BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 61

MISO Tariff Attachment Y

ATTACHMENT Y

Notification of Generation Resource/SCU/Pseudo-tied Out Generator

Change of Status,

Including Notification of Rescission

This is a notification of change of status of a Generation Resource, Synchronous Condenser Unit ("SCU"), or Pseudo-tied out Generator in accordance with Section 38.2.7.a of the Tariff. An electronic form must be submitted to the Transmission Provider via its online application tool in the manner specified by the Transmission Planning Business Practices Manual (BPM-020), and a form will be considered complete on the date of such online application.

The Transmission Provider may request additional information as reasonably necessary to support operations under the Tariff.

Owner of the Generation Resource, SCU or Pseudo-tied out Generator:

_____

Name of Market Participant:_____

Owner's state of organization or incorporation _____

Generation Resource/SCU/Pseudo-tied Out Generator [plant and unit number(s)] _____

_____

Source/Identification of Generation Interconnection Service [name of agreement, parties, date, date filed and docket number, and any other information to identify an agreement] _____

_____

Pursuant to the terms of the MISO Tariff, Owner hereby certifies that it will

[ ] Suspend for economic reasons operation of all or a portion of the Generation Resource/SCU/Pseudo-tied out Generator commencing on ___ [day] of _____ [month] of _____ [year]

[ ] Rescind the current notice to Suspend

The facility is further described as follows:

Location: _____

Unit Name	CPNode (if applicable)	Nameplate Capacity(MW)	Change in Capacity(MW)
_____	_____	_____	_____
_____	_____	_____	_____
_____	_____	_____	_____
_____	_____	_____	_____

Owner understands and agrees that this notification is provided in accordance with Section 38.2.7 of the Transmission Provider's Tariff and will not be made public by the Transmission Provider except as provided for under Section 38.2.7 of the Tariff.

The undersigned certifies that he or she is an officer of the owner of the Generation Resource/SCU/Pseudo-tied out Generator, that he or she is authorized to execute and submit this notification, and that the statements contained herein are true and correct.

_____

Signature

Name: _____ Contact Information

Title: _____ Email: _____

Date: _____ Phone: _____

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 62

FERC Technical Conference Notice

Document Accession #: 20250602-3068 Filed Date: 06/02/2025

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Meeting the Challenge of Resource Adequacy in Regional Transmission Organization and Independent System Operator Regions	Docket No. AD25-7-000

THIRD SUPPLEMENTAL NOTICE OF COMMISSIONER-LED TECHNICAL CONFERENCE

(June 2, 2025)

As announced in the February 20, 2025 Notice in this proceeding, the Federal Energy Regulatory Commission (Commission) will convene a Commissioner-led technical conference in the above-referenced proceeding. The two-day technical conference will take place from 9:00 a.m. to 4:00 p.m. Eastern Time on Wednesday, June 4, 2025, and 9:00 a.m. to 4:15 p.m. Eastern Time on Thursday, June 5, 2025, in the Kevin J. McIntyre Commission Meeting Room at the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426.

The purpose of this technical conference is to discuss generic issues related to resource adequacy constructs, including the roles of capacity markets in the Regional Transmission Organization (RTO)/Independent System Operator (ISO) regions that utilize them and alternative constructs in RTO/ISO regions without capacity markets. The conference will start with a panel discussion on resource adequacy challenges across RTO/ISO regions, including regional differences. The remainder of the first day will include three panels specific to PJM Interconnection, L.L.C. (PJM) that will explore PJM's resource adequacy challenge, PJM states' perspectives, and additional perspectives on PJM's path forward. The second day will start with two panels specific to Midcontinent Independent System Operator, Inc. (MISO) that will explore MISO's resource adequacy challenge and perspectives on MISO's path forward. The remainder of the second day will include one panel to explore the resource adequacy challenge in ISO New England Inc. (ISO-NE) and New York Independent System Operator, Inc. (NYISO) and a final panel on the resource adequacy challenge in California Independent System Operator Corporation (CAISO) and Southwest Power Pool (SPP). The preliminary agenda for this conference is attached to this Supplemental Notice and provides more detail for each panel.

Commission staff will post pre-filed statements submitted by panelists on the FERC technical conference webpage prior to the conference and in eLibrary. With the exception of opening statements on Panel 1, which may be delivered orally, all other

panels will proceed immediately to questions from the Chairman and Commissioners.

All interested persons are also invited to file pre-technical conference comments in eLibrary on the issues of the conference, including the questions listed in the attached agenda. Commenters need not answer all the questions but are encouraged to organize responses using the numbering and sequencing in the attached agenda.

The Commission does not intend to discuss at this technical conference any specific proceeding pending before the Commission, including proceedings that involve similar issues. These proceedings include, but are not limited to:

NRG Business Marketing LLC; NRG Power Marketing LLC	Docket Nos.	ER23-2688, et al.; ER22-1539, et al.
Southwest Power Pool, Inc.	Docket Nos.	ER24-1317-000 ER24-2953-000
H.A. Wagner LLC; Brandon Shores LLC	Docket Nos.	ER24-1787, et al.; ER24-1790, et al.
PJM Interconnection, L.L.C.	Docket No.	ER24-2045-000
California Independent System Operator Corp.	Docket Nos.	ER24-2671, et al.
Southwest Power Pool, Inc.	Docket No.	ER25-89-000
Midcontinent Independent System Operator, Inc.	Docket Nos.	ER25-507, et al.
Manitowoc Public Utilities	Docket No.	ER25-634-000
PJM Interconnection, L.L.C.	Docket Nos.	ER25-682, et al.
PJM Interconnection, L.L.C.	Docket Nos.	ER25-712, et al.
PJM Interconnection, L.L.C.	Docket Nos.	ER25-785, et al.
PJM Interconnection, L.L.C.	Docket Nos.	ER25-1128, et al.
PJM Interconnection, L.L.C.; Commonwealth of Pennsylvania v. PJM Interconnection, L.L.C.	Docket Nos.	ER25-1357, et al.; EL25-46, et al.
PJM Interconnection, L.L.C.	Docket No.	ER25-1525-000

PJM Interconnection, L.L.C.	Docket No. ER25-1623-000
Midcontinent Independent System Operator, Inc.	Docket No. ER25-1674-000
Midcontinent Independent System Operator, Inc.	Docket No. ER25-1729-000
Midcontinent Independent System Operator, Inc.	Docket No. ER25-1802-000
Midcontinent Independent System Operator, Inc.	Docket No. ER25-1886-000
PJM Interconnection, L.L.C.	Docket No. ER25-2002-000
Midcontinent Independent System Operator, Inc.	Docket No. ER25-2050-000
New York Independent System Operator, Inc.	Docket No. ER25-2245-000
Midcontinent Independent System Operator, Inc.	Docket No. ER25-2247-000
Southwest Power Pool, Inc.	Docket No. ER25-2296-000
Southwest Power Pool, Inc.	Docket No. ER25-2297-000
Midcontinent Independent System Operator, Inc.	Docket No. ER25-2298-000
Sierra Club, Natural Resources Defense Council, Inc., and Sustainable FERC Project v. Southwest Power Pool, Inc.	Docket No. EL24-96-000
Sierra Club, Natural Resources Defense Council, Public Citizen, Sustainable FERC Project, and Union of Concerned Scientists v. PJM Interconnection, L.L.C.	Docket No. EL24-148-000
Joint Consumer Advocates, Illinois Citizens Utility Board, Maryland Office of the People's Counsel, New Jersey Division of Rate Counsel, Office of the Ohio Consumers' Counsel, Office of the People's Counsel for the District of Columbia v. PJM Interconnection, L.L.C.	Docket No. EL25-18-000

Constellation Energy Generation, LLC v. PJM Interconnection, L.L.C.	Docket No. EL25-20-000
PJM Interconnection, L.L.C., Allegheny Electric Cooperative, Inc., American Transmission Systems, Incorporated, Atlantic City Electric Company, Baltimore Gas and Electric Company, Delmarva Power & Light Company, Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc., East Kentucky Power Cooperative, Inc., Essential Power Rock Springs, LLC, Hudson Transmission Partners, LLC, Jersey Central Power & Light Company, Mid-Atlantic Interstate Transmission, LLC, Neptune Regional Transmission System, LLC, Old Dominion Electric Cooperative, PECO Energy Company, PPL Electric Utilities Corporation, Potomac Electric Power Company, Public Service Electric and Gas Company, Rockland Electric Company, Trans-Allegheny Interstate Line Company, Transource West Virginia, LLC, UGI Utilities, Inc., Monongahela Power Company, The Potomac Edison Company, Commonwealth Edison Company, Commonwealth Edison Company of Indiana, Inc., The Dayton Power and Light Company, AEP Appalachian Transmission Company, Inc., AEP Indiana Michigan Transmission Company, Inc., AEP Kentucky Transmission Company, Inc., AEP Ohio Transmission Company, Inc., AEP West Virginia Transmission Company, Inc. Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company, Duquesne Light Company, Virginia Electric and Power Company, Linden VFT, LLC,	Docket Nos. EL25-49, et al.

City of Cleveland, Department of Public Utilities, Division of Cleveland Public Power, City of Hamilton, OH, Southern Maryland Electric Cooperative, Inc., Ohio Valley Electric Corporation, AMP Transmission, LLC, Silver Run Electric, LLC, NextEra Energy Transmission MidAtlantic Indiana, Inc., Wabash Valley Power Association, Inc., Keystone Appalachian Transmission Company	
Joint Consumer Advocates v. PJM Interconnection, L.L.C.	Docket No. EL25-76-000
North American Electric Reliability Corporation	Docket No. RD25-7-000

The technical conference will be open to the public. Advance registration is not required, and there is no fee for attendance. Information will also be posted on the Calendar of Events on the Commission's website, www.ferc.gov, prior to the event. To stay apprised of issuances in this docket, there is an "eSubscription" link on the Commission's web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s).

The technical conference will be transcribed and webcast. Transcripts will be available for a fee from Ace Reporting (202-347-3700). A link to the webcast of this event will be available in the Commission Calendar of Events at www.ferc.gov. The Commission provides technical support for the free webcasts. Please call 202-502-8680 or email customer@ferc.gov if you have any questions.

Commission technical conferences are accessible under section 508 of the Rehabilitation Act of 1973. For accessibility accommodations, please send an email to accessibility@ferc.gov or call toll free 1-866-208-3372 (voice) or 202-208-8659 (TTY) or send a fax to 202-208-2106 with the required accommodations.

For more information about this technical conference, please contact Tim Bialecki at timothy.bialecki@ferc.gov or 202-502-8403. For legal information, please contact Nathan Lobel at nathan.lobel@ferc.gov or 202-502-8456. For logistics information, please contact the Office of Public Participation (OPP) at OPP@ferc.gov or 202-502-6595.

Debbie-Anne A. Reese,
Secretary.

Meeting the Challenge of Resource Adequacy in Regional Transmission Organization and Independent System Operator Regions, Docket No. AD25-7-000

Agenda

Wednesday, June 4, 2025

9:00 am – 9:15 am: Welcome and Opening Remarks

9:15 am – 10:30 am: Panel 1: The Resource Adequacy Challenge in RTOs/ISOs

This panel will include opening statements from RTO/ISO representatives and a North American Electric Reliability Corporation (NERC) representative. Panelists should focus on defining resource adequacy, identifying resource adequacy challenges across RTOs/ISOs, and identifying information that will inform and guide later discussions.

In recent years, resource retirements, load growth, and the changing resource mix have contributed to resource adequacy challenges across the nation, including in the RTO/ISO regions. According to NERC's 2024 Long-Term Reliability Assessment, five of the six Commission jurisdictional RTO/ISO regions are at either high or elevated risk of experiencing electricity supply shortfalls.[1] High risk regions are expected to fall below established resource adequacy criteria in the next five years, while elevated risk regions meet resource adequacy criteria but are likely to experience shortfalls in extreme weather conditions. Some trends that continue to challenge regions' abilities to achieve resource adequacy include: increasing amounts of large commercial and industrial loads (e.g. data centers); electrification of energy end uses in transportation and building heating/cooling; retirement of baseload generation resources; and slower than anticipated interconnection of new resources.[2] RTO/ISO representatives should discuss their current resource adequacy constructs, recent resource adequacy challenges and, most importantly, their plans and recommendations to address resource adequacy challenges within their RTOs/ISOs in the future as demand grows.

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[1] NERC, *2024 Long-Term Reliability Assessment* 6 (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[2] *See id.* 8-9, 12, 16, 19.

Questions that panelists could be asked:

1. What is the current state of resource adequacy across RTO/ISO regions? Is this static or variable? Are resource adequacy challenges more acute in RTO/ISO regions with capacity markets compared to those RTO/ISO regions with alternative resource adequacy constructs? Why or why not?

2. Given load growth and generation forecasts, what are your resource adequacy challenges going forward?

3. How do you reconcile your RTO's/ISO's resource adequacy objectives with state public policy requirements, which may accelerate the retirement of certain resource types or limit the entry of other resource types? For example, in light of such state public policy requirements and particularly in multi-state RTOs/ISOs, how does your RTO/ISO ensure resource adequacy?

4. What are the key drivers that cause delays in the construction and interconnection of generators in your RTO/ISO? What can be done to accelerate the interconnection of generators to help meet the resource adequacy challenge? How have factors external to your RTO/ISO, such as supply chains and siting/permitting, impacted generator interconnection timelines? What is the composition of resources in the queue? Will accelerating queue processes help address the challenge of resource adequacy? How many resources (by number and aggregate nameplate capacity) have received approval for interconnection but have not been constructed? How, if at all, are the expected resource adequacy contributions of a resource in the interconnection queue considered during the interconnection process?

5. Are there additional concerns that may affect resource adequacy in the near term (e.g., over the next five years) and in the longer term (e.g., ten years and beyond)?

6. In NERC's view, what aspects of resource adequacy planning could be improved? For example, what type of reliability metric (or metrics) should be used in resource adequacy planning models? What elements of resource adequacy planning can be improved or could serve as best practices?

7. How does your RTO/ISO approach capacity accreditation? What are the benefits and drawbacks of harmonizing capacity accreditation methods across regions versus allowing for regional variation?

    a. Given that many regions use the same probabilistic models for both evaluating resource adequacy and/or reserve margins and for Effective Load Carrying Capability (ELCC) accreditation, are there best practices in approaches that NERC is observing that could help align various regions

across the country in using the best modeling methodologies or data sources, etc.?

b. What are the potential strengths, weaknesses, and implementation considerations of alternatives to ELCC when evaluating the contribution of various types of resources in meeting resource adequacy requirements?

8. How can the RTOs/ISOs ensure that their demand forecasts adequately take into account load growth from data centers and other large loads? How can the RTOs/ISOs ensure there is sufficient supply to meet these demands, and what will those sources of supply be?

9. How can demand flexibility and demand-side management solutions be utilized to address load growth and resource adequacy concerns?

10. How do you reflect transmission availability—both regional and interregional—in your resource adequacy planning and requirements? To what extent do your transmission planning processes capture the resource adequacy benefits of regional and interregional transmission?

Panelists

- Manu Asthana, PJM, President and CEO
- Todd Ramey, MISO, Senior Vice President of Markets and Digital Strategy
- Gordon van Welie, ISO-NE, President and CEO
- Richard J. Dewey, NYISO, President and CEO
- Lanny Nickell, SPP, President and CEO
- Elliot Mainzer, CAISO, President and CEO
- Jim Robb, NERC, President and CEO

10:30 am – 10:45 am: 15-minute Break

10:45 am – 12:00 pm: Panel 2: PJM's Resource Adequacy Challenge

This panel discussion among the Commission, PJM, and stakeholders will focus on resource adequacy challenges specific to PJM, including whether changes to the existing market construct are needed or potential alternatives to the existing mandatory capacity market construct should be considered.

PJM states that it is facing potential capacity shortfalls as soon as the 2026/2027 Delivery Year due to a combination of trends, including growing electricity demand,

rapid retirement of thermal generators, and slow entry of replacement generation.[3] PJM's capacity auction for the 2025/2026 Delivery Year cleared at record high prices due to a variety of factors, including declines in supply, growing demand, a higher reserve requirement, and revised capacity market rules.[4] In response to recent challenges, PJM has revisited several of its capacity market's design elements, such as non-performance penalties, granular resource adequacy modeling, resource accreditation, and the role of reliability must-run resources in PJM's capacity market.[5]

Questions that panelists could be asked:

1. What is the state of resource adequacy in PJM in the near term (e.g., over the next five years) and over the longer term (e.g., ten years and beyond)?

2. Going forward, what steps will PJM need to take to ensure resource adequacy? Is PJM's resource adequacy construct adequate to determine resource adequacy needs given changing circumstances (e.g., unforeseen load growth, changes in state public policy requirements, faster-than-anticipated retirement of resources)?

3. How does PJM establish its load and resource forecasts?

    a. Have the assumptions driving load and capacity resource forecasts changed over time? If so, how?

    b. How do the forecast models weight different inputs? Are some assumptions more uncertain, important, or impactful than others?

    c. How have the forecasts performed historically and are you considering any changes to forecasting models or processes? For example, are you considering requiring demonstration of commercial readiness from prospective new large load additions?

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[3] PJM Board of Directors, Letter to Stakeholders (Dec. 9, 2024), https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2024/20241209-board-letter-outlining-action-on-capacity-market-adjustments-rri-and-sis.pdf.

[4] PJM, *2025/2026 Base Residual Auction Results* (2024), https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2024/20240821/20240821-item-08---2025-2026-base-residual-auction---presentation.pdf.

[5] *See PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,088 (2025); *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,117 (2025).

4. To what extent are barriers to entry (e.g., the interconnection queue backlog, supply chain limitations, siting and permitting delays, etc.) impeding the ability of the capacity market to achieve resource adequacy at just and reasonable rates? What opportunities are there to address these barriers to entry?

5. How does PJM consider electric-gas coordination issues in the context of resource adequacy planning and capacity resource accreditation?

    a. To what extent do uncertainties pertaining to natural gas fuel supplies or infrastructure constraints affect resource adequacy planning in PJM? How can PJM better address those uncertainties?

    b. Does PJM need additional natural gas pipeline infrastructure for the future or is existing infrastructure sufficient?

6. To what extent does the availability of regional and interregional transmission capability affect resource adequacy planning in PJM? How can PJM better address the effect of transmission capability on resource adequacy?

7. Is the PJM capacity market adequately designed to provide correct signals for needed capacity additions? Given the degree to which the capacity market rules have changed in recent years, is the PJM capacity market producing stable investment signals? How have these frequent rule changes affected market participants and consumers? How has PJM sought to maintain stable investment signals in the face of these changes?

8. Do you think PJM's capacity market is more effective at delivering resource adequacy than other RTOs/ISOs' approaches would be in PJM and, if so, why?

9. Are there alternatives to a mandatory capacity market construct that should be considered, such as a residual capacity market construct (e.g., MISO), enhanced use of self-supply mechanisms such as Fixed Resource Requirement (FRR), or other mechanisms, including allowing load-serving utilities to own generation, increased long-term contracting by load-serving utilities, or other alternatives? To what extent do the current PJM market rules allow for these alternatives?

10. Several states in PJM have public policy requirements that drive resource entry and exit decisions. How does PJM work with the states and the District of Columbia to identify and meet the region's resource adequacy needs at just and reasonable rates? Has PJM studied the effects of state public policy on either resource adequacy or capacity market outcomes? What are the effects of state policies on resource adequacy in PJM?

Panelists

- Adam Keech, PJM, Vice President of Market Design and Economics
- Joe Bowring, Monitoring Analytics, President and Independent Market Monitor
- Wendy Stark, PPL Corporation, Executive Vice President of Utilities & Chief Legal Officer
- Brian Tierney, FirstEnergy, Chairman, President, and CEO
- Glen Thomas, PJM Power Providers Group, President
- Marji Philips, LS Power, Senior Vice President of Wholesale Market Policy
- Scott Hallam, Boardwalk Pipelines, President and CEO (on behalf of the Interstate Natural Gas Association of America (INGAA)).

12:00 pm – 1:00 pm: Lunch Break

1:00 pm – 2:15 pm: Panel 3: PJM States' Perspectives

This panel discussion between the Commission and state representatives will focus on the status of resource adequacy, and the role of states in achieving resource adequacy, in PJM.

Questions that panelists could be asked:

1. What should be the allocation of roles and responsibilities between PJM and the states to ensure resource adequacy in the PJM region? Please explain the role your state takes on with regard to the procurement of capacity to meet resource adequacy requirements, including with respect to bilateral contracting, self-supply, and/or purchases from the PJM capacity market. Do states in PJM have appropriate opportunities to participate in PJM decisions regarding resource adequacy? Are there different, or greater, responsibilities that states should assume to ensure resource adequacy?

2. Is PJM's capacity market compatible with state public policy requirements? Why or why not?

3. Do you believe consumers are treated fairly in the PJM capacity market process? If so, why? If not, why not?

4. Are changes necessary to ensure that the PJM capacity market process delivers resource adequacy at just and reasonable rates?

5. What barriers, if any, are there to PJM states assuming more responsibility for resource adequacy via constructs like the Integrated Resource Planning (IRP) model, a hybrid between the capacity market and IRP model, or enhanced use of

self-supply mechanisms such as FRR? Should alternatives to the mandatory capacity market construct be considered or does your state prefer retaining the existing construct?

6. Does your state currently have sufficient expertise on resource adequacy mechanisms and resource adequacy modeling to meet the challenge of resource adequacy without PJM's technical expertise, or does your state need additional resources? If your state would need additional resources, what types of resources would be required and what are the benefits and costs of developing that technical expertise compared with continuing to rely on PJM's expertise? Based on those costs and benefits, would your state prefer to continue to rely on PJM's technical expertise?

7. What state mechanisms, such as long-term bilateral contracts, self-supply arrangements, or other approaches, exist to help ensure that rates for procuring resources will be just and reasonable? Will consumers have access to the information (transparency) to understand their share of the costs for procuring adequate resources?

Panelists

- Chairman Emile C. Thompson, Public Service Commission of the District of Columbia, President of Organization of PJM States, Inc. (OPSI)
- Jacob Finkel, Office of the Governor of Pennsylvania, Deputy Secretary of Policy
- President Christine Guhl-Sadovy, New Jersey Board of Public Utilities
- Commissioner Kelsey Bagot, Virginia State Corporation Commission
- Commissioner Michael Richard, Maryland Public Service Commission
- Commissioner David Veleta, Indiana Utility Regulatory Commission
- Commissioner Dennis Deters, Public Utilities Commission of Ohio

2:15 pm – 2:30 pm: 15-minute Break

2:30 pm – 3:45 pm: Panel 4: Additional Perspectives on PJM's Path Forward and the Future of Resource Adequacy in PJM

Panelists will offer their varied perspectives on the topics discussed in the first two PJM-specific panels. Topics to be explored during this panel may include reforms to the current PJM capacity market design, potential alternatives to the existing mandatory capacity market, the roles and interests of states and other entities (e.g., cooperative and municipal systems) in achieving resource adequacy, and how to ensure resource adequacy at reasonable costs for consumers.

Panelists

- Brian O. Lipman, Consumer Advocates of the PJM States (CAPS), President
- Brian George, Google, US Energy Markets, Senior Lead
- Casey Roberts, Natural Resources Defense Council, Director of RTO Advocacy
- Michelle Bloodworth, America's Power, President and CEO
- Denise Foster Cronin, East Kentucky Power Cooperative, Vice President of Federal and RTO Regulatory Affairs
- Susan E. Bruce, Industrial Energy Consumers of America, PJM Industrial Customer Coalition, Coalition of MISO Transmission Customers, and American Forest & Paper Association, Counsel

3:45 pm – 4:00 pm: June 4 Closing Remarks

Thursday, June 5, 2025

9:00 am – 9:15 am: Welcome and Opening Remarks

9:15 am – 10:45 am: Panel 5: MISO's Resource Adequacy Challenge

This panel discussion among the Commission, MISO, and MISO stakeholders will focus on resource adequacy challenges specific to MISO.

MISO faces the most immediate risk of falling below established resource adequacy criteria compared to all other regions assessed by NERC in its 2024 Long-Term Reliability Assessment.[6] According to MISO's 2024 Regional Resource Assessment (RRA), MISO may need to add 17 gigawatts of new capacity each year for the next 20 years—more than triple the recent average rate of 4.7 gigawatts per year—to reliably meet future demand and policy goals.[7] Although MISO's RRA expects thermal resources and battery storage to account for the bulk of the region's accredited capacity in the future, the capacity of variable energy resources is expected to grow and contribute to

[6] *See* NERC, *2024 Long-Term Reliability Assessment* (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[7] MISO, *2024 Regional Resource Assessment* (Jan. 2025), https://wdeawebsite.blob.core.windows.net/usrfiles/documents/miso%202024%20regional%20resource%20assessment.pdf.

an increasing need for ramp capability.[8]

Questions that panelists could be asked:

1. What is the state of resource adequacy in MISO in the near term (e.g., over the next five years) and over the longer term (e.g., ten years and beyond)?

    a. Is MISO's resource adequacy construct delivering resource adequacy in MISO?

    b. What are the benefits and drawbacks to MISO's resource adequacy construct and residual capacity auction?

2. How have the recent outcomes of MISO's capacity auctions affected market participants and consumers in MISO? Do states and stakeholders have confidence that the MISO capacity market will be effective to achieve resource adequacy at just and reasonable rates?

3. How have the seasonal resource adequacy requirements and revised capacity accreditation methods worked in MISO to date? Have they helped MISO more accurately determine its resource adequacy needs? What issues or challenges has MISO experienced in implementing a seasonal construct and revising capacity accreditation, and how does MISO plan to address those issues or challenges?

4. How does MISO establish its load and resource forecasts?

    a. How does MISO integrate the load forecasts provided by load-serving entities and electric distribution companies into their planning reserve margin requirements? Does MISO verify the forecast methodologies and accuracy of forecasts?

    b. Have the assumptions driving load and resource forecasts changed over time? If so, how?

    c. How do the forecast models weight different inputs? Are some assumptions more uncertain, important, or impactful than others?

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[8] *Id.* at 6-9. The RRA is one of several periodic studies MISO conducts to forecast how the mix of electricity-generating resources in the MISO region could evolve going forward. In other studies, MISO has modeled potential future scenarios where thermal resources have a decreased role in providing accredited capacity. *See, e.g.*, MISO, *Futures Report Series 1A* 75, 92 (Nov. 2023), Series1A_Futures_Report630735.pdf.

d. How have the forecasts performed historically and are parties considering any changes to forecasting models or processes? For example, are you considering requiring demonstration of commercial readiness from prospective new large load additions?

5. To what extent are barriers to entry (e.g., the interconnection queue backlog, supply chain limitations, siting and permitting delays, etc.) affecting resource adequacy in the MISO footprint?

6. To what extent does the availability of regional and interregional transmission capability affect resource adequacy planning in MISO? How can MISO better address the effect of transmission capability on resource adequacy?

7. Would an alternative resource adequacy construct used by another RTO/ISO be more effective at delivering resource adequacy in MISO? If so, why? Are there alternatives to the current residual market construct that should be considered?

8. What should be the allocation of roles and responsibilities between MISO and the states to ensure resource adequacy in the MISO region? How does MISO work with the states to identify and meet the region's resource adequacy needs at just and reasonable rates? Has MISO studied the effects of state public policy on either resource adequacy or capacity market outcomes?

Panelists

- Todd Ramey, MISO, Senior Vice President of Markets and Digital Strategy
- David Patton, Potomac Economics, President and MISO Independent Market Monitor
- Laura Beauchamp, Entergy Louisiana, LLC, Vice President of Business Operations and Strategy
- Andrew Meyer, Ameren Missouri, Sr. Director of Energy Management & Trading
- Steven Lieberman, American Municipal Power Inc., Vice President of Transmission & Regulatory Affairs
- Todd Snitchler, Electric Power Supply Association, President and CEO
- Kelli Joseph, World Resources Institute, Senior Fellow

10:45 am – 11:00 am: 15-minute Break

11:00 am – 12:15 pm: Panel 6: MISO's Path Forward and The Future of Resource Adequacy in MISO

This panel discussion among the Commission, state representatives, and others will focus on the state of resource adequacy, and the role of states in achieving resource adequacy, in MISO. The Commission will explore approaches to address MISO's resource adequacy challenges, and the benefits of and improvements to its resource adequacy construct, to ensure MISO and states achieve resource adequacy.

Questions that panelists could be asked:

1. How do MISO and state resource adequacy processes interact? Do states in MISO have appropriate opportunities to participate in decisions regarding resource adequacy? Are there different or greater responsibilities that states should assume to ensure resource adequacy?

2. Do you believe consumers are treated fairly in the MISO capacity market process? If so, why? If not, why not?

3. Are changes necessary to ensure that the MISO capacity market process delivers resource adequacy at just and reasonable rates?

4. Are there aspects of MISO's resource adequacy construct that may result in inefficient price signals or create unnecessary resource adequacy risks?

5. Could MISO ensure resource adequacy at a lower cost to consumers through modifications to its existing resource adequacy construct? If so, what are the modifications and what are the challenges or downsides to implementing them?

6. Should MISO's capacity market model be replaced?

    a. If MISO's capacity market model should be replaced, what should replace it? Could an alternative resource adequacy program, like in SPP and CAISO, or a more expansive capacity market construct, like in PJM, NYISO, and ISO-NE, achieve resource adequacy at a lower cost than MISO's resource adequacy construct? Would these alternative approaches provide load-serving entities, states, and consumer advocates with the necessary information to monitor their costs for capacity?

    b. What are the potential tradeoffs and challenges of switching to a different resource adequacy construct? What timeline would be needed to determine or vet a replacement and implement it?

Panelists

- Commissioner Marcus Hawkins, Wisconsin Public Service Commission, Chair of the Organization of MISO States (OMS) Resource Adequacy Committee
- Chairman Doug Scott, Illinois Commerce Commission
- Chairman James Huston, Indiana Utility Regulatory Commission
- Commissioner Eric Skrmetta, Louisiana Public Service Commission
- Carrie Zalewski, American Clean Power Association, Vice President of Transmission and Electricity Markets
- Jennifer C. Easler, Iowa Department of Justice Office of Consumer Advocate, Attorney

12:15 pm – 1:15 pm: Lunch Break

1:15 pm – 2:30 pm: Panel 7: The Resource Adequacy Challenge in the Northeast RTOs/ISOs

This panel discussion between the Commission, NYISO, ISO-NE, and relevant stakeholders will focus on resource adequacy challenges specific to NYISO and ISO-NE.

NYISO projects declining statewide resource margins and for the system to approach a loss of load expectation of 1 day in 10 years by 2034.[9] NYISO's resource adequacy forecast is heavily affected by the assumption that approximately 6,400 MW of non-firm, gas-only generation will not be available to serve loads during winter peak demand periods.[10] NYISO explains that decreasing, and even negative, statewide system margins are a leading indicator of the system's inability to reliably serve demand under normal operations while fully maintaining operating reserves.[11] NYISO also notes that the development and commercialization of dispatchable emission-free resources capable of providing sustained on-demand power and system stability will be essential to achieving policy objectives while maintaining a reliable electric grid.[12]

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[9] NYISO, *2024 Reliability Needs Assessment* 9 (Nov. 19, 2024), nyiso.com/documents/20142/2248793/2024-RNA-Report.pdf/.

[10] *Id.*

[11] *Id.* at 10.

[12] NYISO, *NYISO's 2024 Comprehensive Area Review of Resource Adequacy* 37-38 (Dec. 3, 2024), https://cdn.prod.website-files.com/67229043316834b1a60feba3/678584c131bec5c726bae51b_2024%20New%20York%20Comprehensive%20Area%20Review%20of%20Resource%20Adequacy%20P

ISO-NE, in comparison, states that it has procured or will procure the requisite resources needed to adequately meet resource adequacy for each year of the 2024-2028 study horizon.[13] ISO-NE predicts growing peak load through 2032 and identifies potential risks to bulk power system reliability, but expects bulk power system reliability and economic performance to improve over the next decade because of planned transmission upgrades, an improved interconnection process, development of renewable resources with energy storage, imports from neighboring regions, fast-start and flexible ramping resources, and energy efficiency/conservation measures.[14]

Questions that panelists could be asked:

1. What is the state of resource adequacy in NYISO and ISO-NE in the near term (e.g., over the next five years) and over the longer term (e.g., ten years and beyond)?

    a. What factors present the greatest uncertainty when projecting future resource adequacy challenges?

    b. Are the capacity market constructs delivering resource adequacy in these RTOs/ISOs? Why or why not?

2. To what extent do uncertainties external to NYISO and ISO-NE—such as natural gas supplies or infrastructure constraints, supply chain limitations, and siting and permitting delays—affect resource adequacy planning in the Northeast? How can NYISO and ISO-NE better address those uncertainties?

3. How do NYISO and ISO-NE consider electric-gas coordination issues in the context of resource adequacy planning and capacity resource accreditation?

4. How will state public policy requirements change the resource mix and expected seasonal or hourly demand patterns? Do state public policy requirements create challenges for your regions in achieving resource adequacy at just and reasonable rates?

