market Seller to offer or certify EE Resources if an EDC denies such Capacity Market Seller to deliver EE Resources in compliance with rules of Authorized RERRA.

A Capacity Market Seller that cannot satisfy its obligations for the relevant Delivery Year due to the prohibition of participation by Authorized RERRA may be relieved of its Capacity Resource Deficiency Charge by notifying PJM no later than seven calendar days prior to the posting of the Planning Parameters for the Third Incremental Auction of such Delivery Year. After providing such notice, the affected Capacity Market Seller shall not be required to obtain replacement capacity for the affected EE Resource and no Capacity Resource Deficiency Charges shall be assessed for the Seller's deficiency in satisfying its RPM obligation for such EE Resource for the relevant Delivery Year. The Capacity Market Seller shall not be entitled to, nor be paid, any RPM Auction Credits for such EE Resource for the relevant Delivery Year. PJM shall apply corresponding adjustment to the quantity of PJM Buy Bids or Sell Offers in the Third Incremental Auction for such Delivery Year.

4.4.1 Determination of Nominated Value of EE Resource

The Nominated EE Value of an EE Resource is the expected average demand (MW) reduction during the defined EE Performance Hours in the Delivery Year. EE Resources that qualify as a Capacity Performance product type shall also have an expected average load reduction during

winter performance period (i.e., all days from January 1 through February 28, inclusive, of such Delivery Year that is not a weekend or federal holiday, between the hour ending 8:00 EPT and hour ending 9:00 EPT, and between the hour ending 19:00 EPT and hour ending 20:00 EPT), that is not less than the Nominated EE Value determined during the defined EE Performance Hours. If the Nominated EE Value determined during the defined EE Performance hours is greater than the expected average demand during the defined winter hours, the expected demand during the defined winter hours will be the Capacity Performance value of the Capacity Performance EE Resource. The Nominated EE Value of a Summer-Period Energy Efficiency Resource is the expected average demand reduction during the defined EE Performance Hours in the Delivery Year. The minimum Nominated EE Value accepted in the PJM Capacity Market is 0.1 MW.

The Measurement & Verification (M&V) Plan describes the methods and procedures for determining the Nominated EE Value of an EE Resource (value based on load reduction provided during EE Performance Hours) and the Capacity Performance value (value based on the consideration of load reduction provided during EE Performance Hours and winter performance period) and confirming that the Nominated EE Value and Capacity Performance value is achieved.

The Nominated EE Value approved by PJM in EE Resource Provider's Initial/Updated M&V Plan establishes the Nominated EE Value that may be offered in an RPM Auction or committed to an FRR Capacity Plan (on a summer period basis). The Capacity Performance value approved by PJM in the EE Resource Provider's Initial/Updated M&V Plan provides guidance to the EE Resource Provider on the maximum amount of MWs that should be offered in Capacity Performance Offer Segments or committed as Capacity Performance in an FRR Capacity Plan on an annual basis.

The last Post-Installation M&V Report submitted and approved by PJM prior to the Delivery Year that the EE Resource is committed establishes the final Nominated EE Value and final Capacity Performance value that is used to measure RPM Commitment Compliance and FRR Capacity Plan compliance during the Delivery Year. Failure to submit an Initial/Updated Post-Installation M&V Report or failure to demonstrate that post-installation M&V activities were performed in accordance with the timeline in the approved M&V Plan will result in a final Nominated EE Value and final Capacity Performance value equal to zero MWs for the relevant Delivery Year. If an M&V Audit is performed and results finalized prior to the start of a Delivery Year, the Nominated EE Value or Capacity Performance value confirmed by the Audit becomes the final Nominated EE Value or final Capacity Performance value that is used to measure RPM Commitment Compliance during the Delivery Year. If the M&V Audit is performed and results finalized after the start of a Delivery Year, the Nominated EE Value or Capacity Performance value confirmed by the M&V Audit becomes the basis to determine if any incremental RPM Commitment Compliance Shortfall needs to be assessed retroactively from June 1 of the Delivery Year to May 31 of the Delivery Year.

4.4.2 Determination of the UCAP Value of EE Resource

The UCAP value of a Capacity Performance Resource is the Capacity Performance value of the EE Resource multiplied by the Forecast Pool Requirement. The UCAP value of a Summer Period Energy Efficiency Resource is Nominated EE Value multiplied by the Forecast Pool Requirement.

$$UCAPValue_{CP\ EE} = Capacity\ Performance\ Value * FPR$$

$$UCAPValue_{SummerPeriod\ EE} = NominatedEEValue * FPR$$

4.4.3 Energy Efficiency Resource Modifications (EE MODs)

An Energy Efficiency Modification (EE MOD), a type of Capacity Exchange transaction, is used to track an increase or decrease of the EE Nominated Value of a provider's EE Resource in the Capacity Exchange system. EE MODs are no longer submitted by EE Resource Providers. Prior to the commitment of an EE Resource to an FRR Entity's FRR Capacity Plan, PJM submits an EE MOD in the Capacity Exchange system to represent the Nominated EE Value of an EE Resource to be effective June through October and May of the Delivery Year and an EE Mod to represent the Capacity Performance Value of an EE Resource to be effective for November through April of the Delivery Year based on an EE Provider's approved initial/updated EE M&V Plan. Prior to the Delivery Year, PJM submits an EE MOD to represent the final Nominated EE Value of an EE Resource to be effective for June through October and May of the Delivery Year and an EE MOD to represent the Capacity Performance value of the EE Resource to be effective for November through April of the Delivery Year based on PJM's approval of the provider's Post Installation M&V Report for such Delivery Year.

4.5 Qualified Transmission Upgrades

A Qualifying Transmission Upgrade may be offered into the Base Residual Auction to increase import capability into a transmission-constrained LDA (Sink LDA) from a Source LDA. Such transmission upgrade must meet the following minimum requirements.

- Must have been approved and an incremental import capability value must have been assigned by the PJM Planning Department at least 45 days prior to the auction.
- The planned transmission upgrade in-service date must be on or before the start of the Delivery Year.
- At a minimum, Upgrade Customers must be in the Facilities Study phase for the proposed transmission upgrade, in order for approval to be granted and the transmission upgrade must conform to all applicable standards of the PJM Regional Transmission Expansion Planning Process.
- Qualified Transmission Upgrades must establish an RPM Credit Limit prior to an RPM Auction.

- Credit requests should be made to PJM's Treasury Department at least two weeks prior to an RPM Auction.

If a Qualifying Transmission Upgrade that was cleared in the Base Residual Auction is not completed by the start of the Delivery Year, the party who submitted the offer shall provide a replacement in the form of an equivalent amount of capacity resource of the Capacity Performance product type within the Sink LDA by the start of the delivery Year. If replacement capacity is not provided, a Transmission Upgrade Delay Penalty shall apply.

A Qualifying Transmission Upgrade that cleared in the Base Residual Auction will be paid the Locational Price Adder of the Sink LDA less the Locational Price Adder of the Source LDA, multiplied by the megawatt quantity of incremental import capability cleared. A cleared Qualifying Transmission Upgrade is not automatically included in CETL analysis for future delivery years.

Once the Qualifying Transmission Upgrade is in service, the Qualifying Transmission Upgrade is no longer eligible to continue to offer the approved incremental import capability value into future RPM Auctions. Once in service, the transmission upgrade is included in the CETL analysis for future Delivery Years and the approved incremental import capability of the upgrade is valued as an Incremental Capacity Transfer Right as described in section 6.1.2 of this manual.

4.6 Bilateral Transactions

Bilateral Transactions in the Reliability Pricing Model are transactions for capacity between a buyer and seller. Bilateral Transactions may be reported to PJM for inclusion in the PJM billing process for unit-specific capacity or Auction Specific MW capacity. Parties in all bilateral transactions reported to PJM agree to indemnify PJM against non-performance by their counterparties in such transactions.

PJM posts reference prices at various points in order to facilitate bilateral trading on the part of market participants. The posted pricing points include LDA and Hub pricing points (associated with a Base Residual Auction (BRA) Resource Clearing Price in a LDA), Net Load pricing points (associated with a Final Zonal Capacity Price less Final Zonal CTR Credit Rate), PZonal pricing points (associated with Preliminary Zonal Capacity Price), FZonal (associated with Final Zonal Capacity Price), and 1IA, 2IA, and 3IA pricing points (associated with a First Incremental Auction (1IA), Second Incremental Auction (2IA), or Third Incremental Auction (3IA) Resource Clearing Price in an LDA). The available pricing points and their definitions are posted on the PJM website.

Additional pricing points will be added by PJM if requested by stakeholders. However, the definition of the pricing points will remain static once created.

4.6.1 Unit-Specific Bilateral Transactions

The purpose of reporting a unit-specific bilateral transaction to PJM (regardless of the type of capacity transacted) is to transfer the rights to or control of a specified amount of installed capacity from the Seller to the Buyer. Bilateral contracts for unit-specific capacity resources may be offered into PJM's RPM if these products meet the requirements specified in this Manual.

PJM will provide electronic bulletin board functionality in Capacity Exchange. The bulletin board allows participants to post and view requests to buy or offers to sell capacity resources. The purpose of the bulletin board functionality is to facilitate bilateral transaction activity.

4.6.2 Entering Unit-Specific Bilateral Transactions

Unit-specific bilateral transactions reported to PJM may wholly or partially offset an LSE's Locational Reliability Charges in the PJM billing process provided that Available installed capacity purchased through the bilateral transaction is directly offered and cleared in a Base Residual Auction or Incremental Auction or is designated as a self-scheduled resource in a Base Residual Auction (i.e., the RPM Auction Credits received may offset the Locational Reliability Charges assessed in your PJM bill).

The smallest increment of installed capacity that may be reported to PJM as unit-specific transactions is 0.1 MW.

PJM does not recognize "slice of system" or unforced capacity credit bilateral transactions in RPM Auctions.

Both parties of a unit-specific transaction must confirm the transfer of installed capacity from the seller to the buyer via the Capacity Exchange system prior to the start date of the transaction.

Unit-specific transactions to an "External Party" (i.e., "EXT") must be in "Pending PJM" status two business days prior to the start date of the transaction.

All unit-specific bilateral transactions that cover the Delivery Year must be in "Provisionally Approved" or "Approved" status in the Capacity Exchange system prior to the opening of the Base Residual Auction or an Incremental Auction's bidding window in order for the transactions to be considered in a party's Generation Resource Position and the calculation of Available ICAP to offer for a Base Residual Auction or an Incremental Auction or to be used for self-scheduling in the Base Residual Auction.

Unit-specific transactions cannot be created during an RPM Auction's bidding window and clearing week.

Unit-specific transactions that are not in the "Approved" status by the start date of the transaction will have their status changed to "PJM Withdrawn".

Unit-specific bilateral transactions may be reported for the following installed capacity types: Available, Unoffered, or Cleared.

Unit specific transactions reported for either Available or Unoffered capacity must specify:

- The unit to be transacted
- A start and end date for the transaction
- An installed capacity (ICAP) MW value

Unit specific transactions reported for Cleared capacity must specify:

- The unit to be transacted
- A start and end date for the transaction
- The auction in which the unit cleared (Base Residual Auction, First Incremental Auction, Second Incremental Auction, Third Incremental Auction).
- The Capacity Performance offer segment-type applicable to the MWs cleared: Annual, Seasonal-summer, or Seasonal-winter
- The Resource Clearing Price applicable to the MWs cleared in Seasonal Capacity Performance Resource sell offer
- An unforced capacity (UCAP) MW value. Once approved, the unforced capacity MW value will be converted to an installed capacity MW value using the then-current Accredited UCAP Factor for the specified unit. The installed capacity MW value is capped at the ICAP Owned by the Seller.

The following are business rules that apply to Unit-Specific Bilateral Transactions:

- An Aggregate Resource may not be specified as a unit transacted in a Unit-specific transaction.
- If available capacity type is selected, the Capacity Exchange system will validate that the Seller has Daily Available ICAP to offer for the entire term of the transaction. The Daily Available ICAP to offer on a unit is equal to Daily ICAP Owned – Daily Unoffered ICAP - (Daily RPM Resource Commitments/(Accredited UCAP Factor)) – Daily FRR Capacity Plan Commitments.
- Available installed capacity purchased through a bilateral unit-specific transaction that is registered in PJM's Capacity Exchange system may be directly offered into the Base Residual Auction or Incremental Auctions or designated as a self-scheduled resource in the Base Residual Auction.
- If unoffered capacity type is selected, the Capacity Exchange system will validate that the Seller has Daily Unoffered ICAP to offer for the entire term of the transaction and validate that the Buyer is an External Party (EXT).
- The unoffered capacity type may be selected for a unit-specific bilateral transaction if selling a unit externally (formerly known as “delisting”) after the Base Residual Auction has been cleared for the specified transaction dates. To delist a unit before the Base Residual Auction has been run, a party may select the Available capacity type to transact installed capacity to an External Party (EXT).

- If cleared capacity is selected, the Capacity Exchange system will validate that the Seller has cleared capacity of the specified Capacity Performance offer segment-type from the specified auction to offer for the entire term of the transaction.
- An approved unit-specific transaction reported to PJM for Cleared capacity will result in a transfer of the applicable product-specific Auction Credit for the specified number of UCAP MW from the Seller to the Buyer for the entire term of the transaction. In addition, the applicable product-specific RPM Resource Commitment for the specified number of UCAP MWs is also transferred from the Seller to the Buyer for the entire term of the transaction.
- The Seller in a unit-specific transaction for cleared capacity will indemnify PJM Settlement, the LLC, and the Members for any failure by the Buyer of such transaction to pay deficiency penalties and charges owed to PJM Settlement and associated with the capacity that is the basis of the unit-specific capacity transaction for cleared capacity.
- To the extent that capacity identified in the unit-specific transaction for cleared capacity is a resource that has an RPM Credit Requirement, the Buyer must have sufficient credit in place with respect to the credit exposure associated with the obligations of the acquired RPM Resource Commitment.

4.6.3 Exporting a Generation Resource

Exporting (formerly known as “Delisting”) a generation resource is accomplished by reporting a bilateral transaction with “External Party” (i.e., “EXT”) listed as the “Buyer” in the unit-specific transaction.

Exporting any portion of a generation resource below a party’s Daily RPM Resource Commitments/(Accredited UCAP Factor) plus Daily FRR Capacity Plan Commitments for the term of the transaction is not permitted. Only Available or Unoffered ICAP on the unit may be exported.

Exporting of a generation resource may only be done by the party that submitted the Capacity Modification for the unit.

If a portion of a generation resource is to be exported, appropriate documentation must be submitted to PJM to demonstrate that the party exporting the generation resource has a financially and physically firm commitment to an external sale of its capacity and therefore, is exempt from the offer requirement for capacity resources in ***Attachment DD, Section 6.6 of the PJM Open Access Tariff***.

In order for a generation resource that is being exported to be reflected in a party’s Available ICAP Position for an RPM Auction, the associated unit-specific transaction must be in an “Approved” status by the opening of the RPM Auction’s bidding window.

Capacity Export Charge

A Capacity Export Transmission Customer may procure capacity in one PJM Zone and export the capacity from another Zone to outside PJM. Under the FERC approved tariff effective June 1, 2008, the Capacity Export Transmission Customer will pay a Capacity Export Charge and receive a credit similar to the CTR credit if the Final Zonal Capacity Price for the Zone encompassing the interface with the Control Area to which the capacity is exported is higher than the Final Zonal Capacity Price for the Zone in which the resource designated for the export is located. The Capacity Export Charge collected less the credit will be allocated to the LSEs in the Zone from which capacity is exported.

This Capacity Export Charge and credit are assessed daily and billed monthly. These calculations are independent from the CTR calculations based on Base Residual Auction and all Incremental Auctions. The LSE CTR credits and the Incremental CTR credits will not be changed due to Capacity Export Charge/credit calculations.

A Capacity Export Charge is applicable when Long-Term Firm Transmission Service is reserved from export source to export interface.

If more than one Zone forms the interface with the Control Area to which capacity is exported, the Export Reserved Capacity will be apportioned among the Zones. The Export Reserved Capacity is completely apportioned to the Zone if a fully controllable facility crosses the interface (e.g. dc line). The power flow distribution among multiple interface zones for a capacity export would be based on the PJM RTEP Base Power Flow case for the applicable Delivery Year. The power flow distribution calculations are done by modeling the de-listed generator as the source and the designated external load as the sink for the specific capacity exports to be analyzed.

Capacity Export Transmission Customer incurs for each day a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service multiplied by (the Final Zonal Capacity Price for the Zone encompassing the interface with the Control Area to which the capacity is exported minus the Final Zonal Capacity Price for the Zone in which the resource designated for the export is located).

To recognize the value of firm Transmission Service held, the Capacity Export Transmission Customer receives a credit similar to Capacity Transfer Rights (CTRs) credits. The credit is the Final Zonal Capacity price difference used in determining the Capacity Export Charge times Export Customer's Allocated Share of the Export Path Import.

4.6.4 Importing an External Generation Resource

Importing an external generation resource is accomplished by entering into a bilateral transaction with "External Party" (i.e., "EXT") listed as the "Seller" in the unit-specific transaction. A unit-specific transaction that represents a capacity import from an external resource that is offering as Capacity Performance product will not be granted a "Provisionally Approved" unit-specific transaction status until the requirements to offer as Capacity Performance in sections 4.2.2 or 4.2.4 are satisfied and will not be granted an "Approved" unit-specific transaction status until the pseudo-tie for such external resource is actually implemented and the external

resource has satisfied PJM's deliverability standards, which for a Prior CIL Exception External Resource may include completing the necessary actions to make a Prior CIL Exception External Resource Operationally Deliverable for the relevant Delivery Year. Demonstrating deliverability may require transmission upgrades on an external Transmission Provider's system or on PJM's system to be completed prior to June 1st of the delivery year.

See sections 4.2.2 and 4.2.4 for the requirements for offering existing or planned external generation resources into RPM Auctions.

Unit-specific transactions that are not in the "Approved" status by the start date of the transaction will have their status changed to "PJM Withdrawn".

Unit-specific transactions that are "Provisionally Approved" should refer to the RPM credit business rules for their associated credit requirements.

4.6.5 Treatment of Unit-Specific Capacity Transactions that Start/End Mid-Delivery Year

Unit-specific transactions reported with a Start Date that does not correspond to June 1 or an End Date that does not correspond to May 31 will result in installed capacity that cannot be offered into the Base Residual Auction since a single party does not own the installed capacity for the entire Delivery Year. In addition, this installed capacity will be tracked as Unoffered Capacity after the Base Residual Auction. To address this issue, PJM will facilitate a voluntary process to enable the installed capacity to be offered into the Base Residual Auction for the Delivery Year.

In order to participate, each party of the unit-specific transaction that starts/end Mid-Delivery Year must sign and submit a Self-Schedule Authorization Form found in Attachment B of this Manual, which authorizes PJM to self-schedule the capacity on behalf of the parties in the Base Residual Auction for the Delivery Year. The Authorization Form must be submitted to RPM_Hotline@pjm.com at least 5 business days prior to the opening of the bidding window.

Each party of the unit-specific transaction that starts/ends Mid-Delivery Year must submit a new unit-specific transaction in Capacity Exchange with "Self-Scheduling Coordinator (SELFSC)" as the Buyer prior to the opening of the Base Residual Auction bidding window, so the capacity will be transferred into the SELFSC account for the entire Delivery Year at the time of the Base Residual Auction.

Provided the Self-Schedule Authorization Forms are received and the required unit-specific transactions are submitted, PJM will self-schedule and clear the capacity on-behalf of the parties in the Base Residual Auction for the Delivery Year. The Accredited UCAP Factor at the time of the Base Residual Auction will be used in the resource-specific sell offer in the Base Residual Auction.

After the Base Residual Auction results are posted, PJM will submit unit-specific transactions for Cleared MWs with “SELFSC” as the Seller to transfer capacity back to the Parties (i.e., Buyer in the unit-specific transaction) for the appropriate time periods. No confirmation is required by the Buyer of the unit-specific transaction. The approved unit-specific transactions for Cleared MWs will result in the transfer of ICAP Owned, RPM Resource Commitments, and Auction Credits from the SELFSC account to the Buyer. The Buyer of the Cleared MWs is responsible for any Capacity Resource Deficiency Charges that may be assessed during the term of the unit-specific transaction. In addition, the Buyer of the Cleared MWs is responsible for their share of any Non-Performance Charges or Generation Resource Rating Test Failure Charges that may be assessed during the Delivery Year.

4.6.6 Auction Specific MW Transactions

RPM Market Participants have the ability to report Auction Specific MW Transactions to PJM through the Capacity Exchange system. Auction Specific MW Transactions must be for the transfer of physical MW of capacity from a seller to a buyer at the location of the physical resources identified as supplying the transaction.

The following are business rules that apply to Auction-Specific MW Transactions:

- Auction Specific MW Transactions are not eligible to be offered in an RPM auction.
- Auction Specific MW Transactions for a Delivery Year may be submitted following the completion of the RPM auction to which the transaction applies.
- Auction Specific MW Transactions may be submitted for MWs cleared for a seasonal period (summer or winter) of the Delivery Year following the completion of the RPM auction to which the transaction applies.
- Both the Buyer and the Seller of Auction Specific MW Transaction must confirm the Auction Specific MW Transaction via the Capacity Exchange system before the start date of the Delivery Year.
- An Auction Specific MW Transaction must specify the buyer, seller, start and end dates of the transaction.
- The Seller of the Auction Specific MW must also specify the resource(s) (generation resource, demand resource, or energy efficiency resource), Auction Type (Base, First, Second, Third, or Conditional), Capacity Performance offer segment type (Annual, Seasonal-Summer, or Seasonal-Winter), and the MW amount of Auction Specific MW to be transacted from each resource. PJM will verify that the MW of capacity from each of the resources identified as supplying the Auction Specific MW Transaction have cleared in an RPM auction and that at least the MW of cleared capacity indicated for each resource is not committed in any other bilateral transactions. If such sufficient cleared capacity does not exist on any of the indicated resources, PJM will reject reporting of the transaction.
- Auction Specific MW Transactions transfer the capacity rights of the cleared capacity from the Seller to the Buyer. PJM will verify that those capacity rights are not resold by the

Seller in a future bilateral transaction by tracking the Seller's remaining capacity rights for each resource identified in the Auction Specific MW Transaction.

- Auction Specific MW Transactions for MWs cleared on an annual basis must be reported on an annual basis prior to each Delivery Year, therefore, the start and end date of the transaction must correspond to a Delivery Year. Auction Specific MW Transactions for MWs cleared for a seasonal period must be reported for the seasonal period prior to each Delivery Year. Auction Specific MW Transaction for MWs cleared for summer period must be submitted as an Auction Specific MW Transaction with start date of June 1 of Delivery Year and end date of October 30 of Delivery Year and a separate Auction Specific MW Transaction with a start date of May 1 of the Delivery Year and end date of May 31 of the Delivery Year. Auction Specific MW Transaction for MWs cleared for winter period must be submitted with start date of November 1 of Delivery Year and end date of April 30 of the Delivery Year.
- Auction Specific MW Transactions are priced at the weighted average of the Resource Clearing Prices from the RPM auctions in which the MW from the units supplying the transaction cleared.
- The smallest increment that may be transacted through an Auction Specific MW Transaction is 0.1 MW.
- The Seller of the Auction Specific MW is subject to all applicable resource performance charges, including Capacity Resource Deficiency Charges, Non-Performance Charges, and Generation Resource Rating Test Failure Charges.
- The Buyer of the Auction Specific MW will receive any Capacity Performance bonus credits related to the resource(s) identified in the transaction that over-perform during a Performance Assessment Interval. The Buyer's share of bonus credits for each over-performing resource will be based on the ratio of the resource's cleared MWs (in UCAP) transferred in the Auction Specific MW Transaction to the greater of the (a) resource's cleared UCAP transferred or (b) Seller's daily Owned UCAP position for such resource.
- The Buyer will indemnify PJM Settlement, the LLC, and the Members for any failure by the Seller of the Auction Specific MW transaction to pay deficiency penalties and charges owed to PJM Settlement and associated with the capacity that is the basis of the Auction Specific MW transaction.
- PJM reserves the right under the PJM Operating Agreement and PJM Open Access Transmission Tariff, to deny reporting of Auction Specific MW Transactions in the event one of the parties fails to meet any requirements for such reporting.
- The Seller of an Auction Specific MW Transaction will receive a charge equal to the transaction amount (in MW) times the price associated with in the transaction for the term of the transaction.
- The Buyer of an Auction Specific MW Transaction will receive a credit equal to the transaction amount (in MW) times the price associated with the transaction for the term of the transaction.

- The resource(s) transferred to the Buyer in an Auction Specific MW Transaction cannot be subsequently resold in another bilateral transaction by the Buyer during the effective time period of the transaction.

4.6.7 Cleared Buy Bid Transactions

RPM Market Participants have the ability to report Cleared Buy Bid Transactions through the Capacity Exchange system. A Cleared Buy Bid Transaction allows the holder of a Cleared Buy Bid from an Incremental Auction to transfer Cleared Buy Bid MWs to another party for the term of the transaction. A Cleared Buy Bid Transaction will not change the resource position or load obligation of an entity. However, the Buyer may use the Cleared Buy Bid MWs as a replacement resource in a Replacement Capacity Transaction.

The following are business rules that apply to Cleared Buy Bid Transactions:

- Cleared Buy Bid MWs are not eligible to be offered in an RPM auction.
- Both the Buyer and the Seller of Cleared Buy Bid MWs must confirm the Cleared Buy Bid transaction via the Capacity Exchange system by 23:59 EPT before the start date of the transaction.
- A Cleared Buy Bid Transaction must specify the buyer, seller, start and end dates of the transaction, the transaction amount (in MW), the LDA, product-type (and Incremental Auction associated with the Cleared Buy Bid. The product-type specified for a Cleared Buy Bid transaction may only be Capacity Performance product type.
- The smallest increment that may be transacted through a Cleared Buy Bid Transaction is 0.1 MW.
- Cleared Buy Bid transaction results in the “Buyer” receiving the Cleared MWs in the applicable LDA and the associated Incremental Auction Charges that would have been assessed to the Seller for the term of the transaction.

4.6.8 Locational Unforced Capacity (UCAP) Transactions

RPM Market Participants have the ability to report Locational UCAP Transactions through the Capacity Exchange system. A Locational UCAP Transaction allows a party with available resource-specific capacity to transfer Locational UCAP (MWs) to another party. A Locational UCAP Transaction will not change the resource position or load obligation of an entity. However, the Buyer may use the Locational UCAP as a replacement resource in a Replacement Capacity Transaction.

The following are business rules that apply to Locational UCAP Transactions:

- Locational UCAP MWs are not eligible to be offered in an RPM auction.
- Both the Buyer and the Seller of Locational UCAP MWs must confirm the Locational UCAP Transaction via the Capacity Exchange system by 23:59 EPT before the start date of the transaction.

- Locational UCAP transactions for a Delivery Year will be restricted as follows during the following periods:
 - Prior to the locking of the Delivery Year Accredited UCAP Factor: Locational UCAP transactions will not be accepted.
 - After the locking of the Delivery Year Accredited UCAP Factor, but before the Delivery Year's Third Incremental Auction bidding window opens: Locational UCAP transactions may be accepted; however, the Buyer of the Locational UCAP transaction must demonstrate prior to the Third Incremental Auction that the Locational UCAP was used in a replacement capacity transaction. If the Buyer fails to enter into a replacement capacity transaction prior to the Third Incremental Auction, the Locational UCAP transaction will be denied by PJM.
 - During the Delivery Year's Third Incremental Auction: Locational UCAP transactions will not be accepted.
 - After the Delivery Year's Third Incremental: Locational UCAP transactions will be accepted.
- A Locational UCAP Transaction must specify the buyer, seller, product type, start and end dates of the transaction. The product type specified must be Capacity Performance.
- The Seller of the Locational UCAP must also specify the resource (generation resource, demand resource, energy efficiency resource, or aggregate resource) and the MW amount of locational UCAP to be transacted. The resource specified in the transaction must be capable of meeting the requirements of the product type specified in the Locational UCAP transaction.
- The smallest increment that may be transacted through a Locational UCAP Transaction is 0.1 MW.
- A Locational UCAP transaction results in a product-specific RPM Resource Commitment (in UCAP terms), equal to the MW amount of locational UCAP transacted, being placed on the Seller's resource for the term of the transaction.
- The Seller of the Locational UCAP retains ownership of the resource specified in the Locational UCAP Transaction.
- The Seller of the Locational UCAP is subject to all applicable resource performance assessments.
- The Buyer in a Locational UCAP transaction will indemnify PJM Settlement, the LLC, and the Members for any failure by the Seller of such transaction to pay deficiency penalties and charges owed to PJM Settlement and associated with the capacity that is the basis of the Locational UCAP transaction.

4.7 Resource Portfolio

A party's resource portfolio in Capacity Exchange may consist of Generation Capacity Resources, Demand Resources, Energy Efficiency Resources, and Qualifying Transmission Upgrades.

A party's Generation Capacity Resource portfolio may consist of existing generation, planned generation, and bilateral contracts for unit-specific capacity resources. Qualification requirements for generation resources are presented in Existing Generation Capacity Resources, Planned Generation Capacity Resources, and Bilateral Unit-Specific Transaction Sections of this Manual.

4.7.1 Resource Position for Generation Capacity Resources

A party's Daily Generation Capacity Resource Position in unforced capacity terms is calculated dynamically by the Capacity Exchange system for each unit and is equal to the party's Daily ICAP Owned on a unit multiplied by the unit's Accredited UCAP Factor.

A party's Daily ICAP Owned on a unit is calculated by adding the ICAP Value of a unit as determined by a party's approved Capacity Modifications to ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases. The Installed Capacity (ICAP) Value of a unit is determined in accordance with ***PJM Manual for the Rules and Procedures for the Determination of Generating Capability (M-21 and M-21B)***. Through the 2024/2025 Delivery Year, for an ELCC Resource, the term "ICAP" in this manual refers to the lesser of the Accredited UCAP or the resource's CIRs plus any awarded transitional resource MWs in accordance with Manual 21 Section 1.2. The ICAP value of a Winter-Period Capacity Performance Resource is based on an Intermittent or Environmentally Limited Resource's certified Capacity Interconnection Rights for the winter period of the Delivery Year.

A unit that is in a party's Generation Capacity Resource portfolio may be traded bilaterally if the party has Daily Available ICAP to offer from the unit for the entire term of the bilateral unit-specific transaction. If the Daily Available ICAP for the unit varies for the term of the bilateral unit-specific transaction, only the minimum Daily Available ICAP may be sold in the bilateral unit-specific transaction.

For a party, the Daily Available ICAP on a unit is equal to Daily ICAP Owned – Daily Unoffered ICAP - (Daily RPM Resource Commitments/(Accredited UCAP Factor)) – Daily FRR Capacity Plan Commitments.

$$\begin{aligned} \text{DailyAvailICAP}_{\text{GEN}} = & \\ & \text{DailyICAPOwned} - \text{DailyUnofferICAP} - \\ & \left(\frac{\text{DailyRPMResourceCommitments}}{\text{Accredited UCAP Factor}} \right) - \text{DailyFRRCommitments} \end{aligned}$$

A unit that is in a party's Generation Capacity Resource portfolio may be offered into RPM Auctions if the party has available capacity to offer from the unit for the entire term of the RPM Auction Year. A Seasonal Capacity Performance Resource may be offered into RPM Auctions if the party has available capacity to offer from the unit for the entire summer/winter season. For each RPM Auction, PJM will calculate a Current Available ICAP Position.

A party's Current Available ICAP Position on a unit for an RPM Auction is equal to the minimum Daily Available ICAP for such unit during the entire Delivery Year or summer/winter season.

$$\text{CurrentAvailableICAPPosition}_{\text{GEN}} = \text{Min} (\text{DailyAvailableICAP}_{\text{GEN}})$$

A party's Daily Unoffered ICAP for a specific unit is calculated by adding the sum of any Daily Unoffered ICAP for such unit in RPM Auctions to Daily Unoffered ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases.

$$\begin{aligned} \text{DailyUnofferICAP}_{\text{GEN}} = \\ \text{DailyUnofferICAP}_{\text{RPM Auction}} + \text{DailyUnofferICAP}_{\text{Bilateral Sales / Purchases}} \end{aligned}$$

For an RPM Auction, a party's Daily Unoffered ICAP for a generation resource is equal to the party's Current Available ICAP Position minus the Offered ICAP in the party's sell offer. A FRR Entity's Daily Unoffered ICAP for a generation resource is set equal to 0 MW.

$$\text{DailyUnofferICAP}_{\text{GEN}} = \text{CurrentAvailableICAPPosition}_{\text{GEN}} - \text{OfferedICAP}$$

A party's Daily RPM Resource Commitments for a specific generating unit are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such unit in RPM Auctions to decreases/increases of RPM Resource Commitments due to approved unit-specific bilateral sales/purchases of cleared capacity, the specification of replacement resources, and increases of RPM Resource Commitments due to approved Locational UCAP transactions.

A party's Daily FRR Capacity Plan Commitments for a specific unit are equal to the total amount of installed capacity that was committed from the unit for the FRR Capacity Plan.

A party's Daily RPM Generation Capacity Resource Position for a specific unit is equal to the (Daily ICAP Owned – Daily FRR Capacity Plan Commitments – Daily Unoffered ICAP)*(Accredited UCAP Factor).

$$\begin{aligned} \text{DailyRPMPosition}_{\text{GEN}} = \\ (\text{DailyICAPOwned} - \text{DailyFRRCommitments} - \text{DailyUnofferICAP}) * \\ (\text{Accredited UCAP Factor}) \end{aligned}$$

During the Delivery Year, a party's Daily RPM Generation Capacity Resource Position is compared to their Daily RPM Resource Commitments for the generating unit to determine if a Capacity Resource Deficiency Charge is to be assessed.

4.7.2 Resource Position for Demand Resources

A party's Demand Resource portfolio may consist of existing Demand Resources or Planned Demand Resources. Qualification requirements for Demand Resources are presented in Load Management Products Section of this Manual.

A party's Daily ICAP Owned for a specific demand resource is equal to the Daily Nominated DR Value adjusted for the ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases for such demand resource in effect for such day. The Daily Nominated DR Value for a Demand Resource for a Delivery Year is established based on confirmed Demand Resource Registrations in "completed" status linked to such Demand Resource in the DR Hub system. The Daily Nominated DR Value for a Capacity Performance Demand Resource during the summer period of June through October and May of the Delivery Year is based on the sum of the summer nominated DR values of the registrations linked to such Demand Resource. The Daily Nominated DR Value for a Demand Resource during the non-summer period of November through April is based on the lesser of (a) the sum of the summer nominated DR values of the registrations linked to such Demand Resource or (b) the sum of the winter nominated DR values of the registrations linked to such Demand Resource.

A party's Daily Resource Position for a Demand Resource (in unforced capacity terms) is calculated dynamically by the Capacity Exchange system and is equal to the Daily ICAP Owned multiplied by the Forecast Pool Requirement prior to the 2025/2026 Delivery Year, or, multiplied by the applicable ELCC Class Rating beginning with the 2025/2026 Delivery Year.

A Demand Resource that is in a party's Demand Resource portfolio may be offered into RPM Auctions, if there is Available ICAP to offer from the Demand Resource. A Demand Resource's Available ICAP for an RPM Auction is determined based on pre-registration confirmation process in the Capacity Exchange system for such RPM Auction and PJM's approval of the Curtailment Service Provider's DR Sell Offer Plan for such RPM Auction. A Demand Resource's Existing Available ICAP is determined based on the CSP's completion of the pre-registration process and the DR Existing Setup process in the Capacity Exchange system. A Demand Resource's Planned Available ICAP is determined based on PJM's approval of the CSP's DR Sell Offer Plan and the CSP's completion of the DR Planned Setup process in the Capacity Exchange system. A Demand Resource's Available ICAP is equal to the Existing Available ICAP and Planned Available ICAP. A Demand Resource's Existing Available ICAP and Planned Available ICAP is further classified by CSP in the DR Existing/Planned Setup process as MWs intend to offer as Annual Capacity Performance, MWs intend to offer Summer-Period Capacity Performance, and MWs intend to offer as part of an Aggregate Resource.

A party's Daily RPM Resource Commitments for a specific demand resource are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such demand resource in RPM Auctions to decreases/increases of RPM Resource Commitments due to approved unit-specific bilateral sales/purchases of cleared capacity and the specification of replacement resources, and to increases of RPM Resource Commitments due to approved Locational UCAP transactions.

A party's Daily FRR Capacity Plan Commitments for a specific demand resource are equal to the total amount of Nominated DR that was committed from the demand resource for the FRR Capacity Plan.

Through the 2024/2025 Delivery Year, a party's Daily RPM Demand Resource Position for a specific demand resource is equal to the (Daily ICAP Value – Daily FRR Capacity Plan Commitments) * Forecast Pool Requirement.

$$DailyRPMPosition_{DR} = (DailyNomDRValue - DailyFRRCommittments) * FPR$$

Starting with the 2025/2026 Delivery Year, a party's Daily RPM Demand Resource Position for a specific demand resource is equal to the (Daily ICAP Value - Daily FRR Capacity Plan Commitments) * applicable ELCC Class Rating.

$$= (DailyNomDRValue - DailyFRRCommittments) * Applicable \ ELCC \ Class \ Rating$$

During the Delivery Year, a party's Daily RPM Demand Resource Position is compared to their Daily RPM Resource Commitments for the demand resource to determine if a Capacity Resource Deficiency Charge is to be assessed on the delivery day.

4.7.3 Resource Position for Energy Efficiency Resources

A party's EE Resource portfolio may consist of existing or planned EE Resources. Qualification requirements for EE Resources are presented in Energy Efficiency Resource Section of this Manual. A party's Daily ICAP Owned for a specific EE Resource is equal to the Daily Nominated EE Value as determined by party's "Approved" EE Modifications (submitted by PJM to represent the final Nominated EE Value or Capacity Performance value of a provider's EE Resource for the Delivery Year based on PJM's approval of the provider's Post- Installation M&V Report for such Delivery Year) adjusted for any ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases for such EE Resource in effect for such day.

A party's Daily EE Resource Position for an EE Resource (in unforced capacity terms) is calculated dynamically by the Capacity Exchange system and is equal to the Daily ICAP Owned * Forecast Pool Requirement.

$$DailyResourcePosition_{EE} = DailyICAPOwned * FPR$$

An EE Resource that is in a party's EE Resource portfolio may be offered into RPM Auctions, if there is Available ICAP to offer from the EE Resource. An EE Resource's Available ICAP for an RPM Auction is determined based on PJM's approval of the provider's Initial/Updated M&V Plan for such RPM Auction and the provider's completion of the EE Setup process in the Capacity Exchange system prior to the RPM Auction. An EE Resource's Existing Available ICAP is determined based on Nominated EE Value approved by PJM in the most recent Post-Installation M&V Report, prior commitments for such Delivery Year (if applicable), and the EE Provider's completion of the EE Existing Setup process in the Capacity Exchange system. A Energy Efficiency Resource's Planned Available ICAP is determined based on PJM's approval of the provider's Initial/Updated M&V Plan for such RPM Auction and the provider's completion

of the EE Planned Setup process in the Capacity Exchange system. An EE Resource's Available ICAP to offer into an RPM Auction is equal to the Existing Available ICAP and Planned Available ICAP for such EE Resource for the relevant RPM Auction Delivery Year. An Energy Efficiency Resource's Existing Available ICAP and Planned Available ICAP is further classified by the EE Resource Provider in the EE Existing/Planned Setup process as MWs intend to offer as Annual Capacity Performance, MWs intend to offer as Summer-Period Capacity Performance, and MWs intend to offer as part of an Aggregate Resource.

A party's Daily RPM Resource Commitments for a specific EE Resource are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such EE Resource in RPM Auctions to decreases/increases of RPM Resource Commitments due to approved unit-specific bilateral sales/purchases of cleared capacity, the specification of replacement resources or the use of EE Resource in a Locational UCAP transaction.

A party's Daily FRR Capacity Plan Commitments for a specific EE Resource are equal to the total Nominated EE Value that was committed from the EE Resource for the FRR Capacity Plan.

A party's Daily RPM EE Resource Position for a specific EE Resource is equal to the (Daily ICAP Owned – Daily FRR Capacity Plan Commitments * Forecast Pool Requirement).

$$DailyRPMPosition_{EE} = (DailyICAP_{Owned} - DailyFRRCommitments) * FPR$$

During the Delivery Year, a party's Daily RPM EE Resource Position is compared to their Daily RPM Resource Commitments for the EE Resource to determine if a Capacity Resource Deficiency Charge is to be assessed on the delivery day.

4.7.4 Resource Position for Qualified Transmission Upgrades

A party's Qualifying Transmission Upgrade portfolio may consist of planned Qualifying Transmission Upgrades. Qualification requirements for Qualifying Transmission Upgrades are presented in Qualifying Transmission Upgrade Section of this manual.

A Qualifying Transmission Upgrade that is in a party's Qualifying Transmission Upgrade portfolio may be offered into a Base Residual Auction if incremental import capability value into Sink LDA from a Source LDA has been approved by PJM System Planning Department.

A party's Daily Qualifying Transmission Upgrade Position for a Qualifying Transmission Upgrade is calculated dynamically by the Capacity Exchange system and is equal to the incremental import capability value into Sink LDA from a Source LDA that has been assigned by PJM System Planning Department.

A party's Daily RPM Resource Commitments for a specific Qualifying Transmission Upgrade are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such Qualifying Transmission Upgrade in RPM Auctions to any decreases of RPM Resource Commitments due to the specification of replacement resources.

During the Delivery Year, a party's Daily RPM Qualifying Transmission Upgrade Position for a qualifying transmission upgrade is compared to their Daily RPM Resource Commitments for the qualifying transmission upgrade to determine if a Transmission Upgrade Delay Penalty is to be assessed.

4.8 Credit Requirements

The purpose of the RPM credit requirement is to encourage future physical performance, but not necessarily fully guarantee financial obligations related to Capacity. Credit requirements for participating in the RPM, therefore, may be different from the other requirements established separately in the PJM Credit Policy, which are intended for other activities and general financial obligations to PJM.

These business rules are intended to be descriptive of the credit requirements for participants in the RPM, but if any conflict arises between provisions in these rules and provisions in the PJM Operating Agreement or PJM Open Access Transmission Tariff (which includes the PJM Credit Policy as Attachment Q), then the provisions in the Operating Agreement and/or Tariff shall govern.

Since LSE payments due to PJM are included in monthly PJM bills, LSE payment obligations are considered to already be measured and covered by provisions of PJM's Credit Policy. Accordingly, no separate credit requirement will be imposed on LSEs under the RPM.

Participants offering into an RPM Auction existing resources (whether generators, demand resources, energy efficiency resources, or external generation resources with firm transmission), are not required to establish credit for the RPM Auctions.

Participants offering into an RPM Auction any Planned Demand Resource, Planned Energy Efficiency Resource, Planned Generation Resource (including External and Financed), Qualified Transmission Upgrade, or external capacity without firm transmission (these five together considered herein to be Resources Requiring Credit for RPM) must establish a separate RPM Credit Limit prior to and for each RPM Auction in which the participant offers planned MWs from a Resource Requiring Credit for RPM.

Participants nominating PRD in advance of a BRA or Third Incremental Auction (for use in RPM Auction or FRR) must establish an RPM Credit Limit before submitting the PRD Plan in advance of the BRA or Third Incremental Auction.

4.8.1 RPM Credit Limit

Acceptable sources of credit for the RPM Credit Limit may be either of the following:

- Any unsecured credit or collateral available, according to provisions of the PJM Credit Policy, which has not already been designated or required for financial obligations under the Credit Policy or for other financial obligations within PJM.

- For RPM credit purposes only, if a supplier has a history of being a net seller into PJM, on average, over the past 12 months, then PJM will count as available unsecured credit twice the average of that participant's total net PJM bills over the past 12 months.
- A supplier may combine more than one source of credit for RPM credit purposes. Credit provided for RPM must be non-cancelable until at least 10 days after payment is due for the last month for which a committed financial obligation could be created or owed.

For Resources Requiring Credit for RPM, credit requests should be made to PJM's Credit Department at least two weeks prior to an RPM Auction. For price responsive demand requiring credit, credit requests should be made to PJM's Credit Department at least two weeks prior to the deadline for submitting the PRD Plan. Credit previously established with PJM for general market activity will not be available for RPM unless the participant specifically makes such a request to the PJM Credit Department.

Although credit provided by a participant may be administratively separated for RPM (or FTR, etc.), all credit supplied by a PJM member or customer, whether or not designated for RPM (or FTR, or any other PJM obligation), may be utilized to cover any PJM financial obligation, should the member or customer default.

PJM will return or release RPM credit provided by participants upon request, as long as such release would not cause a participant's RPM Credit Requirement and/or Price Responsive Demand Credit Requirement to exceed its RPM Credit Limit. Furthermore, PJM reserves the right to establish a maximum frequency of such returns or releases, but no less frequent than once per calendar quarter.

A participant must, at all times, maintain its RPM Credit Limit at least sufficient to meet its RPM Credit Requirement and/or Price Responsive Demand Credit Requirement. If a participant's RPM Credit Requirement and/or Price Responsive Demand Credit Requirement ever exceeds its RPM Credit Limit, PJM may exercise any of the remedies afforded by the Credit Policy, Tariff, Operating Agreement, or other agreements, business rules or manuals, including demand for additional credit and/or declaration of default. Failure to exercise a remedy at any given time shall not preclude PJM from exercising such remedy at a later time.

4.8.2 RPM Credit Requirement

An RPM Credit Requirement will be established for all participants that are offering into an RPM Auction or have already committed into RPM any Resources Requiring Credit for RPM. The RPM Credit Requirement will be equal to the sum of the individual credit requirements for such resources. The credit requirement for a given resource offered into an RPM auction will be a fixed Auction Credit Rate times the unforced MW offered, times an RPM Credit Adjustment Factor. However, the credit requirement for Planned Financed Generation Capacity Resources and Planned External Financed Generation Capacity Resources shall be one half of the product of the RPM Auction Credit Rate, as provided in Section .VI.B.4 of OATT, Attachment Q, times the megawatts to be offered for sale from such resource in a Reliability Pricing Model Auction (though for Planned External Financed Generation Capacity Resources, this reduction may be

limited subject to limits based on firm transmission secured, as further explained herein). The credit requirement for a given resource committed into RPM will be a fixed Auction Credit Rate times the unforced MW committed, times an RPM Credit Adjustment Factor.

RPM Credit Adjustment Factor

The RPM Credit Adjustment Factor for a given resource depends on its status in becoming a fully qualified resource as follows. The Credit Adjustment Factor for all Resources Requiring Credit for RPM will be one ("1") except as follows:

- For Planned Demand Resources, the Credit Adjustment Factor will be $(1-X)$, where "X" is the Nominated DR that is certified through an Emergency Load Response Registration divided by the Nominated DR value offered/committed by the Planned Demand Resource.
- For Planned Energy Efficiency Resource, the Credit Adjustment Factor will be $(1-X)$, where "X" is the Nominated EE Value that is confirmed through a PJM approved Post-Installation M&V Report divided by the Nominated EE value offered/committed by the planned energy efficiency resource.
- For existing external generation resources without firm transmission service, the Credit Adjustment Factor will be $(1-X)$, where "X" is the MWs of firm transmission service that has been secured for the complete transmission path divided by the MWs of existing external generation resource offered/committed and shall be zero if the Participant has demonstrated that firm transmission service for the complete transmission path has been secured.
- For Planned generation resources (internal and external, financed and non-financed), please see the incremental reduction and associated credit milestones in Section 4.8.5 .
- For Qualifying Transmission Upgrades, the Credit Adjustment Factor will be 0.5 (50%) if a full (not provisional) Generation Interconnection Agreement has been successfully executed but Interconnection Service has not yet begun, and will be zero on the date the Qualifying Transmission Upgrade is placed in service.
- PJM will consider credit adjustment factors other than these on a case-by-case basis.

If a Participant offers a Resource Requiring Credit for RPM into an RPM auction, but the Participant's RPM Credit Limit is insufficient for the participant's RPM Credit Requirement including the new offer, then the offer will be rejected. If the offer was made as part of a sell offer upload file (multiple resources offered simultaneously), then the entire file upload will be rejected. Previous offers made and accepted into an auction will not be rejected solely because a subsequent offer was rejected.

4.8.3 Auction Credit Rate

An Auction Credit Rate is calculated prior to each RPM Auction for such Delivery Year as follows:

- Prior to the posting of the BRA results, the RPM Auction Credit Rate for planned Capacity Performance Resources is equal to the greater of (i) \$20/MW-day or (ii) 0.5 times

applicable Delivery Year's Net CONE for modeled LDA where the resource resides (in \$/MW-day), times the number of days in the Delivery Year. If the resource does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the RPM Credit Rate. The RPM Auction Credit Rate for planned Seasonal Capacity Resources is the same as the RPM Auction Credit Rate for planned Capacity Performance Resources; however, the rate is reduced to be proportional to the number of days in the relevant season.

- Upon posting the BRA clearing results, the RPM Auction Credit Rate used for planned Capacity Performance commitments in the BRA is equal to the greater of [(i) \$20/MW-day, (ii) .2 times the Capacity Performance Resource Clearing Price for the LDA that applies to the planned Capacity Performance resource, or (iii) the lesser of (a) 0.5 times Net CONE for modeled LDA where the resource resides for such Delivery Year (in \$/MW-day) or (b) 1.5 times Net CONE (stated in installed capacity terms as \$/MW-day) for the modeled LDA where the resource resides for such Delivery Year minus the Capacity Performance Resource Clearing Price for the LDA that applies to the planned Capacity Performance Resource], times the number of days in the Delivery Year. If the resource does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the RPM Credit Rate. The RPM Auction Credit Rate used for planned Seasonal Capacity Resource commitments in the BRA is the same as the RPM Credit Rate for planned Capacity Performance commitments in the BRA; however, the rate is reduced to be proportional to the number of days in the relevant season.
- For any planned resource not previously committed for a Delivery Year that participates in an Incremental Auction, the RPM Auction Credit Rate for all planned Capacity Performance Resources is equal to the greater of (i) 0.5 times applicable Delivery Year's Net CONE for modeled LDA where the resource resides (in \$/MW-day) or (ii) \$20 per MW-day, times the number of days in the Delivery Year. If the resource does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the RPM Auction Credit Rate. The RPM Auction Credit Rate for any planned Seasonal Capacity Resource not previously committed for a Delivery Year that participates in an Incremental Auction is the same as the RPM Auction Credit Rate for planned Capacity Performance Resources; however, the rate is reduced to be proportional to the number of days in the relevant season.
- Upon posting the results of an Incremental Auction, the RPM Auction Credit Rate used for planned Capacity Performance commitments is equal to the greater of [(i) \$20/MW-day, (ii) 0.2 times the Capacity Performance Resource Clearing Price in such Incremental Auction for the LDA that applies to the planned resource, or (iii) the lesser of (a) 0.5 times Net CONE for the modeled LDA where resource resides for such Delivery Year (in \$/MW-day) or (b) 1.5 times Net CONE (stated in installed capacity terms as \$/MW-day) minus the Capacity Performance Resource Clearing Price in such Incremental Auction for the LDA that applies to the planned capacity Performance Resource], times the number of days in the Delivery Year. If the resource does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the RPM Auction Credit Rate. The RPM Auction Credit Rate for planned Seasonal Capacity Resource commitments in an Incremental Auction is the same as the RPM Auction Credit Rate for planned Capacity Performance Resource

commitments in an Incremental Auction; however, the rate is reduced to be proportional to the number of days in the relevant season.

- One rate is calculated for each Auction, binding LDA, and resource product type, and applied according to the Auction, LDA, and resource product type in which the capacity was committed.
- For Qualified Transmission Upgrades, the Auction Credit Rate applied will be based on the Locational Deliverability Area in which such upgrade was to increase the Capacity Emergency Transfer Limit (CETL).

4.8.4 Price Responsive Demand Credit Requirement

A PRD Provider seeking to commit PRD in the Base Residual Auction, Third Incremental Auction, or the FRR Alternative, and for which there is a materially increased risk of non-performance for such PRD, must satisfy the Price Responsive Demand Credit Requirement prior to the deadline for submitting the PRD Plan.

The Price Responsive Demand Credit Requirement shall be based on the maximum Nominal PRD Value in the PRD Plan * Forecast Pool Requirement * Price Responsive Demand Credit Rate. For a PRD Provider, the maximum Nominal PRD Value in the PRD Plan may be reduced by the amount of existing PRD that is currently registered and approved in DR Hub system by such PRD Provider on January 1 in advance of the PRD Plan submittal deadline.

Prior to the posting of the results of a Base Residual Auction for a Delivery Year, the Price Responsive Demand Credit Rate shall be (the greater of (i) 0.5 times applicable Deliver Year's Net Cone for the modeled LDA where the price responsive demand resides or (ii) \$20/MW-day times the number of days in such Delivery Year. If the price responsive demand does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the Price Responsive Demand Credit Rate.

After the posting of the Base Residual Auction results, the Price Responsive Demand Credit Rate used for on-going credit requirements for price responsive demand committed in the Base Residual Auction or to the FRR Alternative prior to the Base Residual Auction, shall be the (greater of (i) \$20/MW-day, (ii) 0.2 times the Capacity Performance Resource Clearing Price in such auction for the LDA where the PRD load is located, or (iii) the lesser of (a) 0.5 times Net CONE for the modeled LDA where the price responsive demand resides or (b) 1.5 times Net CONE (stated in installed capacity terms as \$/MW-day) for the modeled LDA where the price responsive demand resides minus the Capacity Performance Resource Clearing Price for such modeled LDA) times the number of days in the Delivery Year. If the price responsive demand does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the Price Responsive Demand Credit Rate.

For any additional PRD that seeks to commit in a Third Incremental Auction or seeks to commit PRD to reduce the final unforced capacity obligation of an FRR Entity, the Price Responsive Demand Credit Rate shall be (the greater of (i) 0.5 times applicable Deliver Year's Net Cone for

the modeled LDA where the price responsive demand resides or (ii) \$20/MW-day) times the number of days in such Delivery Year. If the price responsive demand does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the Price Responsive Demand Credit Rate.

After the posting of the Third Incremental Auction results, the Price Responsive Demand Credit Rate used for on-going credit requirements for Price Responsive Demand committed in the Third Incremental Auction or committed to the FRR Alternative to reduce the final unforced capacity obligation of an FRR Entity, shall be (the greater of (i) \$20/MW-day, (ii) 0.2 times the Capacity Performance Resource Clearing Price in such auction for the LDA where the price responsive demand resides, or (iii) the lesser of (a) 0.5 times Net CONE for the modeled LDA where the price responsive demand resides or (b) 1.5 times Net CONE (stated in installed capacity terms as \$/MW-day) for the modeled LDA where the price responsive demand resides minus the Capacity Performance Resource Clearing Price in such Incremental Auction for such modeled LDA) times the number of days in such Delivery Year. If the price responsive demand does not reside in a modeled LDA, the RTO Net CONE will be used in the determination of the Price Responsive Demand Credit Rate.

4.8.5 Credit Milestones for Planned Generation Capacity Resources

For Planned Generation Capacity Resources, Planned External Generation Capacity Resources and the RPM Credit Requirement shall be reduced by applying the appropriate Incremental Credit Reduction from the tables below as the resource attains the stated milestones. The incremental credit reductions are summed cumulatively to get the total credit reduction from the achieved milestones. To obtain a reduction in RPM Credit Requirement (except for “GIA effective date” and “Commencement of Interconnection Service”), the Capacity Market Seller must submit a sworn, notarized certification of an independent engineer in a form acceptable to PJM, certifying that the engineer has personal knowledge, or has engaged in a diligent inquiry to determine, that the milestone has been achieved and that, based on its review of the relevant project information, the independent engineer is not aware of any information that could reasonably cause it to believe that the Capacity Resource will not be in-service by the beginning of the applicable Delivery Year. The standard certification form can be found on the PJM website. The Capacity Market Seller, must, if requested by PJM, supply to PJM on a confidential basis all records and documents related to the independent engineer's certification. PJM may accept a certification by a Professional Engineer in lieu of a certification by an independent engineer. For Balance sheet financed resources a notarized officer certification of financial close can be used instead of an independent engineer certification of financial close.

The cumulative reduction in credit requirements for planned external resources and planned financed external resources, including the initial 50% reduction for financed resources, shall never be greater than the quotient of the division of firm transmission MW by offered (or cleared) MW.

Credit Reductions (%) for Planned Generation Capacity Resources and Planned External Generation Capacity Resources	
Credit Milestones Certified by an Independent Engineer (where applicable)	Incremental Credit Reduction from Initial Credit Requirements
Effective date of fully executed GIA for Planned Generation Capacity Resources or agreement equivalent to GIA for Planned External Generation Capacity Resources	50%
Financial Close	15%
Full Notice to Proceed and Commencement of construction (e.g. footers or foundation poured)	5%
Main power generating equipment delivered	5%
Commencement of Interconnection Service	25%

The following definitions apply to the terms in the tables above:

- “Effective Date of fully executed GIA” shall be as defined in the relevant GIA.
- “Full Notice to Proceed” means that all material third party contractors have been given the notice to proceed with construction by the Capacity Market Seller or its agent, with a guaranteed completion date backed by liquidated damages.
- “Commencement of construction” means the beginning of major construction of the customer facility or customer interconnection facility.
- “Main power generating equipment delivered” means the main power generating equipment has been delivered to the site.
- “Financial Close” shall mean the resource demonstrated, as supported by a sworn, notarized certification of an independent engineer, certifying that the engineer has personal knowledge, or has engaged in a diligent inquiry to determine, that the Capacity Market Seller or its agent has completed the act of executing the material contracts and/or other documents necessary to (1) authorize construction of the project and (2) establish the necessary funding for the project under the control of an independent third-party entity. For resources that do not have external financing, PJM may accept instead a sworn, notarized certification by an officer of the company that the project has full funding available, specifying that the project has been duly authorized to proceed with full construction by the appropriate governing body of the company.
- All milestones refer to activities materially related to the delivery of electricity or electric services related to the resource’s commitment in the RPM auction.

Example: A Planned Generation Capacity Resource that has committed 10 MW in a Base Residual Auction with an Auction Credit Rate of 36,500/MW-year would have an initial RPM credit requirement of \$365,000. After the effective date of an executed GIA, the RPM credit requirement would be \$182,500 (50% reduction). After Financial Close the credit requirement would be reduced to \$127,750 (65% reduced). Once the Full notice to proceed and Commencement of construction milestone is met then the credit requirement would be \$109,500 (70% reduced). Once the Main Power Generating Equipment Delivered milestone is met, the RPM credit requirement would be \$91,250 (75% reduced). Upon Commencement of Interconnection Service, the credit requirement would be zero.

4.9 Aggregate Resources

Capacity resources which may not, alone, meet the operational requirements of a Capacity Performance product, may combine their capabilities and offer as a single, pseudo aggregate resource¹⁷. Capacity Market Sellers that own one or more Intermittent Resources, Capacity Storage Resources, Demand Resources, Energy Efficiency Resources, or environmentally limited resources may create and offer an Aggregate Resource located in the smallest modeled LDA common to the underlying aggregated resources for a PJM approved unforced capacity value that satisfies the requirements of a Capacity Performance product.

The following business rules apply to Aggregate Resources:

- Intermittent Resources, Capacity Storage Resources, Demand Resources, Energy Efficiency Resources, and environmentally limited resources that are combined to form an Aggregate Resource will be considered to be located in the smallest modeled LDA common to the underlying aggregated resources¹⁸ and must reside in a single Capacity Market Seller account in Capacity Exchange.
- Market Sellers that intend to create an Aggregate Resource must submit a written email request to rpm_hotline@pjm.com at least two weeks prior to the opening of the RPM Auction in order to allow adequate time for PJM to review such request and model an Aggregate Resource in the Capacity Exchange system.
- Aggregate Resource requests must specify the capacity resources that are being combined to form the Aggregate Resource, the installed capacity owned on each

¹⁷ OATT Attachment DD, Section 5.6.2(h)

¹⁸ For example, if one resource is located in EMAAC and the other resource is located in Rest of RTO, the Aggregate Resource will be modeled and compensated in Rest of RTO and compensated at Rest of RTO clearing price. If one resource is located in EMAAC and the other is located in SWMAAC, the Aggregate Resource will be modeled and compensated in MAAC. If one resource is located in COMED and the other resource is located in EMAAC, the Aggregate Resource will be modeled and compensated in Rest of RTO.

generation capacity resource, the Nominated DR Value for a Demand Resource, or Nominated EE Value for an EE Resource, and the requested unforced capacity value of the Aggregate Resource. The request must also include an initial seasonal allocation of the Annual Capacity Performance capability of the Aggregate Resource to the underlying resources.

- Aggregate Resource requests must also include a written explanation, including supporting data, to justify how the Aggregate Resource realize a higher level of Annual Capacity Performance capability (in unforced MWs) than the individual resources could provide if offered separately into the RPM Auction.
- The unforced capacity value of the Aggregate Resource may not exceed the sum of the unforced capacity values of the individual resources that are being combined to form the Aggregate Resources.
- PJM will review the Aggregate Resource request and approve the requested unforced capacity value of the Aggregate Resource provided the unforced capacity value is based on satisfying the requirements of a Capacity Performance product.
- The Market Seller may not offer any of the capacity resources that make up the Aggregate Resource separately into the RPM Auction or use the capacity resources that make up the approved Aggregate Resource request in any bilateral capacity transaction while the Aggregate Resource is in effect. Once an Aggregate Resource is modeled for a Delivery Year and clears any amount in a Delivery Year RPM Auction, such Aggregate Resource must remain in effect for the entire Delivery Year and may not be terminated for the Delivery Year.
- An Aggregate Resource may be specified as a resource in a Locational UCAP transaction or Auction Specific MW transaction.
- An Aggregate Resource may not be specified as a resource in a unit-specific capacity transaction.
- An Aggregate Resource that includes Existing Generation Capacity Resource(s) is subject to the Must Offer requirement.
- An Aggregate Resource that includes an Existing Generation Capacity Resource is subject to mitigation and applicable market seller offer cap.
- An Aggregate Resource that includes a planned capacity resource must establish an RPM Credit Requirement prior to the RPM Auction.
- The total committed quantity of an Aggregate Resource must be allocated to its underlying capacity resources prior to the start of the Delivery Year and must be updated within the Delivery Year if the total commitment of the Aggregate Resource is revised due to replacement of all or any part of the Aggregate Resource's commitment or due to the use of available capacity on the Aggregate Resource as a replacement resource. The total committed quantity must be allocated to the individual underlying resources on a monthly basis and may be updated no later than the last day of each month for months remaining in the Delivery Year. An individual resource may not receive a daily CP commitment allocation that applies for the entire month in excess of their CIRs. The daily commitment

allocation to an underlying capacity resource will be used in the calculation of Expected Performance for such underlying capacity resource in a Performance Assessment Interval for such day.

- If an Aggregate Resource commitment is removed or reduced by a replacement transaction, the Capacity Market Seller responsible for the Aggregate Resource must reduce the allocation of commitment to the underlying resources by a commensurate amount
- If an Aggregate Resource commitment is increased by a replacement transaction, the Capacity Market Seller responsible for the Aggregate Resource must increase the allocation of commitment to the underlying resources by a commensurate amount.
- Individual resources that are part of an Aggregate Resource will be expected to respond to a Performance Assessment Interval (PAI) in the area where they are physically located and its Non-Performance Charge Rate will be based on the location of the physical resources underlying the aggregate. If one or more individual resources that are part of an Aggregate Resource are in the same area where there is a PAI, the under-/over-performance of the Aggregate Resource will be based on the total commitment and performance of all of the individual resources included in the PAI. The Non-Performance Charge Rate applicable to an under-performing Aggregate Resource is based on the rate associated with the LDA in which the under-performing underlying resources are located weighted by the under-performance MW quantity of such resources. The annual non-performance charge limit of an Aggregate Resource is based on the limit applicable to the LDA in which the Aggregate Resource was modeled in the RPM Auction.
- The location of replacement capacity specified for an Aggregate Resource must be in accordance with the Replacement Capacity transaction business rules in Section 8.8 of this manual.

4.10 Seasonal Capacity Performance Resources

Capacity Market Sellers may offer Seasonal Capacity Performance Resources into RPM Auctions. A Seasonal Capacity Performance Resource is a Summer-Period Capacity Performance or Winter-Period Capacity Performance Resource, as described below.

A Summer-Period Capacity Performance Resource may include the following types of Capacity Resources that are eligible to submit a sell offer as a Summer-Period Capacity Resource: Summer-Period Demand Resource, Summer-Period Energy Efficiency Resource, Capacity Storage Resource, Intermittent Resources, or Environmentally-Limited Resource that has an average expected energy output during the summer peak-hour periods consistently and measurable greater than its average expected energy output during winter peak hour periods

Summer-Period Demand Resource is a resource that is placed under the direction of the PJM and will be available June through October and the following May of the Delivery Year, and will be available for an unlimited number of interruptions during such months by PJM, and will be

capable of maintaining each such interruption between hours of 10:00 AM to 10:00 PM Eastern Prevailing Time. The Summer-Period Demand Resource must be available June through October and the following May in the corresponding Delivery Year to be offered for sale in an RPM Auction, or included as Summer-Period Demand Resource in an FRR Capacity Plan for the corresponding Delivery Year.

A Summer-Period Energy Efficiency Resource is a project, including the installation of more efficient devices or equipment or implementation of more efficient process or systems, meeting the requirements of Schedule 6 of the Reliability Agreement and exceeding then-current codes, appliance standards, or other relevant standards, designed to achieve continuous reduction in electric energy consumption at end use customer's retail site during the summer peak periods (i.e., the defined EE Performance Hours in Section 4.4 of this manual) that is not reflected in the peak load forecast used for the Auction Delivery Year for which the Summer-Period EE Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

To the extent that a Summer-Period Capacity Resource clears in an RPM Auction or is otherwise committed as a Summer-Period Capacity Performance Resource, such resource is obligated to deliver energy as scheduled and/or dispatched by PJM during Performance Assessment Intervals occurring during the calendar months of June through October and the following May of the Delivery Year, and must satisfy the requirements of a Capacity Performance Resource for such period of time. A committed Summer-Period Capacity Performance Resource will be subject to the relevant resource performance assessments for capacity performance commitments and the associated deficiency/penalty charges for such period of time.

A Summer-Period Capacity Performance Resource that clears in an RPM Auction will only receive a Daily RPM Auction Credit for the MWs cleared in such auction for the summer period of June through October and May of the Delivery Year.

A Winter-Period Capacity Performance Resource may include the following types of Capacity Resources that are eligible to submit a sell offer as a Winter-Period Capacity Performance Resource: Capacity Storage Resource, Intermittent Resource, and Environmentally-Limited Resource that has an average expected energy output during winter peak-hour periods consistently and measurably greater than its average expected energy output during summer peak hour periods.

By August 31 of each calendar year, PJM shall solicit requests from generation owners of Intermittent Resources and Environmentally Limited Resources which seek to obtain additional Capacity Injection Rights (CIRs) related to the winter period (November through April of a Delivery Year) for the purposes of creating a Winter-Period Capacity Performance Resource or an Aggregate Resource as described in Section 4.9. Such additional CIRs would be for a one year period as specified by PJM in the solicitation. Responses to such solicitation must be submitted by interested owners by October 31 prior to the upcoming Base Residual Auction.

Such requests shall be studied for deliverability similar to any Generation Project Developer seeking to enter the New Service Request study process; however, such requests shall not be required to enter the New Service Request study process. PJM shall study such requests in a manner so as to prevent infringement on available system capabilities on any resource which is already in service, or which has an executed Generation Interconnection Agreement, Transmission Service Agreement, Upgrade Construction Agreement, or has submitted a valid New Service Request. If the Intermittent Resource or Environmentally Limited Resource is accredited as deliverable for additional CIRs for the winter period, such generation owner shall receive the additional CIRs for the winter period of the relevant Delivery Year.

To the extent a Winter-Period Capacity Performance Resource clears an RPM Auction or is otherwise committed as a Winter-Period Capacity Performance Resource, such resource is obligated to deliver energy as scheduled and/or dispatched by PJM during Performance Assessment Intervals occurring in the calendar months of November through April of the Delivery Year, and must satisfy the requirements of a Capacity Performance Resource for such period of time. A committed Winter-Period Capacity Performance Resource will be subject to the relevant resource performance assessments for capacity performance commitments and the associated deficiency/penalty charges for such period of time.

A Winter Period-Capacity Performance Resource that clears in an RPM Auction will only receive a Daily RPM Auction Credit for the MWs cleared in such auction for the winter period of November through April of the Delivery Year.

A Capacity Market Seller that clears a Seasonal Capacity Resource in an RPM Auction will receive a Resource Clearing Price that is applicable to the Capacity Market Seller's Seasonal Capacity Performance sell offer and is reflective of the Locational Price Adder determined as a result of the seasonal matching process in the post-processing of the auction results as described in Section 5.7.2 and 5.8.5 and any make-whole price, if a make-whole payment is required, for such cleared sell offer.

Section 5: RPM Auctions

Welcome to the RPM Auctions section of the **PJM Manual for the Reliability Pricing Model**. In this section, you will find the following information:

- An overview description of the RPM Auctions (see “Overview of the RPM Auctions”)
- The auction timeline for RPM Auctions (see “RPM Auction Timeline”)
- The auction parameters for the RPM Auctions (see “RPM Auction Parameters”)
- The business rules for sell offers in RPM (see “Sell Offers in RPM”)
- The business rules for buy bids in RPM (see “Buy Bids in RPM”)
- The requirements to offer in the PJM Energy Market (see “Energy Market Offer Requirements”)
- The business rules for the Base Residual Auction (see “Base Residual Auction”)
- The business rules for the Incremental Auctions (see “Incremental Auctions”)
- The business rules for the auction clearing results (see “Auction Clearing Results”)
- An overview description of the reliability backstop mechanism (see “Reliability Backstop”)

5.1 Overview of RPM Auctions

The Reliability Pricing Model (RPM) is a multi-auction structure designed to procure resource commitments to satisfy the region’s unforced capacity obligation through the following market mechanisms: a Base Residual Auction, Incremental Auctions and a Bilateral Market.

- **Base Residual Auction** – The Base Residual Auction is held during the month of May three (3) years prior to the start of the Delivery Year. Notwithstanding, the Base Residual Auction for the 2025/2026 through 2029/2030 Delivery years shall be conducted in accordance with the RPM Auction Schedule posted on the PJM website. Base Residual Auction (BRA) allows for the procurement of resource commitments to satisfy the region’s unforced capacity obligation and allocates the cost of those commitments among the Load Serving Entities (LSEs) through a Locational Reliability Charge.
- **Incremental Auctions** – Up to three Incremental Auctions are conducted after the Base Residual Auction to procure additional resource commitments needed to satisfy potential changes in market dynamics that are known prior to the beginning of the Delivery Year.
- The First, Second, and Third Incremental Auctions are conducted to allow for replacement resource procurement, increases and decreases in resource commitments due to reliability requirement adjustments.
- A Conditional Incremental Auction may be conducted if a Backbone transmission line is delayed and results in the need for PJM to procure additional capacity in a Locational Deliverability Area to address the corresponding reliability problem.

- The Bilateral Market – The bilateral market provides resource providers an opportunity to cover any auction commitment shortages. The bilateral market also provides LSEs the opportunity to hedge against the Locational Reliability Charge determined as a result of the RPM Auction process. The bilateral market is facilitated through the Capacity Exchange system.

5.2 RPM Auction Timeline

The following Auction timeline provides the deadline for key RPM activities¹⁹:

RPM Activity	Deadline
Submittal of binding notice of intent to offer Planned Generation Capacity Resource into Base Residual Auction (effective with 2025/2026 Delivery Year)	December 1st immediately preceding Base Residual Auction (except for 2025/2026, 2026/2027 and 2028/2029 Delivery Year); December 12th 2023 (for 2025/2026 Delivery Year); 180 days prior to commencement of offer period (2026/2027 and 2028/2029 Delivery Year)
Post Planning Parameters for BRA	Posting deadline provided in RPM Auction Schedule on PJM website
Post preliminary estimate of the MOPR Floor Offer Price for the relevant Delivery year	150 days prior to commencement of offer period
Data Submittal (Avoidable Cost Data, Opportunity Cost, & Projected Market Revenues) to IMM if submitting non-zero sell offer price	120 days prior to commencement of offer period
IMM to notify Capacity Market Sellers of Market Seller Offer Caps	90 days prior to commencement of offer period
Participant notification to PJM and IMM whether it has reached agreement with the IMM on the level of Market Seller Offer Cap	80 days prior to commencement of offer period
PJM to notify Capacity Market Seller of its determination on Market Seller Offer Cap	65 days prior to commencement of offer period

¹⁹ For delivery years where FERC has approved a compressed auction schedule, the actual deadline may be different from the deadline listed in this activity table. Participants should adhere to the activity deadlines on the RPM Auction Schedule posted on the pjw website.

RPM Activity	Deadline
Submittal of Minimum Offer Price Rule (MOPR) exemption request (Unit-Specific)	120 days prior to commencement of offer period
IMM to notify Capacity Market Seller of determination on MOPR exemption request	90 prior to commencement of offer period
PJM to notify Capacity Market Seller of determination on MOPR exemption request	65 days prior to the commencement of offer period
Submittal of minimum level of Sell Offer commitment consistent with Unit-Specific MOPR request	5 days after receipt of PJM determination on Unit-Specific MOPR request
Submittal of preliminary request to remove a resource from Capacity Resource status and preliminary must-offer exemption request for BRA for the reason specified under OATT Attachment M-Appendix § II.C.4.A	Sept 1 st immediately preceding BRA for applicable Delivery Year
Submittal of final request to remove a resource from Capacity Resource status and final must-offer exemption request for BRA for the reason specified under OATT Attachment M-Appendix § II.C.4.A	Dec 1st immediately preceding BRA for applicable Delivery Year
Submittal of preliminary request to remove resource from Capacity Resource status and preliminary must-offer exemption request for IA for the reason specified under OATT Attachment M-Appendix § II.C.4.A	240 days prior to commencement of offer period
Submittal of final request to remove a resource from Capacity Resource status and final must-offer exemption request for IA for the reason specified under OATT Attachment M-Appendix § II.C.4.A	120 days prior to commencement of offer period
Submittal of must-offer exemption request for any reason other than the reason specified under OATT Attachment M-Appendix § II.C.4.A	120 days prior to commencement of offer period
PJM posts summaries of MW of Generation for which it has received requests to remove a resource from Capacity Resource status, and	No later than 5 Business Days after the request/notification deadline

RPM Activity	Deadline
for exceptions to the must-offer requirement for the reason specified under OATT Attachment M-Appendix § II.C.4.A, on an aggregate basis by Zone and LDA that comprises a subset of a Zone. Postings shall specify the following aggregate ranges: less than 100 MW; 100 to 500 MW; 500 to 1000 MW; and specific MW total if over 1000 MW	
IMM to notify Capacity Market Seller of determination on must-offer exemption request and removal of Capacity Resource status	90 days prior to commencement of offer period
Participant notification to PJM and the MM if it disagrees with the IMM determination of its request to remove a resource from Capacity Resource status or must-offer exception request	80 days prior to commencement of offer period
PJM notification to participant of its determination on must offer exemption request and removal of Capacity Resource status	65 days prior to commencement of offer period
Participant notification to PJM and the IMM whether it intends to exclude from its Sell Offer some or all capacity from its generation resource on the basis of an identified exception to the RPM Must Offer Obligation	65 days prior to commencement of offer period
Submittal of request for alternative maximum EFORD (prior to 2025/2026 Delivery Year)	120 days prior to commencement of offer period
IMM provides determination on request for alternative maximum EFORD (prior to 2025/2026 Delivery Year)	90 days prior to commencement of offer period
Participant notification to PJM and the IMM whether agreement has been reached on alternative maximum EFORD (prior to 2025/2026 Delivery Year).	80 days prior to commencement of offer period
PJM notification to participant of its determination on alternative maximum EFORD (if no agreement reached with IMM) (prior to 2025/2026 Delivery Year).	65 days prior to commencement of offer period

RPM Activity	Deadline
Preliminary ELCC Class Ratings and Accredited UCAP Factors	Posting deadline provided in RPM Auction Schedule on PJM website
Participant submits to PJM its Initial/Updated Energy Efficiency Resource Measurement & Verification Plan	30 days prior to commencement of the offer period
Participant submits to PJM its Energy Efficiency Resource Measurement & Verification Report	15 business days prior to start of Delivery Year for which the resource is committed
Participant submits to PJM its Demand Response Resource Plan	30 days prior to commencement of offer period
Base Residual Auction	May, 3 years prior to the Delivery Year
Submittal of binding notice of intent to offer Planned Generation Capacity Resource into Incremental Auction	90 days prior to commencement of offer period
Post Updated Planning Parameters for First Incremental Auction	1 Month prior to First Incremental Auction
First Incremental Auction	September, 20 months prior to the Delivery Year
Post Updated Planning Parameters for Second Incremental Auction	1 Month prior to Second Incremental Auction
Second Incremental Auction	July, 10 months prior to the Delivery Year
Final EFORd fixed for Delivery Year (prior to 2025/2026 Delivery Year)	By November 30 th prior to the Delivery Year
Final Accredited UCAP Factor for Delivery Year (effective with 2025/2026 Delivery Year)	No later than 5 months prior to the start of the Delivery Year
Post Final Planning Parameters for Third Incremental Auction	1 Month prior to Third Incremental Auction
Third Incremental Auction	February, 3 months prior to the Delivery Year

RPM Activity	Deadline
Conditional Incremental Auction	As Needed

Exhibit 2: RPM Auction Timeline

5.3 RPM Auction Parameters

The following information shall be posted by PJM for each Base Residual Auction with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website:

- Preliminary RTO and Zonal Peak Load Forecasts
- LDAs modeled in the Base Residual Auction
- Installed Reserve Margin (IRM)
- Pool-wide Average EFORd (prior to 2025/2026 Delivery Year) and Pool-wide average Accredited UCAP Factor (beginning 2025/2026 Delivery Year)
- Forecast Pool Requirement (FPR)
- Reliability Requirements of the PJM Region and each modeled LDA
- Variable Resource Requirement (VRR) Curves of the PJM Region and each modeled LDA without FRR Entity adjustments. Adjusted VRR Curves with FRR Entity adjustments will be posted after FRR Capacity Plans are approved.
- CETO and CETL values for each modeled LDA
- Transmission Upgrades projected to be in service for the Delivery Year
- Bidding window schedule for the Base Residual Auction
- Cost of New Entry (CONE) for the PJM Region and each modeled LDA
- Net Energy and Ancillary Services Revenue Offset of the PJM Region and each modeled LDA
- Net Cost of New Entry (Net CONE) for the PJM Region and each modeled LDA
- Auction Credit Rate
- The amount(s) of unforced capacity to be procured by PJM and the buy bid price(s) due to increase in Reliability Requirement or the amount(s) to be released from the commitment and the sell offer price(s) due to a reduction in Reliability Requirement will be posted one month prior to the First, Second, or Third Incremental Auctions. The changes in the CETL values and the amount of unforced capacity to be procured for each LDA will be posted one month prior to an Incremental Auction.

5.4 Sell Offers in RPM

5.4.1 Resource-Specific Sell Offer Requirements

Sell Offers for the Base Residual and Incremental Auctions must be submitted in PJM's Capacity Exchange system. Sell offers are only accepted during a fixed bidding window which is open for at least five (5) business days. The bidding window for a Base Residual Auction and Incremental Auctions will be posted on the PJM website. Sell offers may not be changed or withdrawn after the bidding window for a Base Residual Auction or Incremental Auction is closed.

The following are business rules that apply to Resource-Specific Sell Offers:

- The smallest increment that may be offered into any auction is 0.1 MW
- A resource-specific sell offer will specify, as appropriate:
 - Specific Generating Unit, Demand Resource, Energy Efficiency Resource, or Aggregate Resource
 - Each Existing Generation Capacity Resource with available capacity that is capable or can reasonably become capable of qualifying as a Capacity Performance Resource must submit a Capacity Performance sell offer segment.
 - ELCC Resources that are Generation Capacity Resources may not offer or otherwise provide UCAP MW quantities above the greater of their Capacity Interconnection Rights, or the transitional system capability as limited by the transitional resource MW ceiling for the applicable Delivery Year, please see **Manual 14B: Regional Transmission Planning Process**. Notwithstanding, external resources may offer up to their Accredited UCAP.
 - Notwithstanding the above, ELCC Resources may not offer or otherwise provide UCAP MW quantities above their Accredited UCAP.
 - Exceptions to the capacity performance must-offer requirement will be permitted for a generation capacity resource which the Capacity Market Seller demonstrates is reasonably expected to be physically incapable of satisfying the requirements for a Capacity Performance Generation Resource by the start of the Delivery Year, the resource has a financially and physically firm commitment to an external sale of its capacity, or the resource is seeking to remove Capacity Resource status in accordance with Section 5.4.7 of this manual. The Seller must submit a request for an exception (with all supporting information) no later than 120 days before the offer window opens for the relevant RPM Auction. Nothing herein provides a defense to a claim of withholding, market manipulation, or the exercise of market power by any entity who is affiliated with or are under common ownership or control of a Capacity Market Seller that does not submit an offer into the capacity market.
 - Capacity Market Sellers seeking an exception for a BRA on the basis that the resource is incapable of meeting the Capacity Performance Resource requirements shall include a documented plan with the submission of their

exception request showing the steps the Capacity Market Seller intends to pursue for the resource to become physically capable of satisfying the requirements of a Capacity Performance Resource, and provide periodic updates on the progress of such plan in accordance with Tariff, Attachment DD, section 6.6A(c).

- Capacity Market Sellers may specify multiple auctions in a written must-offer exception request (with all supporting documentation) to be reviewed by the IMM and PJM with each applicable auction. Capacity Market Sellers must notify PJM and the IMM of any material changes related to the request up through the closing of the relevant auction(s) offer window.
 - When multiple auctions are specified in the written request, Capacity Market Sellers should continue to create a new request in the IMM's online system (MIRA) for each relevant subsequent auction and confirm that the documentation represents the best, current information.
- An Existing Generation Capacity Resource that can qualify as Capacity Performance product type, but requires substantial investment to do so, is not excused from the capacity performance must-offer requirement; however,
- Demand Resources are not required to submit a Capacity Performance sell offer segment.
- Minimum and maximum amount of installed capacity offered in MWs for the resource by Capacity Performance (annual) Offer Segment and Maximum amount of installed capacity offered in a Seasonal (summer or winter) Capacity Performance Offer Segment. The Seasonal Capacity Performance Offer Segment is considered a flexible offer segment with a minimum MW quantity set to zero MW.
- Offer Segment price willing to receive in \$/MW-day (in UCAP terms)
- Regular Schedule, Self-Schedule or Flexible Self-Schedule flag
- New Unit Pricing participation flag for Planned Generation Capacity Resources requesting New Unit Pricing Adjustment.
- The ICAP MW quantity specified in the Offer Segment will be converted into an UCAP MW quantity for use in the auction clearing by multiplying the ICAP MW quantity specified by the applicable Accredited UCAP Factor for a Generation Capacity Resource, by the applicable ELCC Class rating for a Demand Resource, and by the Forecast Pool Requirement for an EE Resource. The sell offer price specified in the Offer Segment is in UCAP terms and will not be converted for use in the auction clearing.
- A Capacity Performance (annual), or Seasonal Capacity Performance Offer Segment may be offered as either a single price quantity for the capacity of the resource or divided into up to ten offer blocks with varying price-quantity pairs that represent various segments of capacity from the resource. The Offer Segment will consist of block segments at the specified price-quantity pairs.

- The auction specific Accredited UCAP Factor will be determined by PJM. The seller is willing to accept the clearing of any amount equal to or greater than the minimum MW amount offered and equal to or less than the maximum MW offered.
- If the self-scheduled flag is enabled in the Capacity Performance Offer segment, the sell offer price must be set to zero and the minimum and maximum amounts specified in the sell offer must be equal.
- The acceptance of the sell offer is based on the party's Current Available ICAP Position for the Delivery Year at the opening of the auction's bidding window. The acceptance of the sell offer is based on the party's Current Available ICAP Position for the entire Delivery Year (annual position) if Capacity Performance Resource, Current Available ICAP Position for summer period (summer position) if Summer-Period Capacity Performance Resource, Current Available ICAP Position for winter period (winter position) if Winter-Period Capacity Performance Resource.
- The total MWs offered across all Capacity Performance offer segments may not exceed the Current Available ICAP Position for the Delivery Year (i.e., the annual position). The total MWs offered across the Capacity Performance offer segments and the Seasonal Capacity Performance-Summer offer segments may not exceed the Current Available ICAP Position for summer period (i.e., the summer position). The total MWs offered across the Capacity Performance offer segments and the Seasonal Capacity Performance-Winter offer segments may not exceed the Current Available ICAP Position for winter period (i.e., the winter position).
- If a participant has a zero or negative Current Available ICAP Position, PJM will reject the sell offer.
- A sell offer in an RPM Auction that violates any "Conditions on Sales by FRR Entities" as presented in the FRR Business Rules will be rejected.
- For Planned Resources and external resources without firm transmission, sell offers for which the RPM Credit Requirement exceeds the credit available will be rejected.
- A Capacity Market Seller submitting a sell offer for an existing Generation Capacity Resource greater than \$0/MW-Day must seek a unit-specific exception request for such sell offer by submitting Avoidable Cost Rate data to IMM and PJM 120 days prior to the RPM Auction, or may, at its election, utilize an offer cap based on the default gross Avoidable Cost Rate of the applicable resource type, if available. For any Third Incremental Auction, a Capacity Market Seller submitting a sell offer for an existing Generation Capacity Resource may elect to use a default offer cap equal to 1.1 times the Resource Clearing Price in the Base Residual Auction of the relevant LDA and Delivery Year.
- All sell offers for a supplier that fails the Three-Pivotal Supplier Test will be capped within the mitigated LDA.
- Cleared MWs and make-whole MWs for Capacity Performance Offer Segments are binding commitments to provide capacity for the entire Delivery Year. Cleared MWs for Seasonal Capacity Performance-Summer Offer Segments are binding commitments to

provide capacity for the summer period of June through October and May of the Delivery Year. Cleared MWs for Seasonal Capacity Performance-Winter Offer Segments are binding commitments to provide capacity for the winter period of November through April of the Delivery Year.

5.4.2 Flexible Self Scheduling

An LSE may specify offer segments as flexible self-scheduled in the Base Residual Auction to provide a mechanism to manage the quantity uncertainty related to the Variable Resource Requirement.

To specify a segment as a flexible self-scheduled segment, an LSE must specify the following:

- For each such segment, “flexible self-scheduled” must be selected as the offer type of the segment.
- A flexible self-schedule sell offer must specify an offer price that will be utilized in the market clearing in the event that the resource is not needed to cover the calculated capacity obligation. This is in addition to the data required of a self-schedule resource specific sell offer.
- In conjunction with an offer of a flexible self-schedule segment, the LSE must also submit through Capacity Exchange a percentage of the Preliminary Zonal Peak Load Forecast in each transmission zone the LSE wishes to cover with self-scheduled and flexible self-scheduled resources. This percentage of the peak load forecast will be used to calculate the LSE’s resulting capacity obligation through the auction clearing process that considers the Variable Resource Requirement.

If the same LSE offers both self-scheduled and flexible self-schedule segments to serve an Unforced Capacity Obligation within the same LDA, those segments that are self-scheduled will be used first to meet the obligation. The flexible self-scheduled segments will be automatically cleared in the auction if they are needed to supply the LSEs resulting capacity obligation. In the event that the LSE does not need all of the segments that were specified as flexible self-scheduled to meet its resulting capacity obligation, the RPM clearing function will consider the excess as offered into the market at the price specified with the flexible self-scheduled segment. The segments that are considered excess for this LSE will be those that have the highest specified offer prices.

5.4.3 New Entry Pricing Adjustment

New Entry Pricing Adjustment²⁰ is an incentive provided to Planned Generation Resources where the size of the new entry is significant relative to the size of the LDA and there is a potential for the clearing price to drop when all offer prices including that of the new entry are

²⁰ OATT, Attachment DD, Section 5.14(c)

capped. New Entry Pricing Adjustment allows Planned Generation Capacity Resources to recover the amount of their cost of entry-based offer for up to two additional consecutive years under certain conditions.

New Entry Pricing Adjustment is applicable under the following conditions:

1. The new entry must select the New Entry Pricing Adjustment option at the time the sell offer into the initial BRA (Delivery Year 1 BRA) is submitted.
2. The capacity cleared from the new entry (including any make-whole MW) in the Delivery Year 1 BRA would move the total LDA resources committed in the BRA from below the LDA Reliability Requirement to a MW quantity at or above the MW quantity at the price-quantity point on the VRR Curve where the price is 40% of the Net CONE divided by the quantity one minus pool-wide average EFORD through the 2024/2025 Delivery Year, and beginning with the 2025/2026 Delivery Year, divided by the applicable ELCC Class Rating for the Reference Resource.
3. The seller submits offers into the two immediately following BRAs (Delivery Year 2 BRA and Delivery Year 3 BRA) to sell the entire capacity of the unit committed in the Delivery Year 1 BRA at a price equal to the lesser of (a) the price offered in the Delivery Year 1 BRA where the resource was classified as planned generation; or (b) 90% of the Net CONE applicable in the Delivery Year 1 BRA in UCAP basis.
4. Failure to submit a sell offer consistent with condition (3) above in the Delivery Year 3 BRA shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a sell offer consistent with condition (3) in the Delivery Year 2 BRA shall make the resource ineligible for New Entry Price Adjustment for Delivery Years 2 and 3.

New entry revenues:

1. If the new entry meets conditions (1) and (2) above and is the marginal offer in Delivery Year 1 BRA, it sets the resource clearing price for the LDA in Delivery Year 1 BRA and receives revenues based on this price in the Delivery Year 1 BRA.
2. If the new entry clears its capacity in either of the two subsequent BRAs (Delivery Year 2 BRA or Delivery Year 3 BRA), it will receive revenues based on the LDA clearing price in such subsequent year BRA.

3. If the new entry does not clear in either of the two subsequent year BRAs (Delivery Year 2 BRA or Delivery Year 3 BRA), it will be resubmitted at the highest offer price at which the unforced MW amount cleared in the Delivery Year 1 BRA will clear in the subsequent year BRA (Delivery Year 2 BRA or Delivery Year 3 BRA). The resource clearing price and the resources cleared for such subsequent year BRA will be determined from the clearing with the resubmitted sell offer. The new entry shall clear in such subsequent year BRA and be committed in the amount cleared plus any additional make-whole MW from its Sell Offer for such subsequent year BRA, but such make-whole MWs shall not be greater than the make-whole MWs committed in the Delivery Year 1 BRA. The new entry will receive revenues for the entire committed quantity in such subsequent year BRA based on the sell offer price initially submitted for such subsequent year BRA. The difference between the initially submitted sell offer price and the clearing price in such subsequent year BRA and any difference between cleared quantity and committed quantity in such subsequent year BRA will be paid as Resource Make-Whole payments to the new entry. The other capacity resources that clear such subsequent year BRA will receive the clearing price for such subsequent year BRA.

A Capacity Market Seller may make its Sell Offer in the initial BRA (Delivery Year 1 BRA) contingent upon qualifying for New Entry Price Adjustment. Prior to the close of the BRA offer window, a Capacity Market Seller must notify PJM of a NEPA contingent Sell Offer election via an email to rpm_hotline@pjm.com. PJM shall not clear a NEPA contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

While the New Entry Pricing Adjustment is effective, the LDA in which the New Entry was cleared will be modeled as an LDA in Years 2 and 3 regardless of the amount of LDA Capacity Emergency Transfer Limit margin over Capacity Emergency Transfer Objective in the PJM RTEP Process. After the New Entry Pricing Adjustment period, the LDA will be maintained only if deemed necessary in the PJM RTEP Process.

Market Monitor's existing authority and review responsibilities shall include "New Entry Pricing." Market Monitor shall analyze and report on "New Entry Pricing" in the State of the Market Report.

5.4.4 Sell Offer Caps

Submission of the Avoidable Cost Rate (ACR) Data

120 days prior to the commencement of the offer period for an RPM Auction, participants must submit the data specified in **Section 6.7 of Attachment DD of the Open Access Transmission Tariff** in order to submit a non-zero Sell Offer in the Auction.

Capacity resource owners must supply PJM with their avoidable cost data through the IMM's Member Information Reporting Application ("MIRA").

The avoidable cost calculation is based on the categories of cost that are specified in **Section 6.8 of Attachment DD of the Open Access Transmission Tariff**. The calculation should be based on the annual costs that would be avoidable assuming the unit would otherwise retire.

Where multiple units exist at a single plant, the plant's total avoidable costs shall be allocated to each individual unit in an appropriate manner. The sum of such costs assigned to each unit shall equal the total plant costs.

The avoidable cost data should be for the 12 months preceding the month in which the data must be provided.

For units that are jointly-owned, only one owner, typically the operator is expected to provide avoidable cost data and Projected PJM Market Revenues for the unit.

All joint-owners of a unit can input their own bilateral revenues/costs, opportunity costs and transition adder.

If a unit is not expected to be operational during the Delivery Year, no avoidable cost and opportunity cost data are required, but notice of status is required.

Calculation of Sell Offer Caps

Sell offer caps shall be calculated as specified in **Section 6.4 of Attachment DD of the Open Access Transmission Tariff**.

A unit must submit unit-specific ACR data, specify an opportunity cost, or use the default rate, in order to submit a sell offer greater than zero.

Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-specific bilateral contracts from such Generation Capacity Resource, net of energy and ancillary services market offers for such resource. The calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net revenues from the three most recent whole calendar years prior to the year in which the BRA is conducted as described in **Section 6.8(d) of Attachment DD of the Open Access Transmission Tariff**.

Sell Offer Cap(s) will be calculated for each Market Participant, by unit, by segment.

90 days prior to the commencement of the offer period, the IMM shall calculate and notify the Capacity Market Seller of their Sell Offer Cap consistent with **Section 6 of Attachment DD of the Open Access Transmission Tariff**.

Planned Generation Resources may be mitigated in accordance with OATT, Attachment DD, Section 6.5.

No offer caps are applied to sell offers of Demand Resources or Planned Energy Efficiency Resources.

5.4.5 Deleted

5.4.6 Qualified Transmission Upgrade Sell Offer Requirements

A Qualifying Transmission Upgrade sell offer will specify, as appropriate:

- Increase in CETL provided by the upgrade (maximum MW, as certified by PJM Transmission Planning Department)
- Minimum MW offered (min = max for upgrades that involve a single equipment upgrade, min could be less than max where participant is proposing multiple upgrades or upgrades to several pieces of equipment)
- Source and sink LDAs associated with the upgrade
- Price willing to receive for each segment in \$/MW-day specified as the price difference between the sink LDA price and the source LDA price

The increase in CETL provided by a Qualifying Transmission Upgrade must be certified by PJM at least 45 days prior to the Base Residual Auction.

Cleared sell offers and offers receiving Make-Whole payments are binding commitments to provide capacity.

5.4.7 Removal of Generation Capacity Resource Status

A Capacity Market Seller seeking to remove Capacity Resource status from a Generation Capacity Resource shall submit a preliminary and final written request to PJM and the IMM, along with supporting data and documentation, in accordance with Tariff, Attachment DD, section 6.6(g).

- Requests shall be submitted to PJM via email to the rpm_hotline@pjm.com and to the IMM through the MIRA application.
- Preliminary requests must be submitted no later than September 1 prior to a BRA, and 240 days prior to an IA. Final requests must be submitted no later than December 1 prior to a BRA, and 120 days prior to an IA.
- The preliminary request must provide the following information:
 - Identification of the Generation Capacity Resource and MW
 - The beginning Delivery Year in which the Seller is seeking to remove Capacity Resource status from the resource
 - Supporting data and documentation indicating the reasons and conditions upon which the Seller is relying in its analysis to remove Capacity Resource status from the resource

- PJM will post the preliminary and final requested MW of Capacity Resource status changes on an aggregate basis by Zone and LDA that comprises a subset of a Zone.

A request will not be accepted for a resource that holds a capacity commitment during the time period in which it seeks to no longer be a Capacity Resource.

The IMM will analyze the effects of removing Capacity Resource status with respect to potential market power concerns and notify the Seller and PJM of its determination no later than 90 days prior to the applicable RPM auction. Subsequently, PJM shall provide its final determination no later than 65 days prior to the applicable RPM auction.

PJM Planning will be notified of requests and final approvals to incorporate the loss of Capacity Resource status in the appropriate planning models and reliability studies.

Once the Capacity Resource status is removed from a Generation Capacity Resource:

- The generation unit will no longer qualify as an Existing Generation Capacity Resource, and as such, will be removed from the Capacity Resource model and no longer eligible to offer in RPM auctions or take on a capacity commitment.
- The Capacity Interconnection Rights associated with the resource shall be subject to termination in accordance with the rules described in Tariff, Part VI, section 230.3.3.
 - The relevant GIA or WMPA of a Generation Capacity Resource that is removed of its Capacity Resource status will be amended to reflect any such removal of Capacity Interconnection Rights.

5.4.8 Minimum Offer Price Rule

The Minimum Offer Price Rule (MOPR) provisions of Section 5.14(h-2) of Attachment DD of the PJM OATT are applicable to each Generation Capacity Resource that is offered into RPM Auctions for the 2023/2024 Delivery Year and all subsequent Delivery Years.

5.4.8.1 MOPR-Related Business Rules and Process Timeline

The following business rules apply to the sell offer of any Generation Capacity Resource that in an RPM Auction is subject to the MOPR of Tariff, Attachment DD, section 5.14(h-2):

- The timeline for pre-auction activities related to MOPR is specified in the table below.
- The MOPR Floor Offer Price applicable to a Generation Capacity Resource that based on the certification process described below is subject to the MOPR is dependent upon whether the resource or uprate of the resource previously cleared in an RPM auction for any Delivery Year.
- For a Generation Capacity Resource that is subject to the MOPR and for which a Sell Offer based on that resource, or any uprate of the Generation Capacity Resource, has not previously cleared an RPM Auction for any Delivery Year, the applicable New Entry MOPR Floor Offer Price, based on the net cost of new entry for the resource, shall be, at the election of the Capacity Market Seller, either (i) the unit-specific value determined in

accordance with the unit-specific exception process for MOPR Floor Offer Prices, or (ii) the default New Entry MOPR Floor Offer Price, if available, of the applicable resource type. A Capacity Market Seller must seek a unit-specific MOPR Floor Offer Price if the resource is of a type for which there is no default New Entry MOPR Floor Offer Price, including hybrid resources. Failure to obtain a unit-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer for such resource for the relevant RPM Auction.

- For a Generation Capacity Resource that is subject to the MOPR and for which a Sell Offer based on that resource has previously cleared an RPM Auction for any Delivery Year, the applicable Cleared MOPR Floor Offer Price, based on the net Avoidable Cost Rate, shall be, at the election of the Capacity Market Seller, either (i) the unit-specific value determined in accordance with the unit-specific exception process for MOPR Floor Offer Prices, or (ii) based on the default gross Avoidable Cost Rate, if available, of the applicable resource type net of projected net energy and ancillary service revenues for the resource (Net ACR). A Capacity Market Seller must seek a unit-specific MOPR Floor Offer Price if the resource is of a type for which there is no default gross Avoidable Cost Rate, including hybrid resources. Failure to obtain a unit-specific MOPR Floor Offer Price will result in the Office of the Interconnection rejecting any Sell Offer for such resource for the relevant RPM Auction.
- The MOPR Floor Offer Price of any Capacity Resource that is subject to the MOPR is expressed in terms of Unforced Capacity MW (“UCAP MW”). A resource’s MOPR Floor Offer Price in \$/UCAP MW-Day is applicable to each MW offered by the resource that is subject to MOPR regardless of the actual Sell Offer quantity and regardless of whether the Sell Offer is for a Seasonal Capacity Performance Resource.
- If any of the individual underlying resources of a commercially aggregated resource are subject to a MOPR Floor Offer Price, the MOPR Floor Offer Price applicable to the Sell Offer of such an aggregate resource is equal to the time and MW-weighted average of the applicable MOPR Floor Offer Prices (zero if applicable) of the individual aggregated resources.

MOPR-Related Process Timeline

Activity	Deadline
PJM posts preliminary estimate of MOPR Floor Offer Prices	No later than 150 days prior to commencement of offer period for an RPM Auction
Capacity Market Seller certifies the status of each Generation Capacity Resource it intends to offer as it relates to Conditioned State Support and Exercise of Buyer-Side Market Power	No later than 150 days prior to commencement of offer period for an RPM Auction

PJM and/or IMM notify Capacity Market Seller of fact-specific review of ability and incentive to exercise Buyer-Side Market Power	No later than 135 days prior to commencement of offer period for an RPM Auction
Capacity Market Seller submits request for a Unit Specific Exception with all required documentation simultaneously to both the IMM and PJM	No later than 120 days prior to commencement of the offer period for the RPM Auction
IMM reviews the request and provides its findings to the Capacity Market Seller and PJM of whether the proposed Sell Offer is acceptable	No later than 90 days prior to the commencement of the offer period of the RPM Auction
PJM reviews the request and provides determination to the Capacity Market Seller and the IMM of whether the proposed sell offer is acceptable and if not provides a minimum sell offer based on data and documentation	No later than 65 days prior to the commencement of the offer period of the RPM Auction
Capacity Market Seller notifies PJM and IMM of minimum level of Sell Offer to which it agrees to commit	No later than 60 days prior to the commencement of the offer period of the RPM Auction

5.4.8.2 Certification Requirement

By no later than 150 days prior to the commencement of the offer period of any RPM Auction conducted for the 2024/2025 Delivery Year and all subsequent Delivery Years, and by the date posted on the PJM website for the 2023/2024 Delivery Year, each Capacity Market Seller must certify for each Generation Capacity Resource the Capacity Market Seller intends to offer into the RPM Auction: (i) whether or not the Generation Capacity Resource is receiving or expected to receive Conditioned State Support under any legislative or other governmental policy or program that has been enacted or effective at the time of the certification, and (ii) whether or not the Capacity Market Seller acknowledges and understands that the Exercise of Buyer-Side Market Power is not permitted in RPM Auctions, and does not intend to submit a Sell Offer for their Generation Capacity Resource as an Exercise of Buyer-Side Market Power.

All Capacity Market Sellers are responsible for the timeliness and accuracy of each certification which is undertaken through PJM's Capacity Exchange system. Any Generation Capacity Resource for which a Capacity Market Seller has not timely submitted the certifications shall be subject to the provisions of the Minimum Offer Price Rule. Notwithstanding the foregoing, if a Capacity Market Seller submits a timely unit-specific exception for the relevant Delivery Year,

and PJM approves the unit-specific MOPR Floor Offer Price, then the Capacity Market Seller may use such floor price regardless of whether it timely submitted the foregoing certifications.

Once a Capacity Market Seller has certified whether or not a Generation Capacity Resource is receiving or expected to receive Conditioned State Support, the status of such Capacity Resource will remain unchanged unless and until the Capacity Market Seller (or a subsequent Capacity Market Seller) that owns or controls such Capacity Resource provides a certification of a change in such status, the Office of the Interconnection removes such status, or by FERC order. All Capacity Market Sellers have an ongoing obligation to certify to PJM and the IMM a Generation Capacity Resource's material change in status regarding whether such resource is receiving or expected to receive Conditioned State Support within 30 days of such material change.

A Capacity Market Seller must certify for each Generation Capacity Resource the seller intends to offer into each RPM Auction that the seller acknowledges and understands that the Exercise of Buyer-Side Market Power is not permitted in RPM Auctions, and does not intend to submit a Sell Offer for their Generation Capacity Resource as an Exercise of Buyer-Side Market Power. In other words, this status does not carry forward from one auction to the next as does the status regarding Conditioned State Support.

Conditioned State Support

Conditioned State Support is any financial benefit required or incentivized by a state, or political subdivision of a state acting in its sovereign capacity, that is provided outside of PJM Markets and in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction, where "conditioned on clearing in any RPM Auction" refers to specific directives as to the level of the offer that must be entered for the relevant Generation Capacity Resource in the RPM Auction or directives that the Generation Capacity Resource is required to clear in any RPM Auction. Conditioned State Support shall not include any Legacy Policy defined as any legislative, executive, or regulatory action that specifically directs a payment outside of PJM Markets to a designated or prospective Generation Capacity Resource and the enactment of such action predates October 1, 2021, regardless of when any implementing governmental action to effectuate the action to direct payment outside of PJM Markets occurs.

Government policies or programs that do not provide payments or other financial benefit outside of PJM markets and do not provide payment or other financial benefit in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any RPM Auction do not constitute Conditioned State Support. Examples of such government policies that do not constitute Conditioned State Support may include, but are not limited to: policies designed to procure, incent, or require environmental attributes, whether bundled or unbundled (e.g., Renewable Energy Credits, Zero Emission Credits; Regional Greenhouse Gas Initiative); economic development programs and policies; tax incentives; state retail default service auctions; policies or programs that provide incentives related to fuel supplies; any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state

administered federal regulatory program (e.g., Cross-State Air Pollution Rule). In addition, Conditioned State Support shall not be determined solely based on the business model of the Capacity Market Seller, such that the fact that a Self-Supply Entity is the Capacity Market Seller, for example, is not a basis for determining Conditioned State Support.

If PJM reasonably believes a government policy or program would provide Conditioned State Support or a Capacity Market Seller certifies that it is receiving or is expected to receive Conditioned State Support associated with a given Generation Capacity Resource, PJM shall submit a filing at FERC indicating the intent to classify the government policy or program from which that support is derived as Conditioned State Support (and adding such policy or program to the list in Tariff, Attachment DD-3) and apply the Minimum Offer Price Rule to each Generation Capacity Resource reasonably expected to receive such Conditioned State Support.

Upon FERC acceptance that a government policy or program or contract with a state entity constitutes Conditioned State Support, a Generation Capacity Resource for which a Capacity Market Seller certifies that it is receiving Conditioned State Support or is reasonably expected to receive such Conditioned State Support, as identified by PJM, with the advice and input of the IMM, will be subject to the provisions of the Minimum Offer Price Rule.

Exercise of Buyer-Side Market Power

The Exercise of Buyer-Side Market Power means anti-competitive behavior of a Capacity Market Seller with a Load Interest, or directed by an entity with a Load Interest, to uneconomically lower RPM Auction Sell Offer(s) in order to suppress RPM Auction clearing prices for the overall benefit of the Capacity Market Seller's (and/or affiliates of Capacity Market Seller) portfolio of generation and load or that of the directing entity with a Load Interest. Load Interest means, for the purposes of the minimum offer price rule, responsibility for serving load within the PJM Region, whether by the Capacity Market Seller, an affiliate of the Capacity Market Seller, or by an entity with which the Capacity Market Seller is in contractual privity with respect to the subject Generation Capacity Resource.

If a Capacity Market Seller does not certify that it acknowledges the prohibition of the Exercise of Buyer Side Market Power and the Capacity Market Seller intends to exercise Buyer-Side Market Power for this Generation Capacity Resource, then the underlying Capacity Resource will be subject to the MOPR. If PJM and/or the IMM reasonably suspects that a certification contains fraudulent or material misrepresentations such that the Capacity Market Seller's Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power or otherwise reasonably suspects that a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power, then PJM and/or the IMM shall initiate a fact-specific review into the facts and circumstances regarding the Generation Capacity Resource and whether the Capacity Market Seller has the ability and incentive to exercise Buyer-Side Market Power with respect to such Generation Capacity Resource. During such fact-specific review, the Capacity Market Seller will

have the opportunity to explain and justify why a Sell Offer for the Generation Capacity Resource would not be an Exercise of Buyer-Side Market Power.

PJM and/or the IMM shall notify the Capacity Market Seller of the bases for inquiry and initiation of review at least 135 days in advance of the RPM Auction conducted for the 2024/2025 Delivery Year and all subsequent Delivery Years, and by the date posted on the PJM website for the 2023/2024 Delivery Year. In initiating a review, PJM and/or the IMM shall provide the affected Capacity Market Seller, in writing, the basis for its inquiry, including, but not limited to, the Generation Capacity Resource(s), and the purported beneficiary of any price suppression. PJM and/or the IMM may request from the Capacity Market Seller additional information and documentation that is reasonably related to the basis for its inquiry, provided that, PJM and the IMM shall confer with the Capacity Market Seller in advance of any such requests. The Capacity Market Seller shall provide any additional supporting information and documentation requested by PJM and/or the IMM, and any other information and documentation the Capacity Market Seller believes may justify the conduct or action in question as not representing an Exercise of Buyer-Side Market Power, within 15 days or other such timeline as agreed to in writing by the PJM, Market Monitoring Unit and Capacity Market Seller.

The fact-specific review will determine, as necessary, whether a Capacity Market Seller has the ability and incentive to submit a Sell Offer for the Generation Capacity Resource that could be an Exercise of Buyer-Side Market Power, in accordance with the provisions of Sections 5.14(h-2)(2(B)(i)(a) and (b) of Attachment DD.

The following non-exhaustive list of circumstances would preclude an inquiry into or determination regarding an Exercise of Buyer-Side Market Power in the course of a review: (a) the Generation Capacity Resource is a merchant generation supply resources that is not contracted to an entity with a Load Interest; (b) the Generation Capacity Resource is acquired by or under the contractual control of the Capacity Market Seller through a competitive and non-discriminatory procurement process open to new and existing resources; or (c) the Generation Capacity Resource is owned by or bilaterally contracted to a Self-Supply Seller and such resource is demonstrated as consistent with or included in the Self-Supply Seller's long-range resource plan (e.g., a long-range hedging plan) that is approved or otherwise reviewed and accepted by the RERRA, provided that any such plan approval or contracts do not direct the submission of an uneconomic offer to deliberately lower market clearing prices or for the Capacity Market Seller to otherwise perform an Exercise of Buyer-Side Market Power. In addition, to the extent a Generation Capacity Resource may receive compensation in support of characteristics aligned with well-demonstrated customer preferences, such compensation shall not, in and of itself, be a basis for the determination of Buyer-Side Market Power. For purposes of evaluating Buyer-Side Market Power, Self-Supply Seller is a vertically integrated utility or public power entity where vertically integrated utility means a utility that owns generation, includes such generation in its state-regulated rates, and earns a state-regulated return on its investment in such generation; and public power entity means electric cooperatives that are either rate regulated by the state or have their long-term resource plan approved or otherwise reviewed and accepted by a Relevant Electric Retail Regulatory Authority and municipal utilities or joint

action agencies that are subject to direct regulation by a Relevant Electric Retail Regulatory Authority.

Based on the fact-specific review, including the facts and circumstances of the Generation Capacity Resource, with the advice and input of the IMM, PJM shall determine whether a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power. If PJM determines that a Generation Capacity Resource may be the subject of a Sell Offer that would be an Exercise of Buyer-Side Market Power or the Capacity Market Seller certifies that it intends to exercise Buyer-Side Market Power, then such resource will be subject to the provisions of the Minimum Offer Price Rule. If the resource will be subject to the provisions of the Minimum Offer Price Rule, PJM shall include in the notice a written explanation for such determination. A Capacity Market Seller that is dissatisfied with the PJM's determination of whether a given Generation Capacity Resource is subject to the Minimum Offer Price Rule may seek any remedies available to it from FERC; provided, however, that PJM will proceed with administration of the Tariff and market rules based on its determination unless FERC by order directs otherwise.

5.4.8.3 Unit-Specific Exception Process for MOPR Floor Offer Prices

A. Documentation Required in the Unit-Specific Exception Process for New Entry MOPR Floor Offer Price

The Capacity Market Seller of a Generation Capacity Resource that is subject to the MOPR of OATT Attachment DD, section 5.14(h-2) and for which a Sell Offer based on that resource, or any uprate of the Generation Capacity Resource, has not previously cleared an RPM Auction for any Delivery Year may request a unit-specific MOPR Floor Offer Price based on the net CONE of the resource by no later than 120 days prior to the commencement of the offer period of the relevant RPM Auction. Such request must be made simultaneously to PJM and the IMM and must include all required documentation. The Capacity Market Seller must include in its request for an exception documentation to support the fixed development, construction, operation, and maintenance costs of the Capacity Resource, as well as estimates of the offsetting net revenues or sufficient data for PJM and the IMM to produce such net revenue estimates. Estimates of costs and revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the default New Entry MOPR Floor Offer Price established for various resource types. Supporting documentation for project costs may include, as applicable and available, the following:

- Complete project description;
- Environmental permits;
- Vendor quotes for plant or equipment;
- Evidence of actual costs of recent comparable projects;
- Bases for electric and gas interconnection costs and any costs contingencies;
- Bases for support for property taxes, insurances, operations and maintenance (O&M) contractor costs, and other fixed O&M and administrative or general costs;

- Financing documents for construction-period and permanent financing or evidence of recent debt costs of the seller for comparable investments;
- Bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling; and
- Identification and support for any sunk cost that the Capacity Market Seller has reflected as a reduction to its Seller Offer.

The Capacity Market Seller must submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of the resource-specific exception request and that to the best of their knowledge and belief: (1) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its request for an exception is true and correct; (2) the Capacity Market Seller has disclosed all material facts relevant to the request for the exception; and (3) the request satisfies the criteria for the exception.

The financial modeling assumptions for calculating Cost of New Entry for Generation Capacity Resources shall be: (i) nominal levelization of gross costs, (ii) asset life of twenty years, (iii) no residual value, (iv) all project costs included with no sunk costs excluded, (v) use first year revenues (which may include revenues from the sale of renewable energy credits for purposes other than state-mandated or state-sponsored programs), and (vi) weighted average cost of capital based on the actual cost of capital for the entity proposing to build the Capacity Resource. Notwithstanding the foregoing, a Capacity Market Seller that seeks to utilize an asset life other than twenty years (but no greater than 35 years) shall provide evidence to support the use of a different asset life, including but not limited to, the asset life term for such resource as utilized in the Capacity Market Seller's financial accounting (e.g., independently audited financial statements), or project financing documents for the resource or evidence of actual costs or financing assumptions of recent comparable projects to the extent the seller has not executed project financing for the resource (e.g., independent project engineer opinion or manufacturer's performance guarantee), or opinions of third-party experts regarding the reasonableness of the financing assumptions used for the project itself or in comparable projects. Capacity Market Sellers may also rely on evidence presented in federal filings, such as its FERC Form No. 1 or an SEC Form 10-K, to demonstrate an asset life other than 20 years of similar asset projects.

The request shall identify all revenue sources (exclusive of any Conditioned State Support or bilateral contracts that direct submission of an offer to lower RPM Auction clearing prices) relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well-defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in the region, employing input data from sources readily available to the public. Documentation for net

revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. Any evaluation of net revenues should be consistent with Operating Agreement, Schedule 2, including, but not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable.

The Capacity Market Seller shall provide any additional supporting information reasonably requested by PJM or IMM to evaluate the Sell Offer. Requests for additional documentation shall not extend the deadline by which PJM or IMM must provide their determinations of the MOPR exception request.

An evaluated Sell Offer shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, net cost of new entry is below the MOPR Floor Offer Price, based on competitive cost advantages, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's cost, or based on net revenues that are reasonably demonstrated to be higher than those used by PJM in the development of the MOPR Floor Offer Price. The Capacity Market Seller must demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection.

Failure to adequately support costs or revenues so as to enable PJM to make a determination of the MOPR exception request will result in a denial of an exception by PJM.

B. Documentation Required in the Unit-Specific Exception Process for Cleared MOPR Floor Offer Price

The Capacity Market Seller of a Generation Capacity Resource that is subject to the MOPR of OATT Attachment DD, section 5.14(h-2) and for which a Sell Offer based on that resource has previously cleared an RPM Auction for any Delivery Year may request a unit-specific MOPR Floor Offer Price based on the net ACR of the resource by no later than 120 days prior to the commencement of the offer period of the relevant RPM Auction. Such request must be made simultaneously to PJM and the IMM and must include all required documentation. The Capacity Market Seller shall submit a Sell Offer based on the net ACR of the resource consistent with the unit-specific Market Seller Offer Cap process pursuant to Tariff, Attachment DD, section 6.8; except that the 10% uncertainty adder may not be included in the "Adjustment Factor." In addition and notwithstanding the requirements of Tariff, Attachment DD, section 6.8, the Capacity Market Seller may, at its election, include in its request documentation to support projected energy and ancillary services markets revenues. Such a request shall identify all revenue sources (exclusive of any Conditioned State Support or bilateral contracts that direct submission of an offer to lower RPM Auction clearing prices) relied upon in the Sell Offer to

offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well-defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in the region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. Any evaluation of net revenues should be consistent with Operating Agreement, Schedule 2, including, but not limited to, consideration of Fuel Costs, Maintenance Adders and Operating Costs, as applicable.

The Capacity Market Seller must submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of the unit-specific exception request and that to the best of their knowledge and belief: (1) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its request for an exception is true and correct; (2) the Capacity Market Seller has disclosed all material facts relevant to the request for the exception; and (3) the request satisfies the criteria for the exception.

The Capacity Market Seller shall provide any additional supporting information reasonably requested by PJM or IMM to evaluate the Sell Offer. Requests for additional documentation shall not extend the deadline by which PJM or IMM must provide their determinations of the MOPR exception request.

An evaluated Sell Offer shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, fixed, cost-based offer level is below the MOPR Floor Offer Price, based on competitive cost advantages, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's cost, or based on net revenues that are reasonably demonstrated to be higher than those used by PJM in the development of the MOPR Floor Offer Price. The Capacity Market Seller must demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection.

Failure to adequately support costs or revenues so as to enable PJM to make a determination of the MOPR exception request will result in a denial of an exception by PJM.

5.4.8.4 Default MOPR Floor Offer Prices

A. Default New Entry MOPR Floor Offer Price

The Default New Entry MOPR Floor Offer Price for a Generation Capacity Resource that is subject to the MOPR and for which a Sell Offer based on that resource, or any uprate of the Generation Capacity Resource, has not previously cleared an RPM Auction for any Delivery Year is based on the net cost of new entry (“CONE”) of the applicable resource type. The net CONE values are determined by subtracting the estimated net energy and ancillary service revenues from the gross cost of new entry (“CONE”) values shown in the table below. The gross CONE values of the table below are adjusted for Delivery Years subsequent to the 2022/2023 or 2026/2027 Delivery Year, as applicable, as described below. The net energy and ancillary services revenue estimate is determined for each resource type and for each Zone as described in sections 5.14(h-2)(3)(A)(i) through (viii) of Attachment DD of the PJM OATT.²¹

For the capacity resource types listed in the table below, the Default New Entry MOPR Floor Offer Price is set equal to the net CONE of each resource type expressed in terms of Unforced Capacity (“UCAP”) MW where the net CONE values are initially calculated for each resource type in terms of nameplate MW and then converted to UCAP MW. Through the 2024/2025 Delivery Year the net CONE is converted to UCAP MW terms based on the applicable class average EFORD for thermal generation resource types and battery energy storage resource types and the applicable ELCC Class Rating for battery storage, wind and solar generation resource types. Beginning with the 2025/2026 Delivery Year, the net CONE is converted to UCAP MW terms based on the applicable class average Accredited UCAP Factor (i.e., applicable ELCC Class Rating). The resultant net CONE in nameplate MW terms of the battery energy storage resource type is multiplied by 2.5 prior to converting to UCAP terms.

Gross CONE Values used to Determine Default New Entry MOPR Floor Offer Prices

Resource Type	Through the 2025/2026 Delivery Years: Gross CONE (2022/2023 \$/MW-Day) (Nameplate)	For the 2026/2027 Delivery Year and Subsequent Delivery Years: Gross Cost of New Entry (2026/2027 \$/MW-day Nameplate)
Nuclear	\$2,000	\$2,568

²¹ For the coal resource type, the net energy and ancillary services revenue estimate uses Northern Appalachian delivered prices from rail and barge.

Coal	\$1,068	\$1,480
Combined Cycle	\$320	\$540
Combustion Turbine	\$294	394
Fixed Solar PV	\$271	\$298
Tracking Solar PV	\$290	\$321
Onshore Wind	\$420	\$438
Offshore Wind	\$1,155	\$1,351
Battery Energy Storage	\$532	\$502

Beginning with the 2023/2024 Delivery Year, the gross CONE values of the table above will be adjusted annually based on changes in the Applicable United States Bureau of Labor Statistics (“BLS”) Composite Index. The Applicable BLS Composite Index for the combustion turbine and combined cycle resource types shall be the same Applicable BLS Composite Index as that applied to adjust the gross CONE used to determine the VRR Curve for that Delivery Year (see Section 3.3.1 of this manual). For all other resource types, the “BLS Producer Price Index Turbines and Turbine Generator Sets” component shall be replaced with the “BLS Producer Price Index Final Demand, Goods Less Food & Energy, Private Capital Equipment.” For the 2023/2024 through 2025/2026 Delivery Years, inclusive, the resultant value shall then be then adjusted further by a factor of 1.022 for nuclear and coal resource types or 1.01 for solar, wind, and storage resource types to reflect the annual decline in bonus depreciation scheduled under federal corporate tax law. No such further adjustment shall be made to the resultant values for the 2027/2028 Delivery year and subsequent Delivery Years.

B. Default Gross Avoidable Cost Rate for Determination of Cleared MOPR Floor Offer Prices

For a Generation Capacity Resource that is subject to the MOPR and for which a Sell Offer based on that resource has previously cleared an RPM Auction for any Delivery Year, the applicable Cleared MOPR Floor Offer Price is based on the net Avoidable Cost Rate determined by subtracting the estimated net energy and ancillary service revenues of the resource from the gross ACR of the resource. The Cleared MOPR Floor Offer Price of a Generation Capacity Resource shall be, at the election of the Capacity Market Seller, either (i) based on the unit-specific net Avoidable Cost Rate (“ACR”), or (ii) if available, the default gross ACR of the applicable resource type shown in the table below net of energy and ancillary services revenue determined for the resource as described in section 5.4.8.5 of this manual. The gross ACR values of the table below are adjusted for Delivery Years subsequent to the 2022/2023 or 2026/2027 Delivery Year, as applicable, using the 10-year average Handy-Whitman Index to account for expected inflation.

For purposes of submitting a Sell Offer, the net ACR values are expressed in terms of Unforced Capacity (“UCAP”) MW where the net ACR values are initially calculated for each resource in terms of nameplate MW and then converted to UCAP MW. Through the 2024/2025 Delivery Year the net ACR is converted to UCAP MW terms based on the unit-specific EFORD for thermal generation resource types and battery energy storage resource types and the unit-specific Accredited UCAP value for battery energy storage, solar and wind generation resource types (appropriately time-weighted for any winter Capacity Interconnection Rights). Beginning with the 2025/2026 Delivery Year, the net ACR is converted to UCAP MW terms for all generation resource types based on the resource-specific Accredited UCAP Factor.

Default Gross ACR Values used to determine MOPR Floor Offer Price of Existing Capacity Resource

Existing Resource Type	Through the 2025/2026 Delivery Years: Default Gross ACR (2022/2023 \$/MW-Day) (Nameplate)	For the 2026/2027 Delivery Year and Subsequent Delivery Years: Default Gross ACR (2026/2027) (\$/MW-day) (Nameplate)
Nuclear – Single Unit	\$697	\$591
Nuclear – Multi Unit	\$445	\$537
Coal	\$80	\$94
Combined Cycle	\$56	\$113
Combustion Turbine	\$50	\$52
Steam Oil & Gas	NA	\$64
Solar PV (Fixed and Tracking)	\$40	\$70
Onshore Wind	\$83	147

5.5 Buy Bids in RPM

Buy Bids for the Incremental Auctions must be submitted in PJM’s Capacity Exchange system. Buy Bids are only accepted during a fixed bidding window which is open for at least five (5)

business days. Buy Bids may not be changed or withdrawn after the bidding window for an Incremental Auction is closed.

A Buy Bid must specify:

- Quantify of unforced capacity resources desired, in increments of 0.1 MWs;
- Maximum price willing to pay for unforced capacity resources in \$/MW-day;
- All Buy Bids will be for Capacity Performance Resources
- Desired location (Locational Deliverability Area) for the replacement capacity.

Buy Bids may not specify a minimum MW amount. The Buy Bid may clear any MW amount equal to or less than the quantity of unforced capacity resources desired in the Buy Bid.

In the event of a delay or cancellation of a Qualifying Transmission Upgrade, the Buy Bid will specify the purchase of capacity resources (of the Capacity Performance Resource type) in the LDA for which the Qualifying Transmission Upgrade was to increase the CETL (Sink LDA).

Cleared Buy Bids are binding commitments to purchase capacity.

5.6 Energy Market Offer Requirements

All generation resources that have an RPM Resource Commitment must offer into PJM's Day Ahead Energy Market. Demand Resources that have an RPM Resource Commitment must be registered in the Full Program Option or Capacity Only Option of the Emergency or Pre-Emergency Load Response Program and thus available for dispatch during PJM-declared emergency events. Please refer to the ***Energy & Ancillary Services Market Operations Manual (M-11)*** for details on PJM Energy Market participation.

5.7 Base Residual Auction

The Reliability Pricing Model includes a single Base Residual Auction for each Delivery Year. A Base Residual Auction is held during the month of May three (3) years prior to the start of the Delivery Year. Base Residual Auctions are conducted in accordance with the auction schedule posted on the PJM website.

5.7.1 Participation in the Base Residual Auction

Products that resource providers can offer into PJM's Base Residual Auction include:

- Existing Generation Capacity Resources
- Planned Generation Capacity Resources
- Existing Demand Resources
- Planned Demand Resources
- Energy Efficiency Resources

- Aggregate Resources
- Qualifying Transmission Upgrades

Existing Generation Capacity Resources in a party's RPM Resource Portfolio that have no exception to the RPM must offer requirement and that have available capacity to offer and are not offered into the Base Residual Auction for the Delivery Year shall be excluded from participation in any and all Incremental Auctions conducted for the Delivery Year. Generation is treated as existing when the generation is (a) in service at the commencement of the Base Residual Auction or (b) not yet in service but has cleared in an RPM Auction for any prior Delivery Year. These unoffered MWs from existing generation resources shall be ineligible to serve as capacity resources on behalf of any RPM or FRR Load Serving Entity for such Delivery Year, and are therefore prohibited from receiving any RPM capacity revenues for the Delivery Year and prohibited from being committed to an FRR Entity's FRR Capacity Plan for the Delivery Year. To enforce this business rule, PJM will track Daily Unoffered ICAP amounts for generation resources.

Effective with the 2025/2026 Delivery Year, a Planned Generation Capacity Resource must satisfy the requirements of the binding notice of intent in section 4.2.3.1 in order for the Planned Generation Capacity Resource to be included in a Sell Offer for an RPM Auction.

The following are business rules that apply to the Base Residual Auction:

- Existing Generation Capacity Resources, existing Demand Resources, and Energy Efficiency Resources that have an increase in Available ICAP after the Base Residual Auction are eligible to offer the capacity increase into an Incremental Auction for the Delivery Year if the increase is approved prior to the opening of the Incremental Auction bidding window. See Section 5.8.1 for business rules regarding participation in an Incremental Auction.
- For the Base Residual Auction, a party's Current Available ICAP Position for a specific unit for the Delivery Year are equal to the minimum of (Daily ICAP Owned – Daily FRR Capacity Plan Commitments) for the Delivery Year.

$$AvailICAPPosition_{GEN} = Min_{DY}(DailyICAPOwned - DailyFRRCommitments)$$

- For the Base Residual Auction, a party's Current Available ICAP Position for a specific unit for the summer/winter season is calculated. A party's Current Available ICAP Position for the summer season are equal to the minimum (Daily ICAP Owned – Daily FRR Capacity Plan Commitments) for June through October and May of the Delivery Year. A party's Current, Available ICAP Position for a specific unit for the winter season are equal to the minimum (Daily ICAP Owned – Daily FRR Capacity Plan Commitments) for November through April of the Delivery Year.
- Following a Base Residual Auction, a party's Daily Unoffered ICAP for a generation resource is calculated and is equal to the Available ICAP Position minus the Offered ICAP

in the party's sell offer. A FRR Entity's Daily Unoffered ICAP for a generation resource is set equal to 0 MW.

$$\text{DailyUnofferICAP}_{GEN} = \text{AvailICAPPosition}_{GEN} - \text{OfferedICAP}$$

- A Demand Resource's Available ICAP to offer into a Base Residual Auction is determined based on pre-registration confirmation process in the Capacity Exchange system for such Base Residual Auction and PJM's approval of the Curtailment Service Provider's DR Sell Offer Plan for such Base Residual Auction. A Demand Resource's Existing Available ICAP is determined based on the CSP's completion of the pre-registration process and the DR Existing Setup process in the Capacity Exchange system. A Demand Resource's Planned Available ICAP is determined based on PJM's approval of planned MWs in the CSP's DR Sell Offer Plan and the CSP's completion of the DR Planned Setup process in the Capacity Exchange system. A Demand Resource's Available ICAP is equal to the Existing Available ICAP and Planned Available ICAP. A Demand Resource's Existing Available ICAP and Planned Available ICAP is further classified by the CSP in the DR Existing/Planned Setup process as MWs intend to offer as Annual Capacity Performance, MWs intend to offer as Summer-Period Capacity Performance, and MWs intend to offer as part of Aggregate Resource. Such classification is used to establish the maximum Existing/Planned Available ICAP that may be offered as Capacity Performance (annual) and maximum Existing/Planned Available ICAP that may be offered as Seasonal Capacity Performance (summer).
- An EE Resource's Available ICAP to offer into a Base Residual Auction is determined based on PJM's approval of the provider's Initial/Updated M&V Plan for such Base Residual Auction and the provider's completion of the EE Setup process in the Capacity Exchange system prior to the Base Residual Auction. An EE Resource's Existing Available ICAP is determined based on Nominated EE Value approved by PJM in the most recent Post-Installation M&V Report and the EE Provider's completion of the EE Existing Setup process in the Capacity Exchange system. An Energy Efficiency Resource's Planned Available ICAP is determined based on PJM's approval of the provider's Initial/Updated M&V Plan for such Base Residual Auction and the provider's completion of the EE Planned Setup process for such Base Residual Auction in the Capacity Exchange system. An EE Resource's Available ICAP to offer into an RPM Auction is equal to the Existing Available ICAP and Planned Available ICAP. An Energy Efficiency Resource's Existing Available ICAP and Planned Available ICAP is further classified by the EE Resource Provider in the EE Existing/Planned Setup process as MWs intend to offer as Annual Capacity Performance, MWs intend to offer as Summer-Period Capacity Performance, and MWs intend to offer as part of an Aggregate Resource. Such classification is used to establish the maximum Existing/Planned Available ICAP that may be offered as Capacity Performance (annual) and maximum Existing/Planned Available ICAP that may be offered as Seasonal Capacity Performance (summer).
- Resources may be directly offered into the Base Residual Auction by specifying a MW quantity and sell offer price in the sell offer or may be self-scheduled into the Base

Residual Auction by enabling the self-schedule flag in the sell offer. See the Resource Specific Sell Offer Requirements Section for further details.

- The product offered in the Base Residual Auction must be resource-specific or apply to a Qualifying Transmission Upgrade.
- The smallest increment that may be offered into a Base Residual Auction is 0.1 MW.

5.7.2 Auction Clearing Mechanism – Base Residual Auction

The Base Residual Auction clearing software is an optimization algorithm. This algorithm has the objective of minimizing capacity procurement costs given the supply offers, Variable Resource Requirement Curve(s), and Locational Constraints. The algorithm will also enforce the requirement that the cleared quantity of Summer-Period Capacity Performance Resources equal the cleared quantity of Winter-Period Capacity Performance Resources for the PJM Region. The supply curve formed by the Sell Offers submitted within a modeled LDA shall only consider the quantity of MWs from Summer-Period Capacity Performance Resources that are equally matched with Winter-Period Capacity Performance Resources within the LDA, such that only the equally matched quantity of opposite-season Sell Offers are considered in satisfying the modeled LDA's reliability requirement.

The Base Residual Auction clearing price for each LDA is determined by the optimization algorithm. The Resource Clearing Price within each LDA is the sum of:

- The marginal value of system capacity, and
- Locational Price Adder(s), if any, relevant to such LDA.

The marginal value of system capacity is the clearing price for Capacity Performance Resources in the unconstrained area of the PJM region.

The Locational Price Adder applicable to each cleared Seasonal Capacity Performance Resource is determined during the post-processing of the RPM Auction results consistent with the manner in which the auction clearing algorithm recognizes the contribution of Seasonal Capacity Performance Resource Sell Offers in satisfying an LDA's Reliability Requirement. For each LDA with a positive Locational Price Adder with respect to the immediate higher level LDA, starting with the lowest level constrained LDA and moving up, PJM determines the quantity of equally matched Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources located and cleared within that LDA. Up to this quantity, the cleared Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources with the lowest sell offer prices will be compensated using the highest Locational Price Adder applicable to such LDA; and any remaining Seasonal Capacity Performance Resources cleared within the LDA are effectively moved to the next higher constrained LDA, where they are considered in a similar manner for compensation.

In the event that the Sell Offers forming the supply curve do not result in an intersection with the Variable Resource Requirement Curve, the marginal value of system capacity will be set along

the Variable Resource Requirement Curve by extending the supply curve vertically from its end point until it intersects the Variable Resource Requirement Curve.

5.7.3 Resource Make-Whole Payments in the Base Residual Auction

A resource provider that offered and cleared fewer MWs than the minimum MW specification in the Base Residual Auction would receive a Resource Make-whole payment.

The Resource Make-whole Payment is equal to the product of the Capacity Resource Clearing Price and the quantity difference between the sell offer's minimum MW specification and the cleared MW quantity in the Base Residual Auction.

$$\text{ResourceMakewholePayment} = RCP^*(\text{SellOfferMinMW} - \text{ClearedMW}_{BRA})$$

A resource provider that offered and cleared a Seasonal Capacity Performance sell offer for which the sell offer price exceeded the clearing price determined for such resource as a result of the seasonal matching process in the post-processing of the auction results as described in Section 5.7.2 will receive a Resource Make-whole Payment. The Resource Make-whole Payment is equal to the difference between the sell offer price and clearing price for such resource determined as a result of the seasonal matching process, multiplied by the cleared MW quantity.

Make-whole payments required in the BRA will be charged to all LSEs in the LDA via the Final Zonal Capacity Price.

Only cleared Qualifying Transmission Upgrades, cleared resource-specific sell offers, and cleared flexible self-scheduled offers in excess of their self-scheduled quantity are eligible for make-whole payments in the BRA.

5.7.4 Posting of Base Residual Auction Results

Base Residual Auction results are posted to a participant's Capacity Exchange account and summary results are posted to a public portion of the PJM website. For any Base Residual Auction, clearing results will not be posted until after 4 p.m. EPT on Friday of Auction Clearing week.

Participants can view the resolution of their sell offer in the BRA through Capacity Exchange. The results of their sell offer will be categorized as cleared, uncleared, offered, unoffered, or make-whole.

Base Residual Auction sales are credited weekly during the Delivery Year as the unforced capacity is actually utilized.

5.8 Incremental Auctions

The First, Second, and Third Incremental Auctions are conducted to allow for replacement resource procurement, increases and decreases in resource commitments due to reliability requirement adjustments.

A *Conditional Incremental Auction* may be conducted if a Backbone transmission line is delayed and results in the need for PJM to procure additional capacity in a Locational Deliverability Area to address the corresponding reliability problem.

5.8.1 Participation in the Incremental Auctions

Existing Generation Capacity Resources in a party's RPM Resource Portfolio that have no exception to the RPM must offer requirement and that have available capacity to offer and are not offered into an Incremental Auction for the Delivery Year shall be excluded from participation in any subsequent Incremental Auctions conducted for the Delivery Year. Generation is treated as existing when the generation is (a) in service at the commencement of the Incremental Auction or (b) not yet in service but has cleared an RPM Auction for any prior Delivery Year. These unoffered MWs from existing generation shall be ineligible to serve as capacity resources on behalf of any RPM or FRR Load Serving Entity for such Delivery Year, and are therefore prohibited from receiving any RPM capacity revenues for the Delivery Year and prohibited from being committed to an FRR Entity's Capacity Plan for the Delivery Year. To enforce this business rule, PJM will track Daily Unoffered ICAP amounts of generation resources.

Effective with the 2025/2026 Delivery Year, a Planned Generation Capacity Resource must satisfy the requirements of the binding notice of intent in section 4.2.3.1 in order for the Planned Generation Capacity Resource to be included in a Sell Offer for an RPM Auction.

Products that resource providers can offer into an Incremental Auction include:

- Existing Generation Capacity Resources that were offered and not cleared in a prior auction for the same Delivery Year
- Planned Generation Capacity Resources
- Existing Demand Resources or Energy Efficiency Resources that were offered and not cleared in a prior auction for the same Delivery Year
- Planned Demand Resources or Energy Efficiency Resources
- Transmission upgrades are not eligible to be offered into Incremental Auctions.
(Transmission upgrades are only eligible to be offered into Base Residual Auction)

The following are business rules that apply to the Incremental Auctions:

- The product offered in the Incremental Auction must be resource-specific.
- The smallest increment that may be offered into an Incremental Auction is 0.1 MW.
- Planned Generation Capacity Resources, Planned Demand Resources, or Energy Efficiency Resources that were not eligible to participate at the time of the Base Residual

Auction or prior Incremental Auction, are eligible to participate in subsequent Incremental Auctions if the planned generation, Planned Demand Resource, or Energy Efficiency Resource meets the requirements specified in Section 4 of this manual.

- Existing Generation Capacity Resources and existing Demand Resources or Energy Efficiency Resources that have increases in Available ICAP after an Incremental Auction are eligible to offer the capacity increase into a subsequent Incremental Auction for the Delivery Year if the Available ICAP increase is approved prior to the opening of the subsequent Incremental Auction bidding window.
- For Incremental Auctions, a Current Available ICAP Position is calculated for generation resources. An Available ICAP Position is also determined for demand resources and energy efficiency resources that intend to offer into such Incremental Auction. These Available ICAP positions are determined for annual period and for summer/winter period if Seasonal Capacity Performance Resource.

A party's Current Available ICAP Position on a unit for an Incremental Auction is equal to the minimum Daily Available ICAP for such unit during the Delivery Year or during summer/winter season.

$$CurrentAvailableICAPPosition_{GEN} = Min (DailyAvailableICAP_{GEN})$$

For a party, the Daily Available ICAP on a unit is equal to Daily ICAP Owned – Daily Unoffered ICAP – (Daily RPM Resource Commitments/(Accredited UCAP Factor)) – Daily FRR Capacity Plan Commitments.

$$DailyAvailableICAP_{GEN} = \\ DailyICAPOwned - DailyUnofferICAP - \left(\frac{DailyRPMResourceCommitments}{Accredited\ UCAP\ Factor} \right) \\ - DailyFRRCommitments$$

A party's Daily Unoffered ICAP for a specific unit is calculated by adding the sum of any Daily Unoffered ICAP for such unit in prior RPM Auctions to Daily Unoffered ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases.

$$DailyUnofferICAP_{GEN} \\ = \sum (DailyUnofferICAP_{Prior\ RPM\ Auctions} + UnofferICAP_{Bilateral\ Sales\ / \ Purchases})$$

For an Incremental Auction, a party's Daily Unoffered ICAP for generation resource is equal to the Current Available ICAP Position minus the Offered ICAP in the party's sell offer. A FRR Entity's Daily Unoffered ICAP for a generation resource is set equal to 0 MW.

$$DailyUnofferICAP_{GEN} = MinAvailableICAPPosition - OfferedICAP$$

A Demand Resource's Available ICAP to offer into an Incremental Auction is determined based on pre-registration confirmation process in the Capacity Exchange system for such Incremental Auction and PJM's approval of the Curtailment Service Provider's DR Sell Offer Plan for such

Incremental Auction. A Demand Resource's Existing Available ICAP is determined based on the CSP's completion of the pre-registration process and the DR Existing Setup process in the Capacity Exchange system. A Demand Resource's Planned Available ICAP is determined based on PJM's approval of planned MWs in the CSP's DR Sell Offer Plan and the CSP's completion of the DR Planned Setup process in the Capacity Exchange system. A Demand Resource's Available ICAP is equal to the Existing Available ICAP and Planned Available ICAP. A Demand Resource's Existing Available ICAP and Planned Available ICAP is further classified by the CSP in the DR Existing/Planned Setup process as MWs intend to offer as Annual Capacity Performance and MWs intend to offer as Summer-Period Capacity Performance. Such classification is used to establish the maximum Existing/Planned Available ICAP that may be offered as Capacity Performance (annual) and maximum Existing/Planned Available ICAP that may be offered as Seasonal Capacity Performance (summer).