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[13] ISO-NE, *2023 New England Comprehensive Area Review of Resource Adequacy* 8-10 (Dec. 5, 2023), https://cdn.prod.website-files.com/67229043316834b1a60feba3/67229043316834b1a61003df_2023-new-england-comprehensive-review-of-resource-adequacy.pdf.

[14] *Id.* at 10.

5. How might your capacity markets be improved to meet the challenge of resource adequacy?

6. Would an alternative resource adequacy construct used by another RTO/ISO be more effective at delivering resource adequacy in your regions? If so, why?

7. How do NYISO and ISO-NE work with their states to identify and meet the region's resource adequacy needs and to ensure adequate resources are procured at just and reasonable rates? How do NYISO and ISO-NE work with their states when pursuing capacity market reforms to meet the resource adequacy challenge at the lowest possible cost to consumers? What distinct challenges must be overcome in a multi-state RTO/ISO (ISO-NE) region relative to a single state ISO region (NYISO)?

Panelists

- Emilie Nelson, NYISO, Executive Vice President and Chief Operating Officer
- Stephen George, ISO-NE, Vice President of System Operations and Market Administration
- Adam Evans, New York State Department of Public Service, Chief of Wholesale and Clean Energy Markets
- Chairman Philip L. Bartlett II, Maine Public Utilities Commission
- Commissioner Katie S. Dykes, Connecticut Department of Energy and Environmental Protection
- Michelle Gardner, NextEra Energy Resources, Executive Director Northeast Region
- Sarah Bresolin Silver, New England Power Pool, Chair
- Pallas LeeVanSchaick, Potomac Economics, Vice President; ISO-NE External Market Monitor; NYISO Market Monitoring Unit

2:30 pm – 2:45 pm: 15-minute Break

2:45 pm – 4:00 pm: Panel 8: RTOs/ISOs without Capacity Markets

This panel discussion between the Commission, SPP, CAISO, and relevant stakeholders will focus on resource adequacy programs in SPP and CAISO and how they compare to capacity markets in the other RTOs/ISOs.

In SPP, where each Load Responsible Entity must maintain adequate capacity to meet its Resource Adequacy Requirement, SPP expects no excess capacity to be available in summer 2027, and the planned reserve margin to decline from 20% in

summer 2024 to just 5% in summer 2029—a 5,950 MW deficiency.[15] Over that period, SPP projects resource retirements to outstrip new resource additions by a rate of roughly two-to-one while net peak demand grows by roughly 2% annually.[16] Most projected retirements are coal and natural gas resources.[17]

In California, the Public Utilities Commission (CPUC) oversees a resource adequacy construct to ensure jurisdictional load-serving entities meet those requirements. The CPUC sets system-wide resource adequacy requirements while CAISO sets local and flexible resource adequacy requirements. In recent years, CAISO and the CPUC have implemented regulatory and CAISO market changes to ensure that external capacity resources procured to meet resource adequacy requirements are delivered during peak net load hours.[18]

Questions that panelists could be asked:

1. What is the state of resource adequacy in SPP and CAISO in the near term (e.g., over the next five years) and over the longer term (e.g., ten years and beyond)? What factors present the greatest uncertainty when projecting future resource adequacy challenges?

2. Given load growth and generation entry and retirement forecasts, what resource adequacy challenges does SPP's resource adequacy construct face going forward? How does SPP's resource adequacy construct perform compared to RTO/ISO-administered capacity markets?

3. Given load growth and generation entry and retirement forecasts, what resource adequacy challenges does the CPUC's Resource Adequacy program face going forward? How does California's Resource Adequacy program perform compared to RTO/ISO-administered capacity markets?

4. How do the resource adequacy constructs employed by your RTO/ISO ensure the availability of resources for resource adequacy, and can they adapt to increased

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[15] SPP, *2024 SPP Resource Adequacy Report* 4-5 (June 14, 2024), 2024 spp june resource adequacy report.pdf.

[16] *Id.* at 6 & Table 1.

[17] *Id.*

[18] CAISO Department of Market Monitoring, *2023 Annual Report on Market Issues & Performance* 31-32 (July 29, 2024), 2023-annual-report-on-market-issues-and-performance.pdf.

load growth? How does this compare to attempting to meet these challenges through operation of an RTO/ISO-administered capacity market?

5. How do SPP and CAISO work with states to identify and meet the region's resource adequacy needs and to ensure adequate resources are procured at just and reasonable rates? How do SPP and CAISO work with their states when pursuing resource adequacy reforms to meet the resource adequacy challenge at the lowest possible cost to consumers? What distinct challenges must be overcome in a multi-state RTO/ISO (SPP) region relative to a single state ISO region (CAISO)?

Panelists

- Casey Cathey, SPP, Vice President of Engineering
- Neil Millar, CAISO, Vice President of Transmission Planning and Infrastructure Development
- Chair Patrick O'Connell, New Mexico Public Regulation Commission
- Molly Sterkel, California Public Utilities Commission, Director of Electric Supply, Planning and Costs in the Energy Division
- Stacey Burbure, American Electric Power, Senior Vice President of Transmission Business Development and Joint Ventures
- Gillian Clegg, Pacific Gas and Electric Company, Vice President of Energy Policy and Procurement
- Travis Kavulla, NRG, Vice President of Regulatory Affairs

4:00 pm – 4:15 pm: Closing Remarks

Document Content(s)

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 63

Palgrave Handbook



The Palgrave Handbook of International Energy Economics

Edited by Manfred Hafner · Giacomo Luciani

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rotating standby state through the advanced control system, and the gas turbine is quickly started with load, and the power is immediately transmitted to the power grid.

3.4 Location

Coal power generation location is more restrictive compared to other technologies because coal is a solid and its transport cost is high, while its combustion efficiency is lower than for other technologies. Usually coal plants are located near coal mines and the choice of different means of transport will affect the location of the plant area as well as the size and form of the required land plot, especially for a large power plant. The transportation mode should allow for large volume, low freight, high speed, and flexibility, which will make the location of coal plant all the more difficult.

On the contrary, oil is easy to transport with multiple transportation options including by pipeline and by ship; therefore, oil-fired plants are usually located in coastal areas. A gas-fired power plant is characterized by little land occupation and is very suitable for countries and areas with dense population and scarce land resources. Compared with coal-fired power plants, gas power generation equipment is more compact and does not occupy a large area. Besides, it consumes one-third of the water needed for a coal-fired power plant.

3.5 Expected Service Life

Thermal power plants are designed for an economic lifetime of 30 to 40 years, but some plants have been also used beyond their design life in certain areas. The critical components are the boiler and the turbine. The operation of thermal power generation is faced with both tangible and intangible aging processes. Tangible or physical aging refers to the equipment operating under high pressure and temperature, and bearing mechanical stress, resulting in physical and chemical changes, such as wear, creep, corrosion, and so on, gradually making the equipment unable to continue operating safely under the required design parameters. Invisible aging refers to technological progress. The advent of more efficient or less labor-intensive production equipment means that older equipment will operate under less and less economic conditions. The physical aging of some equipment (such as condenser copper pipes, heater pipes, boiler heating surface pipes, turbine blades, furnace walls, etc.) can be removed during overhaul. However, it is often the aging of these important equipment components that determines the technical and consequently economic lifetime of thermal power plants. Operating experience shows that the service life of equipment operating under 450 °C is between 40 and 50 years. For equipment operating at temperatures above 450 °C, the operating hours could even be reduced to 100,000 hours.

Both gas and steam turbines are devices that drive the rotor to rotate at high speed through high-pressure gas with high temperature and humidity.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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Exhibit 64

IEA Report



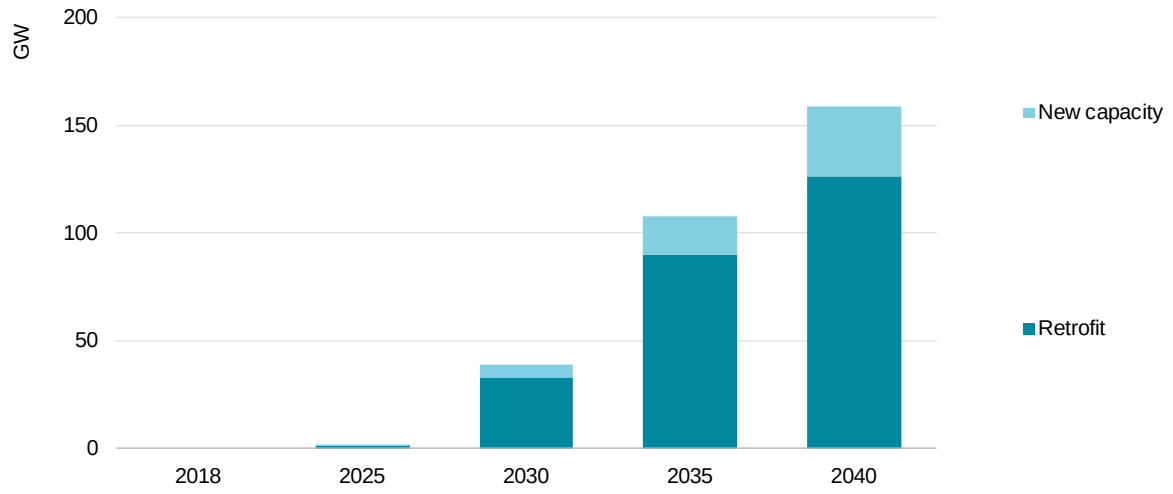
International Energy Agency

The role of CCUS in low-carbon power systems

Without carbon capture, meeting climate goals would ultimately mean almost eliminating the use of fossil fuels for power.

In the Sustainable Development Scenario, 120 GW of existing coal-fired capacity is retrofitted with carbon capture by 2040, accounting for some 80% of the coal plants equipped with these technologies. More than 110 GW of these retrofits are in China, representing a capital investment of around USD 160 billion. A further 10 GW are in the United States. Without carbon capture available at scale in power, coal-fired power generation, and eventually also gas-fired generation, would need to be virtually eliminated to meet long-term climate goals, with significant early retirements and potential stranding of assets.

Figure 4 **Coal-fired power plants equipped with carbon capture in the Sustainable Development Scenario**



Source: IEA (2019), World Energy Outlook 2019.

Over 750 GW of existing coal plants reduce operations to cut emissions in this Scenario, limiting electricity production but still providing system adequacy and flexibility. About one-quarter of the existing fleet would be retired before reaching the typical 50-year lifespan. Shutdowns and reduced operating hours are likely to lead to balance sheet write-downs for some owners of existing facilities. Coal plant retirements also imply greater investment in other low-carbon sources of electricity and associated network infrastructure.

Carbon capture retrofits also play an important role for the gas-fired power plant fleet, which currently has an average age of only around 19 years. In the SDS 155 GW of natural gas-fired power plants are equipped with carbon capture, utilisation and

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Exhibit 65

DOE Transmission Planning Study

National Transmission Planning Study



Chapter 2:

Long-Term U.S. Transmission Planning Scenarios

NREL

Pacific Northwest NATIONAL LABORATORY

GDO GRID DEPLOYMENT OFFICE

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Context

The National Transmission Planning Study (NTP Study) is presented as a collection of six chapters and an executive summary, each of which is listed next. The NTP Study was led by the U.S. Department of Energy's Grid Deployment Office, in partnership with the National Renewable Energy Laboratory and Pacific Northwest National Laboratory.

- The **Executive Summary** describes the high-level findings from across all six chapters and next steps for how to build on the analysis.
- **Chapter 1: Introduction** provides background and context about the technical design of the study and modeling framework, introduces the scenario framework, and acknowledges those who contributed to the study.
- **Chapter 2: Long-Term U.S. Transmission Planning Scenarios (this chapter)** discusses the methods for capacity expansion and resource adequacy, key findings from the scenario analysis and economic analysis, and High Opportunity Transmission interface analysis.
- **Chapter 3: Transmission Portfolios and Operations for 2035 Scenarios** summarizes the methods for translating zonal scenarios to nodal-network-level models, network transmission plans for a subset of the scenarios, and key findings from transmission planning and production cost modeling for the contiguous United States.
- **Chapter 4: AC Power Flow Analysis for 2035 Scenarios** identifies the methods for translating from zonal and nodal production cost models to alternating current (AC) power flow models and describes contingency analysis for a subset of scenarios.
- **Chapter 5: Stress Analysis for 2035 Scenarios** outlines how the future transmission expansions perform under stress tests.
- **Chapter 6: Conclusions** describes the high-level findings and study limitations across the six chapters.

As of publication, there are three additional reports under the NTP Study umbrella that explore related topics, each of which is listed next.[1] For more information on the NTP Study, visit https://www.energy.gov/gdo/national-transmission-planning-study:

- **Interregional Renewable Energy Zones** connects the NTP Study scenarios to ground-level regulatory and financial decision making—specifically focusing on the potential of interregional renewable energy zones.

[1] In addition to these three reports, the DOE and laboratories are exploring future analyses of the challenges within the existing interregional planning landscape and potential regulatory and industry solutions.

- **Barriers and Opportunities To Realize the System Value of Interregional Transmission** examines issues that prevent existing transmission facilities from delivering maximum potential value and offers a suite of options that power system stakeholders can pursue to overcome those challenges between nonmarket or a mix of market and nonmarket areas and between market areas.

- **Western Interconnection Baseline Study** uses production cost modeling to compare a 2030 industry planning case of the Western Interconnection to a high renewables case with additional planned future transmission projects based on best available data.

List of Acronyms

AC	alternating current
AEO	Annual Energy Outlook
APC	adjusted production cost
ATB	Annual Technology Baseline
B2B	back-to-back
BECCS	bioenergy with carbon capture and storage
CAISO	California Independent System Operator
CCS	carbon capture and storage
CO_2(e)	carbon dioxide equivalent
Coal-CCS	coal + carbon capture and storage
CSP	concentrating solar power
CT	combustion turbine
CTS	CO_2 transport and storage
DAC	direct air capture
DC	direct current
dGen	Distributed Generation Market Demand model
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EUE	expected unserved energy
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GADS	Generating Availability Data System

GCM	global climate model
GET	grid-enhancing technologies
GHG	greenhouse gas
GW	gigawatt
H_2-CT	hydrogen combustion turbine
HOT	high opportunity transmission
HVDC	high-voltage direct current
IRA	Inflation Reduction Act
ISO	independent system operator
ISONE	ISO New England
kg	kilogram
km	kilometer
kV	kilovolt
kW	kilowatt
LBNL	Lawrence Berkeley National Laboratory
LCC	line-commutated converter
LCOE	levelized cost of energy
Lim	Limited (transmission framework)
LOLE	loss of load expectations
LOLP	loss of load probability
m	meter
MISO	Midcontinent Independent System Operator
MMT	million metric ton (CO_2)
MT	multiterminal
MW	megawatt

MWh	megawatt-hour
MW-mile	megawatt-mile
NARIS	North American Renewable Integration Study
NEMS	National Energy Modeling System
NERC	National Electric Reliability Corporation
NEUE	normalized expected unserved energy
NG-CC	natural gas combined cycle
NG-CT	natural gas combustion turbine
NPV	net present value
NREL	National Renewable Energy Laboratory
NTP Study	National Transmission Planning Study
SMR	small modular reactor
NYISO	New York Independent System Operator
P2P	point-to-point
POI	point of interconnection
ppm	parts per million
PRAS	Probabilistic Resource Adequacy Suite
PV	photovoltaic
RA	resource adequacy
ReEDS	Regional Energy Deployment System
RTO	regional transmission organization
reV	Renewable Energy Potential
RPS	renewable portfolio standard
SCRTP	South Carolina Regional Transmission Planning
SERTP	Southeastern Regional Transmission Planning

SMR	small modular reactor
SPP	Southwest Power Pool
Sup3rCC	Super-Resolution for Renewable Energy Resource Data with Climate Change Impacts
TES	thermal energy storage
TW	terawatt
TWh	terawatt-hour
TW-mile	terawatt-mile
VRE	variable renewable energy
VSC	voltage source converter
W	watt
WECC	Western Electricity Coordinating Council

Chapter 2 Overview

Accelerating transmission expansion can offer benefits for the contiguous U.S. electricity system under a wide range of future uncertainties. The potential role and impacts of transmission expansion are evaluated in this chapter of the National Transmission Planning Study (NTP Study). The chapter presents the methods, assumptions, and findings from the zonal analysis of long-term U.S. transmission planning scenarios. The analysis compares a "Limited" transmission framework, which constrains transmission expansion, against three accelerated transmission frameworks: Alternating Current (AC), Point-to-Point (P2P), and Multiterminal (MT) (Figure I). Because future transmission expansion can vary depending on external conditions, the analysis compared scenarios across all four transmission frameworks under a range of policy, demand growth, and other conditions. The analysis includes an assessment of 96 total scenarios.

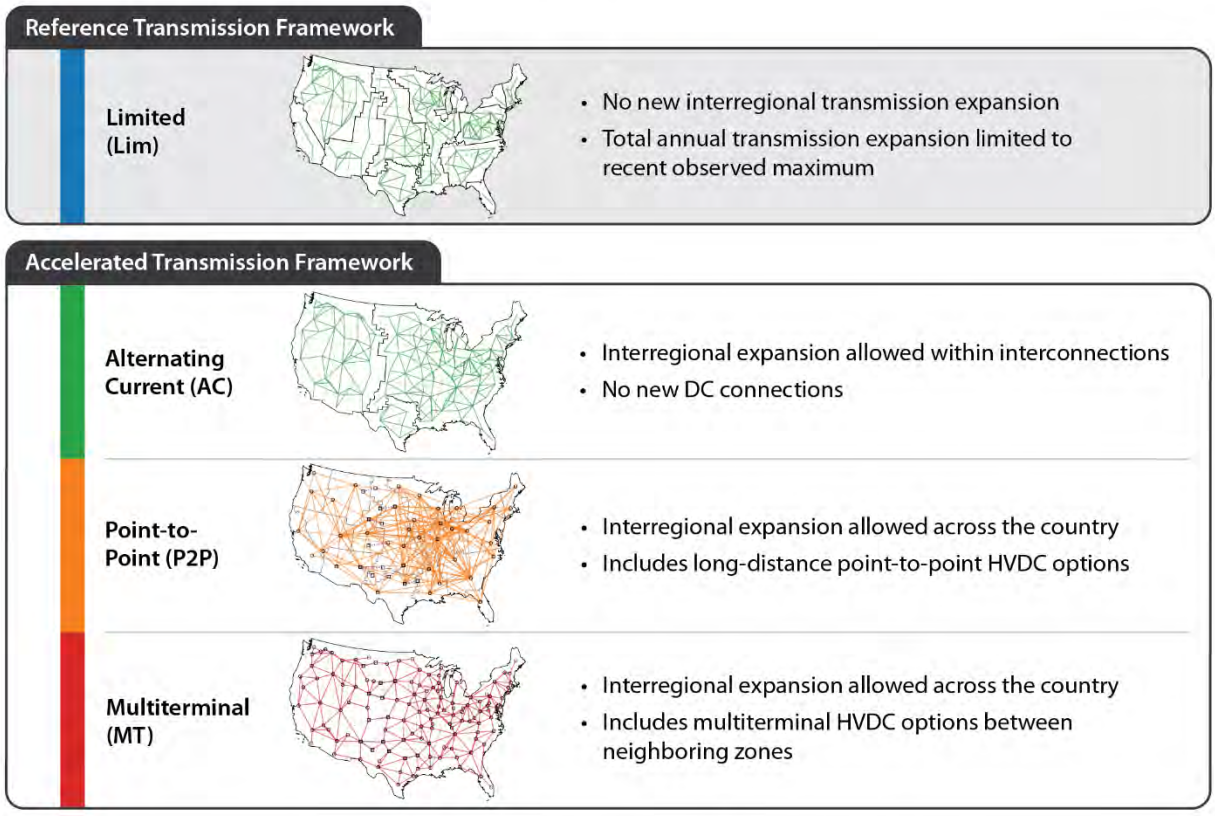


Figure I. NTP Study transmission frameworks

The scenario analysis first compares the different transmission frameworks without any new policies. Benefits from large-scale transmission expansion include billions of metric tons of avoided CO_2 emissions under current policies. Specifically, expanding transmission beyond historical rates—as occurs in the accelerated (AC, MT, P2P) frameworks—reduces power system CO_2 emissions by 10–11 billion metric tons (43%–48%) through 2050, relative to the Limited framework using "Mid" demand growth

assumptions (2.0%/year). The emissions reductions from accelerated transmission expansion are driven by increased wind and solar deployment. Even with expanded transmission, current policies are insufficient to fully eliminate power sector emissions, especially in futures with high demand growth.

The transmission frameworks were then evaluated considering nine decarbonization and demand futures (Figure II). Under these decarbonization conditions, benefits of large-scale transmission expansion include hundreds of billions of dollars in system cost savings. Specifically, in the central decarbonization scenarios—which achieve 90% emissions reductions by 2035 (100% by 2045) and assume Mid demand growth—accelerated transmission expansion leads to national electricity system cost savings through 2050 of $270–$490 billion. Constraining transmission growth results in more nuclear generation, hydrogen, and carbon capture capacity to achieve emissions reduction targets, leading to higher costs. The cost savings from accelerated transmission reveal that the costs of new transmission are outweighed by reductions in capital, operating, and fuel expenditures for generation and storage. Approximately $1.60 to $1.80 is saved for every dollar spent on transmission in the AC, P2P, and MT transmission frameworks under our central decarbonization assumptions.

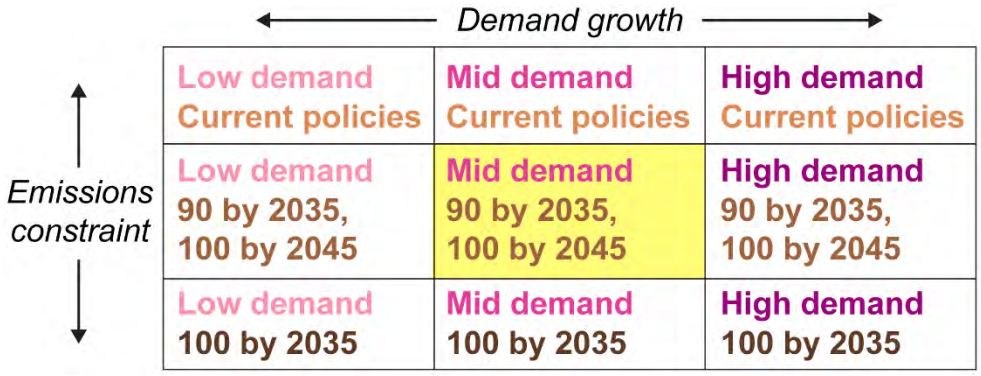


Figure II. Core demand and emissions assumptions.

The central demand and emissions assumption is highlighted in yellow.

The study finds rapid and significant growth in new transmission occurs in scenarios that achieve deep emissions reductions. Specifically, in the central decarbonization scenarios, the contiguous U.S. transmission system expands to 2.4–3.5 times the size of the 2020 system by 2050. This transmission occurs at all scales—including local, regional, and interregional—and for all regions of the country. Expansion of new long-distance transmission is concentrated in the central part of the country to enable increased access to wind and solar. Leveraging high-voltage direct current (HVDC) technologies, including advanced multiterminal converters, results in the greatest benefits. HVDC network solutions will require additional strengthening of AC networks. Similarly, the largest benefits of transmission are realized when interregional transmission is most substantial, including building across the interconnection seams. When U.S. electricity emissions are limited, future transfer capacities for many regions

exceed 30% of the region's peak demand and total aggregate U.S. interregional transfer capacity increases to 2.6–4.6 times the 2020 capacity by 2050.

The analysis includes scenarios with faster rates of decarbonization (100% by 2035) and higher demand growth (2.7%/year) than assumed in the central scenario. These scenarios find that electrification drives greater deployment of transmission and generation capacity. The benefits of transmission expansion scale with the level of electricity demand and rate of decarbonization. Under "High" demand growth, estimated savings from accelerated transmission expansion range from $710 billion to $970 billion, and coupling High demand with more rapid decarbonization can yield more than $1 trillion in electricity system cost savings.

Accelerated transmission deployment consistently reduces system cost across a spectrum of sensitivities with the greatest reductions found when hydrogen, carbon capture, and/or advanced nuclear are unavailable. The economic net benefits of transmission outweigh the incremental transmission costs in all scenarios, leading to a benefit-to-cost ratio of at least 1.5 across all sensitivity cases and exceeding 2.0 in many cases.

All 96 modeled future grid scenarios in the study—including those with approximately 90% of annual generation from variable resources—meet or exceed current industry resource adequacy standards. A variety of technologies supports resource adequacy. Interregional transmission—over spatial scales larger than weather systems—enables the sharing of variable renewables during days with limited local resource availability. In scenarios that allow coordination, transmission flows bidirectionally across many regional interfaces to support resource adequacy. With coordination, system costs through 2050 are lowered by $170 billion to $380 billion. Significant amounts of interregional transmission are built primarily to serve resource adequacy needs.

Lastly, the many scenarios and sensitivity cases in this chapter are also used to inform High Opportunity Transmission (HOT) interfaces that offer a starting point for further study. Spatial patterns in transmission expansion are similar across many sensitivity cases, and the HOT interfaces are defined as transmission expansion through 2035 between subregions that occurs in 75% of the sensitivity cases. Transmission projects that align with these HOT interfaces could be starting points for the grid expansion envisioned in this study.

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1 Introduction

The transmission grid has always played a critical role in the highly interconnected U.S. power system by delivering electricity from generators to load centers and supporting overall system reliability. As the U.S. generation mix undergoes major changes driven by clean energy policies and ambitions for deep decarbonization, the role of transmission is changing. Looking forward, how transmission might evolve to meet transformative generation changes while maintaining reliability is an open question. This chapter presents an analysis designed to answer this question for the contiguous U.S. electricity system.

Recent national decarbonization studies have collectively demonstrated the significant changes required in the U.S. transmission system to dramatically lower national greenhouse gas emissions. These studies include Denholm et al. (2022), the Net Zero America study (Larson et al. 2021), the Solar Futures Study (DOE 2021), Brown and Botterud (2021), and the North American Renewable Integration Study (Brinkman et al. 2021). Chapter 1 of this report and the Transmission Needs Study (DOE 2023a) summarize this body of work.

In addition to national-scale studies, regional planners also regularly conduct studies to examine future transmission expansion needs. These studies can lead to transmission expansion in utility or system plans and, ultimately, transmission procurement. Examples include California's long-term transmission plan (CAISO 2023a) and the Midcontinent Independent System Operator (MISO) Long Range Transmission Planning initiative (MISO 2022). Interregional transmission planning is more limited, but recent examples such as the MISO-Southwest Power Pool (SPP) Joint Targeted Interconnection Queue (SPP and MISO 2022) and the U.S. Department of Energy (DOE) Atlantic Offshore Wind Transmission Study (Brinkman et al. 2024) demonstrate interest in broader multiregional planning efforts.

The analysis presented in this chapter is motivated by the growing awareness of transmission expansion needs and applies a scenario approach like many of the above-referenced national-scale studies. However, this chapter focuses on transmission using a scenario framework, described in Section 2, designed to isolate the impacts of transmission on the U.S. electricity system. The scenario analysis presented in this chapter uses long-term capacity expansion and resource adequacy (RA) modeling to provide insights into the following questions:

- What is the role of transmission in decarbonizing the U.S. energy system?
- What are the economic trade-offs between different transmission futures and corresponding resource mixes?
- What mechanisms help ensure future low-carbon grids are resource adequate, and how does transmission support these mechanisms?
- Which interregional transmission expansions are commonly developed across a range of scenarios?

The focus of the National Transmission Planning Study (NTP Study) on identifying transmission that will provide broad-scale benefits to electricity customers and inform interregional and national strategies to accelerate decarbonization while maintaining system reliability includes examining transformative changes to the entire portfolio and considering a full suite of generation, storage, and transmission options. The capacity expansion modeling used here enables such evaluations and the examination of a range of future conditions, of which there are several important uncertainties—especially for achieving a zero-emissions grid. Incorporating RA tools in the analysis helps develop plausible resource mixes that can be more thoroughly examined for reliability. The scenarios presented in this chapter serve as the starting points for the more detailed power system modeling presented in subsequent chapters to begin to examine other aspects of reliability.

Section 2 describes the grid models used and the scenario design and assumptions, and the appendices provide additional explanation and detail. Results are presented in Section 3, with each subsection presenting a different group of scenarios. Section 3.1 presents results from scenarios that include enacted policies only. Section 3.2 examines how results change under different emissions targets and demand assumptions but uses default assumptions for other model parameters. Section 3.3 focuses on scenarios under central decarbonization assumptions and includes results across the full set of sensitivity cases. Conclusions are discussed in Section 4.

2 Methodology

Two National Renewable Energy Laboratory (NREL) models, the Regional Energy Deployment System (ReEDS)[2] and Probabilistic Resource Adequacy Suite (PRAS),[3] are used for the capacity expansion and RA analysis presented in this chapter. Both open-source models operate with zonal resolution covering the contiguous United States as their geographic scope (Figure 1a). This section briefly describes these two models and additional approaches used for the scenario analysis presented in this chapter.[4]

2.1 Model Descriptions

Regional Energy Deployment System (ReEDS). The ReEDS model is used to create future power system scenarios. ReEDS chooses from a large set of new generation, storage, and transmission options to identify the systemwide least-cost portfolio that meets future demand, grid reliability, and policy requirements. For this study, the model finds the optimal resource mix in 5-year steps between 2020 and 2050. The model applies a centralized planning approach but subdivides the contiguous United States into 134 zones to represent the grid network and to reflect region-specific generation, demand, and policies. For investment and dispatch modeling, each solve year includes 33 representative days with 4-hour resolution from weather year 2012 (P. R. Brown, Cole, and Mai forthcoming). The ReEDS documentation (Ho et al. forthcoming) and 2023 Standard Scenarios report (Gagnon et al. 2024) describe the model in greater detail. Appendix A details newer features of ReEDS used for this study.

Probabilistic Resource Adequacy Suite (PRAS). The PRAS model assesses the resource adequacy[5] of the scenarios generated by ReEDS. PRAS measures adequacy by performing Monte Carlo analysis of thermal generator outages[6] and hourly dispatch over 7 weather years (2007–2013) of renewable energy availability. Reliability metrics estimated by PRAS include loss of load probability (LOLP), loss of load expectation (LOLE), and expected unserved energy (EUE). This study uses the normalized expected unserved energy (NEUE)—EUE divided by total annual load—for the contiguous United States as the principal resource adequacy metric. PRAS has the same geographic scope and 134-zone resolution as ReEDS; however, thermal generator capacity within each zone is further subdivided into individual representative units to appropriately simulate generator outages.

[2] https://www.nrel.gov/analysis/reeds/
[3] https://www.nrel.gov/analysis/pras.html
[4] This chapter presents the methods, assumptions, and findings associated with the “round 2” scenarios of the NTP Study. Chapter 1 describes the primary differences between this round 2 capacity expansion analysis and the earlier round 1 analysis.
[5] The North American Electric Reliability Corporation (NERC) defines resource adequacy as “[t]he ability of the electric system to supply the aggregate electric power and energy requirements of electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components” (NERC 2022).
[6] Transmission outages are not modeled; however, interregional transfer capacity assumed in PRAS and ReEDS partially accounts for transmission contingencies. See Appendix A for further detail.

Integrated ReEDS-PRAS modeling. The optimal resource mix identified by ReEDS accounts for RA by including up to 30 "stress periods" in addition to the 33 representative days. The stress periods are the days with the highest EUE, among 7 weather years, as estimated by PRAS. The stress periods can change over time or between scenarios; for example, with increasing electrification, stress periods can include winter days with high heating demand as well as hot summer days with air conditioning demand. ReEDS iteratively augments the portfolio to meet a user-specified reliability target. This study uses a national RA target of 10 parts per million (ppm) NEUE. Although NEUE-based system planning has yet to become widespread, systems that do use NEUE-based planning tend to use NEUE targets in the range of 10 to 30 ppm (Alberta Electricity system Operator 2017; Electric Power Research Institute 2024; NERC 2024). Appendix B provides further detail on the combined use of ReEDS and PRAS.

Other models. Multiple upstream models are used to develop key inputs for ReEDS. The Distributed Generation Market Demand (dGen) model (Sigrin et al. 2016) simulates the customer adoption of rooftop photovoltaic (PV) systems. Distributed PV projections from dGen are exogenously input to ReEDS. The Renewable Energy Potential (reV) model (Lopez et al. 2024) provides the wind and solar resource potential used in ReEDS as well as the hourly renewable generation profiles used by all the models. Additional key datasets are described in Appendix A.

Transmission value analysis. This chapter's findings include results from an economic analysis of the scenarios, which assesses the relative costs between scenarios, the sources of those cost differences, and regional differences in costs and savings. This transmission value analysis primarily relies on a disaggregation of all the expenditures tracked in ReEDS—including generation, storage, and transmission capital and operating costs—through 2050 with additional adjustments to appropriately assess regional cost distributions.

2.2 Region and Transmission Terminology

The zonal ReEDS modeling represents the contiguous U.S. grid using 134 zones as shown in Figure 1a. These zones serve as the building blocks for larger regions for reporting purposes and to reflect policies and other factors. The zones conform to boundaries for the 48 states within the contiguous United States, which enables the representation of state clean energy policies.[7] This study focuses on 11 transmission "planning regions" that approximate Federal Energy Regulatory Commission (FERC) Order No. 1000 regions[8] and the Electric Reliability Council of Texas (ERCOT). The planning regions comprise aggregate model zones as shown in Figure 1c. These planning regions include the seven independent system operators (ISOs) and regional transmission organizations (RTOs) in the United States. The 11 planning regions are

[7] The District of Columbia (D.C.) is combined with the zone that represents Maryland.
[8] The South Carolina Regional Transmission Planning (SCRTP) region from FERC Order No. 1000 is included in the Southeastern Regional Transmission Planning (SERTP) in the analysis. Nonenrolled members of FERC planning regions and regions that are not part of FERC Order No. 1000 are *included* within the geographic boundaries shown in the figure.

fundamental to the scenario design (as discussed next). Because there is significant variation in geographic size between the 11 planning regions, the larger planning regions are further subdivided into “planning subregions” (Figure 1b).[9] Results are typically reported at the planning region and subregion levels and for the contiguous United States as a whole. Figure 1d also shows the three asynchronous interconnections in the contiguous United States.[10]

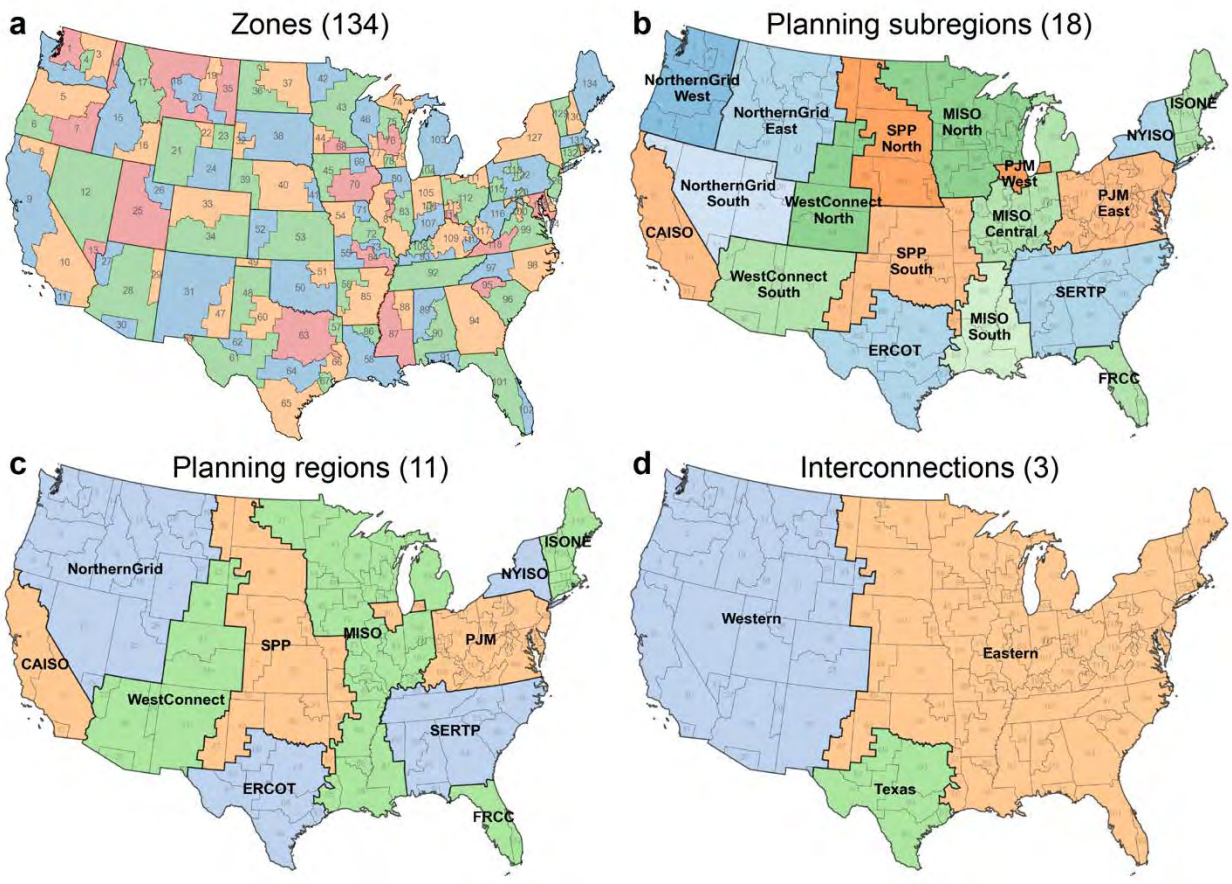


Figure 1. Hierarchy of regions used in the ReEDS model

Regional acronyms: California Independent System Operator (CAISO), Southwest Power Pool (SPP), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), Independent System Operator of New England (ISONE), Southeastern Regional Transmission Planning (SERTP), Florida Reliability Coordinating Council (FRCC).

The geographic regions include Tribal lands within the boundaries shown in Figure 1. The modeling does not specifically exclude or encourage new transmission or generation projects on Tribal lands, but the study team recognizes that energy planning

[9] There are 18 total planning “subregions” in the contiguous United States. NorthernGrid and MISO are both subdivided into three subregions each. WestConnect, SPP, and PJM are subdivided into two subregions each.

[10] The Western and Eastern interconnections also include electrically connected regions in Canada and Mexico. Given the focus on the contiguous U.S. system, international imports and exports are exogenously specified in the modeling. The North American Renewable Integration Study (NARIS) (Brinkman et al. 2021) evaluated cross-border transmission expansion.

on such locations would require engagement, consultation, and participation from the relevant Tribes. Chapter 1 highlights Tribal engagement during the NTP Study.

Different categories and types of transmission, which are partly defined based on the regions, are modeled and reported:

- **Local** transmission refers to estimated transmission expansion *within* each of the 134 model zones. It includes transmission spur lines from wind and solar power plants to a point of interconnection (POI) and network upgrades or reinforcements needed beyond the POI to interconnect these plants to the grid. Local transmission capacity is modeled and tracked only for land-based wind, offshore wind, solar PV, and concentrating solar power (CSP). The costs to interconnect other resources are assumed to be $100/kilowatt (kW) (approximating recent interconnection costs for gas turbines (Seel et al. 2023)) whereas interconnection costs for wind and solar vary widely by location and can be several hundreds of dollars per kW (Lopez et al. 2024).[11]
- **Interzonal** transmission refers to the transfer capacity between any pair of zones from the 134 model zones. Unlike local transmission, interzonal transmission is not specific to any resource but instead serves systemwide needs. Existing transfer capacity between model zones is estimated based on a method summarized in Appendix A and presented by Brown et al. (2023). Expansion of interzonal transmission is a model decision because ReEDS co-optimizes generation, storage, and transmission simultaneously. Interzonal transmission can be based on high-voltage alternating current (AC) or direct current (DC) technology assumptions as specified in the scenarios. DC technology options modeled include back-to-back (B2B) ties across interconnections, line-commutated converters (LCC), and voltage source converters (VSC). In this report, interzonal transmission is presented by transmission technology (AC, B2B, LCC, VSC) or further subdivided as follows:
    - **Regional** transmission refers to interzonal transmission between zones within the same planning region.
    - **Interregional** transmission refers to the transfer capacity between two different planning regions.
    - **Seam-crossing** transmission refers to the subset of interregional transmission that crosses interconnection boundaries.

Unless otherwise noted, “transmission” capacity reported includes all types of transmission, including local and interzonal transmission, and is typically measured in terawatt-miles (TW-miles) to account for both the capacity and the distances of all transmission. *Interregional* transmission capacity is typically reported in gigawatts (GW) or terawatts (TW) to measure the transfer capacity across regional interfaces irrespective of the lengths of the transmission lines that cross these boundaries.

[11] Real 2022 dollars are used unless otherwise noted.

Transmission cost assumptions for local and interzonal transmission of various types are described in Appendix A.

2.3 Scenario Design

The scenario framework includes 96 scenarios modeled using the ReEDS and PRAS models.[12] These scenarios span a range of demand, policy, and technology conditions to assess the varied role and extent of transmission in the future U.S. energy system. The 36 "core" scenarios are all combinations of four transmission frameworks (Figure 2), three demand growth projections, and three levels of power sector emissions constraints (Figure 3). The remaining 60 scenarios studied include 15 different sensitivity cases, each modeled for the four transmission frameworks under the central demand growth and emissions constraint assumptions. No judgment is made about the relative likelihood of different scenarios or assumptions; instead, the scenarios are used to evaluate the role of transmission under a wide range of possible future conditions.

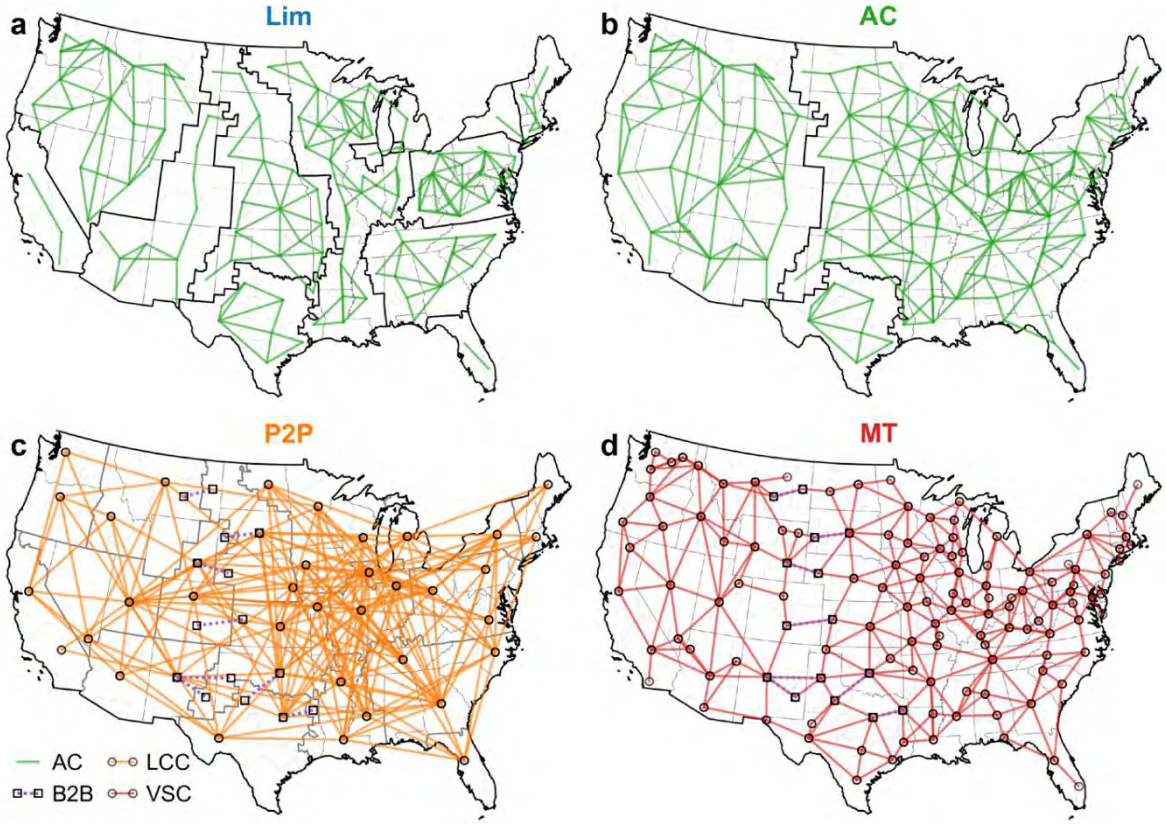


Figure 2. Expandable transmission interfaces in the four transmission frameworks considered in this study

Maps show interfaces where transmission capacity can be expanded under the corresponding transmission framework. AC interfaces in the AC framework are also allowed to be expanded in the point-to-point (P2P) and multiterminal (MT) frameworks but are not shown for clarity. Existing transmission interfaces are not shown. Allowable transmission types are AC (green), high-voltage direct current (HVDC) with line-commutated converters (LCC, orange), HVDC with voltage source converters (VSC, red), and back-to-back interties (B2B, purple dashed).

[12] Additional scenarios beyond these 96 are also modeled to address particular aspects as noted in the results.

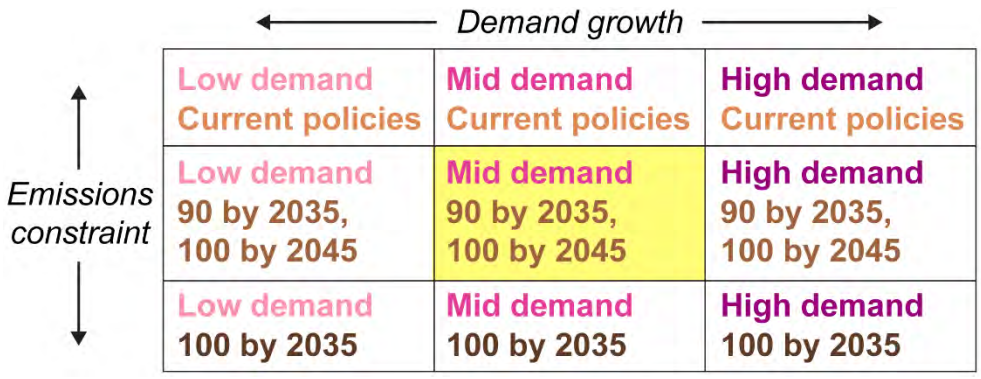


Figure 3. Core demand and emissions assumptions

The central demand and emissions assumption is highlighted in yellow.

2.3.1 Transmission frameworks

The primary comparisons are between transmission frameworks (Figure 2), which enable the impacts of transmission on the overall evolution of the U.S. power system to be isolated. The four transmission frameworks differ by the types of constraints on and options for new transmission expansions. Differences in the constraints on transmission expansion represent factors other than cost that can affect transmission capacity growth (e.g. siting and permitting, interregional coordination). These transmission frameworks span a wide range of possibilities, from a "Limited" framework with severe constraints on new expansion to highly coordinated planning frameworks that incorporate the latest high-voltage direct current (HVDC) technology options.

- **Limited (Lim):** The Limited framework serves as the reference or counterfactual to the other transmission frameworks. In this framework, no new *interregional* transmission is allowed, reflecting a lack of coordination between planning regions or other barriers that prevent expansions of interregional transfer capacities.[13] Within each planning region, *regional* transmission expansion is allowed but is assumed to use AC technology. The exception is for existing HVDC connections, which are allowed to expand using new DC lines. In addition to excluding new interregional transmission, an annual limit on new transmission expansion is also applied in this framework, based on the maximum annual transmission builds since 2014 (Wiser et al. 2023). Using fixed carrying capacity assumptions for different voltages (see Appendix A), this limit is 1.83 TW-miles/year and is applied to total transmission—of all types—installed nationally across the contiguous United States. Because this limit applies to local as well as regional transmission expansion, it creates a de facto constraint on the growth rate for new wind and solar.
- **Alternating Current (AC):** The AC framework does not include an annual limit to the amount of transmission expansion. It also allows for interregional transmission expansion except for seam-crossing transmission. All interzonal transmission is assumed to use AC technology and associated costs and losses

[13] This framework may be more restrictive than current practices given interregional transmission planning processes already underway.

except for existing HVDC connections, where DC expansion is allowed. Transmission cost assumptions are presented in Appendix A.

- **Point-to-Point (P2P):** The P2P framework allows for the same expansions as in the AC framework but also allows new HVDC opportunities. These include B2B DC ties across interconnections and 195 candidate P2P connections, including those between nonadjacent regions. These P2P candidates, shown in Figure 2, are identified based on locations with the highest wind resource and/or demand in each planning subregion. Only connections within 1,000 miles are considered. For these P2P candidates, HVDC line costs, which are lower than AC line costs,[14] and converter costs are based on LCC technologies.[15] Converters and lines are required to be identically sized.
- **Multiterminal (MT):** The MT framework allows for the same expansions as the AC framework but also includes options for HVDC expansion between adjacent zones. HVDC line costs are assumed to be the same as those for the P2P framework, but converter costs are slightly higher and based on VSC technology. However, unlike the P2P framework, converters and lines are independently sized by ReEDS in the MT framework. This approach enables more flexibility for a meshed network design, but this framework does not allow the 195 long-distance candidates from the P2P framework.[16]

The analysis primarily compares results from the AC, P2P, and MT frameworks, which are referred to as *accelerated* transmission frameworks because the rate of transmission expansions can exceed recent maximum annual builds, to the Limited framework. Both the P2P and MT frameworks extend the transmission options allowed in the AC framework by emphasizing HVDC technologies but represent distinct HVDC network designs.

2.3.2 Policy assumptions and emissions targets

How the role of transmission might change depending on decarbonization levels is a key question of the analysis. The baseline level of grid decarbonization is affected by enacted policies, which are included in all 96 scenarios.[17] These electric sector policies include state laws and federal clean energy tax incentives. State policies modeled include 28 renewable portfolio standards (RPSs)[18] and 15 clean energy standards. The assumptions for these factors are based on data from Barbose et al. (2023) and from stakeholder feedback received during the study. Technology-specific requirements from state RPS policies are also modeled, including offshore wind targets. The assumed mandated offshore wind deployment targets are based on analysis from DOE's

[14] HVDC line losses are also lower than AC losses, but additional losses are modeled for the AC-to-DC-to-AC conversions.
[15] Converter costs under the P2P and MT frameworks differ based on the assumed technologies used (LCC and VSC, respectively); however, the modeling is not prescriptive about which technology might be best suited.
[16] Connections between two nonadjacent zones would require multiple separate segments under the MT framework whereas P2P might have a direct connection with a shorter distance and lower costs.
[17] Existing policies as of June 2023 are modeled.
[18] Hawaii is not modeled. Washington, D.C. also has an RPS, and this policy is considered within the zone that includes both Maryland and D.C.

Offshore Wind Market Report: 2023 edition (Musial et al. 2023).[19] Electric sector greenhouse gas (GHG) emissions policies for the Regional Greenhouse Gas Initiative states and California are also included. State retirement policies for existing plants and bans for new nuclear or fossil capacity are also included (Gagnon et al. 2024). County and other local siting ordinances, tracked from Lopez et al. (2023), for new wind and solar development are also modeled as part of the wind and solar resource potential inputs to the model (Lopez et al. 2024).

Federal policies modeled include many of the clean energy tax incentive provisions from the Inflation Reduction Act (IRA) of 2022 and the Bipartisan Infrastructure Law of 2021.[20] The IRA tax incentives include production and investment tax credits for new wind, solar, other renewable energy, energy storage, and carbon capture and storage (CCS).[21] Steinberg et al. (2023) document the assumptions used to represent these policies in ReEDS. The tax credit level and period when the IRA incentives are available vary by technology. The wind, solar, and storage tax credits expire depending on the annual U.S. power sector emissions; the IRA specifies these credits expire when annual emissions are below 25% of 2022 levels or in 2032, whichever is later. For some scenarios, the IRA tax credits phase out as written, and for others the wind, solar, and storage tax credits are assumed to expire in 2032 to facilitate the comparison of scenarios without confounding changes in tax policy conditions.

In addition to the enacted policies, decarbonization scenarios are modeled using national emissions constraints (Figure 3). The following three power sector emissions trajectories are used in the scenarios:

- **Current policies:** Current policies include enacted state and federal policies as of June 2023 as described previously. No other policies, such as a national constraint on emissions, are included.
- **90% by 2035:** In addition to enacted policies, a national annual limit on power sector carbon dioxide equivalent (CO_2(e)) emissions is applied in the 90% by 2035 scenarios.[22] This limit is set to achieve 90% reductions from 2005 levels by

[19] These assumptions result in 47 GW of prescribed offshore wind capacity by the mid-2030s, all of which are off the Atlantic coast except for 4.7 GW of offshore wind by 2035 in the Pacific based on the Base case from the California Public Utilities Commission (2022).
[20] Only major legislation and mandates are included in the modeling. Nonbinding and voluntary targets from states, corporations, or utilities are not included. The modeling is not comprehensive of all policies, especially those applied at the local level. The assumptions also represent a snapshot in time of the policy environment, which can change rapidly.
[21] Tax credits for hydrogen technologies are not included in this analysis because guidance for these tax incentives was not released at the time this analysis was completed. Clean Air Act section 111 standards are not included because they were also not finalized when this analysis was completed.
[22] The limit applies to direct CO_2 emissions from fossil-fuel-fired power plants as well as from upstream CO_2(e) methane emissions. The modeling assumes a 100-year global warming potential of 34 to estimate the CO_2(e) of methane and assume a leakage rate of 2.3% in 2021 (Alvarez et al. 2018), declining by 30% to 1.6% in 2030 and thereafter (Denholm et al. 2022).

2035 and 100% reductions by 2045.[23] The limit declines linearly from 2025 to 2035, declines linearly between 2035 and 2045, and stays at 0 million metric tons (MMT) CO_2 after 2045. Figure 4 shows the emissions trajectory used in these scenarios along with historical emissions for context. This trajectory is used under the central decarbonization assumptions.

- **100% by 2035:** The emissions limit in the 100% by 2035 scenario is applied similarly to the 90% by 2035 scenario, except the trajectory achieves zero emissions by 2035 and stays at that level through 2050 (Figure 4). The 2035 zero emissions limit is consistent with the U.S. carbon-free electricity by 2035 target (Executive Office of the President 2021).

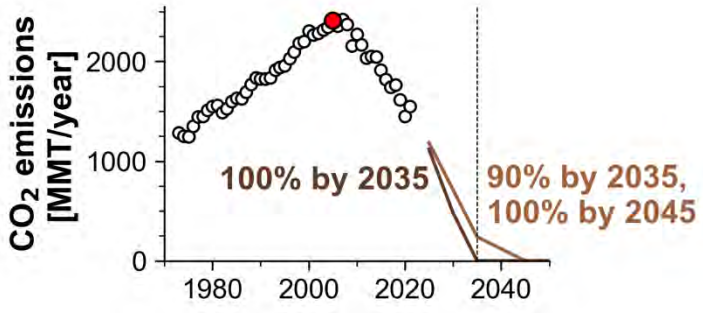


Figure 4. Emissions constraints under grid decarbonization scenarios

Historical emissions are from EIA (2024b). Power sector emissions in 2005 are 2,411 MMT CO_2.

2.3.3 Electricity demand growth assumptions

Historical and future load growth are impacted by macroeconomic factors, energy efficiency, and electrification or potential new sources of demand (e.g., growth in data centers). To account for significant uncertainties with these factors, three demand scenarios spanning a wide range of growth possibilities are modeled (Figure 5). The compound annual growth rate for demand in these scenarios varies from 0.9%/year to 2.7%/year (2021 to 2050) and is largely correlated with the rate of electrification and corresponding reductions in direct emissions from end-use sectors such as transportation, buildings, and industry.[24] For context, U.S. load grew by 1.1%/year during the prior 30 years (1992 to 2021) but experienced much flatter growth during the past 15 years (0.1%/year) and higher growth (2.8%/year) over the longer (1962–2021) period. The three demand trajectories are based on demand-side modeling from Evolved Energy Research and calibrated using 2021 state-level demand data from EIA (2021):

- **Low-Demand:** The Low-Demand trajectory is from the "Baseline" case from the 2022 Annual Decarbonization Pathway (Haley et al. 2022), which largely follows

[23] Noncaptured CO_2 from fossil with CCS plants count against these emissions limits; however, these emissions can be offset by bioenergy with CCS (BECCS) options or other negative emissions technologies when allowed. Direct air capture (DAC) is not included in the core scenarios but is included in a sensitivity. Emissions from fossil plants without CCS are not allowed to be offset in the definition used here.

[24] Appendix A shows the estimated end-use emissions by sector in the three demand cases.

EIA's Annual Energy Outlook (AEO) 2022 Reference case (EIA 2022). It does not include electric vehicle tax credits and other electrification or clean energy tax incentives from the IRA. Annual demand grows by 0.9%/year from 2021 to 2050 under Low-Demand.

- **Mid-Demand:** The Mid-Demand trajectory is more representative of enacted policies because it includes the electrification incentives for various end-use sectors from the IRA. This case features "moderate" electrification assumptions as used in Haley et al. (2023).[25] Load growth is 2.0%/year. This trajectory is used as the central decarbonization assumption.
- **High-Demand:** The High-Demand trajectory includes substantial electrification consistent with achieving net zero energy emissions by 2050. This assumption is from the "Central" case from the 2022 Annual Decarbonization Pathway (Haley et al. 2022). Because of high electrification, demand grows by 2.7%/year, resulting in 2050 annual demand that approximately doubles national demand from 2021.

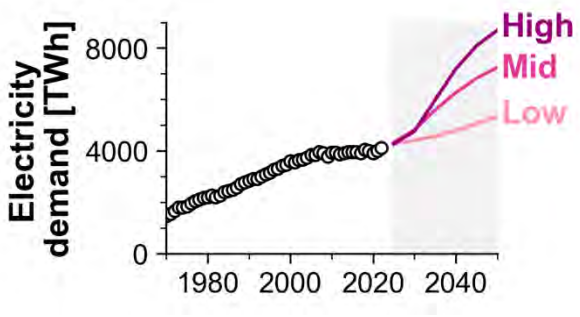


Figure 5. Annual demand assumptions for the contiguous United States

Historical demand shown is electricity sales to ultimate customers from EIA (2024b).

Hourly demand profiles also change over time and vary across the Low-, Mid-, and High-Demand trajectories. Electrification of buildings under Mid- and High-Demand results in winter demand peaks that grow faster than summer peaks in many regions. Figure 6 shows these changes in the demand profile over time for the contiguous United States, but the shifts toward winter peaks are even starker in colder regions. Demand data used in the models are at hourly resolution for each state; all zones within a state share the same normalized load profile, but state annual demand is partitioned based on historical distributions of load.

[25] Specifically, the "Current Policy" scenario from Haley et al. (2023) is used for the Mid-Demand case.

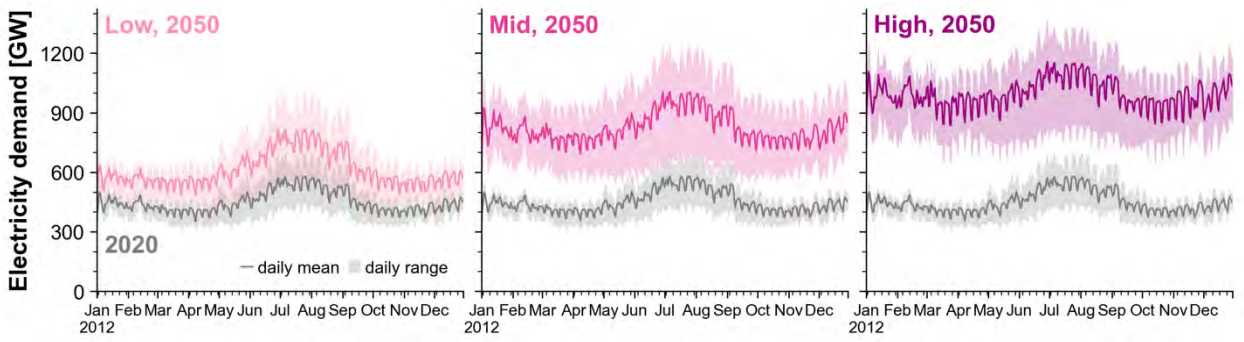


Figure 6. Daily demand profiles for the contiguous United States in 2020 and 2050

The demand profiles shown use 2012 weather.

2.3.4 Other default assumptions

Aside from the differences in transmission framework, power sector emissions target, and demand outlined previously, all other assumptions are the same across the 36 core scenarios. These default assumptions include technology cost and performance assumptions from the NREL Annual Technology Baseline (ATB) 2023 Moderate case (National Renewable Energy Laboratory 2023) (see Appendix C) and fuel costs from the EIA AEO 2023 Reference case (EIA 2023a). Distributed rooftop PV adoption is also held constant between scenarios and is assumed to reach 130 GW_{AC} by 2035 and 170 GW_{AC} by 2050 (Gagnon et al. 2024), compared with 48 GW_{AC} of small scale PV in 2023 (EIA 2024a).

For CO_2 transport and storage costs, a uniform $15/metric ton cost for all regions is applied, without limits on the amount of CO_2 that could be injected.[26] Hydrogen storage is modeled explicitly to ensure sufficient storage capacity for the daily balancing of H_2 production, storage, and use.[27] However, all hydrogen must be used in the same zone in which it is produced; transport of H_2 between zones is not allowed in any scenario. Further work is needed to compare trade-offs between electricity transmission and transport of other energy carriers. Appendix A details the hydrogen representation used for this study.

Unless otherwise noted, all other assumptions are from the NREL Standard Scenarios 2023 Mid-case (Gagnon et al. 2024).

2.3.5 Sensitivity cases

In addition to the core scenarios, 15 sensitivity cases are modeled under all four transmission frameworks. These 60 sensitivity cases all assume 90% by 2035 power sector emissions trajectory and Mid-Demand growth—which represent the central decarbonization conditions. Table 1 summarizes the sensitivity cases.

[26] Brown et al. (forthcoming) presents the endogenous model representation for CO_2 transport and storage. A test scenario using this capability resulted in similar findings to those presented here. Scenarios with greater CCS deployment could have different implications.
[27] No hydrogen demand for industry, transportation, or other uses outside for electricity generation are considered; all reported hydrogen production and use in the scenarios are for grid applications.

Table 1. Sensitivity Cases

Name	Description
PV+Battery Low Cost	PV and battery technologies follow the ATB 2023 Advanced cost and performance projections (National Renewable Energy Laboratory 2023).
Wind Low Cost	Land-based and offshore wind technologies follow the ATB 2023 Advanced cost and performance projections (National Renewable Energy Laboratory 2023).
Electrolyzer Low Cost	Electrolyzer costs are based on DOE (2023b). Electrolyzer costs in the core scenarios decline linearly from $1,750/kW in 2022 to $550/kW in 2030 and stay constant thereafter; costs in this sensitivity case undergo further linear declines from $550/kW in 2030 to $157/kW in 2050.
+Nuclear SMR +DAC	Assumes nuclear small modular reactor (SMR) and direct air capture (DAC) technologies are commercially available. Nuclear SMR costs are from the ATB 2023 Moderate case (National Renewable Energy Laboratory 2023) and DAC costs are from Brown et al. (forthcoming). DAC can be used to offset emissions from fossil CCS plants.
No Interface Expansion Limit	In all other scenarios, a 30-GW limit is imposed for total interzonal capacity (combined existing and new, AC and DC). This sensitivity case eliminates this maximum level.[28]
Transmission 2x Cost	Interzonal $/megawatt-mile (MW-mile) transmission costs are doubled for all interfaces for both AC and DC capacity. Default transmission costs are presented in Appendix A.
No RA Sharing	Requires each of the 18 subregions to meet adequacy needs locally; no trades are allowed across subregion boundaries during the modeled stress periods. This represents a lack of interregional coordination for resource adequacy. (See Appendix A for details.)
Siting Limited	Uses more-constrained siting supply curves for land-based wind and utility PV, based on “Limited Access” from Lopez et al. (2024), as opposed to the default “Reference Access.” This reduces the technical potential from 11.1 TW to 5.9 TW for wind and from 112 TW to 58 TW for PV. Reductions are not uniform by region.
CTS High Cost	CO_2 transport and storage (CTS) costs are assumed to be $36/metric ton instead of $15/metric ton under default assumptions. These assumptions are based on Grant et al. (2019) as discussed in Brown et al. (forthcoming).
Many Challenges	Uses higher technology costs for PV, wind, battery, CCS, and nuclear technologies based on projections from the ATB 2023 Conservative case (National Renewable Energy Laboratory 2023). Uses the more-constrained supply curves for wind and utility PV as in the “Siting Limited” sensitivity.
No H_2	Hydrogen electrolyzers and combustion turbines (CTs) are not available.

[28] The 30-GW limit is based on iterations with the preliminary nodal modeling in the study that indicated expanding beyond this level would be technically challenging.

Name	Description
No CCS	CCS technologies are not available.
No H_2 or CCS	Hydrogen and CCS technologies are not available.
No H_2 or New Nuclear	Hydrogen technologies and new nuclear deployment are not available.
Climate	Modifies demand, solar, and wind profiles to be based on future weather conditions developed from a global climate model and downscaled (Buster et al. 2023). Hydropower capacity during stress periods is assumed to be reduced by 20% in 2050. Summer capacities for thermal generators and transmission for 2050 are derated by 15% and 5%, respectively. Capacity derates ramp linearly from 0% in 2025 to these values. (See Appendix A for details.)

2.4 Modeling and Analysis Limitations

The analysis examines the future role of transmission using sophisticated power sector tools; however, there are limitations of the analysis especially given the transformative and wide-ranging scenarios examined and the very large and complex nature of the U.S. electricity system. Here, several important limitations of the modeling in this chapter are discussed.