An EE Resource's Available ICAP to offer into an Incremental Auction is determined based on PJM's approval of the provider's Initial/Updated M&V Plan for such Incremental Auction and the provider's completion of the EE Setup process in the Capacity Exchange system prior to the Incremental Auction. An EE Resource's Existing Available ICAP is determined based on Nominated EE Value approved by PJM in the most recent Post-Installation M&V Report and the EE Provider's completion of the EE Existing Setup process in the Capacity Exchange system. An Energy Efficiency Resource's Planned Available ICAP is determined based on PJM's approval of the provider's Initial/Updated M&V Plan for such Incremental Auction and the provider's completion of the EE Planned Setup process for such Incremental Auction in the Capacity Exchange system. An EE Resource's Available ICAP to offer into an RPM Auction is equal to the Existing Available ICAP and Planned Available ICAP. An Energy Efficiency Resource's Existing Available ICAP and Planned Available ICAP is further classified by the EE Resource Provider in the EE Existing/Planned Setup process as MWs intend to offer for Annual period and MWs intend to offer for Summer period. Such classification is used to establish the maximum Existing/Planned Available ICAP that may be offered as Capacity Performance (annual) and maximum Existing/Planned Available ICAP that may be offered as Seasonal Capacity Performance (summer).

5.8.2 Timing of the Incremental Auctions

The First Incremental Auction is held during the month of September, twenty (20) months prior to the start of the Delivery Year.

The Second Incremental Auction is held during the month of July, ten (10) months prior to the start of the Delivery Year.

The Third Incremental Auction is held during the month of February, three (3) months prior to the start of the Delivery Year.

Incremental Auctions are conducted in accordance with the auction schedule posted on the PJM website.

5.8.3 Resource Make-Whole Payments in Incremental Auctions

A resource provider that offered and cleared fewer MWs than its minimum MW specification in an RPM Auction would receive a resource make-whole payment. This situation occurs because of the minimum MW specification in the sell offer data. This can occur at most for one resource in each LDA and for a one resource in the unconstrained market region.

The Resource Make-whole Payment is equal to the product of the Capacity Resource Clearing Price and the quantity difference between the sell offer's minimum MW specification and the cleared MW quantity in the Auction.

A resource provider that offered and cleared a Seasonal Capacity Performance sell offer for which the sell offer price exceeded the clearing price determined for such resource as a result of the seasonal matching process in the post-processing of the auction results as described in Section 5.8.5 will receive a Resource Make-whole Payment. The Resource Make-whole Payment is equal to the difference between the sell offer price and clearing price for such resource determined as a result of the seasonal matching process, multiplied by the cleared MW quantity.

Make-whole payments required in the Auction will be charged to all cleared participant and PJM buy bids on pro-rata basis based on the MWs cleared in such auction. Only cleared resource specific sell offers are eligible for make-whole payments in an Incremental Auction.

Make-whole charges assessed to buy bids cleared by PJM will be assessed to LSEs in the LDA via the Final Zonal Capacity Price.

5.8.4 Allocation of Costs in Incremental Auctions

The costs of the incremental commitments that are cleared in Incremental Auctions are allocated to resource providers that cleared Buy Bids in that Incremental Auction based on the cleared Buy Bid MW quantity and the clearing price and to LSEs by adjusting the Zonal Capacity Price.

5.8.5 Auction Clearing Mechanism – Incremental Auctions

The clearing of the Incremental Auctions is determined by the intersection of the supply curve and the demand curve. In the event the Sell Offers forming the supply curve do not intersect with the Buy Bids forming the demand curve, one of the following will occur:

1. The clearing will be set along the demand curve by extending the supply curve vertically upward from its end point until it intersects the demand curve, or
2. The clearing will be set along the supply curve by extending the demand curve vertically downward from its end point until it intersects the supply curve, or

If no intersections occur as a result of the supply curve extension or the demand curve extension, no capacity will be cleared in the Incremental Auction. The Incremental Auction

clearing prices for each Buy Bid or Sell Offer cleared is determined by the same optimization algorithm used in the Base Residual Auction clearing.

The Resource Clearing Price within an LDA is equal to the sum of:

- The marginal value of system capacity and
- The Locational Price Adder(s), if any relevant for such LDA.

The marginal value of system capacity is the clearing price for Capacity Performance Resources in the unconstrained area of the PJM region.

The Locational Price Adder applicable to each cleared Seasonal Capacity Performance Resource is determined during the post-processing of the RPM Auction results consistent with the manner in which the auction clearing algorithm recognizes the contribution of Seasonal Capacity Performance Resource Sell Offers in satisfying participant and PJM Buy Bids in an LDA. For each LDA with a positive Locational Price Adder with respect to the immediate higher level LDA, starting with the lowest level constrained LDA and moving up, PJM determines the quantity of equally matched Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources located and cleared within that LDA. Up to this quantity, the cleared Summer-Period Capacity Performance Resources and Winter-Period Capacity Performance Resources with the lowest sell offer prices will be compensated using the highest Locational Price Adder applicable to such LDA; and any remaining Seasonal Capacity Performance Resources cleared within the LDA are effectively moved to the next higher constrained LDA, where they are considered in a similar manner for compensation.

The First, Second, and Third Incremental Auction clearing software is an optimization algorithm. The algorithm has the objective of minimizing the cost of committing capacity for the submitted Buy Bids given the Locational Constraints and submitted supply offers.

The algorithm will also enforce the requirement that the cleared quantity of Summer-Period Capacity Performance Resources equal the cleared quantity of Winter-Period Capacity Performance Resources for the PJM Region. The supply curve formed by the Sell Offers submitted within a modeled LDA shall only consider the quantity of MWs from Summer-Period Capacity Performance Resources that are equally matched with Winter-Period Capacity Performance Resources within the LDA, such that only the equally matched quantity of opposite-season Sell Offers are considered in satisfying the participant and PJM Buy Bids in a modeled LDA.

5.8.6 Posting of Incremental Auction Results

The Incremental Auction results are posted to a participant's Capacity Exchange account and summary results are posted to a public portion of the PJM website. For any Incremental Auction, clearing results will not be posted until after 4 p.m. EPT on the fifth business day after the close of the RPM Auction offer window.

Participants may view the resolution of their sell offer in the Incremental Auction through Capacity Exchange. The results of their sell offer will be categorized as cleared, offered, unoffered, or make-whole.

Incremental Auction purchases/sales (i.e., Auction Charges/Auction Credits) are charged/credited weekly during the Delivery Year.

5.9 Auction Clearing Results

5.9.1 Zonal Capacity Prices

Zonal Capacity Prices for a Delivery Year are calculated following the Base Residual Auction for the Delivery Year and are adjusted following each Incremental Auction for the Delivery Year.

Preliminary Zonal Capacity Prices are calculated and posted following the Base Residual Auction for each Delivery Year. The Preliminary Zonal Capacity Price for each Zone is the sum of:

1. The marginal value of system capacity for the PJM Region;
2. The Locational Price Adder, if any, for such zones in a constrained Locational Deliverability Area (LDA); and
3. An adjustment in the Zone, if required, to account for any resource make-whole payments.

Make-whole payments are allocated to the entire obligation associated with the area in which the resource is cleared. If the resource clears in the unconstrained area, the make-whole payment is allocated to the entire RTO obligation. If the resource that is made whole clears in located in a constrained LDA, the make-whole payment is allocated to the entire obligation of the constrained LDA.

The following are business rules that apply to the Preliminary Zonal Capacity Prices:

- The Weighted Zonal Capacity Price for a Zone that includes multiple non-overlapping LDAs is the weighted average of the Zonal Capacity Prices for such LDAs, weighted by the Unforced Capacity of Resources Cleared (including Make whole MW) in each such LDA. If the Zone has a smaller LDA within a larger LDA then the Weighted Zonal Capacity Price is calculated using the smaller LDA and the remaining portion of the larger LDA.
- The Locational Price Adder is an addition to the marginal value of unforced capacity within an LDA as necessary to reflect the price of resources required to relieve the applicable binding locational constraints.
- A Locational Price Adder for an LDA shall not be a negative number.

Note:

Preliminary Zonal Capacity Prices for the Delivery Year are posted by PJM at the end of the Base Residual Auction clearing process.

Zonal Capacity Prices for a Delivery Year are adjusted following each Incremental Auction for the Delivery Year. The Adjusted Zonal Capacity Prices for each Zone is the sum of:

1. The average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions conducted to date for the Delivery Year (excluding any Unforced Capacity cleared as replacement capacity);
2. The average Locational Price Adder, if any, weighted by the Unforced Capacity cleared in all auctions conducted to date for the Delivery Year (excluding any Unforced Capacity cleared as replacement capacity)²²; and
3. An adjustment, if required, to account for any resource make-whole payments for all auctions conducted to date for the Delivery Year (excluding any resource make-whole payments to be charged to the buyers of replacement capacity).

Note:

Adjusted Zonal Capacity Prices for the Delivery Year are posted following each Incremental Auction for that Delivery Year.

The Final Zonal Capacity Prices reflect the final price adjustments that are necessary to account for potential decreases in RPM Auction Credits to existing demand resources that were granted relief from Capacity Resource Deficiency Charges due to permanent departure of load. In addition, Final Zonal Capacity Prices reflect any price adjustments that are necessary to account for any transition provisions that are in effect for the Delivery Year (e.g., Prior CIL Exception External Resources that elected prior to the Delivery Year Third Incremental Auction to be relieved of their capacity obligation for such Delivery Year, or EE Resources electing prior to Delivery Year Third Incremental Auction to be relieved of their capacity obligation for such Delivery Year due to prohibition of EE participation by a Relevant Electric Retail Regulatory Authority).

The Final Zonal Capacity Prices are calculated such that the total amount of credit for CTR holders, Incremental CTR Holders, resources cleared for LSEs in all RPM Auctions for a given Delivery Year, Qualifying Transmission Upgrades cleared in the Base Residual Auction, and by LSEs serving load that is committed as price responsive demand for the Delivery Year equals to the total amount of Locational Reliability Charges assessed to loads. The Final Zonal Capacity Price is not net of the Final Zonal CTR Credit Rate.

Note:

The **Final Zonal Capacity Prices** for the Delivery Year are posted by PJM following the Third Incremental Auction for that Delivery Year.

²² A weighted average Locational Price adder may be a negative number.

5.9.2 CTR Credit Rates

The Base Zonal CTR Credit Rate (\$/MW-day) is equal to the Economic Value of CTRs allocated to LSEs in a zone as a result of the Base Residual Auction divided by the Base Zonal UCAP Obligation.

$$\text{BaseZonalCTRCreditRate} = \frac{\text{BRAZonalEconomicValueofCTR}_{\text{LSEs}}}{\text{BaseZonalUCAP}_{\text{Oblig}}}$$

Note:

The **Base Zonal CTR Credit Rate** is posted with the Base Residual Auction results.

The Final Zonal CTR Credit Rate (\$/MW-day) is equal to the Economic Value of CTRs allocated to LSEs in a zone as a result of all RPM Auctions for the Delivery Year divided by the Final Zonal UCAP Obligation.

$$\text{FinalZonalCTRCreditRate} = \frac{\text{FinalZonalEconomicValueofCTR}_{\text{LSEs}}}{\text{FinalZonalUCAP}_{\text{Oblig}}}$$

Note:

The **Final Zonal CTR Credit Rates** are posted by PJM with the Third Incremental Auction clearing results.

5.9.3 CTR Settlement Rates

The CTR Settlement Rate (\$/MW-day) is equal to the total Economic Value of CTRs (\$/day) allocated to LSEs in a zone for all LDAs in which the zone resides as a result of all RPM Auctions for a Delivery Year divided by the maximum of the LDA CTR MWs allocated to LSEs in a zone.

$$\text{FinalZonalCTRSettlementRate} = \frac{\text{FinalZonalEconomicValueofCTR}_{\text{LSEs}}}{\text{ZonalMaxLDACTRMW}_{\text{LSEs}}}$$

Note:

The **CTR Settlement Rates** are posted by PJM with the Third Incremental Auction clearing results.

5.10 Reliability Backstop

The Reliability Backstop provides a mechanism to resolve reliability criteria violations caused by:

- Lack of sufficient capacity committed through the RPM Auctions or
- Near-term transmission deliverability violations identified after the Base Residual Auction is conducted

The purpose of the Reliability Backstop is to guarantee that sufficient generation, transmission and demand response solutions will be available to preserve system reliability. The Reliability Backstop mechanism is based on specific triggers that signal a need for a targeted solution to a reliability problem that was not resolved by the long-term commitment of Capacity Resources committed as a result of the RPM Auctions.

Details on the Reliability Backstop, including the triggering conditions and auction clearing procedures, can be found in ***Section 16 of Attachment DD of the Open Access Transmission Tariff.***

Section 6: Capacity Transfer Rights

Welcome to the *Capacity Transfer Rights* section of the **PJM Manual for the Capacity Market**. In this section, you will find the following information:

- The definition and purpose of Capacity Transfer Rights (see “Definition and Purpose of Capacity Transfer Rights”)
- The business rules for determining Capacity Transfer Rights (see “Determination of Capacity Transfer Rights”)
- The business rules for allocation of Capacity Transfer Rights (see “Allocation of Capacity Transfer Rights”)
- The business rules for determining Capacity Transfer Right credits (see “Capacity Transfer Rights Credits”)
- The business rules for transferring Capacity Transfer Rights (see “Capacity Transfer Rights Transfer”)

6.1 Definition and Purpose of Capacity Transfer Rights

The purpose of Capacity Transfer Rights is to allocate the economic value of transmission import capability that exists into a constrained LDA to holders of Capacity Transfer Rights. Therefore, Capacity Transfer Rights serve to offset a portion of the Locational Price Adder charged to load in constrained LDAs.

As explained in Section 3, constrained Locational Deliverability Areas (LDAs) are modeled with their own VRR curves in the auction clearing process. The transmission import capability limit into a constrained LDA would require clearing resources with higher offer prices in the LDA (but at less than the prices on the LDA VRR Curve) to achieve the highest possible reliability in the LDA. This process would typically result in a price separation with LDA clearing price being higher than the unconstrained RTO clearing price. The Zonal Capacity Prices calculated in the constrained LDA would also be higher as they are a function of this higher clearing price. LSE Locational Reliability Charge in a zone is the LSE unforced capacity obligation multiplied by the Zonal Capacity Price. However, part of the LSE unforced capacity obligation is met by imported resources that receive auction credits at a lower price than the LDA clearing price. The credit to account for these lower-priced imported resources is achieved by allocating Capacity Transfer Rights (CTRs) to LSEs. CTRs would amount to dollar credits that would reduce the LSE load charges.

It is important to note that the LDA Reliability Requirement (based on the internal generation and CETO) used in the clearing process is typically higher than the unforced capacity obligation (based on coincident peak load) used for load charges and the CTR determination. Since the concept of CTRs is to provide credit towards the portion of the obligation met by imported resources, CTRs are calculated as the difference between the zonal (LDA) unforced capacity

obligation and the unforced capacity cleared in the zone (LDA). The total CTRs are typically lower than the LDA import capability (CETL) while the CETL is fully utilized in meeting the LDA Reliability Requirement and calculating the LDA clearing price. LSEs in the constrained LDA benefit when the CETL into the LDA is increased by transmission upgrades.

A transmission upgrade may be funded by a Project Developer, Eligible Customer, or Upgrade Customer (or, for facilities or upgrades in PJM queue prior to March 1, 2007 to an Interconnection customer) obligated to fund a transmission facility or upgrade through a rate or charge specific to such facility or upgrade. In this case, the customer is allocated Incremental CTRs (Participant-Funded Project ICTRs). Alternately, a transmission upgrade may be offered as a Qualified Transmission Upgrade (QTU) in the Base Residual Auction. A cleared QTU will receive auction credits.

Incremental Capacity Transfer Rights (ICTRs) associated with Regional Facilities and Necessary Lower Voltage Facilities that are Incremental Rights-Eligible Required Transmission Enhancements will be allocated to Responsible Customers to whom the costs of the Regional Facilities and Necessary Lower Voltage Facilities are assigned. ICTRs associated with Lower Voltage Facilities that are Incremental Rights-Eligible Required Transmission Enhancements are also allocated to Responsible Customers to whom the costs of the Lower Voltage Facilities are assigned. Incremental Rights-Eligible Required Transmission Enhancements are Regional Facilities and Necessary Lower Voltage Facilities or Lower Voltage Facilities (as defined in Scheduled 12 of the Tariff) and meet one of the following criteria: (1) cost responsibility assigned to non-contiguous Zones that are not directly electrically connected; or (2) cost responsibility is assigned to Merchant Transmission Providers that are Responsible Customers.

In these cases the total CTRs are reduced to provide credits to these parties before distributing the CTRs to LSEs.

6.1.1 Capacity Transfer Rights

The following are business rules that apply to Capacity Transfer Rights:

- Capacity Transfer Rights are applicable only for the Delivery Year for which they were defined.
- Capacity Transfer Rights are specified to the nearest 0.1 MW.
- The total amount of Capacity Transfer Rights that are allocated to LSEs in an LDA are equal to the amount of unforced capacity imported into such LDA based on the results of the Base Residual Auction and all Incremental Auctions for such Delivery Year less [the Participant-Funded ICTRs and Incremental Rights-Eligible Required Transmission Enhancements ICTRs that are allocated into the LDA for the Delivery Year less the amount of import capability increase into the LDA attributed to Qualifying Transmission Upgrades for the Delivery Year]. Capacity Transfer Rights (CTRs) for LSEs will be allocated in MWs for each modeled LDA in which the RPM Auctions for the Delivery Year resulted in a non-zero average weighted Locational Price Adder with respect to the immediate higher level LDA.

- The economic value (in \$/day) of Capacity Transfer Rights in an LDA as a result of all RPM Auctions for the Delivery Year is equal to (i) the average weighted Locational Price Adder for such LDA determined with respect to the immediate higher level LDA as a result of all RPM Auctions for such Delivery Year, multiplied by (ii) the MW quantity of CTRs allocated to LSEs in the LDA. The total economic value (in \$/day) of Capacity Transfer Rights to LSEs in a zone is the sum of the economic values of Capacity Rights in an LDA for all LDAs in which such zone resides.

6.1.2 Participant-Funded Project Incremental Capacity Transfer Rights

Incremental Capacity Transfer Rights (ICTRs) are allocated to an Upgrade Customer (or, for facilities or upgrades in PJM queue prior to March 1, 2007 to an Interconnection customer) obligated to fund a transmission facility or upgrade through a rate or charge specific to such facility or upgrade, to the extent such upgrade or facility increases the import capability into an LDA. Such incremental Capacity Transfer Rights allocation is based on the incremental increase in import capability across a Locational Constraint that is caused by the transmission facility upgrade.

Incremental Capacity Transfer Rights will be effective for thirty years or the life of the facility or upgrade, whichever is less. Under conditions when the internal resources cleared in the LDA are high, the total amount of Capacity Transfer Rights is limited, which may reduce the Incremental Capacity Transfer Rights available to Participant-Funded Projects.

If a customer funds advancement of a network transmission upgrade, the customer will receive Incremental CTRs for the years the upgrade is advanced based on the incremental CETL into a constrained LDA as certified by PJM. The customer should request PJM to certify the Incremental CTRs due to an advancement of a network transmission upgrade at least 90 days prior to the Base Residual Auction.

Participants must request PJM to certify the Incremental CTRs into the constrained LDAs modeled in RPM at least 90 days prior to the Base Residual Auction. PJM will certify the Incremental CTRs into the constrained LDA at least 45 days prior to the Base Residual Auction.

For LDAs in which the RPM Auctions for such Delivery Year result in a positive average weighted Locational Price Adder with respect to the immediate higher level LDA, the holder of a Participant-Funded ICTR into such LDA shall receive a payment equal to (i) average weighted Locational Price Adder for the LDA into which the associated facility or upgrade increased import capability, multiplied by (ii) MW amount of ICTRs allocated to holder. No payment will be issued to the holder when a zero or negative average weighted Locational Price Adder with respect to the immediate higher level LDA is calculated as a result of the RPM Auctions for such Delivery Year.

Participant-Funded ICTRs may be traded similar to CTRs.

6.1.3 Incremental Capacity Transfer Rights Associated with Incremental Rights-Eligible Required Transmission Enhancements

Incremental Rights-Eligible Required Transmission Enhancements may include Regional Facilities and Necessary Lower Voltage Facilities, and Lower Voltage Facilities. Regional Facilities are Transmission Facilities as defined in section 1.27 of the Consolidated Transmission Owners Agreement (Rate Schedule FERC No. 42) that are included in Regional Transmission Expansion Plan (RTEP) and operate at or above 500 kV. Necessary Lower Voltage Facilities are Transmission Facilities that operate below 500 kV and must be constructed or strengthened to support new Regional Facilities. Lower Voltage Facilities are Transmission Facilities that operate below 500 kV which are included in RTEP to address one or more reliability violations or to address operational adequacy and performance issues and are not Necessary Lower Voltage Facilities. Responsible Customers, as defined in Schedule 12 of the Tariff, that are Network Customers, Transmission Customers with an agreement for Firm Point-to-Point Service, or Merchant Transmission Facility Owners, and that are assigned cost responsibility for an Incremental Rights-Eligible Required Transmission Enhancement shall be allocated a share of the ICTRs associated with such facility in accordance with the percentage cost responsibility assigned to Responsible Customers for such facility as set forth in Schedule 12-Appendix to the Tariff.

ICTRs associated with Regional Facilities and Necessary Lower Voltage Facilities are determined and allocated to Responsible Customers. ICTRs associated with Lower Voltage Facilities are also determined and allocated to Responsible Customers. The ICTRs (in MWs) associated with a given Incremental Rights-Eligible Required Transmission Enhancement are established by PJM prior to the conduct of the Base Residual Auction for the first Delivery Year for which such facility is to be in service. Once established, the ICTRs for such facility are available for allocation for 30 years or the life of the project, whichever is less.

PJM determines the increase in CETL into an applicable LDA as a result of an Incremental Rights-Eligible Transmission Enhancement planned for the Delivery Year. The increase in the CETL represents the ICTRs (in MWs) into the LDA provided by such planned facility. If such facility increases CETL into multiple LDAs, PJM will calculate 'simultaneous' increases in CETL into the LDAs and determine a separate ICTR MW amount for each LDA, equal to the respective increase in CETL into such LDA. .

The allocation (in MWs) of a Delivery Year's ICTRs for the Incremental Rights-Eligible Required Transmission Enhancement to a Responsible Customer may change during the Delivery Year if the percentage cost responsibility assigned to the Responsible Customers for such facility as set forth in Schedule 12-Appendix to the Tariff changes during the Delivery Year.

During the Delivery Year, each Network Customer (LSE) within a zone will be allocated a share of the zone's ICTRs associated with Incremental Rights-Eligible Required Transmission Enhancements for such Delivery Year in proportion to the customer's share of the zonal NSPL. These allocations may change day to day as end-use customers change from LSE to LSE.

ICTRs associated with Incremental Rights-Eligible Required Transmission Enhancements may be traded similar to CTRs.

The economic value of Incremental Rights-Eligible Required Transmission Enhancement ICTRs may change from year to year and will become zero when a zero or negative average weighted Locational Price Adder with respect to the immediate higher level LDA is calculated as a result of RPM Auctions for such Delivery Year.

The economic value (in \$/day) of Incremental Rights-Eligible Required Transmission Enhancement ICTRs in an LDA as a result of all RPM Auctions for the Delivery Year is equal to (i) the average weighted Locational Price Adder for such LDA determined with respect to the immediate higher level LDA as a result of all RPM Auctions for such Delivery Year, multiplied by (ii) the MW quantity of Regional Project ICTRs in an LDA allocated to Responsible Customers.

6.2 Determination of Capacity Transfer Rights

For LDAs in which a positive average weighted Location Price Adder with respect to the immediate higher level LDA is calculated as a result of all RPM Auctions for the Delivery Year, the total amount of Capacity Transfer Rights in such LDA are equal to the Final Unforced Capacity Imported into such LDA as a result of all RPM Auctions for the Delivery Year. The Total CTRs into a constrained LDA are reduced by (1) an equivalent QTU import capability cleared, (2) Participant-Funded Project ICTRs, and (3) Incremental Rights-Eligible Required Transmission Enhancement ICTRs, and the remaining CTRs are allocated to the LSEs in the LDA (Zone). ICTRs may be reduced if the Total CTRs calculated for a constrained LDA are limited in any Delivery Year. If the Total CTRs are limited, CTRs will first be allocated to a cleared QTU. Any remaining CTRs will be allocated to ICTRs associated with Participant-Funded Projects and Incremental Rights-Eligible Required Transmission Enhancements pro rata based on their original ICTR certified amount. For LDAs in which the average Locational Price Adder with respect to the immediate higher level LDA is negative, the Total CTRs are allocated only to LSEs.

$$LDACTR_{LSEs} = FinalLDAUCAPImported - LDAQTUEquivalents - LDAICTRs$$

Where:

Final Unforced Capacity Imported into an LDA

is equal to the Final Unforced Capacity Obligation for such LDA as a result of all RPM Auctions for such Delivery Year less the net participant buy bid/sell offers cleared in the LDA for all RPM Auctions for such Delivery Year.

Final LDA Unforced Capacity Obligation

is equal to the sum of the Final Zonal Unforced Capacity Obligations for the zones in the LDA.

equivalent QTU import capability cleared into an LDA

is determined as the QTU BRA Auction Credits (\$/day) received by the cleared QTU into an LDA divided by the weighted locational price adder of such LDA with respect to the immediate higher level LDA.

If the LDA into which the Incremental Capacity Transfer Rights are allocated or the import capability is increased by a Qualifying Transmission Upgrade is a part of a zone (e.g., DPL South or PS North), the calculations will be made based on the zone instead of the LDA using a Weighted Locational Price Adder for the zone with respect to the immediate higher level LDA to determine an equivalent Incremental Capacity Transfer Rights into the zone or an equivalent import capability into the zone in the case of a Qualifying Transmission Upgrade.

6.3 Allocation of Capacity Transfer Rights

The allocation of the total Capacity Transfer Rights in an LDA is performed on a pro-rata basis for each LSE based on the Daily Unforced Capacity Obligation that they serve in zones included in the constrained LDA. The allocated CTRs in an LDA will be reallocated to LSEs on a daily basis as load switches between retail suppliers within each zone.

When a Zone and its sub-zones are constrained LDAs, CTR calculations are performed on a Zonal basis.

When an LDA is entirely contained within another LDA (e.g., a Zone is a smaller LDA within a Group of Zones which is a larger LDA), a portion of the larger LDA Capacity Transfer Rights will be allocated to the smaller LDA, based on the smaller LDA's proportion of the larger LDA's unforced capacity obligation.

6.4 Capacity Transfer Rights Credits

LSEs that were allocated CTRs in a zone will receive a daily zonal CTR Credit as described in the Settlements section of this Manual.

Participants that were allocated Incremental CTRs into an LDA will receive a daily Incremental CTR Credit equal to the total Incremental CTRs allocated times the Final Incremental CTR Credit Rate for such LDA.

The Final Incremental CTR Credit Rate for an LDA is equal to the LDA's weighted Locational Price Adder with respect to the immediate higher level LDA as a result of all RPM Auctions for such Delivery Year.

6.5 Capacity Transfer Rights Transfers

RPM Market Participants will have the ability to request CTR or ICTR Transfers by notifying PJM. The purpose of a CTR Transfer is to transfer the ownership of a specified amount of CTR MWs in a given zone from the Seller to the Buyer.

The following are business rules that apply to Capacity Transfer Rights Transfers:

- CTR Transfer requests must specify the buyer, seller, start and end dates of the transfer, the transfer amount (in MW), and the zone from which to transfer the CTRs.
- CTR Transfers will result in the “Buyer” receiving the credit that would have been due to the “Seller” of the CTRs.
- The smallest increment of CTRs that may be transferred is 0.1 MW.
- Both the Buyer and the Seller of a CTR Transfer Transaction must submit the CTR Transfer request to PJM before the following daily accounting deadlines (all times in Eastern Prevailing Time):
 - 1:00 PM (Tuesday – Friday) for transactions beginning on the previous day
 - 5:00 PM (Monday) for transactions beginning on Friday, Saturday, and Sunday
 - 5:00 PM (a day after the holiday) for transactions beginning on a holiday

Section 7: Load Obligations

Welcome to the *Load Obligations* section of the ***PJM Manual for the PJM Capacity Market***. In this section, you will find the following information:

- An overview description of Load Obligations (see “Overview of Load Obligations”)
- The business rules for determining Unforced Capacity Obligations (see “Unforced Capacity Obligations”)
- The business rules for determining RPM Scaling Factors (see “RPM Scaling Factors”)
- The business rules for determining Obligation Peak Load values (see “Obligation Peak Load”)
- The process for determining load obligations (see “Process for Determining Load Obligations”)
- The business rules for the treatment of Non-Zone Load (see “Non-Zone Load”)

7.1 Overview of Load Obligations

In the Reliability Pricing Model, Unforced Capacity is the basis for the market product that is cleared in each auction. Unforced Capacity (UCAP) is a) installed capacity rated at summer conditions that is not, on average, experiencing a forced outage or forced de-rating or b) Effective UCAP provided by ELCC Resources. While unforced capacity (UCAP) is the basis for the valuation of generating capacity, in RPM, this concept is also used to value load management (Demand Resources (DR) , Energy Efficiency, Reliability Requirements of RTO and LDAs, and to define load obligations of Load Serving Entities. Load obligations are obligations to serve load or obligations to reduce load during the Delivery Year valued as unforced capacity.

Load Obligations are based on the Unforced Capacity Obligation procured in Base Residual Auction and all the Incremental Auctions.

7.2 Unforced Capacity Obligations

7.2.1 Determination of Unforced Capacity Obligations

Unforced Capacity Obligations are obligations for load to be served during the delivery year in unforced capacity terms. However, since RPM auction participants are not bidding in the demand for UCAP in the RPM process, the reliability requirement is forecasted on an aggregate basis prior to the clearing of the RPM Auctions as an input into the clearing process.

In the Reliability Pricing Model, unforced capacity obligations are determined for the RTO and Zones as a result of the Base Residual Auction and all Incremental Auctions.

The following parameters, discussed in detail below, are values used in the determination of Unforced Capacity Obligations:

- Peak Load Forecasts
- Forecast Pool Requirement (FPR)

7.2.2 Base Unforced Capacity Obligations

A Base RTO Unforced Capacity Obligation is determined after the clearing of the Base Residual Auction and is posted with the Base Residual Auction results. The Base RTO Unforced Capacity Obligation is equal to the sum of the unforced capacity obligation satisfied through the Base Residual Auction.

$$BaseRTOUCAPOblig = UCAPOblig_{BRA}$$

RTO Unforced Capacity Obligation satisfied in Base Residual Auction is used to determine the Base Zonal RPM Scaling Factors for use in determining Base Zonal Unforced Capacity Obligation. See Section 7.3.2 for Base Zonal RPM Scaling Factor equation.

Base Zonal Unforced Capacity Obligation

Zonal Unforced Capacity Obligations are determined based on an allocation of the RTO Unforced Capacity Obligation based on zonal peak load forecasts. As a result of the RPM Auction clearing process, additional resources above those required to meet the IRM may be procured and allocated to the zones. Since resource requirements in the constrained zones may be higher than those required based on IRM (FPR) these requirements affect the clearing price in the zones but not the allocation of RTO obligations to zones.

A Base Zonal Unforced Capacity Obligation is determined for each zone and is equal to the (Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year* Base Zonal RPM Scaling Factor * the Forecast Pool Requirement).

$$BaseZonalUCAPOblig = (ZWNSP_{DY-4} * BaseZonalRPMScalingFactor * FPR)$$

Note:

Base Zonal Unforced Capacity Obligations are posted with the Base Residual Auction clearing results.

7.2.3 Final Zonal Unforced Capacity Obligations

The Final RTO Unforced Capacity Obligation is determined after the clearing of the final Incremental Auction for the Delivery Year. The Final RTO Unforced Capacity Obligation is equal to the RTO unforced capacity obligations satisfied through all RPM Auctions for the Delivery Year. The RTO unforced capacity obligation through all RPM Auctions is equal to the total MWs

cleared in PJM Buy Bids in RPM Auctions less the total MWs cleared in PJM Sell Offers in RPM Auctions.

$$FinalRTOUCapOblig = \sum PJMBuyBidMWsCleared - \sum PJMSellOffersCleared$$

The Final Zonal Unforced Capacity Obligation is determined for each zone and is equal to zonal allocation of the Final RTO Unforced Capacity Obligation. The Final RTO Unforced Capacity Obligation is allocated to the zones on a pro-rata basis based on the Final Zonal Peak Load Forecasts.

$$FinalZonalUCAPOblig = \left(\frac{ZonalFinalPeakLoadForecast}{RTOFinalPeakLoadForecast} \right) * FinalRTOUCAPOblig$$

Note:

The Final Zonal Unforced Capacity Obligations are posted after the clearing of the final Incremental Auction for the Delivery Year.

7.3 RPM Zonal Scaling Factors

RPM Zonal Scaling Factors are calculated as a result of RPM Auctions and are constant for the Delivery Year. The following RPM Zonal Scaling Factors are determined:

- Base Zonal Scaling Factors – determined for each zone after the clearing of the Base Residual Auction
- Final Zonal Scaling Factors –determined for each zone with the clearing of the final Incremental Auction.

These scaling factors account for (1) load growth from a prior-year summer to the Delivery Year; (2) any excess resources procured above those required to exactly meet the FPR requirements.

The following parameters are values used in the determination of RPM Zonal Scaling Factors:

- RTO Unforced Capacity Obligation (Base & Final)
- Zonal Peak Load Forecasts (ZPLF) (Preliminary & Final)
- Forecast Pool Requirement (FPR)
- Zonal Weather Normalized Summer Peaks (ZWNSP)

The purpose of RPM Zonal Scaling Factors is to determine the LSE Daily UCAP Obligations in the zones from the Daily Obligation Peak Loads.

7.3.1 Zonal Weather Normalized Summer Peaks

To account for the load growth from a prior-year summer to each Delivery Year, PJM determines Zonal Weather Normalized Summer Peaks by October 31 prior to the start of the

Delivery Year. The Zonal Weather Normalized Summer Peaks are calculated in accordance with the **Load Forecasting & Analysis Manual (M-19)**.

The RTO Weather Normalized Summer Peak is the sum of the Zonal Weather Normalized Coincident Summer Peaks.

The Electric Distribution Company (EDC) is responsible for allocating the Zonal Weather Normalized Summer Peak for the summer prior to the Delivery Year and providing to PJM an Obligation Peak Load allocation for each Capacity Exchange defined “area” within their zone by December 31 prior to the start of the Delivery Year. See **Reliability Assurance Agreement Schedule 8, Section A and Generator Operational Requirements Manual (14-D), Appendix A** for the limitations in the netting of operating Non-Retail Behind the Meter Generation against wholesale area load.

7.3.2 Base Zonal RPM Scaling Factor

A Base Zonal RPM Scaling Factor is determined for each zone and is equal to the [(Preliminary Zonal Peak Load Forecast for the Delivery Year divided by the Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year)* ((RTO Unforced Capacity Obligation Satisfied in Base Residual Auction divided by the (RTO Preliminary Peak Load Forecast * the Forecast Pool Requirement))]. Zonal peak load is adjusted for peak loads of zone/areas that elected FRR option.

$$\text{BaseZonalRPMScalingFactor} = \left(\frac{\text{PrelimZPLF}}{\text{ZWNSP}_{(DY-4)}} \right) * \left(\frac{\text{RTOUCAPOblig}_{\text{BRA}}}{\text{RTO Prelim Peak Load Forecast} * \text{FPR}} \right)$$

Note:

Base Zonal RPM Scaling Factors are posted with the Base Residual Auction results.

7.3.3 Final Zonal RPM Scaling Factor

The Final Zonal RPM Scaling Factors are used in determining an LSE’s Daily Unforced Capacity Obligation. A Final Zonal RPM Scaling Factor for a zone is equal to the Final Zonal Unforced Capacity Obligation divided by (FPR times the Zonal Weather Normalized Peak for the summer prior to the Delivery Year).

$$\text{FinalZonalRPMScalingFactor} = \frac{\text{FinalZonalUCAPOblig}}{\text{FPR} * \text{ZWNSP}_{\text{DY}-1}}$$

7.4 Obligation Peak Load

Obligation Peak Load is the peak load value on which LSEs’ Unforced Capacity Obligations are based. Each PJM Electric Distribution Company (EDC) is responsible for allocating its

normalized previous summer's peak to each customer in the zone (both retail and wholesale). LSE Obligation Peak Load represents the summation of Peak Load Contributions for each of an LSE's customers.

The following business rules apply to Delivery Year Obligation Peak Load data for a zone/area:

- The Obligation Peak Load allocation for a zone/area is constant and effective for the entire Delivery Year.
- The EDC is also responsible for allocating the Obligation Peak Load for a zone/area among end-use customers by calculating Peak Load Contributions (i.e., "capacity tickets") for each end-use customer by December 31 prior to the start of the Delivery Year.
- The EDC must make Peak Load Contribution information available to LSEs by December 31 prior to the start of the Delivery Year.
- Non-dispatched charging energy for Energy Storage Model Participants and Open-Loop Hybrid Resources shall not be allocated a Peak Load Contribution value in accordance with Manual 27.

7.5 Daily Unforced Capacity Obligations

The following business rules apply to daily Obligation Peak Load data used in determining LSE Daily Unforced Capacity Obligations:

- The EDC is responsible for uploading Obligation Peak Load data into Capacity Exchange for every LSE serving load in their zone/area during the Delivery Year. The file upload must be performed in accordance with Capacity Exchange's file format specifications and by the file upload deadline (36 hours before the start of the operating day). Corrections to Obligation Peak Load data may be made up to 12:00 PM Eastern Prevailing Time of the next business day following the Operating Day.
- The daily sum of all the LSEs' Obligation Peak Load data in a zone/area must equal the EDC's Obligation Peak Load allocation to the zone/area.
- A Daily Obligation Peak Load Scaling Factor will be used to scale the uploaded LSE Obligation Peak Load values to the fixed Obligation Peak Load Allocation of the zone/area in the event that the Obligation Peak Load values uploaded by the EDC do not exactly sum to the Annual Obligation Peak Load Allocation for the zone/area.

$$\text{DailyObligPeakLoadScalingFactor} = \frac{\text{AnnualZoneAreaObligPeakLoadAllocation}}{\sum \text{ZoneAreaObligPeakLoadUploads}}$$

- The daily sum of the Obligation Peak Load data for all areas in a zone must equal the Zonal Weather Normalized Summer Peak for the summer prior to the Delivery Year.

The Daily Unforced Capacity Obligation of an LSE in a zone/area equals the LSE's Obligation Peak Load in the zone/area * the Final Zonal RPM Scaling Factor * the Forecast Pool Requirement.

$$\text{DailyUCAPOblig} = \text{ObligPeakLoad} * \text{FinalZonalPRMScalingFactor} * \text{FPR}$$

7.6 Process for Determining Load Obligations

The process that was described in the previous sections is illustrated below.

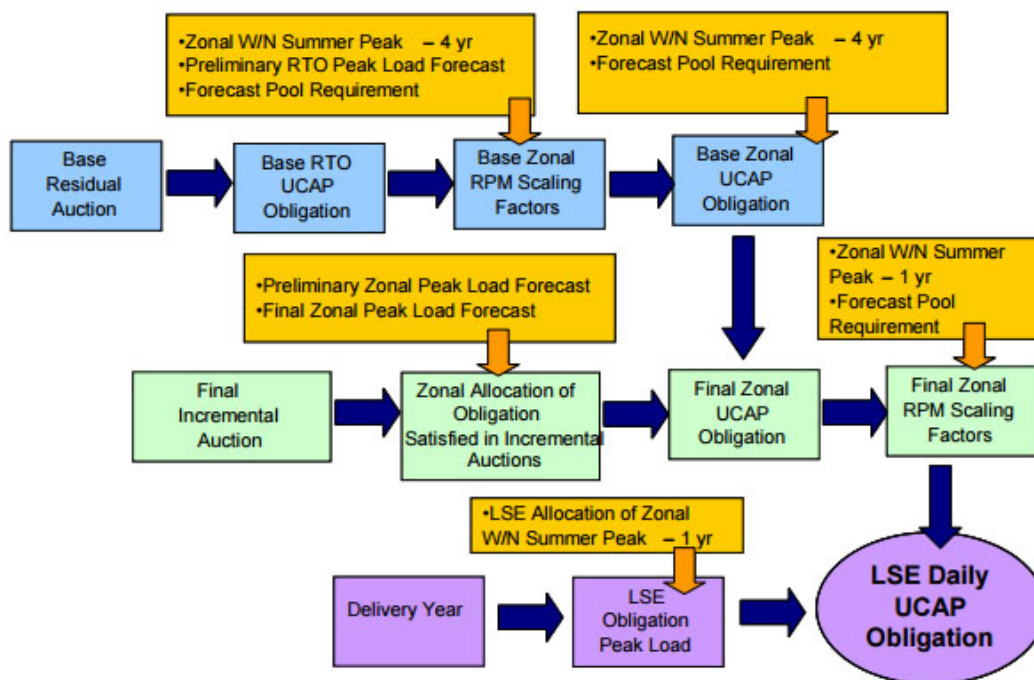


Exhibit 3: Process for determining Load Obligations

7.7 Treatment of Non-Zone Load

Non-Zone Load is the load that is located outside of the PJM Region served by a PJM Load Serving Entity using PJM internal resources. Non-Zone Load is included in the load of the Zone from which the load is served.

The following are business rules that apply to Treatment of Non-Zone Load:

- Non-Zone Load may be Non-Zone Network Load (Tariff 1.27B) that is charged a Network Integration Transmission Service (NITS) charge (Tariff Attachment H-A) or other load that may be 'grandfathered' from the NITS charge.
- PJM forecasts the Preliminary Non-Zone Load for the RPM Delivery Year and includes it in the Preliminary RTO Forecast Peak Load and the Preliminary Zonal Forecast Peak Load

of the Zone from which the Non-Zone Load is served, by February 1 prior to the Base Residual Auction.

- Non-Zone Load cannot be served in a Delivery Year using resources committed to RPM if it is not included in the Preliminary RTO Forecast Peak Load and the Preliminary Zonal Forecast Peak Load prior to the RPM Base Residual Auction for the Delivery Year.
- PJM forecasts the final Non-Zone Load for the RPM Delivery Year and includes it in the Final RTO Forecast Peak Load and the Final Zonal Forecast Peak Load that is posted by January prior to the Final Incremental Auction.
- EDC that is responsible to determine the Obligation Peak Loads for the Zone will also establish the Obligation Peak Load associated with the Non-Zone Load by December 31 prior to the start of the Delivery Year.
- Non-Zone load will be modeled as a defined “area” in the zone from which it is served in the Capacity Exchange system.

The LSE serving the Non-Zone Load will be assessed a Daily Unforced Capacity Obligation and will be responsible to pay an RPM Locational Reliability Charge.

Section 8: Resource Performance Assessments

Welcome to the *Resource Performance Assessments* section of the **PJM Manual for the PJM Capacity Market**. In this section, you will find the following information:

- An overview description of the resource performance assessments (see “Overview of Resource Performance Assessments”)
- The business rules for determining RPM commitment compliance (see “RPM Commitment Compliance”)
- The business rules for determining generating unit peak-hour availability (see “Generating Unit Peak-Hour Availability”)
- The business rules for determining Non-Performance Assessment (see “Non-Performance Assessment”)
- The business rules for assessing compliance with Summer/Winter capability testing (see “Summer/Winter Capability Testing”)
- The business rules for determining load management test compliance (see “Load Management Test Compliance”)
- The business rules for replacement resources (“see “Replacement Resources”)

8.1 Overview of Resource Performance Assessments

The PJM Capacity Market is designed to ensure that capacity market prices are consistent with system reliability metrics. All LSEs must satisfy their capacity obligation either through the RPM or through the FRR Alternative. If a resource receives capacity payments, or in the case of FRR Alternative, is committed to directly satisfy load obligation requirements, there is an expectation that the resource will honor their commitments and provide reliability services when required. The following performance assessments provide the means to assess whether or not a resource honored their commitments and provided the expected reliability services during the Delivery Year.

- RPM Commitment Compliance
- Generation Operational Testing
- Summer/Winter Capacity Testing
- Non-Performance Assessment
- Load Management Test Compliance
- EE Measurement & Verification (M &V) Audit (see Manual 18-B)

Collectively, the performance assessments provide consumers, who have paid for a high level of reliability through their capacity market payments, with reasonable assurance that the resources committed to RPM or FRR Alternative will perform at adequate levels during the

Delivery Year. Since failure to perform in a performance assessment results in deficiency or penalty charges, resource providers are incented to ensure that their committed resources perform during the Delivery Year in order to limit their exposure to deficiency or penalty charges.

A resource will have an RPM Resource Commitment if the resource cleared or received make-whole payments through an RPM Auction or if the unit was specified as a replacement resource or as the source of a Locational UCAP transaction. A resource will have an FRR Capacity Plan commitment if the unit was included in an FRR Capacity Plan. Portions of the resource that do not have an RPM Resource Commitment or FRR Capacity Plan Commitment during the Delivery Year are not subject to resource performance assessments and the associated deficiency/penalty charges.

The performance assessments are not applicable to all types of resources committed to RPM or FRR Alternative. The following matrix provides an overview of the applicability of resource performance assessments.

Assessment	Generation (except Variable Resources)	Variable Resources	DR	EE	QTU
RPM Commitment Compliance	X	X	X	X	X
Generation Operational Test	X				
Summer/Winter Capability Testing	X				
Load Management Test Compliance			X		
M&V Audit				X	
Non-Performance Assessment	X	X	X	X	X

8.2 RPM Commitment Compliance

A resource committed to RPM is expected to be able to deliver unforced capacity during the Delivery Year that is equal to or greater than the unforced capacity committed through RPM Auctions or through the specification of replacement capacity. RPM Commitment Compliance is evaluated daily during the Delivery year on a resource-specific basis to determine if a party

satisfied their Daily RPM Resource Commitments on their generation resources, demand resources, and Qualifying Transmission Upgrades (QTUs).

A resource or portion of a resource committed to the FRR Alternative is not subject to RPM Commitment Compliance. Instead of unit-specific commitment compliance, FRR Entities are subject to daily unforced capacity obligation compliance.

8.2.1 Generation

A generation resource provider may be unable to satisfy their RPM Resource Commitments during the Delivery Year due to the following reasons:

- Unit cancellations and delays – A planned generation is cancelled or delayed and does not commence Interconnection Service prior to the start of the Delivery Year.
- Unit deratings and retirements – The generation resource is derated (through a Capacity Modification decrease) prior to or during the Delivery year. (Retirements result in derating the installed capacity value of a unit to zero MWs through a Capacity Modification decrease in the Capacity Exchange system).
- Accredited UCAP Factor decreases – The final Accredited UCAP Factor for a generation resource for the Delivery Year results in fewer UCAP MW on the resource than that cleared in RPM Auctions for the Delivery Year.

During the Delivery Year, failure to meet generation resource commitments will be determined by comparing a party's Daily RPM Generation Resource Position to their Daily RPM Resource Commitments for such resource. If a party's Daily RPM Generation Resource Position is less than their Daily RPM Resource Commitments for such resource on a delivery day, a Daily Capacity Resource Deficiency Charge will be assessed on the RPM Commitment Shortage.

A party's Daily RPM Generation Resource Position for a specific unit is equal to the (Daily ICAP Owned – Daily FRR Capacity Plan Commitments – Daily Unoffered ICAP)*(Accredited UCAP Factor).

$$\begin{aligned} & \text{DailyRPMPosition}_{GEN} \\ &= (\text{DailyICAPOwned} - \text{DailyFRRCommitments} - \text{DailyUnofferICAP}) \\ & \quad *(\text{Accredited UCAP Factor}) \end{aligned}$$

A party's Daily RPM Resource Commitments for a specific generating unit are calculated by adding the sum of any UCAP Cleared plus UCAP Make-whole for such unit in RPM Auctions to decreases/increases of RPM Commitments due to approved unit-specific bilateral sales/purchases of cleared capacity and the specification of replacement resources.

A party's Daily RPM Commitment Shortage for a specific unit is calculated as Daily RPM Resource Commitments minus Daily RPM Generation Resource Position. A positive Daily RPM Commitment Shortage represents a failure to meet the RPM resource commitments.

$$\text{DailyRPMCommitmentShortage}_{\text{GEN}} = \text{DailyRPMCommitments} - \text{DailyRPMPosition}_{\text{GEN}}$$

8.2.2 Demand Resources

A demand resource provider may be unable to satisfy their RPM Resource Commitments during the Delivery Year due to the following reasons:

- Load management program cancellation or delay– The load management program(s) associated with the planned demand resource is cancelled or delayed and is not installed prior to the start of the Delivery Year.
- Decrease in nominated value of demand resource – The final nominated value of the demand resource during the Delivery Year is less than the nominated value of the demand resource used in cleared offers in RPM Auctions for the Delivery Year due to a decrease in the peak load contributions (i.e., capacity tickets) of end-use customers providing the actual load response.
- Failure to have enough sites registered and approved in the DR Hub system prior to the start of the Delivery Year to support the nominated value of the demand resource committed for such Delivery Year. The sites registered and approved in the DR Hub system must be of the Capacity Performance product-type and sufficient to support the summer and non-summer commitments on the Demand Resource.
- Decrease in the Forecast Pool Requirement or ELCC Class Rating- The final UCAP value of the demand resource during the Delivery Year is determined based on the final FPR for the Delivery Year (prior to the 2025/2026 Delivery Year) or the final applicable ELCC Class Rating (starting with the 2025/2026 Delivery Year). Decreases in either of these factors can result in a final UCAP value being less than the UCAP MW cleared by the demand resource in RPM Auctions for the Delivery Year.
- During the Delivery Year, failure to meet demand resource commitments will be determined by comparing a party's Daily RPM Demand Resource Position to their Daily RPM Resource Commitments for such resource. If a party's Daily RPM Demand Resource Position is less than their Daily RPM Resource Commitments for such resource on a delivery day, a Daily Capacity Resource Deficiency Charge will be assessed on the RPM Commitment Shortage.

Through the 2024/2025 Delivery year, a party's Daily RPM Demand Resource Position for a specific demand resource is equal to the (Daily ICAP Owned – Daily FRR Capacity Plan Commitments) * Forecast Pool Requirement.

$$\text{DailyRPMPosition}_{\text{DR}} = (\text{DailyICAPOwned} - \text{DailyFRRCommitments}) * \text{FPR}$$

Starting with the 2025/2026 Delivery Year, a party's Daily RPM Demand Resource Position for a specific demand resource is equal to the (Daily ICAP Owned - Daily FRR Capacity Plan Commitments) * applicable ELCC Class Rating.

$$\text{DailyRPMPosition}_{\text{DR}} = (\text{DailyICAPOwned} - \text{DailyFRRCommitments}) * \text{applicable ELCC Class Rating}$$

A party's Daily ICAP Owned for a specific demand resource is equal to Daily Nominated DR Value adjusted for the ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases for such demand resource in effect for such day. The Daily Nominated Value of a Demand Resource for a Delivery Year is based on confirmed registrations in "completed" status linked to such Demand Resource in the DR Hub system. The Daily Nominated Value of a Demand Resource is determined for summer period of June through October and May of Delivery Year and non-summer period of November through April of Delivery Year based on information provided in the linked Capacity Performance registrations in the DR Hub system.

A party's Daily RPM Resource Commitments for a specific demand resource are calculated by adding the sum of any UCAP Cleared plus UCAP Make-whole for such demand resource in RPM Auctions to decreases/increase of RPM Resource Commitments due to the specification of replacement resources or use of such demand resource in a Locational UCAP transaction.

A party's Daily RPM Commitment Shortage for a specific demand resource is calculated as Daily RPM Resource Commitments minus Daily RPM Demand Resource Position. A positive Daily RPM Commitment Shortage represents a failure to meet the RPM resource commitments.

$$\begin{aligned} & \text{DailyRPMCommitmentShortage}_{DR} \\ &= \text{DailyRPMCommitments} - \text{DailyRPMPosition}_{DR} \end{aligned}$$

Existing demand resources that offered and cleared in Base Residual Auction, First Incremental Auction, or Second Incremental Auction can receive relief from deficiency charges if they failed to meet their RPM Resource Commitments due to a decrease in Peak Load Contributions (i.e., "capacity ticket(s)") that were due to the permanent departure of load from the transmission system (e.g., plant closure, efficiency gains, or similar reasons) that was relied upon for load response. The resource provider of the existing Demand Resource must provide PJM with all information deemed necessary by PJM to assess the merits of the request for relief.

Request for relief from deficiency charges must be made no later than two weeks in advance of the opening of the Third Incremental Auction. Failure to maintain Demand Resources will not permit relief. If relief from deficiency charges is granted, the resource provider will receive a reduction in their RPM Auction Credits and a reduction in their RPM Resource Commitments. Any reduction in Auction Credits is factored into the calculation of the Final Zonal Capacity Price. There is no relief from deficiency charges for existing Demand Resources that offered and cleared in a Third Incremental Auction.

8.2.3 Energy Efficiency Resources:

An EE resource provider may be unable to satisfy their RPM Resource Commitments during the Delivery Year due to the following reasons:

- Energy efficiency installation cancellation or delay– The energy efficiency installation(s) associated with the planned EE Resource is cancelled or delayed and is not installed prior to the start of the Delivery Year.

- Decrease in Nominated EE value or Capacity Performance Value of EE Resource – The final nominated value or final Capacity Performance value of the energy efficiency resource for the Delivery Year is less than the Nominated value or Capacity Performance Value that was used as the basis of the energy efficiency resource cleared offers in RPM Auctions for the Delivery Year due to a change in number of planned installations associated with the planned EE Resource, change in EDC loss factor, or change due to post-installation measurement and verification activities, or reduction in nominated value due to failure to meet the precision standard requirement for measurement and verification activities in accordance with the PJM Manual for Energy Efficiency Measurement & Verification.

During the Delivery Year, failure to meet EE Resource commitments will be determined by comparing a party's Daily RPM EE Resource Position to their Daily RPM Resource Commitments for such resource. If a party's Daily RPM EE Resource Position is less than their Daily RPM Resource Commitments for such resource on a delivery day, a Daily Capacity Resource Deficiency Charge will be assessed on the RPM Commitment Shortage.

A party's Daily RPM EE Resource Position for a specific EE resource is equal to the (Daily ICAP Owned – Daily FRR Capacity Plan Commitments) * Forecast Pool Requirement).

$$DailyRPMPosition_{EE} = (DailyICAP_{Owned} - DailyFRR_{Commitments}) * FPR$$

A party's Daily ICAP Owned for a specific EE Resource is equal to the initial ICAP Owned set by PJM through "Approved" EE Modifications, adjusted for any ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases for such EE Resource in effect for such day.

A party's Daily RPM Resource Commitments for a specific EE resource are calculated by adding the sum of any UCAP Cleared plus UCAP Make-whole for such EE resource in RPM Auctions to decreases/increases of RPM Resource Commitments due to the specification of replacement resources or use of such EE resource in a Location UCAP transaction.

A party's Daily RPM Commitment Shortage for a specific EE resource is calculated as Daily RPM Resource Commitments minus Daily RPM EE Resource Position. A positive Daily RPM Commitment Shortage represents a failure to meet the RPM resource commitments.

$$DailyRPMCommitmentShortage_{EE} = DailyRPMCommitments - DailyRPMPosition_{EE}$$

8.2.4 Qualifying Transmission Upgrade (QTU):

A provider of a Qualifying Transmission Upgrade may be unable to satisfy their RPM Resource Commitments during the Delivery Year due to the following reasons:

- Upgrade cancellations and delays– A qualifying transmission upgrade is cancelled or delayed and does not commence Interconnection Service prior to the start of the Delivery Year.

During the Delivery Year, failure to meet qualifying transmission upgrade commitments will be determined by comparing a party's Daily RPM QTU Position to their Daily RPM Resource Commitments for such upgrade. If a party's Daily RPM QTU Position is less than their Daily RPM Resource Commitments for such upgrade on a delivery day, a Transmission Upgrade Delay Penalty will be assessed on the RPM Commitment Shortage.

A party's Daily RPM QTU Position for a Qualifying Transmission Upgrade is equal to the approved incremental import capability value into the Sink LDA from a Source LDA for such upgrade.

A party's Daily RPM Resource Commitments for a specific Qualifying Transmission Upgrade are calculated by adding the sum of any UCAP Cleared plus UCAP Make whole for such qualifying transmission upgrade in RPM Auctions to decreases of RPM Resource Commitments due to the specification of replacement resources.

A party's Daily RPM Commitment Shortage for a Qualifying Transmission Upgrade is calculated as Daily RPM Resource Commitments minus Daily RPM QTU Position. A positive Daily RPM Commitment Shortage represents a failure to meet the RPM resource commitments.

$$\text{DailyRPMCommitmentShortage}_{QTU} = \text{DailyRPMCommitments} - \text{DailyRPMQTUPosition}$$

8.3 Commitment Level Used in Summer/Winter Capability Tests (Through the 2024/2025 Delivery Year)

Since the RPM Resource Commitments or FRR Capacity Plan Commitments on a unit can vary daily during the delivery year, a Total Unit ICAP Commitment Amount (TUICA) is calculated for each unit and used as the basis for assessing the performance of a unit for summer/winter capability tests through the 2024/2025 Delivery Year.

Since replacement resources can be specified anytime during the Delivery Year, the Total Unit ICAP Commitment Amount is not finalized until after the conclusion of the Delivery Year.

The Total Unit ICAP Commitment Amount on a specific unit is equal to the lesser of (a) the Unit Average Daily ICAP Commitment Amount for the Delivery Year²³ or (b) maximum Summer Net Dependable Rating of the Unit during the Delivery Year.

$$TUICA = \text{lesser of } (\text{UnitAvgDailyICAPCommitment}_{GEN}, \text{Max DYSummerRating})$$

The Unit Average Daily ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the (sum of all Daily RPM Resource Commitments on such unit for the Delivery Year

²³ For days in which unit's Daily ICAP Commitment is greater than Daily ICAP Owned, Daily ICAP Owned is used in determining Unit Average Daily ICAP Commitment for DY.

divided by one minus the Effective EFORD plus the sum of all Daily FRR Capacity Plan Commitments on such unit for the Delivery Year) divided by 365 days (or 366 days).

$$\text{UnitAvgDailyICAPCommitment}_{\text{GEN}} = \frac{\left(\frac{\sum \text{DailyRPMCommitment}}{1 - \text{EffectiveEFORD}} \right) + \sum \text{DailyFRRCommitment}}{365 \text{ (or 366) days}}$$

Since a single unit can have both RPM Commitments and FRR Capacity Plan Commitments during the Delivery Year, a Unit Average Daily FRR ICAP Commitment Amount and Unit Average Daily RPM ICAP Commitment Amount for the Delivery Year are calculated for each unit.

The Unit Average Daily FRR ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the sum of all Daily FRR Capacity Plan Commitments on such unit for the Delivery Year) divided by 365 days (or 366 days).

$$\text{UnitAvgDailyFRRICAPCommitment} = \frac{\sum \text{DailyFRRCommitment}}{365 \text{ (or 366) days}}$$

The Unit Average Daily RPM ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the Total Unit ICAP Commitment Amount less the Unit Average Daily FRR ICAP Commitment Amount.

$$\begin{aligned} \text{UnitAvgDailyRPMICAPCommitment}_{\text{GEN}} &= \\ \text{TUICA} - \text{UnitAvgDailyFRRICAPCommitment} \end{aligned}$$

Since a single unit can be committed by multiple parties, a Provider's Average Daily FRR ICAP Commitment Amount, Provider's Average Daily RPM ICAP Commitment Amount, and Provider's Share of Total Unit ICAP Commitment Amount for each unit is calculated in order for PJM to allocate any unit shortfalls calculated for, summer/winter capability testing.

A Provider's Average Daily FRR ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the sum of the Provider's Daily FRR Capacity Plan Commitments on such unit for the Delivery Year) divided by 365 (or 366 days).

$$\begin{aligned} \text{ProviderAvgDailyFRRICAPCommitment}_{\text{GEN}} &= \\ \frac{\sum \text{ProviderDailyFRRCommitment}}{365 \text{ (or 366) days}} \end{aligned}$$

A Provider's Average Daily RPM ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the sum of the Provider's Daily RPM Resource Commitments on such unit the Delivery Year divided by the sum of all Daily RPM Resource Commitments on such unit for the Delivery Year, multiplied by the Unit Average Daily RPM ICAP Commitment Amount.

$$\begin{aligned} \text{ProviderAvgDaily RPMICAPCommitment}_{\text{GEN}} &= \\ \frac{(\sum \text{ProviderDailyRPMCommitments})}{\sum \text{TotalDailyRPMCommitments}} * \text{UnitAvgDailyRPMICAPCommitment}_{\text{GEN}} \end{aligned}$$

A Provider's Share of the Total Unit ICAP Commitment Amount on a specific unit for the Delivery Year is equal to the Provider's Average Daily FRR ICAP Commitment Amount plus the Provider's Average Daily RPM ICAP Commitment Amount.

$$\text{ProviderShareTUICA}_{\text{GEN}} = \text{ProviderAvgDailyFRRICAPCommitment} + \text{ProviderAvgDailyRPMICAPCommitment}$$

8.4 Deleted

8.4A Non-Performance Assessment

A Non-Performance Assessment²⁴ will assess performance of resources during emergency conditions. Non-Performance Assessment applies to Capacity Performance Resource commitments and Price Responsive Demand commitments. Capacity Performance Resource commitments and PRD commitments are exposed to Non-Performance Charges for under-performance during Emergency Actions throughout the entire Delivery Year. Resources that fail to perform are subject to Non-Performance Charge and resources that over-perform may be eligible for Bonus Performance Credit.

The Non-Performance Assessment will compare each Capacity Resource's Expected Performance against its Actual Performance for each Performance Assessment Interval. Performance Assessment Interval shall mean each Real-time Settlement Interval for which an Emergency Action as defined in the OATT has been declared by PJM. A Performance Assessment Interval is triggered based on either of the two conditions defined below and such condition must be in effect for the entire Real-time Settlement Interval.

- Condition 1 - A Primary Reserve Shortage is determined for the Reserve Zone or active Reserve Sub-zone and one of the following emergency procedures is issued that encompasses such Reserve Zone or active Reserve Sub-zone:
 - Voltage Reduction Warning and Reduction of Non-Critical Plant Load
 - Manual Load Dump Warning
 - Maximum Emergency Generation Action
 - Voltage Reduction Warning and Curtailment of Non-Essential Building Load

The following table illustrates which resources will be assessed for a PAI based on the location of the resource and the location of the above Emergency Procedure and location of the Primary Reserve Shortage

²⁴ OATT, Attachment DD, Section 10A

		Primary Reserve Shortage			
Condition 1 Emergency Procedures		Reserve Zone (RTO)	Reserve Subzone (MAD)	Reserve Zone and Reserve Subzone (RTO & MAD)	None
	Reserve Zone (RTO)	RTO	MAD	RTO	None
	Reserve Subzone (MAD)	None	MAD	MAD	None
	None	None	None	None	None

- Condition 2 - One of the following emergency procedures is issued for the entire Reserve Zone or Sub-Zone:
 - Deploy All Resources Action
 - Voltage Reduction Action
 - Manual Load Dump Action
 - Load Shed Directive

See Manual 13 for details on the issuance of emergency procedures and Manual 11 for detail on Primary Reserve Shortage which is determined when the reserve MW assigned in the dispatch run is less than the Primary Reserve requirement for either the Reserve Zone or active Reserve Sub-zone.

When assessment is for the Reserve Sub-zone, the list of resources subject to assessment is determined based on the active subzone bus and resource list effective at the time of the PAI. The posting is found on the Ancillary Service page of PJM.com. DR/PRD dispatched and located in the Reserve Sub-zone will be included in the Reserve Sub-zone assessment.

If the Emergency Action area is for the Reserve Zone, Net Energy Imports are included in this assessment. External Generation Capacity Resources are included in the assessment if such external resource would have helped resolve the declared Emergency Action that was the subject of the assessment. At the start of the Delivery Year, PJM will inform the Capacity Market Seller of an external resource as to which Locational Deliverability Area it has been assigned for Non-Performance Assessment purposes. QTUs will be deemed to be located in the LDA into which such upgrade increased the CETL and the QTU will be included in the Non-Performance Assessment only if, and to the extent that, the declared Emergency Action encompasses only the LDA into which the upgrade increased the CETL.

For each Performance Assessment Interval, the Actual Performance and the Expected Performance is used to calculate a Performance Shortfall that determines both the Non-Performance Charge and Bonus Performance Credit applicability.

For each Performance Assessment Interval, the Actual Performance is equal to:

- for each generation resource (including External Generation Capacity Resources when applicable), the metered output of delivered energy plus the resource's real-time reserve or regulation assignment²⁵, if any; however, the resulting MW quantity is floored at 0 MW;
- for each Demand Resource, the demand response provided plus the resource's real-time reserve or regulation assignment, if any;
- for each Energy Efficiency Resource, the load reduction quantity approved by PJM subsequent to the pre-delivery year submittal of a post-installation M&V Report;
- for each entity providing Net Energy Imports during a PJM-wide event, the Net Energy Import quantity excluding any energy delivered from External Generation Capacity Resources ;
- for each Qualified Transmission Upgrade, the cleared MW quantity of the QTU if it is in-service prior to the start of the day of the Performance Assessment Interval, and zero if it is not in-service prior to the start of such day; and,
- For each PRD Provider, the Actual Performance is calculated in accordance with Section 3A.6.2A.

For each Performance Assessment Interval, the Expected Performance is equal to:

- for each generation resource (including External Generation Capacity Resources when applicable), the resource's committed Unforced Capacity times the ratio²⁶ of [(total amount of Actual Performance for all generation resources, plus net energy imports²⁷, plus total Demand Response Bonus Performance for that interval, plus total PRD Bonus Performance for that interval / (total amount of committed Unforced Capacity of all Generation Capacity Resources)];
- for each Demand Resource and Energy Efficiency Resource, the resources' committed capacity without making any adjustment for the Forecast Pool Requirement (i.e., the actual load reduction quantity the resource committed to provide);
- for each Qualified Transmission Upgrade, the committed MW quantity; and,
- for each PRD Provider, the Expected Performance is calculated in accordance with Section 3A.6.2A.

²⁵ The metered output of jointly owned generation resources is allocated to each owner pro-rata with each owner's share of the total Installed Capacity of the resource.

²⁶ This ratio will be capped at 1.

²⁷ Net Energy Imports are only included in this formula for PJM-wide emergency events.

The Performance Shortfall for a resource or PRD Provider is calculated as Expected Performance minus the Actual Performance. If the Performance Shortfall for such resource or PRD Provider is a positive number, the under-performing resource or PRD Provider is subject to a Non-Performance Charge. If the Performance Shortfall is a negative number, the over-performing resource or PRD Provider may be eligible for Bonus Performance Credit.

For generation resources with a positive Performance Shortfall amount, the Performance Shortfall may be adjusted downward due to exempt MWs. Exempt MWs consist of the following:

- Unavailable MWs associated with a generator's approved planned or maintenance outage during the Performance Assessment Interval;
- MWs for which the resource was not scheduled to operate by PJM; or
- MWs for which the resource was on-line but was scheduled down by PJM based on the determination by PJM that such scheduling action was appropriate to the security constrained economic dispatch of the PJM Region²⁸.
- If such 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 a market-based offer higher than its cost-based offer, then these MWs will not be considered exempted and will not result in a downward adjustment to the Performance Shortfall.
- For purposes of the Non-Performance Assessment for demand resources, compliance will be measured in accordance with Section 8.6 of this manual.
- During the Performance Shortfall calculation and the exempt MW determination, PJM will ensure that each energy offer complies with Manual 11, Section 2.3.7 and has the required associated information. If this information is not included, then no MWs will be exempt.

For purposes of calculating Bonus Performance quantity, the Actual Performance for a dispatchable resource shall not exceed the MW level at which such resource was scheduled and dispatched by PJM during the Performance Assessment Interval²⁹. During the Bonus Performance quantity calculation, PJM will ensure that each energy offer complies with Manual 11, Section 2.3.7 and has the required associated information associated. If this information is not included, then the Bonus Performance quantity will be zero. For self-scheduled generation resources not dispatchable by PJM, the Actual Performance will not exceed the LMP Desired MW value as calculated by PJM based upon the higher of the cost or price schedules submitted for the resource, and will be zero if the LMP Desired MW is less than the lowest point on the higher of the cost or price schedules submitted for the resource.

²⁸ Scheduled MW appropriate to the security constrained economic is determined based on the results of the Dispatch Run described in Manual 11

²⁹ Scheduling and dispatch shall be determined based on the results of the Dispatch Run described in Manual 11

The interval Non-Performance Charge is calculated as Performance Shortfall multiplied by the Non-Performance Charge Rate. The Non-Performance Charge Rate for Capacity Performance commitments is equal to {[the modeled LDA through the 25/26 DY, otherwise the RTO Net CONE (\$/MW-day in installed capacity terms) for which the resource resides times number of days in the Delivery Year] divided by 30} divided by the number of Real-Time Settlement Intervals in an hour. The modeled LDAs and their respective Net CONE are provided in the Delivery Year BRA Planning Parameters posted on the PJM website.

Through the 2024/2025 Delivery Year, for Capacity Performance Resources or PRD Providers, the maximum yearly Non-Performance Charge is 1.5 times the modeled LDA Net CONE (\$/MW-day in installed capacity terms) in which the resource resides times number of days in Delivery Year times the maximum daily unforced capacity committed by the resource or PRD Provider during June 1 of the Delivery Year through the end of the billing month for which the Non-Performance Charge was assessed. For Seasonal Capacity Performance Resources, the maximum yearly Non-Performance Charge is based the number of days of the applicable season and the maximum daily unforced capacity committed by the resource for such season. The modeled LDAs and their respective Net CONE are provided in the Delivery Year BRA Planning Parameters posted on the PJM website.

Effective with the 2025/2026 Delivery Year for Capacity Performance Resources or PRD Providers, the maximum yearly Non-Performance Charge is 1.5 times the RPM Base Residual Auction clearing price applicable to the modeled LDA in which the resource resides times number of days in Delivery Year times the maximum daily unforced capacity committed by the resource or PRD Provider during June 1 of the Delivery Year through the end of the billing month for which the Non-Performance Charge was assessed. For Seasonal Capacity Performance Resources, the maximum yearly Non-Performance Charge is based on the number of days of the applicable season and the maximum daily unforced capacity committed by the resource for such season. The modeled LDAs and their respective clearing prices are provided in the Delivery Year BRA results posted on the PJM website

Revenue collected from payment of Non-Performance Charges will be distributed to resources (of any type, even if they are not Capacity Resources) and PRD Providers that perform above expectations. A resource or PRD Provider 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 Credit. This credit is based on the ratio of its Bonus Performance quantity to the total Bonus Performance quantity (from all resources or PRD Providers) for the same Performance Assessment Interval.

The billing of any Non-Performance Charges incurred in any given month will be done within three calendar months after the calendar month that included such Performance Assessment Intervals and such billing of charges will be spread over the remaining months in the Delivery Year. Bonus Performance Credits will follow the same billing methodology as Non- Performance Charges.

For Public Distribution Microgrid Generators that are Generation Capacity Resources:

- If the Public Distribution Microgrid load is reported to PJM as wholesale load when the PDM is islanded, then any islanded generation MWh output that is settled through the PJM energy market counts towards Capacity Performance obligation as Actual Performance.
- If the Public Distribution Microgrid load is not reported to PJM as wholesale load when the PDM is islanded, then any islanded Public Distribution Microgrid Generators should not report their islanded output as PJM supply. In this case, the islanded Public Distribution Microgrid Generator is not available to supply PJM load, and their Actual Performance is zero for the intervals in which the Public Distribution Microgrid is islanded.
- Whether a Public Distribution Microgrid load is or is not reported to PJM as wholesale load when the PDM is islanded, the Expected Performance during a Performance Assessment Interval is what it would have been had the Public Distribution Microgrid Generator still been grid-connected.

Definitions and additional business rules for Public Distribution Microgrids can be found in PJM Manual 14D, Appendix B: Public Distribution Microgrid Business Rules and PJM Manual 14D, Appendix C: Voluntary Guideline on Public Distribution Microgrid Operations.

8.5 Summer/Winter Capability Testing

During the Delivery Year, generation owners are responsible to perform Summer/Winter Net Capability Verification (i.e., Capability Testing) in accordance with **PJM's Rules and Procedures for Determination of Generating Capability (M-21)** through the 2024/2025 Delivery Year and M-21B effective with the 2025/2026 Delivery Year and submit test results through the eGADS system. Variable Resources, and variable components of Hybrid Resources, are exempted from the summer/winter capability testing requirement and are not assessed Generation Resource Rating Test Failure Charges. The purpose of the summer/winter net capability verification is to demonstrate that the unit can achieve the claimed summer/winter net capability rating of the unit. PJM will use the results of the summer/winter net capability testing to assess whether a unit that was committed to RPM or FRR Alternative was able to achieve a Summer/Winter Net Corrected Test Capability value at least equal to the total daily ICAP commitment level on the unit, or non-variable components of a Hybrid Resource. The Summer/Winter Net Corrected Test Capability value of a Hybrid Resource with multiple non-variable resource components will be the sum of the Summer/Winter Net Corrected Test Capability values of the non-variable resource components. The total daily ICAP commitment level of the non-variable component(s) of a Hybrid Resource during the Jun-October and May of the Delivery Year equals the total daily ICAP commitment level of the Hybrid Resource minus the actual 95th percentile hourly summer net output between the hours ending 11AM and 10PM EPT for the variable component(s). The total daily ICAP commitment level of the non-variable component(s) of a Hybrid Resource during November through April of the Delivery Year equals the total daily commitment level of the Hybrid Resource minus the actual 95th percentile hourly winter net output in all hours except for hours beginning 9AM to 5PM EPT for the variable

component(s). Through the 2024/2025 Delivery Year, a unit's total daily ICAP commitment level is measured by the unit's Total Unit ICAP Commitment Amount ("TUICA") which is determined as described in section 8.3 of this manual. Effective with the 2025/2026 Delivery Year, a unit's total daily ICAP commitment level is determined each day of the delivery year and is calculated as the resource's total daily UCAP commitment level divided by the Accredited UCAP Factor of such resource.

In accordance with M-21 and 21B, a Net Capability Test must be performed during both the Summer and the Winter testing periods. The Summer test period begins the first day of June and ends the last day of August. The Winter test period begins the first day of December and ends on the last day of February. If the entire unit is on a forced or planned outage during the entire summer or winter testing period, the unit is expected to submit an out-of-period capability test when the outage ends.

An unlimited number of tests may be performed on the unit during each testing period. If none of the tests certify full delivery of the total daily ICAP commitment level, those parties with RPM Resource Commitments and FRR Capacity Plan Commitments from such unit may be subject to Generation Resource Rating Test Failure Charges.

The unit's installed capacity shortfall for the testing period is determined by the test that resulted in the highest installed capacity rating (i.e., the highest Summer/Winter Net Corrected Test Capability as described in **PJM's Rules and Procedures for Determination of Generating Capability (M-21 and M-21B)**). Through the 2024/2025 Delivery Year, the Unit ICAP Shortfall is determined as described in Section 8.5.1. Effective with the 2025/2026 Delivery Year, the Unit ICAP Shortfall is determined as described in Section 8.5.2. A Unit ICAP Shortfall forms the basis for a Generation Resource Rating Test Failure Charge.

8.5.1 Determination of Unit ICAP Shortfall (through the 2024/2025 Delivery Year)

Through the 2024/2025 Delivery Year, the Unit ICAP Shortfall for the summer/winter testing period is equal to the Total Unit ICAP Commitment Amount minus the highest Summer/Winter Net Corrected Test Capability achieved in a summer/winter capability test.

A positive shortfall indicates a failure to certify the Total Unit ICAP Commitment Amount during the testing period. A negative shortfall indicates that the Total Unit ICAP Commitment Amount was exceeded during the testing period.

The following business rules apply in the determination of the Unit ICAP Shortfall:

- If a unit is on a partial outage during the test, the amount of the partial outage is added to the highest installed capacity rating in the test to determine the Unit ICAP Shortfall for the summer or winter test period.
- The Unit ICAP Shortfall for the summer testing period will be applied daily for the months of June through November of the Delivery Year. The Unit ICAP Shortfall for the winter testing period will be applied daily for the months of December through May of the Delivery

Year. If the Unit ICAP Shortfall as a result of the winter testing period is less than the Unit ICAP Shortfall as a result of the summer testing period, the Unit ICAP Shortfall as a result of the summer testing period will be applied daily for the months of December through May of the Delivery Year.

- If the entire unit is on a forced or planned outage from June 1 to December 1 of the Delivery Year, a Unit ICAP Shortfall for the summer testing period is not calculated.
- If the entire unit is on a forced or planned outage from December 1 – May 31 of the Delivery Year, the Unit ICAP Shortfall for the winter testing period is the calculated Unit ICAP Shortfall for the summer testing period.
- If the winter rating on a unit is less than the summer rating on the unit and the Total Unit ICAP Commitment Amount is greater than the winter rating, the Unit ICAP Shortfall for the winter testing period will be calculated as the winter rating of the unit (instead of the Total Unit ICAP Commitment Amount) minus the highest installed capacity rating achieved in a winter capability test.
- If a unit is exempt from the winter net capability verification requirement the Unit ICAP Shortfall that is calculated as a result of a summer capability test would also apply for the months of December through May of the Delivery Year.
- In the case of hydro generation, the Unit ICAP Shortfall that is calculated as a result of the single capability test submitted is applied for the entire Delivery Year.
- If a daily RPM commitment compliance shortage on a unit occurs due to a unit delay, derating, or retirement during the Delivery Year, the Daily Unit ICAP Shortfall will be reduced by the portion of the daily RPM commitment compliance shortage (in UCAP) due to the unit delay, derating, or retirement divided by one minus the unit's Effective EFORD for the Delivery Year. The Daily Unit ICAP Shortfall for the unit will not be reduced to a value less than zero.³⁰

If portions of the unit were committed by multiple Resource Providers, the Daily Unit ICAP Shortfall is allocated to the Resource Providers based on the provider's pro-rata share of the unit's Total Unit ICAP Commitment Amount.

A Provider's Daily ICAP Shortfall for a unit is equal to the Daily Unit ICAP Shortfall times the Provider's Share of Total Unit ICAP Commitment Amount divided by Total Unit ICAP Commitment Amount.

$$\text{ProviderDailyICAPShortfall}_{\text{GEN}} = \frac{\text{DailyUnitICAPShortfall} * \text{ProviderShareTUICA}}{\text{TUICA}}$$

³⁰ This implicitly occurs through the calculation of the unit's Total Unit ICAP Amount. For days in which a unit's Daily ICAP Commitment is greater than Daily ICAP Owned, Daily ICAP Owned is used in determining Unit Average Daily ICAP Commitment for the Delivery Year.

If a Resource Provider has both RPM Resource Commitments and FRR Capacity Plan Commitments on the unit, the Provider's Daily ICAP Shortfall for such unit will be separated into a Daily ICAP Shortfall for RPM Resource Commitments and Daily ICAP Shortfall for FRR Capacity Plan Commitments.

A Resource Provider's Daily ICAP Shortfall for RPM Resource Commitments is equal to the Provider's Daily ICAP Shortfall times the Provider's Average Daily RPM ICAP Commitment Amount divided by the Provider's Share of the Total Unit ICAP Commitment Amount.

$$\text{ProviderDailyICAPShortfall}_{RPM} = \frac{\text{ProviderDailyICAPShortfall}_{GEN} * \text{ProviderAvgDailyRPMICAPCommitment}}{\text{ProviderShareTUICA}}$$

A Resource Provider's Daily ICAP Shortfall for FRR Capacity Plan Commitments is equal to the Provider's Daily ICAP Shortfall times the Provider's Average Daily FRR ICAP Commitment Amount divided by the Provider's Share of the Total Unit ICAP Commitment Amount.

$$\text{ProviderDailyICAPShortfall}_{FRR} = \frac{\text{ProviderDailyICAPShortfall}_{GEN} * \text{ProviderAvgDailyFRRICAPCommitment}}{\text{ProviderShareTUICA}}$$

A Resource Provider with a positive Daily ICAP Shortfall will be assessed The Generation Resource Rating Test Failure Charge.

8.5.2 Determination of Unit ICAP Shortfall (Effective with the 2025/2026 Delivery Year)

Effective with the 2025/2026 Delivery Year, the Unit ICAP Shortfall is determined for each Generation Capacity Resource (with the exception of Variable Resources) on a daily basis. Each day of the Delivery Year, the Daily Unit ICAP Shortfall is calculated as (i) the installed capacity committed for that day (adjusted for any replacement capacity), minus (ii) the highest Summer/Winter Net Corrected Test Capability determined for the resource in any test during the relevant testing period.

The summer period capability test result submitted in eGADS is used in this determination for each day in the months of June through October and the following May of each Delivery Year, and, winter period capability test result submitted in eGADS is used in this determination for each day in the months of November through April of each Delivery Year.

In the event a resource is eligible for an out of period capability test for the relevant season, as described in **PJM Rules and Procedures for Determination of Generating Capability Manual (M21B)** an updated Unit ICAP Shortfall would be determined based on the out of period test and the updated Unit ICAP Shortfall becomes effective on the date of the out of period test, and extends through the relevant seasonal period.

A positive Unit ICAP Shortfall in any day represents a failure to certify the total daily ICAP commitment amount on such resource through capability testing.

If portions of the unit were committed by multiple Resource Providers, the Daily Unit ICAP Shortfall is allocated to the Resource Providers based on each provider's pro-rata share of the total installed capacity commitment for that day (adjusted for any replacement capacity).

The daily installed capacity committed used for determining a resource's shortfall, or allocating a resource's shortfall to multiple providers, shall be capped at the ICAP Owned for such resource or provider to avoid double counting of shortfalls under the capability testing assessment and commitment compliance.

If a Resource Provider has both RPM Resource Commitments and FRR Capacity Plan Commitments on the unit, the Provider's Daily ICAP Shortfall for such unit will be separated into (i) a Daily ICAP Shortfall for RPM Resource Commitments based on the ratio of the Provider's installed capacity committed to RPM for the day divided by the Provider's total installed capacity committed for the day and (ii) a Daily ICAP Shortfall for FRR Capacity Plan Commitments based on the ratio of the Provider's installed capacity committed to FRR for the day divided by the Provider's total installed capacity committed for the day.

A Resource Provider with a positive Daily ICAP Shortfall will be assessed The Generation Resource Rating Test Failure Charge as described in Section 9.1.5.

8.5A Generation Operational Testing

Effective with the 2025/2026 Delivery Year, Generation Capacity Resources, with the exception of Variable Resources, that are committed to RPM or FRR shall be subject to operational testing initiated by the Office of the Interconnection up to two times in each of the summer and winter seasons during the relevant Delivery Year. The operational testing requirements, retest requirements, and determination of when a shortfall is assessed are found in **Generator Operational Requirements Manual (M14D)**.

When a unit fails a retest of the Generation Operational Test, a Generation Operational Test Failure Charge may be assessed. The Generation Operational Test Failure Charge shall equal the Daily Deficiency Rate multiplied by the applicable daily committed UCAP MW of such Generation Capacity Resource.

The applicable daily committed UCAP MW value subject to the Generation Operational Test Failure Charge will account for:

- any RPM and FRR commitments on the unit;
- any unit modeling differences that may exist between the energy market and capacity market; and
- any portions of the unit that were committed by multiple Capacity Market Sellers, provided, however, a Capacity Market Seller shall not be assessed a Generation Operational Test

Failure Charge to the extent (i.e., for the same megawatts and time period) that such seller is assessed a Capacity Resource Deficiency Charge for such resource.

The Daily Deficiency Rate shall equal the value defined in section 9.1.5A.

8.6 Measuring Compliance during Performance Assessment Interval for Demand Resources

A Capacity Performance Demand Resource is subject to Non-Performance Assessment during a Performance Assessment Interval that occurs during the Delivery Year during the availability window when linked registrations to such Capacity Performance Demand Resource are dispatched by PJM during such Performance Assessment Interval. A Summer-Period Capacity Performance Demand Resource is subject to Non-Performance Assessment during a Performance Assessment Interval that occurs during June through October and May of the Delivery year during the availability window when linked registrations to such Summer-Period Capacity Performance Demand Resource are dispatched by PJM during such Performance Assessment Interval.

Compliance is the process utilized to review Demand Resource performance during a Performance Assessment Interval and establishes a Performance Shortfall or Bonus Performance for such Demand Resource.

Compliance will be measured for each registration dispatched by PJM within the area defined by the Emergency Action for each Performance Assessment Interval. Compliance is measured for partial clock hour dispatch if dispatched for 30 minutes or more of the clock hour. Compliance is not measured if dispatched for less than 30 minutes of the clock hour.

DR Providers are responsible for submittal of compliance information to PJM through the DR Hub System within 45 days after the end of the month in which a Performance Assessment Interval occurred.

PJM verifies compliance on an end-use customer basis by reviewing the data submitted by the DR Provider through the DR Hub system. Load management compliance for non-interval metered residential customers may be verified using a statistical sample of end-use customers in accordance with **PJM Manual 19: Load Forecasting & Analysis, Attachment D** and subject to PJM approval.

DR Providers may use substitute registrations of a different resource product type to cover the commitment of non-performing registrations that cannot respond for the Performance Assessment Interval. The non-performing registration(s) and corresponding substitute registration(s) must be in the same geographic location defined by the PJM dispatch instruction with the same designated lead time. In addition, the total nominated value (summer or non-summer, as applicable) of the substitute registration(s) must be comparable (within either +/- 25% or +/- 0.5 MW) to the total nominated value (summer or non-summer, applicable) of the

corresponding non-performing registration(s). DR Providers that use substitute registrations must submit their list of nonperforming registrations and corresponding substitute registrations to PJM by 11:59 pm on the day of the Performance Assessment Interval in the appropriate PJM system. PJM may also request that resource providers submit evidence that notification to respond were sent to substitute registrations in advance or during the Performance Assessment Interval to verify that meter data was not used after the fact in finding the substitutes. Any registration used as a substitute must be included in the submittal of compliance information to the appropriate PJM system. The reduction value(s) of the substitute registration(s) will be used by PJM when measuring compliance during a Performance Assessment Interval for the corresponding non-performing registration(s). Non-performing registration(s) will be considered to have not performed. Registrations used as substitutes during an event will have the same obligation to respond to future event(s) as if it did not respond to such event. A registration may only be used as a substitute for a non-performing registration dispatched for a Performance Assessment Interval in the winter period if the registration provided winter data (Winter Peak Load, winter Firm Service Level, or winter Guaranteed Load Drop data) at the time of registration and meets the criteria outlined above.

For a Firm Service Level (FSL) customer on a registration, the actual load reduction provided for the hour ending that includes a Performance Assessment Interval(s) in the summer period (June through October and May of the Delivery Year) is calculated as the end-use customer's Peak Load Contribution minus (the hourly metered load multiplied by the loss factor). A load reduction will only be recognized if the hourly metered load multiplied by the loss factor is less than the Peak Load Contribution. For the non-summer period (November through April of the Delivery Year), the actual load reduction for a Performance Assessment Interval is calculated as (end-use customer's Winter Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by loss factor) minus (the hourly metered load multiplied by the loss factor). A load reduction will only be recognized if the hourly metered load multiplied by the loss factor is less than the Winter Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by the loss factor.

For a Guaranteed Load Drop (GLD) customer on registration, the actual load reduction provided for the hour ending that includes a Performance Assessment Interval(s) in the summer period is calculated as the lesser of (a) the (comparison load minus the hourly metered load) multiplied by the loss factor or (b) end-use customer's Peak Load Contribution minus (hourly metered load multiplied by loss factor). A load reduction will only be recognized if the hourly metered load multiplied by the loss factor is less than the Peak Load Contribution. For the non-summer period (November through April of the Delivery Year), the actual load reduction for a Performance Assessment Hour is calculated as lesser of (a) (comparison load minus the hourly metered load) multiplied by the loss factor or (b) the end-use customer's Winter Peak Load multiplied by Zonal Winter Weather Adjustment Factor multiplied by loss factor minus (the hourly metered load multiplied by the loss factor). A load reduction will only be recognized if the hourly metered load multiplied by loss factor is less than the Winter Peak Load multiplied by the Zonal Winter Weather Adjustment Factor multiplied by the loss factor.

DR Provider must submit 24 hours of actual load data for the day in which Performance Assessment Interval occurred and for all days required to determine comparison loads. Comparison loads must be developed in accordance with the guidelines included in **PJM Manual M-19 Load Forecasting & Analysis, Attachment A: Load Drop Estimate Guidelines**, and note which method was employed.

A Load Management customer may not reduce their metered load below zero (i.e., export energy into the system). No compliance credit will be given for the incremental load drop below zero. Hourly load reduction for a registration is floored at 0 MW.

For a partial dispatch clock hour, the Expected Performance of a Demand Resource is not adjusted by the percentage of the hour dispatched. When five-minute revenue meter data is submitted to determine compliance for a Performance Assessment Interval, the actual load reduction for a Performance Assessment Interval is calculated using the five-minute metered load data for such Performance Assessment Interval as opposed to using hourly metered load data. When five-minute revenue meter data is not submitted to determine compliance of a Demand Resource for a Performance Assessment Interval, the actual hourly load reduction for the hour ending that includes a Performance Assessment Interval(s) is flat-profiled over the set of dispatch intervals in the hour. The actual load reduction for a Performance Assessment Interval is calculated as the actual hourly load reduction multiplied by (twelve divided by the number of five-minute intervals the Demand Resource was dispatched in the hour). The actual load reduction for a registration for a Performance Assessment Interval is capped at the Peak Load Contribution of the registration in the summer period and at the Winter Peak Load of the registration multiplied by Zonal Winter Weather Adjustment Factor in the winter period.

For each dispatched registration in the Emergency Action Area, the Actual Performance is equal to the actual load reduction plus any real-time reserve or regulation assignment for such registration for the Performance Assessment Interval. The Actual Performance for a Demand Resource for a Performance Assessment Interval is equal to the sum of the Actual Performance of the dispatched registrations linked to such Demand Resource. If a Demand Resource is owned by multiple parties, the Actual Performance of a Demand Resource shall be allocated to the owners of the Demand Resource based on ICAP ownership share to determine each Capacity Market Seller's Actual Performance for such Demand Resource.

The Expected Performance for the Performance Assessment Interval for a Capacity Market Seller's Demand Resource³¹ is equal the Capacity Market Seller's committed capacity on the Demand Resource in installed capacity terms (i.e., the actual load reduction quantity the

³¹ The Actual and Expected Performance of dispatched economic registrations are not considered in the performance of a committed Demand Resource. Actual Performance will be calculated for an economic registration in the same way it is calculated for a Pre-Emergency or Emergency registration and such registration may be eligible for Bonus Performance since its Expected Performance will be zero MW.

resource committed to provide), adjusted to account for any linked registrations that were not dispatched by PJM.

The Capacity Market Seller's Expected Performance minus the Actual Performance for a Demand Resource establishes the seller's initial Performance Shortfall for such Demand Resource. A positive initial Performance Shortfall indicates the seller's Demand Resource under-complied for the Performance Assessment Interval. A negative initial Performance Shortfall indicates the seller's Demand Resource over-complied for the Performance Assessment Interval. The Capacity Market Seller's initial Performance Shortfalls for Demand Resources in the Emergency Action Area (EAA) are netted to determine a net EAA Performance Shortfall for the Performance Assessment Interval. Any net positive EAA Performance Shortfall is allocated to the Capacity Market Seller's Demand Resources that under-complied within the EAA on a pro-rata basis based on the under-compliance MWs, and such seller's Demand Resources will be assessed a Performance Shortfall for the Performance Assessment Interval. Any net negative EAA Performance Shortfall is allocated to the Market Seller's Demand Resources that over-complied within the EAA on a pro-rata basis based on over-compliance MWs, and such Market Seller's Demand Resources will be assessed Bonus Performance.

8.7 Load Management Test Compliance

DR Resource providers are subject to Load Management Test Compliance.

For Demand Resources committed for the 2023/2024 Delivery Year and subsequent Delivery Years:

1. For Annual Demand Resources: if an Annual Demand Resource registration for the 2023/2024 Delivery Year is not dispatched by the Office of the Interconnection for a Load Management event in the Delivery Year or if an Annual Demand Resource registration for the 2024/2025 Delivery Year or subsequent Delivery Years is not dispatched by the Office of the Interconnection for a Load Management event in a Delivery Year and assessed for performance during Performance Assessment Intervals, then the registration committed by a Capacity Market Seller in a zone shall be tested as described in section (3) listed below, for a two-hour period between the hours of 11:00 EPT and 18:00 EPT of a non-NERC holiday weekday during June through October or November through March of the relevant Delivery Year, where date and time are selected by the Office of the Interconnection and notice is provided consistent with the procedure described in sections (4) and (5) listed below. If an Annual Demand Resource registration for the 2023/2024 Delivery Year is dispatched by the Office of the Interconnection for a Load Management event during the Delivery Year or if an Annual Demand Resource Registration for 2024/2025 Delivery Year or subsequent Delivery Years is dispatched by the Office of the Interconnection for a Load Management event in a Delivery Year and assessed for performance during Performance Assessment Intervals, then no test will be required.

Subject to the conditions in this paragraph beginning in Delivery Year 2024/2025 and subsequent Delivery Years, CSPs may elect to use performance data from a Load Management event that was not subject to a Non-Performance Assessment (a non-PAI LM event) as performance data for a PJM zonal test event. Elections are made on or after June 1 and no later than July 14th after the Delivery Year in the DR Hub system. Data required for compliance evaluation must be submitted no later than July 14th after the Delivery Year. Only one event result (either test event or non-PAI LM event) for each end use customer site will be used in the zonal test evaluation:

- a. The duration of non-PAI LM event must be at least 30 minutes of a clock hour
- b. The election of non-PAI LM events to be used as zonal test performance will be done at the registration lead time interval.
- c. For purposes of this election, the calculated reduction value for a registration in the non-PAI LM event is the average of the registration's hourly reductions within the product period hourly window.
- d. CSP's Load Reduction Capability data submission(s) must account for registrations that will not participate in a PJM scheduled test.
 - i. In accordance with the load reduction reporting requirements in section 4.3.9, any updates to the Load Reduction Capability data for non-participation in PJM scheduled test must be reported no later than 4 p.m. on the day prior to the PJM scheduled test.

PJM will take into consideration non-PAI LM events when scheduling tests. This could result in test event postponements when non-PAI LM events occur within a scheduled test window.

2. For Summer-Period Demand Resources: if a Summer- Period Demand Resource registration for the 2023/2024 Delivery Year is not dispatched by the Office of the Interconnection for a Load Management event during June through October or the following May of the Delivery Year or if a Summer-Period Demand Resource registration for the 2024/2025 Delivery Year or subsequent Delivery Years is not dispatched by the Office of the Interconnection for a Load Management event during the June through October or the following May of the Delivery Year and assessed for performance during Performance Assessment Intervals, then the registration committed by a Capacity Market Seller must demonstrate that it was tested as described in section (3) listed below, for a two-hour period between the hours of 11:00 EPT and 18:00 EPT of a non-NERC holiday weekday, during June through October of the relevant Delivery Year, where date and time are selected by the Office of the Interconnection and notice is provided consistent with the procedure described below.

Subject to the conditions in this paragraph beginning in Delivery Year 2024/2025 and subsequent Delivery Years, CSPs may elect to use performance data from a Load Management event that was not subject to a Non-Performance Assessment (a non-PAI LM event) as performance data for a PJM zonal test event. Elections are made on or after June 1 and no later than July 14th after the Delivery Year in the DR Hub system. Data required for compliance evaluation must be submitted no later than July 14th after the Delivery Year. Only one event result (either test event or non-PAI LM event) for each end-use customer site will be used in the zonal test evaluation:

- a. The duration of a non-PAI LM event must be at least 30 minutes of a clock hour
- b. The election of non-PAI LM events to be used as zonal test performance will be done at registration lead time level.
- c. The non-PAI LM event must have occurred in the summer.
- d. For purposes of this election, the calculated reduction value for a registration in the non-PAI LM event is the average of the registration's hourly reductions within the product period hourly window.
- e. CSP's Load Reduction Capability data submission(s) must account for registrations that will not participate in a PJM scheduled test.
 - i. In accordance with the load reduction reporting requirements in section 4.3.9, any updates to Load Reduction Capability data non-participation in PJM scheduled test must be reported no later than 4 p.m. on the day prior to the PJM scheduled test.

PJM will take into consideration non-PAI LM events when scheduling tests. This could result in test event postponements when non-PAI LM events occur within a scheduled test window.

3. All registrations in a zone will be tested simultaneously for two hours for each product. Registration performance will be calculated as the two hour average reduction. The Office of the Interconnection may, at its discretion, cancel a test and retest on an event day to ensure system reliability.
 - a. If less than 25 percent (by megawatts) of a Curtailment Service Provider's total Demand Resources in a zone fail the test, the Curtailment Service Provider may conduct re-tests limited to all registrations that failed to meet their seasonal nominated ICAP in the prior test, provided that such re-test(s) must be during the same season period (except if test was conducted in March in which case retest can be conducted in May), at the same time of day and under approximately the same weather conditions as the prior test, and provided further that all affiliated registrations must test simultaneously, where affiliated means registrations that have any ability to shift load and are owned or controlled by the same entity. If less than 25 percent of resources fail the test and the Curtailment Service Provider chooses to conduct a retest, the Curtailment Service Provider may elect to maintain the performance compliance result for the registration(s) that achieved during the test if Curtailment Service Provider: (1) notifies the Office of the Interconnection 48 hours prior to the retest under this election; and (2) the Curtailment Service Provider retests affiliated registrations under this election as set forth in the PJM Manual.
 - b. If 25 percent or more (by megawatts) of a Curtailment Service Provider's Demand Resources fail the test, the Curtailment Service Provider may request the Office of Interconnection to schedule a one-time retest limited to all registrations that failed to meet their seasonal nominated ICAP in the prior test, provided that all affiliated registrations must test simultaneously. Affiliated means registrations that have any ability to shift load and are owned or controlled by the same entity. The request must be made before the 46th day after the test. The Office of the Interconnection will select the date and time of the retest during the same season period (except if test was conducted in March in which case retest may be conducted in May) and notice is provided consistent with the procedure described below.
4. Notification of the initial Office of the Interconnection scheduled test will be provided based on the following procedure.
 - a. The Office of Interconnection shall schedule, on an alternating basis, one test during June through October or November through March for each Delivery Year that a test is required. On the first business day of a week, PJM will provide notice of all zones to be tested during the following two week test window. The test window opens the first business day of the week following the notice. By 10:00 EPT the day before the test, the Office of the Interconnection will post on its website the test date and zones. The Office of the Interconnection will also notify the Curtailment Service Providers of the test date. On the test date, Curtailment Service Providers will be notified of start time of test through the same notification protocol used for an event and as described in the PJM Manuals.

5. Notification of any scheduled retest by the Office of the Interconnection will be provided based on the following procedure.
 - a. By 10:00 EPT the day before the retest, the Office of the Interconnection will post the retest date on its website. PJM will also notify the Curtailment Service Providers the retest date. On the retest date, Curtailment Service Providers will be notified of start time of retest through the same notification protocol used for an event and as described in the PJM Manuals.

Load Management test compliance for a registration will be measured based on Performance Assessment Interval compliance for a registration; however, for purposes of Load Management test compliance the Resource Compliance Position for a registration considers the Summer Average RPM/FRR Commitment as opposed to the RPM/FRR Commitment on the day of the event or Performance Assessment Interval and performance will be aggregated to the zone and not Performance Assessment Area.

Resource Compliance Position for a registration for a test is determined as the Nominated Load Reduction Value reported in the DR Hub system minus the actual load reduction, where the Nominated Load Reduction Value is capped at the Summer Average RPM/FRR Commitment for such registration. The Nominated Load Reduction Value determined based on summer capability is used to test Capacity Performance DR product-type registrations.

Summer Average RPM/FRR Commitment for a Demand Resource is the daily average of the RPM/FRR resource commitments for such Demand Resource from June 1st through September 30th of the Delivery Year. If multiple registrations are linked to a committed Demand Resource in the Capacity Exchange system, the Summer Average RPM/FRR Commitment for such Demand Resource is allocated to the registrations pro-rata based on the nominated load reduction value of the registrations.

For any Load Management test, a provider's net testing shortfall in a zone for a product type is calculated by netting the Resource Compliance Positions of the product-type registrations tested in a zone. A resource provider with a positive net testing shortfall in a zone for a product type (i.e., under compliance MWs in zone for a product type) will be assessed a Zonal Load Management Test Failure Charge. A net testing shortfall in zone for Capacity Performance DR product-type (which may include Summer-Period DR) may be separated into net testing shortfall in zone due to annual commitments or summer-only commitments, as appropriate.

If a Demand Resource is committed by multiple parties, a portion of the provider's net testing shortfall in a zone for a product-type may be assessed to each party that has a commitment if tested registrations linked to such Demand Resource under-complied, based on the each party's commitment share of the Demand Resource.

8.8 Replacement Resources

Participants may specify replacement resources in order to avoid or reduce resource performance assessment shortfalls and the associated deficiency/penalty charges. Participants may not specify replacement resources in order to avoid or reduce performance assessment shortfalls and associated deficiency/penalty charges related to price responsive demand.

Replacement capacity for generation resources, Demand Resources, Energy Efficiency Resources, or Qualifying Transmission Upgrades committed to RPM may be specified via the Capacity Exchange system by entering a “Replacement Capacity” transaction before the start of the Delivery Day. However, upon a request to PJM made no later than three business days after a Delivery Day containing a Performance Assessment Interval, Replacement Capacity Transactions may be permitted retroactively effective with the Delivery Day provided such transaction meets the following criteria: (1) the replacement resource must have already been in the same sub-account as the resource being replaced on the Delivery Day, (2) the replacement resource must have been included in the same Performance Assessment Intervals as the resource being replaced, (3) the replacement resource must have the same or better temporal availability characteristics as the resource being replaced, (4) the replacement resource must be located in the same LDA (or a more constrained child LDA) as the resource being replaced, and (5) the resulting total Daily Resource Commitments (RPM and FRR) (in UCAP terms) on a generation resource used as a replacement resource cannot exceed such replacement resource’s Actual Performance during the Performance Assessment Intervals. Such requests must be submitted to rpm_hotline@pjm.com and include the start date and end date, resource being replaced, replacement resource, and the desired change in Daily RPM Commitments (in UCAP terms) for the resource being replaced and product type (Capacity Performance) of the commitment being replaced.

Through the “Replacement Capacity” transaction functionality in Capacity Exchange, PJM will provide participants with a list of the available capacity for each generation or demand resource in their portfolio as well as a list of cleared buy bids from any Incremental Auction via the Capacity Exchange system and a list of resources with RPM Resource Commitments. Participants will have the ability to match a generation, Demand Resource, Energy Efficiency Resource or Qualifying Transmission Upgrade resource committed to RPM that they would like to replace with available capacity from a generation resource, demand resource, cleared buy bids in an Incremental Auction, or from Locational UCAP transactions. Available capacity from an EE Resource may be utilized to replace the commitment of only another EE Resource because such commitments are accompanied by the adjustment that is required to avoid double-counting of energy efficiency measures as described in section 2.4.5 of this manual.

The following are business rules that apply to Replacement Resources for Resources Committed to RPM:

- The start date and end date of the replacement must be specified.

- The Delivery Year commitment of a Generation Capacity Resource may not be replaced until after the final Accredited UCAP Factor for the Delivery Year has been locked in the Capacity Exchange system. After the final Accredited UCAP Factor for the prior Delivery Year has been locked in and prior to the conduct of the Third Incremental Auction for the Delivery Year, the commitment of such a resource may be replaced but only up to the quantity of any commitment deficiency of the resource.
- Any or all of a Delivery Year commitment of a Generation Capacity Resource, Demand Resource, or Energy Efficiency Resource may be replaced any time prior to the conduct of the Third Incremental Auction for that Delivery Year when the owner of the replaced resource provides transparent and verifiable evidence to support the expected final physical position of the resource at the time of request. Such requests shall be submitted in writing simultaneously to PJM rpm_hotline@pjm.com and the Independent Market Monitor rpmacr@monitoringanalytics.com documenting the reason for the early replacement. PJM will approve or deny a request for early Replacement Capacity, based upon the below criteria, with input from the Market Monitor, within 15 days of receiving a completed early Replacement Capacity request.
 - Acceptable reasons for early replacement are:
 - Generator Deactivation (properly noticed to PJM and posted to the website)
 - A pending request to PJM for removal of Generation Capacity Resource status (in accordance with Manual 18, section 5.4.7, and subject to PJM approval)
 - Withdrawal of generation New Service Request/ cancellation of generation project (accompanied by written notification to PJM Interconnection Projects manager)
 - Generation delayed in-service date (accompanied by written notification to PJM Interconnection Projects manager)
 - Permanent departure of load used as a basis for an existing DR or EE resource at the time of commitment
 - A financially and physically firm commitment to an external sale of its capacity for the entire Delivery Year that is demonstrated with supporting evidence as specified in Tariff, Attachment DD, Section 6.6(g), for the 2023/24, 2024/25, 2025/26 Delivery Years where there is only one Incremental Auction
 - Generation replaced may not be recommitted for the Delivery Year. Therefore, the resource may not resell the replaced MW in a subsequent RPM auction for the applicable Delivery Year, and has no requirement to submit a Must-Offer Exception request for such auctions.
 - DR/EE sites replaced may not be registered or committed for the Delivery Year.
- A Replacement Resource used to reduce a Demand Resource commitment shall be specified for no less than the balance of the Delivery Year. An available Demand Resource may only be used as a Replacement Resource when the start date of the Replacement Capacity transaction is from June 1 through September 30th unless the Demand Resource

can demonstrate through the prior summer's event or test compliance data that the Demand Resource met both its Summer Average RPM Commitment and the new daily RPM commitment level that would result if the Replacement Capacity transaction was approved.

- The desired change in Daily RPM Resource Commitments (in UCAP terms) for the resource being replaced and the replacement resource must be specified. The change in Daily RPM Resource Commitments cannot result in a negative value for the Daily RPM Resource Commitments for the resource being replaced. The desired change in Daily RPM Resource Commitments (in UCAP terms) for the resource being replaced must also indicate the product type (Capacity Performance) of the commitment being replaced.
- The replacement resource must be located in the same sub-account as the resource that is being replaced.
- The replacement resource must be located in the same LDA as the resource that is being replaced or reside in the Sink LDA of the Qualifying Transmission Upgrade being replaced. However, if there is remaining import capability into the LDA after the Third Incremental Auction, a replacement resource may be located in a parent LDA, subject to the following restrictions. The ability to submit a replacement transaction from a parent LDA into a child LDA is limited by the import capability remaining into the LDA. After the Third Incremental Auction, the remaining import capability of each LDA is posted on the PJM website.
- Resources located in a constrained LDA can serve as replacement capacity for a generation resource located in a less constrained parent LDA.
- The replacement resource must have the same or better temporal availability characteristics as the resource that is being replaced.
- Capacity Performance Resource commitments can only be replaced by available capacity from a capacity resource that is eligible to be committed as CP, or by cleared Buy Bids or Locational UCAP of the Capacity Performance product type.
- Available capacity of a Capacity Resource with State Subsidy for which the Capacity Market Seller has not elected to forego receipt of any State Subsidy for the relevant Delivery Year and does not qualify for one of the categorical exemptions may not be used to replace the commitment of a Capacity Resource that (1) is not a Capacity Resource with State Subsidy or (2) is a Capacity Resource with State Subsidy for which the Capacity Market Seller elected the competitive exemption and reported that it will forego receipt of any State Subsidy for the relevant Delivery Year or (3) a Capacity Resource with State Subsidy that qualifies for one of the categorical exemptions.
- If a generation, demand, or EE resource is used as replacement capacity, a decrease in the Daily RPM Resource Commitments for the resource that is being replaced will result and a corresponding increase in the Daily RPM Resource Commitments for the replacement generation, demand, or EE resource will result during the time period specified for replacement. A change in the Daily RPM Resource Commitments for a generation resource will result in a change in the Total Unit ICAP Commitment Amount for the generation resource.

- If cleared buy bids from an Incremental Auction or Locational UCAP transactions are used as replacement capacity, a decrease in the Daily RPM Commitments for the resource that is being replaced will result during the time period specified for replacement. A change in the Daily RPM Commitments for a generation resource will result in a change in the Total Unit ICAP Commitment Amount for the generation resource.

Replacement resources for Generation Capacity Resources, QTU, Energy Efficiency Resources, or Demand Resources committed to FRR Capacity Plan are specified by an FRR Entity through the update of the FRR Entity's FRR Capacity Plan prior to the start of the Delivery Day. FRR Entities may update their FRR Capacity Plan to reduce the FRR Capacity Plan Commitment on the resource being replaced and increase the FRR Capacity Plan Commitment on a replacement resource. The change in the Daily FRR Capacity Plan Commitments for a generation resource will result in a change in the Total Unit ICAP Commitment Amount for the generation resource.

8.8.1 Excess Commitment Credits

LSEs may receive credits when Reliability Requirements decrease resulting in an excess capacity.

The Excess Capacity Credits will be the PJM Sell Offers in the Scheduled Incremental Auctions that do not clear less the PJM Buy Bids in Incremental Auctions that do not clear. The Excess Capacity Credits in PJM will be allocated to LDAs pro rata based on the reduction in LDA peak load forecast from BRA to the time of Third Incremental Auction, provided the amount allocated does not exceed the reduction in the corresponding LDA Reliability Requirement. There will not be an allocation to LDA with an increase in load forecast.

The amount allocated to LDA will be further allocated to LSEs that are charged a Locational Reliability Charge, based on the Daily Unforced Capacity Obligation of the LSEs as of June 1 of the Delivery Year, and the credits will be constant for the entire Delivery Year. Excess Commitment Credits may be used as Replacement Capacity or traded bilaterally.

Section 9: Settlements

Welcome to the *Settlements* section of the **PJM Manual for the PJM Capacity Market**. In this section, you will find the following information:

- The business rules for the deficiency and penalty charges in RPM/FRR for committed supply resources (see “Deficiency and Penalty Charges”)
- The business rules for Locational Reliability Charges (see “Locational Reliability Charges”)
- The business rules for RPM auction credits and charges (see “Auction Credits and Charges”)
- The business rules for the penalty charges in RPM/FRR for non-performance of price responsive demand (see “Penalties for Non-Performance of Price Responsive Demand”)
- The business rules for the PRD Credits (see “PRD Credits”)

9.1 Deficiency and Penalty Charges

9.1.1 Deleted

9.1.2 Deleted

9.1.3 Capacity Resource Deficiency Charge

The Daily Capacity Resource Deficiency Charge is applicable to a capacity resource with a RPM commitment that does not have enough unforced capacity value on such resource to cover its RPM commitments. 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.

$$\text{DailyCapResourceDeficiencyCharge} = \text{DDR} * \text{DailyRPMCommitmentShortage}$$

The Daily Deficiency Rate (\$/MW-day) applicable to a shortage is equal to the Party's Weighted Average Resource Clearing Price for such resource plus the higher of 0.2*Party's Weighted Average Resource Clearing Price for such resource or \$20/MW-day. In the case where a Party's Weighted Average Resource Clearing Price for such resource is equal to \$0/MW-day because the committed resource did not clear in any RPM Auction (i.e., commitments were due to the resources being used as a source of a Locational UCAP transaction or as replacement capacity), a PJM Weighted Average Resource Clearing Price in an LDA will be used.

A party's Weighted Average Resource Clearing Price for such resource's commitments is determined by calculating the weighted average of segment-specific (i.e., annual, seasonal-summer, seasonal-winter) resource clearing prices received on the deficient day for such resource across all Delivery Year RPM Auctions, weighted by a party's segment-specific

cleared and make-whole MWs for such resource. Segment-specific cleared MWs acquired or transferred through a Unit Specific Transaction for cleared capacity are accounted for in the calculation of a party's Weighted Average Resource Clearing Price.

The PJM Weighted Average Resource Clearing Price for commitments in an LDA is determined by calculating the c weighted average of segment-specific resource clearing prices applicable in the LDA across all Delivery Year RPM Auctions, weighted by the total segment-specific cleared and make-whole MWs in the LDA.

A resource that is also subject to a Non-Performance Charge during one or more Performance Assessment Intervals occurring during a continuous time period of Daily RPM Commitment Shortages associated with Capacity Performance commitments shall be 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.

Note:

Daily Capacity Resource Deficiency Charges are assessed daily and billed weekly.

9.1.4 Transmission Upgrade Delay Penalty Charge

The Daily Transmission Upgrade Delay Penalty Charge is equal to the QTU Delay Penalty Rate times the Daily RPM Commitment Shortage for the QTU.

$$\text{DailyQTUDelayPenaltyCharge} = \text{QTUDelayPenaltyRate} * \text{DailyRPMCommitmentShortage}$$

The QTU Delay Penalty Rate is equal to the higher of (i) 1.2 times the Capacity Resource Clearing Price of the LDA into which the QTU is cleared or (ii) the Net Cost of New Entry.

A QTU that is also subject to a Non-Performance Charge during one or more Performance Assessment Intervals occurring during a continuous time period of Daily RPM Commitment Shortages shall be assessed a charge equal to the greater of (a) the total Daily Transmission Upgrade Delay Penalty Charges calculated 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 Transmission Upgrade Delay Penalty Charges and Non-Performance Charges actually billed for such continuous time period may not exceed the resultant greater of charge.

Note:

Transmission Upgrade Delay Penalty Charges are assessed daily and billed weekly.

9.1.5 Generation Resource Rating Test Failure Charge

The Daily Generation Resource Rating Test Failure Charge is applicable to all generation resources (with the exception of Variable Resources) committed to RPM or FRR that have a positive Daily Unit ICAP shortfall due to a rating test failure. The determination of the Daily Unit ICAP Shortfall for a generation resource and a Provider's Daily ICAP Shortfall is described in Section 8.5.1 for Delivery Years through the 2024/2025 Delivery Year and Section 8.5.2 for Delivery Years starting with the 2025/2026 Delivery Year.

For Delivery Years through the 2024/2025 Delivery Year, the Daily Generation Resource Rating Test Failure Charge shall be equal to the Daily Deficiency Rate times: a) for Combination Resources and Limited Duration Resources, the appropriate Accredited UCAP value that corresponds to the Provider's Daily ICAP Shortfall, or; b) for Unlimited Resources, the Provider's Daily ICAP Shortfall times (1 – Effective EFORD) for a generation resource.

Effective with the 2025/2026 Delivery Year, the Daily Generation Resource Rating Test Failure Charge shall be equal to the Daily Deficiency Rate times the Provider's Daily ICAP Shortfall of the resource converted to Unforced Capacity terms using the Generation Capacity Resource's final Accredited UCAP Factor for the Delivery Year.

$$\text{GenerationResourceRatingTestFailureCharge} = \text{DDR} * \text{DailyICAPShortfall} * \text{AUCAPFactor}$$

The Daily Deficiency Rate applied to a Daily ICAP Shortfall for RPM Resource Commitments is equal to the Party's Weighted Average Resource Clearing Price for such resource plus the higher of 0.2*Party's Weighted Average Resource Clearing Price for such resource or \$20/MW-day. In the case where a Party's Weighted Average Resource Clearing Price for such resource is equal to \$0/MW-day because the committed resource did not clear in any RPM Auction (i.e., commitments were due to the resources being used as a source of a Locational UCAP transaction or as replacement capacity), a PJM Weighted Average Resource Clearing Price in an LDA will be used.

The Daily Deficiency Rate applied to Daily ICAP Shortfall for FRR Resource Commitments is equal to 1.2 times the weighted average of the resource clearing prices across all Delivery Year RPM Auctions for the LDA encompassing the zone of the FRR Entity, weighted by the quantities cleared in the RPM Auctions.

A resource that is also subject a Non-Performance Charge during one or more Performance Assessment Intervals occurring during a continuous time period of Daily ICAP Shortfalls due to rating test failure shall be assessed a charge equal to the greater of (a) the total Daily Generation Resource Rating Test Failure Charges calculated for such continuous time period or (b) the total Non-Performance Charges for the Performance Assessment Intervals occurring during such continuous time. The sum of the Daily Generation Resource Rating Test Failure Charges and Non-Performance Charges actually billed for such continuous time period may not exceed the resultant greater of charge. A resource that is subject to a Generation Operational Test Failure Charge shall not also be subject to a Generation Resource Rating Test Failure Charge for the same megawatts during overlapping time periods.

Note:

Generation Resource Rating Test Failure Charges are assessed daily for the entire Delivery Year and are billed retroactively for the entire Delivery Year in the June monthly bill issued in July after the conclusion of the Delivery Year.

9.1.5A Generation Operational Test Failure Charge

The Generation Operational Test Failure Charge is applicable to all generation resources (with the exception of Variable Resources) committed to RPM or FRR that fail the Generation Operational retest in accordance with Manual 14D.

The Daily Generation Operational Test Failure Charge applicable to RPM commitments shall be equal to the Daily Deficiency Rate times the applicable daily RPM committed UCAP MW of that Generation Resource.

$$\text{RPM Daily Generation Operational Test Failure Charge} = \text{DDR} \times \text{Applicable Daily RPM Committed UCAP MW}$$

The Daily Deficiency Rate applicable to RPM Resource Commitments is equal to the Party's Weighted Average Resource Clearing Price for such resource plus the higher of 0.2*Party's Weighted Average Resource Clearing Price for such resource or \$20/MW-day. In the case where a Party's Weighted Average Resource Clearing Price for such resource is equal to \$0/MW-day because the committed resource did not clear in any RPM Auction (i.e., commitments were due to the resources being used as a source of a Locational UCAP transaction or as replacement capacity), a PJM Weighted Average Resource Clearing Price for the corresponding LDA will be used.

The Daily Generation Operational Test Failure Charge applicable to FRR commitments shall be equal to the Daily Deficiency Rate times the applicable daily FRR committed UCAP MW of that Generation Resource).

$$\text{FRR Daily Generation Operational Test Failure Charge} = \text{DDR} \times \text{Applicable Daily FRR Committed UCAP MW}$$

The Daily Deficiency Rate applicable to FRR Resource Commitments is equal to 1.2 times the weighted average of the resource clearing prices across all RPM Auctions for the relevant Delivery Year, for the LDA encompassing the zone of the FRR Entity, weighted by the quantities cleared in the RPM Auctions.

A resource that is also subject to a Non-Performance Charge during one or more Performance Assessment Intervals occurring during a continuous time period of a generation operational test failure shall be assessed a charge equal to the greater of (a) the total Daily Generation Operational Test Failure Charges calculated for such continuous time period or (b) the total Non-Performance Charges for the Performance Assessment Intervals occurring during such continuous time. The sum of the Daily Generation Operational Test Failure Charges and Non-Performance Charges actually billed for such continuous time period may not exceed the resultant greater of charge.

9.1.6 Load Management Test Failure Charge

The Daily Load Management Test Failure Charge is equal to the net testing shortfall in zone (expressed in UCAP) times the LM Test Failure Charge Rate. A net testing shortfall in zone will be separated into net testing shortfall in zone due to annual commitments and summer-only commitments, as appropriate.

The Daily Load Management Test Failure Charge Rate for zonal net testing shortfall due to annual commitments is equal to the Provider's Weighted Daily Revenue Rate for annual commitments in such zone plus the greater of (0.20 times the Provider's Weighted Daily Revenue Rate for annual commitments in such zone, or \$20/MW-day). In the case where a Provider's Weighted Daily Revenue Rate for annual commitments in zone is \$0/MW-day because the underlying committed resource(s) did not clear in any RPM Auction (i.e., commitments were due to the resource(s) being used as a source of a Locational UCAP transaction or as replacement capacity or commitments due to FRR Alternative), a PJM Weighted Daily Revenue Rate for annual commitments in such zone will be used. A Daily Load Management Test Failure Charge, equal to the net testing shortfall in zone due to annual commitments times the Daily Load Management Test Failure Charge Rate, will apply for each day in the Delivery Year.

The Daily Load Management Test Failure Charge Rate for zonal net testing shortfall due to summer-only commitments is equal to the Provider's Weighted Daily Revenue Rate in such zone for summer-only commitments plus the greater of (0.20 times the Provider's Weighted Daily Revenue Rate in such zone for summer-only commitments, or \$20/MW-day). In the case where a Provider's Weighted Daily Revenue Rate in such zone for summer-only commitments is \$0/MW-day because the underlying committed resource(s) did not clear in any RPM Auction (i.e., commitments were due to the resource(s) being used as source of a Locational UCAP transaction or as replacement capacity or commitments due to FRR Alternative), a PJM Weighted Daily Revenue Rate in such zone for summer-only commitments will be used. A Daily Load Management Test Failure Charge, equal to net testing shortfall in zone due to summer-only commitments times the Daily Load Management Test Failure Charge Rate, will apply for June through October and May of the Delivery Year.

Note:

The Load Management Test Failure Charges will be assessed in August monthly bill issued in September after the conclusion of the Delivery Year.

9.1.7 Allocation of Deficiency and Penalty Charges

The Daily Capacity Resource Deficiency Charges, Daily Transmission Upgrade Delay Penalties, Daily Generation Resource Rating Test Failure Charges, Generation Operational Test Failure Charges, and Load Management Test Failure Charges are distributed on a pro-rata basis to

LSEs who were charged a Daily Locational Reliability Charge for the day in order to compensate for resource adequacy that was not delivered.

Daily Capacity Resource Deficiency Charges, Daily Transmission Upgrade Delay Penalties, Daily Generation Resource Rating Test Failure Charges, and Load Management Test Failure Charges are allocated on a pro-rata basis to LSEs based on their daily unforced capacity obligation.

9.1.8 Emergency Procedures Charges

The Emergency Procedures Charges outlined in **Schedule 13 of the Reliability Assurance Agreement and section 13 of Attachment DD of OATT** for refusal to comply or failure to employ all reasonable efforts to comply will remain in effect, and will be assessed in addition to any penalty described here.

9.1.9 Non-Performance Charge/Bonus Performance Credit

Non-Performance Charge will be assessed to a resource provider or PRD Provider that had a Performance Shortfall for a Performance Assessment Interval.

Non-Performance Charge is equal to the Performance Assessment Interval Performance Shortfall (MW) times Non-Performance Charge Rate (\$/MWh).

The Non-Performance Charge Rate to be applied to shortfalls associated with Capacity Performance commitments or PRD commitments is equal to {[the modeled LDA Net CONE for which the resource resides (\$/MW-day in installed capacity terms) times number of days in Delivery Year divided by 30} divided by the number of Real-Time Settlement Intervals in an hour.

Stop-loss provisions limit the total Non-Performance Charge that can be assessed on each Capacity Resource or to a PRD Provider. The stop-loss provision (i.e., the maximum year Non-Performance Charge) is covered in section 8.4A of this Manual.

Revenue collected from payment of Non-Performance Charges will be distributed to resources (of any type, even if they are not Capacity Resources) and PRD Provider that perform above expectations. A resource or PRD Provider 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 Credit. This credit is based on the ratio of its Bonus Performance quantity to the total Bonus Performance quantity (from all resources and PRD Providers) for the same Performance Assessment Interval.

Note:

The billing of any Non-Performance Charges incurred in any given month will be done within three calendar months after the calendar month that included such Performance Assessment Intervals and such billing of charges will be spread over the remaining months in the Delivery Year. Bonus Performance Credits will follow the same billing methodology as Non-Performance Charges.

9.2 Locational Reliability Charges

9.2.1 Calculation of Locational Reliability Charges

All LSEs pay a Locational Reliability Charge equal to their Daily Unforced Capacity Obligation in a zone times the applicable Final Zonal Capacity Price.

$$\text{LocationalReliabilityCharge} = \text{DailyUCAPOblig} * \text{FinalZonalCapacityPrice}$$

Each LSE that serves load in a PJM Zone or load outside PJM using PJM resources (Non-Zone Network Load) during the Delivery Year is responsible for paying a Locational Reliability Charge equal to their Daily Unforced Capacity Obligation in a Zone times the applicable Final Zonal Capacity Price for that Delivery Year.

Note:

Locational Reliability Charges are calculated daily and billed weekly during the Delivery Year.

9.3 Auction Credits and Charges

9.3.1 Calculation of Auction Credits

$$\text{RPM Auction Credits} = \text{MWCleared}_{LDA} * \text{RCP}_{LDA}$$

Each generation, demand, energy efficiency, or QTO resource provider that clears Capacity Performance sell offer segments in an RPM Auction will receive a Daily Auction Credit equal to the total MW amount that cleared in Capacity Performance sell offer segments times the applicable LDA resource clearing price in such RPM Auction for the entire Delivery Year.

Each generation, demand, or energy efficiency resource provider that clears Seasonal Capacity Performance-Summer sell offer segments in an RPM Auction will receive a Daily Auction Credit equal to the total MW amount that cleared in Seasonal Capacity Performance-Summer sell offer segments times the resource clearing price applicable to the resource's Seasonal Capacity Performance-Summer sell offer segments in such RPM Auction. The Daily Auction Credit shall apply for June through October and May of the Delivery Year.

Each generation resource provider that clears Seasonal Capacity Performance-Winter sell offer segments in an RPM Auction will receive a Daily Auction Credit equal to the total MW amount that cleared in Seasonal Capacity Performance-Winter sell offer segments times the resource clearing price applicable to the resource's Seasonal Capacity Performance-Winter sell offer segments in such RPM Auction. The Daily Auction Credit shall apply for November through April of the Delivery Year.

The PJM Generation Deactivation Credits received by units with Reliability Must Run (RMR) contracts will be reduced by the Auction Credits received by the RMR unit in a RPM Auction.

Note:

Auction Credits are calculated daily and billed weekly during the Delivery Year.

9.3.2 Calculation of Auction Charges

Each resource provider that clears a Buy Bid in an Incremental Auction will receive an Auction Charge (referred to as Resource Substitution Charge in OATT) equal to the MW amount that cleared in the LDA times the Resource Clearing Price in the LDA in the applicable Incremental Auction.

$$RPM\text{AuctionCharges} = MWCleared_{LDA} * RCP_{LDA}$$

Note:

Auction Charges are calculated daily and billed weekly during the Delivery Year.

9.3.3 Resource Make-Whole Credit

A Resource Make-Whole Credit is paid to the marginal resource in an RPM auction as appropriate to ensure the seller is paid the sell offer MW times the sell offer price. Resource Make-Whole Credit is equal to the product of the Resource Clearing Price and the quantity difference between the sell offer's minimum MW specification and the cleared MW quantity in the RPM Auction. The difference between the minimum MW offered and the cleared MW quantities is equal to the Make-whole MWs.

$$Resource\text{MakeWholeCredit} = (Min\ MW\text{Offered} - MWCleared) * RCP_{LDA}$$

A resource provider that offered and cleared a Seasonal Capacity Performance sell offer for which the sell offer price exceeded the clearing price determined for such resource as a result of the seasonal matching process in the post-processing of the auction results as described in Section 5.7.2 and 5.8.5 will receive a Resource Make-whole Credit. The Resource Make-whole Credit is equal to the difference between the sell offer price and clearing price for such resource determined as a result of the seasonal matching process times the cleared MWs.

The Resource Make-whole Credit to a Seasonal Capacity Performance sell offer is incorporated in the Daily Auction Credit to the Seasonal Capacity Performance Resource since the Resource Clearing Price applicable to the Seasonal Capacity Performance Resource will include a seasonal make-whole price, if applicable.

Resource Make-Whole Credits from the First, Second, or Third Incremental Auctions are charged to all cleared participant and PJM buy bids on a pro-rata basis based on the MWs cleared in such auction. Make-whole charges assessed to buy bids cleared by PJM will be assessed to LSEs in the LDA via the Final Zonal Capacity Price

9.3.4 Capacity Transfer Rights Credit

Each Zonal Capacity Transfer Rights (CTRs) owner will receive a daily Zonal CTR Credit equal to the Zonal CTRs owned multiplied by the Zonal CTR Settlement Rate. Zonal CTRs owned include the Zonal CTRs allocated to an LSE and the results of any CTR transfers. The Zonal CTR Settlement Rate is the Total Economic Value of CTRs in Zone (\$/day) for all LDAs in which the zone resides as a result of all RPM Auctions for such Delivery Year divided by the maximum LDA CTRs (MWs) allocated to LSEs in a zone.

$$ZonalCTRCredit = ZonalCTRsOwned * ZonalCTRSettlementRate$$

Each Incremental CTR owner will receive a daily Incremental CTR Credit equal to the Incremental CTRs owned for the LDA multiplied by the LDA Incremental CTR Credit Rate. The LDA Incremental CTR Credit Rate is equal to the average weighted Locational Price Adder for such LDA determined with respect to the immediate higher level LDA as a result of all RPM Auctions for such Delivery Year.

$$IncrementalCTRCredit = IncrementalCTRsOwned * LDAIncrementalCTRCreditRate$$

Note:

CTR Credits will be calculated daily and billed weekly during the Delivery Year.

9.3.5 Auction Specific MW Transaction Credits and Charges

The Seller of an Auction Specific Capacity Transaction will receive a charge equal to the transaction amount (in MW) times the price associated with the transaction. The price associated with the transaction is a weighted average of the Resource Clearing Prices of the resource-specific, auction-specific, segment-specific Cleared MWs identified in the transaction.

$$SellerCharge = TransactionAmount * WeightedAvgRCP$$

The Buyer of an Auction Specific MW Transaction will receive a credit equal to the transaction amount (in MW) times the price associated with the transaction.

$$BuyerCredit = TransactionAmount * WeightedAvgRCP$$

Note:

Charges and Credits for Auction Specific MW Transactions are calculated daily and billed weekly for the duration of the transaction during the Delivery Year.

9.3.6 Capacity Export Charges and Credits

Capacity Export Charge = Export Reserved Capacity * (Final Zonal Capacity Price for the Zone encompassing the interface with the Control Area to which the capacity is exported - Final Zonal Capacity Price for the Zone in which the resource designated for the export is located)

Where, Export Reserved Capacity = Reserved Capacity of Long-Term Firm Transmission Service used for the export.

Capacity Export Credit = Export Customer's Allocated Share * (Final Zonal Capacity Price for the Zone encompassing the interface with the Control Area to which the capacity is exported - the Final Zonal Capacity Price for the Zone in which the resource designated for the export is located)

Where,

Export Customer's Allocated Share = (Unforced Capacity imported) * [Export Reserved Capacity / (Export Reserved Capacity + Unforced Capacity Obligations of all LSEs in the Zone)]

Unforced Capacity imported = Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located =

[(Export Reserved Capacity + Unforced Capacity Obligations of all LSEs in the Zone) – (Unforced Capacity cleared in the Zone)] *

(Ratio, as determined by PJM, of the CETL from the Zone in which the resource designated for export is located to the total CETL into the export interface Zone).

The revenues collected from Capacity Export Charge less the credit provided will be distributed to the LSEs in the export-interface Zone that were assessed Locational Reliability Charge for the delivery year (RPM LSEs) based on their Daily Unforced Capacity Obligations.

9.4 Penalties for Non-Performance of Price Responsive Demand

9.4.1 PRD Commitment Compliance Penalty & Credits

A PRD Provider with a positive daily commitment compliance shortfall in a sub-zone/zone for RPM or FRR will be assessed a Daily PRD Commitment Compliance Penalty.

The Daily PRD Commitment Compliance Penalty is equal to the MW shortfall in the Sub-zone/Zone * Delivery Year Forecast Pool Requirement * PRD Commitment Compliance Penalty Rate.

The MW Shortfall in Sub-zone/Zone for RPM is the Daily Nominal PRD Value committed in BRA and/or Third IA by the PRD Provider minus the Daily Nominal PRD Value for RPM determined from approved and effective PRD registrations for such PRD Provider.

The MW Shortfall in Sub-zone/Zone for FRR is the Daily Nominal PRD Value committed for FRR by the PRD Provider minus the Daily Nominal PRD Value for FRR determined from approved and effective PRD registrations for such PRD Provider.

The PRD Commitment Compliance Penalty Rate for a PRD Provider that committed PRD for RPM is equal to PRD Provider's Weighted Final Zonal Capacity Price in \$/MW-Day + higher of $[0.2 * \text{PRD Provider's Weighted Final Zonal Capacity Price or } \$20/\text{MW-day}]$.

A PRD Provider's Weighted Final Zonal Capacity Price is the average of the Final Zonal Capacity Price and the price component of the Final Zonal Capacity Price due to the Third Incremental Auction, weighted by the Nominal PRD Values committed by such PRD Provider in Base Residual Auction and Third Incremental Auction.

The PRD Commitment Compliance Penalty Rate for a PRD Provider that committed PRD for FRR is 1.20 times the weighted-average Resource Clearing Price resulting from all RPM Auctions for the Delivery Year for the LDA where the FRR PRD commitment resides, weighted-averaged for the Delivery year based on the prices established and quantities cleared in the RPM Auctions for such Delivery Year.

The revenue collected from assessment of the PRD Commitment Compliance Penalty shall be distributed on a pro-rata basis as Daily PRD Commitment Compliance Credit to all entities that committed Capacity Resources in the RPM Auctions for such Delivery Year, pro rata based on each such entity's daily revenues from Capacity Market Clearing Prices in such auctions, net of any daily compliance charges incurred by such entity.

9.4.2 Deleted

9.4.3 PRD Test Failure Charges & Credits

Each PRD Provider with a positive net testing shortfall in a zone will be assessed PRD Test Failure Charge.

The PRD Test Failure Charge is equal to the net testing shortfall in zone times * Delivery Year Forecast Pool Requirement * PRD Test Failure Charge Rate

The PRD Test Failure Charge Rate for RPM PRD is equal to the PRD Provider's Weighted Final Zonal Capacity Price in such Zone plus the greater of (0.20 times the PRD Provider's Weighted Final Zonal Capacity Price in such Zone or \$20/MW-day) times the number of days in the Delivery Year.

A PRD Provider's Weighted Final Zonal Capacity Price is the average of the Final Zonal Capacity Price and the price component of the Final Zonal Capacity Price due to the Third Incremental Auction, weighted by the Nominal PRD Values committed by such PRD Provider in BRA and Third IA.

The PRD Test Failure Charge Rate for FRR PRD is 1.20 times the weighted-average Resource Clearing Price resulting from all RPM Auctions for the Delivery Year for the LDA where the FRR PRD commitment resides, weight-averaged for the Delivery year based on the prices established and quantities cleared in the RPM Auctions for such Delivery Year.

The PRD Test Failure Charge shall be assessed daily and billed retroactively in the August bill issued in September after the conclusion of the Delivery Year.

The revenue collected from assessment of the PRD Test Failure Charges shall be distributed on a pro-rata basis as Daily PRD Test Failure Credits to all entities that committed Capacity Resources in the RPM Auctions for such Delivery Year, pro rata based on each such entity's daily revenues from Capacity Market Clearing Prices in such auctions, net of any daily compliance charges incurred by such entity.

9.4.4 PRD Credit

The PRD Provider identified in the PRD registration will receive a Daily PRD Credit each day that the PRD registration is effective. The PRD Provider (FRR Entity) identified in the PRD registration will not receive a Daily PRD Credit.

PRD Credit = [(Share of Zonal Nominal PRD Value committed in Base Residual Auction * * Final Zonal RPM Scaling Factor * FPR * Final Zonal Capacity Price) + (Share of Zonal Nominal PRD Value committed in Third Incremental Auction * * Final Zonal RPM Scaling Factor * FPR * Final Zonal Capacity Price * Third Incremental Auction Component of Final Zonal Capacity Price stated as a Percentage)].

.

Where:

Share of Zonal Nominal PRD Value Committed in Base Residual Auction = Nominal PRD Value for such registration/Total Zonal Nominal PRD Value of all Price Responsive Demand registered by the PRD Provider of such registration * Zonal Nominal PRD Value committed in the Base Residual Auction by the PRD Provider of such registration.

Share of Zonal Nominal PRD Value Committed in Third Incremental Auction = Nominal PRD Value for such registration/Total Zonal Nominal PRD Value of all Price Responsive Demand registered by the PRD Provider of such registration * Zonal Nominal PRD Value committed in the Third Incremental Auction by the PRD Provider of such registration.

When the PRD registration is associated with a sub-Zone, the Share of the Nominal PRD Value Committed in Base Residual Auction or Third Incremental Auction will be based on the Nominal PRD Values committed and registered in a sub-Zone.

A PRD Provider will receive a PRD Credit for each approved Price Responsive Demand registration that is effective and applicable to load served by such Load Serving Entity on a given day. The total daily credit to a PRD Provider in a Zone shall be the sum of the credits received as a result of all approved registrations in the Zone on a given day. The PRD Credit PRD Performance penalties are assessed to the PRD Provider in the registration.

Section 10: Capacity Exchange

Welcome to the *Capacity Exchange* section of the ***PJM Manual for the PJM Capacity Market***. In this section, you will find the following information:

- A description of the PJM Capacity Exchange tool (see "PJM Capacity Exchange Overview").

10.1 Overview

PJM Capacity Exchange tool is an Internet application that allows Market Participants to participate in PJM's RPM Auctions, the FRR Alternative, and view load and obligation data.

The graphic below presents a conceptual view of the RPM auction subsystems.

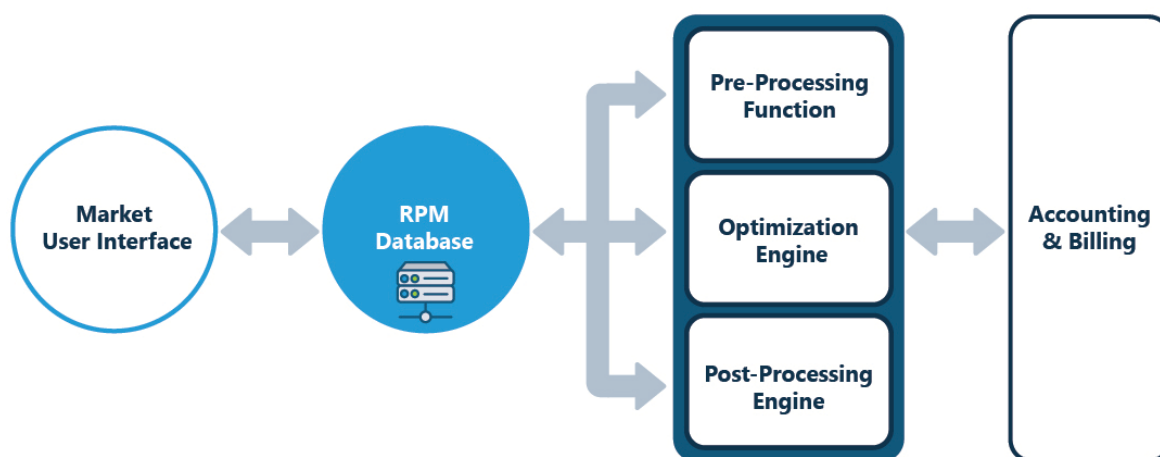


Exhibit 4: RPM Auction Subsystems

The Market User Interface (MUI) allows market participants to:

- Maintain their resource portfolio by increasing or decreasing their installed capacity values for generation via Capacity Modifications.
- View resource position
- Report Unit Specific Bilateral Transactions with a counterparty
- Report Auction Specific MW Transactions with a counterparty
- Report Locational UCAP Transactions
- Report Cleared Buy Bid Transactions
- Submit Resource Offers to sell capacity into an RPM auction

- Submit replacements for RPM Auction Commitments
- View Auction Results
- View load and obligation data
- Submit FRR Capacity Plan
- View deficiency data related to RPM/FRR Commitments

All data entered into the MUI is validated and entered into the RPM database by the MUI.

A **Capacity Exchange User Guide** is posted on the pjmc website to help participants use the Capacity Exchange tool.

The RPM auction subsystem consists of the following three components:

- *Pre-processing Function* – performs all activities necessary to setup Auctions, including specifying the Planning Year Parameters as inputs into the solution and evaluating submitted resource offers.
- *Optimization Engine* – performs auction clearing process to ensure the most economical capacity threshold is met. Assigns unit commitments based on the entered offers, demand curves, and specific planning year parameters.
- *Post-processing Function* – ensures that the appropriate data items are transferred to the RPM auction database for posting on the MUI and ensures the results are transferred to the accounting and billing subsystems.

Section 11: Fixed Resource Requirement Alternative

Welcome to the *Fixed Resource Requirement Alternative* section of the **PJM Manual for the PJM Capacity Markets**. In this section, you will find the following information:

- An overview of the Fixed Resource Requirement Alternative (see “Overview of the Fixed Resource Requirement Alternative”)
- The business rules for determining Load Obligations in FRR (see “Load Obligations”)
- The business rules for creating the Capacity Plan in FRR (see “Capacity Plan”)
- The business rules for supply resources in the FRR Alternative (see “Supply Resources in the FRR Alternative”)
- The business rules for locational constraints in the FRR Alternative (see “Locational Constraints in the FRR Alternative”)
- The conditions on sales by FRR Entities (see “Conditions on Sales by FRR Entities”)
- The business rules for Delivery Year Activity (see “Deliver Year Activity”)
- The business rules for the calculation of deficiency charges and penalties (see “Deficiency Charges and Penalties”)
- The business rules for the allocation of deficiency charges (see “Allocation of Deficiency Charges”)
- The business rules for Auction Specific MW Transactions (see “Auction Specific MW Transactions”)

11.1 Overview

11.1.1 Definition and Purpose of Fixed Resource Requirement Alternative

The purpose of the Fixed Resource Requirement (FRR) Alternative is to provide a Load Serving Entity (LSE) with the option to submit a FRR Capacity Plan and meet a fixed capacity resource requirement as an alternative to the requirement to participate in the PJM Reliability Pricing Model (RPM), which includes a variable capacity resource requirement.