Behavioral, institutional, and regulatory aspects are not fully reflected in the models. The models apply a centralized economic optimization approach rather than the more-complex decision-making reality in today's energy system. Diverse decision makers can have different objectives and considerations that would lead to different planning and operational outcomes than those found by the models. Select sensitivity cases partially address interregional coordination and uncertainties with siting and permitting renewable energy projects. Additional analysis is needed to study these issues in greater depth and to quantify their impacts.

Energy planning for transmission and other electricity resources is complicated by the limited foresight of future policy, market, and technology conditions and the long-lived nature of these assets. These uncertainties are partially captured through the wide range of scenarios modeled; however, the capacity expansion modeling used here does not reflect the limited foresight conditions of reality. Specifically, ReEDS finds the optimal resource mix sequentially for each 5-year increment from 2020 to 2050 with no foresight on how policies, technologies, or fuel prices might change. This would give a suboptimal solution relative to an intertemporally optimized model that sees the full 30-year period altogether. On the other hand, ReEDS assumes the construction, permitting, and other planning and approval efforts are successfully executed prior to the modeled installation dates. This perfect "construction" foresight approach does not account for manufacturing, supply chain, and workforce needs that may impact the rate of technology deployment. The modeling does not directly reflect all these complexities—either inside or outside of the electricity sector—that may be required to realize these scenarios. Similarly, perfect foresight is assumed in the dispatch decisions from ReEDS and PRAS.

Comprehensively evaluating full economywide and broader societal cost and benefits of the scenarios is outside the scope of this analysis. The analysis compares differences in direct power system expenditures, nationally and by region, to evaluate the economic viability of transmission under a range of future conditions. This includes all expenditures for the bulk power system but does not include distribution system expenditures or an economic evaluation of the demand-side sectors under the various electrification futures modeled. Moreover, the cost, benefits, and impacts of GHG emissions levels or other air pollution are out of scope. Finally, distributional impacts to different demographic groups and stakeholders are also not evaluated in this analysis.

Although the analysis includes many scenarios, not all possibilities are analyzed. Importantly, the modeling does not explicitly include all technology options. For example, the cost assumptions for new transmission are based on estimates for greenfield projects; transmission upgrades or grid-enhancing technologies (GETs) that could yield expanded transfer capacity at potentially lower costs are not directly modeled in ReEDS. Some of the expanded transmission capacities reported can be realized through these other options. ReEDS modeling also includes diurnal and seasonal (hydrogen) energy storage (see Appendix A) but does not explicitly include other long-duration storage options. The scenarios also include increases in rooftop PV capacity, but other distributed energy resources, demand response, and demand-side flexibility options are not modeled.[29] The omission of demand flexibility—including managed electric vehicle charging—could be particularly important with respect to the RA results presented.

This chapter's analysis includes RA modeling but does not fully consider other elements of reliability, such as operational reliability and resilience. Resource adequacy is considered through the integrated ReEDS-PRAS modeling, which includes generator outages and variability, weather-driven variability, a wide range of long-term demand projections, and approximations for transmission contingencies through interregional capacity derates. However, generator fuel supply limits, correlated outages, and transmission outages are not modeled. Appendix B discusses these and other limitations of the RA analysis. Subsequent chapters supplement the analysis with other elements of reliability not considered by the capacity expansion models used in this chapter.

Further study is needed to examine these important aspects.

[29] Sensitivity cases with higher distributed PV levels were modeled in earlier stages of the study but had less impact on the scenario outcomes than many other sensitivity cases presented here.

3 Results

3.1 Current Policies

This section reports findings from scenarios assuming current policies (as of June 2023) only. Scenarios with additional constraints on national carbon emissions are presented in subsequent sections.

3.1.1 Benefits from large-scale transmission expansion include billions of metric tons of avoided CO_2 emissions

Accelerating transmission expansion beyond the historical rate specified in the Limited framework has a strong effect on electricity sector CO_2 emissions under current policies (Figure 7). Under mid demand, modeled electricity sector emissions in 2035 are roughly 810 MMT CO_2 per year in the Limited framework and 440–460 MMT/year in the three accelerated transmission frameworks (AC, P2P, MT), a 44%–45% reduction. Annual emissions reductions from accelerated transmission are even larger in 2050, roughly 56%–61%. On a cumulative (2025–2050) basis, the accelerated frameworks avoid 10.2–11.2 billion metric tons of CO_2 (43%–48%) relative to the Limited framework.

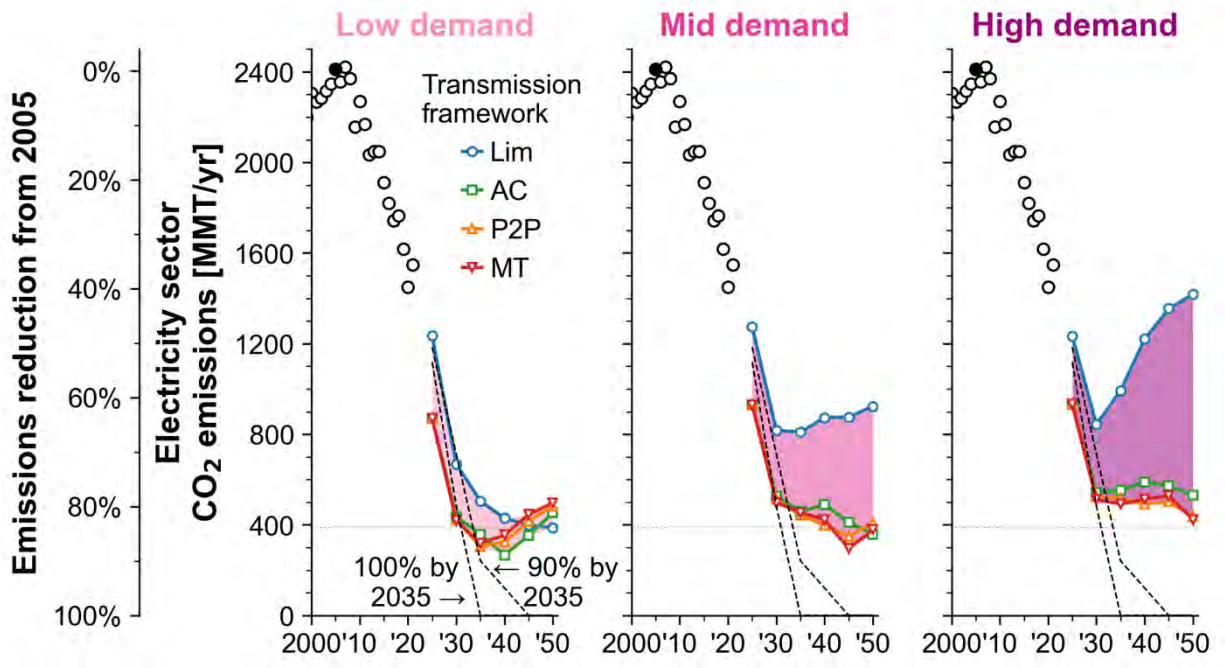


Figure 7. Electricity sector CO_2 emissions under current policies across demand assumptions

The 90% by 2035/100% by 2045 and 100% by 2035 emissions trajectories are indicated by black dashed lines. The IRA tax credit phaseout threshold (75% CO_2 emissions reduction compared to 2022) is indicated by gray dotted lines. Historical emissions (black circles) are from EIA (EIA 2024b). The shaded area represents the change in emissions from the Limited transmission framework.

Notably, even without new policies, each of the three accelerated transmission frameworks is on track for CO_2 emissions reductions on par with both the 90% by 2035 and 100% by 2035 emissions trajectories through 2030 (Figure 7). The Limited transmission framework, by contrast, reaches at most a 66% emissions reduction

relative to 2005. As discussed below, under current policies, emissions reductions stall or even reverse after 2030 as a result of the phaseout of the IRA tax credits (with low demand) or accelerated demand growth in the decades after 2030 (with mid or high demand).

Modeled emissions also depend strongly on the assumed demand growth. In the Limited transmission framework, 2050 CO_2 emissions with High-Demand are 3.7 times the emissions under Low-Demand (Figure 7a,c). The annual emissions reductions from accelerated transmission under high demand are 44%–50% in 2035 (440–500 MMT CO_2/year) and 62%–70% in 2050 (890–990 MMT CO_2/year), resulting in cumulative CO_2 savings of 14.3–15.7 billion metric tons (48%–52%). Conversely, cumulative CO_2 savings are more modest with Low-Demand (3.1–3.8 billion metric tons, or 21%–26%). This comparison applies only to electricity sector emissions; different demand trajectories have very different direct end-use emissions (Appendix A).

The emissions trends are complicated by the phaseout conditions for the IRA tax credits; as written, the credits start phasing out in 2032 or the year in which electricity sector emissions drop 75% below their 2022 level, whichever is later. The three accelerated transmission frameworks trigger the tax credit phaseout under Low-Demand growth, leading to increasing emissions between 2040 and 2050, whereas the Limited transmission framework never reaches 75% emissions reductions and thus never triggers the phaseout.

Emissions reductions from accelerated transmission expansion are driven by increased wind and solar deployment

Wind and solar deployment are significantly accelerated in the AC, P2P, and MT transmission frameworks compared to the Limited framework (Figure 8) because the annual deployment limits on local interconnection capacity (required for new wind and solar) and long-distance transmission are removed. Under Mid-Demand Current Policies assumptions, wind capacity expands to 5.8 times its 2020 capacity by 2050 in the Limited framework and 8.6–8.8 times in the accelerated transmission frameworks; solar capacity expands 10 times in the Limited framework and 14–17 times in the accelerated transmission frameworks. In 2035, wind capacity is 34%–42% higher in the accelerated transmission frameworks than in the Limited framework; solar capacity is 32%–59% higher. The share of total 2050 generation from variable renewable energy (VRE)—wind and solar combined—expands to 55% in the Limited framework and 77%–79% in the three accelerated transmission frameworks.

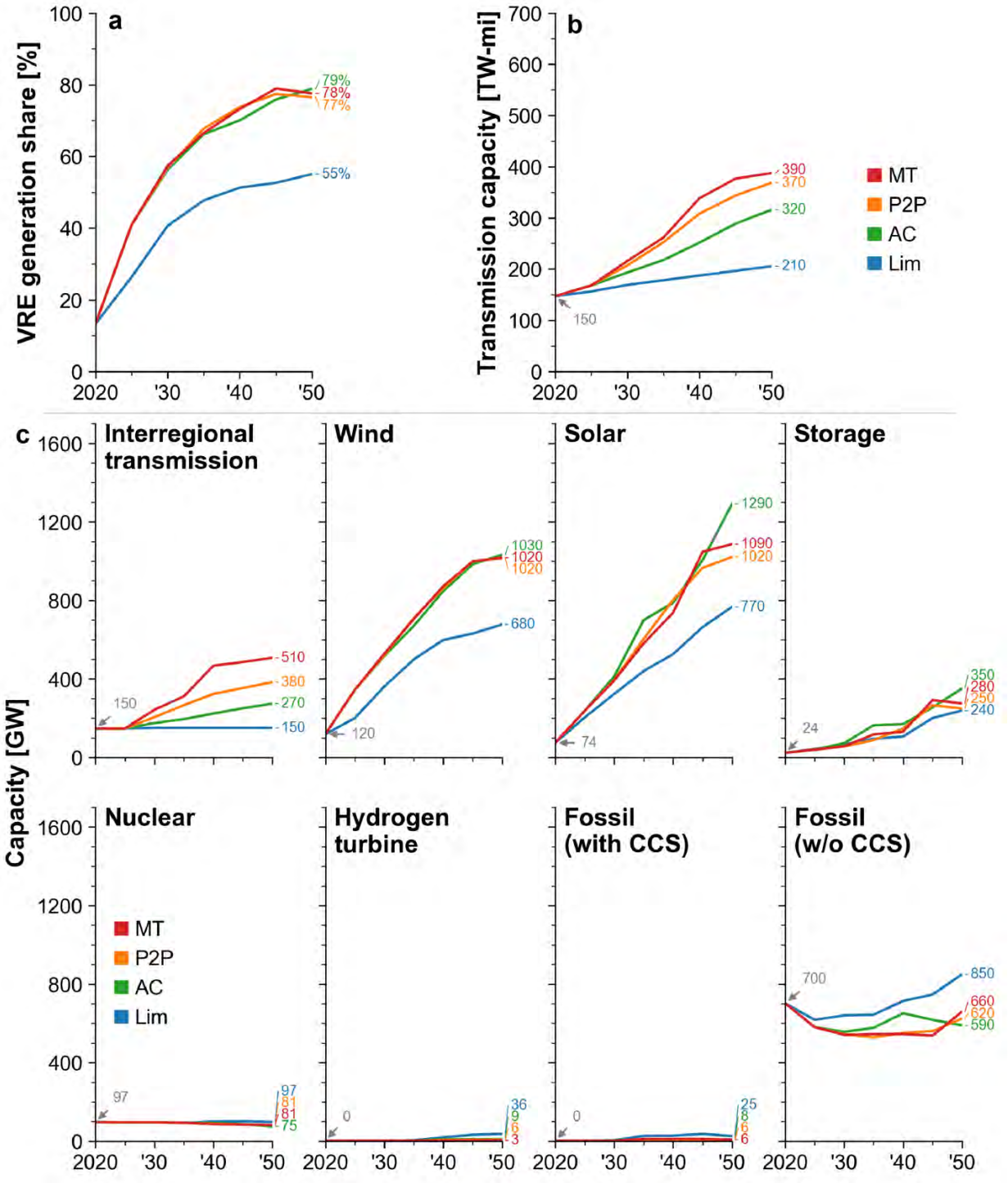


Figure 8. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under mid demand and current policies

"Total" transmission capacity (Figure 8b), including both local interconnection capacity (spur lines and network reinforcement associated with new wind and solar additions) within the 134 ReEDS model zones and long-distance interzonal transmission capacity between the model zones, is reported in units of TW-miles. Compared to the estimated

2020 capacity of ~150 TW-miles, total transmission capacity in 2050 grows to 1.4 times in the Limited framework, 2.1 times in the AC framework, 2.5 times in the P2P framework, and 2.6 times in the MT framework. “Interregional” transmission (Figure 8c) is shown in GW and represents the total bidirectional transfer capability between the 11 planning regions (Figure 1c). Compared to the estimated 2020 transfer capacity of ~150 GW, interregional transmission capacity does not expand in the Limited framework (as required by the scenario design, discussed in Section 2.3.1) and grows to 1.9 times in AC, 2.6 times in P2P, and 3.5 times in MT.

Even with expanded transmission, current policies are insufficient to fully eliminate power sector emissions, especially in futures with high demand growth

Though modeled power sector emissions are in line with the 90% by 2035 and 100% by 2035 trajectories through 2030, they diverge over the subsequent two decades (Figure 7). Fossil capacity is higher in 2050 than in 2020 in the Limited framework because the total transmission deployment limit of ~1.83 TW-miles/year substantially constrains the deployment of competing wind and solar technologies. Even in the accelerated transmission frameworks, fossil capacity in the Mid-Demand scenarios never drops more than 25% below its 2020 capacity under current policies (Figure 8), and electricity sector CO_2 emissions never drop more than 81% below their 2022 level (Figure 7).

3.2 Demand Growth and Emissions Constraints

This section presents findings from the core scenarios (Figure 3), including those that span multiple demand growth trajectories and different constraints on national power sector emissions. Unless otherwise noted, in the following results the IRA tax credits are assumed to expire in 2032 to facilitate more direct comparisons using the same policy conditions.

3.2.1 Rapid and significant growth in new transmission capacity occurs in scenarios that achieve deep emissions reductions

Applying an emissions requirement significantly expands the deployment of transmission in frameworks that allow transmission expansion (Figure 9). Under Mid-Demand assumptions, 2050 transmission capacity is 37%–68% higher with a 90% by 2035 emissions requirement than with Current Policies for each of the three accelerated transmission expansion frameworks. The Limited transmission framework is bound by the 1.83 TW-miles/year deployment constraint in nearly all scenarios.[30] Because the 90% by 2035 and 100% by 2035 scenarios achieve 100% emissions reductions by 2045 at the latest, the 2050 transmission capacity does not change significantly between these scenarios when demand scenario and transmission framework are held constant. However, near-term transmission deployment is accelerated in the 100% by 2035 scenarios: 2035 transmission capacity is 15%–34% higher in the 100% by 2035 scenarios than in the 90% by 2035 scenarios for the three accelerated transmission frameworks.

[30] With low demand and current policies, the annual transmission growth constraint of the Limited framework is not reached.

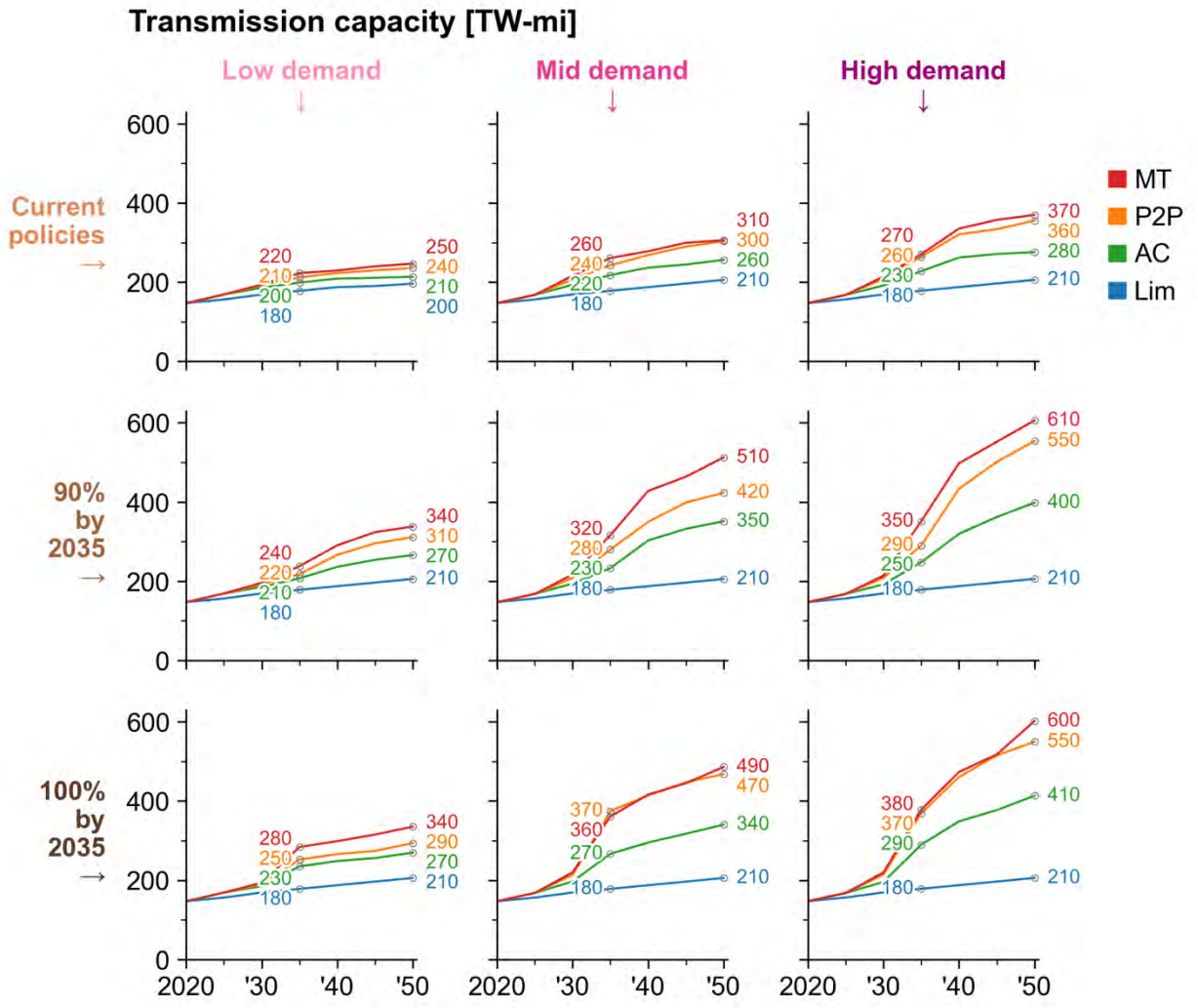


Figure 9. Total transmission capacity as a function of demand (columns) and emissions constraint (rows)

Total transmission capacity includes local interconnection capacity (spur lines and network reinforcement) within the 134 ReEDS zones and long-distance interzonal transmission capacity between ReEDS zones. For this plot, the IRA tax credit is assumed to begin phasing out in 2032 for all scenarios (including for current policies), irrespective of emissions, to facilitate comparison across scenarios while keeping policy assumptions constant.

For context, Figure 10 shows the average transmission growth rate between 2025 and 2050 compared to different benchmarks for historical transmission deployment. In the central Mid-Demand 90% by 2035 scenario, annual transmission additions in the three accelerated transmission frameworks range from 2.0 to 3.8 times the maximum annual rate of transmission deployment observed in the United States since 2009. Alternatively, comparing the modeled rate of annual transmission deployment to individual HVDC links that have been built in the past in a collection of countries shows this rate of growth equates to the addition of 2.7–5.1 “Pacific-DC Intertie” links (built in the United States in 1970 and upgraded since) per year (Pierre et al. 2019), 0.8–1.5 “Rio Madeira” links (completed in Brazil in 2014) per year (Hitachi 2022), or one “Changji-Guquan” link (completed in China in 2019) every 1.8–3.3 years (Hitachi 2020).

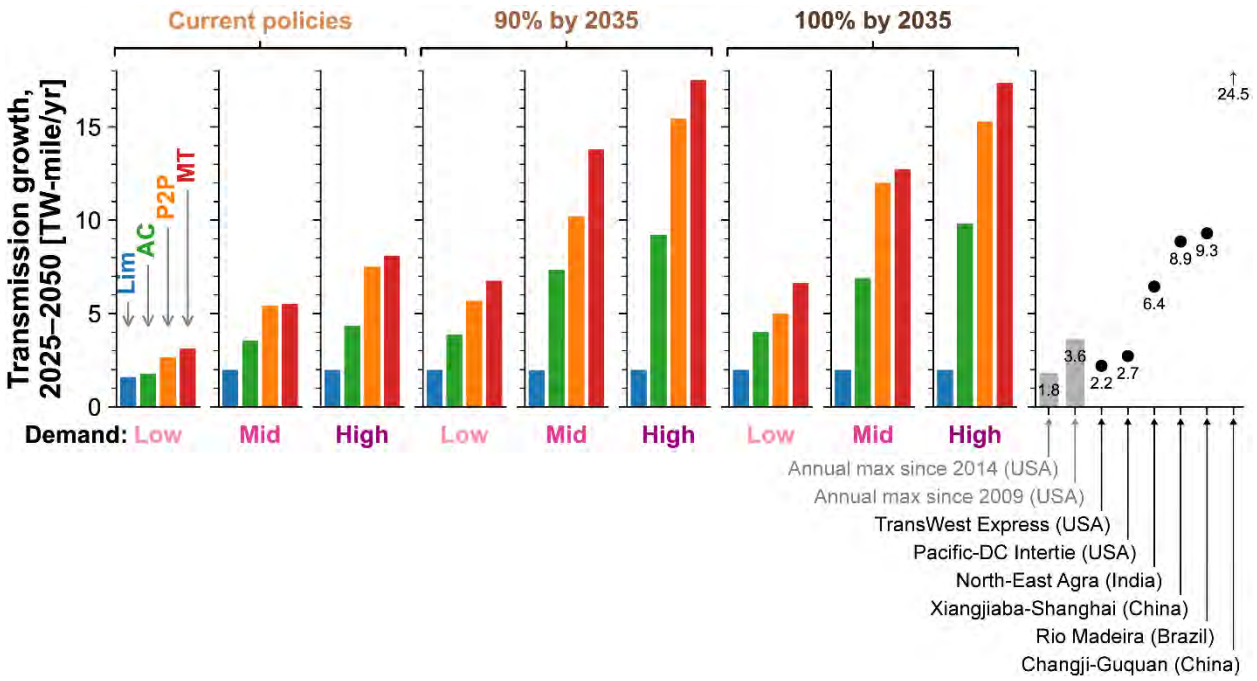


Figure 10. Total transmission growth rate in TW-miles/year as a function of demand, emissions constraint, and transmission framework

The gray bars for "Annual max since 2009" and "Annual max since 2014" refer to U.S. transmission additions as discussed in Wiser et al. (2023). The filled markers indicate individual historically constructed HVDC projects for scale (Pierre et al. 2019; TransWest Express 2024; Power Technology 2020; Hitachi 2020; 2022; 2024).

Electrification drives greater deployment of transmission and generation capacity

The assumed level of demand growth has a significant impact on total transmission deployment. Relative to 2020 transmission capacity, the 2050 transmission capacity in the three accelerated transmission scenarios grows from 1.5 to 1.7 times for low demand to 1.9–2.5 times for high demand under current policies (Figure 9). Combined with a decarbonization policy, the impact of demand growth is even stronger: With 90% by 2035 and 100% by 2035 emissions reductions, 2050 transmission capacity grows from 1.8 to 2.3 times its 2020 level for low demand to 2.7–4.1 times for high demand. Scenarios with high demand through electrification and that achieve 100% grid emissions reductions approximate net zero emissions for the U.S. energy system as a whole (Section 2.3.3).

As with total transmission capacity, demand growth and decarbonization policy are strong drivers of interregional transmission deployment (Figure 11). Interregional transmission capacity, which is defined as the capacity between the 11 planning regions in Figure 1c, grows to 1.5–2.7 times its 2020 capacity by 2035 in the three accelerated transmission frameworks in the Mid-Demand 90% by 2035 scenario and 1.6–3.3 times in the High-Demand 100% by 2035 scenario. By 2050, these ranges grow to 2.6–4.6 times in the Mid-Demand 90% by 2035 scenario and 2.6–5.3 times in the High-Demand 100% by 2035 scenario.

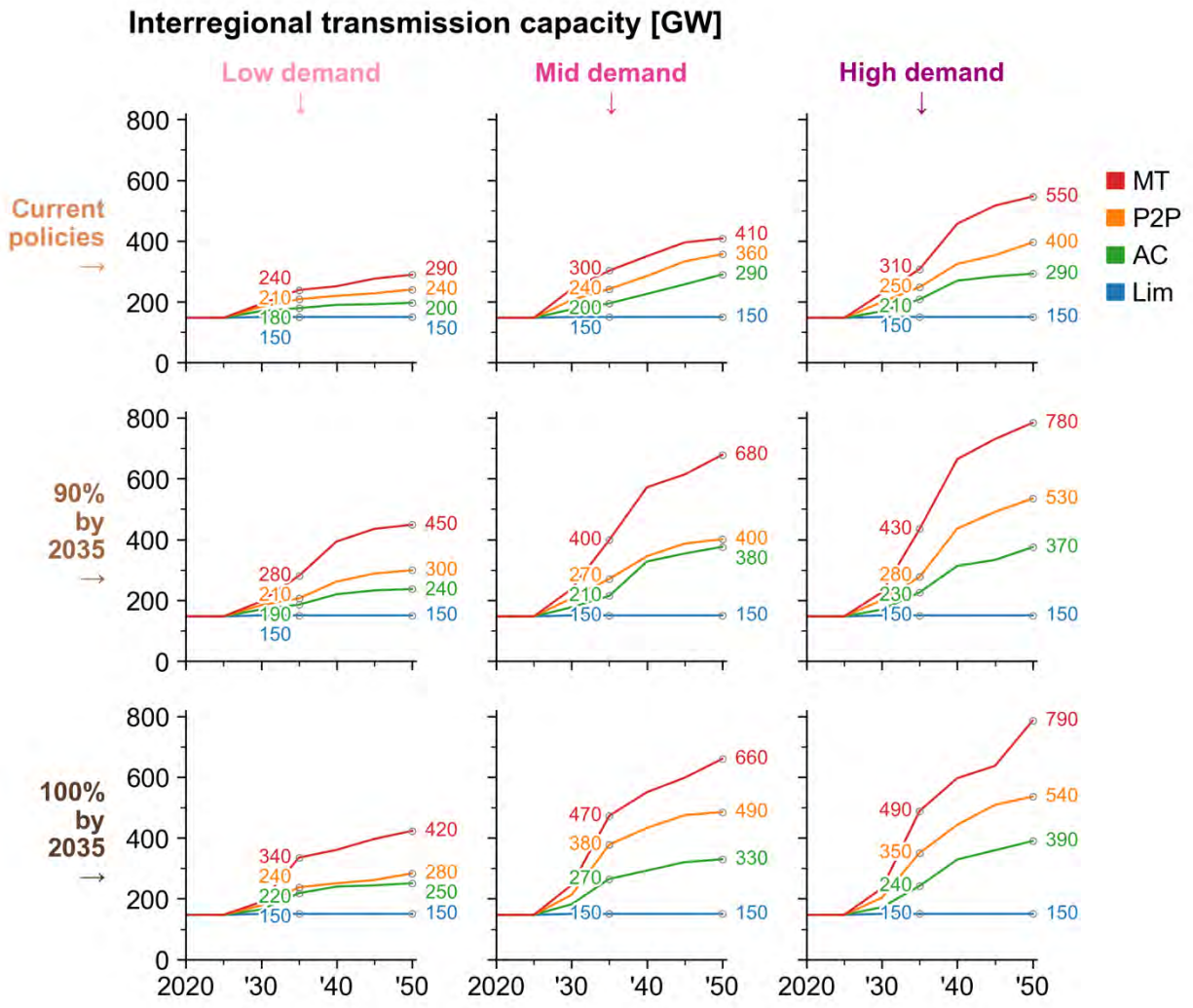


Figure 11. Interregional transmission capacity as a function of demand (columns) and emissions constraint (rows)

"Interregional" transmission capacity is measured between the 11 planning regions shown in Figure 1. For this plot, the IRA tax credit phaseout is assumed to begin in 2032 for all scenarios (including for current policies) to facilitate comparison across scenarios while keeping policy assumptions constant.

Installed wind and solar capacity also scales with demand growth in the accelerated transmission frameworks (Figure 12). In the 90% by 2035 scenarios, 2050 wind capacity grows to 6–7 times its 2020 capacity with low demand, 9–10 times with mid demand, and 12–13 times with high demand; PV capacity grows to 13–14 times, 15 times, and 18–19 times, respectively. Nuclear capacity grows appreciably only in the Limited transmission framework with mid/high demand and either 90% by 2035 or 100% by 2035 emissions constraints, where it grows to ~2 times 2020 capacity under mid demand and ~4 times under high demand (compared to ≤3% growth in all other transmission frameworks and demand/emissions assumptions).

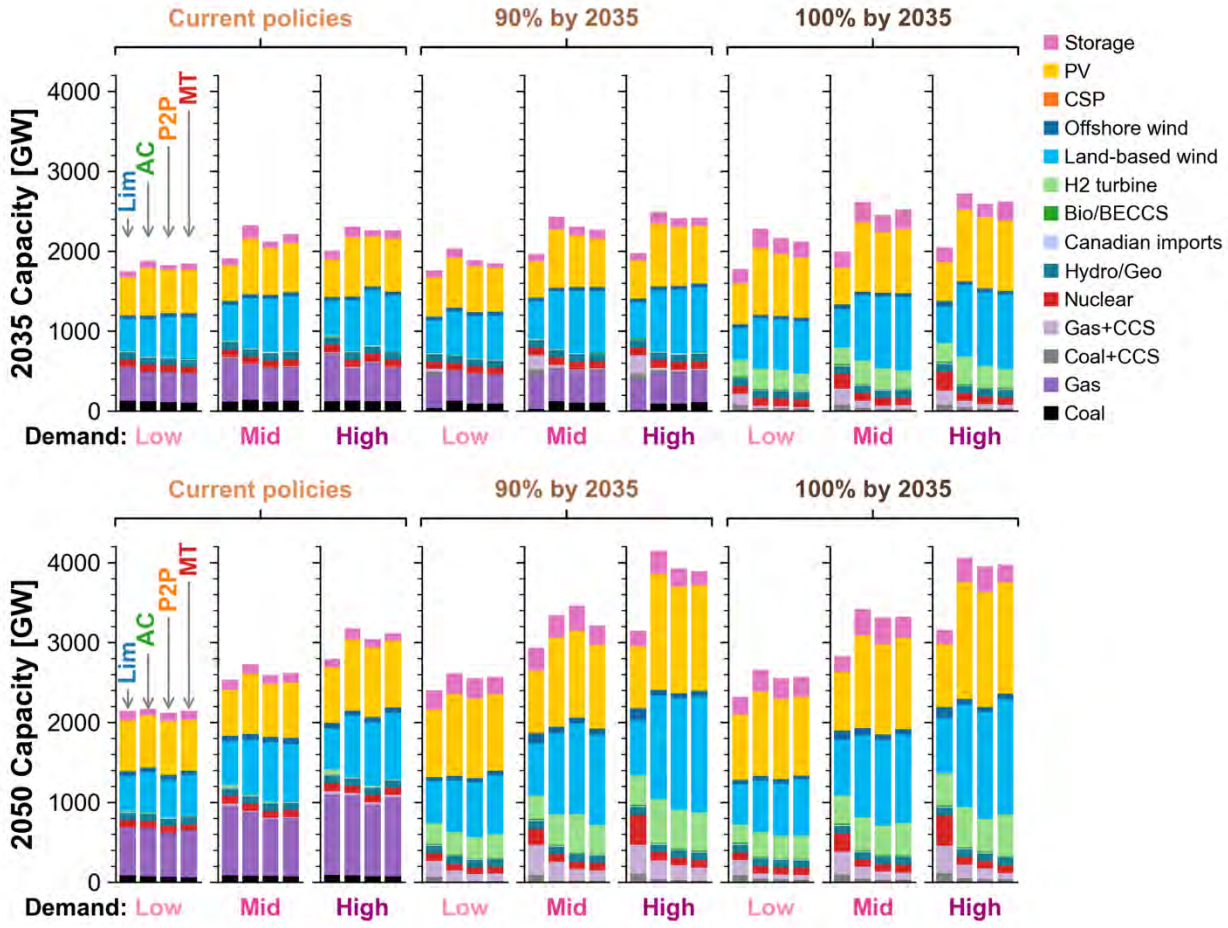


Figure 12. Generation capacity in 2035 and 2050 as a function of demand, emissions constraint, and transmission framework

3.2.2 Benefits from large-scale transmission expansion include hundreds of billions of dollars in system cost savings under decarbonization futures

Though accelerating transmission expansion leads to reductions in CO_2 emissions under current policies, with national emissions limits that fully eliminate grid emissions, the primary impact of accelerated transmission expansion is a reduction in electricity system costs. The main cost metric is the net present value (NPV) of total electricity system costs through 2050, including fixed and operating costs and tax incentives for electricity producers.[31] Figure 13 shows this metric across the 90% by 2035 and 100% by 2035 emissions assumptions (rows), three demand trajectories (columns), and four transmission frameworks (bars). Accelerating transmission expansion reduces costs by $270–490 billion under Mid-Demand/90% by 2035 assumptions, with the AC framework at the bottom of the range of savings and MT at the top (a 4%–8% reduction compared to the $6,370 billion NPV of system costs in the Limited framework).