The FRR Alternative allows an LSE, subject to certain conditions, to avoid direct participation in the RPM Base Residual Auctions and the Incremental Auctions; however, such LSE is required to submit a FRR Capacity Plan to satisfy the unforced capacity obligation for all loads in an FRR Service Area, including all expected load growth in the FRR Service Area.

An LSE serving load in an FRR Service Area under the FRR Alternative does not pay an RPM Locational Reliability Charge. The portions of capacity resources included in an LSE’s FRR Capacity Plan do not receive any RPM Resource Clearing Prices.

11.1.2 Implementation of the FRR Alternative

PJM's Planning Period is defined as an annual period from June 1 to May 31. The Delivery Year is the Planning Period for which resources are being committed and for which a constant load obligation for the entire PJM region exists. For example, the 2012/2013 Delivery Year corresponds to the June 1, 2012-May 31, 2013 Planning Period.

FRR Entities may commit Capacity Performance Resources and Seasonal Capacity Performance Resources to their FRR Capacity Plan.

11.1.3 Participation in the FRR Alternative

An LSE may participate in the Fixed Resource Requirement (FRR) Alternative and avoid participation in RPM, only if the LSE meets the eligibility requirements of the Fixed Resource Requirement (FRR) Alternative as defined in Schedule 8.1 of the Reliability Assurance Agreement (RAA).

To elect the FRR Alternative for the first time, an LSE must notify PJM of such election in writing at least four months before the conduct of the Base Residual Auction (BRA) for the first Delivery Year that such election is to be effective.

The election of the FRR Alternative shall be for a minimum term of five consecutive Delivery Years.

The written election notification must provide adequate information to demonstrate that the LSE meets the eligibility requirements of the FRR Alternative and that the FRR Service Area identified to be served by the LSE under the FRR Alternative complies with the meaning of an FRR Service Area as defined in the RAA. The written election must also indicate whether or not the LSE intends to sell capacity resources to a direct or indirect purchaser that may use such capacity resources in any RPM Auctions or as replacement resources in RPM or whether the LSE intends to serve load in another area under RPM.

Within ten business days of the receipt of the written election notification, PJM will validate that the LSE meets the eligibility requirements of the FRR Alternative. PJM will also request confirmation from the EDC that the identified FRR Service Area is metered and complies with the meaning of an FRR Service Area as defined in the RAA. PJM will (1) notify such LSE in writing that its election of the FRR Alternative is valid and the appropriate modifications to the Capacity Exchange database have been completed to allow the LSE to submit a FRR Capacity Plan through the Capacity Exchange system or (2) notify an LSE in writing that its election of the FRR Alternative is invalid since it did not meet the eligibility requirements of the FRR Alternative or that the identified FRR Service Area does not comply with the meaning of an FRR Service Area as defined in the RAA.

If PJM has provided written notice to an LSE that its election of the FRR Alternative is invalid, the LSE will be required to serve its load under the RPM for the Delivery Year such election was to be effective.

If PJM has provided written notice to an LSE that its election of the FRR Alternative is valid, an LSE must submit its initial FRR Capacity Plan through the Capacity Exchange system at least one month prior to the conduct of the Base Residual Auction for the first Delivery Year that such election is to be effective.

An LSE may terminate its election of the FRR Alternative effective with the commencement of any Delivery Year following the minimum term of five consecutive Delivery Years. An FRR Entity may terminate its election of the FRR Alternative prior to meeting its minimum five year commitment without penalty for any Delivery Year after the first Delivery Year of the FRR Entity's minimum five year commitment for which PJM will be required to establish a separate Variable Resource Requirement Curve, as described in Section 11.5 below. Written notice of such termination must be provided to PJM no later than two months prior to the Base Residual Auction (BRA) for such Delivery Year. In addition, an FRR Entity that elected the FRR Alternative for a Delivery Year prior to the 2025/2026 Delivery Year, may terminate its election of the FRR Alternative prior to meeting the minimum term of five years without penalty by providing written notice of such termination to the Office of the Interconnection no later than two months prior to the Base Residual Auction for a Delivery Year through and including the 2028/2029 Delivery Year.

An LSE that has terminated its election of the FRR Alternative shall not be eligible to re-elect the FRR Alternative for a period of five consecutive Delivery Years following the effective date of such termination.

In the event of a State Regulatory Structural Change as defined in the RAA, an LSE may elect or terminate its election of the FRR Alternative effective as to any Delivery Year by providing written notice to PJM of the election or termination of FRR Alternative. The written notice shall be provided in good faith as soon as the LSE becomes aware of such State Regulatory Change, but no later than two months prior to the BRA for such Delivery Year.

To facilitate the election and notices required by the FRR Alternative, except a new FRR Entity's initial election, the following information shall be posted by PJM with the BRA Planning Parameters in accordance with the posting deadline provided on the RPM Auction Schedule on the PJM website:

- Preliminary RTO and Zonal Peak Load Forecasts
- LDAs modeled in the Base Residual Auction
- Installed Reserve Margin (IRM)
- Pool-wide Average EFORD through 2024/2025 Delivery Year
- Pool-wide average Accredited UCAP Factor starting with the 2025/2026 Delivery Year
- Forecast Pool Requirement (FPR)
- Reliability Requirements of the PJM Region and each modeled LDA
- Variable Resource Requirement (VRR) Curves of the PJM Region and each modeled LDA
- CETO and CETL values for each modeled LDA

- Transmission Upgrades projected to be in service for the Delivery Year
- Cost of New Entry (CONE) for the PJM Region and each modeled LDA
- Net Energy and Ancillary Services Revenue Offset of the PJM Region and each modeled LDA
- Base Zonal FRR Scaling Factor
- Percentage of Internal Resources Required in an LDA
- Deadline for FRR Capacity Plan Submittal
- Auction Credit Rate

LSEs electing the FRR Alternative will be subject to the same credit requirements as suppliers of resources into the RPM auctions, to the extent that they submit as part of their FRR Capacity Plan any resources for which credit would be required if offered into an RPM auction. However, if an alternative retail LSE is providing capacity resources to the FRR Entity to satisfy the alternative retail LSE's capacity obligation in lieu of providing compensation to the FRR Entity in accordance with RAA Schedule 8.1D, section 9; the alternative retail LSE as opposed to the FRR Entity will be subject to any applicable credit requirements for capacity resources provided.

Any credit provided by an LSE to satisfy its credit requirements under the FRR Alternative must be established prior to the deadline for submitting the FRR Capacity Plan.

11.2 Load Obligations

Similar to RPM load obligations, FRR load obligations are calculated in two steps. First, prior to the RPM Base Residual Auction based on Preliminary Zonal Peak Load Forecast; then prior to the Third Incremental Auction based on the Final Zonal Peak Load Forecast. Base and Final Zonal FRR Scaling Factors and Forecast Pool Requirement are used in calculating the FRR Entity Unforced Capacity Obligations.

11.2.1 Preliminary Unforced Capacity Obligation

PJM will notify the Electric Distribution Company (EDC) that an election of the FRR Alternative was made by an LSE in their zone within two business days of the receipt of the written election notification.

An approved FRR Service Area will become a defined “area” within a zone in the Capacity Exchange system.

Only one LSE shall be responsible for serving the entire load in an FRR Service Area.

The Electric Distribution Company (EDC) is responsible for allocating the Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year and providing to PJM a Base Obligation Peak Load allocation for the FRR Service Area(s) in their zone within five business days of the receipt of notice of an FRR Service Area within their zone.

The Preliminary Daily Unforced Capacity Obligation of an LSE serving load in an FRR Service Area in a zone equals the LSE's Base Obligation Peak Load in the zone/area * the Base Zonal FRR Scaling Factor * the Forecast Pool Requirement.

The Preliminary Daily Unforced Capacity Obligation of an LSE serving load in an FRR Service Area shall be reduced by the Nominal PRD Value associated with such load that was approved by PJM in advance of the BRA for such Delivery Year, multiplied by the BRA Forecast Pool Requirement.

The Preliminary Daily Unforced Capacity Obligation of an LSE serving load in an FRR Service Area shall be increased by the UCAP Value of any EE Resource that is used in the FRR Capacity Plan because energy efficiency measures are reflected in the peak load forecast that is used as the basis for determining the UCAP Obligation of the FRR Entity.

The Base Zonal FRR Scaling Factor is equal to Preliminary Zonal Peak Load Forecast divided by the Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year. The Base Zonal FRR Scaling Factor is posted by February 1 three years prior to the Delivery Year.

The EDC is responsible for allocating the Zonal Weather Normalized Summer Peak for the summer one year prior to the Delivery Year and providing to PJM a Final Obligation Peak Load allocation for the FRR Service Area(s) in their zone by December 31 prior to the start of the Delivery Year.

The Final Zonal FRR Scaling Factor is equal to Final Zonal Peak Load Forecast divided by the Zonal Weather Normalized Summer Peak for the summer one year prior to the Delivery Year. The Final FRR Zonal Scaling Factor is determined by PJM and provided to the FRR Entity by February 1 prior to the Delivery Year.

The following parameters used in the determination of FRR load obligations are determined in accordance with Section 2 of this manual: Preliminary and Final Zonal Peak Load Forecasts, Zonal Weather Normalized Summer Peaks, Forecast Pool Requirement (FPR), Installed Reserve Margin (IRM), Pool-wide Average EFORd through the 2024/2025 Delivery Year, and the Pool-wide average Accredited UCAP Factor starting with the 2025/2026 Delivery Year.

11.2.2 Treatment of Non-Zone Load

Treatment of Non-Zone Load is similar to the treatment under RPM. The FRR Alternative is available to an LSE serving Non-Zone Load if the LSE meets the eligibility and election requirements of the FRR Alternative.

Non-Zone Load is the load that is located outside of the PJM Region served by a PJM Load Serving Entity using PJM internal resources. Non-Zone Load is included in the load of the Zone from which the load is served.

Non-Zone Load may be Non-Zone Network Load (Tariff 1.27B) that is charged a Network Integration Transmission Service (NITS) charge (Tariff Attachment H-A) or other load that may be 'grandfathered' from the NITS charge.

PJM forecasts the Preliminary Non-Zone Load for the RPM Delivery Year and includes it in the Preliminary RTO Forecast Peak Load and the Preliminary Zonal Forecast Peak Load of the Zone from which the Non-Zone Load is served, by February 1 prior to the Base Residual Auction.

To serve Non-Zone Load in a Delivery Year under the Fixed Resource Requirement Alternative, the Non-Zone Load should be included in the Preliminary RTO Forecast Peak Load and the Preliminary Zonal Forecast Peak Load prior to the RPM Base Residual Auction for the Delivery Year. In addition, the LSE must satisfy the eligibility and election requirements of the FRR Alternative.

PJM forecasts the final forecast of the Non-Zone Load and includes it in the Final RTO Forecast Peak Load and the Final Zonal Forecast Peak Load that is posted one month prior to the Third Incremental Auction.

EDC that is responsible to determine the Obligation Peak Loads for the Zone will also establish the Obligation Peak Load associated with the Non-Zone Load by December 31 prior to the start of the Delivery Year.

The LSE serving the Non-Zone Load under the FRR Alternative will be responsible to commit resources in their FRR Capacity Plan to cover the non-zone load.

11.2.3 Annexation & Switching of Load

The following business rules address the annexation of service territory by a Public Power Entity and load switching between FRR Entity and RPM LSEs. If an LSE that is a Public Power Entity annexes service territory to include new customers on sites where no load had previously existed, the incremental load will be treated as unanticipated load growth, and the LSE must commit additional resources to cover the additional load obligation associated with this annexed load.

If an LSE that is a Public Power Entity annexes service territory and the load was already included in the Base Residual Auction, the LSE cannot cover the incremental load obligation using the excess of resources from their FRR Capacity Plan. Instead, the LSE will pay the RPM Locational Reliability Charge for this incremental load obligation (including any additional demand curve obligation) since RPM process has already procured capacity resources to cover this load. The charges collected from the LSE will be used to pay capacity resources that that cleared in the Base Residual Auction for that LDA.

If an LSE that is a Public Power Entity annexes service territory and the Base Residual Auction was not held, the LSE must commit resources to cover this incremental load obligation in its FRR Capacity Plan.

If an LSE that has not elected the FRR Alternative acquires load from an FRR LSE after the Base Residual Auction, the shifted load will be considered as unanticipated load growth for purposes of determining RTO/LDA Reliability Requirements in all future Incremental Auctions for such Delivery Year, and such shifted load shall pay a Locational Reliability Charge for such Delivery Year. For the next Incremental Auction, the FRR Entity would have an RPM must offer requirement for a fixed amount of unforced capacity equal to the shifted load times the updated Forecast Pool Requirement applicable to the next Incremental Auction. The FRR Entity would continue to have an RPM must offer requirement for all future Incremental Auctions for such Delivery Year; however, the RPM must offer requirement would terminate once the FRR Entity cleared the required fixed amount of Unforced Capacity in Incremental Auction(s) for such Delivery Year.

If an LSE that has not elected the FRR Alternative acquires load from an FRR LSE and the Base Residual Auction has not been conducted for a Delivery Year, the FRR LSE should no longer commit capacity resources for the shifted load in its FRR Capacity Plan. PJM will include the shifted load in the future Base Residual Auctions.

11.3 Capacity Plan

The most important requirement in electing FRR Alternative is for the FRR Entity to commit Capacity Resources to meet their daily unforced capacity obligations, any applicable Percentage of Internal Resources Required in an LDA, plus any additional threshold if the FRR Entity plans to sell capacity. Failure to commit the required resources would result in FRR Commitment Insufficiency Charge and ineligibility to continue the FRR Alternative. An FRR Capacity Plan is the long-term plan for the commitment of Capacity Resources to satisfy the daily zonal unforced capacity obligations of an LSE that has elected the FRR Alternative in an FRR Service Area and any applicable Percentage of Internal Resources Required in a Locational Deliverability Area (LDA).

If the LSE intends to sell capacity resources to a direct or indirect purchaser that may use such a resource in any RPM Auctions or as a replacement resource in RPM, the LSE must also maintain a Threshold Quantity in its FRR Capacity Plan prior to the Delivery Year.

The Threshold Quantity is equal to the Preliminary Daily Unforced Capacity Obligation plus the lesser of (a) $0.03 \times \text{Preliminary Daily Unforced Capacity Obligation}$ or (b) 450 MW.

An LSE must submit an initial FRR Capacity Plan at least one month prior to the conduct of the Base Residual Auction for the first Delivery Year by demonstrating that it has sufficient capacity resources in its FRR resource portfolio in Capacity Exchange to satisfy:

- LSE's Preliminary Daily Unforced Capacity Obligations by zone for its FRR Service Area;

- any applicable Percentage of Internal Resources Required in LDA; and
- Threshold Quantity, if applicable.

If the initial FRR Capacity Plan does not satisfy the LSE's Preliminary Daily Zonal Unforced Capacity Obligations, any applicable Percentage of Internal Resources Required in LDA, and Threshold Quantity, if applicable, by the posted deadline for FRR Capacity Plan submittal, the LSE's election of the FRR Alternative will not be approved by PJM. The LSE will be required to serve its entire load in the FRR Service Area under the RPM for the Delivery Year such election was to be effective.

An LSE must annually demonstrate through the Capacity Exchange system no later than one month prior to the Base Residual Auction for each succeeding Delivery Year that it has extended the commitment of sufficient capacity resources to satisfy:

- LSE's Preliminary Daily Unforced Capacity Obligations by zone for its FRR Service Area;
- any applicable Percentage of Internal Resources Required in LDA; and
- Threshold Quantity, if applicable.

If the FRR Capacity Plan for a succeeding Delivery Year does not satisfy the LSE's Preliminary Daily Unforced Capacity Obligations, any applicable Percentage of Internal Resources Required in LDA, and Threshold Quantity, if applicable, by the posted deadline for FRR Capacity Plan submittal, the LSE will be assessed an FRR Commitment Insufficiency Charge for any shortage of unforced capacity in meeting the Percentages of Internal Resources Required in LDA or the Preliminary Daily Unforced Capacity Obligations (including any Threshold Quantity) for any remainder of the minimum term of the FRR election. The shortage is defined as the shortage in meeting the Percentage of Internal Resources Required in LDA plus any additional shortage in meeting the Preliminary Daily Unforced Capacity Obligation including any Threshold Quantity Requirement. The shortage amount identified in the first delivery year that this charge is to be assessed is to be applied in the remaining delivery years that the charge is to be assessed. Through the 2024/2025 Delivery Year, the FRR Commitment Insufficiency Charge in a zone is equal to two times the Cost of New Entry (\$/MW-day) in the zone times the shortage amount. For Delivery Years between the 2025/2026 Delivery Year through the 2028/2029 Delivery Year, no FRR Commitment Insufficiency Charge shall be assessed. Effective with the 2029/2030 Delivery Year and subsequent Delivery Years, an FRR Commitment Insufficiency Charge is equal to the price level corresponding to point (1) of the Variable Resource Requirement curve for the relevant Locational Deliverability Area, in \$/MW-day, times the shortage amount.

FRR Commitment Insufficiency Charges are allocated on a pro-rata basis to all other LSEs (including RPM LSEs) in the RTO based on their Daily Unforced Capacity obligations.

Existing generation, planned generation, bilateral contracts for unit-specific capacity resources, existing demand resources, planned demand resources, energy efficiency resources, Aggregate Resources, and Seasonal Capacity Performance Resources may be used in the FRR Capacity

Plan if these resources meet the requirements specified in the PJM Agreements and Business Rules.

Existing generation that is located outside of the PJM market footprint may be used in the FRR Capacity Plan if the external generation meets the requirements specified in PJM Agreements and Section 4 of this manual.

Capacity Performance Resources or Seasonal Capacity Performance Resources may be included in the FRR Capacity Plan.

Through the 2024/2025 Delivery Year, at the FRR Entity's election, the UCAP MW quantity of generation resources that are committed to the initial FRR Capacity Plan will be determined using the lower of the generation resources' EFORD calculated based on outage data for the 12 months ending September 30th prior to the Base Residual Auction or the 5 Year Average EFORD based on outage data for the 12 months ending September 30th prior to the Base residual Auction. The EFORD applied to the Final FRR Capacity Plan evaluated throughout the Delivery Year will be determined by PJM using the forced outage data for the 12 months ending September 30th prior to the Delivery Year. The final Accredited UCAP value of a resource will be applied to the Final FRR Capacity Plan evaluated throughout the Delivery Year.

Effective with the 2025/2026 Delivery Year, the UCAP MW quantity of generation resources that are committed to the initial FRR Capacity Plan will be based on the Accredited UCAP Factor determined for each generation resource prior to the Base Residual Auction, and the UCAP MW quantity of committed demand resources will be based on the applicable ELCC Class Rating determined prior to the Base Residual Auction. The final Accredited UCAP Factor of a generation resource and the final applicable ELCC Class Rating for a demand resource for the Delivery Year will be applied to the Final FRR Capacity Plan evaluated throughout the Delivery Year.

Qualifying Transmission Upgrades may be used to reduce the Percentage of Internal Resources Required in an LDA for the FRR LSE if the Qualifying Transmission Upgrade meets the requirements specified in the PJM Agreements and Section 4 of this manual.

A capacity resource used in an FRR Capacity Plan must be on a unit-specific basis, and may not include "slice of system" or similar agreements that are not unit-specific.

An LSE's FRR Capacity Plan for the Delivery Year shall not include any MWs committed to RPM for such Delivery Year.

Any capacity resource that was not offered by the FRR Entity or offered but did not clear by the FRR Entity in any RPM Auction for such Delivery Year may be included in an FRR Capacity Plan. Such MWs are classified as Available MWs and would be eligible to commit to an FRR Capacity Plan.

An LSE's FRR Capacity Plan for the Delivery Year may include resources that are committed for less than a full Delivery Year; however, the FRR Capacity Plan in aggregate must satisfy all obligations for the Delivery Year.

If an LSE has committed capacity to meet a Threshold Quantity, the LSE shall maintain such resources until the Delivery Year's Final Unforced Capacity Obligation and final requirements (Percentage of Internal Resources Required in LDA) are known. The LSE may use such resources during the Delivery Year to meet any increased capacity obligation resulting from an increase in Final Obligation Peak Load from Base Obligation Peak Load, or sell the resources to another FRR Entity in PJM or to an External Party.

All generation resources that have a FRR Capacity Plan Commitment must offer into PJM's Day Ahead Energy Market. Demand Resources that have an FRR Capacity Plan Commitment must be registered to participate in the Full Program Option or Capacity Only Option of the Emergency or Pre-Emergency Load Response Program and thus be available for dispatch during PJM-declared emergency event.

Prior to the start of each Delivery Year, the FRR entity must elect whether it seeks to be subject to the Non-Performance Charge or to physical non-performance assessments for such Delivery Year. An FRR Entity may not elect the physical non-performance assessment option if such FRR Entity will not be an FRR Entity for the following Delivery Year and will be serving load their under the RPM. If such FRR Entity opted to be subject to physical non-performance assessments, the FRR Entity will be required to update their FRR Capacity Plan for the following Delivery Year with additional MW of Capacity Performance Resources for each MW of FRR net Performance Shortfall for each Performance Assessment Interval in accordance with Section 11.8. Such FRR Entity shall not be eligible for, or subject to, Bonus Performance Credits.

11.4 Supply Resources in the FRR Alternative

The supply resources available and the qualification requirements for use in FRR Capacity Plans are very similar to RPM resources.

11.4.1 Resource Portfolio

An FRR Entity must specify through the Capacity Exchange system, before the FRR Capacity Plan submittal deadline, the amounts of installed capacity from resources in their Capacity Exchange resource portfolio that are being committed to their FRR Capacity Plan for the Delivery Year.

A party's Daily Generation Resource Position is calculated dynamically by the Capacity Exchange system for each unit and is equal to the Daily ICAP Owned on a unit multiplied by the unit's Accredited UCAP Factor

The Daily ICAP Owned on a unit is calculated by adding the ICAP Value of a unit as determined by a party's approved Capacity Modifications to ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases.

Through the 2024/2025 Delivery Year, the Accredited UCAP Factor shall mean one minus EFORD. The EFORD of a unit is based on forced outage data from an October through September period.

If a unit does not have a full one-year history of forced outage data, the EFORD will be calculated using class average EFORD and the available history as described in the Reliability Assurance Agreement, Schedule 5, Section B.

New units are initially assigned a class average EFORD.

The class average EFORDs that are used by PJM to calculate a unit's EFORD are posted to the PJM website by November 30 prior to the Delivery Year.

The Effective EFORD is the EFORD that is effective for the delivery day in the Capacity Exchange system.

Prior to the Delivery Year, the Effective EFORD is the most recently calculated EFORD that has been bridged to the Capacity Exchange system.

During the Delivery Year, the Effective EFORD is based on forced outage data from the October through September period prior to the Delivery Year.

The EFORD that is effective for the Delivery Year is considered locked in the Capacity Exchange system by November 30 prior to the execution of the Third Incremental Auction.

Effective with the 2025/2026 Delivery Year, the Accredited UCAP Factor is the ratio of the Capacity Resource's Accredited UCAP as determined by ELCC analysis (see Section 4.2.7 Accredited UCAP for ELCC Resources) to the Capacity Resource's installed capacity.

A unit that is in a party's Generation Resource portfolio in Capacity Exchange may be committed to FRR Capacity Plan if the party has Daily Available ICAP to commit from the unit for the entire term of the commitment specified in the FRR Capacity Plan.³² If the party's Daily Available ICAP for the unit varies for the term of the commitment specified in the FRR Capacity Plan, only the minimum Daily Available ICAP may be committed for the term of the commitment specified in the FRR Capacity Plan.

³² The term of the resource's commitment to the FRR Capacity Plan may be less than a Delivery Year.

For a party, the Daily Available ICAP to commit on a unit is equal to Daily ICAP Owned - (Daily RPM Resource Commitments/(Accredited UCAP Factor)) – Daily FRR Capacity Plan Commitments.

A party's Daily RPM Resource Commitments for a specific generating unit are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such unit in RPM Auctions to decreases/increases of RPM Resource Commitments due to approved unit-specific bilateral sales/purchases of cleared capacity, approved locational UCAP transactions, and the specification of replacement resources.

A party's Daily FRR Capacity Plan Commitments for a specific generating unit are equal to the total amount of installed capacity that was committed from the unit for the FRR Capacity Plan.

A party's Daily FRR Generation Resource Position for a specific unit is calculated by multiplying the Daily FRR Capacity Plan Commitments by (Accredited UCAP Factor).

An LSE's Daily Total FRR Generation Resource Position is calculated by summing the Daily FRR Generation Resource Positions of all units in their resource portfolio in Capacity Exchange.

An LSE's Daily LDA FRR Generation Resource Position is calculated by summing the Daily FRR Generation Resource Positions of all units in the LDA.

A party's Daily ICAP Owned for a specific demand resource is equal to the Daily Nominated DR Value adjusted for the ICAP amounts transacted through a party's approved unit-specific bilateral sales/purchases for such demand resource in effect for such day. Prior to the Delivery Year demand resource registration process in DR Hub system, the Daily Nominated DR Value for an FRR Entity's Demand Resource is established based on PJM's approval of the FRR Entity's DR Sell Offer Plan and PJM's submittal of a corresponding DR Modification into the Capacity Exchange system. After the Delivery Year demand resource registration process begins in DR Hub system, the Daily Nominated DR value for a Demand Resource for a Delivery Year is established based on confirmed Demand Resource Registrations in "completed" status linked to the DR Resource in the DR Hub system in accordance with Section 4.3.4 of Manual 18.

Through the 2024/2025 Delivery Year, a party's Daily Demand Resource Position for a Demand Resource is calculated dynamically by the Capacity Exchange system and is equal to the Daily ICAP Owned * Forecast Pool Requirement. Starting with the 2025/2026 Delivery Year, a party's Daily Demand Resource Position for a Demand Resource is calculated dynamically by the Capacity Exchange system and is equal to the Daily ICAP Owned * applicable ELC Class Rating. A Demand Resource that is in a party's Demand Resource portfolio may be committed to the FRR Capacity Plan, if there is Daily Available ICAP to commit from the Demand Resource for the entire term of the commitment specified in the FRR Capacity Plan.

Through the 2024/2025 Delivery Year, a party's, Daily Available ICAP for a specific demand resource is equal to the resource's Daily ICAP Owned- (Daily RPM Resource Commitments/

Forecast Pool Requirement) – Daily FRR Capacity Plan Commitments. Effective with the 2025/2026 Delivery Year, a party's Daily Available ICAP for a specific demand resource is equal to the resource's Daily ICAP Owned - (Daily RPM Resource Commitments/applicable ELCC Class Rating) - Daily FRR Capacity Plan Commitments.

A party's Daily RPM Resource Commitments for a specific demand resource are calculated by adding the sum of any UCAP Cleared plus UCAP Makewhole for such demand resource in RPM Auctions to decreases/increases of RPM Resource Commitments due to the specification of replacement resources, approved unit specific transactions for cleared capacity, and approved locational UCAP transactions.

A party's Daily FRR Capacity Plan Commitments for a specific demand resource are equal to the total amount of Nominated DR that was committed from the Demand Resource for the FRR Capacity Plan.

Through the 2024/2025 Delivery Year, a party's Daily FRR Demand Resource Position for a specific demand resource is equal to Daily FRR Capacity Plan Commitments* Forecast Pool Requirement. Effective with the 2025/2026 Delivery Year, a party's Daily LDA FRR Demand Resource Position is calculated by summing the Daily FRR Demand Resource Positions of all demand resources in the LDA.

A party's Daily FRR Capacity Plan Commitments for a specific EE Resource are equal to the total amount of Nominated EE that was committed from the EE Resource for the FRR Capacity Plan.

A party's Daily FRR EE Resource Position for a specific EE Resource is equal to Daily FRR Capacity Plan Commitments* Forecast Pool Requirement. A LSE's Daily Total FRR EE Resource Position is equal to the sum of the Daily FRR EE Resource Position of all EE resources in their resource portfolio in Capacity Exchange.

A LSE's Daily LDA FRR EE Resource Position is calculated by summing the Daily FRR EE Resource Positions of all EE resources in the LDA.

An LSE's Daily Total FRR Resource Position is calculated by summing the Daily FRR Generation Resource Positions, Daily FRR Demand Resource Positions, and Daily FRR EE Resource Positions of all resources in their Capacity Exchange resource portfolio. After the FRR Capacity Plan submittal deadline, an LSE's Daily Total FRR Resource Position is compared to their Daily Preliminary Unforced Capacity Obligation to determine if the LSE has satisfied their Preliminary Unforced Capacity Obligation for the entire Delivery Year.

After the FRR Capacity Plan submittal deadline, an LSE's Daily Total FRR Resource Position is compared to their Daily Threshold Quantity, if applicable, to determine if the LSE has satisfied their Daily Threshold Quantity for the entire Delivery Year.

During the Delivery Year, an LSE's Daily Total FRR Resource Position is compared to their Daily Final Unforced Capacity Obligation to determine if a Capacity Resource Deficiency Charge is to be assessed.

An LSE's Daily LDA FRR Resource Position is calculated by summing the Daily LDA FRR Generation Resource Positions, Daily LDA FRR Demand Resource Positions, and Daily LDA FRR EE Resource Positions of all resources in their FRR Capacity Plan.

After the FRR Capacity Plan submittal deadline, an LSE's Daily LDA FRR Resource Position is compared to Amount of Internal Resources Required in the LDA to determine if the LSE has satisfied the Percentage of Internal Resources Required in the LDA for the entire Delivery Year.

During the Delivery Year, an LSE's Daily LDA FRR Resource Position is compared to the Amount of Internal Resources Required in the LDA to determine if a Capacity Resource Deficiency Charge is to be assessed.

11.4.2 Existing Generation

Existing generation located within the PJM region or outside the PJM region is eligible to be committed to the FRR Capacity Plan if it meets the requirements set forth in Section 4 of this manual.

11.4.3 Planned Generation

Planned generation located within the PJM region or outside the PJM region is eligible to be committed to the FRR Capacity Plan if it meets the requirements set forth in Section 4 of this manual.

11.4.4 Capacity Modifications (Cap Mods)

RPM Business Rules regarding Capacity Modifications in Section 4 of this manual apply to the FRR Alternative.

CAP MODs with a start date that occurs on or before the start of the Delivery Year must be submitted and "Provisionally Approved" in the Capacity Exchange system in order for the CAP MODs to be considered in a party's Daily Generation Resource Position and the calculation of Available ICAP to commit to the FRR Capacity Plan.

If the status of a "Provisionally Approved" CAP Mod changes to "Denied" or "PJM Withdrawn" all bilateral transactions for the unit will be changed from "Approved" to "Denied". There will be no change to any party's RPM Resource Commitments; however, there may be a change to a party's FRR Capacity Commitments.

11.4.5 Bilateral Unit-Specific Transactions

RPM Business Rules regarding Bilateral Unit-Specific Transactions in Section 4 of this manual apply to the FRR Alternative.

Available installed capacity purchased through a bilateral unit-specific transaction that is reported via PJM's Capacity Exchange system may be committed to an FRR Capacity Plan.

All unit-specific bilateral transactions that are in the "Provisionally Approved" or "Approved" status in the Capacity Exchange system will be considered in a party's Daily Generation Resource Position and the calculation of Daily Available ICAP to commit.

The Capacity Export Charge and Credit described in Section 4: Supply Resources in the Reliability Pricing Model, under 4.6.3 Exporting a Generation Resource and in Section 9: Settlements are applicable to resources owned by FRR Entities also.

11.4.6 Qualified Transmission Upgrade

A Qualified Transmission Upgrade may be included in an LSE's FRR Capacity Plan. Such a transmission upgrade must be approved and assigned an incremental import capability value into the constrained LDA by the PJM Planning Department at least 45 days prior to deadline for submitting the initial FRR Capacity Plan for the Delivery Year.

An approved Qualified Transmission Upgrade may be used to reduce the Amount of Internal Capacity Required in the LDA for the FRR LSE.

The planned transmission upgrade in-service date must be on or before the start of the Delivery Year.

At a minimum, the Upgrade Customer must be in the Facilities Study phase for the proposed transmission upgrade, in order for approval to be granted and the transmission upgrade must conform to all applicable standards of the PJM Regional Transmission Expansion Planning Process.

If a Qualified Transmission Upgrade is not completed by the start of the Delivery Year, the LSE who included the upgrade as part of their FRR Capacity Plan for the Delivery Year shall provide a replacement in the form of an equivalent amount of capacity resource capability within the applicable LDA by the start of the delivery Year. If replacement capacity is not provided, a Capacity Resource Deficiency Charge may apply.

11.4.7 Load Management Products

A Load Management program (e.g., Firm Service Level or Guaranteed Load Drop program) is eligible to be committed as a Demand Resource (DR) to the FRR Capacity Plan, if the program meets the requirements specified in the ***Load Forecasting & Analysis Manual (M-19)*** and Section 4.3 of this manual.

In order to commit a Demand Resource to the initial FRR Capacity Plan for a Delivery Year, an FRR Entity must submit no later than 30 days prior to the initial FRR Capacity Plan submittal deadline a DR Sell Offer Plan as described in Attachment C of this Manual (i.e., a completed DR Plan template and DR Officer Certification Form). The completed DR Plan template must

clearly identify in the Summary section the Existing Nominated DR Value or Planned Nominated DR Value in ICAP MWs that the FRR Entity intends to commit to their initial FRR Capacity Plan. The FRR Entity must further classify the Existing/Planned Nominated DR Value as MWs intend to commit as Annual Capacity Performance for annual period and MWs intend to commit as Summer–Period Capacity Performance for summer period, and MWs intend to commit as part of an Aggregate Resource. Actual deadline date for the DR Plan template and DR Officer Certification is provided in the RPM Auction Schedule posted on the PJM website.

If an FRR Entity intends to commit demand resources located in a pre-identified zone/sub-zone, PJM will grant conditional approval of the total Nominated DR Value in such zone/sub-zone pending the PJM review of DR Sell Offer Plans for the Base Residual Auction for such Delivery Year.

An FRR Entity with PJM approved or conditionally approved Nominated DR Value(s) in zone/sub-zone(s) will be permitted to commit the associated Demand Resource(s) to the FRR Capacity Plan, provided credit has been posted with the PJM Treasury Department for any Planned Demand Resource(s).

If a review of the DR Sell Offer Plans for the Base Residual Auction for such Delivery Year reveals that any of the conditionally approved MWs in a pre-identified zone/sub-zone are ascribed to another CSP by a letter of support from an end-use customer, such MWs shall be uncommitted from the FRR Capacity Plan and additional capacity resources shall be committed by the FRR Entity to the FRR Capacity Plan to satisfy the FRR Entity's Preliminary Unforced Capacity Obligation.

The UCAP value of a Demand Resource committed to an FRR Capacity Plan is equal to the Nominated DR Value committed * Forecast Pool Requirement through the 2024/2025 Delivery Year, and starting with 2025/2026 Delivery Year is equal to the Nominated DR Value committed * the applicable ELCC Class Rating. The Nominated DR Values (summer, winter, or annual) for a load management program registration are determined in accordance with Section 4.3.7 of this manual and the Daily Nominated DR Value of a Demand Resource for a Delivery Year is established based on confirmed Demand Resource Registrations in “completed” status linked to such Demand Resource in DR Hub system in accordance with Sections 4.3.4 and 4.7.2 of this manual.

A resource provider who has FRR Capacity Plan Commitments for their demand resource must meet (or contract with another party to meet the requirements specified in Section 4.3.1 of this manual.

A resource provider who has FRR Capacity Plan Commitments for their demand resource will be subject to Non-Performance Assessment and Load Management Test Compliance in accordance with Section 8 of this manual.

11.4.8 Demand Resource Modifications (DR MODs)

RPM Business Rules for DR MODs in Section 4 of this manual apply to the FRR Alternative.

DR MODs are no longer submitted by participants. A DR Mod submitted by PJM based on FRR Entity's approved DR Sell Offer Plan must be in a "Provisionally Approved" or "Approved" status in order for the DR MOD to be considered in a party's Demand Resource Position and in the calculation of Available ICAP to commit to the FRR Capacity Plan. After the Delivery Year demand resource registration process begins in DR Hub system, the Daily Nominated DR value for a Demand Resource for a Delivery Year is established based on confirmed Demand Resource Registrations in "completed" status linked to the DR Resource in the DR Hub system in accordance with Sections 4.3.4 and 4.7.2 of this manual.

11.4.9 Energy Efficiency Resources

An EE Resource may commit to an FRR Capacity Plan for a maximum of up to four consecutive Delivery Years. The time period of an Energy Efficiency installation determines whether an installation is eligible to be a capacity resource for a Delivery Year. The time period of Energy Efficiency installations and their associated eligibility, in addition to the modeling of EE Resources in the PJM Capacity Market, is presented in ***PJM Manual 18B: Energy Efficiency Measurement & Verification***.

An EE Resource must meet the following minimum requirements:

- Submit Initial Measurement & Verification (M&V) Plan no later than 30 days prior to the FRR Capacity Plan submittal in which the EE Resource is initially committed
- Submit Updated M&V Plan no later than 30 days prior to next FRR Capacity Plan submittal in which EE Resource is subsequently committed
- Establish credit with PJM Credit Department prior to FRR Capacity Plan submittal (for planned EE Resources)
- Submit Energy Efficiency Resource Modification (EE MOD) in Capacity Exchange system (An EE MOD is submitted by PJM)
- Submit Initial Post-Installation M&V Report no later than 15 business days prior to first Delivery Year that the EE Resource is committed
- Submit Updated Post-Installation M&V Reports no later than business 15 days prior to each subsequent Delivery Year that the EE Resource is committed
- Permit Post- Installation M&V Audit(s) by PJM or Independent Third Party.

PJM Manual 18B: Energy Efficiency Measurement & Verification establishes the requirements for the Initial M&V Plan, Updated M&V Plans, Initial Post-Installation M&V Report, Updated Post-Installation M&V Reports, and the M&V Audit.

11.4.10 Energy Efficiency Modifications (EE MODs)

RPM Business Rules for EE MODs in Section 4 of this manual apply to the FRR Alternative.

EE MODs submitted by PJM based on the FRR Entity's approved initial/updated M&V Plan must be in a "Provisionally Approved" or "Approved" status in order for the EE MOD to be considered in a party's EE Resource Position and in the calculation of Available ICAP to commit to the FRR Capacity Plan.

An EE MOD may be required prior to the Delivery Year to reflect the final Nominated EE Value or final Capacity Value of an EE Resource for the Delivery Year. An EE MOD decrease may result in the reduction of FRR Capacity Plan Commitments.

11.5 Locational Constraints in the FRR Alternative

As discussed in Section 2, locational constraints may require modeling constrained Locational Deliverability Areas (LDAs) separately. Locational Constraints are used to define the minimum Percentage of Internal Resources Required for a constrained LDA in the FRR Capacity Plan. For each LDA for which PJM is required to establish a separate Variable Resource Requirement Curve for the Delivery Year, a Percentage of Internal Resources Required for such LDA will be defined. PJM shall be deemed required to establish a separate Variable Resource Requirement Curve for an LDA if the LDA is Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), or Mid-Atlantic Region ("MAR"), or for other LDAs if separate modeling is required by Section 5.10(a)(ii)(A) or (B) of Attachment DD of the OATT.

The constrained Locational Deliverability Areas that will be modeled for a particular Delivery Year and Percentage of Internal Resources Required for such LDA (if applicable) will be posted on the PJM website by February 1 prior to the commencement of the Base Residual Auction for that Delivery Year.

An LDA has a limited import capability to import resources from outside the LDA. In RPM these imported resources are considered in clearing the auction in an LDA and the auction results would reflect the effect of the imports in reducing the LDA clearing price. Similar to RPM Entities, FRR Entities are provided the benefit of import capability by allowing them to include some resources from outside the LDA in their Capacity Plan. For each LDA that PJM is required to establish a separate Variable Resource Requirement Curve for the Delivery Year, the minimum Percentage of Internal Resources Required for such constrained LDA for the Delivery Year will be posted by February 1 prior to the commencement of the RPM Base Residual Auction for such Delivery Year. This Percentage of Internal Resources Required in an LDA is used to determine the Amount of Internal Resources Required (UCAP MWs) by the FRR LSE in the LDA. An approved Qualified Transmission Upgrade may be used to reduce the Amount of Internal Capacity Required in the LDA for the FRR LSE. An LSE must include enough capacity resource in its FRR Capacity Plan to satisfy the Amount of Internal Resources Required in the LDA. These capacity resources must be physically located in the LDA in which the FRR Service Area is located in order to satisfy this requirement.

The LDA Reliability Requirement is the projected internal capacity in the LDA plus the Capacity Emergency Transfer Objective (CETO) for the Delivery Year, as determined by the RTEP

process. The internal resource requirement in an LDA is the LDA Reliability Requirement less the Capacity Emergency Transfer Limit (CETL) for the Delivery Year, as determined by the RTEP process. This internal resource requirement is expressed as a percentage of the Unforced Capacity Obligation based on Preliminary LDA/Zonal Peak Load Forecast multiplied by FPR to determine the Amount of Internal Resources (UCAP MWs) Required by the FRR LSE in the LDA.

Capacity Transfer Rights (CTRs) are implicitly allocated to the FRR LSE in the determination of the Percentage of Internal Resources Required in an LDA. An FRR LSE will not be eligible for any explicit CTRs.

11.6 Conditions on Sales by FRR Entities

If an FRR LSE has not satisfied a Threshold Quantity, they may not offer to sell capacity in excess of the amount needed to satisfy Preliminary/Final Daily Unforced Capacity Obligation bilaterally into RPM or in RPM Auctions; however, they may offer to sell such excess capacity to an External Party (i.e., delist) or to an FRR Entity. If an FRR LSE has satisfied a Threshold Quantity, they may offer to sell capacity in excess of the amount needed to satisfy their Threshold Quantity bilaterally into RPM or in RPM Auctions up to a Sales Cap Amount. The Sales Cap and other rules related to sales by FRR Entities are shown below:

- The Sales Cap Amount is equal to the lesser of (a) $0.25 * \text{Preliminary Unforced Capacity Obligation}$ or (b) 1300 MW.
- If an FRR LSE has satisfied a Threshold Quantity, they may offer to sell capacity in excess of the Preliminary/Final Daily Unforced Capacity Obligation to an External Party (i.e., delist) or to another FRR Entity. In order for this type of sale to proceed, the Seller's FRR Capacity Commitments on the unit must be reduced.
- Sell offers in RPM Auctions and bilateral unit-specific transactions will be subject to offer and bilateral transaction checks to ensure that the seller does not violate any "Conditions on Sales by FRR Entities".
- A sell offer in an RPM Auction that violates any "Conditions on Sales by FRR Entities" will be rejected.

If an FRR LSE serves load under the FRR Alternative and additional load under the RPM, the LSE may self-supply capacity resources in RPM Auctions and avoid the requirement to satisfy a Threshold Quantity; however, the MW amount of their sell offer(s) may not exceed a Self-Supply Offer Cap Amount, where:

- The Self-Supply Offer Cap Amount is the lesser of (a) $0.25 * (\text{FRR Preliminary Daily Unforced Capacity Obligation} + \text{RPM Expected UCAP Obligation})$ or (b) 200 MW.
- An LSE's RPM Expected UCAP Obligation in a Zone is equal to the LSE's allocation of the Zonal Weather Normalized Summer Peak for summer four years prior to the Delivery Year (i.e., an Obligation Peak Load) * (Preliminary Zonal Peak Load Forecast/Zonal Weather

Normalized Summer Peak for summer four years prior to Delivery Year) * Forecast Pool Requirement.

11.7 Delivery Year Activity

11.7.1 Final Daily Unforced Capacity Obligation

The Final Daily Unforced Capacity Obligation of an LSE in a zone equals the LSE's Final Obligation Peak Load in the zone * the Final Zonal FRR Scaling Factor * the Forecast Pool Requirement. The Forecast Pool Requirement updated for the RPM Third Incremental Auction will be used in determining the Final Daily Unforced Capacity Obligation.

The Final Daily Unforced Obligation shall be reduced by the committed Nominal PRD Value associated with such load that was approved by PJM in advance of the BRA and Third IA for such Delivery Year, multiplied by final Forecast Pool Requirement for the Delivery Year.

A reduction in the Daily Unforced Capacity Obligation is applicable in the case of annexation of service territory where the FRR load is acquired by a party that has not elected FRR alternative.

11.8 Deficiency Charges & Penalties

11.8.1 FRR Capacity Resource Deficiency Charges

An LSE participating in the FRR Capacity Plan Alternative will pay a FRR Capacity Resource Deficiency Charge in the delivery year for any shortage of resources to meet the Final Daily Unforced Capacity Obligation and the Amount of Internal Resources Required in an LDA.

A shortage/excess of resources to meet the Amount of Internal Resources Required in an LDA is calculated by comparing an LSE's Daily LDA FRR Resource Position to the Amount of Internal Resources Required in an LDA. If the Daily LDA FRR Resource Position is less than the Amount of Internal Resources Required in an LDA, a FRR Capacity Resource Deficiency Charge for this shortage will be assessed.

A shortage/excess of resources to meet the Final Daily Unforced Capacity Obligation is calculated by comparing an LSE's Daily Total FRR Resource Position to their Final Daily Unforced Capacity Obligation. If the Daily Total FRR Resource Position is less than Final Daily Unforced Capacity Obligation, a deficiency charge for this shortage less the shortage calculated for failure to satisfy the Amount of Internal Resources Required in the LDA will be assessed.

Through the 2024/2025 Delivery Year, the FRR Capacity Resource Deficiency Charge is equal to 1.2 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing such zone, weight-averaged for the Delivery Year based on the prices established and the quantities cleared in such auctions, multiplied by the shortage. The weighted average resource clearing price for the LDA will be calculated

considering all cleared MWs in RPM Auctions for the Delivery Year and such weighted average resource clearing price will apply to all shortages for the Delivery Year. Starting with the 2025/2026 Delivery Year, the FRR Capacity Resource Deficiency Charge is equal to the price level corresponding to Point (1) of the Variable Resource Requirement curve for the Locational Deliverability Area encompassing the Zone of the FRR Entity, multiplied by the shortage. FRR Capacity Resource Deficiency Charges are assessed daily and billed weekly.

11.8.2 Transmission Upgrade Delay

If a Qualifying Transmission Upgrade is not completed by the start of the Delivery Year and the upgrade was not replaced with an equivalent amount of Capacity Resources in the LDA into which the import capability was to be increased, then the Amount of Internal Capacity Resources Required in an LDA will be increased and the LSE may be assessed a FRR Capacity Resource Deficiency Charge.

11.8.3 Deleted

11.8.4 Generation Resource Rating Test Failure Charge

All generation resources that have FRR Capacity Plan Commitments are subject to Capacity Testing for both the Summer and Winter Periods.

RPM Business Rules regarding the Capacity Testing and Generation Resource Rating Test Failure Charges apply to the FRR Alternative.

11.8.5 Load Management Test Compliance

DR Resource providers are required to simultaneously test all of their non-dispatched registrations in a zone in the absence of being dispatched by PJM for an Emergency Action that triggers a Non-Performance Assessment during the Delivery Year.

Please see Section 8.7 of this manual for details on Load Management Test Compliance.

11.8.6 Non-Performance Charge/Bonus Performance Credit

An FRR Entity that elected to be subject to financial non-performance assessment as opposed to physical non-performance assessments will be subject to Non-Performance Assessment Charge for each resource committed to the FRR Capacity Plan or price responsive demand committed to reduce the FRR Entity's unforced capacity obligation that had a Performance Shortfall for a Performance Assessment Interval. If a resource committed to the FRR Capacity Plan or price responsive demand committed to reduce the FRR Entity's unforced capacity obligation had Bonus Performance for a Performance Assessment Interval, such resource or price responsive demand will be eligible for Bonus Performance Credits.

Please see Section 9.1.11 of this manual for details on Non-Performance Charge/Bonus Performance Credit.

11.8.7 Physical Non-Performance Assessment

An FRR Entity that elected to be subject to physical non-performance assessment for resources committed to the Delivery Year FRR Capacity Plan or price responsive demand committed to reduce the FRR Entity's unforced capacity obligation as opposed to financial non-performance assessment for such resources will be required to update the subsequent Delivery Year's FRR Capacity Plan and commit additional Capacity Performance Resources or Seasonal Capacity Performance Resources beyond the amount of Capacity Performance Resources required for the subsequent Delivery Year as a penalty for those resources committed to the FRR Capacity Plan that experienced Performance Shortfalls for Performance Assessment Interval during the relevant Delivery Year.

For each Performance Assessment Interval, the Actual Performance and Expected Performance of each resource contained in an FRR Entity's Capacity Plan will be determined according to the rules and formulas described in the Non-Performance Assessment section 8.4A, and for such interval, a net Performance Shortfall associated with FRR commitments³³ shall be determined for Capacity Performance Resources. The net Performance Shortfall for Capacity Performance Resources shall also include the performance of Seasonal Capacity Performance Resources included in the FRR Capacity Plan and include the performance of price responsive demand committed to reduce the FRR Entity's unforced capacity obligation.

The FRR Entity's net Performance Shortfall among Capacity Performance Resources and price responsive demand, if any, for each Performance Assessment Interval shall be multiplied by a rate of 0.00139 MWs/Performance Assessment Interval [i.e., 0.5 MWs/30 PAHs/12 intervals per hour]] to establish the additional MW of Capacity Performance Resources that such FRR Entity must add to its FRR Capacity Plan for the following Delivery Year. The maximum additional MW required by the FRR Entity as a result of non-performance from the FRR Entity's Capacity Performance Resources during a Delivery Year shall not exceed 50% of the MW quantity of the Capacity Performance Resources committed in the FRR Capacity Plan for such Delivery Year and price responsive demand committed for such Delivery Year.

The additional MWs of Capacity Performance Resources required for Performance Assessment Intervals (PAIs) that occur during February through May of the Delivery Year shall be committed to the FRR Entity's FRR Capacity Plan for the remainder of the following Delivery Year by established deadlines below.

- February PAIs: by July 1 of the following Delivery Year
- March PAIs: by August 1 of the following Delivery Year
- April PAIs: by September 1 of the following Delivery Year

³³ If a market participant has both RPM commitments and FRR commitments on a resource, the final Shortfall MW or Bonus MW on a resource will be allocated to RPM and FRR commitments on a pro-rata basis based on the amount of RPM and FRR CP commitments in unforced capacity terms.

- May PAIs: by October 1 of the following Delivery Year

11.9 Allocation of Deficiency Charges

The Daily FRR Capacity Resource Deficiency Charges, FRR Transmission Upgrade Delay Penalties, Generation Resource Rating Test Failure Charges, and Load Management Test Failure Charges are distributed on a pro-rata basis to the LSEs in the RTO that were charged an RPM Locational Reliability Charge.

Daily Capacity Resource Deficiency Charges, Transmission Upgrade Delay Penalties, Generation Resource Rating Test Failure Charges, and Load Management Test Failure Charges are allocated on a pro-rata basis to RPM LSEs based on their daily unforced capacity obligation.

11.10 Auction Specific MW Transactions

LSEs that elect the FRR Alternative may report Auction Specific MW Transactions if they have cleared capacity in RPM Auctions through the Capacity Exchange system.

The MWs associated with approved Auction Specific MW Transactions do not contribute to the Sales Cap Amount for RPM Auctions described in the FRR Business Rules.

Attachment A: Glossary of Terms

Welcome to the *Glossary of Terms* section of the **PJM Manual for the Capacity Market**. In this section, you will find the following information:

Adjusted Zonal Capacity Prices – are determined based on the results of RPM Incremental Auctions. Preliminary Zonal Capacity Prices that result from the Base Residual Auction are adjusted to account for the procurement in the RPM Incremental Auctions.

Accredited UCAP is defined in the RAA as the quantity of Unforced Capacity, as denominated in Effective UCAP, that an ELCC Resource is capable of providing in a given Delivery Year.

Auction Specific MW Transactions – are transactions reported to PJM via Capacity Exchange between a buyer and seller that report the transfer of physical MW between the buyer and seller using the Capacity Exchange system and PJM settlement process. Auction Specific MW Transactions are not eligible to be offered in an RPM auction. Auction Specific MW Transactions are settled at the weighted average Resource Clearing Price of the MW supplying the transaction.

Available Transfer Capability (ATC) – is the amount of energy above “base case” conditions that can be transferred reliably from one area to another over all transmission facilities without violating any pre- or post-contingency criteria for the facilities in the PJM Control Area under specified system conditions.

Base LDA Unforced Capacity Obligation – is equal to the sum of the Base Zonal Unforced Capacity Obligations for all the zones in an LDA and is the result of the clearing of the Base Residual Auction.

Base Residual Auction (BRA) – allows for the procurement of resource commitments to satisfy the region’s unforced capacity obligation and allocates the cost of those commitments among the LSEs through the Locational Reliability Charge.

Base RTO Unforced Capacity Obligation – determined after the clearing of the BRA and is posted with the BRA results. The Base RTO Unforced Capacity Obligation is equal to the sum of the unforced capacity obligation satisfied through the BRA.

Base Unforced Capacity Imported into an LDA – is equal to the Base LDA Unforced Capacity Obligation less the LDAs Unforced Capacity cleared in the Base Residual Auction. This value is used to determine the maximum total amount of Capacity Transfer Rights that are allocated into an LDA in the Base Residual Auction for the Delivery Year.

Base Zonal RPM Scaling Factor – is determined for each zone and is equal to the $\left[\frac{\text{Preliminary Zonal Peak Load Forecast for the Delivery Year}}{\text{Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Years}} \right] * ((\text{RTO}$

Unforced Capacity Obligation Satisfied in Base Residual Auction divided by the (RTO Preliminary Peak Load Forecast * the Forecast Pool Requirement)]]. Base Zonal RPM Scaling Factors are posted with the Base Residual Auction results.

Base Zonal Unforced Capacity Obligation – determined for each zone and is equal to the (Zonal Weather Normalized Summer Peak for the summer four years prior to the Delivery Year* Base Zonal RPM Scaling Factor * the Forecast Pool Requirement). Base Zonal Unforced Capacity Obligations are posted with the Base Residual Auction clearing results.

Behind the Meter Generation – a generating unit that delivers energy to load without using the Transmission System or any distribution facilities (unless the entity that owns or leases the distribution facilities consented to such use of the distribution facilities and such consent has been demonstrated to the satisfaction of the Office of Interconnection. Behind the Meter Generation may not include at any time any portion of a generating unit's capacity that is designated as a Capacity Resource or any portion of the output of a generating unit that is sold to another entity for consumption at another electrical location or into the PJM Interchange Energy Market at any time.

Bilateral Market – provides LSEs the opportunity to hedge the Locational Reliability Charge determined through the RPM Auctions by purchasing available capacity in the bilateral market to offer into an RPM Auction. The bilateral market also provides resource providers an opportunity to cover any auction commitment shortages.

Bilateral Unit-Specific Transaction – transaction that enables reporting of the transfer of ownership of a specified amount of installed capacity from a specific unit from one party to another.

Capacity Modification (Cap Mod) – transaction that enables generation owners to request the addition of a new unit or the removal of an existing unit from their resource portfolio in Capacity Exchange, or to request an MW increase or decrease in the summer or winter installed capacity rating of an existing unit.

Capacity Resources – includes megawatts of (i) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources meeting the requirements of Schedules 9 and 10 of the RAA that are or will be owned by or contracted to a Party and that are or will be committed to satisfy that Party's obligations under the RAA, or to satisfy the reliability requirements of the PJM Region, for a Delivery Year; (ii) net capacity from Existing Generation Capacity Resources or Planned Generation Capacity Resources not owned or contracted for by a Party which are accredited to the PJM Region pursuant to the procedures set forth in Schedules 9 and 10 of the RAA; and (iii) load reduction capability provided by Demand Resources or Energy Efficiency Resources that are accredited to the PJM Region pursuant to the procedures set forth in Schedule 6 of the RAA.

Capacity Resource with State Subsidy – (1) a Capacity Resource that is offered into an RPM Auction or otherwise assumes an RPM commitment for which the Capacity Market Seller

receives or is entitled to receive one or more State Subsidies for the applicable Delivery Year; (2) a Capacity Resource that has not cleared an RPM Auction for the Delivery Year for which the Capacity Market Seller last received a State Subsidy (or any subsequent Delivery Year) shall still be considered a Capacity Resource with State Subsidy upon the expiration of such State Subsidy until the resource clears an RPM Auction; (3) a Capacity Resource that is the subject of a bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6) shall be deemed a Capacity Resource with State Subsidy to the extent an owner of the facility supporting the Capacity Resource is entitled to a State Subsidy associated with such facility even if the Capacity Market Seller is not entitled to a State Subsidy; and (4) any Jointly Owned Cross-Subsidized Capacity Resource.

Capacity Emergency Transfer Limit (CETL) – the capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.

Capacity Emergency Transfer Objective (CETO) – the amount of electric energy that a given area must be able to import in order to satisfy the locational reliability criteria established in the RAA, M20, and M20A.

Capacity Only Option - participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Attachment DD of the Tariff and as applicable, a capacity payment for load reductions during a pre-emergency or emergency event.

Capacity Transfer Rights (CTR) – rights used to allocate the economic value of transmission import capability that exists into a constrained LDA. Serve to offset a portion of the Locational Price Adder charged to load in constrained LDAs.

Combination Resource is defined in the RAA as a Generation Capacity Resource that has a component that has the characteristics of a Limited Duration Resource combined with (i) a component that has the characteristics of an Unlimited Resource or (ii) a component that has the characteristics of a Variable Resource.

Control Area – electric power system or combination of electric power systems bounded by interconnection metering and telemetering to which a common generation control scheme is applied in order to:

- Match the power output of the generators within the electric power system(s) and energy purchased from entities outside the electric power system(s) with the load within the electric power system(s)
- Maintain scheduled interchange with other Control Areas
- Maintain the frequency of the electric power system(s)
- Maintain power flows on transmission facilities within appropriate limits to preserve reliability
- Provide sufficient generating capacity to maintain operating reserves.

Cost of New Entry (CONE) – Levelized annual cost in ICAP \$/MW-Day of a reference combustion turbine to be built in a specific location.

CTR Settlement Rate – The CTR Settlement Rate (\$/MW-day) is equal to the Economic Value of CTRs allocated to LSEs in a zone as a result of the Base Residual Auction and RPM Incremental Auctions divided by the Total CTR MWs allocated to LSEs in the zone.

Daily Unforced Capacity Obligation - equals the LSE's Obligation Peak Load in the zone/area * the Final Zonal RPM Scaling Factor * the Forecast Pool Requirement for an LSE in a zone/area.

Daily Capacity Resource Deficiency Charge – assessed to party when the Daily RPM Resource Position of its resource is less than the Daily RPM Resource Commitment for such resource on a delivery day. This charge is applicable to generation resource, Demand Resource, Energy Efficiency Resource, Aggregate Resource or Qualified Transmission Upgrade committed to RPM.

Delivery Year – Planning period for which resources are being committed and for which a constant load obligation for the entire PJM region exists. For example, the 2012/2013 Delivery Year corresponds to the June 1, 2012 – May 31, 2013 Planning Period.

Demand Resource – an Annual Demand Resource or Summer-Period Demand Resource with a demonstrated capability to provide a reduction in demand or otherwise control load in accordance with the requirements of RAA, Schedule 6. A Demand Resource may be an existing or planned resource.

Demand Resource Modification (DR Mods) – transaction submitted by PJM to track an increase or decrease of the nominated value of the Demand Resource in a party's resource portfolio in Capacity Exchange.

Demand Resource Registration - a registration in the Full Program Option or Capacity Only Option of the Emergency or Pre-Emergency Load Resource Program in accordance with OATT, Attachment K-Appendix, Section 8. A Demand Resource Registration is linked to a Demand Resource.

Effective UCAP is defined in the RAA as a unit of measure that represents the capacity product transacted in the Reliability Pricing Model and included in FRR Capacity Plans. One megawatt of Effective UCAP has the same capacity value of one megawatt of Unforced Capacity.

ELCC Resource is defined in the RAA as a Generation Capacity Resource that is a Variable Resource, a Limited Duration Resource, or a Combination Resource (through the 2024/2025 Delivery Year). Effective with the 2025/2026 Delivery Year, an ELCC Resource is a Generation Capacity Resource or a Demand Resource.

Electric Cooperative – an entity owned in cooperative form by its customers that is engaged in the generation, transmission, and/or distribution of electric energy.

Electric Distribution Company (EDC) – PJM Member that owns or leases with rights equivalent to ownership electric distribution facilities that are used to provide electric distribution service to electric load within the PJM Control Area.

Emergency – an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

End Use Customer – a member that is a retail end-user of electricity within the PJM region.

Equivalent Demand Forced Outage Rate (EFORd) – is a measure of the probability that generating unit will not be available due to a forced outages or forced deratings when there is a demand on the unit to generate. See Generator Resource Performance Indices Manual (M-22) for equation.

Equivalent Demand Forced Outage Rate (EFORd-5) (Prior to the 2025/2026 Delivery Year)– is EFORd determined based on five years of outage data through September 30 prior to the Delivery Year. This is an index similar to EFORd that is the basis for a unit's UCAP value for the Delivery Year, and it includes the events that are outside management control (OMC events). The index is calculated using Generator Availability Data System (GADS) data in PJM. If a generating unit does not have a full 5 years of history, the EFORd-5 will be calculated using class average EFORd and the available history as described in Reliability Assurance Agreement, Schedule 5, Section C. The class average EFORd will be used for a new generating unit. The class average EFORds that are used by PJM to calculate a unit's EFORd-5 are posted to the PJM website by November 30 prior to the Delivery Year.

Effective EFORd (Prior to the 2025/2026 Delivery Year)– the most recently calculated EFORd that has been bridged to the Capacity Exchange system. During the Delivery Year, the Effective EFORd is based on forced outage data from the October through September period prior to the Delivery Year. This is the basis for a unit's UCAP value, and it includes the events that are outside management control (OMC events).

FERC – Federal Energy Regulatory Commission or any successor federal agency, commission or department.

Final RTO Unforced Capacity Obligation –The Final RTO Unforced Capacity Obligation is equal to the RTO unforced capacity obligations satisfied through all RPM Auctions for the Delivery Year. The RTO unforced capacity obligation through all RPM Auctions is equal to the

total MWs cleared in PJM Buy Bids in RPM Auctions less the total MWs cleared in PJM Sell Offers in RPM Auctions.

Final Zonal Capacity Prices – are the capacity prices assessed to RPM Load Serving Entities through the RPM Locational Reliability Charge. The Final Zonal Capacity Prices are determined by PJM after the Third Incremental Auction. Final Zonal Capacity Prices reflect the final price adjustments that may be necessary to account for any granted requests for relief from Capacity Resource Deficiency Charges due to permanent departure of load or to account for Non-Viable MWs for any transition provisions that are in effect for the Delivery Year.

Final Zonal RPM Scaling Factors – used in determining an LSE's Daily Unforced Capacity Obligation. A Final Zonal RPM Scaling Factor for a zone is equal to the Final Zonal Unforced Capacity Obligation divided by (FPR times the Zonal Weather Normalized Peak for the summer prior to the Delivery Year). The Final Zonal RPM Scaling Factors are posted with the results of the final Incremental Auction.

Final Zonal Unforced Capacity Obligation – The Final Zonal Unforced Capacity Obligation is equal to the zonal allocation of the Final RTO Unforced Capacity Obligation and is allocated to the zones on a pro-rata basis based on the Final Zonal Peak Load Forecasts. The Final Zonal UCAP Obligations are determined after the clearing of the final Incremental Auction for the Delivery Year.

Firm Transmission Service – transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency, and unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility, or other event beyond the control of the owner or operator of the facility or the Office of the Interconnection.

Fixed Resource Requirement (FRR) – an alternative method for a Party to satisfy its obligation to provide Unforced Capacity. Allows an LSE to avoid direct participation in the RPM Auctions by meeting their fixed capacity resource requirement using internally owned capacity resources.

Flexible Self-Scheduled Resources – are resources specified by an LSE in the Base Residual Auction to provide a mechanism to manage quantity uncertainty related to the Variable Resource Requirement. For each resource-specific sell offer, the LSE must designate a flexible self-scheduling flag as well as an offer price that will be utilized in the market clearing in the event the resource is not needed to cover a specified percentage of the LSE's capacity obligation. Flexible self-scheduled resources will automatically clear the auction if they are needed to supply the LSE's resulting capacity obligation.

Forecast Pool Requirement (FPR) – the amount equal to one plus the unforced reserve margin (stated as a decimal number) for the PJM Region.

FRR Capacity Plan – a long-term plan for the commitment of Capacity Resources to satisfy the capacity obligations of a Party that has elected the FRR alternative.

FRR Service Area – the service territory of an IOU as recognized by state law, rule, or order; the service area of a Public Power Entity or Electric Cooperative as recognized by franchise or other state law, rule, or order; or a separately identifiable geographic area that is bounded by wholesale metering, or similar appropriate multi-site aggregate metering, that is visible to and regularly reported to the Office of Interconnection or an EDC who agrees to aggregate the meters' load data for the FRR Service Area and regularly report the information to the Office of Interconnection or for which the FRR Entity has or assumes the obligation to provide capacity for all load (including load growth) within the area excluding the load of Single-Customer LSEs that are FRR Entities. In the event that the service obligations of an Electric Cooperative or Public Power Entity are not defined by geographic boundaries but by physical connections to a defined set of customers, the FRR Service Areas is defined as all customers physically connected to transmission or distribution facilities of the Electric Cooperative or Public Power Entity within an area bounded by appropriate wholesale aggregate metering as described above.

Full Requirements Service – wholesale service to supply all of the power needs of a LSE to serve end-users within the PJM Region that are not satisfied by its own generation facilities.

Full Program Option - participation in Emergency Load Response Program or Pre-Emergency Program which allows, pursuant to Attachment DD of the Tariff and as applicable, (i) an energy payment for load reductions during a pre-emergency or emergency event, and (ii) a capacity payment for load reductions during a pre-emergency or emergency event.

Generation Capacity Resource – A Generating Facility, or the contractual right to capacity from a specified Generating Facility, that meets the requirements of RAA, Schedule 9 and RAA, Schedule 10, and, for Generating Facilities that are committed to an FRR Capacity Plan, that meets the requirements of RAA, Schedule 8.1. A Generation Capacity Resource may be an Existing Generation Capacity Resource or a Planned Generation Capacity Resource.

Generation Owner – a Member that owns or leases with rights equivalent to ownership facilities for the generation of electric energy that are located within the PJM Region. Purchasing all or a portion of the output of a generation facility is not sufficient to qualify a Member as a Generation Owner.

Generator Forced Outage – an immediate reduction in output or capacity or removal from service of a generating unit by reason of an Emergency or threatened Emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility, as specified in the relevant portions of the PJM Manuals. A reduction in output or removal from service of a generating unit in response to changes in market conditions does not constitute a Generator Forced Outage.

Generation Interconnection Agreement – an agreement among the Transmission Provider, a Project Developer, and applicable to a Generation Interconnection Request or Transmission Interconnect Request.

Generator Maintenance Outage – the scheduled removal from service of a generating unit in order to perform repairs on specific components of the facility, if removal of the facility qualifies as a maintenance outage.

Generator Planned Outage – the scheduled removal from service of a generating unit for inspection, maintenance or repair with the approval of the office of the Interconnection.

Incremental Auctions – Allow for an incremental procurement/release of resource commitments to satisfy an increase/decrease in the RTO/LDA Reliability Requirements through PJM Buy Bids/Sell Offers. Allows a resource provider to submit a Sell Offer to procure replacement capacity to cover commitment shortfalls due to a generation resource cancellation, delay, derating, EFORd increase, Accredited UCAP Factor decrease, or decrease in the unforced capacity value of a Demand Resource or Energy Efficiency Resource.

Incremental Capacity Transfer Rights – allocated to transmission expansion projects associated with new generation interconnection that were required to meet PJM Deliverability requirements and to Merchant Transmission Expansion projects and are applicable to all such projects that have gone through the PJM interconnection process since the beginning of the PJM RTEPP in 1999. Such incremental Capacity Transfer Rights allocation is based on the incremental increase in import capability across a Locational Constraint that is caused by the transmission facility upgrade. Incremental capacity transfer rights associated with Incremental Rights-Eligible Required Transmission Enhancements are allocated. Incremental Rights-Eligible Required Transmission Enhancements may include Regional Facilities and Necessary Lower Voltage Facilities, and Lower Voltage Facilities.

Installed Capacity (ICAP) – value determined in accordance with PJM's Rules and Procedures of the Determination of Generating Capacity in M21, M21A, and M21B. For an ELCC Resource through the 2024/2025 Delivery Year, the term "ICAP" in this manual refers to the lesser of the Accredited UCAP or the resource's CIRs plus any awarded transitional MWs.

Installed Reserve Margin (IRM) – used to establish the level of installed capacity resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. The IRM is determined by PJM in accordance with the PJM Resource Adequacy Analysis Manual (M-20) and (M-20A). The IRM is approved and posted prior to its use in an RPM Auction for the Delivery Year.

Investor Owned Utility (IOU) – an entity with substantial business interest in owning and/or operating electric facilities in any two or more of the following three asset categories: generation, transmission, distribution.

Jointly Owned Cross-Subsidized Capacity Resource – a Capacity Resource that is supported by a facility that is jointly owned, where at least one owner is entitled to or receives a State Subsidy associated with such Capacity Resource, and therefore shall be considered a Capacity Resource with State Subsidy; provided however, in the event that the material rights and obligations of such generating facility are in pari passu, meaning that such rights and

obligations are allocated among the owners pro rata based on ownership share, only Capacity Resources of those owners entitled to receive or receiving a State Subsidy shall have their share of such resource considered a Capacity Resource with a State Subsidy and Capacity Resources of owners not entitled to a State Subsidy shall not be considered a Capacity Resource with a State Subsidy. Each of these designations may be overcome by either Capacity Market Seller demonstrating to the Office of Interconnection, with advice and input from the Market Monitoring Unit, that there is no cross-subsidization or the Office of the Interconnection, with review and input from the Market Monitor, finds based on sufficient evidence, that there is cross-subsidization.

Limited Duration Resource is defined in the RAA as a Generation Capacity Resource that is not a Variable Resource, that is not a Combination Resource, and that is not capable of running continuously at Maximum Facility Output for 24 hours or longer. A Capacity Storage Resource is a Limited Duration Resource.

Load Management – is the ability to reduce metered load, either manually or automatically, by the customer, after a request from the resource provider which holds the Load management rights or its agent.