[31] Unless otherwise noted, the NPV costs are for all expenditures from 2022 to 2050 using a 1.7% societal real discount rate (OMB 2023).

Savings from accelerated transmission increase when decarbonization is achieved more quickly (to $570–810 billion under Mid-Demand/100% by 2035 assumptions) and when demand growth increases (to $710–970 billion in High demand/90% by 2035 and to $860–1,220 billion in High demand/100% by 2035).

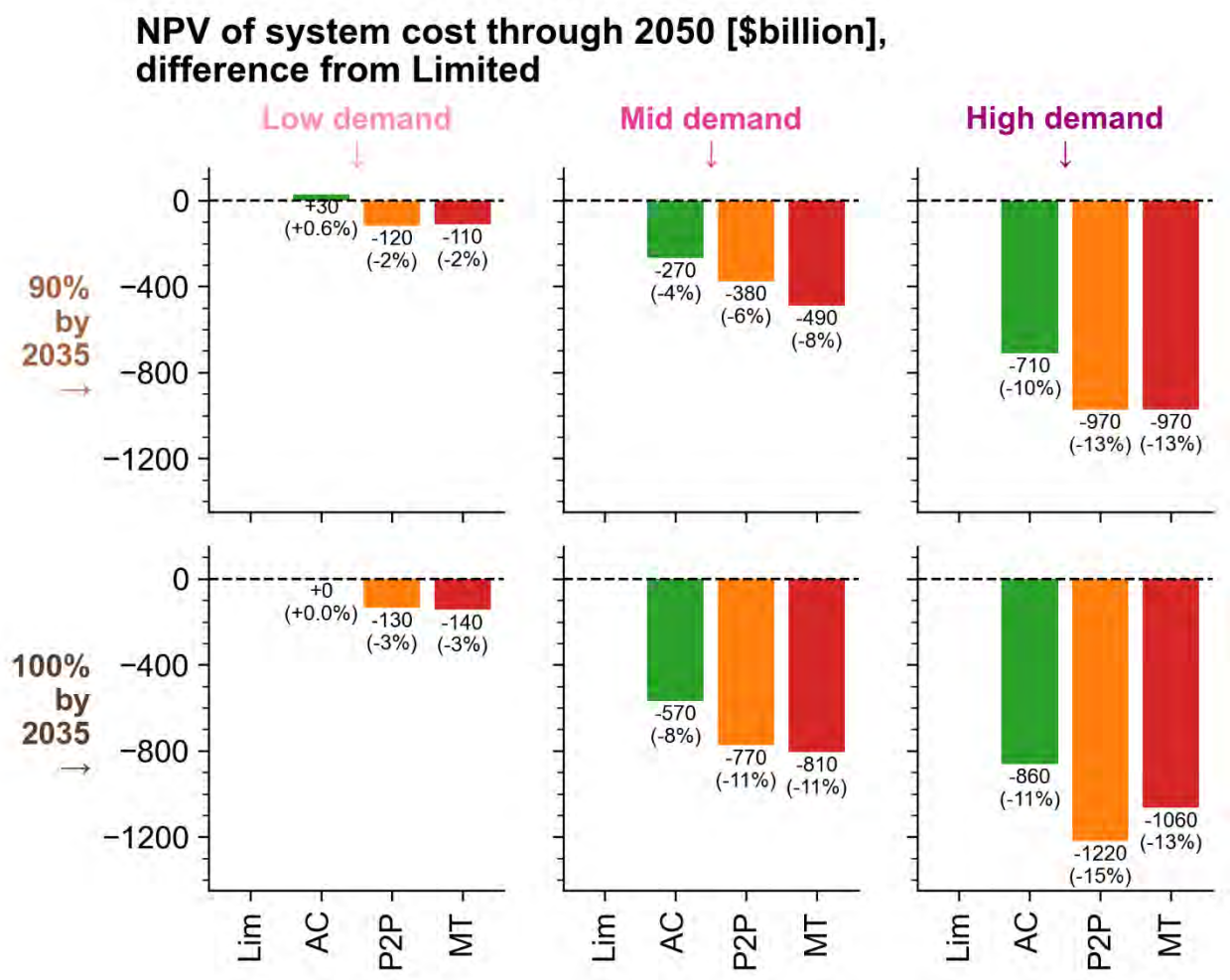


Figure 13. Net present value of total system cost through 2050 expressed as savings relative to the Limited framework

The cost change in each of the three accelerated transmission frameworks relative to the Limited framework is given in $billion and as a percent change below each bar. Differences below ~1% (~$50 billion) are considered within the model uncertainty bounds resulting from imperfect foresight and scenario-specific stress periods.

3.3 Central Demand and Emissions Assumptions

Sections 3.1 and 3.2 show results across all core scenarios, which cover a range of emissions reductions and demand growth assumptions. This section presents findings from the central demand and emissions constraint scenarios, which assume Mid-Demand growth trajectories and 90% emissions reductions by 2035 (100% by 2045). These central scenarios include both the core and the 15 sensitivity cases (Table 1).

3.3.1 Accelerating transmission deployment consistently reduces system cost across a spectrum of sensitivity cases

Across all modeled sensitivity cases, the system cost of a given case is uniformly lower in the three accelerated transmission frameworks than in the Limited transmission framework (Figure 14, Figure 15, and Figure 16), and transmission expansion consistently delivers hundreds of billions of dollars of savings. The core scenario savings of $270–490 billion are on the low end of the modeled sensitivity cases (Figure 16): The range of savings across all sensitivity cases is $270–760 billion for the AC framework; $380–1,170 billion for P2P; and $350–1,170 billion for MT.

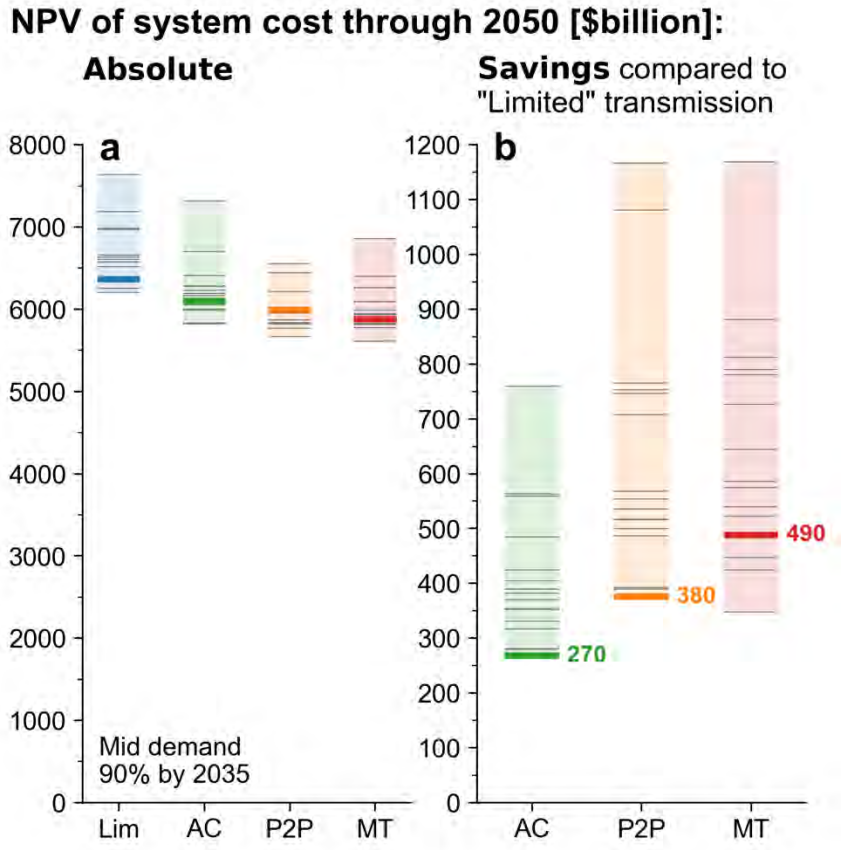


Figure 14. Net present value of total system cost through 2050 under central (Mid-Demand 90% by 2035) assumptions expressed in absolute terms (a) and as savings relative to the Limited framework (b)

Note the change in y-axis scale between panels (a) and (b). Bold line indicates the core scenario result.

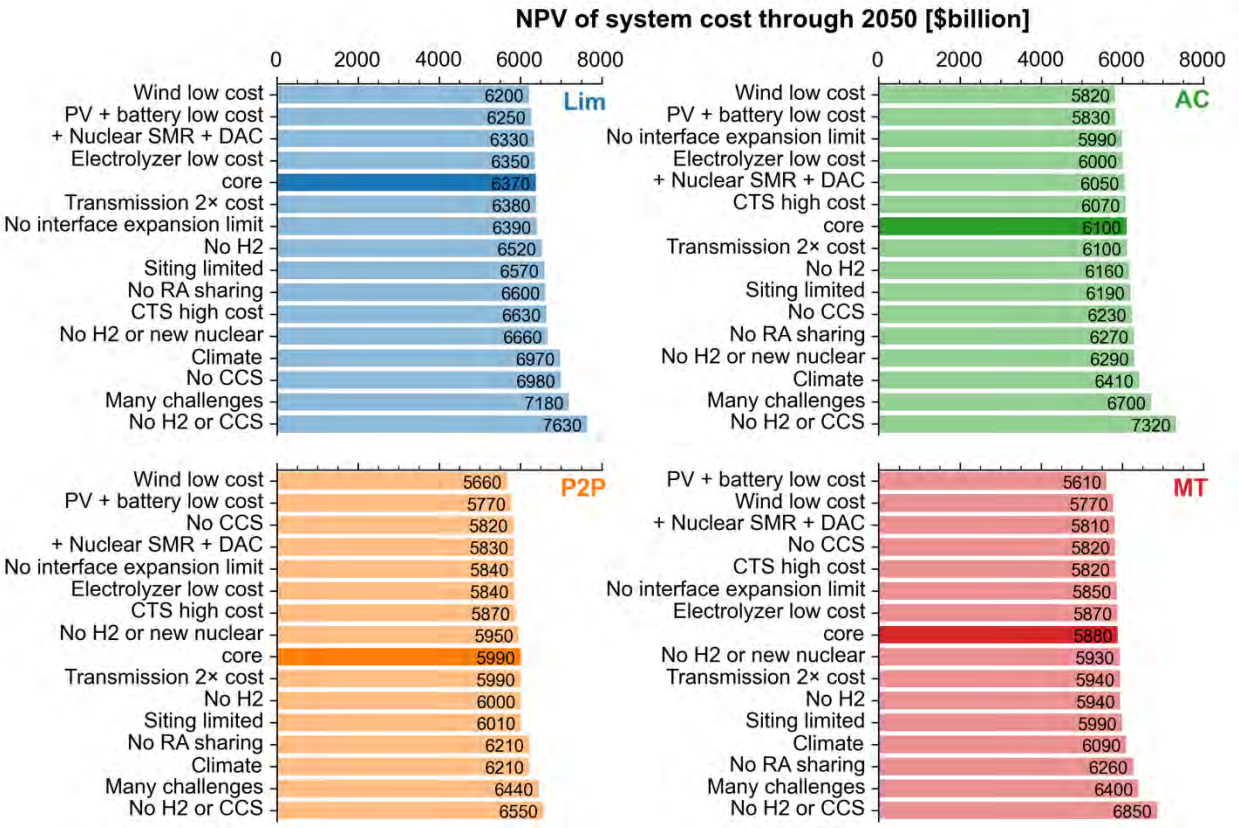


Figure 15. Net present value of total system cost through 2050 for each transmission framework and sensitivity case under Mid-Demand 90% by 2035 assumptions

The savings in each of the three accelerated transmission frameworks relative to the Limited framework are given as numbers in billions of dollars at the right of each bar. Scenarios within each transmission framework are sorted by absolute system cost.

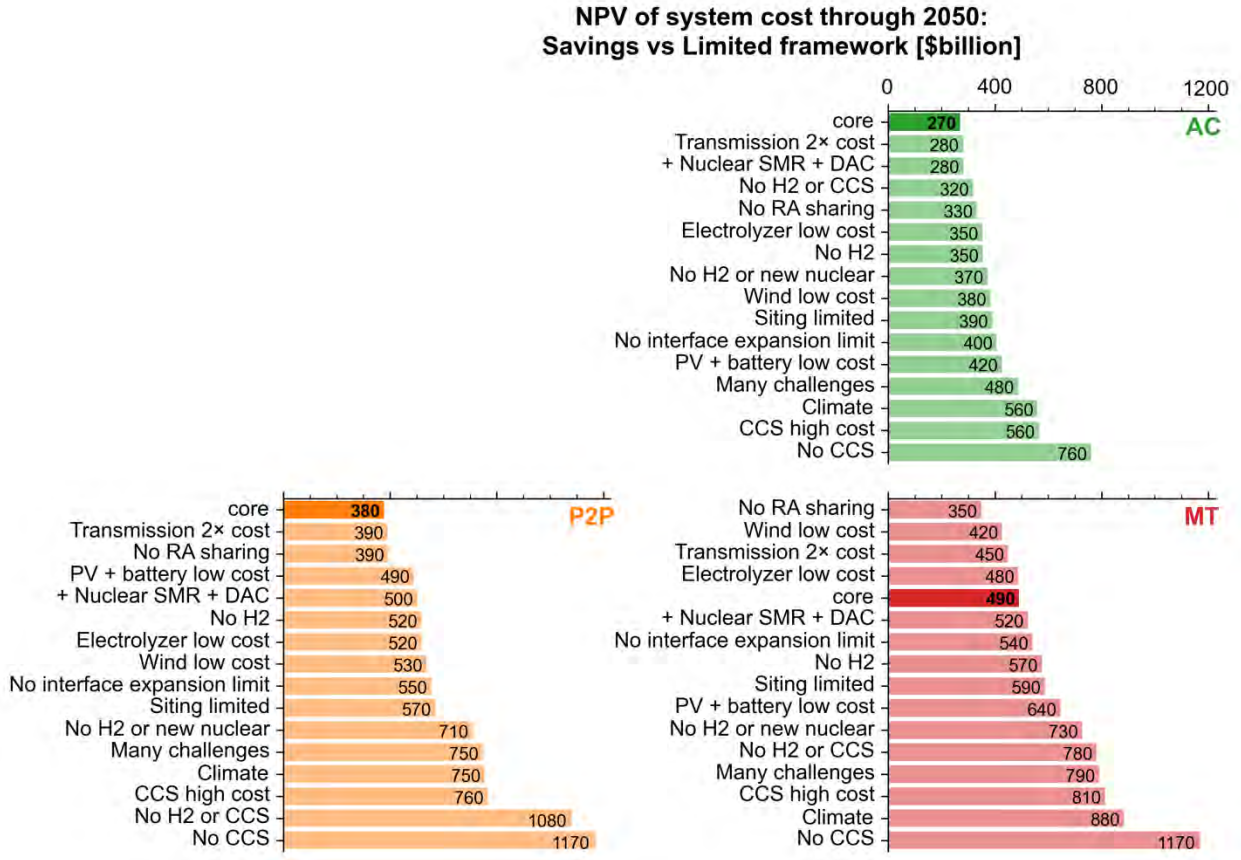


Figure 16. Net present value of total system cost savings relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

Scenarios within each transmission framework are sorted by system cost savings relative to the Limited framework.

Savings from accelerated transmission are largest in futures where alternative technologies are constrained or more expensive. The highest savings from accelerated transmission are in the "No CCS" sensitivity case: Without CCS, costs rise by ~$600 billion in the Limited framework but are relatively unaffected in the other frameworks, leading to savings of ~$800–1,200 billion from accelerated transmission when CCS is unavailable. Transmission-induced savings also increase in the "No H_2" and "No H_2 or new nuclear" sensitivity cases. Transmission expansion could help hedge against the possibility that new low-carbon technologies face difficulties in scaling up from their currently low annual deployment rates. Conversely, if these low-carbon generation technologies become commercially available—as assumed under the core scenarios—the benefits of accelerated transmission expansion are lower but still substantial as discussed previously. Savings from accelerated transmission expansion are also $100–190 billion higher in the "Siting limited" case than in the core scenario, $220–370 billion higher in the "Many challenges" case, and $290–390 billion higher in the "Climate" case. Notably, cost savings from accelerated transmission expansion under the "Transmission 2× cost" case ($280–450 billion) are similar to savings under the core scenario.

Lower system costs in the accelerated transmission frameworks significantly outweigh the costs of new transmission

Across all accelerated transmission frameworks and sensitivity cases, the system cost savings exceed the additional cost of building the transmission compared to the Limited scenario. Figure 17 shows the range of benefit-to-cost ratios for the portfolio of transmission investments in the AC, P2P, and MT scenarios for the 90% by 2035 emissions constraint scenarios.[32] The highest benefit-to-cost ratios are achieved in the P2P and MT scenarios that allow for HVDC transmission development. The core P2P and MT scenarios achieve a benefit-to-cost ratio of 1.7 and 1.8, respectively, compared to the core AC scenario benefit-to-cost ratio of 1.6. As with system cost savings, the benefit-to-cost ratios for the core scenarios are toward the lower end of the ranges. Many sensitivity cases have benefit-to-cost ratios close to 2. Sensitivity cases where new low-carbon technologies are not available typically have higher benefit-to-cost ratios (1.9 to 2.3). The benefit-to-cost ratio exceeds 1.5 across all sensitivity cases; for context, the maximum threshold allowed in FERC Order No. 1000 to determine whether transmission facilities have significant enough benefits to be selected in a regional transmission plan for the purpose of cost allocation is 1.25 (Federal Energy Regulatory Commission 2011).[33]

[32] Benefits are defined as the difference in total nontransmission system costs including generation and storage capital and operating costs and policy incentives between the accelerated transmission framework (AC, P2P, or MT) and the Limited framework. Costs are defined as the NPV of transmission capital and operating costs for all transmission types including spurline, intra- and interzonal lines, and converter stations. More information on the cost analysis is provided in Appendix E.

[33] FERC Order No. 1000 specifies that a benefit-to-cost ratio of 1.25 is the maximum threshold for determining if transmission facilities have sufficient net benefits to be included in regional transmission plans.

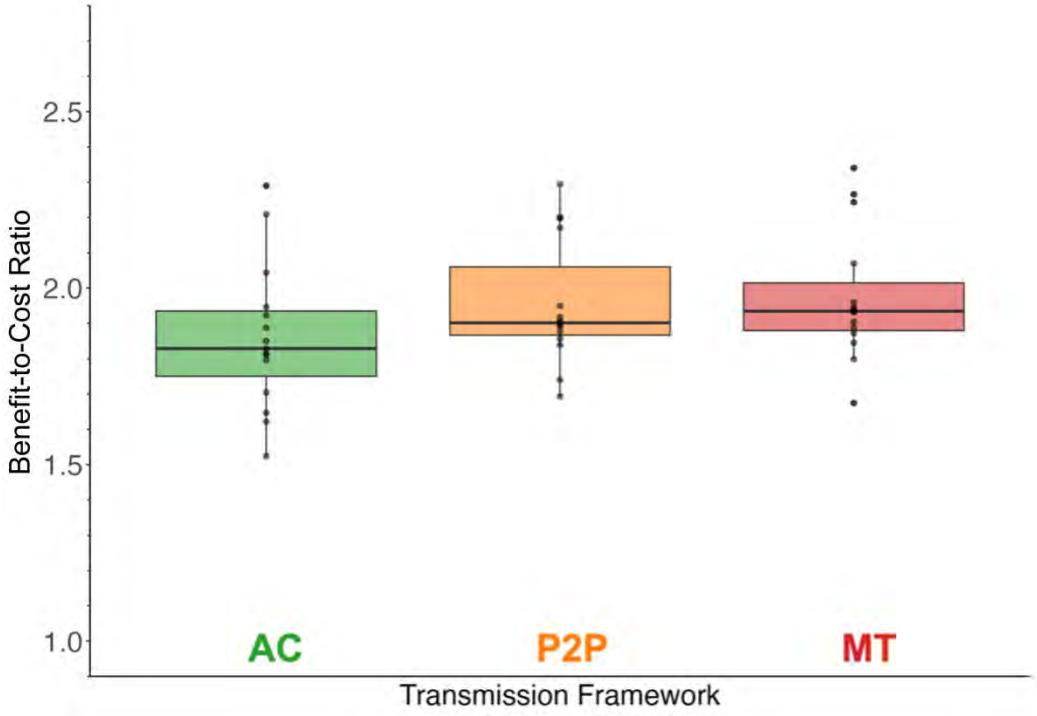


Figure 17. Benefit-to-cost ratio of systemwide savings compared to additional transmission costs relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

The center line indicates the median value, and upper and lower box lines indicate the 25th and 75th percentiles, respectively. The benefit-to-cost ratios exclude the added cost of transmission when calculating benefits.

Transmission expansion helps reduce capital, operating, and fuel expenditures for generation and storage

Historically, savings in production costs have been the primary metric for valuing transmission investments (Chang, Pfeifenberger, and Hagerty 2013; Federal Energy Regulatory Commission 2022). However, transmission development can—positively and negatively—impact a broader range of system costs, including capital investments, fixed operation and maintenance (O&M) costs, and the ability to capture policy incentives. The impact on system costs may change over time as the underlying generation mix changes. Figure 18 shows the change in different types of system costs for the AC, P2P, and MT scenarios compared to the Limited framework from 2025 through 2050.

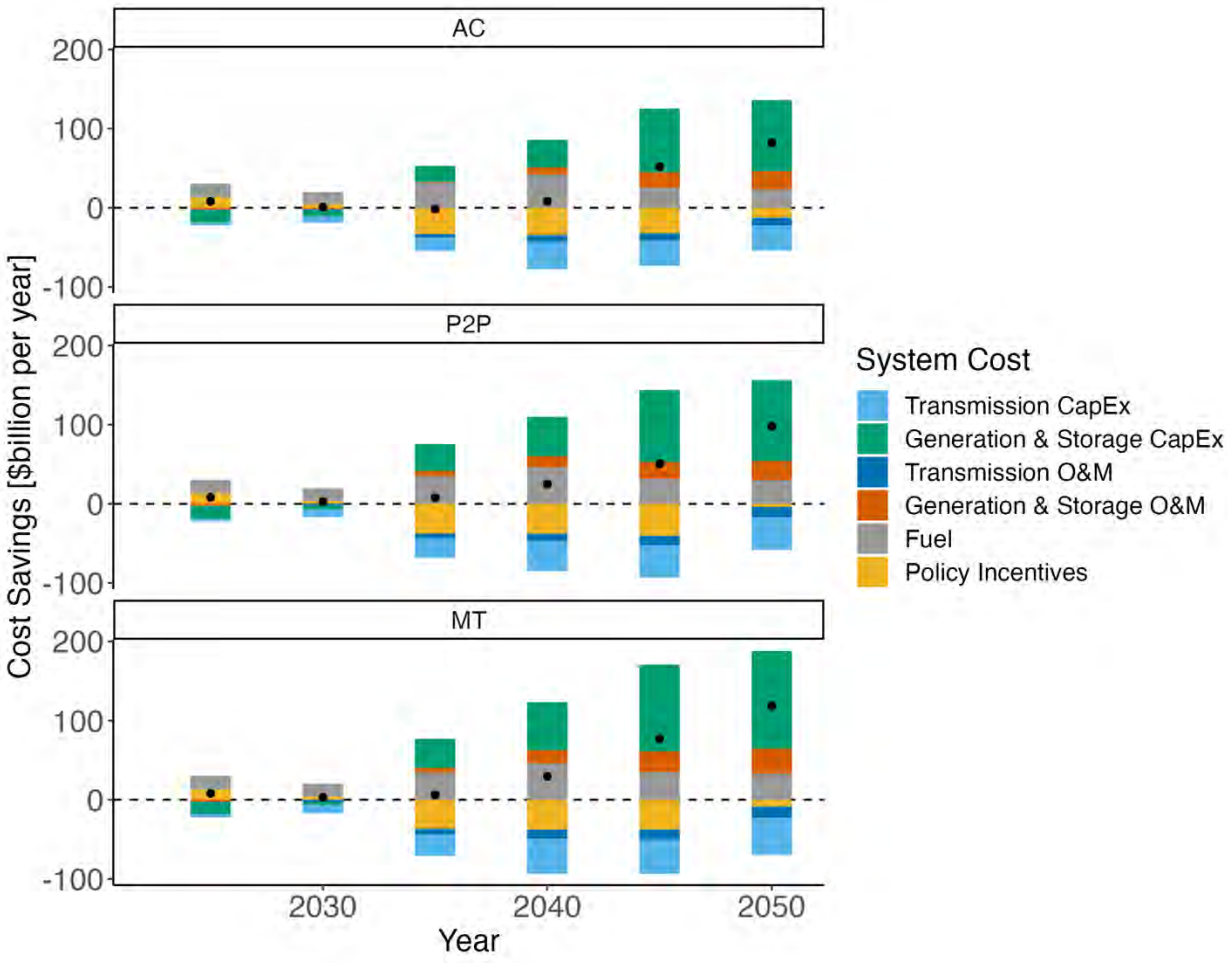


Figure 18. Source of cost savings (real $billion per year) compared to the Limited framework under Mid-Demand 90% by 2035 assumptions

Negative values indicate greater costs compared to the Limited framework; positive values represent savings. Black dots indicate net savings across all system cost categories.

Savings in generation and storage capital costs are the largest source of system savings, totaling $420 billion in the AC framework and more than $700 billion in the MT framework (present value), equivalent to an 11%–20% reduction in total generation and storage capital costs. These savings do not begin until after 2030 and increase in magnitude over the planning period. Reductions in fuel costs make up the second largest source of savings because increased investments in transmission enable greater use of VRE resources, resulting in a 44%–49% decrease in fuel expenditures. Annual savings from avoided fuel costs peak around 2040 and start to decline as the share of VRE increases and opportunities to displace fuel generation are reduced.

Though total system costs decrease in the accelerated transmission development scenarios, capital and operating costs for transmission increase compared to the Limited framework as investments in all types of transmission increase. Total expenditures for transmission (present value) are $760 billion; $1,220 billion; $1,320 billion; and $1,390 billion for the Limited, AC, P2P, and MT frameworks, respectively

(Figure 19). Investments and operating costs for local transmission infrastructure make up the largest share of transmission costs, accounting for more than 40% of total transmission expenditures for all transmission frameworks. Investments in interregional transmission are smaller in all scenarios but grow noticeably after 2030 in the accelerated transmission frameworks (AC, P2P, MT) and reach $12 billion per year by 2050. For context, recent historical transmission investments are estimated to be $20–25 billion per year (Edison Electric Institute 2024).[34] Annual fixed O&M costs for transmission infrastructure—assumed to be 1.5% of the upfront capital cost—make up a significant share of total expenditures, accounting for 50% of total transmission expenditures in 2025, falling to 30% by 2050. Increased transmission development also impacts the tax credit outlay, particularly including the production and investment tax credits for wind, solar, and storage as well as the CO_2 capture tax credit.[35]

[34] The scope of Edison Electric Institute's estimates may not align with the transmission cost categories. In particular, spur lines and other interconnection investments modeling may not be included in the historical data.

[35] The system cost metric and associated benefit-cost-ratio method includes the value of tax credits (tax credits are treated as negative costs to the electricity system) because this metric is intended to measure the impact from the perspective of the electricity system, including producers. This electric sector perspective differs from an economywide perspective where tax credits are typically viewed as transfers between taxpayers and those receiving the credits. When tax credits are excluded in the cost metrics to be more aligned with this perspective, the system cost savings from accelerated transmission change to $570–830 billion (compared with $270–490 billion) under the core scenarios and the benefit-cost ratios change to 2.2–2.3 (compared with 1.6–1.8).

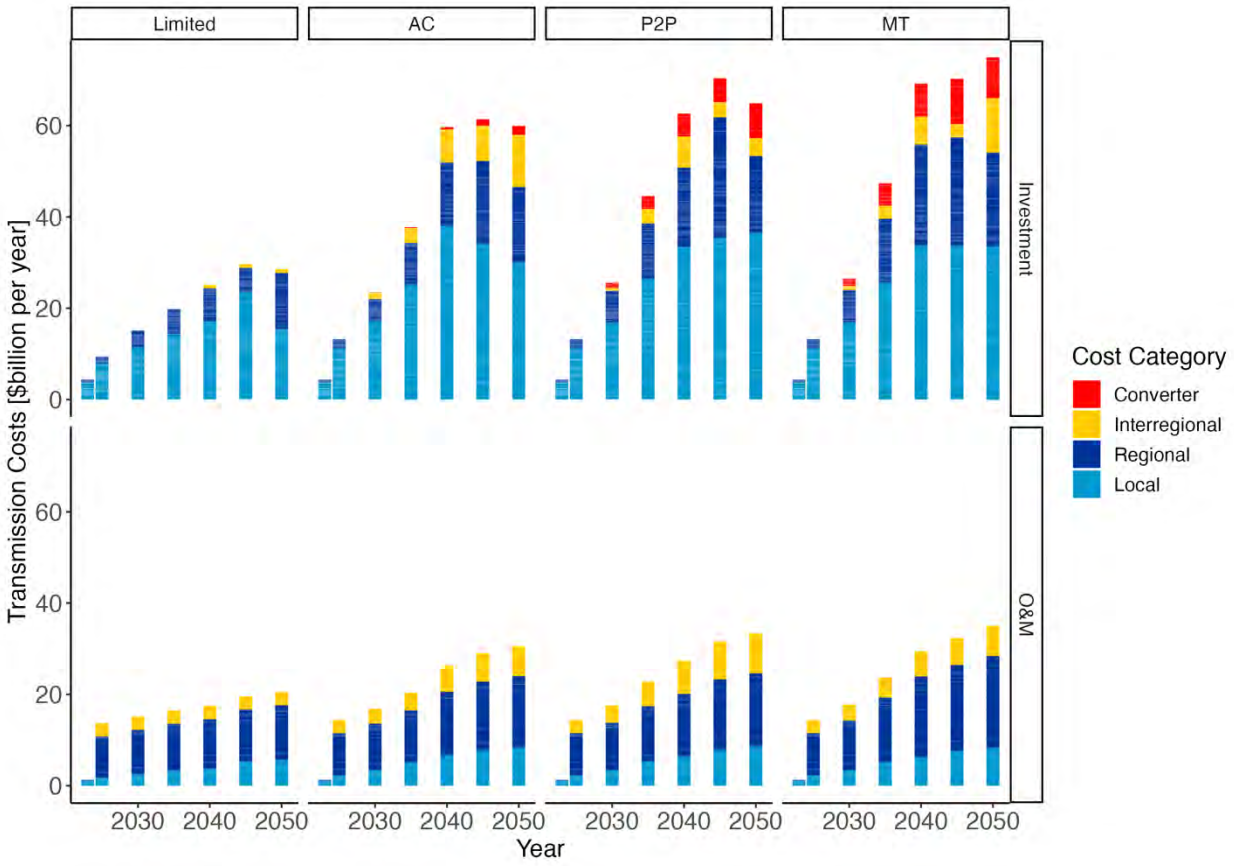


Figure 19. Transmission costs under Mid-Demand 90% by 2035 assumptions

Investments in converters serve both regional and interregional transmission needs.