Load Serving Entity (LSE) – any entity (or the duly designated agent of such an entity), including a load aggregator or power marketer that (a) serves end-users within the PJM Control Area, and (b) is granted the authority or has an obligation pursuant to state or local law, regulation or franchise to sell electric energy to end-users located within the PJM Control Area.

Locational Constraints – localized capacity import capability limitations that are caused by transmission facility limitations, voltage limitations or stability limitations that are identified for a Delivery Year in the PJM Regional Transmission Expansion Planning Process (RTEPP) prior to each Base Residual Auction. Such Locational Constraints are included in the RPM to recognize and to quantify the locational value of capacity.

Locational Deliverability Area (LDA) – sub-regions used to evaluate locational constraints. LDAs include EDC zones, sub-zones, and combination of zones.

Locational Price Adder – an addition to the marginal value of unforced capacity within an LDA as necessary to reflect the price of resources required to relieve the applicable binding locational constraints.

Locational Reliability Charge – Fee applied to each LSE that serves load in PJM during the delivery year. Equal to the LSEs Daily Unforced Capacity Obligation multiplied by the applicable Final Zonal Capacity Price.

Nested LDAs – when an aggregate of Zones, a Zone and its sub-zones are constrained LDAs, the LDAs are referred to as “Nested”. When LDAs are nested, the Zonal CTR calculations include allocation of CTRs from RTO to aggregate of Zones as well as CTRs from aggregate of Zones to the Zone.

Net Energy & Ancillary Services (E&AS) Offset – is used to offset the value of Cost of New Entry (CONE) to determine the net value of CONE. This value is calculated using the historical averages of energy revenue data for a reference combustion turbine and an assumed value for ancillary services revenues as set forth in OATT. The energy revenues are calculated using a historical average of the three most recent calendar years preceding the Base Residual Auction.

New Entry Pricing – is an incentive provided to a Planned Generation Resource where the size of the new entry is significant relative to the size of the LDA and there is a potential for the clearing price to drop when all offer prices including that of the new entry are capped. This allows Planned Generation Resources to recover the amount of its cost of entry-based offer for up to two additional consecutive years, under certain conditions, and to set the clearing price of all resources within that LDA for all three years.

New Service Request – Interconnection Request.

Nominated DR Value – the nominated value of a Demand Resource is the value of the maximum load reduction and the process to determine this value is consistent with the process for the determination of the capacity obligation for the customer. The maximum load reduction for Capacity Performance registration also takes into consideration the Winter Peak Load for the customer. The maximum load reduction for each resource is adjusted to include system losses.

Non-Retail Behind the Meter Generation – Behind the Meter Generation that is used by municipal electric systems, electric cooperatives, and electric distribution companies to serve load.

Non-Zone Load – the load that is located outside of the PJM Region served by a PJM Load Serving Entity using PJM internal resources. Non-Zone Load is included in the load of the Zone from which the load is served.

Obligation Peak Load – the summation of the weather normalized coincident summer peaks for the previous summer of the end-users for which the Party was responsible on that billing day.

Office of the Interconnection – the employees and agents of PJM Interconnection, L.L.C., subject to the supervision and oversight of the PJM board.

Partial Requirements Service – wholesale service to supply a specified portion, but not all, of the power needs of a LSE to serve end-users within the PJM Region that are not satisfied by its own generating facilities.

Percentage Internal Resources Required – for purposes of an FRR Capacity Plan, the percentage of the LDA Reliability Requirement for an LDA that must be satisfied with Capacity Resources located in that LDA.

Planned Demand Resource – a Demand Resource that does not currently have the capability to provide a reduction in demand or to otherwise control load, but that is scheduled to be capable of providing a reduction or control on or before the start of the Delivery Year for which the resource is to be committed.

Planned Generation Capacity Resource – a Generation Capacity Resource participating in the generation interconnection process for which Interconnection Service is scheduled to commence on or before the first day of the Delivery Year for which the resource is to be committed. At a minimum, planned generation resources greater than 20 MW must be in the Phase III System Impact Study and planned generation resources less than or equal to 20 MW must be in the Phase II System Impact Study for the unit to participate in the Base Residual Auction. Generation Interconnection Agreement (GIA) or Wholesale Market Participant Agreement (WMPA) must be executed prior to any Incremental Auctions for the corresponding Delivery Year.

Planning Year – Annual period from June 1 to May 31 (also may be referred to as Planning Period).

Pool-Wide Average EFORd (Prior to the 2025/2026 Delivery Year)– average of the forced outage rates, weighted for unit capability and expected time in service, attributable to all units that are planned to be in service during the delivery year. Determined by PJM and is approved and posted by February 1 prior to its use in the Base Residual Auction for the Delivery Year. OMC events are considered in the EFORd values used to calculate Pool-Wide Average EFORd.

Public Power Entity – any agency, authority, or instrumentality of a state or of a political subdivision of a state, or any corporation wholly owned by any one or more of the above, that is engaged in the generation, transmission, and/or distribution of electric energy.

Qualifying Transmission Upgrade (QTU) – a proposed enhancement or addition to the Transmission System that will increase the Capacity Emergency Transfer Limit (CETL) into an LDA by a megawatt quantity certified by PJM. A Qualified Transmission Upgrade is scheduled to be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction. Prior to the conduct of the Base Residual Auction for such Delivery Year, at a minimum the Upgrade Customer must be in the Facilities Study phase for their proposed transmission upgrade.

Regional Transmission Expansion Planning Process (RTEPP) – is PJM's comprehensive annual process that examines the three interrelated components of electric power system reliability: load, generation, and transmission. The RTEP Process employs a range of planning study tools and methodologies to analyze and assess each component to ensure that reliability remains firm. The RTEP Process is designed to meet established reliability criteria, keep markets robust and competitive, and ensure stable operations.

Regional Transmission Owner (RTO) – Each entity that owns, leases, or otherwise has a possessory interest in facilities used for the transmission of electric energy in interstate

commerce or that provides Transmission that is a party to the PJM Transmission Owners Agreement and PJM Operating Agreement

Reliability Pricing Model (RPM) – is PJM’s resource adequacy construct. The purpose of RPM is to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP). RPM adds stability and a locational nature to the pricing signal for capacity.

Resource Clearing Price – is the clearing price in the Base Residual Auction or Incremental Auctions as determined by optimization algorithm for each auction. The Resource Clearing Price within an LDA is equal to the sum of (1) the marginal value of system capacity; and (2) the Locational Price Adder, if any, for the LDA. The Resource Clearing Price for Capacity Performance Resources in the Unconstrained Market Area is the marginal value of system capacity. PJM posts the Resource Clearing Prices for all resources that clear in the Base Residual Auction and all Buy Bids and Sell Offers that clear in the Incremental Auctions.

RPM Resource Commitment – MWs committed from a Capacity Resource to RPM as a result of such Capacity Resource clearing or receiving make-whole MWs in a Delivery Year RPM Auction(s), being specified as a replacement resource in a Replacement Capacity transaction(s), or being specified as the source of a Locational UCAP transaction(s).

RTO Unforced Capacity Obligation – established in the BRA and is used to determine the Base Zonal RPM Scaling Factors to use in determining Base Zonal Unforced Capacity Obligation.

RTO Weather Normalized Summer Peak – the sum of the Zonal Weather Normalized Summer Coincident Peaks.

Self-Scheduled Resources – are resources specified by a resource provider in the Base Residual Auction to provide a mechanism to guarantee that the resource will clear in the Base Residual Auction. For each resource-specific sell offer, if a resource is designated as self-scheduled by the resource provider, the minimum and maximum MW amounts specified must be equal and the sell offer price will be set to zero. Self-Scheduled resources will be cleared first in the Base Residual Auction, and cannot set the clearing price as the marginal resource, since these resources lack flexibility.

State Subsidy – a direct or indirect payment, concession, rebate, subsidy, nonbypassable consumer charge, or other financial benefit that is as a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that (1) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce; or (2) will support the construction, development, or operation of a new or existing Capacity Resource; or (3) could have the effect of allowing the unit to clear in any PJM capacity auction. Notwithstanding the foregoing, State

Subsidy shall not include (a) payments, concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area or designed to incent siting facilities in that county or locality rather than another county or locality; (b) state action that imposes a tax or assesses a charge utilizing the parameters of a regional program on a given set of resources notwithstanding the tax or cost having indirect benefits on resources not subject to the tax or cost (e.g., Regional Greenhouse Gas Initiative); (c) any indirect benefits to a Capacity Resource as a result of any transmission project approved as part of the Regional Transmission Expansion Plan; (d) any contract, legally enforceable obligation, or rate pursuant to the Public Utility Regulatory Policies Act or any other state-administered federal regulatory program (e.g., the Cross-State Air Pollution Rule); (e) any revenues from the sale or allocation, either direct or indirect, to an Entity Providing Supply Services to Default Retail Service Provider where such entity's obligations was awarded through a state default procurement auction that was subject to independent oversight by a consultant or manager who certifies that the auction was conducted through a non-discriminatory and competitive bidding process, subject to the below condition, and provided further that nothing herein would exempt a Capacity Resource that would otherwise be subject to the minimum offer price rule pursuant to this Tariff; (f) any revenues for providing capacity as part of an FRR Capacity Plan or through bilateral transactions with FRR Entities; or (g) any voluntary and arm's length bilateral transaction (including but not limited to those reported pursuant to Tariff, Attachment DD, section 4.6), such as a power purchase agreement or other similar contract where the buyer is a Self-Supply Entity and the transaction is (1) a short term transaction (one-year or less) or (2) a long-term transaction that is the result of a competitive process that was not fuel-specific and is not used for the purpose of supporting uneconomic construction, development, or operation of the subject Capacity Resource, provided however that if the Self-Supply Entity is responsible for offering the Capacity Resource into an RPM Auction, the specified amount of installed capacity purchased by such Self-Supply Entity shall be considered to receive a State Subsidy in the same manner, under the same conditions, and to the same extent as any other Capacity Resource of a Self-Supply Entity. For purposes of subsection (e) of this definition, a state default procurement auction that has been certified to be a result of a non-discriminatory and competitive bidding process shall:

(i) have no conditions based on the ownership (except supplier diversity requirements or limits), location (except to meet PJM deliverability requirements), affiliation, fuel type, technology, or emissions of any resources or supply (except state-mandated renewable portfolio standards for which Capacity Resources are separately subject to the minimum offer price rule or eligible for an exemption);

(ii) result in contracts between an Entity Providing Supply Services to Default Retail Service Provider and the electric distribution company for a retail default generation supply product and none of those contracts require that the retail obligation be sourced from any specific Capacity Resource or resource type as set forth in subsection (i) above; and

(iii) establish market-based compensation for a retail default generation supply product that retail customers can avoid paying for by obtaining supply from a competitive retail supplier of their choice.

Steady State Period – period of time where the auction schedule follows the proposed three year forward planning dates. The steady-state condition of RPM begins with the 2011/12 Delivery Year.

Transmission Facilities – facilities within the PJM Region that have been approved by or meet the definition of transmission facilities established by FERC; or have been demonstrated to the satisfaction of the Office of Interconnection to be integrated with the PJM Region transmission system and integrated into the planning and operation of the PJM Region to serve all of the power and transmission customers within the PJM Region.

Transmission Owner – a Member that owns or leases, with rights equivalent to ownership, Transmission Facilities. Taking transmission service is not sufficient to qualify a Member as a Transmission Owner.

Unforced Capacity (UCAP) – prior to the 2025/2026 delivery year, the installed capacity rated at summer conditions that are not on average experiencing a forced outage or forced derating, calculated for each generation Capacity Resource based on EFORD data for the 12-month period from October to September without regard to the ownership of or the contractual rights to the capacity of the unit. For an ELCC Resource, the UCAP is the Accredited UCAP of the unit, not to exceed its Capacity Interconnection Rights plus any awarded transitional resource MWs. Effective with the 2025/2026 Delivery Year, for an ELCC Resource that is a Generation Capacity Resource, the UCAP is the Accredited UCAP of the unit, not to exceed its Capacity Interconnection Rights plus any awarded transitional resource MWs.

Unlimited Resource is defined in the RAA as a generating unit having the ability to maintain output at a stated capability continuously on a daily basis without interruption. Through the 2024/2025 Delivery Year, an Unlimited Resource is a Generation Capacity Resource that is not an ELCC Resource.

Variable Resource is defined in the RAA as a Generation Capacity Resource with output that can vary as a function of its energy source, such as wind, solar, run of river hydroelectric power without storage, and landfill gas units without an alternate fuel source. All Intermittent Resources are Variable Resources, with the exception of Hydropower with Non-Pumped Storage.

Variable Resource Requirement Curve (VRR) – defines the maximum price for a given level of Capacity Resource commitment relative to the applicable reliability requirement. VRR Curves are defined for the PJM Region and each of the constrained LDAs within the PJM region.

Weighted Average Resource Clearing Price – the average of the segment-specific Resource Clearing Prices that result in all the auctions for a party's specific Capacity Resource, weighted

by the segment-specific Unforced Capacity cleared for that particular resource. This value is used to determine a party's Daily Deficiency Rate for an individual resource.

Zonal Capacity Price – the price of UCAP in a Zone that an LSE that has not elected the FRR Alternative is obligated to pay for a Delivery Year. Zonal capacity prices are calculated as a result of the clearing of all RPM Auctions for the Delivery Year. A zonal capacity price consists of the following price components: (1) the marginal value of system capacity for the PJM Region; (2) the Locational Price Adder, if any, for such zones in a constrained Locational Deliverability Area (LDA); and (3) an adjustment in the Zone, if required, to account for any resource make-whole payments. *Preliminary Zonal Capacity Prices* are the result of the clearing of the Base Residual Auction. *Adjusted Zonal Capacity Prices* are the result of the clearing of the Base Residual Auction and any Incremental Auction(s). *Final Zonal Capacity Prices* are determined after the Final Incremental Auction for the Delivery Year.

Zonal CTR Credit Rate (Base and Final) – the rate calculated as a ratio of economic value of CTRs to zonal unforced capacity obligation. These rates are calculated as the Base Zonal CTR Credit Rate after the Base Residual Auction and as the Final CTR Credit Rate adjusted for the results of all RPM Auctions. Zonal CTR Credit Rate is subtracted from Zonal Capacity Price to estimate Net Load Price.

Zonal CTR Settlement Rate – a rate calculated as a ratio of economic value of CTRs to total CTRs allocated to LSEs in a zone. This rate is used to settle CTRs by calculating credit for CTRs owned.

Zone – an area within the PJM Region or such areas that may be combined as a result of mergers and acquisitions; or added as a result of the expansion of the boundaries of the PJM Region. A Zone will include any Non-Zone Network Load located outside the PJM Region that is served from inside a particular Zone.

Attachment B: Authorization to Self-Schedule Capacity

Authorization to Self-Schedule Capacity

This Authorization to Self-Schedule Capacity (“Authorization”) of _____ (“Owner”), effective this ____ day of ____, 20____, hereby authorizes PJM Interconnection, L.L.C. (“PJM”) to self-schedule on its behalf as (“Product type”), the capacity associated with a specific generating unit _____ (“Unit”), which it will own or control for a portion of the delivery year from June 1 to May 31, 20____ to 20____ (“Delivery Year”), with the following other party or parties owning or controlling the Unit for the balance of such delivery year (if known): _____ (“Other Owners”). Owner states that it will own or control the Unit during the period(s) within the Delivery Year from ____/____/____ to ____/____/____ and any additional periods listed hereafter: _____.

Recitals:

WHEREAS, PJM Interconnection, L.L.C. (“PJM”) is a Regional Transmission Organization (“RTO”) that administers the Reliability Pricing Model (“RPM”), a centralized market for obtaining the electric capacity resources necessary to ensure resource adequacy in its control area;

WHEREAS, a capacity resource must remain available for the entire delivery year in order to be eligible to offer its capacity in RPM auctions;

WHEREAS, an owner may seek to sell capacity in an RPM auction associated with a generating unit that such owner owns or controls for only a portion of the delivery year as result of a transaction specific to such unit commencing or terminating within a delivery year;

WHEREAS, PJM, in order to facilitate participation in its auctions of all capacity resources potentially available, permits owners collectively to authorize PJM to self-schedule the Unit on their behalf capacity owned or controlled by such owner for a portion of the delivery year,

Authorization

NOW, THEREFORE, Owner authorizes PJM to self-schedule its Unit during the years during which it will own or control the Unit for only a portion of the identified delivery year(s), and

acknowledges that it understands and accepts the following terms and conditions of this authorization:

1. Each Owner and Other Owner (i) must submit to the PJM-designated electronic mail address a fully prepared and executed Authorization from the Owner and each Other Owner at least 5 business days prior to the opening of the bidding window of an RPM auction and (ii) must submit as the “seller” into the Capacity Exchange electronic interface system a new unit-specific transaction(s) indicating “Self Scheduling Coordinator (SELFSC)” as the “buyer” prior to the opening of the auction bidding window. Owner understands that failure of any Other Owner to satisfy both of these requirements shall preclude a Unit from participation in an RPM auction even where Owner otherwise has otherwise fully complied.
2. Because PJM will use the Unit’s current Accredited UCAP Factor in the self-schedule, Owner recognizes that, consequently, the Unit’s unforced capacity value may change between the time the Unit is offered into the RPM Auction and the delivery year for which the Unit was self-scheduled.
3. Because PJM will self-schedule the Unit, Owner recognizes that the Unit’s offer will always clear an auction and that Owner must accept the applicable clearing price.
4. PJM automatically will transfer to Owner (and each Other Owner) the cleared capacity of the Unit for the portion of the Delivery Year during which it owns or controls the Unit, and that, as the “buyer” in this unit specific transaction, the Owner will for the duration of this period be responsible for any Capacity Resources Deficiency Charges and Non-Performance Assessment Charges that may be assessed (including those resulting from a reduced Accredited UCAP), and, for the duration of the delivery year, its proportional share of any Generation Test Resource Rating Test Failure Charges, or that may be assessed under RPM rules.

The undersigned, having been granted Capacity Exchange Read/Write Access by Owner and duly authorized to act on Owner’s behalf, declares to PJM the authority described here above and intends that PJM may rely upon such declaration even to Owner’s detriment.

Signed this ____th day of _____, 20____

Signed by: _____ Title: _____

Attachment C: Demand Resource Sell Offer Plan

The Demand Resource Sell Offer Plan (DR Sell Offer Plan) is a PJM template document, requiring the information set forth below, together with an accompanying signed PJM Demand Resource Officer Certification Form (DR Officer Certification Form). A completed DR Sell Offer Plan (including a signed DR Officer Certification Form) must be submitted to PJM no later than 15 business days prior to the relevant RPM Auction by Curtailment Service Providers (CSPs) that intend to offer Demand Resources (DR) in RPM Auctions. The DR Sell Offer Plan must provide information that supports the CSP's intended DR Sell Offers and demonstrates that the DR is being offered with the intention that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource Registrations for the relevant Delivery Year.

The DR Sell Offer Plan encompasses both existing DR and Planned DR. Existing DR is identified as end-use customer sites that the CSP has under contract for the current Delivery Year (i.e. end-use customer sites registered in the PJM DR Hub system for the current Delivery Year)³⁴ and that the CSP intends to have under contract for the auction Delivery Year. Planned DR is that quantity of the CSP's intended total DR Sell Offer in excess of the CSP's existing DR and is subject to an RPM Credit Requirement. The CSP shall not include Critical Natural Gas Infrastructure in their Plan.

Both the signed DR Officer Certification Form and the completed DR Sell Offer template must be submitted to PJM via email to rpm_hotline@pjm.com no later than 15 business days prior to the relevant RPM auction. PJM will review the DR Sell Offer Plan and notify the CSP via email no later than 10 business days prior to the RPM Auction if another CSP has identified the same end-use customer site(s) in their DR Sell Offer Plan and request supporting documentation, such as a letter of support from the end-use customer indicating that the end-use customer and CSP are likely to execute a contract for the auction Delivery Year. Supporting documentation must be submitted via email to the rpm_hotline@pjm.com no later than 7 business days prior to the RPM Auction. PJM will notify all CSPs via the Capacity Exchange system of the approved DR MW quantity by zone/sub-zone that the CSP is permitted to offer into the RPM Auction no later than 5 business days prior to the RPM Auction.

I. PJM Demand Resource Officer Certification Form

³⁴ For a Base Residual Auction and a Third Incremental Auction, end-use customer sites registered in the PJM DR Hub system for the subsequent Delivery Year may also be considered as existing DR provided the Demand Resource Registrations are in "Confirmed" status by specified deadlines established by PJM and communicated to CSPs in advance of the DR Sell Offer Plan submittal deadline.

A DR Officer Certification Form is located in Attachment D of Manual 18 and is posted on the PJM web site. A signed DR Officer Certification Form must accompany the DR Sell Offer Plan. The DR Officer Certification Form specifies that the signing officer has reviewed the DR Sell Offer Plan, that the information provided therein is true and correct, and that the MW quantity that clears the auction is reasonably expected to be physically delivered through Demand Resource Registrations for the relevant Delivery Year.

II. DR Sell Offer Plan Template

A DR Sell Offer Plan template (in Excel format) is provided on the PJM web site, and consists of the following three sections:

- A. DR Sell Offer Plan Summary
- B. Planned DR Details
- C. Schedule

A. DR Sell Offer Plan Summary

The DR Sell Offer Plan requires the following information to be provided:

- Company name
- Contact information (name, phone number and email address of submitter)
- Existing Nominated DR Value in ICAP MWs by zone/subzone that CSP intends to offer
- Planned Nominated DR Value in ICAP MWs by zone/subzone that CSP intends to offer

Existing DR is identified by the CSP as end-use customer sites that the CSP has under contract and registered in the PJM eLRS/DR Hub System for the current Delivery Year and that the CSP also intends to have under contract for the auction Delivery Year. Planned DR is identified by the CSP as described in the Planned DR Details section of the DR Sell Offer Plan template. Based on the information provided above, a total Nominated DR Value in MWs will be calculated for each zone/sub-zone as the addition of the Nominated DR Value of existing DR plus the Nominated DR Value of Planned DR. The total Nominated DR Value represents the maximum MW amount that the CSP intends to offer for the zone/sub-zone. Effective with the 2020/2021 Delivery Year, a CSP must apportion the total Nominated DR Value for the zone/sub-zone into the quantity that the CSP intends to offer into the auction as Annual Capacity Performance, the quantity that the CSP intends to offer into the auction as Summer-Period Capacity Performance, and the quantity that the CSP intends to offer into the auction as part of an Aggregate Resource, such that, the sum of such quantities must equal the total Nominated DR Value. The actual MW value(s) submitted by a CSP in their Sell Offer(s) for a zone/sub-zone during the auction bidding window may be less than the total Nominated DR Value in their DR Sell Offer Plan Summary.

Certain zones/sub-zones will be pre-identified by PJM as zones for which DR Sell Offers may require additional information to support the plan. Additional information may be required to support DR Sell Offer Plans for zones/sub-zones for which the quantity of cleared zonal/sub-zonal DR from the last BRA exceeds a threshold determined for the applicable LDA group (EMAAC, SWMAAC, Rest of MAAC, or Rest of RTO) as the higher of the maximum DR/ILR quantity registered in eLRS/DR Hub over the past three Delivery Years for the zones in the LDA group or the zonal DR potential quantity for the zones in the LDA group estimated based on a June 2009 FERC Staff Report on “A National Assessment of Demand Response Potential”, where DR quantities are expressed in all cases as a percent of the forecasted zonal peak load. This determination of the identified zones is made each year prior to each BRA and is applicable to all auctions conducted for that Delivery Year. Zones or sub-zones remain on the identified list unless the threshold is not exceeded for three consecutive years. Identified zones for a Delivery Year will be posted by PJM to the pjw website no later than December 1 prior to the Base Residual Auction for such Delivery Year. Updates, if any, made to the 2009 FERC Staff Report will be subject to stakeholder review and considered for use in the establishment of thresholds in the future.

For these pre-identified zones/sub-zones, a CSP sell offer threshold is determined for each CSP; and DR sell offer quantities in excess of the CSP sell offer threshold will require site-specific information, as this quantity in excess of the CSP sell offer threshold should reflect Planned DR associated with end-use customer sites that the CSP has a high degree of certainty that it will physically deliver for the Delivery Year. The CSP sell offer threshold is determined as the higher of [(the CSP’s maximum DR quantity registered in eLRS/DR Hub for that zone/sub-zone over the past three Delivery Years) or (the CSP’s maximum cleared DR quantity for the past three BRAs for that zone/sub-zone) or (10 MW)].

B. Planned DR Details

The Planned DR Details section describes the program or strategy for procuring end-use customers and provides the details and key assumptions behind the development of the Planned DR quantities contained in the CSP’s DR Sell Offer Plan. The Planned DR Details section is comprised of three sub-sections.

1. Description and Key Assumptions of Planned DR

The CSP must describe the program(s) that the CSP plans to employ to achieve the Planned Nominated DR Value indicated on the DR Sell Offer Plan Summary. This section must describe key program attributes and assumptions used to develop the Planned Nominated DR Value. This section must include, but is not limited to, discussion of:

- Method(s) of achieving load reduction at customer site(s)
- Equipment to be controlled or installed at customer site(s), if any
- Plan and ability to acquire customers
- Types of customer targeted

- Support of market potential and market share for the target customer base, with adjustments for existing DR customers within this market and the potential for other CSPs targeting the same customers
- Assumptions regarding regulatory approval of program(s), if applicable

2. Planned Nominated DR Value by Customer Segment

For those Planned Nominated DR Values for which an end-use customer site is not identified in section 3 of the Planned DR Details, the CSP must identify the Planned Nominated DR values by zone/sub-zone and by end-use customer segment. End-use customer segments include residential, commercial, small industrial (less than 3 MW), medium industrial (between 3 MW and 10 MW) and large industrial (greater than 10 MW). If known, the CSP may identify more specific customer segments within the commercial and industrial category.

By zone/sub-zone and by end-use customer segment, the CSP must provide estimates of the following information regarding the Planned DR component of the DR Sell Offer Plan:

- Number of end-use customers to be registered for auction Delivery Year
- Average Peak Load Contribution (PLC) per end-use customer in kW
- Average Nominated DR Value per customer in kW

Based on the above provided information, a total Planned Nominated DR Value in MW will be calculated for each end-use customer segment and for each zone/sub-zone. The total Planned Nominated DR values identified by customer segment and aggregated for each zone/sub-zone in Section 2 of the Planned DR Details plus the total Planned Nominated DR Values identified by end-use customer site(s) and aggregated for each zone/sub-zone in Section 3 of the Planned DR Details must equal the total Planned Nominated DR Value for each zone-sub-zone as identified in the DR Sell Offer Plan Summary.

3. Planned Nominated DR Value by End-Use Customer Site

This section must be completed by the CSP when the end-use customer is known at the time of the submittal of the DR Sell Offer Plan. This section must also be completed for DR Sell Offer quantities identified in the DR Sell Offer Plan Summary as requiring site-specific information, since this identified quantity should reflect Planned DR associated with specific end-use customer sites for which the CSP has a high degree of certainty that it will physically deliver for the relevant Delivery Year.

The CSP must provide the following information:

- Customer EDC account number (if known)
- Customer name
- Customer premise address
- Zone/Sub-zone

- Customer segment
- Actual value (if known) or estimate of current PLC and estimate of expected auction Delivery Year PLC in kW
- Estimated Nominated DR Value in kW

In the event that multiple CSPs identify the same end-use customer site, the MWs associated with such site will not be approved for offering into the RPM auction by any of the CSPs, unless it can be supported by evidence, such as a letter of support from the end-use customer indicating that they have been in contact with the CSP and are likely to execute a contract with that CSP for the relevant Delivery Year. In the event that multiple letters of support indicating different CSPs are provided from the end use customer, the MWs associated with the end-use customer site will not be approved for offering into the RPM auction by any of the CSPs.

C. Schedule

The CSP must provide an approximate timeline for procuring end-use customer sites in order to physically deliver the total Nominated DR Value (existing and Planned DR) by zone/sub-zone in the DR Sell Offer Summary. For each zone/sub-zone and for each customer segment, the CSP must specify the cumulative number of customers and the cumulative Nominated DR Value associated with that group of customers that the CSP expects to have under contract by the beginning of each of the full Delivery Years occurring between the time of the auction and the auction Delivery Year.

Attachment D: Demand Resource Officer Certification Form

PJM DEMAND RESOURCE SELL OFFER PLAN OFFICER CERTIFICATION FORM

Market Participant Name: _____ (“Participant”)

I, _____, a duly authorized officer of Participant, understanding that PJM Interconnection, L.L.C. (“PJM”) and PJM Settlement, Inc. (“PJM Settlement”) are relying on this certification as evidence that Participant meets all requirements for participating in PJM’s Reliability Pricing Model (“RPM”) auctions, as set forth in the PJM Open Access Transmission Tariff (“PJM Tariff”), the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (“Operating Agreement”), the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region (“RAA”), and in the PJM Manuals, hereby certify that, as of the date of this certification, to my knowledge and belief:

1. I have reviewed Participant’s Demand Resource Sell Offer Plan (the “Plan”) and the information supplied to PJM in support of the Plan is true and correct as of the date of this certification.
2. The Participant is submitting the Plan with the reasonable expectation, based upon its analyses as of the date of this certification, to physically deliver all megawatts that clear the RPM Auction through Demand Resource registrations by the specified Delivery Year.
3. This certification does not in any way abridge, expand, or otherwise modify the current provisions of the PJM Tariff, Operating Agreement and/or RAA, or the Participant’s rights and obligations thereunder, including Participant’s ability to adjust capacity obligations through participation in PJM incremental auctions and bilateral transactions.

Date: _____ By: _____

(Signature)

Print Name: _____ Title: _____

Revision History

Revision 60 (06/01/2025):

- Conforming changes were made to the following sections to incorporate provisions of FERC's CIFP-RA order (ER24-99)
- 8.1 - Overview of Resource Performance Assessments
- 8.3 - Commitment Level Used in Summer/Winter Capability Tests (through the 2024/2025 Delivery Year)
- 8.5 - Summer/Winter Capability Testing
- 8.5.1 - Determination of Unit ICAP Shortfall (through the 2024/2025 Delivery Year)
- 8.5.2 - Determination of Unit ICAP Shortfall (effective with the 2025/2026 Delivery Year)
- 8.5A - Generation Operational Testing
- 9.1.5 - Generation Resource Rating Test Failure Charge
- 9.1.5A - Generation Operational Test Failure Charge
- 9.1.7 - Allocation of Deficiency and Penalty Charges
- Update 5.2 to include preliminary ELCC Class Rating and Accredited UCAP Factors on the auction timeline as approved by the 5/21/25 MRC.

Administrative Change (Pete Langbein approved 02/26/2025):

- Added missing content in Section 8.7.1

Revision 59 (06/27/2024):

- Conforming changes were made to the following sections to incorporate provisions of FERC's CIFP-RA order (ER24-99) and CONE Area 5 order (ER24-462):
- 1.2.2 Participation of Resource Providers
- 2.1.1 Installed Reserve Margin
- 2.1.2 Peak Load Forecasts
- 2.1.3.1 Pool-wide Average EFORd (Through 2024/2025 Delivery Year)
- 2.1.3.2 Pool-wide average Accredited UCAP Factor (Starting with 2025/2026 Delivery Year)
- 2.1.4 Forecast Pool Requirement
- 2.1.5 Effective Load Carrying Capability and ELCC Resources in Capacity Exchange
- 2.2 Role of Load Deliverability in the Reliability Pricing Model
- 2.3 Locational Constraints in the Reliability Pricing Model
- 2.3.1 Locational Constraints in the Reliability Pricing Model
- 2.4 Reliability Requirements

- 3.3 Parameters of the Variable Resource Requirement
 - 3.3.1 Cost of New Entry
- 3.4 Plotting the Variable Resource Requirement Curve
- 4.2.1 Existing Generation Capacity Resource – Internal
- 4.2.2 Existing Generation Capacity Resources – External
- 4.2.3 Planned Generation Capacity Resources – Internal
 - 4.2.3.1 Binding Notice of Intent to Offer (Effective with the 2025/2026 Delivery Year)
- 4.2.4 Planned Generation Capacity Resources – External
- 4.2.5 Equivalent Demand Forced Outage Rate
- 4.2.7 Accredited UCAP for ELCC Resources
- 4.3.1 Requirements of Load Management Products in RPM
- 4.3.8 Determination of the UCAP Value of Load Management
- 4.4 Energy Efficiency Resources
- 4.6.2 Entering Unit-Specific Bilateral Transactions
- 4.6.3 Exporting a Generation Resource
- 4.6.5 Treatment of Unit-Specific Capacity Transactions that Start/End Mid-Delivery Year
- 4.6.8 Locational Unforced Capacity (UCAP) Transactions
- 4.7.1 Resource Position for Generation Capacity Resources
- 4.7.2 Resource Position for Demand Resources
- 5.2 RPM Auction Timeline
- 5.3. RPM Auction Parameters
 - 5.4.1 Resource-Specific Sell Offer Requirements
 - 5.4.3 New Entry Pricing Adjustment
 - 5.4.4 Sell Offer Caps
 - 5.4.8.4 Default MOPR Floor Offer Prices
- 5.7.1 Participation in the Base Residual Auction
- 5.8.1 Participation in the Incremental Auctions
- 8.1 Overview of Resource Performance Assessments
 - 8.2.1 Generation (RPM Commitment Compliance)
 - 8.2.2 Demand Resources (RPM Commitment Compliance)
 - 8.4A Non-Performance Assessment
- 8.7 Load Management Test Compliance
- 8.8 Replacement Resources
- 9.1.9 Non-Performance Charge/Bonus Performance Credit

- 11.1.3 Participation in the FRR Alternative
- 11.2.1 Preliminary Unforced Capacity Obligation
- 11.3 Capacity Plan
- 11.4.1 Resource Portfolio
- 11.4.7 Load Management Products
- 11.8.1 FRR Capacity Resource Deficiency Charges

Revision 58 (11/15/2023):

- Conforming changes for interconnection process (ER22-2110)
- Section 4.7.1, 4.2.6, 4.2.7: RAA updated for Transitional MW (Docket No. ER23-1067-000)
- Section 7.4: Conforming language for Order 841 and Hybrid Order (ER22-1420)
- Section 8.2.2: Remove reference to DR Factor
- Section 3.3 and 3.4: Conforming to approved quad review filing (ER22-2984-000)
- Section 8.4A: Change to PAI Trigger (ER23-1996-000)
- Section 5.4.8.4: Updated Default Gross CONE and Gross ACR for MOPR (ER23-1700)

Revision 57 (07/26/2023):

- Interconnection Process Reform Taskforce nomenclature updates
 - Section 4.2.3: Updated terminology for IPRTF updates
 - Section 4.2.4: Updated terminology for IPRTF updates
 - Section 4.5: Updated terminology for IPRTF updates
 - Section 4.8.2: Updated terminology for IPRTF updates
 - Section 4.8.5: Updated terminology for IPRTF updates
 - Section 4.10: Updated terminology for IPRTF updates
 - Section 5.4.7: Updated terminology for IPRTF updates
 - Section 6.1: Updated terminology for IPRTF updates
 - Section 6.1.2: Updated terminology for IPRTF updates
 - Section 8.8: Updated terminology for IPRTF updates
 - Section 11.4.6: Updated terminology for IPRTF updates
 - Glossary A: Updated terminology for IPRTF updates

Administrative Change (Approved by Peter Langbein 04/28/2023):

- Removed reference to Manual 10 Section 6 in Section 8.5. Justification for this change is due to the decision for Section 6's removal stated in M10 "based on RFC Standard MOD-024-RFC-01, which permits verification of winter gross Real Power capability by adjusting the summer verification, eliminating the need for exemption program. Revisions approved by stakeholders at MRC on November 30, 2009"

Revision 56 (02/09/2023):

- Change to Section 8.8 to allow early replacement actions for export under specific conditions as approved at 11/16/22 MRC.

Revision 55 (02/09/2023):

- Updated section 3A.3 and Attachment C to prohibit Critical Natural Gas Infrastructure

Administrative Change (Approved by Peter Langbein 01/05/2023):

- Section 5.4.8.3: Updated binary pronoun usage (e.g., “his/her” to a gender-neutral equivalent (e.g., “their,” etc.) in order to support PJM’s diversity, equity and inclusion efforts.

Revision 54 (09/21/2022):

- Periodic Review updates include:
 - Deletion of outdated information in the following sections:
 - Section 1.5
 - Sections 2.1.3, 2.2, 2.3, 2.3.4, 2.4.3, 2.4.3A, 2.4.4, & 2.4.5
 - Sections 3.3.1, 3.3.2, 3.4, 3.5, 3A.1, 3A.2, 3A.3, 3A.4.1, 3A.4.2, 3A.5, 3A.6, 3A.6.2, & 3A.6.2A
 - Sections 4.1, 4.2.2, 4.2.4, 4.2.5, 4.2.6, 4.3.1, 4.3.3, 4.3.4, 4.3.5, 4.3.7, 4.3.8, 4.3.10, 4.4, 4.4.1, 4.4.2, 4.4.3, 4.5, 4.6.2, 4.6.4, 4.6.5, 4.6.6, 4.6.7, 4.6.8, 4.7.1, 4.7.2, 4.7.2, 4.7.3, 4.8.3, 4.8.4, 4.8.5, 4.9, & 4.10
 - Sections 5.3, 5.4.1, 5.4.4, 5.4.5, 5.4.8, 5.5, 5.7.1, 5.7.2, 5.7.3, 5.8.1, 5.8.3, 5.8.5, & 5.9.1
 - Section 6.1.3
 - Section 7.2.2
 - Sections 8.1, 8.2.1, 8.2.2, 8.2.3, 8.3, 8.4, 8.4A, 8.5, 8.6, 8.7, 8.8
 - Sections 9.1.1, 9.1.2, 9.1.3, 9.1.5, 9.1.6, 9.1.9, 9.3.1, 9.3.3, 9.4.2, 9.4.4
 - Sections 11.1.2, 11.3, 11.4.1, 11.4.7, 11.4.8, 11.8.1, 11.8.3, 11.8.5, 11.8.6, & 11.8.7
 - Attachment A: Glossary of Terms
 - Added reference to Section 3.4 for development of VRR Curves (Sections 2.4.4 & 2.4.5)
 - Added missing OVEC zone to CONE Area (Section 3.3.1)
 - Added footnote to clarify the Reliability Requirement used in UCAP quantity equation for points (a), (b), and (c) of VRR Curve excludes any adjustment for PRD or EE (Section 3.4)
 - Clarified VRR Curve is adjusted rightward for EE addback (Section 3.4)

- Clarified information to be verified in Resource Confirmation process to reflect current practice in Capacity Exchange system (Section 4.1)
- Clarified generation resource committed to FRR Capacity Plan must satisfy same qualification requirements as resource offering into RPM Auction (Section 4.2)
- Moved Prior CIL Exception Resource definition from Section 2.3 to this section (Section 4.2.2)
- Clarified load management programs and EE installations are eligible to be committed to FRR Capacity Plan (Section 4.3 & Section 4.4)
- Updated DR Plan deadline from 15 business prior to 30 days prior (Sections 4.3.1, 5.2, 11.4.7, & Attachment C: DR Sell Offer Plan)
- Replaced "annual" product availability with "Capacity Performance" (Section 4.3.10)
- Added Nominated EE Value Template requirement to reflect current practice (Section 4.4)
- Updated EE Modification process to reflect current practice (Section 4.4.3)
- Clarified UCAP Value of CP EE Resource and Summer Period EE Resource (Section 4.4.2)
- Added Generation Resource Rating Test Failure Charge to list of charges applicable to Seller of Auction Specific MW Transaction (Section 4.6.6)
- Added footnote to reference RPM Auction schedule on website for DYs FERC approved a compressed auction schedule (Section 5.2)
- Added Capacity Performance value when missing (Section 8.2.3)
- Clarified party/PJM Weighted Average Resource Clearing Price to consider segment-specific RCPs (Section 9.1.3)
- Clarified LDA Incremental CTR Credit Rate (Section 9.3.4)
- Changed "product-specific" to "segment-specific" in description of price applicable to Auction Specific MW transaction (Section 9.3.5)
- Clarified Capacity Exchange tool functionality (Section 10.1)
- Clarified alternative retail LSE is subject to credit requirement as opposed to FRR Entity for alternative retail LSE's Planned Resources (Section 11.1.3)
- Corrected the treatment of switched load between FRR Entity and RPM LSEs to be in compliance with RAA (Section 11.2.3)
- Clarified EE Modification submittal process (Section 11.4.9)
- Clarified the requirement to perform Load Management test (Section 11.8.5)
- Added footnote to clarify final Shortfall or Bonus MW will be allocated to RPM and FRR if have both RPM and FRR commitments on resource (Section 11.8.7)
- Clarified definition of DR Mod, EFORD, Effective EFORD, Nominated DR Value, Pool-wide average EFORD, Resource Clearing Price, Weighted Average Resource Clearing Price, and Zonal Capacity Price (Attachment A: Glossary of Terms)

- Administrative updates throughout manual
 - Corrected manual or agreement references
 - Consolidated information
 - Deleted duplicative information
 - Updated tool name to Capacity Exchange
 - Corrected grammar and formatting
- Update the process for Capacity Market Seller to demonstrate written commitment to must-offer requirement for an External Resource via Officer Certification Form as opposed to External Resource Must Offer Agreement (Section 4.2.2)
- Updates to include certain Hybrid Resources in the exemption to the RPM must offer requirement (Sections 4.7.1, 5.4.1, 5.7.1, and 5.8.1)
-

Revision 53 (07/27/2022):

- Conforming revisions for FERC Order ER20-1590-000 issued on September 3, 2020 approving changes to Load Management and Price Responsive Demand testing requirements to make testing more closely simulate actual emergency events. This includes details on scheduling tests, notification of tests, duration of tests and retesting provisions.
 - Section 3A.6.3A establishes the testing requirements for PRD effective with 2023/2024 Delivery Year.
 - Section 8.7 modified for Load management testing requirements effective with 2023/2024 Delivery Year.

Revision 52 (02/24/2022):

- Update to section 3.3.2 to reflect that Net EAS of the Reference Resource CT is calculated using the forward-looking methodology with application of the 10% adder for only the 2022/2023 Delivery Year. The Net EAS is determined using the historical approach and without application of the 10% adder for all other delivery years.
- Update to section 5.4.1 to reflect that sell offers of existing generation capacity resources above \$0/MW-Day must seek unit-specific exception or elect to use MSOC based on gross ACR of applicable resource type, if available, effective 9/2/2021. Added language specifying that sellers may elect to use a default offer cap of 1.1 times the BRA RCP for any 3rd IA.
- Updated section 5.4.4 to reflect that the Net EAS of units seeking a net ACR-based exception is calculated using the forward-looking methodology for only the 2022/2023 Delivery Year. The Net EAS is determined by historical net revenues for all other delivery years.
- Updated section 5.4.5 to make clear that this section and its sub-sections which describe the MOPR provisions of Sections 5.14(h) and 5.14(h-1) of Attachment DD of the PJM

OATT are not applicable after the 2022/2023 Delivery Year. Deleted language in section 5.4.5.2 describing consequences of accepting State Subsidy after electing competitive exemption or certifying that resource is not state subsidized.

- Added new section 5.4.8 to describe the MOPR provisions of Section 5.14(h-2) of Attachment DD of the PJM OATT which are effective with the 2023/2023 Delivery Year.

Revision 51 (10/20/2021):

- Updates to Section 2.4.5 to reflect new EE Addback methodology to be used in all RPM Auctions conducted for the 2023/2024 Delivery Year and all subsequent delivery years.

Revision 50 (09/01/2021):

Revision includes:

- Updates to Section 8.4A to clarify Scheduled MW used for Excusal and Bonus purposes in Performance Assessment Interval settlement is calculated using Dispatch Run LMP due to Fast Start Pricing implementation on 9/1/2021.

Revision 49 (08/01/2021):

Revised the following sections to make confirming changes to implement Effective Load Carrying Capability to calculate the capacity value of renewables and storage. Unless otherwise noted, section changes were made to update and clarify terminology usage related to ICAP, UCAP, and EFORD, and replacing the terms “wind” and “solar” with “Variable Resources”:

- New Section 2.1.5 – provides a summary description of ELCC and describes the use of the terms “ICAP” and “UCAP” for ELCC Resources in the context of Manual 18
- 4.2.5 and 4.2.6
- New Section 4.2.7 – provides a summary description of ELCC and describes the use of the terms “ICAP” and “UCAP” for ELCC Resources in the context of Manual 18
- 4.7.1 – clarifies that ELCC Resources may not offer or otherwise provide UCAP MW quantities above their Capacity Interconnection Rights.
- 5.4.1 and 5.4.5.6
- 7.1
- 8.1 – revised the table of generator assessments to reflect rules for Variable Resources
- 8.4
- 8.5
- 8.8 – reflects application of commitment deficiency rules given the Accredited UCAP values of ELCC Resources
- 9.1.1
- 9.1.5 – reflects application of the Daily Generation Resource Rating Test Failure Charge given the Accredited UCAP value of ELCC Resources

- 11.3
- 11.4.1
- Attachment A – added the RAA definitions for several new ELCC-related terms, such as Accredited UCAP, Combination Resource, Variable Resource, ELCC Resource, etc.

Revision 48 (05/26/2021):

- New paragraph in Section 8.4A to clarify treatment of Public Distribution Microgrid Generators that are Generation Capacity Resources for Non-Performance Assessment.
- PRD – Approved as per Docket Nos. ER21-1243--0000 and ER21-1243-001 on 4/28/2021, effective on 06/01/2021:
 - Removed reference to LSE from PRD Provider description (Section 1.2.3)
 - Revised PRD Provider description, changed PRD Credit recipient from LSE to PRD Provider (Section 3A.1)
 - Removed LSE-specific requirements for PRD (Section 3A.4.2)
 - Removed section 3A.4.2.1 - Verification of Retail Rate Structure with LSE
 - Removed reference to LSE (Section 3A.4.2.2)
 - Removed identification of LSE from registration requirement (Section 3A.5)
 - Changed PRD Credit recipient from LSE to PRD Provider (Section 9.4.4)

Revision 47 (01/27/2020):

- Conforming changes were made to the following sections to incorporate provisions of FERC's expanded MOPR order (EL16-49, EL18-178, ER18-1314) and Forward Net EAS order (EL19-58):
 - Section 3.3.2 Demand in RPM
 - Section 5.4.4 Sell Offer Caps
 - Section 5.4.5 Minimum Offer Price Rule (MOPR)
 - Section 8.8 Replacement Resources
 - Attachment A Glossary of Terms

Revision 46 (11/19/2020):

- Section 8.4A – Corrected effective date from 2021/2022 to 2020/2021 Delivery Year for when External Generation Capacity Resources that would have helped resolve the declared Emergency Action are included in a performance assessment in order to conform with the effective date in the OATT.

Administrative Change (06/23/2020):

- Updated manual ownership to Peter Langbein

Revision 45 (05/28/2020):

- Conforming revisions for FERC Order ER20-271-001 issued on February 28, 2020 to clarify that Price Responsive Demand (PRD) registration will not be considered in the calculation of a performance shortfall or bonus performance for a Performance Assessment Interval (PAI) when the PRD Curve associated with registration indicates a price point where no demand reduction is expected at the real-time LMP recorded during the PAI. (Section 3A.6.2A)
- Conforming revisions for FERC Order ER20-217-000 issued on December 30, 2019 to update certain rules and requirements for PRD to conform to rules and requirements for Capacity Performance resources.
 - Added prior to 2022/2023 Delivery Year, PRD Provider is subject to performance compliance during Maximum Emergency Events. Added effective with 2022/2023 Delivery Year, PRD Provider is subject to Non-Performance Assessment during the Delivery Year (Sections 3A.1, 3A.3, 3A.6, 3A.6.2, 8.4A, 9.1.9, and 9.4.2)
 - Deleted outdated provisions related to the Transition Period for PRD (Section 3A.2)
 - Added footnote that any PRD Plan submitted and approved for 2022/2023 Delivery Year BRA may be withdrawn or modified no later than 30 days prior to the commencement of the 2022/2023 Delivery Year BRA. (Section 3A.4.1)
 - Added that Zonal Scaling Factors for use in preparation of PRD Plans will be posted by PJM prior to the 2022/2023 Delivery Year. (Section 3A.4.1)
 - Added effective with 2022/2023 Delivery Year, the PRD Value for Zone/LDA provided in a PRD Plan is based on a Zonal/LDA Peak Load Contribution (PLC) value minus (the Zonal/LDA Firm Service Level (FSL) quantity times the loss factor). (Section 3A.4.2)
 - Added Expected Peak Load Value of PRD is submitted prior to 2022/2023 Delivery Year and Peak Load Contribution value of PRD is submitted effective with 2022/2023 Delivery Year. (Section 3A.4.2)

Revision 44 (12/05/2019):

- Conforming revisions for FERC Order ER19-2417 issued on September 16, 2019 that (1) enable Capacity Market Sellers to request removal of the Generation Capacity Resource Status and (2) require Capacity Market Sellers seeking an exception to the RPM must offer requirement on the basis that an existing Generation Capacity Resource is physically unable to satisfy the requirements of Capacity Performance (CP) to include a documented plan to become capable of participating in RPM.
 - Updated RPM Auction Timeline to include activities associated with removal of a resource from Capacity Resource status (Section 5.2)
 - Included the requirement to submit a documented plan showing steps that intend to pursue for a resource to become physically capable of satisfying the requirements of a CP Resource, and provide periodic updates on progress of such plan, effective with must-offer exception requests for the 2023/2024 Delivery Year (Section 5.4.1)

- Added new section “Removal of Generation Capacity Resource Status” to document the process to voluntarily request removal of a Capacity Resource from Generation Capacity Resource status (Section 5.4.7)
- Clarification updates to RPM must-offer exception process:
 - Clarified that timing is an acceptable reason for must-offer exception request (Section 5.4.1)
 - Clarified that sellers may specify multiple auctions in a written must-offer exception request (Section 5.4.1)
 - Added that a pending request to PJM for removal of Generation Capacity Resource status is an acceptable reason for early replacement (Section 8.8)

Revision 43 (12/03/2019):

- Conforming revision for FERC Order 841: Electric Storage participation (ER19-462) in Section 7.4 to address Energy Storage Resources not being allocated a Peak Load Contribution.

Revision 42 (07/25/2019):

- Periodic Review updated to address:
 - Corrections/Clarifications of Existing Provisions
 - Clarify Delivery Year applicability of Limited Resource Constraint, Sub-Annual Resource Constraint, Base Capacity Demand Resource Constraint, and Base Capacity Resource Constraint for FRR Alternative in Sections 2.4.3A, 2.4.3B and 5.3
 - Clarify treatment of Qualifying Transmission Upgrade once in service in Section 4.5
 - Clarify Behind the Meter Generation provisions in Sections 4.3.3 and 7.3.1
 - Correct Non-Performance Charge Rate in Sections 8.4A, 9.1.11 and 11.8.8
 - Clarify replacement capacity rules when remaining import capability into an LDA in Section 8.9
 - Add Aggregate Resource to list of capacity resources in Sections 4.1, 5.7.1 and Glossary
 - Clarify charges applicable to Owner in Authorization to Self-Schedule Capacity in Attachment B
 - Deletion of Outdated Provisions
 - Capacity Performance Transition IAs in Sections 1.5, 4.6.2, 4.6.6, 5.1, 5.8 and 5.9
 - Minimum Annual and Extended Summer Requirements in Sections 2.4.3, 2.4.4, 2.4.5, 3.5, 5.3, 5.7.2, 5.8.5, 5.9, 11.1.3, 11.3 and 11.8
 - EE adjustments for 2016/17 – 2018/2019 Delivery Years in Section 2.4.5

- Short-term Resource Procurement Target in Sections 3.3, 3.5, 5.1, 5.4.3, 5.8, 6.1, 7.2.2, 11.1.3 and Glossary
- Demand Response Legacy Direct Load Control Transition Provision in Sections 3.5 and 5.9
- Limited Resource Constraint and Sub-Annual Resource Constraint (when it relates to RPM Auctions) in Sections 3.5, 5.7.2, 5.8.5, and 5.9
- Product types (Limited DR, Extended Summer, and Annual) for RPM Auctions in Sections 4.1, 4.5, 4.6.2, 4.6.7, 4.6.8, 4.8.3, 5.5, 8.2.2, and 8.9
- Out-dated qualification requirements for generation resource prior to 2019/2020 Delivery Year in Section 4.2.3
- Legacy Direct Load Control Programs in Section 4.3.1
- Credit-Limited Offers in Section 4.8.4
- Coupled Sell Offers in Section 5.4
- Peak Season Maintenance Compliance in Sections 8.1, 8.6, 9.1.6, 9.1.8 and 11.8.5
- Load Management Event Compliance in Sections 8.1, 8.7, 9.1.9 and 11.8.6
- Non-Performance Assessment provisions for 2016/2017 – 2017/2018 Delivery Years in Sections 8.4A, 9.1.4 and 9.1.11
- Conforming Revisions for FERC Orders
 - OVEC Integration (ER18-459, ER18-460) in Section 2.3.1
 - Periodic Review of Variable Requirement Curve Shape and Key Parameters (Quadrennial Review) (ER19-105-001,002) in Sections 3.3 and 3.4
 - Energy Efficiency Resources Compliance with Authorized Relevant Electric Retail Regulatory Authority (RERRA) Rules to Opt-Out or Restrict Sales of EE Resources (ER18-870) in Sections 3.5, 4.4 and 5.9
 - Minimum Offer Price Rule Remand (ER13-535-005, 006) in Sections 5.2 and 5.4.5
 - FERC Order 841: Electric Storage Participation (ER19-462) in Section 5.4.1

Revision 41 (01/01/2019):

- Revisions for FERC Order ER19-244, accepted on December 31, 2018 and effective January 1, 2019, to amend Demand Resource registration rules and define a summer period and winter period nominated value for a Capacity Performance registration and to change the methodology used to determine the daily nominated capacity values for Capacity Performance Demand Resources.
- Revisions for FERC Order ER19-142, accepted on December 17, 2018 and effective December 17, 2018, to modify the definition of Winter Peak Load to exclude atypically low usage winter peak days from the calculation of Winter Peak Load.

Revision 40 (02/22/2018):

- Conforming revisions for FERC Order ER17-1138, accepted on November 17, 2017 and effective May 9, 2017 to implement enhancements to the rules for external capacity resources.

Revision 39 (12/22/2017)

- Revisions to Sections 4.3 (4.3.1, 4.3.5, & 4.3.10), 4.6 (4.6.6), 4.9, 4.10, 8.4, 8.4A, 8.7A, 8.8, 8.9, 9.1 (9.1.3, 9.1.4, 9.1.5, & 9.1.11), 11.3, and 11.8 (11.8.8 & 11.8.9) to accommodate sub-hourly settlements (FERC Order 825).

Revision 38 (07/27/2017)

- Revisions to Section 8.4A to describe that if energy offer does not comply with Manual 11, Section 2.3.7, then no MWs from generation resource will be exempt or considered for bonus performance during the Performance Assessment Hour.

Revision 37 (4/27/2017)

- Conforming revisions for FERC Order ER17-367 issued on March 21, 2017, to enhance aggregation rules, implement Seasonal Capacity Performance Resources, provide opportunity for Intermittent and Environmentally Limited Resources to request additional Capacity Interconnection Rights in winter, and modify measurement and verification rules for Demand Resources.

Revision 36 (12/22/2016)

- Revisions to include restrictions on early replacement of RPM capacity commitments as endorsed by MRC on 12/22/2016 (Section 8.9)

Revision 35 (11/17/2016)

- Revisions to remove the restrictions on early replacement of RPM capacity commitments as endorsed by MRC on 11/17/2016 (Section 8.9).

Revision 34 (07/28/2016)

- Revisions to clarifying the details of Auction Specific MW bilateral transactions (Section 4.6.6)

Revision 33 (06/30/2016)

- Revisions needed as a result of a Cover to Cover Periodic Review
- Revisions needed to clarify the implementation details of Capacity Performance

Revision 32 (04/01/2016)

- Conforming revisions for FERC Order ER16-873-000, accepted on 4/1/2016 and effective 4/1/2016 to eliminate the RRMSE requirement for Load Management registrations that will use a customer baseline to measure capacity compliance in non-summer periods.

Revision 31 (02/25/2016)

- Conforming revisions for FERC Order ER16-333, accepted on 12/22/2015 and effective 01/16/2016 to change (1) instances in which FRR Entities would not be required to meet the Percentage of Internal Resource Requirement, (2) circumstances in which an FRR Entity can terminate its five-year minimum commitment period, and (3) the FRR Alternative election dates for new FRR Entities (Sections 11.1.3 & 11.6).

Revision 30 (12/17/2015)

- Revisions to accommodate EE Resource participation in the PJM capacity market when the peak load forecast reflects energy efficiency measures (sections 2.4.5, 4.4, 8.7 & 11.2.1).

Revision 29 (10/16/2015)

- Revisions to Section 8.7, endorsed at the July 23, 2015 MRC meeting, to add provisions for replacement capacity transactions earlier than November 30th prior to start of Delivery Year when the owner of the replaced resource provides transparent and verifiable evidence to support the expected final physical position of resource at the time of the request.

Revision 28 (08/03/2015)

- Conforming revisions for FERC Order ER15-623 (i.e., Capacity Performance filing), accepted on 06/09/2015 and effective April 1, 2015 to better ensure that committed resources will perform when called upon to meet the reliability needs of the PJM Region.
- Conforming revisions for FERC Order ER15-1849, accepted on 7/23/15 and effective 8/3/15, to improve measurement and verification procedures for CSPs with Residential Demand Response Customers. Direct Load Control is re-defined as Legacy Direct Load Control and is only effective through May 31, 2016. Statistical sampling may be used instead of customer-specific compliance and verification information for residential customers without interval metering.

Revision 27 (01/22/2015)

- Conforming revisions for FERC Order ER14-2940, accepted on 11/28/2014 and effective 12/01/2014, to revise the shape of Variable Resource Requirement Curve, the gross Cost of New Entry values, and the methodology to determine Net Energy and Ancillary Services Revenue Offset and Net Cost of New Entry. (Sections 3.3.1, 3.3.2, 3.3.3, 3.4, & 3.4.1)

Revision 26 (01/01/2015)

- Conforming revisions for FERC Order ER15-134-000, accepted on 12/01/2014 and effective 01/01/2015, to allow Electric Distribution Companies to correct the Obligation Peak Load data up to 12 noon on the next business day after the Operating Day.

Revision 25 (10/30/2014)

- Conforming revisions for FERC Order ER11-2288-000, accepted on 01/31/2011 and effective 02/1/2011, to clarify the Annual DR Maintenance Outage process.

Revision 24 (07/31/2014)

- Revision to allow Auction Specific MW Transactions for a Delivery Year to be submitted following the completion of the RPM auction to which the transaction applies (Section 4.6.6).

Revision 23 (06/01/2014)

- Conforming revisions for FERC Order ER14-822, accepted on 05/09/2014, and effective on 06/01/2014 for various DR operational changes including: (i) requiring all Demand Resources participating in PJM's capacity market to serve as Pre-Emergency Load Response, unless the resource utilizes behind-the-meter generation that is subject to an environmental restriction; (ii) requiring, on a phased-in basis, that all Demand Resources reduce load reductions within 30 minutes of notification from PJM to the CSP, unless PJM has granted an exemption for a Demand Resource; (iii) limiting the duration of the required minimum load response reduction period from two hours to one hour; (iv) modifying measurement and verification for capacity compliance for all hours where PJM has dispatched the resource for at least 30 minutes of the wall clock hour; (v) modifying measurement and verification to allow aggregation of compliance results by compliance aggregation areas and provide further clarification on definition of "Load Management Event"; and (vi) CSP expected load reductions must be reported at more granular basis to include these changes. (Sections 4.3.1, 4.3.2, 4.3.4, 4.3.5, 4.3.6, 4.3.7, 4.3.9, 8.5, 8.5.1, and 8.5.2)
- Revision to include the ability to request an adjustment to the Nominated DR Value (in MWs) associated with an end-use customer site and used in the determination of a CSP's Existing MWs if certain criteria are satisfied. (Section 4.3.3)

Revision 22 (04/24/2014)

- Conforming revisions for FERC Order ER14-504, accepted on 01/30/2014, and effective on 01/21/2014 to retire the Minimum Annual Resource Requirements and Minimum Extended Summer Resource Requirements and implement Limited Resource Constraints and Sub-Annual Resource Constraints effective with the 2017/2018 Delivery Year. (Sections 2.4.3, 2.4.3A, 2.4.4, 3.5, 5.3, 5.6.2, 5.7.5, 5.8.1, 11.1.3, 11.3, 11.4.1, & 11.9.1)
- Confirming revisions for FERC Order ER14-503 to employ Capacity Import Limits for RPM Auctions effective with the 2017/2018 Delivery Year. (Sections 2.1.2, 2.2, 2.3, 2.3.4, & 5.8.1)
- Conforming revisions for hydro and pumped storage units to perform rating tests during summer verification window in accordance with PJM Manual 21, Rules and Procedures for Determination of Generating Capability, Revision 11, effective 03/05/2014. (Section 8.4.6)

- Clarifications to deficiency/penalty charge rates when committed capacity resources did not clear in any RPM Auctions (Sections 9.1.1, 9.1.3, 9.1.5, 9.1.6, 9.1.7, & 9.1.9)
- Revisions to permit the maximum credit requirement specified in a credit-limited sell offer to exceed the RPM Credit Limit of a resource when the RPM Credit Adjustment Factor of the resource is less than one (Section 4.8.4).

Revision 21 (01/30/2014)

- Revisions to include demand resource product substitution rules for a load management event (Section 8.5).

Revision 20 (11/21/2013)

- Conforming revisions for FERC Order ER12-513, accepted on 01/31/2013 and effective 01/31/2013, to update Gross CONE values for CONE areas, region-wide Gross CONE value, and Benchmark CONE values. (Section 3.3.1)
- Conforming revisions for FERC Order ER12-513, accepted on 01/30/2012 and effective 01/31/2012, to revise definition of peak-hour dispatch to provide for day-ahead energy market revenues to be considered in the determination of Energy & Ancillary Services revenues. (Section 3.3.2)
- Conforming revisions for FERC Order ER13-535, accepted on 05/02/2013 and effective 02/05/2013, to revise the Minimum Offer Price Rule. (Section 5.2 and 5.3.5)
- Conforming revisions for FERC Order ER13-2140, accepted on 10/10/2013 and effective 10/15/2013, to change the deadline for submission of must-offer exemption requests for resources that are expected to be deactivated prior to or during the relevant Delivery Year. (Section 5.2)
- Conforming revisions for FERC Order ER13-1023, accepted on 04/30/2013 and effective 05/01/2013, to correct the NEPA qualification calculation and allow NEPA contingent sell offers in Base Residual Auction. (Section 5.3.3)
- Revision to correct LSE's options to hedge Locational Reliability charges by offering and clearing resources in Base Residual Auction and Incremental Auctions. (Section 1.2.1)
- Removal of obsolete reference to information on Transition Period. (Section 1.4)
- Revisions to correct number of LDAs and RECO's relationship to parent LDA. (Section 2.3.1)
- Revisions to correct terminology from "Capacity Injection Rights" to "Capacity Interconnection Rights, the defined term in OATT. (Section 4.2.6)
- Revisions to correct indemnification provision for Unit-specific transactions for Cleared MWs to conform with current tariff language. (Section 4.6.2)
- Revisions to correct business rules regarding start and end dates of Auction Specific MW transactions to conform with current tariff language. (Section 4.6.6)
- Removal of obsolete ILR references (Sections 4.6, 7.1, 8.5, & Attachment A).

- Revisions to clarify bill timing for Peak Hour Period Availability Charges/Credits, Generation Resource Rating Test Failure Charges/Credits, and PSM Compliance Charges/Credits (Sections 9.1.2, 9.1.5, and 9.1.6)
- Revisions to clarify that factor for On-Peak Load Management Compliance Penalty Rate is based on number of on-peak events.(Section 9.1.9)

Revision 19 (06/01/2013)

- Revisions for EKPC integration (Section 2.3.1)
- Revisions for Load Reduction Reporting for Emergency Demand Response capacity resources (Section 4.3.9)

Revision 18 (3/18/2013)

- Proposed revisions for Demand Resource Sell Offer Plan Enhancements (Sections 4.3.1, 4.3.3, 4.3.6, and 11.4.7, Attachments C and D)

Revision17 (12/20/2012)

- Conforming revisions in Docket ER13-305-000 to add a Cleveland LDA (Section 2.3.1)
- Conforming revisions in Docket ER13-149-000 to incorporate task oriented deadlines to ensure timely submission of offer data, exception requests and unit-specific requests by market participants as well as timely responses thereto by PJM and the IMM
- Removal of language restricting replacement transactions on EE Resources with non-EE Resources (Section 8.7)
- Removal of ILR related content
- Removal of Transition Period (2007/08 – 2010/11 Delivery Year) related content
- Removal of pre-2012/13 Delivery Year-specific content
- Glossary updates

Revision 16 (09/27/2012)

- Conforming revisions for FERC Order ER11-4628 accepted on 12/14/2011 and effective 05/15/2012 to integrate Price Responsive Demand (PRD) in PJM Capacity Market.

Revision 15 (06/28/2012)

- Conforming revisions for FERC Order ER12-1372 accepted on 05/31/2012 and effective 06/01/2012, to clarify load management event and test compliance requirements related to sub-zonal and product-specific dispatch (Sections 4.3.1, 8.5, 8.5.2, 8.6, 9.1.7, and 9.1.9).
- Conforming revisions for FERC Order ER11-3322 conditionally accepted on 02/24/2012 and effective June 1, 2012, to implement a Demand Response Transition Provision (DR Capacity Transition Credit and Alternate DR Transition Credit) for the 2012/2013 through 2014/2015 Delivery Years (Sections 8.8 and 9.4).

- Conforming revisions for FERC Order ER12-513, accepted on 01/30/2012 and effective 01/31/2012, to revise point (a) on the VRR Curve (Section 3.4) and clarify New Entry Pricing provision (Section 5.3.3).
- Conforming revisions for FERC Order ER12-636, accepted on 02/16/2012, and effective 02/18/2012, to make corrections, clarifications identified as a result of the Quality Project Initiative including revisions for CTRs and ICTRs (Sections 5.8.3, 5.8.4, 6.1.1, 6.1.2, 6.1.3, 6.2, 6.3, 6.4, and 9.3.4) and removal of obsolete provisions for Single Customer LSE electing the FRR Alternative and the Unauthorized Load Transfer Charge (Section 11.2.3).
- Revisions to correct bill timing from monthly to weekly for Capacity Resource Deficiency Charges (Section 9.1.3), Locational Reliability Charges (Section 9.2.1), Auction Charges/ Credits (Sections 9.3.1 and 9.3.2), CTR and ICTR Credits (Section 9.3.4), Auction Specific MW Transaction Credits (Section 9.3.5), and ILR Credits (Section 9.3.6).

Revision 14 (02/23/2012)

- Conforming Revisions for FERC Order ER11-2287, accepted on 01/31/2011, and effective 01/31/2011 to revise the definition of an Existing Generation Resource for the purposes of must-offer and mitigation provisions (Section 1.2, 5.6.1, 5.7.1).
- Conforming Revisions needed to include updates to Installed Reserve Margin, Pool-wide average EFORD, Forecast Pool Requirement, CETO, and CETLs prior to Incremental Auctions and conform to Attachment DD of Open Access Transmission Tariff. (Sections 2.1.1, 2.1.3, 2.1.4, and 2.3)
- Conforming Revisions for FERC Order ER11-2287, accepted on 01/31/2011 and effective 02/01/2011 to establish three product alternatives (limited, extended summer, and annual) for demand resources seeking to participate in PJM's capacity market. (Sections 2.4.3, 4.3, 4.3.1, 4.3.2, 4.3.7, 5.3, 5.3.1, 5.4, 5.6.2, 5.7.5, 5.8.1, 8.2.2, 8.5, 8.5.1, 8.5.2, 8.6, 8.7, 9.1.7, 9.1.9, 11.1.3, 11.3, 11.9.1)
- Conforming Revisions for FERC Order ER11-3365, accepted on 6/6/2011 and effective 06/17/2011, to refine the calculations of the amount of capacity commitments that PJM seeks to procure or release in Incremental Auctions and the amount of Excess Committed Credits commencing with the 2012/2013 Delivery Year (Sections 3.5 and 8.7.2)
- Conforming Revisions for FERC Order ER05-1410-015, et al., accepted on 05/20/2010 to implement the use of an Updated VRR Curve Increment/Decrement in developing PJM Buy Bids/Sell Offers in Incremental Auctions (Section 3.5).
- Conforming Revisions for FERC Order ER12-125 accepted on 12/02/2011 and effective 12/19/2011 to clarify that PJM Emergency Load Response Registrations must be submitted to PJM no later than one day before the tenth business day preceding the relevant Delivery year, and must be approved on or before May 31st preceding the relevant Delivery Year (Section 4.3.7)
- Conforming Revisions for FERC Order ER10-1003, accepted on 05/05/2010, and effective 06/01/2010 to revise PJM's credit risk management rules for certain bilateral transactions

(unit-specific transactions for cleared capacity, Auction Specific MW transactions, and Locational UCAP transactions) (Sections 4.6.2, 4.6.6, and 4.6.7).

- Conforming Revisions needed to clarify the Auction Credit Rate and conform to Attachment Q of Open Access Transmission Tariff. (Section 4.8.3)
- Conforming Revisions for FERC Order ER11-2913, accepted on 4/13/2011 and effective 04/20/2011, to allow Credit-Limited Offers in RPM Auctions for planned resources (whether generation, demand resources, or energy efficiency) (Section 4.8.4).
- Conforming Revisions for FERC Order ER11-4143, accepted on 09/12/2011 and effective 06/01/2007, to correct time periods for critical peak periods for the assessment of Peak Hour Period Availability from eastern prevailing time (EPT) to local prevailing time (LPT) (Section 8.4).
- Conforming Revisions for FERC Order ER09-412, accepted on 03/26/2009, and effective 06/01/2009 to allow excess available capacity that satisfies all capacity resource obligations of a committed resource to serve as replacement capacity to offset potential peak hour period availability penalties. (Sections 8.4.5 and 8.4.5.1)
- Conforming Revisions for FERC Order ER10-2917, accepted on 10/29/2010, and effective 11/23/2010 to further clarify that PJM considers committed capacity first in determining net peak hour period capacity shortfalls in an LDA and then considers uncommitted, available capacity to adjust the net peak hour period capacity shortfall in an LDA only to extent necessary to mitigate or eliminate any availability shortfalls for committed capacity (Sections 8.4.5 and 8.4.5.1).
- Conforming Revisions for FERC Order ER12-271, accepted on 12/27/2011 and effective 12/30/2011, to modify the bill timing of the Demand Resource and ILR Compliance Penalty Charge such that charges are assessed and billed in two phases. (Section 9.1.9)
- Conforming Revisions needed to clarify Fixed Resource Requirement Alternative business rules in Section 11.3 and conform to Schedule 8.1 of the Reliability Assurance Agreement.
- Conforming Revisions for FERC Order ER11-2875 regarding MOPR (Section 5.3.5)

Revision 13 (11/17/2011)

- Revisions for DEOK integration (Sections 2.3.1, 2.3.4, 3.3.1, and Attachment B)

Revision 12 (05/25/2011)

- Confirming Revisions for FERC Order ER11-2898, accepted on 04/04/2011 and effective 04/18/2011, to include changes for:
 - Requirement to provide meter data on a 24-hour basis during the day on which a Load Management event or performance test occurs and for all hours during any other days as required by PJM to calculate load reduction
 - Avoiding double assessment of a penalty (penalty for both RPM Commitment Compliance and Load Management Event or Test Compliance) for a Demand Resource

- Modification to the load management retest rules
- Modification and clarification of the rules for use of Demand Resources as replacement capacity
- Confirming Revisions for FERC Order ER11-1909, accepted on 12/20/2010 and effective on 12/27/2010, to include a change to clarify the definition of an EE Resource to reflect that a project qualifying as an EE Resource is one installed at an end-use customer's retail site.
- Revisions to EFORD used for a generation resource in the initial evaluation of a FRR Entity's FRR Capacity Plan for a Delivery Year as approved by stakeholders at the MRC on August 5, 2010.

Revision 11 (04/28/2011)

- Revisions for ATSI integration (Sections 2.3.1, 2.3.4, 3.3.1, and Attachment B)

Revision 10 (06/01/2010)

- Revisions made to rules for Non Unit-specific Capacity Transactions to clarify that PJM will be the counterparty to all transactions, unless market participants expressly and mutually contract between themselves (or self schedule to themselves). Revisions have been approved at the Markets and Reliability Committee on April 21, 2010 and by FERC (Order ER10-1003 issued on May 5, 2010)
- (Reference: [FERC Order ER10-1003](#))

Revision 9 (03/01/2010)

- Clarifying Revisions
- Conforming Revisions for FERC Order ER10-15, accepted on 11/13/09 and effective 12/01/09, to include changes to Credit Rate Change
- Conforming Revisions for FERC Order ER09-1679 accepted on October 29, 2009 and effective November 1, 2009 to include changes for:
 - New Entry Pricing Adjustment
 - Removal of Existing EE and DR offer caps
 - Allocation of LM Test Failure Charges
 - Planned DR Deadline - change to 15 business days
 - Excess Commitment Credit for LSEs if cannot sell excess in IA
 - Reduction in FRR Obligation when Load Forecast is reduced
- Conforming Revisions for FERC Order ER05-1410 accepted on October 30, 2009 and effective 11/1/09 to include changes to Incremental Auctions design
- Conforming Revisions for FERC Order ER09-412 accepted on November 5, 2009 and effective November 13, 2009, to include changes to the trigger for a Conditional IA only for delay of Backbone Transmission Upgrade

- Conforming Revisions for ER09-1679 to include changes to Revisions for the automated adjustment to Net CONE
- Conforming Revisions for FERC Order ER10-366 accepted on January 22, 2010 and effective January 31, 2010, to include changes
- evaluate the method for creation of additional CONE regions
- Revisions to allow Energy Efficiency Resources to participate in Earlier Deliver Years
- RPM Incremental Auction Times

Revision 8 (01/01/10)

- Revisions approved by stakeholders at MRC on November 11, 2009
- One CSP Rule (Section 4, p 33)
- Permanent Load Departure (Section 8, p 98)
- Tracking Existing DR (Section 4, pp 30-31)
- Revisions approved by stakeholders at MRC on November 30, 2009 (awaiting FERC approval by February 1, 2010)
- Winter Capacity Test Exemption (Sections 4 & 8, pp 24, 27, 104-105)

Revision 7 (08/18/2009)

- Revision to Section 4 to modify business rules to state that RPM suppliers must confirm the modeling of each of their capacity resources (Zone, LDA, Unit Type, State Location) prior to any RPM auction.
- Revision to Section 5 to modify business rules to state that RPM Auction Results will not be posted until 4pm or later on Friday of Auction Clearing week.

Revision 06 (06/18/2009)

- Revisions to include business rules for Cleared Buy Bid and Locational UCAP transactions.
- Revisions required as a result of the March 26, 2009 FERC Order regarding Reliability Pricing Model

Revision 05 (10/03/2008)

- Revisions regarding Transmission Service for External Resources offering into RPM.

Revision 04 (06/08/2008)

- Incorporate Rules for Capacity Export Charge per FERC Order ER07-1050 (Effective May 30, 2008)

Revision 03 (04/01/2008)

- Established a Min and Max capacity value for Wind Resources offering into an RPM Auction.

Revision 02 (02/21/2008)

- Correct an error in the original posting of this Manual. Remove the word “not” in the End-Use Customer Aggregation section of Section 4 to reflect the fact that aggregation of Interruptible for Load (ILR) Resources is allowed.

Revision 01 (02/03/2008)

- Revisions made for the following changes:
 - Current, Minimum, Maximum Available Capacity Position Definitions.
 - Change Final Zonal RPM Scaling Factors posting date from October 31st to January 5th.
 - Allow for Combined Demand Resources and ILR Resources at the same location.

Revision 00 (06/01/07)

- Manual Created for the Implementation of the Reliability Pricing Model, and the Fixed Resource Requirement Alternative.

EXHIBIT 40

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

	)	
Federal Power Act Section 202(c)	)	Order No. 202-25-4
Emergency Order: PJM Interconnection	)	
And Constellation Energy	)	
	)	

Motion to Intervene and Request for Rehearing of
Natural Resources Defense Council, Citizens for Pennsylvania’s Future,
Environmental Defense Fund, Sierra Club and Public Citizen

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I. INTRODUCTION

Pursuant to section 313 of the Federal Power Act (“the Act”), 16 U.S.C. § 825l, Natural Resources Defense Council, Citizens for Pennsylvania’s Future, Environmental Defense Fund, Sierra Club, and Public Citizen (together “Public Interest Organizations”) request that the Department of Energy (“Department” or “DOE”) grant rehearing of Order No. 202-25-4 (May 30, 2025) (the “Order”).¹ Acting on its own motion and without providing notice, the Department issued the Order on May 30, 2025, pursuant to its emergency authority under section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c) (“Section 202(c)”), to instruct PJM Interconnection, LLC (“PJM”) and Constellation Energy Corporation (“Constellation”) to “take all measures necessary to ensure that” Units 3 and 4 of the Eddystone Generating Station, in Eddystone, Pennsylvania, (“Eddystone” or the “Eddystone Units”), remain “available to operate” until August 28, 2025, and further directed PJM to “take every step to employ economic dispatch” during that time period. Ex. 1 at 3. Prior to the Department’s eleventh-hour intrusion, Constellation was preparing to retire these two oil- and gas-burning units on May 31, 2025, with PJM’s approval.

The Department should grant rehearing and rescind this costly, harmful, unnecessary, and unlawful order. There is no energy emergency in the PJM region as defined by Section 202(c). The Eddystone Units were scheduled to deactivate only following analysis showing that this would not cause any transmission

¹ A copy of the Order is attached as Exhibit 1.

instability and that replacement economic capacity resources were available. The result of the Department's overreach will be unnecessary costs imposed on already-overburdened ratepayers, needless pollution emitted into Pennsylvania and neighboring states, and unprecedented interference with regulation of grid resource adequacy, an area Congress reserved for other authorities. 16 U.S.C. § 824(b)(1).

The Order's emergency declaration cannot withstand even the mildest scrutiny. On its face, the Order fails to identify conditions necessary to invoke Section 202(c)'s extraordinary powers, which are reserved for sudden, imminent, and unexpected energy shortages.² The Order offers only selective quotes from PJM documents about potential future risks of shortages well outside the 90-day period covered by the Order. In fact, the cited documents refute the Department's conclusory assertions. Nor does the Order's reference to the "declared state of national energy emergency" cure the defect. Ex. 1 at 2. The vague, unsupported assertions in Executive Order ("EO") 14,156 *Declaring a National Energy Emergency* ("Energy Emergency EO")—belied by the U.S. Energy Information Administration's current data³—do not override Section 202(c), nor do they supply

² As the Department's own regulations emphasize, an "emergency," arises when there is an "unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities," due to weather, acts of God, "sudden" increases in demand, inability to obtain fuel, or a regulatory action prohibiting the use of certain facilities. 10 C.F.R. § 205.371. The Department makes no pretense of identifying these conditions as the bases for the Order.

³ Indeed, U.S. energy production and exports are currently at an all-time high: Energy Info. Admin., U.S. primary energy production, consumption, and exports increased in 2024 (June 20, 2025), <https://www.eia.gov/todayinenergy/detail.php?id=65524>.

the specific information needed to support issuance of this Order or any other Section 202(c) order. The Order also refers to EO 14,262 (*Strengthening the Reliability and Security of the United States Electric Grid*) (“Grid EO”), but that order merely directs the Department to develop an as-yet unpublished methodology to analyze grid reliability to support future 202(c) orders, and can’t be bootstrapped to supply a *post hoc* basis for this Order.

Even assuming there is an emergency under Section 202(c), the Order also fails to demonstrate that continued operation of the Eddystone Units is the action that “best meet[s] the emergency and serve[s] the public interest.” 16 U.S.C. § 824a(c). The Order completely fails to address alternatives to continued operation of the Eddystone Units, including PJM’s contracted demand reserve programs,⁴ which ensure grid reliability at a lower cost even in the event of historically high demand peaks. Nor does the Order provide sufficiently clear instructions for Constellation and PJM, both as to plant operations and economic dispatch. And compounding these failures, the Order makes no effort to limit the environmental and public health harms that Eddystone imposes on the surrounding communities, despite explicit instruction from Congress to do so.

In short, the Order is an unlawful abuse of the Department’s emergency authority and should be rescinded. The statutory bases for issuing an order under

⁴ See PJM Interconnection, PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing Risk, Inside Lines (May 9, 2025), <https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/> (hereinafter “Summer Outlook 2025”).

Section 202(c) are not present; and even if they were, the Order would still be unlawful because it fails to comply with the substantive requirements of Section 202(c), resulting in a twofold blow to PJM ratepayers: higher rates and more pollution with no net benefit received. The Department is authorized only to use Section 202(c) for real emergencies, not to usurp authority for grid reliability planning and to prop up fossil fuel businesses.

II. STATEMENT OF ISSUES AND SPECIFICATION OF ERROR

The undersigned Public Interest Organizations move to intervene and request rehearing and a stay pursuant to section 313(a) of the Federal Power Act, 16 U.S.C. § 825(a), and the applicable rules of practice and procedure,⁵ based upon the following errors and issues:

- The order exceeds the Department's authority because it has not, and cannot, demonstrate an unexpected emergency under Section 202(c) necessitating continued operation of Eddystone. 16 U.S.C. § 824a(c).
- Section 202(c) only authorizes the Department to respond to specific, imminent, unexpected, and temporary events, not to mandate generation based on longer-term reliability concerns. 16 U.S.C. § 824a(c); H.R. Rep. No. 114-357 § 61002 (2015); *Jarecki v. G.D. Searle & Co.*, 367 U.S. 303 (1961); *Richmond Power & Light of City of Richmond, Ind. v. FERC*, 574 F.2d 610

⁵ U.S. Dep't of Energy, DOE 202(c) Order Rehearing Procedures, <https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures> (last visited June 18, 2025) (attached as Ex. 2) (hereinafter "DOE Rehearing Procedures"). This website was altered after June 18, 2025, and the procedures were removed.

Compare

<https://web.archive.org/web/20250604093213/https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures> with the current website. *See also* Ex. 3 (Email from Lot Cooke, U.S. Dep't of Energy to Linda Alle-Murphy Re: Rehearing procedures for DOE Order No. 202-05-3 (December 28, 2005)) (recommending that "a party seeking rehearing can look for procedural guidance to [Federal Energy Regulatory Commission's ("FERC")] Rules of Practice and Procedure, 18 CFR Part 385.").

(D.C. Cir. 1978); S. Rep. No. 74-621 (1935); 16 U.S.C. § 824a(a) & (b); *Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232 (8th Cir. 1970); 16 U.S.C. § 824o; 70 Fed. Reg. 53,117; S. Rep. No. 109-78 (2005); *Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009); 16 U.S.C. § 824o(c)-(d); 16 U.S.C. § 824o(a)(3); 16 U.S.C. § 824o(d)(2)-(4); 16 U.S.C. § 824o(e); 16 U.S.C. § 824o(i)-(j); *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120 (2000); *Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395 (D.C. Cir. 2004); 10 C.F.R. § 205.371; 10 C.F.R. § 205.375; 46 Fed. Reg. 39,984; *FTC v. Bunte Brothers, Inc.*, 312 U.S. 349 (1941).

- There is no factual basis supporting the Department's Order. 16 U.S.C. § 824a(c); 10 C.F.R. § 205.371; *Biden v. Nebraska*, 600 U.S. 477 (2023); S. Rep. No. 94-1168 (1976); 1976 U.S.C.C.A.N. 2288; 16 U.S.C. § 824o-1; 16 U.S.C. § 809; 16 U.S.C. § 824a; 50 U.S.C. § 1631; Executive Order 14,156, Declaring a National Energy Emergency, 90 Fed. Reg. 8,433 (Jan, 20, 2025); 42 U.S.C. § 7172; 5 U.S.C. § 706(2)(A); 10 C.F.R. 205.375; *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260 (2016); *Dep't of Homeland Sec. v. Regents of the Univ. of California*, 140 S. Ct. 1891 (2020); Order Accepting Tariff Revisions Subject to Condition, 190 FERC ¶ 61,088 (2025); *Youngstown Sheet & Tube Co. v. Sawyer*, 343 U.S. 579 (1952); *Dept. of Com. v. New York*, 588 U.S. 752 (2019); *Motor Vehicle Mfrs. Ass'n of the U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983); *Amerijet Int'l, Inc. v. Pistole*, 753 F.3d 1343 (D.C. Cir. 2014); *D.C. Fed'n of Civic Ass'ns v. Volpe*, 459 F.2d 1231 (1971).
- The Order will undermine competitive markets to the detriment of consumers and reliability. Executive Order 14,156, Declaring a National Energy Emergency, 90 Fed. Reg. 8,433 (Jan, 20, 2025); 16 U.S.C. § 824a(c); 16 U.S.C. § 824d; Order Terminating Rulemaking Proceeding, Initiating New Proceeding, And Establishing Additional Procedures, 162 FERC ¶ 61,012 (2018); Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996); Order No. 888-A, FERC Stats. & Regs. ¶ 31,048; Order No. 888-B, 81 FERC ¶ 61,248 (1997); Order No. 888-C, 82 FERC ¶ 61,046 (1998); *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000); *New York v. FERC*, 535 U.S. 1 (2002); Order No. 890, FERC Stats. & Regs. ¶ 31,241 (1997); Order No. 2000, FERC Stats. & Regs. ¶ 31,089 (1999); Order 787, 145 FERC ¶ 61,134 (2013); Order 809, 151 FERC ¶ 61,049 (2015); Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, 149 FERC ¶ 61,145 (2014); Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and EOP-012-1 and Directing Modification of Reliability Standard EOP-012-1, 182 FERC ¶ 61094 (2023); Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification, 187 FERC ¶ 61,204 (2024); Order Accepting Tariff Revisions Subject to Condition, 186 FERC ¶ 61,080 (2024).

- Even if there were a short-term need—there is not—the Order does not comply with the statutory command to set terms that best meet the emergency and serve the public interest. 16 U.S.C. § 824a(c)(1); *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208 (2009); *Sierra Club v. Env't. Prot. Agency*, 353 F.3d 976 (D.C. Cir. 2004); *Dep't of Homeland Sec. v. Regents of the Univ. of Calif.*, 591 U.S. 1 (2020); *Motor Vehicle Mfrs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983); *Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200 (D.C. Cir. 2013); *Chamber of Com. of the U.S. v. Secs. & Exch. Comm'n*, 412 F.3d 133 (D.C. Cir. 2005); 10 C.F.R. § 205.370; 16 U.S.C. § 824a(c); 10 C.F.R. § 205.373; *Wabash Valley Power Ass'n*, 268 F.3d 1105 (D.C. Cir. 2001); *Gulf States Utils. Co. v. Fed. Power Comm'n*, 411 U.S. 747 (1973); *California v. Fed. Power Comm'n*, 369 U.S. 482, 484–86 (1962); *NAACP v. Fed. Power Comm'n*, 425 U.S. 662 (1976); *Otter Tail Power Co. v. United States*, 410 U.S. 366 (1973); *Pa. Water & Power Co. v. Fed. Power Comm'n*, 343 U.S. 414 (1952); 46 Fed. Reg. 39,985.
- Because the order is ambiguous, it fails to provide fair notice to the public and regulated entities and conflicts with limitations on the Department's authority. *Fed. Commc'ns Comm'n v. Fox Telev. Stations, Inc.*, 567 U.S. 239 (2012); *Grayned v. City of Rockford*, 408 U.S. 104 (1972); 16 U.S.C. § 824a(c); *Allentown Mack Sales & Serv., Inc. v. N.L.R.B.*, 522 U.S. 359 (1998).
- The Order fails to provide the conditions necessary to override environmental standards under Section 202(c)(2). 16 U.S.C. § 824a(c)(2); *City of New Orleans v. FERC*, 67 F.3d 947 (D.C. Cir. 1995); *Fla. Power & Light Co. v. FERC*, 88 F.3d 1239 (D.C. Cir. 1996); 68 Fed. Reg. 1660.
- The Order and the Department's continued conduct are inconsistent with departmental procedure, depriving the public and the Public Interest Organizations of fair Notice and an adequate record. *Morton v. Ruiz*, 415 U.S. 199 (1974); *Mine Reclamation Corp. v. FERC*, 30 F.3d 1519 (D.C. Cir. 1994); *United States v. Nova Scotia Food Prods. Corp.*, 568 F.2d 240 (2d Cir. 1977).

III. INTERVENORS' INTERESTS

As further discussed below, each of the Public Interest Organizations has interests that may be directly and substantially affected by the outcome of this proceeding. Each party may therefore intervene in this proceeding. DOE Rehearing Procedures; *see also* 18 C.F.R. § 385.214.

Each of the Public Interest Organizations also demonstrate a concrete injury arising from the Order that is redressable by a favorable outcome. Each organization is therefore aggrieved by the Order and may properly apply for rehearing. *See* 16 U.S.C. § 8251(a); *Wabash Valley Power Ass'n, Inc. v. FERC*, 268 F.3d 1105, 1112-13 (D.C. Cir. 2001); *NextEra Energy Res. v. ISO New Eng., Inc.*, 157 FERC ¶ 61,059, at P 5 (2016).

A. Natural Resources Defense Council

Natural Resources Defense Council (“NRDC”) is a national non-profit membership organization whose mission includes ensuring the rights of all people to clean air, clean water, and healthy communities. NRDC has a longstanding organizational commitment to protect the interests of its members and to reducing pollution caused by fossil fuel fired power plants such as Eddystone. NRDC works to achieve clean energy solutions that will lower consumer energy bills, meet greenhouse gas emission reduction goals, accelerate the use of energy efficiency and renewable energy, and ensure that clean energy is affordable and accessible to all.

NRDC and its members are aggrieved by the Order. Over 19,800 NRDC members reside in Pennsylvania, over 1,500 NRDC members reside in Delaware, over 9,600 NRDC members reside in Maryland, and 12,600 NRDC members reside in New Jersey. Of these, approximately 1,300 members reside within ten miles of the Eddystone Units. These NRDC members are harmed by the order to operate Eddystone beyond its planned retirement date because continued operation will subject NRDC members to air and water pollution in the areas where they live, work, and recreate. NRDC members are also exposed to the noise and visual

impacts of the plant's operation. The impact of the Order on the health, aesthetic, and recreational interests of NRDC members is compounded by the Order's failure to address the Federal Power Act's requirements for environmental protection that apply even in true emergencies (discussed in section V.G. below). In addition, NRDC members are ratepayers in the PJM region who will be subject to higher electric bills as a result of the Order. NRDC also operates an office in Washington D.C., which is in the PJM region. NRDC pays for the electricity used by its Washington D.C. office and will be subject to higher electric bills as a result of the Order. Moreover, NRDC has a sustainable operations plan with a goal of reducing net creation of greenhouse gas emissions derived from building operational activity to zero. NRDC and its members therefore have a strong interest in promoting actions that displace less cost-effective fossil generation with more cost-effective clean energy.

B. Citizens for Pennsylvania's Future

Citizens for Pennsylvania's Future ("PennFuture") is a Pennsylvania-based statewide environmental organization dedicated to leading the transition to a clean energy economy in Pennsylvania and beyond. PennFuture has approximately 1,000 members across the state. PennFuture's mission is to protect our air, water, and land, and to empower citizens to build sustainable communities for future generations. One focus of PennFuture's work is to address the climate-warming pollution from Pennsylvania's power fleet. PennFuture also works to advance understanding and recognition of Pennsylvania's Environmental Rights Amendment, contained in Article 1, Section 27 of Pennsylvania's Constitution and

to ensure that Commonwealth entities meet their obligations under the Amendment as trustees of Pennsylvania's public natural resources. To promote affordable and clean energy, PennFuture advocates before government entities, including local, state, and federal agencies such as FERC, on issues related to electricity markets, policies affecting the clean energy transition, and just and reasonable rates. This proceeding raises issues which are important to the environmental, public health, and affordability interests that PennFuture seeks to advance.

C. Environmental Defense Fund

The Environmental Defense Fund ("EDF") is a nonprofit membership organization with hundreds of thousands of members nationwide, including more than thirteen thousand members in Pennsylvania, whose mission is to build a vital Earth for everyone by preserving the natural systems on which all life depends. Guided by expertise in science, economics, law, and business partnerships, EDF seeks practical and lasting solutions to address environmental problems and protect human health, including in particular by addressing pollution from the power sector. On behalf of its members, EDF works with partners across the private and public sectors to engage in utility regulatory forums at the federal level and throughout the United States to advocate for policies that will create an affordable, reliable, and low pollution energy system. The Order harms EDF members because it will result in increased pollution that will impact the health of people and nature and because it will increase energy costs for EDF members throughout the PJM region.

D. Sierra Club

Sierra Club and its members are aggrieved by the Order. Over 55,000 Sierra Club members reside in Pennsylvania and New Jersey; and over 4,000 of those members reside in one of the four counties most likely to be impacted by pollution from Eddystone. Sierra Club members are harmed by pollution produced by operating the Eddystone Units. The Order to operate the plant beyond its planned retirement date will subject Sierra Club members to additional air pollution in the areas where they live and recreate. The Order's impact on the health, aesthetic, and recreational interests of Sierra Club members is heightened by the Order's failure to address the Federal Power Act's requirements for environmental protection that apply even in true emergencies. In addition, Sierra Club operates multiple offices in the PJM region, and has well over 100,000 members living in the PJM region, all of whom will be subject to higher electric bills as a result of the Department's Order.

E. Public Citizen

Established in 1971, Public Citizen is a national, not-for-profit, non-partisan, research and advocacy organization representing the interests of household consumers. Public Citizen has over 500,000 members and supporters across the United States, including in PJM and Pennsylvania. Public Citizen is active before FERC promoting just and reasonable rates, and supporting efforts for utilities to be accountable to the public interest. Public Citizen's interests in this proceeding are unique, and cannot be represented by any other party.

IV. BACKGROUND

A. Constellation Energy Group and the Eddystone Plant

The Eddystone Generating Station is owned and operated by Constellation. It is a six-unit, 820 megawatt (“MW”) power plant located along the banks of the Delaware River in Eddystone, Pennsylvania, just south of Philadelphia and in the PJM regional transmission organization (“RTO”).⁶ Units 3 and 4 are both 380 MW capacity steam boiler-turbine generator units that can run on either natural gas or distillate fuel oil. These units were installed between 1967 and 1970 and are “peakers,” i.e., units that run only during periods of high demand. The plant also includes two smaller pairs of oil fueled peaking units—Units 10, 20, 30, and 40—which have a total combined capacity of 60 MW that were also installed between 1967 and 1970. Eddystone Units 1 and 2, which operated on coal, were both closed over ten years ago. As shown in Table 1 below, Eddystone Units 3 and 4 have each operated less than 1% of the time during the last four years. In Pennsylvania’s restructured utility market, generation units like Eddystone are not committed to serve customers of a particular utility; rather, Constellation submitted offers into regional markets for services that Eddystone was eligible to provide and generated energy or provided other services when those offers were selected by the market mechanism.

⁶ Constellation, Eddystone Generating Station, <https://www.constellationenergy.com/our-company/locations/location-sites/eddystone-generating-station.html> (last visited June 20, 2025).

Table 1						
Capacity Factor	2020	2021	2022	2023	2024	Average
Capacity Factor	0.18%	0.25%	0.27%	0.40%	0.92%	0.40%
Sources: EIA, <i>Form EIA-923: Power Plant Operations Report, Net Generation Data for Eddystone Generating Station, 2020–2023</i> , https://www.eia.gov/electricity/data/eia923/ (accessed June 20, 2025); EPA, <i>CEMS Gross Load Data for Eddystone Generating Station, 2020–2023</i> , CAMPD, https://campd.epa.gov/ (accessed June 20, 2025) (2024 capacity factor estimated using average gross-to-net ratio from 2020–2023).						

The Eddystone Units are located just outside of Chester, Pennsylvania, a community that faces one of the nation’s worst cases of environmental racism.⁷ Whenever it is operating, Eddystone contributes to the pollution impacting this community. On a yearly basis, Eddystone emits thousands of tons of criteria air pollutants, *see* Table 2, and large amounts of water pollutants.⁸ And when Eddystone operates on oil rather than natural gas, it emits higher levels of both criteria pollutants and hazardous air pollutants.⁹ These air pollutants are linked to

⁷ *See* Chester Residents Concerned for Quality Living, <https://chesterpaej.org/> (last visited June 26, 2025); University of Pennsylvania, Perelman School of Medicine, Center of Excellence in Environmental Toxicology, *Chester*, <http://ceet.upenn.edu/community/target-communities/chester/> (last visited June 26, 2025).

⁸ EPA, Pollutant Loading Report, https://echo.epa.gov/trends/loading-tool/reports/dmr-pollutant-loading?permit_id=PA0013714&year=2024 (last visited June 26, 2025) (including over 2 million pounds of total suspended solids, and over 25,000 pounds of ammonia, as well as 1,617 pounds of copper and 564 pounds of lead, in 2024 alone).

⁹ Ex. 4 (Eddystone Title V Permit) at 28, 50 (noting sulfur content of oil and higher NOx emissions from oil-fired generation); 68 Fed. Reg. 1660,1678 (Jan. 13, 2003) (noting that switching from oil to natural gas “would reduce mercury, metallic [toxics], and inorganic” hazardous air pollutant emissions).

respiratory symptoms like asthma,¹⁰ cancer, reproductive difficulties, and other health problems.¹¹

Table 2						
Annual Emissions	2020	2021	2022	2023	2024	Cumulative Emissions
CO ₂ (tons)	11,167	14,943	18,636	28,332	58,566	131,644
NO _x (lbs)	11,918	15,488	20,506	29,606	59,232	136,750
SO ₂ (lbs)	128	176	234	322	704	1,564
Source: EPA, <i>Annual Emissions Data for Eddystone Generating Station, 2020–2024</i> , available at CAMPD, https://campd.epa.gov/ (accessed June 20, 2025).						

On December 1, 2023, Constellation notified PJM of its intent to deactivate Eddystone Units 3 and 4 effective May 31, 2025.¹² In that letter, Constellation explained that it was “retiring Eddystone Units 3 and 4 because continued operation of these units is expected to be uneconomic.”¹³ Such a notice triggers PJM’s process under Section 113.2 of its Open Access Transmission Tariff to study whether the deactivation will cause any reliability violations. In February 2024, PJM sent a letter to Constellation indicating that it had completed its study and no

¹⁰ EPA, Effects of NO₂, Health Effects, <https://www.epa.gov/no2-pollution/basic-information-about-no2#:~:text=Health%20effects,more%20about%20Visibility%20and%20Haze;https://www.epa.gov/so2-pollution/sulfur-dioxide-basics> (last visited June 26, 2025).

¹¹ EPA, Health and Environmental Effects of Hazardous Air Pollutants, <https://www.epa.gov/haps/health-and-environmental-effects-hazardous-air-pollutants> (last visited June 26, 2025).

¹² Letter from Bryan Hanson, Constellation, to Michael Bryson, PJM (Dec. 1, 2023), <https://www.pjm.com/-/media/DotCom/planning/gen-retire/deactivation-notices/eddytone-deactivation-letter.pdf>.

¹³ *Id.*

reliability violations had been identified; PJM granted permission to deactivate “on May 31, 2025, or sooner if desired.”¹⁴

B. How PJM Ensures Resource Adequacy and Reliability

PJM serves as the grid operator for a region that spans all or part of 13 states and the District of Columbia.¹⁵ PJM has established rules and processes for maintaining grid reliability that meet both industry standards and the requirements of the FERC certified Electric Reliability Organization—the North American Electric Reliability Corporation (“NERC”)—including through ensuring resource adequacy. Electric utilities and other load-serving entities that have joined PJM comply with those rules and participate in those processes to maintain regional reliability. Many of the utilities in PJM own few or no generation assets and therefore rely substantially on PJM-run markets to procure both energy and other services that support the reliable operation of the grid.

PJM’s primary tool to maintain resource adequacy throughout the region, including the state of Pennsylvania, is its Reliability Pricing Model (“RPM”), commonly known as its capacity market, which is designed to ensure there is enough energy supply on the system to meet demand, especially during high-risk

¹⁴ Letter from Paul McGlynn, PJM, to Bryan Hanson, Constellation (Feb. 27, 2024), <https://www.pjm.com/-/media/DotCom/planning/gen-retire/deactivation-notice/pjm-response-letter-eddystone.pdf>.

¹⁵ PJM, About PJM, <https://www.pjm.com/about-pjm> (last visited June 20, 2025).

periods.¹⁶ The capacity market does not pay for energy itself but pays resources for the promise to make a given quantity of energy available for sale at any time over the course of one year (the contracted “delivery year”) upon demand of the grid operator.¹⁷ For each “delivery year,” which begins June 1, PJM determines the region’s “Reliability Requirement” and sub-regional reliability requirements for any “locational deliverability areas” that are transmission-constrained.¹⁸ PJM determines the Reliability Requirement based on a granular risk model of the system that reflects variability in consumer demand as well as the performance of all the supply resources on its system. The determination of the Reliability Requirement includes a forecast of the peak load and the addition of a reserve margin to account for uncertainties, in order to meet the reliability standard set out in PJM’s Reliability Assurance Agreement—i.e., a loss of load expectation (“LOLE”)

¹⁶ High risk periods are generally winter storms and hot summer days. *See Advanced Energy Mgmt. All. v. FERC*, 860 F.3d 656, 659-61 (D.C. Cir. 2017); *see also* PJM, PJM Capacity Market: Promoting Future Reliability, <https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/pjm-capacity-market-promoting-future-reliability-fact-sheet.pdf> (Jan. 25, 2025).

¹⁷ *See* PJM, Capacity Market (RPM) <https://learn.pjm.com/three-priorities/buying-and-selling-energy/capacity-markets.aspx> (last visited June 26, 2025); FERC, An Introductory Guide to Electricity Markets Regulated by the Federal Energy Regulatory Commission, https://www.ferc.gov/introductory-guide-electricity-markets-regulated-federal-energy-regulatory-commission#_ednref2 (last visited June 26, 2025).

¹⁸ PJM, Manual 18: PJM Capacity Market, Revision 57, at 26 (July 26, 2023), <https://www.pjm.com/-/media/DotCom/documents/manuals/archive/m18/m18v57-capacity-market-07-26-2023.pdf>.

no greater than one occurrence in ten years.¹⁹ The systemwide Reliability Requirement is the number of megawatts of capacity needed to ensure adequate reserve margins during high-risk periods; Local Reliability Requirements for constrained locational deliverability areas reflect the local capacity needed to ensure adequate reserve margins during high risk periods, when accounting for transmission constraints applicable to that area. Using the same granular risk model, PJM determines the capacity accreditation values for each supply resource on its system—these values represent the amount of capacity, in “unforced capacity” or “UCAP” terms that a resource may offer into the capacity market. Since 2024, PJM has determined these accreditation values using a marginal effective load carrying capability (“ELCC”) methodology, that assesses how much adding one additional megawatt of a particular generation type to the system increases the system’s ability to serve consumer demand.²⁰ A generator or demand response resource’s marginal ELCC value is expressed as a percentage—the unit can sell capacity equivalent to its nameplate capacity times that percentage. When PJM applied ELCC to oil and gas resources, the capacity accreditation values for these sources decreased from prior values, due to their historically poor performance

¹⁹ See *PJM Interconnection LLC*, 186 FERC ¶ 61,080, at P 2 (2024) (citing PJM Resource Adequacy Planning, 2022 PJM Reserve Requirement Study (Oct. 4, 2022)).

²⁰ *PJM Interconnection, L.L.C.*, 186 FERC ¶ 61,080 (2024) (approving PJM’s proposal to adopt use of ELCC methodology for capacity accreditation).

during extreme winter weather.²¹ In other words, PJM concluded that oil and gas resources such as Eddystone should be deemed to contribute less to capacity requirements than it previously had assumed.

For each delivery year, PJM conducts a series of auctions to procure commitments from supply resources to provide capacity—to be available to generate power (or curtail power in the case of demand response) when needed by PJM as the system operator. The primary event is the Base Residual Auction, typically held three years in advance of the delivery year. In this auction, supply resources submit offers for the price at which they are willing to sell the quantity of capacity that reflects their ELCC. Demand in the auction is represented by the Variable Resource Requirement Curve, which reflects the administratively determined price that, in PJM’s judgment, consumers should be willing to pay to attract sufficient supply to the auction. PJM constructs a supply curve from the sellers’ offers. Where this supply curve crosses the demand curve determines the quantity of capacity that will be obligated for the delivery year, as well as the clearing price that will be paid to all sellers that submitted offers at or below that price level.

Between the Base Residual Auction and the delivery year, PJM will conduct one or

²¹ Ex. 5, Affidavit of Adam Keech on Behalf of PJM Interconnection LLC in *PJM Interconnection, L.L.C.*, FERC Accession No. 20231013-5157 (Oct. 13, 2023) (PJM’s filing in the above docket) ¶ 9: “Winter Storm Elliott represents the fifth event where, ‘cold weather-related generation outages jeopardized bulk power system reliability,’” (citing FERC, NERC, and Regional Entity Joint Staff Inquiry, December 2022 Winter Storm Elliott Grid Operations: Key Findings and Recommendations, Federal Energy Regulatory Commission, 3 (Sept. 21, 2023), <https://www.ferc.gov/news-events/news/presentation-ferc-nerc-regional-entity-joint-inquiry-winter-storm-elliott>.)

more incremental auctions that allow additional capacity to be procured, or released if the load forecast declines relative to the three-year ahead forecast, and for suppliers to be relieved of their obligations or take on new ones.

In addition to these market mechanisms, RPM also includes a reliability backstop mechanism.²² As PJM’s Senior VP of Markets recently described it, this mechanism exists in part “to resolve reliability criteria violations caused by . . . lack of sufficient capacity committed through the Reliability Pricing Model auctions” and is “intended to guarantee that sufficient generation, transmission and demand response solutions will be available to preserve system reliability.”²³

Load-serving entities in PJM are utilities or competitive retail suppliers that have obligations to serve retail electricity consumers. PJM requires these load-serving entities to purchase an amount of capacity for each delivery year that corresponds to their peak-load contribution—the amount of electricity they serve consumers (the load) during specific times when demand is highest on PJM’s system.²⁴ Load-serving entities have two options for demonstrating compliance—they can either have capacity purchased on their behalf through the auction, or opt out of participation in the auction by meeting 100% of their obligations through a

²² See PJM Open Access Transmission Tariff, Att. DD, section 16 (Reliability Backstop), <https://agreements.pjm.com/oatt/5130>.

²³ Prefiled Statement of Adam Keech on Behalf of PJM Interconnection, L.L.C., FERC Docket No. AD25-7, at p. 6 n.7 (June 4, 2025), <https://www.ferc.gov/media/adam-keech-pjm-vice-president-market-design-and-economics>.

²⁴ PJM Reliability Assurance Agreement, Rate Schedule FERC No. 44, <https://www.pjm.com/pjmfiles/directory/merged-tariffs/raa.pdf>.

“Fixed Resource Requirement” plan. Most load-serving entities in PJM, including those that serve load in Pennsylvania, choose the prior option.

PJM is responsible for aspects of reliability beyond resource adequacy. For example, PJM maintains operational reliability of the system on a minute-to-minute basis through its use of security-constrained economic dispatch of generators and energy storage resources on its system.²⁵ In addition to paying generators for their actual production of electricity in response to PJM’s dispatch instructions, PJM also pays generators and storage providers for ancillary services. These services include operating reserves that remain available on short notice to respond to disturbances on the system, such as other generators unexpectedly dropping offline. Market participants utilize PJM’s Markets Gateway software system to submit information and otherwise participate in PJM’s energy and ancillary service markets.²⁶

Another tool that PJM has to maintain reliability and reduce energy costs for consumers is interregional transmission with its neighboring grid regions. As PJM’s President recently explained, PJM’s “strong interconnected ties with our neighbors have allowed us to facilitate exports to our neighbors in MISO

²⁵ PJM, Manual 11: Energy & Ancillary Services Market Operations, Revision 120, at 54 (2022), <https://www.pjm.com/-/media/DotCom/documents/manuals/archive/m11/m11v120-energy-and-ancillary-services-market-operations-05-25-2022.pdf>. See PJM, Understanding the Differences Among PJM’s Markets (2025), <https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/understanding-the-difference-among-pjms-markets.pdf>.

²⁶ See PJM, Markets Gateway, <https://www.pjm.com/markets-and-operations/etools/markets-gateway.aspx> (last visited June 26, 2025).

[Midcontinent Independent System Operator], TVA [Tennessee Valley Authority], Duke Energy-Carolinas and the Southwest Power Pool (SPP) during tight conditions” and “also enables us to import energy from our neighbors when our system is stressed.”²⁷ PJM incorporates some benefits from these interregional ties into its resource adequacy planning, which reduces the amount of capacity it must procure internally and thus lowers costs for consumers.²⁸

Moreover, to ensure the stability of the transmission system when generators deactivate, PJM requires generators to provide advance notice of such deactivations so that PJM can study the impacts and determine whether any system upgrades are needed to maintain the stability of the system upon deactivation. In some cases, these upgrades won’t be operational until after the generator’s planned deactivation date, in which case PJM will seek to retain the generator to operate under specific conditions through a Part V agreement, commonly known as a reliability-must-run agreement (“RMR”). The Eddystone units were studied under those provisions, and in February 2024, PJM reported that it “did not identify any reliability violations resulting from the proposed deactivation of the Eddystone Generating Units #3&4” and stated that “[b]ecause there are no reliability

²⁷ Testimony of Manu Asthana, President and CEO, PJM Interconnection, Before the Subcomm. on Energy of the H. Comm. on Energy & Com. 3 (Mar. 25, 2025), <https://docs.house.gov/meetings/IF/IF03/20250325/118040/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf>.

²⁸ Adria Brooks, et al., Resource Adequacy Value of Interregional Transmission at 49-50 (June 2025), https://cleanenergygrid.org/wp-content/uploads/2025/06/250610_RAValueInterregionalTx_Corrections.pdf.

violations associated with the deactivation of this generator...the generating unit may deactivate on May 31, 2025, or sooner if desired.”²⁹

PJM states retain authority that strongly influences resource adequacy, including authority to approve and site new generation and energy storage projects, and to incentivize the development and utilization of particular types of resources.³⁰ While some PJM states have retained traditional vertically integrated utilities, others—such as Pennsylvania—have restructured their utilities so that they no longer own generation facilities, and have introduced retail choice to permit end use consumers to purchase power from a load-serving entity other than their utility.³¹ Pennsylvania state utility regulators expressly rely on PJM’s markets to ensure resource adequacy,³² while also actively shaping those markets to prioritize

²⁹ Letter from PJM to Bryan C. Hanson, Constellation Re: Deactivation Notice for Eddystone Generation Units #3&4 at 1 (Feb. 27, 2024), <https://www.pjm.com/-/media/DotCom/planning/gen-retire/deactivation-notices/pjm-response-letter-eddystone.pdf>.

³⁰ See 16 U.S.C. § 824(b)(1) (reserving authority over generation facilities to the states); see also *Devon Power LLC et al.*, 109 FERC ¶ 61,154, P 47 (2004) (“Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.”).

³¹ Electricity Generation Customer Choice and Competition Act, Pa. Code Ch. 28. See also, Electric Choice, The Ultimate Guide to Pennsylvania Electricity Deregulation, [https://www.electricchoice.com/blog/guide-deregulation-pennsylvania/#:~:text=Pennsylvania%20decided%20in%20favor%20of,save%20\\$2.5%20billion%20every%20year](https://www.electricchoice.com/blog/guide-deregulation-pennsylvania/#:~:text=Pennsylvania%20decided%20in%20favor%20of,save%20$2.5%20billion%20every%20year) (last visited June 27, 2025).

³² See, e.g., Letter from Pennsylvania PUC to PJM Board of Managers 1, (July 7, 2021), <https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/20210706-pa-puc-letter-regarding-minimum-offer-price-rule.pdf> (“Pennsylvania was one of the first restructured states in PJM that embraced the

affordability.³³ Through a combination of market signals and state policies, Pennsylvania has added nearly 3.5 gigawatt (“GW”) UCAP of capacity, net of retirements, since 2015—the most of any state in PJM.³⁴

C. The Department’s May 30, 2025 202(c) Order and PJM’s June 13 Letter

On May 30, 2025, the Department issued the Order based on its “determin[ation] that an emergency exists in portions of the electricity grid operated by PJM due to a shortage of facilities for the generation of electric energy, resource adequacy concerns, and other causes.” Ex. 1 at 1. The Order provides a brief, general description of the “Emergency Situation” based primarily on PJM public statements and regulatory filings referring to a “growing resource adequacy concern” that PJM asserts will arise by the end of the decade due to exceptional load growth and a rate of new entry that is inadequate to replace resource

promise of competition in the wholesale generation market and then spent considerable time and effort developing a burgeoning retail electricity market built on the expectations and benefits of a properly functioning wholesale market.”); *see also* Comments of the Pennsylvania Public Utility Commission, Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, AD13-7-000 (Jan. 8, 2014), https://www.puc.pa.gov/General/pdf/FERC/DN_AD13-7-000.pdf.

³³ *See, e.g.*, Pa. PUC Dkt. No. M-2024-3051988 (hosting a technical conference and collecting extensive public comments regarding steps the PUC can take to ensure resource adequacy for retail customers), <https://www.puc.pa.gov/filing-resources/issues-laws-regulations/technical-conference-on-resource-adequacy/>; Pa. PUC, Technical Conference on Resource Adequacy, <https://www.puc.pa.gov/filing-resources/issues-laws-regulations/technical-conference-on-resource-adequacy/> (last visited June 26, 2025).

³⁴ Prefiled Statement of Manu Asthana on Behalf of PJM Interconnection, L.L.C., at 9, Table 2, Meeting the Resource Adequacy Challenge in RTOs/ISOs, FERC Dkt. No. AD25-7 (May 20, 2025) (Acc. No. 20250520-5173).

retirements. *Id.* The “declared state of national energy emergency” is also cited as a basis for the Department’s determination of an emergency. The Department asserts that the retirement of the Eddystone Units would “further decrease available dispatchable generation within PJM’s service territory” and therefore exacerbate these general issues. *Id.* at 2. The Order was effective immediately, expiring at 5:03 pm ET on August 28, 2025. *Id.* at 3.

Based on this determination, the Department orders Constellation to take all measures necessary to ensure that the Eddystone Units are available to operate and orders PJM to take steps to employ economic dispatch for the Units. *Id.* The Order includes various reporting requirements and instructs PJM and Constellation to file tariff revisions or waivers necessary to effectuate the order. *Id.*

The Order also requires PJM, by June 15, 2025, to provide the Department “with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with the public interest.” *Id.* PJM published the letter it provided to the Department on June 13, 2025.³⁵ That letter indicates that PJM has worked with Constellation to develop an Operations Memorandum setting out the circumstances in which Eddystone can be committed to run. In a summary of that Memorandum, PJM states that Constellation “will maintain active cost offers in Markets Gateway that

³⁵ Letter from Michael Bryson, PJM, to Secretary of Energy Christopher Wright, PJM Report in Compliance with Ordering Paragraph D of the Department of Energy’s May 30, 2025 Order No. 202-25-4 (June 13, 2025), <https://www.pjm.com/-/media/DotCom/documents/other-fed-state/20250613-doe-pjm-report-on-compliance-with-Eddystone-order-202-25-4.pdf>.

reflects the prevailing costs . . . to operate on gas or oil for both Eddystone 3 and 4, unless either fuel is unavailable or if the units are on a Planned, Maintenance or Forced outage,” but that “[t]he units will be shown as ‘unavailable’ until PJM operators direct the units” to operate “for reliability purposes.”³⁶ Those purposes include: (1) supporting the PJM system operation within established thermal, voltage, and stability limits, when these needs “cannot otherwise be met with available economically dispatched generating resources;” (2) system restoration needs; and (3) a Capacity Emergency, during which “PJM determines that the resources scheduled for an operating day are not sufficient to maintain the appropriate reserve levels for PJM.”³⁷

PJM’s June 13 letter to the Department expresses PJM’s “understanding that the Eddystone Units have been available to operate, consistent with the DOE Order, since the order’s issuance on May 30, 2025.”³⁸ It also states that “PJM and [Constellation] have coordinated, pursuant to existing generation outage coordination practices and procedures, outages needed by the Eddystone Units to ensure their operational availability consistent with the public interest.”³⁹ A Constellation’s spokesperson has publicly stated that, “we are working quickly to

³⁶ PJM, Eddystone 3 and 4 Unit Reporting and Commitment Process (June 12, 2025), <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/postings/20250612-eddystone-3-and-4-unit-reporting-and-commitment-process.pdf>.

³⁷ *Id.*

³⁸ *Id.*

³⁹ *Id.* at 3.

retain necessary staff and perform necessary maintenance to allow for safe and reliable operations this summer and beyond.”⁴⁰

V. REQUEST FOR REHEARING

A. The Order Exceeds the Department’s Authority Because It Has Not, and Cannot, Demonstrate an Unexpected Emergency Under Section 202(c) Necessitating Continued Operation of Eddystone.

Section 202(c) confers an extraordinary power; it permits the Department to command action from market participants and to do so freed from core procedural safeguards, jurisdictional boundaries, and substantive limitations that undergird the rest of the Federal Power Act. *See* 16 U.S.C. § 824a(c). It comes as no surprise, then, that when Congress granted this power, Congress narrowly tailored its use to extraordinary circumstances. Simply, the Order here exceeds the Department’s authority because this is not one of those extraordinary circumstances. There is no emergency within the meaning of Section 202(c).

The Order fails to meet the standards of Section 202(c) both because the Department does not demonstrate that any emergency currently exists and because the resource adequacy concerns it does describe are long-term concerns, that no one has even alleged, much less provided a credible projection, will ripen into actual supply shortages within the ninety-day term of the Order. As detailed *infra*, Section V.B, Section 202(c) provides the Department with a limited authority to

⁴⁰ Jon Hurdle, Aging Pennsylvania Power Plant to Keep Running after Trump Order on Eve of Shutdown, *Pennsylvania Capital-Star* (June 9, 2025), <https://penncapital-star.com/energy-environment/aging-pennsylvania-power-plant-to-keep-running-after-trump-order-on-eve-of-shutdown/>.

address immediate electric supply shortages to meet emergency conditions; it does not authorize the Department to address long-term energy system shifts by appointing itself the central planner and supplanting the decisions of participants in an organized electric market. Yet here, even though the Department claims that the “Order is limited in duration to align with the anticipated emergency circumstances,” Ex. 1 at 2, the Department offers no evidence of an emergency in the specified period. The Order speaks only of “growing resource adequacy *concern*,” resource adequacy constraints that “*could* exist,” and the “increasing risk of reliability risk in *the coming years*.” Ex. 1 at 1 (emphasis added).

In fact, the results of the 2025-2026 Base Residual Auction demonstrate that the PJM grid has more than enough committed capacity to offer reliable service throughout Summer 2025 without the need for the Eddystone Units, and even if there were to be supply shortages, PJM has mechanisms to handle them.⁴¹ Furthermore, PJM has rules and processes in place to ensure long-term reliability even as shifts occur in electric demand and resource availability, and has access to a number of both short-term and long-term tools that are better suited to address long-term resource adequacy concerns than an unlawful Section 202(c) Order.⁴²

⁴¹ Summer Outlook 2025, *supra* n. 4.

⁴² PJM Interconnection, LLC, PJM Capacity Market: Promoting Future Reliability (2025), <https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/pjm-capacity-market-promoting-future-reliability-fact-sheet.pdf>.

B. Section 202(c) Only Authorizes the Department to Respond to Specific, Imminent, Unexpected, and Temporary Events, Not to Mandate Generation Based on Longer-Term Reliability Concerns.

The plain language and structure of Section 202(c), the legislative history for the provision, the Federal Power Act overall, as well as case law interpreting Section 202(c), the Department's regulations, and its historic use of Section 202(c) all establish that an "emergency" under Section 202(c) must be sudden, unexpected, imminent, and specific.

1. Section 202's Text and Structure Establish that Emergency Authority Can Only Be Invoked to Address Imminent, Certain Supply Shortfalls Requiring Immediate Response.

Section 202(c)'s text and context confirm that it provides only authority to address imminent, near-term, and exigent electricity supply shortfalls requiring immediate response; it does not permit the Department to act based merely on concerns over long-term reliability. Had Congress intended to vest regulatory authority over long-term reliability in Section 202(c), it would have stated so clearly. But it did not.⁴³

The statute's text empowers the Department to act only upon "emergency." 16 U.S.C. § 824a(c). The statute itself does not define "emergency." At the time Congress enacted Section 202(c), Webster's New International Dictionary of the English Language (1930) defined "emergency" as a "*sudden or unexpected*

⁴³ Congress amended Section 202(c) in 2015, but it did not alter the description of conditions that trigger the Department's grant of authority to issue emergency orders; it only addressed occasions on which a Department order might produce a conflict with other laws. *See* H.R. Rep. No. 114-357 § 61002 (2015).

appearance or occurrence... An *unforeseen* occurrence or combination of circumstances which calls for *immediate* action or remedy; *pressing* necessity; exigency.” (emphasis added).⁴⁴ Contemporary dictionaries similarly define “emergency” as demanding imminence: an emergency is “an *unforeseen* combination of circumstances or the resulting state that calls for *immediate* action.”⁴⁵

The remainder of Section 202(c) underscores the exigency inherent in the governing term “emergency”: the authority granted by Section 202(c) is, in the first instance, a wartime power. 16 U.S.C. § 824a(c) (beginning with “[d]uring the continuance of any war in which the United States is engaged”); *see Jarecki v. G.D. Searle & Co.*, 367 U.S. 303, 307 (1961) (noting that statutory terms should be interpreted in the context of nearby parallel terms “in order to avoid the giving of unintended breadth to the Acts of Congress”). An “emergency” under the statute is limited to circumstances of similar urgency: “a *sudden* increase in the demand for electric energy,” for example. 16 U.S.C. § 824a(c) (emphasis added); *see Richmond Power & Light of City of Richmond, Ind. v. FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978) (holding that Section 202(c) “speaks of ‘temporary’ emergencies, epitomized by wartime disturbances”); S. Rep. No. 74-621, at 49 (1935) (explaining that Section

⁴⁴ *See also* 3 Oxford English Dictionary 119 (1st ed. 1913) (defining emergency similarly as “a state of things unexpectedly arising, and urgently demanding immediate action” (emphasis added)).

⁴⁵ *Emergency*, Merriam-Webster Dictionary, <https://www.merriam-webster.com/dictionary/emergency> (last visited June 27, 2025) (emphasis added)); *See also* Benjamin Rolsma, The New Reliability Override, 57 Conn. L. Rev. 789, 812 n.147 (2025) (noting that dictionaries have given the term “emergency” the “same meaning for many years”).

202(c) provides “temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose”).

The text’s use of the present tense also underscores that focus on imminent and certain shortfalls: it empowers the Department to act only where “an emergency *exists*.” 16 U.S.C. § 824a(c) (emphasis added). That near-term focus, along with the statute’s strictly “temporary” authority, 16 U.S.C. § 824a(c), precludes use of Section 202(c) to pursue long-term policy goals, such as a preference for a particular fuel source. *Richmond Power & Light*, 574 at 615 (Section 202(c) “is aimed at situations in which demand for electricity exceeds supply and not those in which supply is adequate but a means of fueling its production is in disfavor.”).

Section 202’s overall structure further highlights Section 202(c)’s emphasis on imminent, near-term concerns. The preceding subsections 202(a) and (b) together define and limit the tools by which the federal government may pursue “abundant” energy supplies in the normal course. 16 U.S.C. § 824a(a) (seeking “abundant supply of electric energy” by directing the federal government to “divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy”) & § 824a(b) (allowing the federal government to order “physical connection . . . to sell energy or to exchange energy” upon application, and after an opportunity for hearing). The resulting statutory “machinery for the promotion of the coordination of electric facilities” comprises the following: in subsection (a), an

instruction to establish a general framework meant to facilitate “coordination by voluntary action;” in subsection (b), “limited authority to compel interstate utilities to connect their lines and sell or exchange energy,” subject to defined procedural and substantive requirements, when “interconnection cannot be secured by voluntary action;” and in subsection (c), “much broader” but “temporary” authority “to compel the connection of facilities and the generation, delivery, or interchange of energy during times of war or other emergency.” S. Rep. No. 74-621 at 49 (1935).

That tiered structure—relying on voluntary action for quotidian energy planning, specifying limited authority where that voluntary system fails, and allowing for “temporary” central command-and-control only in case of “emergency”—requires that Section 202(c) remain narrowly bounded to instances of an immediate and unavoidable “break-down in electric supply,” *id.*, rather than mere want of more abundant supply in the future, *cf.* Ex. 1 at 2 (imposing responsibility on PJM “to ensure maximum reliability on its system”). Interpreting Section 202(c)’s “emergency” powers to encompass longer-term concerns—e.g., potential shortfalls years into the future—would unwind the careful balance of voluntary, market-driven action and federal power set out in subsections 202(a) and 202(b). *See infra*, Section V.D. Such an interpretation cannot be squared with the statutory text and structure. *See Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232, 233-34 (8th Cir. 1970) (holding that Section 202(c) “enables the Commission to react to a war or national disaster,” while Section 202(b) “applies to a crisis which is likely to develop in the foreseeable future”).

2. Congress' Enactment of a Specific, Cabined Scheme to Address Reliability Concerns Confirms that Section 202(c) Cannot be Expanded to Impose Requirements Related to Long-Term Reliability.

That Section 202(c) cannot be used to enforce the Department's view of long-term reliability needs is confirmed by Section 215 of the Federal Power Act—which specifically and directly delineates the scope of federal power to enforce mandatory long-term reliability requirements. 16 U.S.C. § 824o (“Section 215”). Congress added Section 215 to the Federal Power Act in 2005 precisely because the Act as it then existed—including Section 202(c)—did not provide the federal government with the power to enforce measures designed to ensure broad, long-term reliability. *See* 70 Fed. Reg. 53,117, 53,118 (“In 2001, President Bush proposed making electric Reliability Standards mandatory and enforceable,” leading to enactment of Section 215 in 2005); Report of the National Energy Policy Development Group (May 2001) at p. 7-6⁴⁶ (noting that “[r]egional shortages of generating capacity and transmission constraints combine to reduce the overall reliability of electric supply in the country” and that “[o]ne factor limiting reliability is the lack of enforceable reliability standards” because “the reliability of the U.S. transmission grid has depended entirely on *voluntary* compliance,” and then recommending “legislation providing for enforcement” of reliability standards) (emphasis added); S. Rep. No. 109-78 at 48 (2005) (Section 215 “changes our current voluntary rules system to a mandatory rules system” for long-term reliability). *See Alcoa, Inc. v. FERC*, 564 F.3d 1342, 1344 (D.C. Cir. 2009) (noting that prior to the Energy Policy Act of 2005,

⁴⁶ <https://www.nrc.gov/docs/ml0428/ml042800056.pdf>.

“the reliability of the nation’s bulk-power system depended on participants’ voluntary compliance with industry standards”).

By enacting Section 215, Congress provided a comprehensive and carefully circumscribed scheme to empower the federal government to enforce long-term reliability requirements. That statutory scheme strikes a careful balance between state and federal authority, and between private, market-driven decisions and top-down control. Reliability standards are devised by NERC independent “of the users and owners and operators of the bulk-power system” but with “fair stakeholder representation.” 16 U.S.C. § 824o(c)-(d). *See also id.* 824o(a)(3) (defining reliability standards as “a requirement ... to provide for reliable operation of the bulk-power system”). FERC may approve or remand those standards (but not replace them with its own) and is required to “give due weight” to NERC’s “technical expertise” while independently assessing effects on “competition.” *Id.* § 824o(d)(2)-(4). Section 215 provides specified enforcement mechanisms and procedures for reliability standards. *Id.* § 824o(e). And it carefully preserves state authority over “the construction of additional generation” and in-state resource adequacy, establishing regional advisory boards to ensure appropriate state input on the administration of reliability standards. *Id.* § 824o(i)-(j).

Interpreting Section 202(c) to permit the Department to mandate generation based on its declaration that non-imminent reliability concerns create an “emergency” would effectively allow the Department to bypass Section 215’s procedural safeguards, constraints on federal authority, and protection of state

power. Such a bypass would impermissibly “contradict Congress’ clear intent as expressed in its more recent,” reliability-specific “legislation,” enacted “with the clear understanding” that the Department had “no authority” to address long-term reliability through Section 202(c). *See FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 142 & 149 (2000); *see also Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 401–02 (D.C. Cir. 2004) (“Congress’s specific and limited enumeration of [agency] power” over a particular matter in one section of the Federal Power Act “is strong evidence that [a separate section] confers no such authority on [agency].”). Congress has, in Section 215, directly established the mechanisms (and limitations) by which the federal government may compel action to ensure long-term electric-system reliability. In so doing, it has confirmed that the word “emergency,” in Section 202(c), does not extend to long-term reliability concerns.

3. Regulations Similarly Establish that Section 202(c) Emergency Authority Can Only Be Invoked to Address Imminent, Certain Supply Shortfalls Requiring Immediate Response.

The Department’s regulations demonstrate its own long-standing understanding that Section 202(c)’s authority is confined to imminent and unavoidable resource shortages, rather than long-term reliability concerns. The regulations define an emergency as “an *unexpected* inadequate supply of electric energy which may result from the *unexpected* outage or breakdown” of generating or transmission facilities—not a means of planning against distant expectations or risks. 10 C.F.R. § 205.371 (emphasis added). Emergencies “may result” from a number of events. *Id.* (“may result from the unexpected outage,” “may be the result of weather conditions,” “can result from a sudden increase in customer demand”).

The use of the verb “result,” defined as “arise as a consequence, effect, or conclusion,”⁴⁷ suggests that the event triggering the emergency has already happened rather than that there is a speculation that it could occur. Moreover, the events are characterized by those produced by “weather conditions, acts of God, or *unforeseen* occurrences not reasonably within the power of the affected ‘entity’ to prevent,” *id.* (emphasis added), not an event that can be planned for because there is a forecasted risk. Where the culprit is increased demand, it must be “a *sudden* increase in customer demand” producing a “*specific* inadequate power supply situation,” *id.* (emphasis added), rather than long-term demand projections producing general reliability concerns. The need for both specificity and certainty is repeated in the Department’s regulations defining an inadequate energy supply: “A system may be considered to have” inadequate supply when “the projected energy deficiency... *will* cause the applicant [for a 202(c) Order] to be unable to meet its normal peak load requirements based upon use of all of its otherwise available resources so that it *is* unable to supply adequate electric service to its customers.” 10 C.F.R. § 205.375 (emphasis added).

And while the regulations suggest that “inadequate planning or the failure to construct necessary facilities *can result* in an emergency,” they recognize that the Department may not utilize a “continuing emergency order” to mandate long-term system planning. 10 C.F.R. § 205.371 (also recognizing that “where a shortage of

⁴⁷ *Result*, Merriam-Webster Dictionary, <https://www.merriam-webster.com/dictionary/result> (last visited June 27, 2025).

electricity is projected due solely to the failure of parties to agree to terms, conditions, or other economic factors” there is no emergency “unless the inability to supply electric service is *imminent*”) (emphasis added). An emergency may exist where past planning failures produce an immediate, present-tense shortfall (that is where, a shortfall *results* from insufficient planning); the Department has no authority to commandeer long-term planning merely because it deems current plans inadequate to meet far-distant needs. *See* 10 C.F.R. § 205.375 (requiring present inability to meet demand to demonstrate inadequate energy supply). As the Department stated when it promulgated those regulations, the statute allows the Department to provide “assistance [to a utility] during a period of unexpected inadequate supply of electricity,” but does not empower it to “solve long-term problems.” 46 Fed. Reg. 39,984, 39,985–86 (Aug. 6, 1981).

4. Courts Have Uniformly Held that Section 202(c) Can Be Invoked Only in Immediate Crises.

Two courts have addressed the scope of authority under Section 202(c), and both determined that this Section applies only when there is a sudden, unexpected, imminent, and specific emergency.

Richmond Power and Light of City of Richmond, Indiana v. FERC, 574 F.2d 610 (D.C. Cir. 1978) arose out of the 1973 oil embargo. The Federal Power Commission (“Commission”) needed to decide how to respond to oil shortages, and decided to call for the voluntary transfer of electricity from non-oil power plants to areas of the country that relied heavily on oil, such as New England. *Id.* at 613. The New England Power Pool was not convinced that the voluntary program would

work and petitioned the Commission for a 202(c) order. *Id.* The Commission instead facilitated an agreement between state commissions and supplying utilities, which satisfied the New England Power Pool and it withdrew its petition. *Id.* A dissatisfied utility sought judicial review of the Commission’s decision to allow the withdrawal of the Section 202(c) petition. *Id.* at 614.

The court easily upheld the Commission’s decision not to invoke Section 202(c). *Id.* Though the oil embargo had ended, the utility argued that the “high cost and uncertain supply of imported oil” justified an emergency order. *Id.* The Commission countered that the voluntary program had worked, the New England Power Pool never interrupted service, and there was no need for a Section 202(c) order. *Id.* at 615. The court agreed with the Commission. *Id.*

Trying another tactic, the utility argued that “dependence on imported oil leaves this country with a *continuing* emergency.” *Id.* (emphasis added). The court observed that Section 202(c) “speaks of ‘temporary’ emergencies, epitomized by wartime disturbances.” *Id.* Interpreting this statutory language, the court upheld the Commission’s view that Section 202(c) cannot be used when “supply is adequate but a means of fueling its production is in disfavor.” *Id.* Section 202(c) is not an appropriate means to implement long-term national policy to switch fuels. It is only a temporary fix for a temporary problem.

The Eighth Circuit has similarly held that Section 202(c) can only be used to respond to immediate crises. In *Otter Tail Power Co. v. Federal Power Commission*, 429 F.2d 232 (8th Cir. 1970), a utility insisted that the only way for the Commission

to properly order the utility to connect to a municipal power provider was to issue a Section 202(c) order. Demand for electricity in the city had increased, and the peak load of the municipal power provider was getting to be so high that both of its two generators would likely need to be used simultaneously in the near future, “causing a possible loss of service should one malfunction during a peak period.” *Id.* at 233-34. To avoid this possible loss of service, the Commission issued a Section 202(b) order, requiring the utility to connect the municipal power provider. *Id.* at 234. The utility argued that the Commission used the wrong section and should have used Section 202(c) instead. *Id.*

The court explained that Section 202(c) “enables the Commission to react to a war or national disaster” by ordering “immediate” interconnection during an “emergency.” *Id.* (citing 16 U.S.C. § 824a(c)). For non-emergency situations, “[o]n the other hand, § 202(b) applies,” including when there is a “crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission.” *Id.* The court upheld the Commission’s use of Section 202(b) instead of Section 202(c) because there was no immediate emergency.

The case law uniformly supports the interpretation that Section 202(c) can only be used in acute, short-term, urgent emergencies.

5. The Department’s Prior Orders Recognize that Section 202(c) Does Not Confer Plenary Authority Over Long-Term Resource Adequacy.

The Department’s consistent application of Section 202(c) further corroborates the urgency of the conditions necessary to invoke the provision. *See FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941) (“[J]ust as established

practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred.”). The Department has only ever used Section 202(c) to address specific, imminent, and unexpected shortages—never to address longer-term reliability concerns or demand forecasts. *See, e.g.*, Ex. 6, Department of Energy Order No. 202-22-4 (Dec. 24, 2022) (responding to ongoing severe winter storm producing immediate and “unusually high peak load” between December 23 and December 26); Ex. 7, Department of Energy Order 202-20-2 (Sept. 6, 2020) at 10-2 (responding to shortages produced by ongoing extreme heat and wildfires); *see also* Rolsma, 57 Conn. L. Rev. at 803-4 (describing “sparing[]” use of Section 202(c) outside of wartime shortages during the twentieth century). The Department has also narrowly tailored the remedies in Section 202(c) orders to ensure that the orders only address the stated emergency, to limit the order to the minimum period necessary, and to mitigate violations of environmental requirements and impacts to the environment. *See, e.g.*, Ex. 6, Department of Energy Order No. 202-22-4 (Dec. 24, 2022) at 4-7 (limiting order to the 3 days of peak load, directing PJM to exhaust all available resources beforehand, requiring detailed environmental reporting, notice to affected communities, and calculation of net revenue associated with actions violating environmental laws); Ex. 7, Department of Energy Order 202-20-2 (Sept. 6, 2020) at 3-4 (limiting order to the 7 days of peak load, directing CAISO to

exhaust all available resources beforehand, requiring detailed environmental reporting).

Public Interest Organizations are not aware of any instance in which the Department has utilized Section 202(c) to mandate generation the Department views as necessary to ensure long-term resource sufficiency, or to retain fuel sources that the Department believes beneficial, *Richmond Power and Light*, 574 F.2d at 616—and for good reason.

C. There Is No Factual Basis Supporting the Department’s Order.

The Department asserts that the Order is justified by “the declared state of national energy emergency” and “resource adequacy concerns.” Ex. 1 at 2. However, the Department fails to demonstrate that either of these factors constitutes an emergency under Section 202(c). 16 U.S.C. § 824a(c). No agency can lean exclusively on a Presidential declaration of an emergency; emergency authority is circumscribed by the authority granted by Congress. Further, a broad, generic declaration of a national emergency is not sufficient on its own to justify the use of emergency powers under a statute with specific requirements. And the Department fails to provide evidence that there are such imminent resource adequacy shortfalls that an emergency exists pursuant to Section 202(c). The Department’s suggestion that there is an emergency due to resource inadequacy is also belied by the robust portfolio of capacity resources available this summer.

1. The Energy Emergency Executive Order does not provide a valid basis under Section 202(c).

The Order generally states that the availability of Eddystone is necessary considering “the declared state of national energy emergency,” but fails to explain what state of emergency it refers to or cite any evidence supporting this claim. Without more, this statement of a national emergency is not specific enough to provide evidence of an emergency for purposes of Section 202(c). *See* 10 C.F.R. § 205.371 (defining emergency as a “*specific* inadequate power supply situation”) (emphasis added). Even assuming the Order refers to the Energy Emergency EO, that Executive Order also does not provide a valid basis for an emergency under Section 202(c). To the extent that the Order is a stopgap to maintain Eddystone until the Department can produce its national methodology meant to address the alleged national energy emergency, that too is beyond the authority of Section 202(c). *See infra*, Section V.C.2.

If the Department’s reference to a national energy emergency is meant to serve as evidence of an emergency as defined under Section 202(c), it is insufficient. An emergency under Section 202(c) must be “a *specific* inadequate power supply situation,” 10 C.F.R. 205.371 (emphasis added), but the Energy Emergency EO only generically claims “[t]he energy ... generation capacity of the United States [is] far too inadequate to meet our Nation’s needs.” The EO provides no evidence of inadequate generation nationwide, let alone in Pennsylvania specifically.⁴⁸ An

⁴⁸ Indeed, U.S. energy production and exports are currently at an all-time high. U.S. Energy Information Administration, U.S. primary energy production,

emergency under Section 202(c) also must be imminent. *See supra*, Section V.B. But the EO only generically claims that “this situation will dramatically deteriorate in *the near future*.” As we demonstrate *infra*, Section V.C.3, there is sufficient generation for the claimed “emergency” period in Pennsylvania.

Indeed, unlike in previous 202(c) orders, the Department does not even claim there is an emergency specifically in Pennsylvania. Rather, in addition to citing the “national” emergency, the Order appears to describe resource concerns throughout PJM. But nowhere does the Department explain why a power plant retirement in a single state—Pennsylvania—supports the existence of an emergency in the whole region, let alone the whole country. We further demonstrate *infra*, Section V.C.3, that there is no 202(c) “emergency,” and, in fact, sufficient generation in PJM.

Even if the declared national energy emergency were legitimate, a presidential declaration of an emergency does not unlock unlimited powers. *See Biden v. Nebraska*, 600 U.S. 477, 500-01 (2023) (presidential declaration of national emergency does not change the limitations on agency’s emergency authority as written into statute). President Trump issued the Energy Emergency EO pursuant to authority from the National Emergencies Act.⁴⁹ Congress explained that the

consumption, and exports increased in 2024 (Jun. 20, 2025), <https://www.eia.gov/todayinenergy/detail.php?id=65524>.