Interregional transmission enables cost savings for most regions

Though the systemwide value and benefit-cost ratio of each accelerated transmission framework are high, they are not uniform across all individual transmission planning regions. When evaluating the benefit distribution among regions, further consideration of where power is exported and imported—and the value of the power traded—is needed to capture the transmission benefits of interregional trade to each region. To disaggregate benefits regionally, operational costs are adjusted to approximate how these costs might be allocated between importing and exporting regions. To do so, the analysis uses the adjusted production cost (APC) metric.[36] This metric is the difference in total production costs adjusted for import costs and export revenues with and without a proposed transmission investment. For this study, the APC is based on zonal marginal prices from the capacity expansion model. Further study with full 8,760 hourly resolution at a nodal resolution can be used to refine the estimated adjusted production costs for each region. The following figures show the total savings to each region

[36] See Appendix E for more details on the APC method used in current planning processes and the adjustment values calculated for the core transmission scenarios.

compared to the Limited scenario by system cost category (Figure 20a) and as a share of each region's costs (Figure 20b).

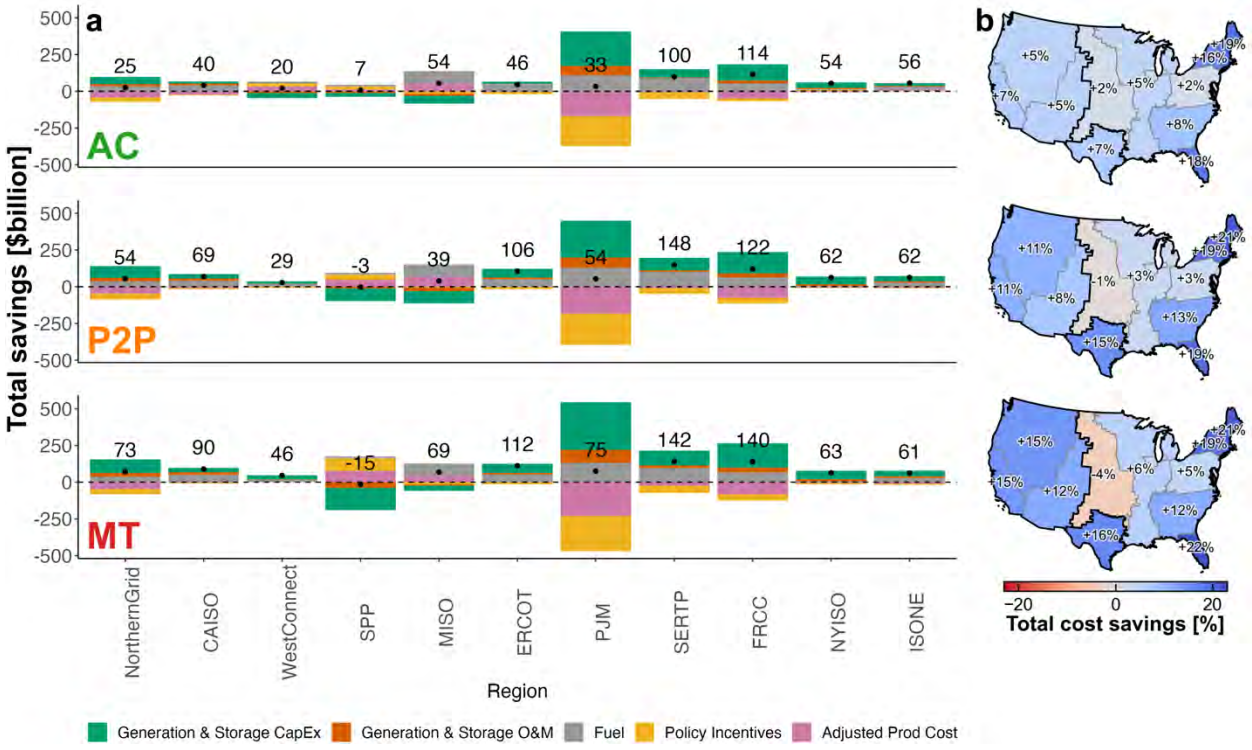


Figure 20. Net present value of system savings by region in absolute $billion (a) and percentage (b) of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

Black dots in (a) indicate net savings across all system cost categories. These results show the disaggregation of system benefits evaluated as part of this study and are not intended to prescribe any specific cost allocation among planning regions.

Among planning regions, savings from increased transmission interconnection in 90% by 2035 Mid-Demand scenarios are highest in the Southeast (SERTP, FRCC) and Texas (ERCOT). These regions see large decreases in fuel costs and generation and storage capital costs because the transmission network allows them to make greater use of lower-cost resources located in other regions. As a share of total costs, ISONE, FRCC, and NYISO see the highest savings, with costs declining by more than 20% in the MT framework. In other regions, such as SPP, total costs increase in some scenarios compared to the Limited framework because these regions are building more generation capacity to export to neighboring regions. In these regions, the additional benefits from collecting more investment and production tax credits and increased generation revenues from selling power to neighbors do not outweigh the additional cost of building and operating more generation capacity.

Similar to systemwide cost savings, the regional transmission value—measured by the savings in investment and operating costs transmission can provide—is sensitive to technology availability and costs, climate impacts, siting constraints, and other varying system characteristics. Figure 21 shows the range of transmission values by region across all sensitivity cases using the Mid-Demand 90% by 2035 assumptions.

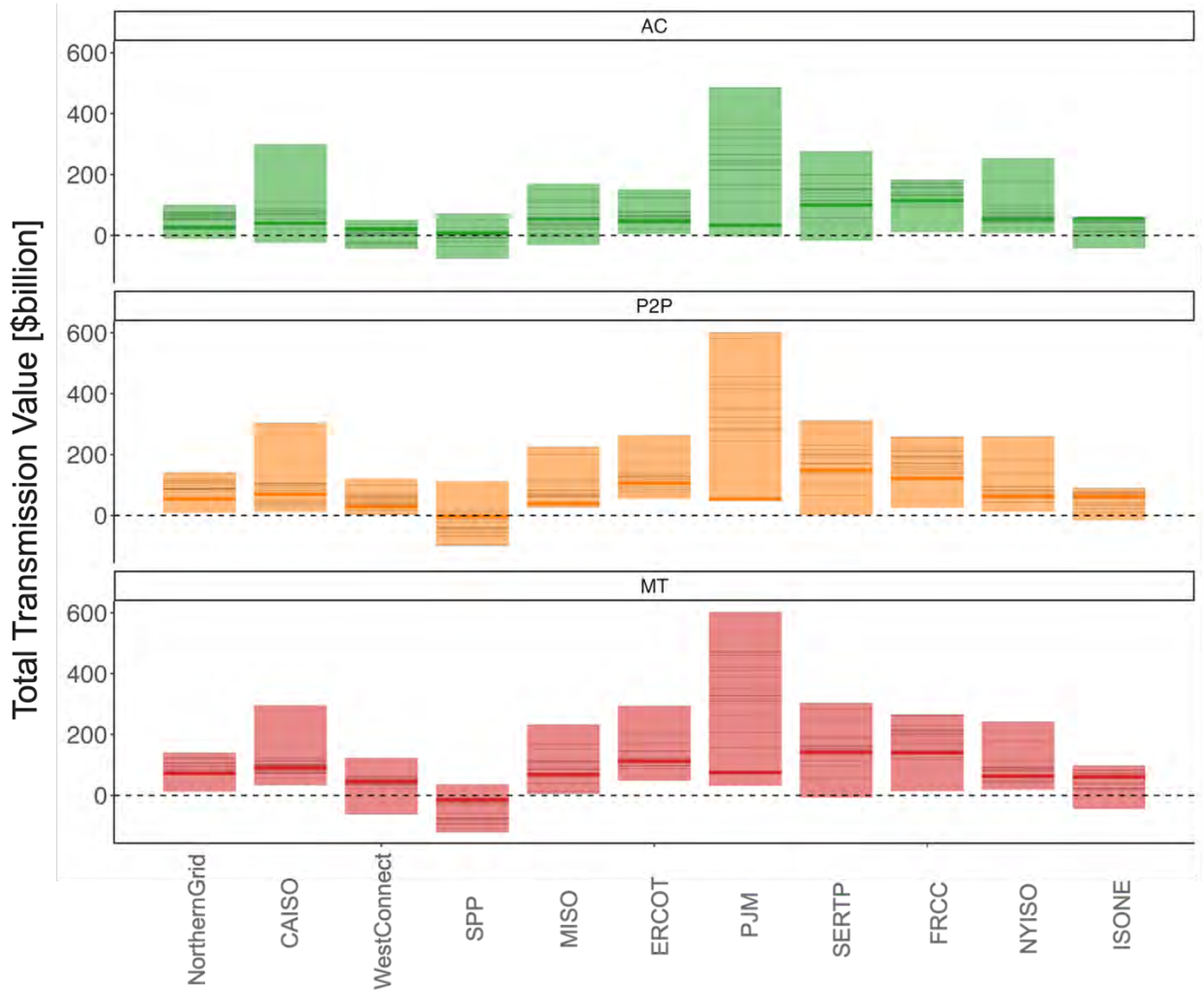


Figure 21. Net present value of total system cost savings to each transmission planning region relative to the Limited framework under Mid-Demand 90% by 2035 assumptions

Bold line indicates the core scenario result.

The impact of each sensitivity varies by region. For example, in regions that rely on CCS and H_2 technologies to achieve emissions reductions targets, the value of transmission increases when these technologies are not available. Detailed results for each modeled sensitivity are presented in Appendix D.4.

3.3.2 Transmission expansion enables increased access to wind and solar

As in the Current Policies scenarios (Section 3.1), accelerating transmission expansion increases the share of VRE in the resource mix across all sensitivity cases (Figure 22). The VRE share (annual solar and wind generation divided by total annual generation from all sources) is ~20% higher in the AC, P2P, and MT core scenarios (77%–82% VRE share) than in the Limited core scenario (58% VRE share).

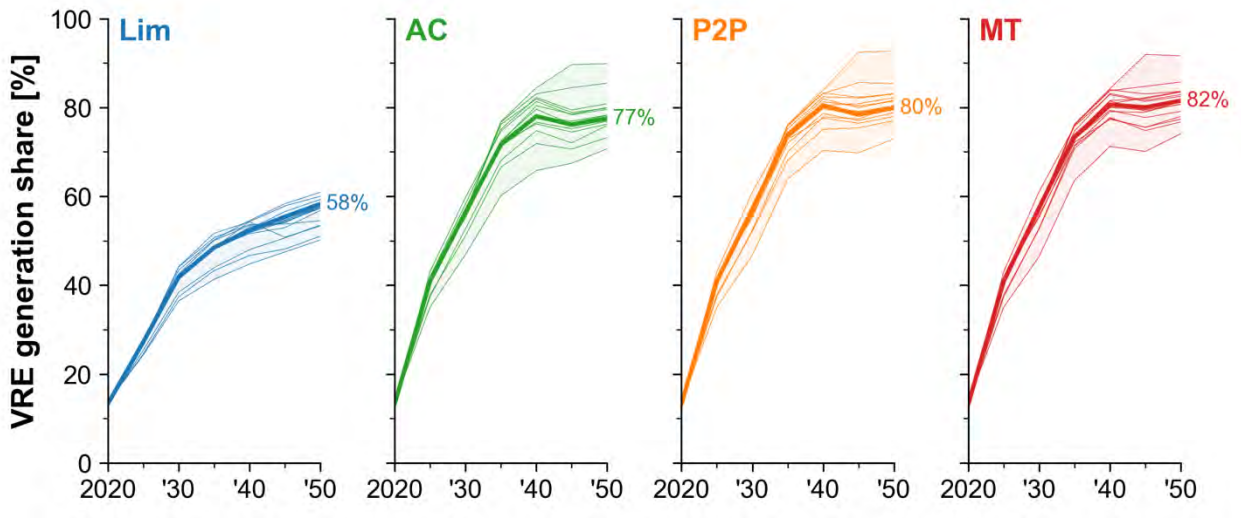


Figure 22. VRE share of total generation for the Mid-Demand 90% by 2035 scenarios for each transmission framework

Core scenarios are shown by a thick line, with the 2050 value labeled; sensitivity cases are shown by thin lines, with the shaded area showing the range between sensitivity cases.

There is considerable spread in 2050 VRE share across sensitivity cases for a given transmission framework, but the sizable increase in VRE through accelerated transmission is consistently observed across all sensitivity cases. The 2050 VRE share in the Limited framework ranges from 50% to 61% across sensitivity cases, versus 71%–90% in the AC framework, 73%–93% in P2P, and 74%–92% in MT. Excluding the "No CCS," "No H_2 or CCS," "No H_2," and "No H_2 or new nuclear" sensitivity cases, the nuclear generation share ranges from 16% to 27% in the Limited framework and 6% to 9% in the accelerated transmission frameworks. The generation share from fossil generation with CCS ranges from 12% to 18% in the Limited framework and 2% to 11% in the accelerated transmission frameworks. Figure 23 shows the 2050 generation mix for all sensitivity cases. The capacity mix for all sensitivity cases is shown in a similar format in Figure D-10.

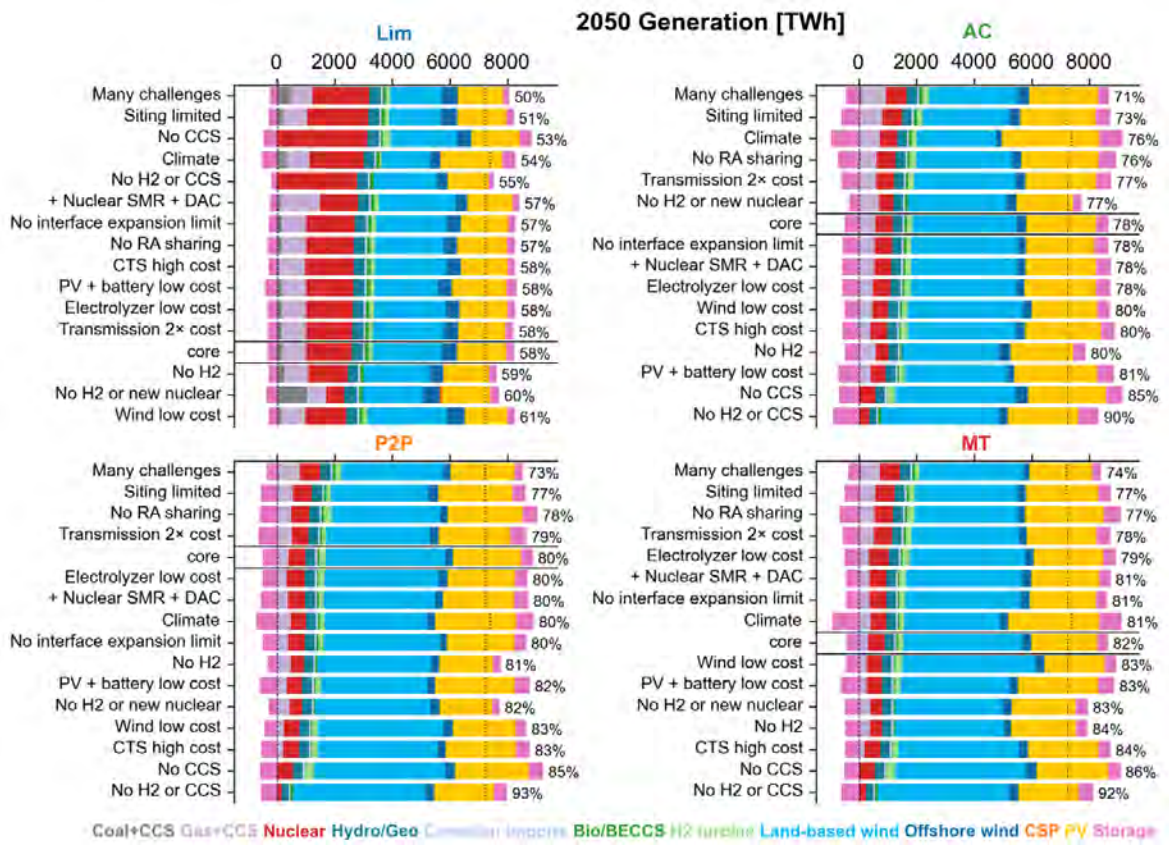


Figure 23. National generation mix in 2050 for the Mid-Demand 90% by 2035 scenarios for each transmission framework and sensitivity case

Within each transmission framework, the sensitivity cases are sorted by 2050 VRE share (indicated by the percentage value to the right of each generation bar). Total generation is greater than end-use demand (vertical dotted line) because of transmission and distribution losses, storage losses, and generation for hydrogen production via electrolyzers. Total storage charging is shown as negative values and discharging as positive values.

3.3.3 Significant amounts of transmission are added at all scales (local, regional, and interregional) in decarbonized systems

When transmission additions are limited, local generator interconnection takes precedence over longer-distance transmission

Both long-distance and local transmission expansion play large roles in the lowest-cost decarbonized power systems (Figure 24). But in the Limited transmission framework, where annual total transmission additions are limited to 1.83 TW-mile/year, the large majority of the limited “budget” for transmission additions is used for local interconnection of new wind and solar resources in both the core scenarios (Figure 24) and sensitivity cases (Figure 25). Roughly 92% of total transmission additions between 2020 and 2050 in the Limited framework is associated with local interconnection. As the availability of new long-distance transmission increases, this fraction drops—to 56% in the AC framework, 42% in the P2P framework, and 31% in the MT framework—although the absolute amount of new interconnection capacity is greater in the accelerated transmission frameworks (110–120 TW-miles) than in the Limited framework (~50 TW-miles), reflecting the larger renewable energy share in these scenarios.

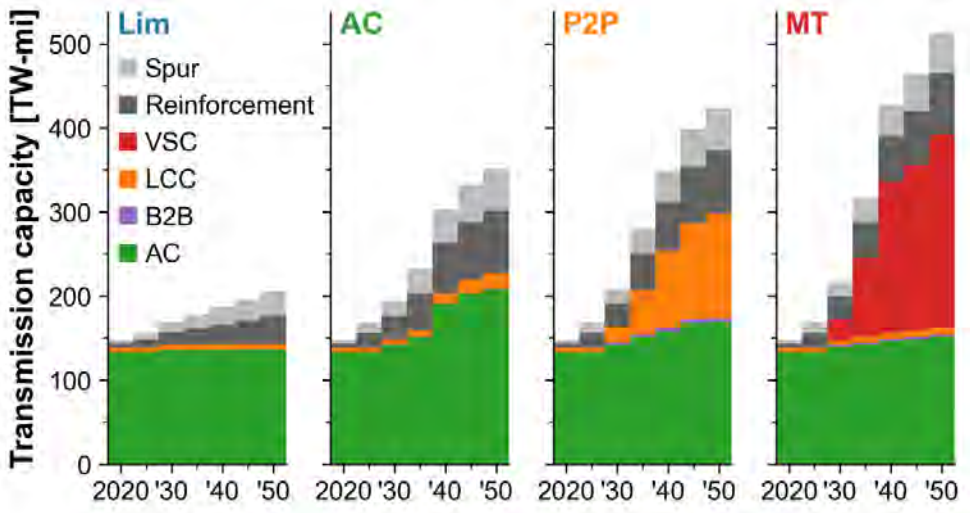


Figure 24. Transmission capacity under Mid-Demand 90% by 2035 assumptions for each transmission framework

Local transmission for wind and solar interconnections includes both spur and reinforcement capacity. Other categories are for interzonal transmission.

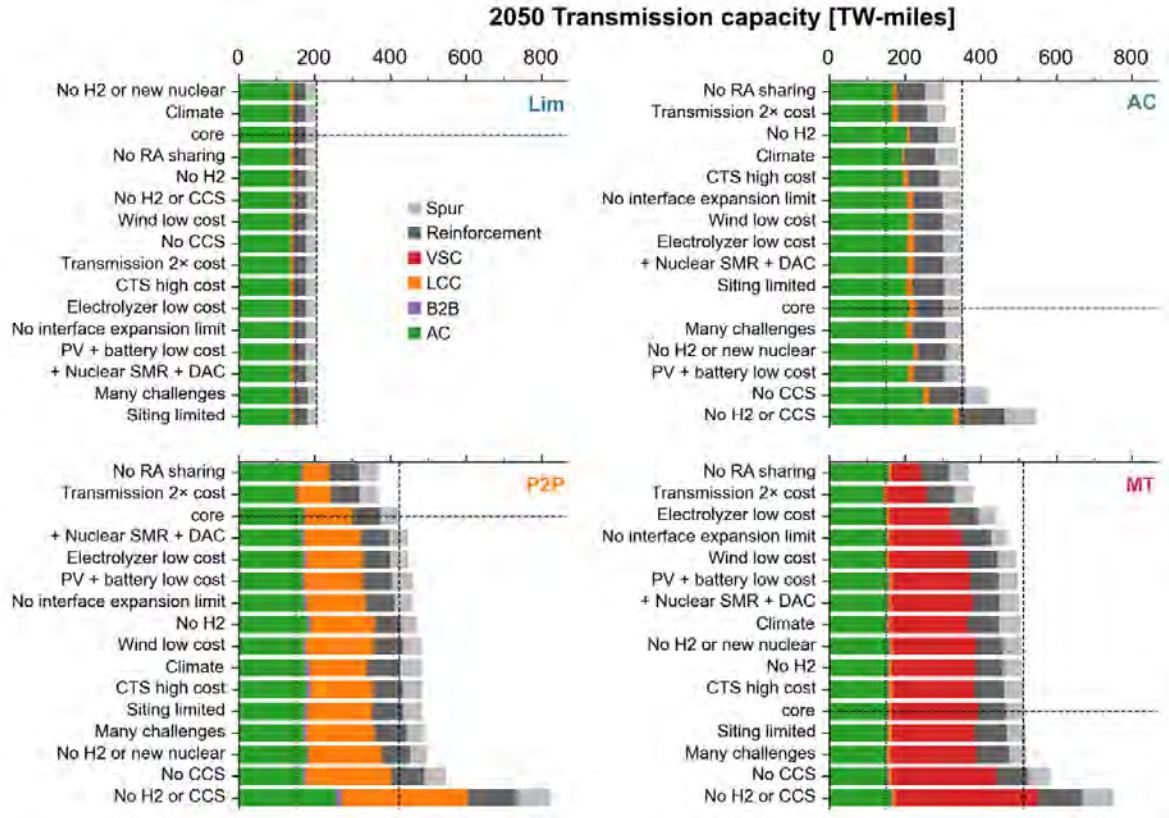


Figure 25. Transmission capacity in 2050 in the Mid-Demand 90% by 2035 scenario for each transmission framework and sensitivity case

Values for the core scenarios for each transmission framework are marked by dashed black lines. Within each transmission framework, sensitivity cases are sorted by total transmission capacity in 2050. The lighter vertical dashed line shows the 2020 capacity (~150 TW-miles). The 1.83-TW-mile/year limit on annual transmission additions is binding in all sensitivity cases for the Limited transmission framework, making 2050 transmission capacity the same in all sensitivity cases for this framework.

If available, HVDC transmission additions outpace AC additions for long-distance transmission

Both AC and HVDC transmission additions are allowed in the P2P and MT frameworks, but HVDC additions significantly outweigh interzonal AC additions in all sensitivity cases in these frameworks (Figure 25). The amount of new HVDC capacity added through 2050 is 2.3–6.0 times the amount of new interzonal AC capacity in the P2P framework and 3.9–16 times in the MT framework. ReEDS does not explicitly model AC power flow or the implications of DC protection on system design; the choice between AC and DC for interzonal transmission investments is thus driven solely by $/MW cost (including the cost of AC/DC converter stations and associated reactive power support) and losses, both of which are lower for DC than AC when distances exceed ~200–500 miles (Alassi et al. 2019).

3.3.4 Expansion of interregional transmission is significant in decarbonized systems

Expansion of long-distance transmission is concentrated in the central part of the country

Previous studies have noted the synergy between transmission and wind deployment (P. R. Brown and Botterud 2021; Denholm et al. 2022); because wind capacity factors exhibit greater spatial variability than solar capacity factors (Figure 26) and because daily solar variability is well-matched with short-duration storage, transmission deployment tends to be correlated with wind deployment and storage deployment tends to be correlated with solar deployment (Blair et al. 2022; Frazier et al. 2021). A similar relationship—that the greatest density of new long-distance (interzonal) transmission additions occurs around the midwestern “wind belt” (Figure 26, Figure 27)—is observed in the scenarios. The trend is most pronounced in the AC transmission framework, where three multilink connections are observed between the wind belt and demand centers in the Southwest, Midwest, and Southeast. A greater amount of long-distance transmission overall is added in the P2P and MT frameworks, but most of the largest links have an endpoint in the wind belt. Though some north-south additions are observed, most new long-distance transmission capacity is oriented predominantly east-west.

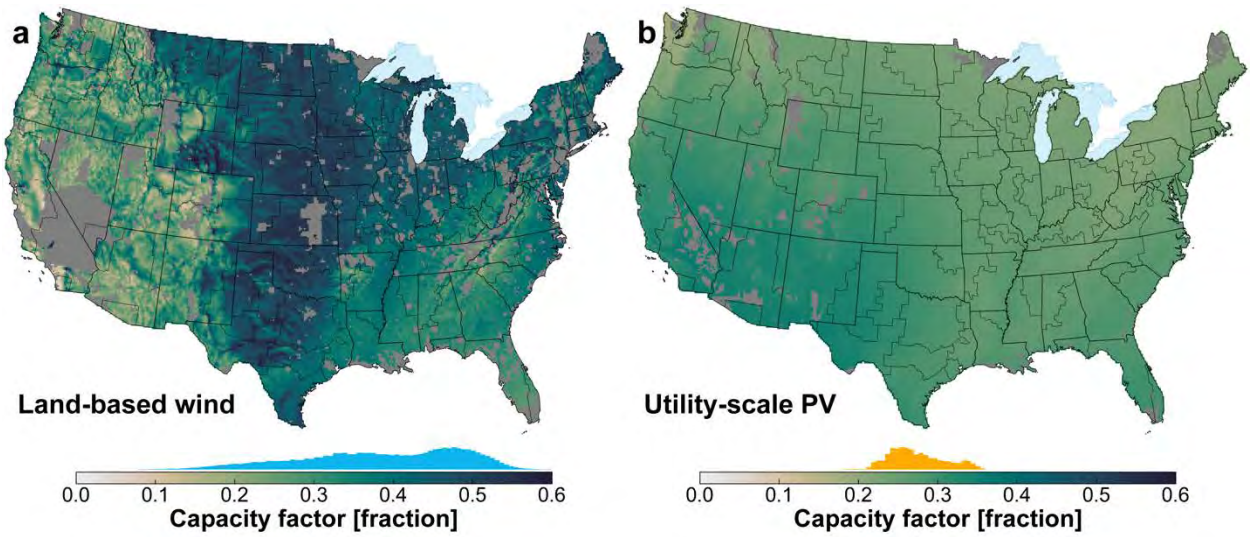


Figure 26. Average capacity factor of land-based wind (a) and utility-scale PV (b) over 2007–2013

Both maps assume Reference Access siting (Appendix A); sites without developable capacity are shown in gray. Both maps show AC capacity factor using the same color scale range. The "wind belt" refers to the darkest-colored (highest-capacity-factor) region in the wind map extending from north to south through the center of the country. Histograms above color bars indicate the frequency of occurrence of the indicated capacity factor values across the ~50,000 reV model sites shown in the corresponding map.

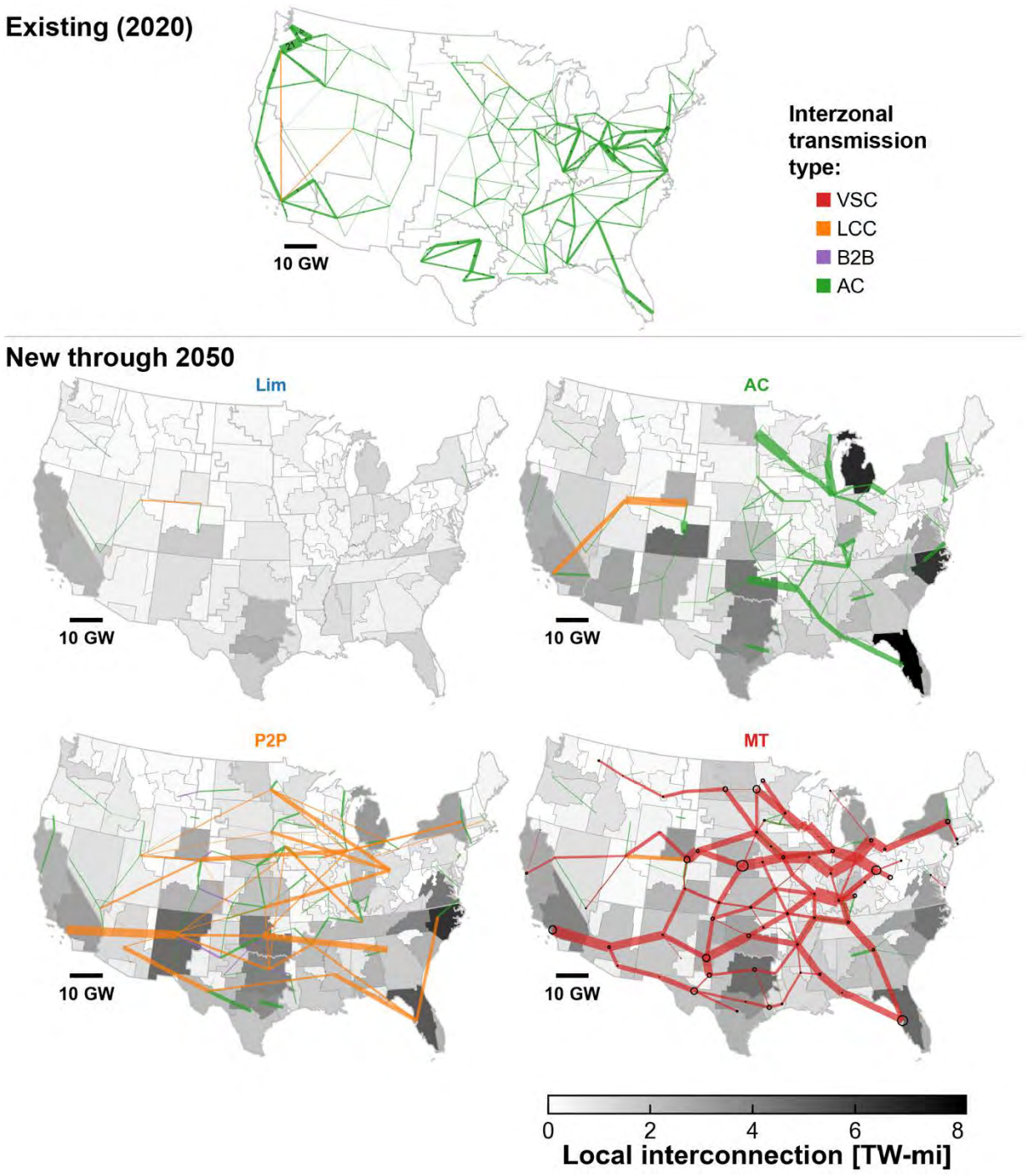


Figure 27. New local and long-distance transmission through 2050 in the Mid-Demand 90% by 2035 scenarios for each transmission framework, with existing 2020 long-distance transmission capacity for context (top)

Interface transfer capability is indicated by the thickness of the lines connecting ReEDS zones. Converter capacity in the MT framework is indicated by the diameter of empty black circles, using the same length scale as the interface lines. The depiction of interzonal transmission capacity as straight lines between zone centers is a visual simplification; in practice, the interzonal transfer capacity would be spread across many transmission corridors for each interface.

The MT scenario tends to make the most efficient use of AC/DC converter capacity. Some zones have minimal converter capacity (indicated by the small black circles in Figure 27), instead acting primarily as pass-throughs in the HVDC network, while exporting zones (in the wind belt) and importing zones (in southwestern and eastern demand centers) install converters sized to their usage needs. The P2P scenario, on the other hand, may make more efficient use of transmission rights-of-way by using higher-voltage (thus higher-power-capacity) LCC architectures (Alassi et al. 2019), although transmission land use is not directly considered here.

Regional transmission trends can be summarized at the planning region level using the ratio of “transfer capability to other planning regions” (GW) to “peak demand within the planning region” (GW) (Figure 28). A range of interregional transfer capabilities is observed in the current (2020) system: ERCOT has a transfer capability ratio of 0.01; ISONE, SERTP, and FRCC range from 0.1 to 0.3, and other regions range from 0.3 to 0.7. In the Limited transmission framework, new additions of interregional transfer capacity are not allowed; thus, as peak demand increases over time, the transfer capability ratio falls. In the AC framework, many regions maintain transfer capability ratios similar to their 2020 values, although there are notable increases in SPP and MISO. The transfer capability ratio increases dramatically for the wind-rich regions of SPP, MISO, and WestConnect in the MT transmission framework, reaching ~2.6 for SPP and ~1.8 for MISO and WestConnect. When interconnection-seam-crossing capacity additions are allowed in the two HVDC scenarios, the transfer capability ratio in ERCOT increases to roughly 0.3, on par with other regions with stronger existing connections to neighboring regions.

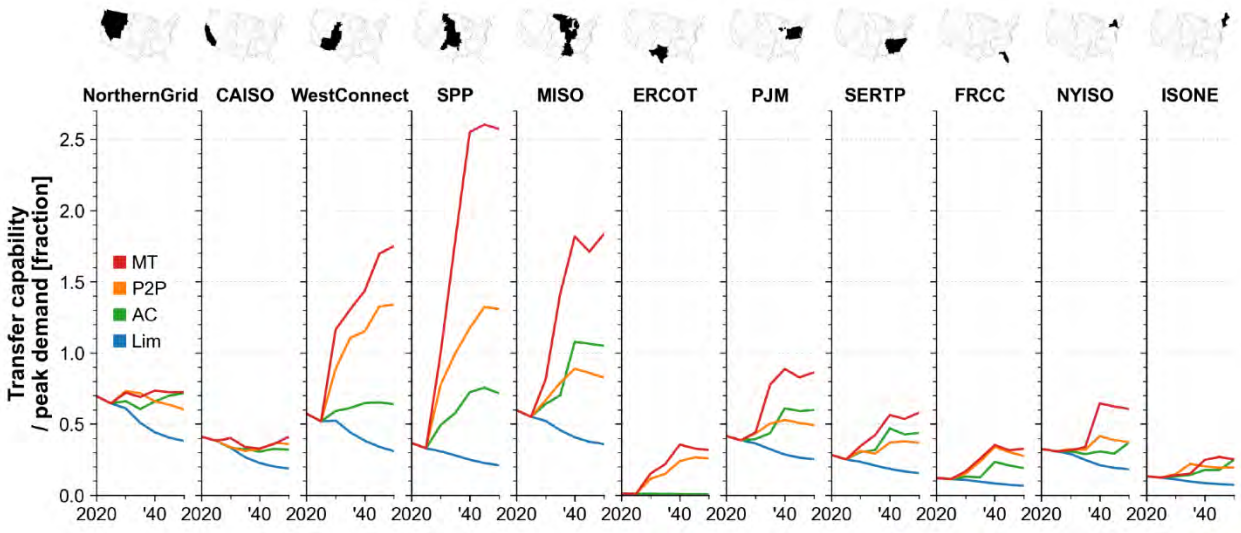


Figure 28. Ratio of interregional transfer capability to peak demand for the 11 planning regions with Mid-Demand 90% by 2035 assumptions across the four transmission frameworks

Interregional transfer capability for a given planning region is defined as the sum of import/export capacity between that planning region and other planning regions.

When allowed, transmission capacity expands significantly across the three interconnection seams

Though many interregional interfaces host large transmission capacity additions in the decarbonization scenarios, the interconnection "seams" demonstrate particularly large capacity additions relative to their currently small transfer capability (Figure 29). New seam-crossing capacity is not allowed in the Limited or AC frameworks but expands to ~80 GW by 2050 in the P2P framework (~37 times the currently installed seam-crossing capacity of 2.1 GW) and ~110 GW (~50 times) in the MT framework. By 2035, the seam-crossing capacity reaches roughly half of its 2050 value: 44 GW in P2P and 52 GW in MT. Transmission capacity is added across each of the three seams in both HVDC frameworks.

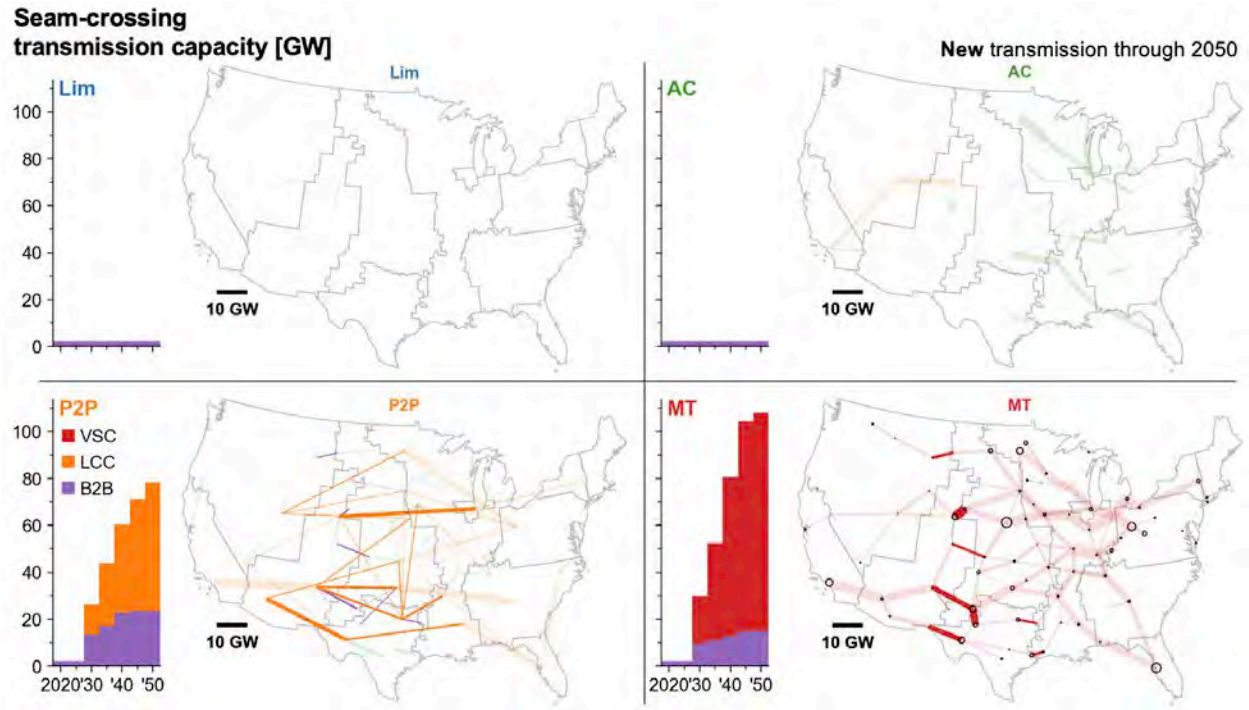


Figure 29. New interconnection-seam-crossing transmission capacity in each of the transmission frameworks with Mid-Demand 90% by 2035 assumptions.

Spatial patterns in transmission expansion are similar across many sensitivity cases

The transmission deployment maps shown thus far have used core scenario assumptions, but there is significant uncertainty in the projected cost and availability of different technologies between now and 2050. It is therefore important to understand whether the spatial trends discussed thus far vary under different assumptions regarding technology evolution, here parameterized through the 15 sensitivity cases described previously. Though the absolute amount of transmission capacity deployed varies substantially across sensitivity cases for a given transmission framework (Figure 25), the spatial distribution of new long-distance transmission is largely consistent (Figure 30, Figure 31, and Figure 32). The greatest density of long-distance transmission additions is observed around the wind belt, and the orientation of new long-distance transmission additions (particularly in the P2P and MT frameworks) is predominantly east-west.

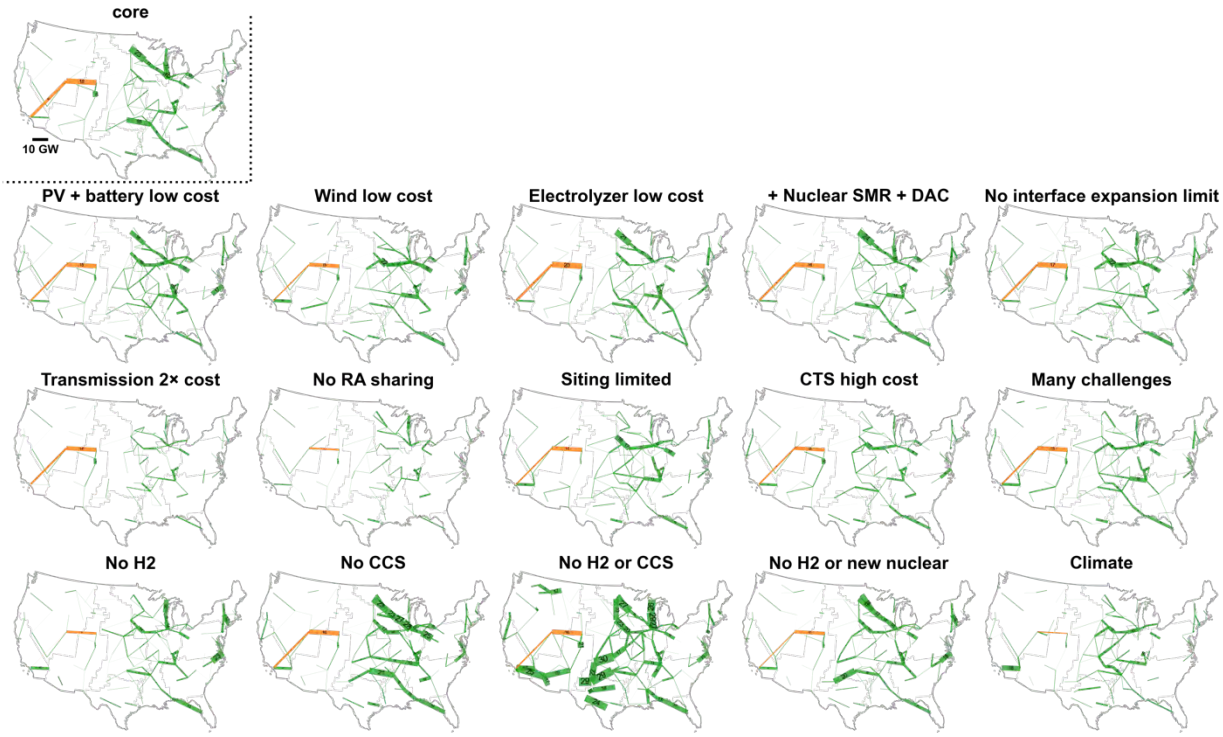


Figure 30. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the AC transmission framework

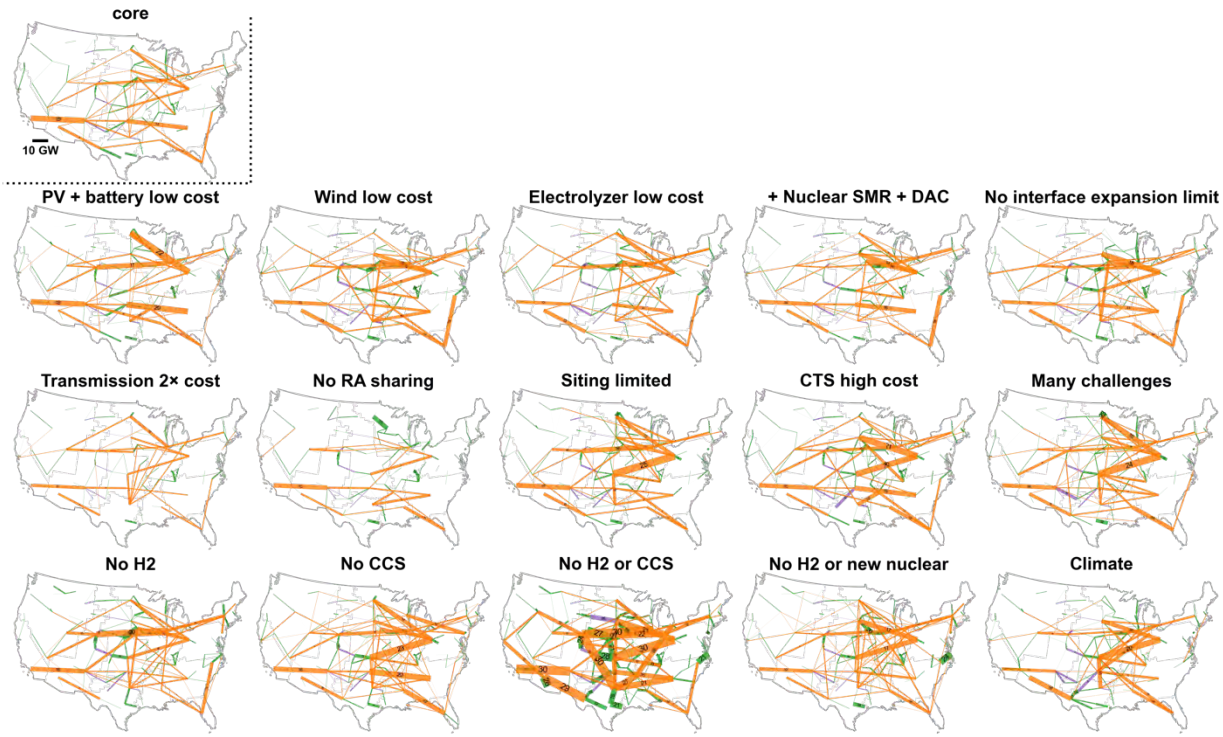


Figure 31. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the P2P transmission framework

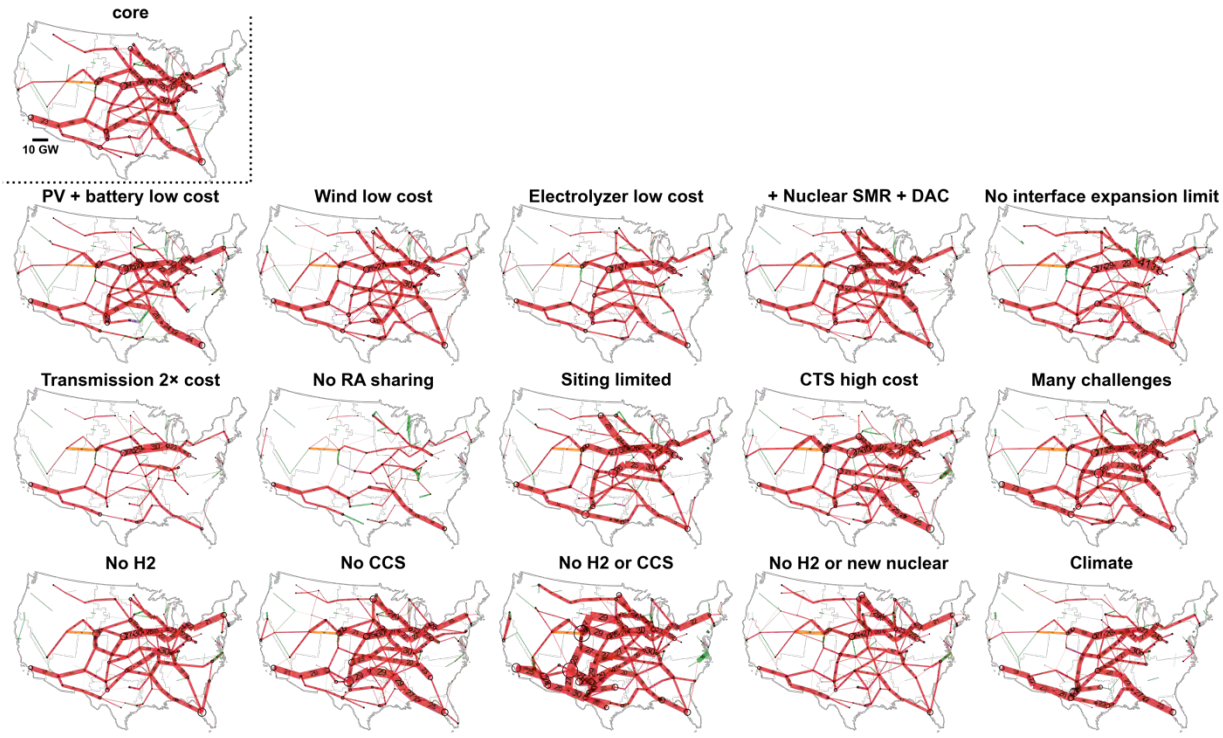


Figure 32. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the MT transmission framework

Figure 30, Figure 31, and Figure 32 visually demonstrate the similarity in the spatial trends in transmission development across the sensitivity cases modeled. The following text box presents an analysis that more systematically evaluates interregional transmission expansion in these scenarios to identify subregional High Opportunity Transmission (HOT) interfaces from the scenarios. The HOT interfaces serve as an initial screening to determine how much and where additional high-capacity transmission may be needed between the subregional pairs given the full set of sensitivity cases considered here.

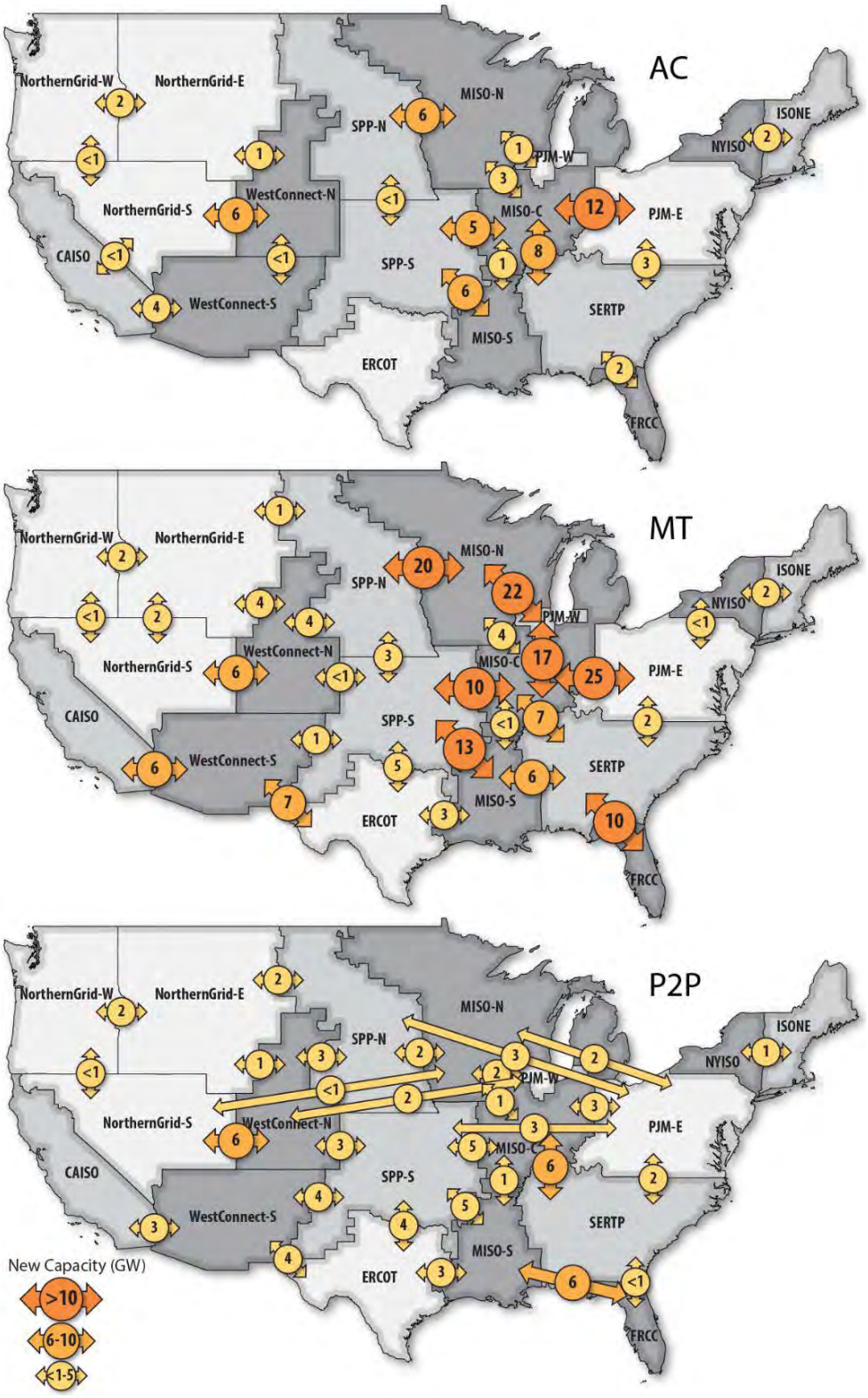
High Opportunity Transmission

An objective of the NTP Study is to identify potential transmission solutions that will provide broad-scale benefits to electricity customers under a wide range of potential futures. To support this objective, this text box presents a screening analysis to identify High Opportunity Transmission (HOT) interfaces between planning subregions developed using the scenarios presented in this chapter.

Subregional HOT interfaces are specified by the amount of transfer capacity expanded between a pair of planning subregions (Figure 1b) from 2020 to 2035. These interfaces are found by systematically evaluating this transfer capacity increase from the 16 scenarios (one core scenario plus 15 sensitivity cases) under the central demand/emissions assumptions (Mid-Demand, 90% by 2035) for each of the three accelerated transmission frameworks (AC, P2P, and MT). Specifically, a HOT interface capacity is defined as the expansion between subregions that occurs in 75% of the scenarios, i.e., the 25th percentile of transmission expansion. This 25th percentile is chosen to reflect robustness in development across a wide range of future conditions about technology costs and availability, renewable energy siting, and level of interregional coordination.

The following maps show HOT interfaces identified for the three accelerated transmission frameworks. In all frameworks, HOT interfaces are found for all regions although a concentration is found in MISO and neighboring regions. The HVDC frameworks (P2P and MT) generally have more HOT interfaces, and their capacities tend to be greater than those in the AC framework. The P2P framework includes long-distance connections, including between nonadjacent planning regions. The MT framework has the highest-capacity HOT interfaces with several having an increased transfer capacity of 10–25 GW. Although some HOT interfaces have very high capacities, a significant fraction of the benefits of interregional transmission can be realized with a smaller amount of expansion as revealed from a side analysis that tests the same scenarios with maximum limits on transmission development across major subregions.

Appendix F provides additional information for the HOT interfaces for each planning region. It also includes the 50th and 75th percentile results to inform more ambitious transmission development opportunities. The HOT interfaces are found by systematically examining the capacity expansion scenarios but are limited by the number and type of sensitivity cases modeled. Additional sensitivity cases would increase the robustness of the interfaces identified, and further assessments are required to determine the viability of any individual project that may align with the HOT interfaces shown. Nonetheless, these subregional HOT interfaces provide a general scale of how much new interregional transmission capacity is needed over the next decade to realize many of the decarbonization scenarios envisioned.



High Opportunity Transmission interfaces with Mid-Demand 90% by 2035 assumptions under the (top) AC, (middle) MT, and (bottom) P2P transmission frameworks

3.3.5 Zero-carbon power systems dominated by variable renewable energy can meet resource adequacy targets

The NTP Study uses a coupled ReEDS-PRAS modeling approach, described above, which results in power system reliability levels (for systems with net zero carbon emissions and generation mixes dominated by VRE) that fall comfortably within the range of resource adequacy targets used in industry (Figure 33). The median NEUE for the Mid-Demand 90% by 2035 scenarios across all model years, transmission frameworks, and sensitivity cases (384 total observations) is 0.9 ppm, well below the industry target range of 10–30 ppm (Alberta Electricity system Operator 2017; Electric Power Research Institute 2024; NERC 2024). In 2045 and 2050—the years in which these scenarios are constrained to net zero electricity system emissions—the median NEUE stays similarly low.

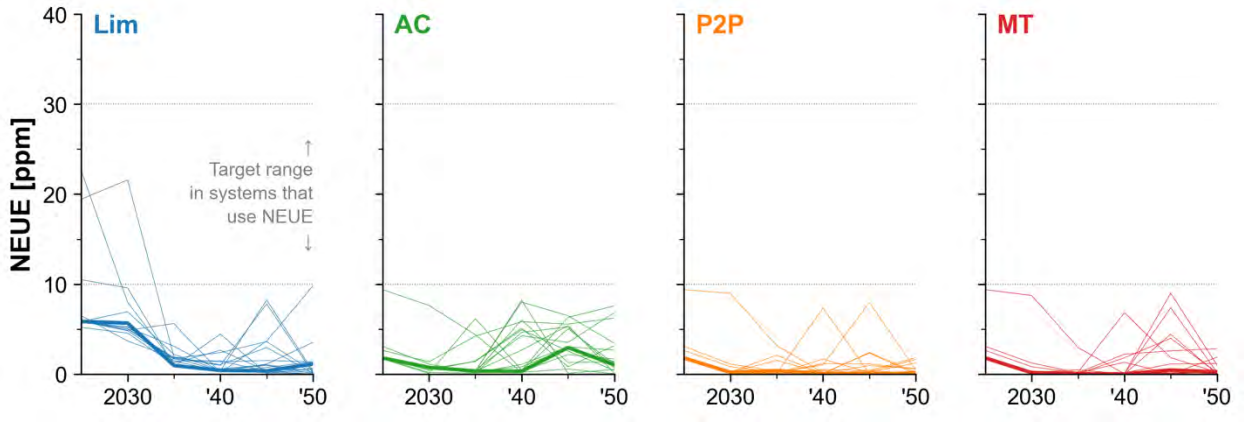


Figure 33. Normalized expected unserved energy (NEUE) in each transmission framework and sensitivity case with Mid-Demand 90% by 2035 assumptions.

Results for the core scenarios are indicated by thick lines; results for sensitivity cases are indicated by thin lines.

Because systems are planned to ensure a minimum RA target is met, there is no trend in RA outcomes between transmission frameworks. Instead, the value of transmission for RA is realized as the change in cost of meeting RA needs, discussed in Section 3.3.1.

A variety of technologies supports resource adequacy

As discussed in Section 2.1 and Appendix B, the coupled ReEDS-PRAS model addresses RA requirements by identifying “stress periods” with a high risk of unserved energy and including them in the co-optimization of generation, storage, and transmission capacity/operation in ReEDS. Though the nameplate capacity and average generation mix of the decarbonized systems explored here are dominated by wind and solar (Figure 23), wind and solar make up a smaller share of the generation mix during stress periods than during representative periods[37] (Figure 34). Hydropower and thermal technologies, conversely, make up a larger share of the generation mix

[37] Low availability of wind and/or solar on a given day can be the reason that day qualifies as a stress period.

during stress periods than during representative periods. These results show that all technologies—including wind and solar—contribute to the energy and RA needs although the relative contributions between technologies can vary significantly.

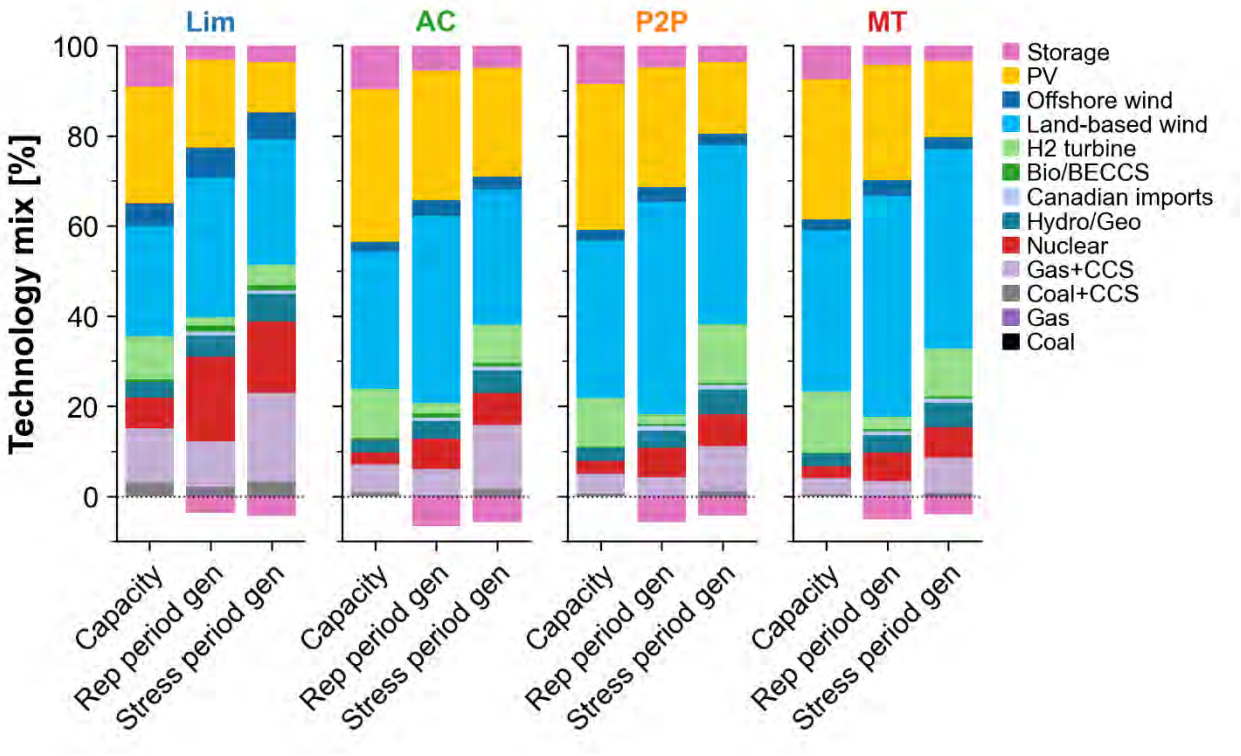


Figure 34. Nameplate capacity mix, representative period generation mix, and stress period generation mix for the core transmission frameworks in 2050 under Mid-Demand 90% by 2035 assumptions.

Stress periods in this study are modeled as coincident 24-hour days over the contiguous United States.

Though wind and solar contribute more to the bulk energy mix (the “Rep period gen” bars in Figure 34) than to the stress period resource mix, accelerating transmission deployment increases the contribution of wind and solar to the resource mix during stress periods. In the Mid-Demand 90% by 2035 scenario in 2050, wind and solar constitute 44% of the stress-period generation mix in the Limited transmission framework and 57%–64% in the accelerated transmission frameworks. The generation fractions provided here are for all hours of the modeled stress periods and for the contiguous United States as a whole; in particular hours and regions, the contribution of wind and solar can be much smaller (e.g., during low-wind or nighttime hours), and hydro/thermal technologies make up a larger share (Figure 35).

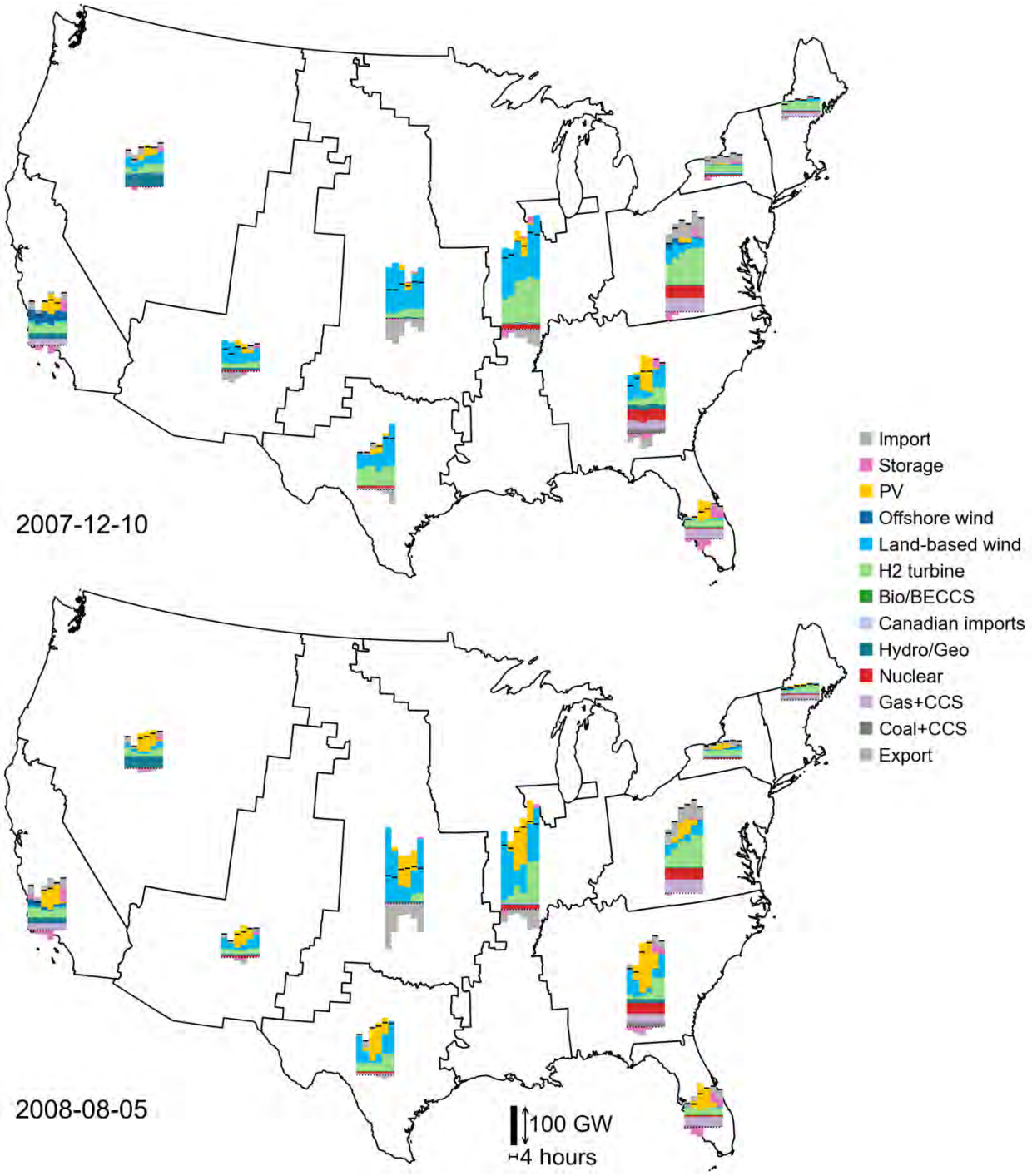


Figure 35. Regional dispatch in the MT framework under Mid-Demand 90% by 2035 assumptions in 2050 modeled in ReEDS during two example stress periods

Dates in this figure are given as year-month-day. The dates shown here refer to weather days from the 2007–2013 weather sample; the capacity and demand mix are for the 2050 model year. 2007-12-10 is the stress period with least VRE generation; 2011-08-05 is the stress period with peak load. Regional load is indicated by thin black lines. Storage charging and exports to other regions are shown as negative values. Daily profiles are at the 4-hour resolution used within the ReEDS model for this study.