⁴⁹ Under the National Emergencies Act, no emergency powers unlocked by a Presidential declaration of a national emergency “shall be exercised unless and until the President *specifies the provisions of law* under which he proposes that he, or other officers will act.” 50 U.S.C. § 1631 (emphasis added). The Energy Emergency EO does not adhere to this requirement. EO 14,156 (Jan. 20, 2025) (generically directing agencies to “identify and exercise any lawful emergency

National Emergencies Act “is not intended to enlarge or add to Executive power. Rather, the statute is an effort by Congress to establish clear procedures and safeguards for the exercise by the President of emergency powers *conferred on him by other statutes*.” S. Rep. No. 94-1168, 3 (1976), (emphasis added). Congress sometimes ties emergency authority to a president’s declaration of a national emergency and sometimes to a determination by the head of an agency. The Federal Power Act contains both types of emergency authority: two provisions of the Federal Power Act provide the President with emergency authority (section 215A, 16 U.S.C. § 824o-1, and 16 U.S.C. § 809), but Section 202(c) requires that “the *Commission* determine[] that an emergency exists.” 16 U.S.C. § 824a (emphasis added).⁵⁰ Thus, the burden is on the Department to demonstrate that there is an emergency pursuant to the narrow language of Section 202(c); simply pointing to the Energy Emergency EO without determining for itself that an emergency exists results in an arbitrary and capricious order.

2. The Department Failed to Produce Evidence of an Emergency.

None of the sources that the Department relies on in the Order provides evidence that a 202(c) emergency exists. The Order relies on four sources of evidence for its emergency declaration: (1) a March 2025 testimony of the President and CEO of PJM, (2) the FERC order accepting PJM’s Reliability Resource

authorities available to them, as well as all other lawful authorities they may possess, to facilitate the ... generation of domestic energy resources.”).

⁵⁰ The Department has exercised certain powers under Section 202(c) since the DOE Organization Act of 1977. 42 U.S.C. § 7172.

Initiative, (3) PJM’s 2023 report *Energy Transition in PJM*, and (4) PJM’s 2025 Summer Outlook. Ex. 1 at 1. The Department misconstrues these sources and consequently its reliance on them is not reasoned decision-making. *See* 5 U.S.C. § 706(2)(A) (agency actions that are “arbitrary” or “capricious” are to be “set aside”). Even if there were longer-term risks of an energy supply shortage some number of years in the future, that would not constitute a legal basis for invoking Section 202(c).

First, the Department notes that “PJM has recently stated its system faces ‘growing resource adequacy concern’ due to load growth, the retirement of dispatchable resources, and other factors,” citing testimony from PJM’s current President, Manu Asthana, to the U.S. House of Representatives Committee on Energy and Commerce, and contends that retirement of the Eddystone Units will “exacerbate” these issues.⁵¹ While President Asthana’s testimony indeed describes an emerging—but not present—resource adequacy concern, the primary focus of his testimony was on how PJM is preparing to meet resource adequacy challenges that PJM forecasts may emerge later in the decade as a result of potential data center growth in the region.⁵² According to President Asthana, PJM has instituted reforms to PJM’s interconnection process that will permit new resources to come

⁵¹ Ex. 1 at 1 (citing Testimony of Manu Asthana, President and CEO, PJM Interconnection, to the U.S. House of Representatives, Committee on Energy and Commerce, Subcommittee on Energy (Mar. 25, 2025), <https://www.pjm.com/-/media/DotCom/library/reports-notices/testimony/2025/20250325-asthana-testimony-us-house-subcommittee-on-energy.pdf>).

⁵² Testimony of Manu Asthana, at 1, 4.

online in the PJM region much more quickly than they have in recent years (though not as quickly as FERC Order 2023 would require), thus responding to capacity market price signals that incentivize that new entry.⁵³ As President Asthana notes, these reforms include not only changes to PJM’s interconnection tools and processes it employs, but also the introduction of an interconnection fast track for resources that PJM concludes will substantially contribute to resource adequacy (the Reliability Resource Initiative), and two pathways for new generation to be added at existing points of interconnection (capacity interconnection rights transfer and surplus interconnection service).⁵⁴ He also describes changes that PJM has made to its capacity market to ensure that market prices accurately reflect available supply, concluding that “[c]ollectively, the various proposals and reforms that PJM have pursued are making a difference as they are rolled out and implemented.”⁵⁵ Specifically, he notes that “since the beginning of last year, 1,100 MW of existing generation chose to remain as supply resources in PJM after previously submitting a notice to retire,” and expresses optimism that this process will continue given market reforms.⁵⁶

A full review of President Asthana’s testimony demonstrates the inappropriateness of 202(c) emergency action based on resource adequacy shortfalls that may arise in future years. PJM has already identified actions it is taking

⁵³ *Id.* at 8.

⁵⁴ *Id.*

⁵⁵ *Id.* at 8-9.

⁵⁶ *Id.* at 11.

through its rates and practices overseen by FERC to address the same long-term resource adequacy concerns relied upon in the Order, and the Department neither suggests nor demonstrates that PJM’s long-term market mechanisms will not be successful in addressing resource adequacy needs.

Indeed, Constellation itself takes a bullish view on the state of reliability in Pennsylvania as a result of PJM’s markets:⁵⁷

Notably, investment in new generation resources is currently being proposed in Pennsylvania. Constellation has announced the relaunch of the renamed Crane Clean Energy Center (“CCEC”) in Dauphin County, which will add approximately 835 MWs of carbon-free baseload generation to the grid. Likewise, just last month, Homer City Generation Station, the largest coal-burning facility in Pennsylvania before it was closed in 2023, announced plans to restart and increase its generating capacity through burning natural gas. In addition, 31,608 MW of new generation is proposed to be built in Pennsylvania, according to the PJM generation interconnection queue. In short, the PJM markets are working to ensure resource adequacy in Pennsylvania.

Second, the Order cites FERC’s approval of the Reliability Resource Initiative filed by PJM to alleviate “the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry”⁵⁸—a possibility that would only come to pass well after the 90-day period relevant to the Order. Curiously, the Order fails to discuss the results of the Reliability Resource Initiative published in May, which PJM intends will expedite interconnection for 9.3 GW of capacity, most of it thermal resources, by 2031—the vast majority of it by

⁵⁷ Comments of Constellation at 2, Pennsylvania Public Utility Commission Docket No. M-2024-3051988, <https://www.puc.pa.gov/pdocs/1861961.pdf>.

⁵⁸ Ex. 1 at 1 (citing PJM Interconnection LLC, 190 FERC ¶ 61,084 (Feb. 11, 2025)).

2030.⁵⁹ On the time scale relevant to PJM’s expressed concerns about a growing resource adequacy problem, the existence of the Reliability Resource Initiative demonstrates the effectiveness of existing tools to avoid an emergency arising. Suffice it to say, the Department’s citation of an approved solution to a problem that would otherwise arise in several years does not constitute evidence of an emergency in the next 90 days as required for a Section 202(c) order.

Third, the Order cites PJM’s February 2023 assessment, “Energy Transition in PJM: Resource Retirements, Replacements & Risks,” commonly known as the “R4” report, in which “PJM highlights the increasing risk of reliability risk in the coming years due to the ‘potential timing mismatch between resource retirements, load growth and the pace of new generation entry’ under ‘low new entry’ scenarios for renewable generation.” Ex. 1 at 1.⁶⁰ The problems with the Order’s reliance on this 2023 assessment are manifold.

As the Department’s statement makes plain, the February 2023 R4 Report describes only “increasing risk of reliability risk,” *id.*, over a period of seven years, which falls far short of an emergency within the meaning of Section 202(c), which must be imminent and certain. *See supra*, Section V.B., 10 C.F.R. 205.375, 205.371.

⁵⁹ Donnie Bielak, Reliability Resource Initiative Results Summary (May 6, 2025), <https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250506/20250506-item-06---reliability-resource-initiative---summary-results.pdf>.

⁶⁰ Citing PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks (Feb. 24, 2023), <https://www.pjm.com/-/media/DotCom/library/reports-notice/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx>.

The potential risk of a risk of inadequacy does not meet these standards.

Furthermore, the February 2023 R4 Report's assessment of increasing risk is flawed on its own terms. The most fundamental problem is that PJM failed to account for the operation of its own capacity market in ensuring resource adequacy, by assuming that capacity prices would remain at their then-recent low levels even as reserve margins shrunk. As economist James F. Wilson explained in a critique published in May 2023, this ignores that the sloped demand curve utilized in the capacity auction prevents this very result—as supply becomes more scarce, prices increase dramatically, thus incentivizing more new entry and retention of existing generators.⁶¹ Additional flaws with PJM's R4 Report that undermine its validity as a basis for the Order include:

- Ignoring reliability safety valve mechanisms in state policies to which PJM attributes anticipated retirements, which allow for delays in retirements in the case of reliability issues.⁶²
- Overstating retirements that would result from certain U.S. Environmental Protection Agency rules affecting the power sector, by assuming that all facilities subject to these rules would retire rather than retrofit.⁶³
- Presenting a low new entry scenario based on historic rates of new entry that occurred during a time period when the PJM capacity market was oversupplied and prices were low.⁶⁴

⁶¹ Ex. 8 James F. Wilson, Maintaining the PJM Region's Robust Reserve Margins A Critique of the PJM Report: Energy Transition in PJM: Resource Retirements, Replacements and Risks, 8 (May 2023)

⁶² *Id.* at 10 fn. 36.

⁶³ *Id.*

⁶⁴ *Id.* at 12.

- Assuming without explanation that only one-third of the natural gas generation with a signed interconnection agreement would enter service, even while assuming that large numbers of existing thermal units would retire.⁶⁵
- Assuming no increase in demand response resources, despite the increased capacity prices that would accompany declining reserve margins.⁶⁶
- Overstating retirements that will result from state policies.⁶⁷

The February 2023 R4 Report is also stale. As the PJM region now sees a level of supply that balances current demand, PJM capacity prices have skyrocketed substantially compared to the prices assumed in the R4 Report, which reflected the market's then-state of oversupply.⁶⁸ Specific unit retirements that PJM accounted for in the R4 analysis, such as those of Talen Energy's Brandon Shores and Wagner facilities in Maryland, have not occurred. These particular facilities, representing

⁶⁵ *Id.* at 12. *See also* PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks (Feb. 24, 2023) at 3, 10, <https://www.pjm.com/-/media/DotCom/library/reports-notice/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx>.

⁶⁶ *Id.*

⁶⁷ *See* Statement of President Christine Guhl-Sadovy of the New Jersey Board of Public Utilities, at 8-9, FERC Docket No. AD 25-7, (describing how PJM's R4 report overstated retirements in 2027 associated with New Jersey's greenhouse gas regulations and failed to correct this once it was pointed out by the New Jersey Board of Public Utilities).

⁶⁸ *Compare* PJM, 2023/2024 RPM Base Residual Auction Results, <https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2023-2024/2023-2024-base-residual-auction-report.pdf> *with* PJM 2025/2026 Base Residual Auction Results (Aug. 21, 2024), <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2024/20240821/20240821-item-08--2025-2026-base-residual-auction--presentation.pdf>. *See also*, PJM, 2025/2026 Base Residual Auction Report (July 30, 2024), <https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.pdf>.

about 1.5 GW of capacity, will continue operating under RMR agreements through the end of the decade.⁶⁹ And as noted above, PJM has taken steps intended to improve its processes to enable new resources to come online, which in combination with the higher prices, are already bearing fruit. None of these changes are reflected in the low new entry scenario described in the R4 Report and upon which the Order relies.

In addition to relying on stale evidence of low new entry, all of PJM's assessments of possible resource adequacy shortfalls later this decade depend on whether forecasted data center load growth materializes at the scale, and in the locations, that PJM currently anticipates.⁷⁰ As PJM's Vice President of Market Design and Economics recently explained, "any technology that is early in its development cycle is uncertain. Data centers are still relatively new, and there's uncertainty on how big their demand might be, and there's added uncertainty as to where they might ultimately be developed."⁷¹ PJM is evaluating ways to facilitate developers of data centers bringing their own supply to the market, incentivizing

⁶⁹ Talen Energy, FERC Approves Reliability Must Run Settlement Agreement for Units at Talen Energy's Brandon Shores and H.A. Wagner Power Plants (May 1, 2025), <https://ir.talenenergy.com/news-releases/news-release-details/ferc-approves-reliability-must-run-settlement-agreement-units>. See generally FERC Docket No. ER24-1790 (Brandon Shores LLC submits tariff filing: RMR Arrangement).

⁷⁰ See, e.g., Joe Bowring, Pre-Technical Conference Comments of the Independent Market Monitor for PJM at 3, FERC Docket No. AD25-7 (May 27 2025), <https://www.ferc.gov/media/joe-bowring-monitoring-analytics-president-and-independent-market-monitor>.

⁷¹ Adam Keech, Prefiled Statement on Behalf of PJM Interconnection, L.L.C. at 7, FERC Docket No. AD25-7.

higher degrees of data center participation as a demand response resource, or allowing for lower-cost, faster interconnection by data centers that are willing to have their usage curtailed.⁷² A recent study showed that even a very small degree of data center load flexibility enables large amounts of data centers—18 GW in PJM—to be added to the system without increasing the system peak that is a major input to the resource adequacy analysis.⁷³ Meanwhile, utilities and states are taking significant steps to require deposits and other commitments from large loads, such as data centers, to ensure that the load forecasts driving pessimism about PJM’s long-term resource adequacy don’t include speculative or duplicative projects.⁷⁴

Fourth, the Department offers a single piece of evidence relating to near-term conditions—a PJM newsletter summarizing its outlook for the summer. But it too does not demonstrate an emergency. According to the Department, “PJM indicates that resource constraints could exist within the service territory under peak load conditions, stating that ‘available generation capacity may fall short of required

⁷² Tim Horger, Senior Director, Forward Market Operations & Performance Compliance, “Large Load Additions Workshop,” PJM (May 9, 2025), <https://www.pjm.com/-/media/DotCom/committees-groups/workshops/llaw/2025/20250509/20250509-item-02---large-load-additions-workshop---presentation.pdf>.

⁷³ Tyler H. Norris et al., *Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems* 20, 22 (Duke Univ. Nicholas Inst. for Energy, Env’t & Sustainability ed. 2025), <https://nicholasinstitute.duke.edu/publications/rethinking-load-growth>.

⁷⁴ Adam Keech, *Prefiled Statement on Behalf of PJM Interconnection, L.L.C.* at 7-8, FERC Docket No. AD25-7.

reserves in an extreme planning scenario.”⁷⁵ As PJM further explains: “Demand response programs pay customers who have opted in to reduce their electricity use in times of system emergencies.”⁷⁶ The Department’s brief quotation of this summer outlook article omits a key point that is prominent in PJM’s article—that “[u]nder such circumstances, PJM would call on contracted demand response programs to meet its required reserve needs.”⁷⁷ PJM’s plan to call on demand response is also noted in the article’s subheading and first paragraph—it is not a subtle point.

The possibility that PJM might ask demand response resources to activate is not an “emergency” within the meaning of Section 202(c). That is exactly the point of such resources— they offer to curtail their use of power on demand in exchange for hefty payments.⁷⁸ Instead of an emergency, it is indicative of routine analysis and planning to rely upon the most cost-effective resources available to the grid operator. *See infra*, Section V.C.3. As PJM’s Vice President of Markets, Adam Keech, explains, demand response is important to “maintaining resource adequacy

⁷⁵ Order at 1 (quoting Summer Outlook 2025, *supra* n. 4).

⁷⁶ Summer Outlook 2025, *supra* n. 4.

⁷⁷ *Id.*

⁷⁸ *See, e.g., FERC v. Elec. Power Supply Ass’n*, 577 U.S. 260, 269 (2016), *as revised* (Jan. 28, 2016) (explaining that market operators like PJM devised wholesale demand response programs, which “induce consumers to refrain from using ... electricity during peak periods” for situations whenever “doing that costs less than adding more power” in order to “bring electricity supply and demand into balance at a lower price ... [and] ease pressure on the grid, thus protecting against system failures”).

both currently and in the future.”⁷⁹ He notes that “demand response accounted for approximately 4.5% of capacity that cleared” in the 2025/26 Base Residual Auction, and that “[i]f generation resources are unable to be developed economically to meet anticipated load growth in PJM, it will be critical to have flexible demand that is willing to curtail in order to maintain reliability.”⁸⁰ The Department’s own regulations explicitly acknowledge that inadequate energy is an emergency only if the grid operator is unable to meet “normal peak load requirements based upon use of all of its otherwise available resources.” 10 C.F.R. 205.375. Thus, the Order arbitrarily ignores PJM’s plan to rely upon demand response in the event that its generation resources are inadequate to maintain the required operating reserves during extreme load conditions this summer.

Finally, the Order mentions in the description of the emergency situation the Department’s intent to consider Eddystone in the as-yet unpublished resource adequacy methodology the Department is developing pursuant to the Grid EO. Ex. 1 at 2. This context cannot be evidence of an emergency under Section 202(c) for the simple reason that the methodology does not yet exist. And any reliance on the methodology, once it is published, as evidence to support the issuance of the Order will be impermissible *post hoc* rationale. *Dep’t of Homeland Sec. v. Regents of the Univ. of California*, 140 S. Ct. 1891, 1907 (2020) (“foundational principle of administrative law’ that judicial review of agency action is limited to ‘the grounds

⁷⁹ Adam Keech, Prefiled Statement on Behalf of PJM Interconnection, L.L.C. at 5, FERC Docket No. AD25-7.

⁸⁰ *Id.* at 5-6.

that the agency invoked when it took the action.”). Further, this context suggests that the Order in reality is merely a preliminary step in the long-term strategy to preserve fossil fuel generation under the guise of grid reliability concerns. As discussed *infra*, Section V.C.4., regardless of this Administration’s policy goals, the Department’s actions must adhere to the Administrative Procedure Act’s requirement of reasoned decision making as well as remain within the statutory limits Congress wrote into the Federal Power Act.

The Department’s claims represent a blinkered and incorrect review of the evidence: while there is the possibility for energy demand growth over the coming years, and there has been an increase in generator retirements, PJM is equipped with the tools to address those system changes in a way that maintains resource adequacy and reliability, and indeed is already doing so. Rather than recognizing this broader picture, the Department points to cherry-picked statements by PJM that if certain conditions arise—such as particular levels of load growth and low new entry of capacity resources—then, in several years’ time, the PJM region would have reserve margins below its target if appropriate action were not taken to address those conditions. The Department takes PJM’s warnings of future risk that might arise out of context and ignores other mechanisms at work to address the longer-term risk and thereby prevent any energy shortfall from arising.

3. PJM Has Sufficient Capacity Resources for Summer 2025 Without Eddystone.

The Base Residual Auction for the delivery year encompassing the period of emergency that the Department identifies in the Order—Delivery Year 2025-2026—

cleared more capacity than the Reliability Requirement.⁸¹ Specifically, the auction cleared 135,684 MW of unforced capacity, representing a 18.6% reserve margin—0.8 percentage points higher than the target reserve margin of 17.8%.⁸² Constellation did not offer the Eddystone Units into the auction, considering its June 1, 2025 deactivation date was accepted by PJM, and Constellation’s 2023 notice that it would seek removal of its capacity resource status.⁸³ Thus, the auction cleared more than sufficient resources for the 2025-2026 delivery year without Eddystone’s capacity being included or otherwise counted on. Clearing an amount of capacity close to, and indeed above, the Reliability Requirement is consistent with the capacity market’s design objectives.⁸⁴

Indeed, the auction-clearing results *understate* the quantity of resources available in the PJM region for at least two reasons. The supply curve did not

⁸¹ PJM, 2025/2026 Base Residual Auction Report 3 (July 30, 2024), <https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.pdf>.

⁸² *Id.* Two transmission-constrained areas that must import capacity cleared at the price cap for those areas, indicating that they had insufficient internal capacity to meet their internal demand for the delivery year. These two areas—Baltimore Gas & Electric and Dominion—are in Maryland and Virginia, respectively, and would not be able to import any additional capacity even if it were available elsewhere in the region, due to the transmission constraints.

⁸³ *See supra*, Section IV.A. Constellation is contemporaneously submitting a written request to PJM and the IMM for removal of capacity resource status beginning with the 2025/26 delivery year.

⁸⁴ *See* Kathleen Spees et al., Sixth Review of PJM’s Variable Resource Requirement Curve for Planning Years 2028/29 through 2031/32, at 19 (Apr. 9, 2025), <https://www.brattle.com/wp-content/uploads/2025/04/Sixth-Review-of-PJMs-Variable-Resource-Requirement-Curve.pdf> (“By design, RPM aims to support long-term reliability by targeting a cleared volume of capacity resources consistent with the reliability requirement, the 1-in-10 reliability standard.”).

include nearly 1.5 GW of capacity available in the Baltimore Gas & Electric zone that are committed to operate under RMR agreements during the 2025-2026 delivery year.⁸⁵ FERC has since approved tariff revisions filed by PJM that will, in future auctions, account for the capacity value of RMR units with obligations to perform during capacity emergencies, like the units in the Baltimore Gas & Electric zone.⁸⁶ In addition, approximately 1.6 GW of accredited wind, solar, and storage capacity did not offer into the auction for the 2025-2026 delivery year; these resources have capacity interconnection rights and will be available to provide energy, including during many of PJM's riskiest hours of this delivery year.⁸⁷

NERC's 2025 Summer Reliability Assessment, published in May 2025, indicates that PJM has adequate anticipated resources for both normal and extreme summer load conditions, and that PJM anticipates calling upon demand response resources during any extreme high temperatures.⁸⁸ It further notes that "PJM is forecasting 27% installed reserves (including expected committed demand

⁸⁵ See Maryland Office of People's Counsel, Bill and Rate Impacts of PJM's 2025/2026 Capacity Market Results & Reliability Must-Run Units in Maryland 6 (Aug. 2024), https://opc.maryland.gov/Portals/0/Files/Publications/RMR%20Bill%20and%20Rates%20Impact%20Report%202024-08-13%20Final%20corrected%208-29-24.pdf?ver=fHKA18_idtwi4Rm4OeK-7A%3d%3d.

⁸⁶ See *Order Accepting Tariff Revisions Subject to Condition, PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,088, at P 1 (2025).

⁸⁷ See *Extending the Capacity Must-Offer Requirement to All Generation Capacity Resources, PJM Interconnection, L.L.C.*, FERC Docket No. ER25-785-000 (2024), at P 7.

⁸⁸ NERC, 2025 Summer Reliability Assessment 5, 25 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.

response), which is above the target installed reserve margin of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.”⁸⁹

The heat wave that occurred June 23-26, 2025, and PJM’s response thereto, demonstrate that the PJM system is working as it should to maintain grid reliability—and it would have worked as planned even without the Eddystone Units running. On June 22, 2025, PJM projected that its forecasted load across PJM from June 23 through 26 would range from 148,500 to 161,000 MW.⁹⁰ While these load forecasts are higher than PJM’s summer forecast peak, they are lower than PJM’s extreme planning scenario of more than 166,000 MW and lower than the 187,100 MW of total generation capacity and demand response that PJM has available this summer.⁹¹ Thus, PJM called on ordinary economic resources to respond to this event, but also had additional typical resources it could call on to address the peak forecasts, and still would have even without Eddystone operating. PJM reached the last step before an emergency⁹²—Pre-emergency Load Management Reduction, in other words, demand response.⁹³ Ultimately, PJM hit a peak load of approximately

⁸⁹ *Id.* at 25.

⁹⁰ *June 23 Update: Maximum Generation Alert Issued for June 24*, PJM Inside Lines (June 19, 2025), <https://insidelines.pjm.com/pjm-issues-hot-weather-alert-for-expected-heat-wave-june-22-25/>.

⁹¹ Summer Outlook 2025, *supra* n. 4.

⁹² PJM, PJM Manual 13: Emergency Operations 20-21 (Feb. 20, 2025), <https://www.pjm.com/-/media/DotCom/documents/manuals/m13.pdf>.

⁹³ While this is an action under PJM’s Capacity Emergency, *id.*, PJM’s Operating Agreement explains that “[a] pre-emergency event is implemented when economic resources are not adequate to serve load and maintain reserves or maintain system reliability, and *prior to proceeding into emergency procedures.*”

160,000 MW on June 23 and 158,000 on June 24⁹⁴ and still had additional demand response available (at least 3,640 MW) that it could have relied on rather than running Eddystone's 820 maximum MW.⁹⁵

This event was not an emergency as defined by Section 202(c) because it did not produce a "specific inadequate power supply situation," 10 C.F.R. § 205.371. And Department regulations define an inadequate energy supply as when "the projected energy deficiency... will cause the [utility] to be unable to meet its *normal peak load* requirements based upon *use of all of its otherwise available resources*." 10 C.F.R. § 205.375 (emphasis added). For this event, PJM kept net load below its summer seasonal peak load through relying on only some of its otherwise available resources. The June 23-26 event demonstrates that PJM has sufficient capacity resources for summer 2025.

PJM, 8.5 Pre-Emergency Operations, Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. 516, <https://www.pjm.com/library/governing-documents> (emphasis added). In fact, the purpose of pre-emergency Load Management Reduction is to "potentially avoid, or at least reduce the duration and breadth of, a system emergency." PJM tariff filing, Revisions to the PJM OATT, OA & RAA, FERC Accession # 20131224-5000, at 8 (Dec. 24, 2013).

⁹⁴ <https://www.gridstatus.io/live/pjm?date=2025-06-23to2025-06-25>.

⁹⁵ PJM only issued a Pre-Emergency Load Management Reduction Action calling on only some of the available short and long capacity performance demand response (<https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf#>). But PJM also has 3640 MW of quick demand response. James McAnany, PJM, 2025 Demand Response Operations Markets Activity Report (June 10, 2025), <https://www.pjm.com/-/media/DotCom/markets-ops/dsr/2025-demand-response-activity-report.pdf> (45.5% of total 25/26 demand response is quick).

4. The Order Is Based on a False Premise and Violates the Department's Duties Under the Administrative Procedure Act.

On its face, the Department's decision to require Eddystone to recommence and continue operations over the next 90 days is completely untethered from the statutory and regulatory requirements of Section 202(c). Given the incongruity of the record and the result, the Department's decision to require Eddystone to return to service shows itself to be nothing more than a brazen effort to prop up fossil fuel generation— to the detriment of PJM ratepayers and the surrounding community— by manufacturing an “emergency” and illegally abusing an important statutory safeguard. *See, e.g. Youngstown Sheet & Tube Co. v. Sawyer*, 343 U.S. 579, 649-54, (1952) (Jackson, J., concurring) (“[Our founding fathers] knew what emergencies were, knew the pressures they engender for authoritative action, knew, too, how they afford a ready pretext for usurpation. We may also suspect that they suspected that emergency powers would tend to kindle emergencies.”)⁹⁶

⁹⁶ Administrative review does not require “exhibit[ing] a naiveté from which ordinary citizens are free,” *Dep’t of Com. v. New York*, 588 U.S. 752, 785 (2019). That the Department's action is intended to support the White House's stated goals of keeping fossil fuel plants from retiring is evidenced by a wealth of publicly available information surrounding the Administration's policies and stated intent. *See, e.g., Agenda47: America Must Have the #1 Lowest Cost Energy and Electricity on Earth*, Trump-Vance 2025 (Sept. 7, 2023), <https://www.donaldjtrump.com/agenda47/agenda47-america-must-have-the-1-lowest-cost-energy-and-electricity-on-earth>; Jill Colvin & Bill Barrow, *Trump's Vow to Only be a Dictator on 'Day One' Follows Growing Worry over his Authoritarian Rhetoric*, Associated Press (Dec. 7, 2023, 4:58 PM), <https://apnews.com/article/trump-hannity-dictator-authoritarian-presidential-election-f27e7e9d7c13fabbe3ae7dd7f1235c72> (President Trump indicated he was not concerned about statutory compliance when he stated repeatedly that he would “be a dictator” on Day One in order to “drill, drill, drill.”).

Whatever the political aspirations of the Executive may be or its demands of its agency leaders, actions by the Department are still governed by the Administrative Procedure Act, which requires that a court “hold unlawful and set aside agency action, findings, and conclusions found to be arbitrary, capricious, [or] an abuse of discretion.” 5 U.S.C. § 706(2)(A). The Administrative Procedure Act requires agencies to make a reasoned explanation for their actions by examining the relevant data and providing a rational connection between the facts found and the choice made. *Motor Vehicle Mfrs. Ass’n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983). And because an agency’s authority rests squarely within the four corners of Congress’ delegation, agencies are not permitted to make decisions based on factors which Congress has not intended it to consider. *Id.*; see also *Amerijet Int’, Inc. v. Pistole*, 753 F.3d 1343, 1350 (D.C. Cir. 2014).

The Department’s use of Section 202(c) is thus arbitrary and capricious because it is not tied to the requirements of the statute and is instead a product of impermissible political influence beyond those requirements. *D.C. Fed’n of Civic Ass’ns v. Volpe*, 459 F.2d 1231, 1248 (1971). As explained by the Supreme Court:

The reasoned explanation requirement of administrative law, after all, is meant to ensure that agencies offer genuine justifications for important decisions, reasons that can be scrutinized by courts and the interested public. Accepting contrived reasons would defeat the purpose of the enterprise. If judicial review is to be more than an empty ritual, it must demand something better ... [and] agencies must pursue their goals reasonably.

Dep’t of Com., 588 U.S. at 785.

D. The Order Will Undermine Competitive Markets to the Detriment of Consumers and Reliability.

When viewed together with the Energy Emergency EO,⁹⁷ Grid EO, and the Department's nearly identical 202(c) order regarding the Campbell coal plant,⁹⁸ the Department advances an illegal command-and-control energy policy that effectively overrides the capacity and energy markets to force a private entity to continue operating an uneconomic unit they wished to decommission and for ratepayers to pick up the tab. Congress delegated to FERC the authority to regulate wholesale energy markets and interstate transmission and granted the Department only a narrow, backstop authority through Section 202(c). 16 U.S.C. § 824a(c). If left to stand, the Department's overbroad Order will forebode a fundamental undermining of competitive markets for energy, leading to a system that will deliver less reliability to consumers at greater cost.

1. Competitive Markets Have a Long History of Success.

For nearly a century, FERC's core responsibility under the Federal Power Act has been to ensure that rates, terms, and conditions employed by utilities for wholesale energy sales and transmission are just, reasonable, and not unduly discriminatory. 16 U.S.C. § 824d ("Section 205"). While the initial utility structure was vertically integrated such that generation, transmission, and distribution resources were all held by the same entity, advances in technology and statutory

⁹⁷ Exec. Order No. 14,156 Declaring a National Energy Emergency, 90 Fed. Reg. 8,433 (Jan, 20, 2025).

⁹⁸ Ex. 9 at 1-2, DOE Order No. 202-25-3 (May 23, 2025) (directing dispatch of the Campbell plant, which was scheduled to cease operations the following week).

changes led to the development of energy markets and merchant generation.⁹⁹ Further regulation by FERC in the 1990s with Order Nos. 888, 890, and 2000 fostered the establishment of several independently operated RTOs, which set up competitive markets that determine the prices for energy, capacity, and ancillary services based on procurement and dispatch of least-cost resources.¹⁰⁰ As RTO markets expanded, many states deregulated their utility monopolies and required them to join RTOs. Generating resources in competitive RTOs are built and retired by private investors in response to market price signals designed to encourage new investment when supply is tight and to encourage the retirement of facilities that are no longer competitive when capacity is plentiful. RTOs now account for approximately 2/3 of all electricity sales in the U.S. and have saved consumers billions of dollars, increased reliability, and reduced environmental harm.¹⁰¹

⁹⁹ See, e.g., *Order Terminating Rulemaking Proceeding, Initiating New Proceeding, And Establishing Additional Procedures*, 162 FERC ¶ 61,012, PP 7-11 (2018); *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,639-31,645 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

¹⁰⁰ Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 638-41 (1996), Order No. 890, FERC Stats. & Regs. ¶ 31,241, at 124-352 (1997), Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at 99-130 (1999).

¹⁰¹ See, e.g., Judy Chang et al., *The Brattle Group, Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers*, 1, 3-7 (April 2019), <https://www.brattle.com/wp->

As explained by FERC, its “support of competitive wholesale electricity markets has been grounded in the substantial and well-documented economic benefits that these markets provide to consumers.”¹⁰² In addition to billions of dollars of consumer savings, FERC found that competitive markets protect consumers by “providing more supply options, encouraging new entry and innovation, spurring deployment of new technologies, promoting demand response and energy efficiency, improving operating performance, exerting downward pressure on costs, and shifting risk away from consumers.”¹⁰³

As part of its role in regulating markets, FERC has implemented Congressional mandates to ensure system reliability, including working with NERC to set industry standards for grid reliability;¹⁰⁴ coordination requirements for the

[content/uploads/2021/05/16092_nc_wholesale_power_market_whitepaper_april_2019_final.pdf](#) (discussing billions of dollars in estimated cost saving); Jennifer Chen & Devin Hartman, *Why wholesale market benefits are not always apparent in customer bills*, R Street (Nov. 10, 2021), <https://www.rstreet.org/commentary/why-wholesale-market-benefits-are-not-always-apparent-in-customer-bills/> (same); Jeff St. John, *A Western US energy market would boost clean energy. Will it happen?*, Canary Media (Jun. 10, 2024), <https://www.canarymedia.com/articles/utilities/a-western-us-energy-market-would-boost-clean-energy.-will-it-happen>; John Tsoukalis et al., *Assessment of Potential Market Reforms for South Carolina’s Electricity Sector*, at 6, 46, 77-78 (Apr. 27, 2019), <https://www.scstatehouse.gov/CommitteeInfo/ElectricityMarketReformMeasuresStudyCommittee/2022-04-27%20-%20SC%20Electricity%20Market%20Reform%20Brattle%20Report.pdf> (discussing cost savings across regional wholesale markets).

¹⁰² Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures, 162 FERC ¶ 61,012, P 11 (2018).

¹⁰³ *Id.* (citation omitted).

¹⁰⁴ PJM, NERC and Reliability (Jan. 5, 2025), <https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/nerc-and-reliability-fact-sheet.pdf>.

natural gas and electricity market scheduling;¹⁰⁵ investigation and improvements required in light of the grid's response to extreme weather events;¹⁰⁶ and reviewing capacity accreditation processes to ensure that capacity markets generate reliable results.¹⁰⁷

2. Command and Control Orders Run Counter to Federal Power Act Requirements and Fundamental Market Principles.

Despite the decades of evidence that competitive energy markets deliver reliable energy at least cost to consumers, as well as the extensive and constant oversight of these markets by FERC, the Order operates under the implicit

See also PJM, PJM Ensures a Reliable Grid (Jan. 29, 2025), <https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/reliability-fact-sheet.pdf>.

¹⁰⁵ PJM, PJM Promotes Gas/Electricity Industry Coordination (Jan. 29, 2025), <https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/gas-electric-coordination-fact-sheet.pdf>. *See also*, Order 787, 145 FERC ¶ 61,134 (2013); Order 809, 151 FERC ¶ 61,049 (2015).

¹⁰⁶ *See, e.g., Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators*, 149 FERC ¶ 61,145 (2014) (order addressing technical conferences on, among other things, the 2014 Polar Vortex); *Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and EOP-012-1 and Directing Modification of Reliability Standard EOP-012-1*, 182 FERC ¶ 61094 (2023); *Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification*, 187 FERC ¶ 61,204 (2024). *See also*, FERC, NERC and Regional Staff, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott (Oct. 2023), https://www.ferc.gov/sites/default/files/2023-11/24_Winter-Storm_Elliott_1107_1300.pdf; FERC, NERC and Regional Staff, The February 2021 Cold Weather Outages in Texas and the South Central United States (Nov. 2021), <https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/FERC%20Presentation-Phase%202.pdf>; PJM, Winter Storm Elliott Event Analysis and Recommendation Report (2023), <https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf?ref=blog.gridstatus.io>.

¹⁰⁷ *Id.*; *see also* Order Accepting Tariff Revisions Subject to Condition, 186 FERC ¶ 61,080 (2024).

assumption that capacity market results are not reliable, and that market-driven generator retirement is cause for alarm. This is not the first time this President has sought to require preferential treatment for retiring resources he preferred for grid reliability.¹⁰⁸ When the Department proposed to have a rule that would require tariff provisions designed to prevent the retirement of preferred resources, FERC rejected the proposal unanimously.¹⁰⁹ FERC found that the allegations that potential retirements of particular resources would lead to grid reliability problems did not demonstrate that existing rules were unjust and unreasonable.¹¹⁰ Nor was there evidence from the RTOs that any particular generator retirement would be a threat to grid resilience.¹¹¹ Moreover, FERC found that the proposal to pay cost-of-service rates for only certain types of resources “regardless of need or cost to the system” would not be just, reasonable, or unduly discriminatory.¹¹²

Similar to this prior effort, the Order proposes to force the Eddystone Units to run regardless of need or cost to the system. The Order demands that PJM “take every step to employ economic dispatch,” which it fails to define. Ex. 1 at 3. As discussed above in section IV., PJM dispatches generators based on the lowest

¹⁰⁸ See, e.g., Casey Roberts, *FERC Rejects DOE’s Dangerous Proposal to Shield Coal and Nuclear From Clean Energy Competition*, Sierra Club (Jan. 9, 2018), <https://www.sierraclub.org/compass/2018/01/ferc-doe-coal-nukes-perry-subsidies>

¹⁰⁹ Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures, 162 FERC ¶ 61,012 (2018).

¹¹⁰ *Id.* at PP 15-16.

¹¹¹ *Id.*

¹¹² *Id.* at P 16.

marginal price. The low historic utilization of Eddystone reflects that its costs to operate are so much higher than alternative resources that it isn't being dispatched enough of the time—even during times of peak load—to warrant keeping the unit online. *See supra*, Section IV.B. Constellation was well aware of PJM's load forecasts and the related high capacity prices when it opted to retire the Eddystone Units. This indicates that Constellation either didn't see Eddystone becoming economic even in future scenarios and/or that it felt it could make more money by retiring the Eddystone Units and investing in other options that offered the ability to dispatch more frequently and earn a greater return on investment. By forcing Eddystone to stay on the system despite this, the Department will raise prices for consumers by forcing them to pay for a resource that is unnecessary to meet PJM's Reliability Requirement for the current delivery year. Keeping Eddystone online also forces Constellation to continue to invest its money in an aging and expensive unit instead of investing in newer, more profitable units.

Should the Order be extended, as the Department suggests it will be, the consequences will become further reaching. Mandating that Eddystone remain online over a longer timeline forces PJM and Constellation to tie up the transmission capacity rights owned by the Eddystone Units that could otherwise be repurposed by Constellation for a new unit at the Eddystone site or put back into the system for allotment to new, more efficient resources waiting in PJM's

infamously years-delayed interconnection queue.¹¹³ In other words, the Order forces Constellation to tie up an incredibly valuable transmission resource by maintaining that transmission headroom for a resource that is no longer useful and is unlikely to actually need to be used. As such, this decision is the very opposite of the bedrock principle of utility law that asset expenditures must be used and useful.¹¹⁴ Moreover, it defeats the Administration's alleged concern that there are more retirements than new resources coming on the system. Ex. 1 at 1. As mentioned above, PJM has instituted new procedures for allowing resources needed for reliability to advance to the front of the interconnection queue. By tying up unused transmission capacity at the Eddystone Units, it also prevents new, more affordable and reliable resources already waiting to replace it from doing so. While extensions of the Order beyond the initial 90-days would almost certainly be unlawful and unreasonable, the Department appears to be contemplating

¹¹³ Joseph Rand et. al., *Queued Up: 2024 Edition*, *Lawrence Berkeley National Laboratory* (April 2024) at 35, https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf (showing that PJM has the longest queue processing timelines in the U.S.); Synapse Energy Economics, Inc., Sabine Chavin et al., *Tackling the PJM Electricity Cost Crisis* (Apr. 2025), <https://www.synapse-energy.com/sites/default/files/Evergreen%20PJM%20Queue%20Report%204.10.25%20final%2024-145.pdf>; Grid Strategies, *Generator Interconnection Scorecard* (Feb. 2024) <https://gridstrategiesllc.com/wp-content/uploads/2024/03/AEI-2024-Generation-Interconnection-Scorecard.pdf> (scoring PJM's overall interconnection a D-).

¹¹⁴ *See* FERC, *Energy Primer*, at 55 (2024), https://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf; Jim Lazar, *Electricity Regulation in the US: A Guide*, Second Edition, at 91 (2016), <https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-electricity-regulation-US-june-2016.pdf>.

extensions given the statement that “DOE plans to use [the Grid EO] methodology to further evaluate Eddystone Units 3 and 4.” Ex. 1 at 2.

Finally, the longer-term impacts of the Department’s strategy send signals that will disrupt market stability. Markets ultimately still depend on private investors, who will be less likely to invest billions of dollars in an energy system run according to personal whim rather than on market forces. The need for market stability across administrations and department heads is why Congress deliberately placed the authority for utility regulation—a matter so fundamentally central to the entire economy and well-being of the nation—in the hands of independent regulators with specialized expertise and only allowed the Department to intervene in true emergencies.¹¹⁵ In usurping the role of FERC and RTO markets to regulate the energy markets so that the Department can prioritize resources it favors and thwart the development of those it dislikes, the ultimate message is for private investors not to invest. As noted by former FERC Commissioner Brownell, to do otherwise “will have a chilling effect on markets because investors will be unlikely to risk hundreds of billions of dollars on investments regulated by politically influenced non-transparent decisions.”¹¹⁶

¹¹⁵ See generally, Patrick M. Corrigan & Richard L. Revesz, *The Genesis of Independent Agencies*, 92 N.Y.U. L. Rev. 637 (2017).

¹¹⁶ Herman K. Trabish, *Trump executive order threatens transmission, interconnection initiatives: former FERC commissioners*, Utility Dive (Mar. 26, 2025), <https://www.utilitydive.com/news/trump-executive-order-agency-independence-ferc-transmission-interconnection-initiatives/742356/>. See also Oskar Dye-Furstenberg, *The Hollow Energy Agenda of Trump’s First Four Months*, Roosevelt Institute (May 29, 2025), <https://rooseveltinstitute.org/blog/the-hollow-energy-agenda-of-trump/>.

E. Even If There Were a Short-Term Need—There Is Not—the Order Does Not Comply with the Statutory Command to Set Terms That Best Meet the Emergency and Serve the Public Interest.

1. Section 202(c)(1) Only Authorizes the Department to Require Generation that Best Meets the Emergency and Serves the Public Interest.

Even if there were a Section 202(c) emergency, which as shown above there is not, Section 202(c)(1) requires the Department only impose requirements that (i) “best” (ii) “meet the emergency and” (iii) “serve the public interest.” 16 U.S.C. § 824a(c)(1). The Department therefore must consider alternatives and choose the alternative that is most advantageous to meeting the emergency and serving the public interest as defined by the Federal Power Act.

The term “best” demands a comparative judgment that there are no better alternatives. The word “best” is inherently a comparative term and means “that which is ‘most advantageous.’” *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208, 218 (2009) (quoting Webster’s New International Dictionary 258 (2d ed.1953)); *cf. Sierra Club v. Env’t. Prot. Agency*, 353 F.3d 976, 980, 983–84 (D.C. Cir. 2004) (explaining that statutory “best available control technology” requirement demands sources in a category clean up emissions to the level that peers have shown can be achieved). Consequently, the Department must, at minimum, consider alternatives and evaluate whether and to what extent a given alternative addresses the alleged emergency and serves the public interest, including deficiencies associated with each option.

Moreover, the Department must consider alternatives as part of exercising reasoned decision-making. It need not consider every conceivable alternative, but it

must consider alternatives within the ambit of the existing policy as well as alternatives which are significant and viable or obvious. *See Dep't of Homeland Sec. v. Regents of the Univ. of Calif.*, 591 U.S. 1, 30 (2020) (failure to consider alternative was arbitrary and capricious); *Motor Vehicle Mfrs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 51 (1983) (must consider alternatives “within the ambit of the existing standard”); *Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200, 215 (D.C. Cir. 2013) (“agency must consider and explain its rejection of reasonably obvious alternatives” (cleaned up)). Intervenors and the public may also introduce information that requires the Department to evaluate alternatives and reconsider its decision to impose or maintain a requirement. *See, e.g., Chamber of Com. of the U.S. v. Secs. & Exch. Comm'n*, 412 F.3d 133, 144 (D.C. Cir. 2005) (holding that agency’s failure to consider the disclosure alternative raised by dissenting Commissioners and introduced by commenters violated the Administrative Procedure Act); *cf.* 10 C.F.R. § 205.370 (stating the Department’s right “to cancel, modify, or otherwise change” an order). To be sure, the nature and extent to which the Department must consider alternatives depends on the emergency. An emergency that truly requires the Department to act within hours, for instance, would permit a more abbreviated consideration than an emergency for which the Department has days to decide. 16 U.S.C. § 824a(c) (directing the Department to exercise its judgment).

The Department’s regulations and practice suggest relevant alternatives for its consideration. The regulations specify information the Department shall

consider in deciding to issue an order under Section 202(c), and require an applicant for a 202(c) order to provide the information. 10 C.F.R. § 205.373. The specified information includes “conservation or load reduction actions,” “efforts . . . to obtain additional power through voluntary means,” 10 C.F.R. § 205.373(g)–(h), and “available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions.” Ex. 6 at 4-5 (DOE Order No. 202-22-4).

The statutory command to take only measures that serve the public interest further constrains the Department’s authority. The public interest element demands that the Department advance, or at least consider, the various policies of the Federal Power Act. *Cf. Wabash Valley Power Ass’n*, 268 F.3d at 1115 (interpreting the “consistent with the public interest” standard in Section 203 of the Federal Power Act); *see Gulf States Utils. Co. v. Fed. Power Comm’n*, 411 U.S. 747, 759 (1973) (discussing “public interest” standard in other provisions); *California v. Fed. Power Comm’n*, 369 U.S. 482, 484–86, 488 (1962). Primary policies of the Federal Power Act include protecting consumers against excessive prices; maintaining competition to the maximum extent possible consistent with the public interest; and encouraging the orderly development of plentiful supplies of electricity at reasonable prices. *NAACP v. Fed. Power Comm’n*, 425 U.S. 662, 670 (1976) (orderly development); *Otter Tail Power Co. v. United States*, 410 U.S. 366, 374 (1973) (maintaining competition); *Pa. Water & Power Co. v. Fed. Power Comm’n*, 343 U.S. 414, 418 (1952) (excessive prices). And because Section 202(c) expressly

protects environmental considerations, these are part of the public interest element too. *See NAACP*, 425 U.S. at 669 (“[T]he words ‘public interest’ . . . take meaning from the purposes of the regulatory legislation.”).

2. The Order Does Not Contain a Reasoned Basis that Eddystone Best Meets the Claimed Emergency and Serves the Public Interest.

Even if the scenario the Order lays out were an emergency pursuant to Section 202(c), the Department has not explained why ordering Eddystone to be available to operate is the best means to meet that scenario. Ex. 1 at 1 & n.2

The operational status of Eddystone suggests that it may be unable to meet purported emergencies. Although a spokesperson for Constellation indicated recently that the units were in “ready” status, that statement also indicated a need to take steps to “retain necessary staff and perform necessary maintenance to allow for safe and reliable operations.”¹¹⁷ And while the Eddystone Units did run during the June 23-26 heatwave, Unit 4 “went offline.”¹¹⁸ These old, ready-to-retire Units are themselves likely to be unreliable.

Moreover, the Order also does not address readily available and obvious alternatives which, in point of fact, would better compensate for the supposed “resource adequacy issues” asserted (inaccurately) by the Order. Ex. 1 at 1. PJM’s

¹¹⁷ Jon Hurdle, *Aging Pennsylvania power plant to keep running after Trump order on eve of shutdown*, Pennsylvania Capital-Star (June 9, 2025), <https://penncapital-star.com/energy-environment/aging-pennsylvania-power-plant-to-keep-running-after-trump-order-on-eve-of-shutdown/>.

¹¹⁸ PJM Interconnection, LLC, Compliance Report (June 24, 2025), <https://www.pjm.com/-/media/DotCom/documents/other-fed-state/20250624-doe-compliance-report-for-eddystone-units-3-and-4.pdf>.

own summer outlook predicts that even in the case of an all-time peak load, PJM would be able to meet its required reserve needs through its existing programs.¹¹⁹ PJM has already contracted demand response programs—a lower cost means to address grid reliability concerns—that can meet even a record-high summer demand peak this year and will continue to be available, and even expanded, in the coming years.¹²⁰ Additionally, Public Interest Organizations have highlighted above the robust transmission connectivity between PJM and neighboring regions, which PJM has accessed on a regular basis to support the stability of its grid. *See supra*, Section IV.B. This is consistent with the Department’s long-standing recognition that power pools and utility coordination “are a basic element in resolving electric energy shortages.” 46 Fed. Reg. at 39,985–86. The Department offers no reasonable basis to question the availability of resources from neighboring regions. But even if there were some barrier to transmission from those regions, the Department has not (and likely could not) explain why the Order provides a better means of ensuring resource sufficiency than addressing those barriers directly through its power to require “interchange” and “transmission” of electric energy from those neighboring regions. 16 U.S.C. § 824a(c)(1). Finally, even if

¹¹⁹ *See* Summer Outlook 2025, *supra* n. 4.

¹²⁰ *Id.* Commissioner Chang commended PJM’s use of demand response in the June 23-26 heatwave. (“In particular, I do want to highlight the PJM’s use of nearly 4,000 MW of demand response to reduce the peak load, their peak load, on Tuesday from what would have been the third highest peak load experienced on the PJM system. I see load flexibility as a key tool for grid operators to meet the challenges that we face and I commend PJM for the successful use of demand response during the system strain.”) FERC Commission Meeting, June 2025 Open Meeting, https://youtu.be/eAHyYMKI_Yg.

preventing the retirement of existing facilities was the best means of addressing the alleged emergency, the Order does not address why maintaining the Eddystone Units over other retiring units is the best means. Buchanan Units 1 and 2 are set to retire by July 1, 2025.¹²¹ These more modern combustion turbines, with a combined name plate generation of 88 MW, were constructed in 2002. Not only are these units newer than Eddystone, but their recent annual generation has been at least six times as much GWh and the plant has run almost twice as efficiently.¹²²

The Order's failure to include any consideration of these other alternatives. And the Order contains no reasoning demonstrating why Eddystone is the best alternative, or a better alternative than other options. As such, the Order is unlawful.

F. Because the Order Is Ambiguous, It Fails to Provide Fair Notice to the Public and Regulated Entities and Conflicts with Limitations on the Department's Authority.

The Order requires PJM and Constellation to "take all measures necessary to ensure that Eddystone Units are available to operate." Ex. 1 at 3. The Order further requires PJM to "take every step to employ economic dispatch of the units to minimize cost to ratepayers." *Id.* Those directions are so vague that neither the public nor the regulated entities have fair notice of the Department's actions, and so

¹²¹ Letter from Jason P. Connel, VP Planning, PJM to Nathan Dixon, VP Buchanan Generation, LLC, *Deactivation Notice for Buchanan Unit 1 & Unit 2* (May 30, 2025) <https://www.pjm.com/-/media/DotCom/planning/gen-retire/deactivation-notices/buchanan-unit-1-unit-2-pjm-response.pdf>.

¹²² See U.S. Energy Information Administration., Form EIA-923: Power Plant Operations Report (2023), <https://www.eia.gov/electricity/data/eia923/>.

imprecise as to conflict with the limitations on the Department's authority under Section 202(c).

The Department's direction to "ensure that Eddystone Units are available to operate" is impermissibly ambiguous and vague. Ex. 1 at 3. The Order does not explain, for instance, whether it requires (a) only that PJM and Constellation take measures so they are ready to send, receive, and respond to dispatch instructions to the extent capable with no other actions, or (b) that PJM and Constellation take additional measures that enlarge their capabilities to operate (like capital investments). It is also unclear whether PJM and Constellation are required to take measures to ensure that each of the units is equally "available to operate." *Id.* at 3.

Additionally, the Order's reference to "ratepayers" is impermissibly ambiguous and vague. *Id.* For instance, does the Order refer to ratepayers in the PJM wholesale energy markets, the PJM capacity market and ancillary services markets, bilateral markets, retail ratepayers, some combination of these ratepayers, or some other set of ratepayers? The Order also contains no geographic limit on the referenced ratepayers, such that it is not clear whether PJM is directed to minimize costs to ratepayers in Pennsylvania, across PJM, or some other area. It further contains no temporal limit, such that it is unclear whether PJM is directed to minimize cost to current ratepayers, future ratepayers, or both. Moreover, the Order contains no standards or guidance on how PJM is to reconcile or balance countervailing tensions, like minimization of costs to current and future ratepayers.

The ambiguities also make unclear the scope of activities and omissions coming within the effect of Section 202(c)(3), leaving the public and Public Interest Organizations in the dark as to what pollution is and is not allowed.

The above defects are fatal to the Order's validity. The Order does not give PJM and Constellation reasonably clear direction. And a reasonably prudent person—regardless of whether such person is familiar with the electric industry—cannot ascertain the Order's meaning. As such, the Order does not give fair notice of conduct that is forbidden or required, and it is therefore unlawful. *Fed.*

Comm'ns Comm'n v. Fox Telev. Stations, Inc., 567 U.S. 239, 253 (2012) (“A fundamental principle in our legal system is that laws which regulate persons or entities must give fair notice of conduct that is forbidden or required”); *Grayned v. City of Rockford*, 408 U.S. 104, 108–09 (1972) (“an enactment is void for vagueness if its prohibitions are not clearly defined”).

In addition, the ambiguities of the Order permit such a wide variety of actions and interpretations by PJM and Constellation that the Department has not met the statutory requirement to select only the activity that “*best* meet[s] the emergency and serves the public interest.” 16 U.S.C. § 824a(c) (emphasis added). There can only be one “best” in the Department’s judgment. Given the vagaries of the Order, many potential activities could be allowed, and the Department has not specified which activity is “best,” much less explained why. As such, the Department fails to comply with Section 202(c)(1) and the Order is consequently arbitrary and capricious, an abuse of discretion, not in accordance with law, and

beyond the Department’s statutory authority. *Cf. Allentown Mack Sales & Serv., Inc. v. NLRB*, 522 U.S. 359, 375 (1998).

G. The Department’s Order Fails to Provide the Conditions Necessary to Override Environmental Standards Under Section 202(c)(2).

The Order purports to authorize operations that may “conflict with environmental standards and requirements.” Ex. 1 at 2. Where an order may produce such a conflict, Section 202(c)(2) requires the Department to “ensure:” (1) that it compels “generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet the emergency and serve the public interest;” (2) that operations are “to the maximum extent practicable . . . consistent with any applicable Federal, State or local environmental law[s];” and (3) that it minimizes any adverse environmental impact, regardless of the facility’s compliance (or non-compliance) with environmental standards. 16 U.S.C § 824a(c)(2). The Order here violates all three of those statutory obligations—a failure with especially severe consequences given the pollution produced by the Eddystone Units.

First, the Order directly contradicts the Department’s obligation to require generation “only during hours necessary to meet the emergency.” *Id.* The Order instead states: “For the duration of this order, PJM is directed to take every step to employ *economic dispatch* of the units to *minimize cost* to ratepayers.” Ex. 1 at 3 (emphasis added). *See also* Ex. 10¹²³ (PJM stating that “Constellation will maintain active cost offers” on Markets Gateway to “operate on gas or oil for both

¹²³ Ex. 10 (PJM Reporting and Commitment Process).

Eddystone 3 and 4, unless either fuel is unavailable or if the units are on a Planned, Maintenance or Forced outage”). The “emergency” nominally described by the Order is “the potential loss of power to homes and local businesses in the areas that may be affected by curtailments,” during the Order’s 90-day span. Ex. 1 at 2. Even if the Department had substantiated that emergency (which it has not) the Federal Power Act would allow the Department to compel generation only when such losses would occur absent operation of the Eddystone Units. 16 U.S.C. 824a(c)(2); *see, e.g.*, Ex. 11 at 9 (DOE Order No. 202-17-4 Summary of Findings) (“authorizing operation of” units subject to emergency order “only when called upon . . . for reliability purposes,” according to “dispatch methodology” approved by Department). “Economic dispatch,” in sharp contrast, requires “the lowest-cost resources [to] run first,” in pursuit of “the lowest-cost energy available.” *City of New Orleans v. FERC*, 67 F.3d 947, 948-49 (D.C. Cir. 1995); *see also Fla. Power & Light Co. v. FERC*, 88 F.3d 1239, 1241 (D.C. Cir. 1996) (noting distinction between economic dispatch and reserve capacity rules). PJM has, for the time being, accepted that it may only dispatch the units to address immediate reliability and capacity needs.¹²⁴ But even that has proven not precise enough; on June 23 and 24, 2025, PJM allowed Eddystone to run¹²⁵ before relying on all of its demand response

¹²⁴ *Id.*

¹²⁵ *See* Compliance Report, *supra* n. 118; PJM Interconnection, LLC, Compliance Report (June 25, 2025), <https://www.pjm.com/-/media/DotCom/documents/other-fed-state/20250625-pjm-report-in-compliance-w-ordering-paragraph-b-of-the-doe-20250530-order-no-202-25-4.pdf>. In fact, on June 24 Eddystone Unit 3 ran for 24 hours and Eddystone 4 ran for 20. This appears to be beyond even the vague requirements of the Order.

resources.¹²⁶ The fact that PJM had additional demand response resources available to more than cover the day-ahead load forecast and in reality did have excess demand response resources means that the emergency claimed by the Order—“the potential loss of power to homes and local businesses”—was not in play and therefore Eddystone should not have been run. Moreover, any assurance by PJM does not alter the Order’s unlawful terms. By directing PJM to dispatch the plant along cost-based principles, rather than “only during hours necessary to meet the emergency,” the Department has violated Section 202(c)(2). 16 U.S.C. § 824a(c)(2).

Second, the Order fails to ensure that Eddystone operates, “to the maximum extent practicable,” in conformity with applicable environmental rules. *Id.* The Order paraphrases the statutory text—that “operation of the Eddystone Units must comply with applicable environmental requirements . . . to the maximum extent feasible,” but fails to specify *who* bears that responsibility or *what* such operation entails. Ex. 1 at 3. It imposes no further conditions beyond requiring Constellation to “pay fees or purchase offsets or allowances for emissions.” *Id.* The direction to “comply . . . to the maximum extent feasible” is, as a result, potentially unenforceable; the Order provides no basis for the Department, or anyone else, to determine whether the plant is in fact complying or who might face the consequences of any failure to do so. *See* Ex. 6 at 5–7 (DOE Order No. 202-22-4)

¹²⁶ *See* PJM Emergency Procedures, Postings, Effective from 06/23/2025 to 06/26/2025, <https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf> (calling on some but not all demand response).

(requiring, *inter alia*, reporting of “number and actual hours each day” of operation “in excess of permit limits or conditions,” and information describing how generators met their requirement to comply with environmental requirements to the maximum extent feasible). As such, the Order does not meet the Department’s statutory obligation to “*ensure*” the maximum feasible compliance with applicable environmental standards. 16 U.S.C. § 824a(c)(2) (emphasis added).

Third, the Order fails to provide any conditions at all to “minimize[] any adverse environmental impacts.” 16 U.S.C. § 824a(c)(2). That mandate is textually and substantively distinct from the Department’s (also unfulfilled) obligation to ensure maximum practicable compliance with environmental standards. *Id.* The Order fails, most importantly, to include measures, such as utilization of demand response resources, that would mitigate impacts when compliance with environmental standards proves impracticable. Past orders have routinely included such measures. *See, e.g.*, Ex. 11 at 2 (DOE Order No. 202-17-4 Summary of Findings) (permitting non-compliant operation only during specified hours, and requiring exhaustion of “all reasonably and practicably available resources,” including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions); Ex. 6 at 7 (DOE Order No. 202-22-4) (requiring “reasonable measures to inform affected communities” of non-compliant operations). At a minimum the statute requires the Department to include sufficiently detailed reporting obligations to ascertain what impacts result from emergency operations; without such reporting, the Department

has no ability to “ensure” that adverse impacts are minimized. *See, e.g.*, Ex. 12 Department of Energy, Order No. 202-24-1, at 5 (Oct. 9, 2024) (requiring detailed data on emissions of pollutants). The Order here instead gestures towards “such additional information” as the Department may (or may not) “request[] . . . from time to time.” Order at 3. That possibility of future, unspecified inquiry cannot satisfy the statute’s demand that the Department “ensure” that its Order minimizes environmental impacts. 16 U.S.C. § 824a(c)(2).

Failure to meet those conditions is especially critical because the Eddystone Units can be operated on either gas or oil. PJM and Constellation have both indicated that the units intend to use fuel oil, rather than gas, when economically favorable. Ex. 10 (PJM Reporting and Commitment Process). Allowing the units to utilize oil based solely on cost—especially absent a requirement to exhaust demand-response and other available resources prior to dispatching the units at all—does not minimize environmental impacts “to the maximum extent practicable.” 16 U.S.C. 824a(c)(2). *See* Ex. 13 (stating that Eddystone Units may alter fuels based on “pricing changes”).¹²⁷ Oil-fired generation results in higher emissions of both criteria pollutants and hazardous air pollutants. Ex. 4 (Eddystone Title V Permit) at 28, 50 (noting sulfur content of oil and higher NO_x emissions from oil-fired generation); 68 Fed. Reg. 1660, 1678 (Jan. 13, 2003) (noting that switching from oil to natural gas “would reduce mercury, metallic [toxics], and inorganic” hazardous

¹²⁷ Constellation Energy, *Eddystone Generating Station*, <https://www.constellationenergy.com/our-company/locations/location-sites/eddystone-generating-station.html> (last visited June 27, 2025).

air pollutant emissions). The months during which the Order operates do not pose a risk that natural gas will be unavailable, so even if an emergency requiring generation from the Eddystone Units existed—which it does not—gas-fired generation would be entirely practicable. Ex. 14 (Natural gas may not be available to Eddystone Units “[w]hen there’s a cold snap” or during “a polar vortex”).¹²⁸ The Order’s failure to at least ensure that the Eddystone Units operate only on the least-polluting fuel available to them, even as it authorizes violation of governing environmental standards, violates the law. 16 USC § 824a(c)(2). At a minimum, the Department should impose tighter limits on the dispatch of Eddystone.

H. The Order and the Department’s Continued Conduct Are Inconsistent with Departmental Procedure, Depriving the Public and the Public Interest Organizations of Fair Notice and an Adequate Record.

According to the Department’s procedures, the agency will use “best efforts” to post filings on a specified website within 24 hours of receipt.¹²⁹ The Department has received, and is supposed to receive, materials related to this proceeding that it has not posted. On June 13, 2025, the Department received a letter from PJM reporting on its compliance with the 202(c) Order.¹³⁰ The Public Interest

¹²⁸ Constellation Energy, *Natural Gas and Oil*, <https://www.constellationenergy.com/our-work/what-we-do/generation/natural-gas-and-oil.html> (last visited June 27, 2025).

¹²⁹ Ex. 2 DOE Rehearing Procedures, *supra* n. 5.

¹³⁰ Letter from Michael Bryson, PJM, to Secretary of Energy Christopher Wright, *PJM Report in Compliance with Ordering Paragraph D of the Department of Energy’s May 30, 2025 Order No. 202-25-4* (June 13, 2025), <https://www.pjm.com/-/media/DotCom/documents/other-fed-state/20250613-doe-pjm-report-on-compliance-with-Eddystone-order-202-25-4.pdf>.

Organizations have been able to access this letter because PJM published the letter to its website. The Department still has not met its obligation to publish this letter to its website. The Department may have received additional materials. The Order requires daily notifications on operations, p. 3 ¶ B, and such additional information regarding environmental impacts as the Department requests, p. 3 ¶ D. None of those materials are posted on the Department’s 202(c) website.¹³¹

The Department must follow its own procedures. *See Morton v. Ruiz*, 415 U.S. 199, 235 (1974); *Mine Reclamation Corp. v. FERC*, 30 F.3d 1519, 1524 (D.C. Cir. 1994). The Department’s failure to follow its procedures deprives the public and Public Interest Organizations of fair notice and an adequate record. *See United States v. Nova Scotia Food Prods. Corp.*, 568 F.2d 240, 249 (2d Cir. 1977).

VI. REQUEST FOR STAY

Public Interest Organizations further move the Department for a stay of the Order until the conclusion of judicial review. 18 C.F.R. § 385.212.¹³² The Department has the authority to issue such a stay under the Administrative Procedure Act and should do so where “justice so requires.” 5 U.S.C. § 705. In

¹³¹ The Department still has not posted filings for other recent 202(c) orders, either. *See e.g.*, U.S. Dep’t of Energy, *Federal Power Act Section 202(c) Midcontinent Independent System Operator (MISO)*, <https://www.energy.gov/ceser/federal-power-act-section-202c-midcontinent-independent-system-operator-miso> (last visited June 27, 2025) (the Department received at least two requests for rehearing of the Campbell 202(c) order that it has not posted).

¹³² Pursuant to FPA Section 313 and Rule 713(e) of the applicable rules, the filing of a request for rehearing does not automatically stay a Department Order. 16 U.S.C. § 825A(c), 18 C.F.R. § 385.713(e).

deciding whether to grant a request for stay, agencies consider: (1) whether the party requesting the stay will suffer irreparable injury without a stay; (2) whether issuing a stay may substantially harm other parties; and (3) whether a stay is in the public interest. *See Nken v. Holder*, 556 U.S. 418, 434, 436 (2009); *Ohio v. EPA*, 603 U.S. 279, 291 (2024); *see, e.g., Midcontinent Indep. Sys. Operator, Inc.*, 184 FERC ¶ 61,020, at P 41 (2023); *ISO New Eng. Inc.*, 178 FERC ¶ 61,063, at P 13 (2022), *rev'd on other grounds sub nom. In re NTE Conn., LLC*, 26 F.4th 980, 987-88 (D.C. Cir. 2022).

Injuries under this standard must be actual, certain, imminent, and beyond remediation. *Mexichem Specialty Resins, Inc. v. EPA*, 787 F.3d 544, 555 (D.C. Cir. 2015); *Wis. Gas Co. v. FERC*, 758 F.2d 669, 674 (D.C. Cir. 1985); *ANR Pipeline Co.*, 91 FERC ¶ 61,252, at p. 61,887 (2000); *City of Tacoma*, 89 FERC ¶ 61,273, at p. 61,795 (1999) (recognizing that, absent a stay, options for “meaningful judicial review would be effectively foreclosed”). Financial injury is only irreparable where no “adequate compensatory or other corrective relief will be available at a later date, in the ordinary course of litigation.” *Wis. Gas Co.*, 758 F.2d at 674 (quoting *Va. Petroleum Jobbers Ass’n v. Fed. Power Comm’n*, 259 F.2d 921, 925 (D.C. Cir. 1958)); *see also In re NTE Conn., LLC*, 26 F.4th at 990-91. Environmental injury, however, “can seldom be adequately remedied by money damages and is often permanent or at least of long duration, *i.e.*, irreparable. If such injury is sufficiently likely, therefore, the balance of harms will usually favor the issuance of an

injunction to protect the environment.” *Amoco Prod. Co. v. Vill. of Gambell*, 480 U.S. 531, 545 (1987).

A. Intervenor Are Irreparably Harmed by the Order.

Here, a stay is necessary to ensure that Eddystone does not continue with activities that are already causing irreparable harm to Public Interest Organizations, their members, and the public as a result of the Order.¹³³

Operating the Eddystone Units, which burn oil and natural gas, results in emissions of dangerous air pollutants, including sulfur dioxide (“SO₂”), nitrogen oxides (“NO_x”), particulate matter (“PM”), and carbon dioxide (“CO₂”) that would not otherwise have occurred but for the Order blocking the deactivation of the Eddystone Units.¹³⁴ These pollutants cause and exacerbate respiratory problems, cardiovascular issues, and other health conditions. These impacts are accentuated by Eddystone’s location in an area already disproportionately overburdened by heavily polluting industrial sources and toxic waste sites.¹³⁵

The Order also causes irreparable harm by imposing costs on PJM ratepayers that would not otherwise be borne and will not be recoverable through litigation. Constellation is complying with the Order and is seeking cost recovery through

¹³³ The Eddystone Units have in fact operated as a result of the Order. *See, e.g., Compliance Report, supra* n. 118.

¹³⁴ *Id.*

¹³⁵ *See supra*, Section IV.A.

FERC.¹³⁶ If that request is granted, costs will be borne by PJM ratepayers, and the Department does not identify any clear recourse for a refund in the event the Order is declared unlawful. In forcing ratepayers to reopen and operate an uneconomic, unreliable, and obsolete resource that was already approved for closure, the Order also jeopardizes the diversification of generating resources the Department itself has said increases grid reliability and will inherently and unjustifiably add to ratepayer costs.¹³⁷ As there is no clear recourse to recovering these costs from the Department should Public Interest Organizations prevail in their challenge, a stay pending judicial review is necessary to protect ratepayers from unwarranted energy cost increases-especially at a time when energy prices are already on the rise.¹³⁸

B. A Stay Would Not Result in Harm to Any Other Interested Parties.

No other interested parties would be harmed by a stay. The issuance of a stay would not harm end-use electricity consumers because the lack of an actual emergency means that a stay would not disrupt the provision of electricity. *See supra*, Section V.C.3. Furthermore, because Constellation and PJM had both already planned for the closure of the Eddystone Units, a stay would only have the

¹³⁶ *See* Letter from David E. Mills, Chair, PJM Board, to PJM Members and Stakeholders (June 26, 2025), [20250626-pjm-board-letter-re-results-of-the-cifp-process-for-doe-202-c-order-for-eddystone-units-3-and-4.pdf](https://www.pjm.com/commitments-and-contracts/cifp-process-for-doe-202-c-order-for-eddystone-units-3-and-4.pdf).

¹³⁷ *See* U.S. Dep't of Energy, Energy Reliability and Resilience, <https://www.energy.gov/eere/energy-reliability-and-resilience> (last visited June 26, 2025).

¹³⁸ *See* Mitchell Terpstra, *2024 News Release: PJM Capacity Auction Prices Skyrocket*, Energy Choice Blog (Oct. 2, 2024), <https://electricityrates.com/resources/pjm-capacity-auction-spike/>.

effect of relieving them of the administrative, compliance, and planning burdens imposed by the Order. *See, e.g.*, Ex. 1 at 2-3. On the balancing of equities, there is therefore no meaningful countervailing harm that would follow from a stay.

C. A Stay is in the Public Interest.

There is no public interest served by the Order, and a stay will only benefit the public. First, the Order exceeds the Department’s authority; it has provided no reasonable grounds to substantiate any near-term or imminent shortfall in electricity supply that would justify the Eddystone Units’ continued operation. *See League of Women Voters v. Newby*, 838 F.3d 1, 12 (D.C. Cir. 2016) (noting that “there is a substantial public interest ‘in having governmental agencies abide by the federal laws that govern their existence and operations’”) (quoting *Washington v. Reno*, 35 F.3d 1093, 1103 (6th Cir. 1994)). Second, a stay would protect the broader public—beyond Public Interest Organizations and their members—from the costs and additional pollution produced by unnecessary operation of the Eddystone Units.

VII. CONCLUSION

For the reasons set forth above, the undersigned Public Interest Organizations respectfully request that the Department grant intervention; grant rehearing and rescind the Order (and any renewals of the Order); and stay the Order.

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