Interregional transmission—over spatial scales larger than weather systems—enables the sharing of variable renewables during days with limited local resource availability

Figure 34 shows wind and solar make up a larger share of the stress period generation mix in the accelerated transmission frameworks than in the Limited framework. Though improved access to high-quality resource regions with uniformly higher capacity factors explains part of this trend, interregional transmission also smooths out the geographic variability of these weather-dependent resources, particularly for wind (Kempton et al. 2010; Grams et al. 2017; Goggin 2021).

On the least-windy day in the weather dataset for a given planning region, neighboring regions are often significantly windier (Figure 36). For example, on ERCOT's least-windy day (2012-09-15), when the daily average capacity factor of ERCOT wind is only 6%, the wind capacity factor is 31% in neighboring SPP and 34% in MISO (a ~5 times difference). For CAISO, where daily wind capacity factor drops to 2% on 2013-11-17, the capacity factor in neighboring WestConnect and NorthernGrid is 40%–45%, ~20 times higher. These opportunities are sometimes bidirectional: On WestConnect's least-windy day (7% on 2010-12-05), neighboring CAISO has a wind capacity factor of 42%, ~6 times higher.[38]

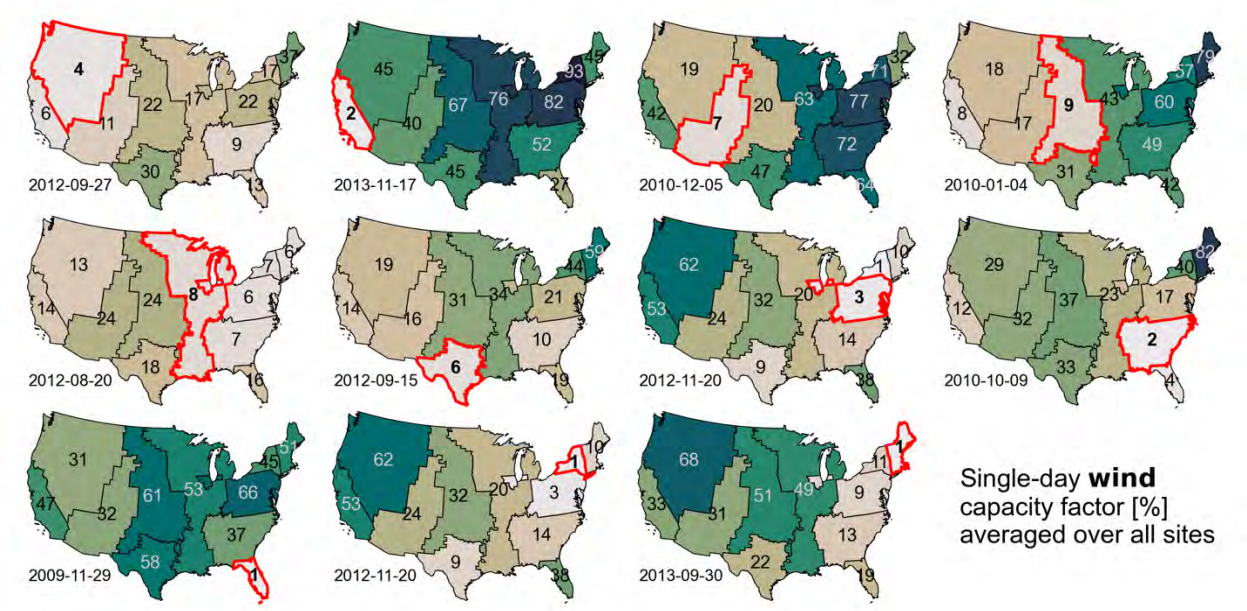


Figure 36. Single-day wind capacity factor on the least-windy day from 2007 to 2013 weather years in each planning region

For each map, the focused planning region is outlined in red, the date of the least-windy day in that region is given in the lower left, and the values and colors in each region represent the daily wind capacity factor on that date. Planning region values are taken as the available-capacity-weighted average modeled capacity factor over all resource sites in the planning region. Capacity factors are modeled using the reV model as discussed in Appendix A.2. Most of these sites are never developed; if only developed or higher-quality resource sites in each planning region were included, the capacity factors would be higher than shown here.

[38] Complementarity between different resource types—illustrated in Figure D-14—provides further flexibility: On 2012-08-20, MISO and all its eastern neighbors aside from FRCC have wind capacity factors ≤8%, but solar capacity factor in these regions is above average on this summer day.

Similar examples can be observed for solar (Figure 37), though to a smaller degree than for wind given the uniformly greater seasonal variability of solar (all of the lowest-regional-capacity-factor days for solar occur during winter, with fewer hours of sunlight available regardless of weather). Though there are some strong resource-sharing opportunities—on MISO's least-sunny day (1% on 2009-12-24), the capacity factor in neighboring PJM is ~10 times higher—there are also days when large fractions of the country have uniformly low resource: On 2007-12-28, no planning region east of SPP has higher than a 6% capacity factor. On ISONE's least-sunny day (1% on 2012-12-10), resource sharing would have to extend to MISO or SERTP to reach ≥5% capacity factor.

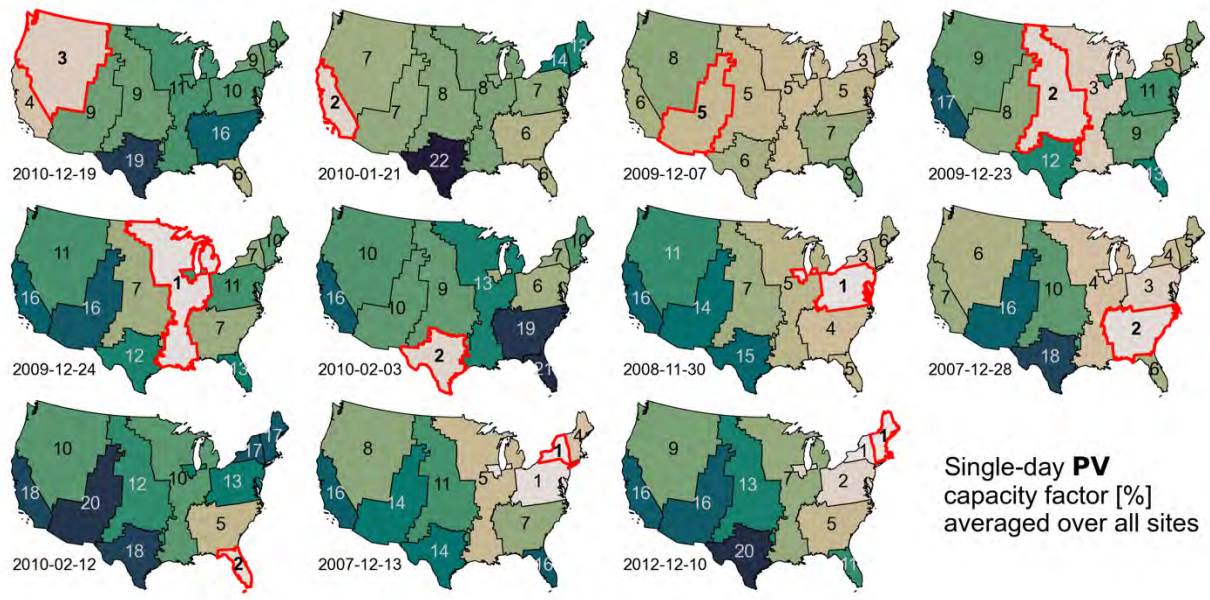


Figure 37. Single-day PV capacity factor on the least-sunny day from 2007 to 2013 weather years in each planning region

For each map, the focused planning region is outlined in red, the date of the least-sunny day in that region is given in the lower left, and the values and colors in each region represent the daily PV capacity factor on that date. Planning region values are taken as the available-capacity-weighted average modeled capacity factor over all resource sites in the planning region. Capacity factors are modeled using the reV model as discussed in Appendix A.2. Most of these sites are never developed; if only developed or higher-quality resource sites in each planning region were included, the capacity factors would be higher than shown here.

Electricity demand also demonstrates interregional variability, which can be smoothed by interregional transmission (Figure 38) although the opportunities are less pronounced than for wind and solar. Here, if adjacent planning regions reach peak demand on different days, they could have spare capacity to assist neighboring regions in meeting their peaks. The greatest opportunity observed in the Mid-Demand scenario for 2050 is on MISO's peak day of 2009-01-15, when demand in neighboring ERCOT reaches only 69% of its peak. For most regions on their peak-containing day, demand in neighboring regions is ~85%–90% of its regional peak.

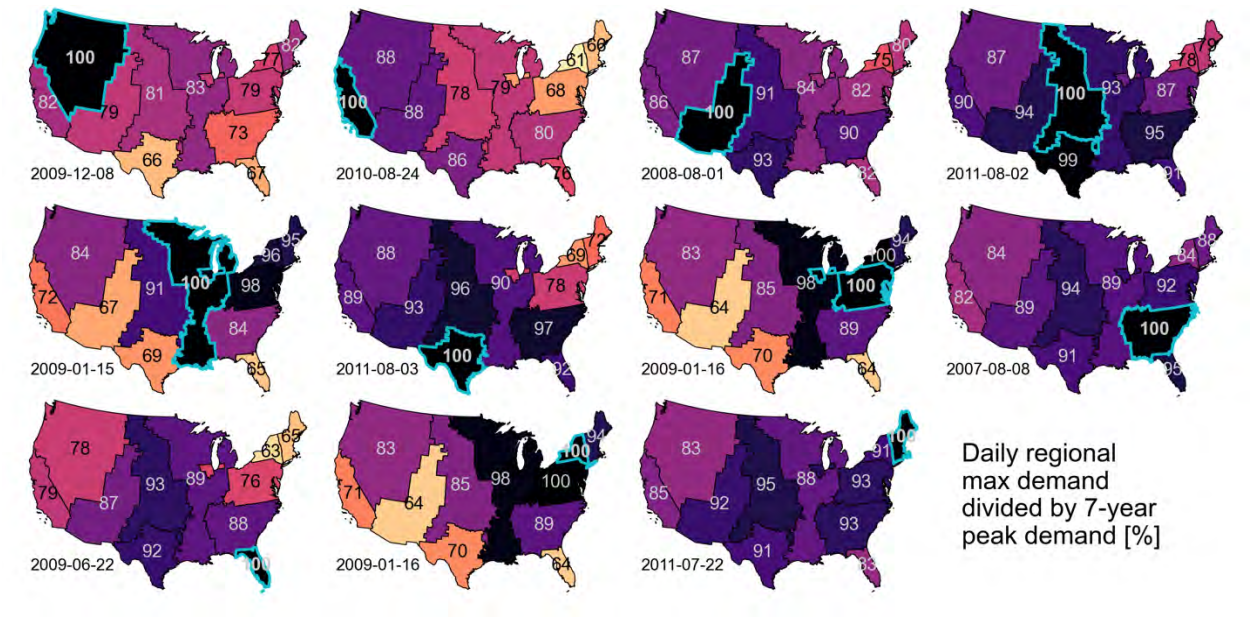


Figure 38. Daily regional maximum demand divided by 7-year peak demand for that region, shown for the regional peak demand day from 2007 to 2013 weather years for each planning region

For each map, the focused planning region is outlined in blue, the date of the peak demand day in that region is given in the lower left, and the values and colors in each region represent the relative regional peak demand (normalized to the total regional peak demand across all 7 weather years) on that date. For example, 2009-12-08 is the peak demand day for NorthernGrid over 2007–2013; on that day, CAISO demand reaches 82% of peak CAISO demand over 2007–2013. Demand data are from the Mid-Demand assumption for 2050.

Bidirectional power flows between regions support resource adequacy

Within the PRAS model, transmission is used only to avoid dropping load; PRAS does not consider variations in marginal cost between generation technologies. Transmission flows in PRAS thus illuminate the use of transmission specifically related to grid reliability when local generation alone does not meet RA needs.

A diversity of usage patterns is observed in the PRAS model results for interregional transmission in the accelerated transmission frameworks (Figure 39). Hourly flow patterns are presented in Appendix D.3. Some interfaces in the P2P framework are used almost entirely unidirectionally: for the SPP→SERTP, MISO→FRCC, and MISO→PJM interfaces, 99.9+% of RA flows are in the indicated direction on a megawatt-hour (MWh) basis. Others are bidirectional: For the MISO→ERCOT, NYISO→ISONE, ERCOT→WestConnect, MISO→SPP, and CAISO→NorthernGrid interfaces, the distribution of RA flows between the two directions is between 50/50 and 60/40, with the arrow denoting the predominate flow direction. For the SPP→PJM interface, the large majority (98%) of RA flows are from wind-rich SPP to demand centers in PJM, but ~900 hours in the 7-year weather sample have energy flows from PJM to SPP to help SPP meet its RA needs. This observation mirrors the examples shown in Figure 35 and Figure 36, where high-renewable-resource regions can still be aided by neighbors on locally poor resource days.

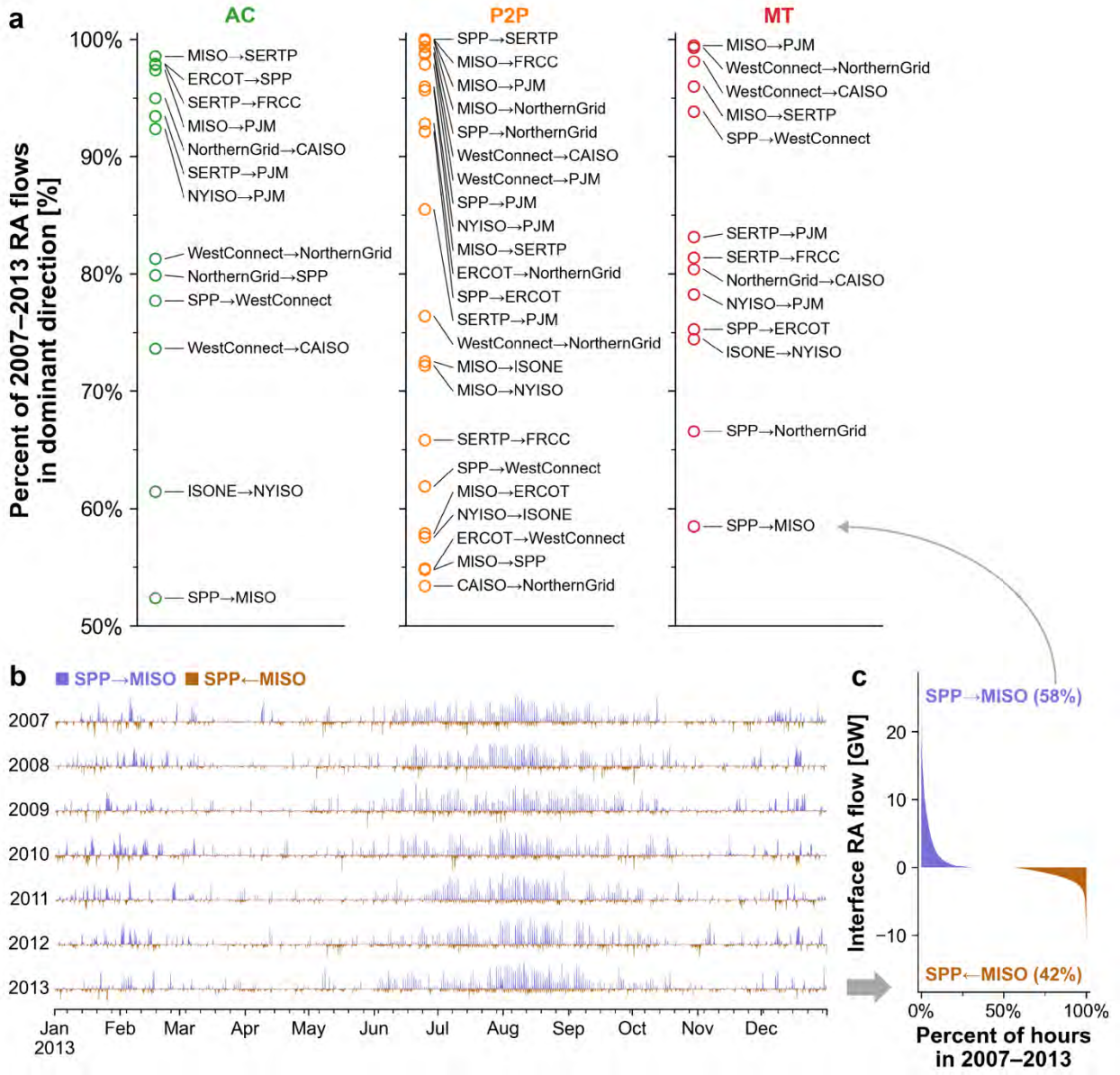


Figure 39. Bidirectional transmission flows between regions for resource adequacy in 2050 under Mid-Demand 90% by 2035 conditions as modeled by PRAS

For each interface between planning regions (Figure 1c), the dominant direction is determined by the fraction of total hourly flow modeled in PRAS on a MWh basis over the 7 weather years spanning 2007–2013, and the percent of total flow in the dominant direction for each interface is shown in panel (a). Illustrative hourly flows and the sorted distribution of flows for the SPP→MISO interface in the MT framework are shown in (b) and (c), respectively.

Interregional resource adequacy coordination reduces the cost of meeting resource adequacy requirements

Because ReEDS co-optimizes the deployment and operation of generation and transmission to meet demand in both representative and outlying periods at least cost, it is difficult to disentangle the “energy value” and “RA value” (or “capacity value”) of interzonal transmission investments within a single ReEDS scenario.

To isolate the effects of interregional coordination of RA planning (or “RA sharing”) on system cost and transmission deployment, two scenarios are compared: the “core” scenario using default assumptions and the “No RA sharing” sensitivity case where transmission flows are not allowed between planning subregions (Figure 1b) to meet RA needs. In effect, this sensitivity case requires each planning subregion to meet its RA needs solely from resources within its own borders rather than rely on interregional transmission and excess resource availability from neighbors.

Total costs through 2050 are notably higher in the “No RA sharing” case than in the “core” scenario that allows regions to coordinate to meet RA needs—roughly $200 billion higher in the Limited, AC, and P2P transmission frameworks and ~$380 billion higher in the MT framework (Figure 40a). Substantial savings could accrue from using existing interregional transmission for RA sharing, as evidenced by the large savings in the Limited transmission framework where new interregional transmission additions are not allowed.

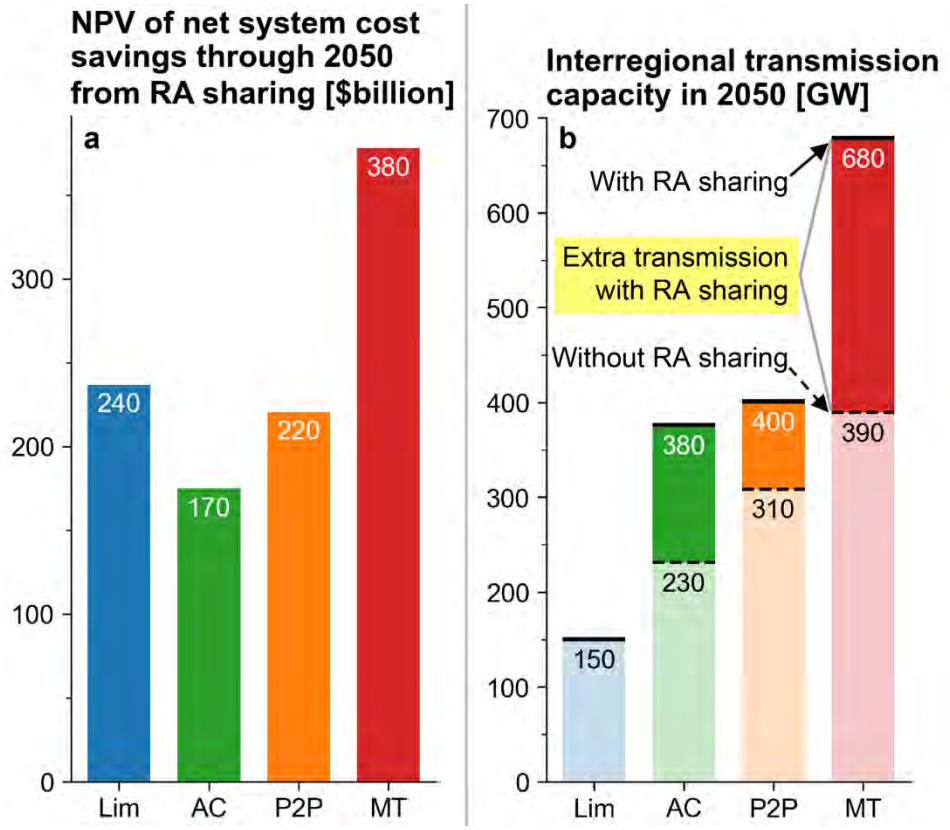


Figure 40. Impact of the allowance of interregional RA sharing on system cost (a) and optimized interregional transmission capacity (b)

System cost savings (as shown in panel (a)) for each of the demand and emissions assumptions shown in Figure 3 are provided in Figure D-17.

Significant amounts of interregional transmission are built primarily to serve resource adequacy needs

The ability to use interregional transmission to meet RA needs also leads to substantial additions of new interregional transmission in scenarios that allow it (Figure 40b and Figure 41). Cost-minimizing interregional transmission capacity additions drop by ~40%–60% across the three accelerated transmission frameworks if RA sharing is not allowed, contributing to the ~$200–350 billion higher system cost compared to when RA sharing is allowed. Large interregional transmission additions in the upper Midwest drop out of the optimal solution if RA sharing is not allowed, highlighting the significant value of transmission during scarce but high-consequence periods of system stress and aligning with recent studies exploring the contribution of short-duration electricity price spikes to long-distance transmission value (Millstein et al. 2022).

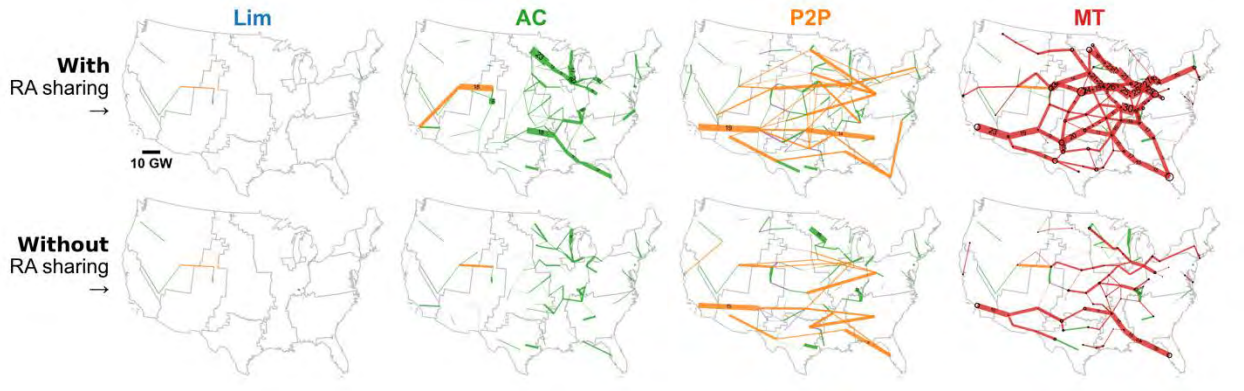


Figure 41. New transmission through 2050 with Mid-Demand 90% by 2035 assumptions for the four transmission frameworks with (top) and without (bottom) RA sharing between planning subregions.

Conclusions

This chapter documents the methods, assumptions, scenario design, and results from the zonal capacity expansion, resource adequacy, and transmission value analyses of the NTP Study. The analysis is designed to assess the role of transmission in the future U.S. electricity system. It compares how different transmission frameworks—ranging from those where transmission expansion is limited to futures with highly coordinated transmission planning and development with advanced technologies—might impact this role. The analysis includes 96 scenarios that capture a broad range of possible market, policy, and technology uncertainties.

Overall, the analysis finds that accelerating transmission expansion enables decarbonization of the U.S. power system at lowest cost by enabling the interconnection and delivery of large amounts of inexpensive wind and solar energy—and other low-emissions resources—to all electricity consumers and to support resource adequacy.

Under Current Policies scenarios—which do not apply a limit on national emissions—accelerating transmission expansion can lead to cumulative CO_2 emissions reductions of 10.2–11.2 billion metric tons (43%–48%). With a limit on national CO_2 emissions, the benefits of transmission expansion are expressed through lower total system costs. These benefits increase with more rapid grid decarbonization and greater electrification. With the core central decarbonization assumptions, which include 90% emissions reductions by 2035 and Mid-Demand growth (2.0%/year), accelerated transmission expansion saves $270–490 billion in electricity system expenditures through 2050. The system cost savings outweigh expenditures for transmission, resulting in high transmission benefit-cost ratios (above 1.5) for all scenarios and sensitivity cases.

Significant amounts of transmission are added in the decarbonized systems modeled. In the central decarbonization scenarios, total U.S. transmission grows to 2.4–3.5 times the size of the 2020 grid by 2050 across the accelerated transmission frameworks; the amount of growth scales with decarbonization rate and demand growth. Transmission expansion occurs at all scales, including local interconnections for new wind and solar, longer-distance interregional transmission, and, when allowed, seam-crossing transmission that increases the transfer capacities between the Western, Eastern, and Texas interconnections. Scenarios that consider HVDC additions result in greater total regional and interregional transmission expansions and yield the largest economic benefits.

Transmission is added in all regions of the country, but the highest concentration is developed in the central wind belt. This geographic distribution of transmission development is robust across the sensitivity cases modeled. The amount and location of interregional transmission expansion between subregional pairs by 2035 is identified based on the full suite of sensitivity cases and referred to as High Opportunity Transmission (HOT) interfaces. Further study is needed to identify potential transmission projects that align with the subregional HOT interfaces.

Resource adequacy is considered in the development of all the scenarios modeled to ensure RA needs are met in decarbonized systems, including those with significant transmission expansion and much greater reliance on remote and variable resources. A variety of technologies contributes to meeting adequacy needs. Transmission can support RA by enabling the sharing of resources and increasing geospatial diversity of load and VRE, especially with interregional transmission over spatial scales larger than weather systems. Without interregional RA coordination to take advantage of transmission's capabilities to support RA, total system costs to decarbonize are estimated to increase significantly and less transmission development occurs. In other words, RA is an important source of value for transmission in the future.

These findings demonstrate how accelerating transmission expansion can support a lower-cost transition toward energy system decarbonization while maintaining reliability. However, the complexities of transmission planning require higher-fidelity analysis to increase confidence in these results. For example, this chapter examines resource adequacy for the scenarios, but operational reliability and resiliency are not analyzed. The scenario analysis presented in this chapter provides the starting point for further study. Subsequent chapters present the production cost, power flow, and other detailed analysis for a subset of—and variations to—the scenarios described in this chapter.

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Appendix A. Regional Energy Deployment System (ReEDS) Model

The National Renewable Energy Laboratory (NREL) ReEDS model is a capacity expansion model for the contiguous United States electricity system. ReEDS co-optimizes generation, storage, and transmission to find the systemwide least-cost portfolio that meets demand, grid reliability, and policy requirements. For this study, ReEDS starts in 2020 and optimizes each 5-year solve period sequentially through 2050. The ReEDS documentation (Ho et al. forthcoming) and latest NREL Standard Scenarios report (Gagnon et al. 2024) provide further details about the model. The model is open source and can be accessed at https://www.nrel.gov/analysis/reeds/. Earlier versions of ReEDS have been used in several transmission, grid integration, and policy and scenario studies, such as the North American Renewable Integration Study (Brinkman et al. 2021), Denholm et al. (2022), and the Electrification Futures Study (C. Murphy et al. 2021).

This appendix highlights newer capabilities in ReEDS that are relevant to the NTP Study.

A.1 Transmission Modeling

This section describes multiple aspects of transmission modeling in ReEDS: 1) existing interface transfer limits for the zonal structure of the model, 2) prescribed transmission projects in the scenarios, 3) transmission cost assumptions, 4) high-voltage direct current (HVDC) specific assumptions and modeling, and 5) assumptions for the annual build limits applied in the Limited framework.

For generation and storage, the model is initialized using unit-level data from the EIA Annual Energy Outlook. The capacity for each of these units is associated with a generator or storage type and one of the 134 model zones.[39] Retirements and new capacity builds are primarily endogenously determined as part of the model's decision-making process.[40]

Initializing the current transmission capacity for the zonal model is more challenging because of the alternating current (AC) nature of power flow dictated by Kirchhoff's laws. In particular, the aggregate interface transfer limit between two zones cannot be simply approximated by the sum of thermal capacities of the lines crossing the zonal boundary. A better approximation for the interface limits uses a method documented in Brown et al. (2023), which applies a DC power flow approximation approach. The approach starts with a nodal transmission dataset and results in estimates for the maximum transfer capacities across all interfaces for the 134 model zones.

[39] Multiple vintages are also tracked particularly to reflect the range of heat rates for thermal generators.
[40] Recently installed (2021–2023) capacity and projects that are under final stages of deployment, as identified by EIA, are also prescribed for development in the model across all scenarios. Similarly, announced plant retirements from EIA are also modeled.

For most interfaces, the method assumes all lines are available when estimating the interface transfer limits. However, for interregional interfaces—interfaces between zones in different transmission planning subregions, e.g., between SPP-North and MISO-North—a more conservative approach where the single largest line crossing the interface is assumed to be unavailable, reducing the maximum transfer limits between such zones, is applied. This approach serves as a proxy for the transfer capacity between planning subregions accounting for N-1 contingencies. One MW of new transmission between two zones adds one MW of transfer capability between the zones (no derate), but the sum of new transmission crossing between transmission planning subregions is derated by 15% for the determination of maximum interregional flows (so if 100 MW of new transmission capacity is added across interfaces between SPP-North and MISO-North, the transfer capability between SPP-North and MISO-North is increased by 85 MW) as a linear approximation of security constraints.

The ~65,000-bus North American Renewable Integration Study (NARIS) database (Brinkman et al. 2021) represents expected transmission capacity for 2024 and is used to estimate currently installed transmission in ReEDS. ReEDS begins installing new, currently unplanned transmission in the 2030 solve year to minimize total system cost. Select transmission projects that are under construction but not yet completed are prescribed to be built in the model during the 2030 solve period.[41]

In addition to the existing transfer capacity and prescribed transmission projects, ReEDS can decide to build new transmission capacity as part of its co-optimization framework. The cost for new transmission is based on cost estimates from Western Electricity Coordinating Council (WECC) (Western Electricity Coordinating Council 2019), MISO (MISO 2021), Southern California Edison (Southern California Edison 2021), and a representative southeast utility. Transmission cost estimates also account for terrain, land type, and other siting factors included in the Renewable Energy Potential (reV) model (Lopez et al. 2024).[42] For interzonal transmission, distances between model zones are estimated based on a least-cost path method between the largest load centers in the zones. These distances are longer than the straight-line paths between the load centers. For interzonal AC transmission, assumed costs are based on new greenfield 500-kilovolt (kV) (1500-MW) single-circuit lines (Western Electricity Coordinating Council 2019). Figure A-1 shows the resulting interzonal AC transmission capital costs that result from this process. Annual transmission fixed O&M costs are assumed to be 1.5% of the upfront capital costs per year (European Commission. Joint Research Centre. Institute for Energy and Transport. and SERTIS. 2014).

[41] Prescribed transmission projects in the scenarios include Colorado Power Pathway (3,274 MW), TransWest Express (3,000 MW), Greenlink Nevada (2,000 MW), and Boardman to Hemingway (1,732 MW). Several other transmission projects, some announced after the analysis was completed, are at various stages of development. Their exclusion does not imply any judgment about their viability.
[42] https://github.com/NREL/reV

The same approach for estimating transmission costs is used to estimate interconnection costs for new wind and solar capacity (see Section A.2) but with lower voltages and associated higher costs on a per MW-mile basis.

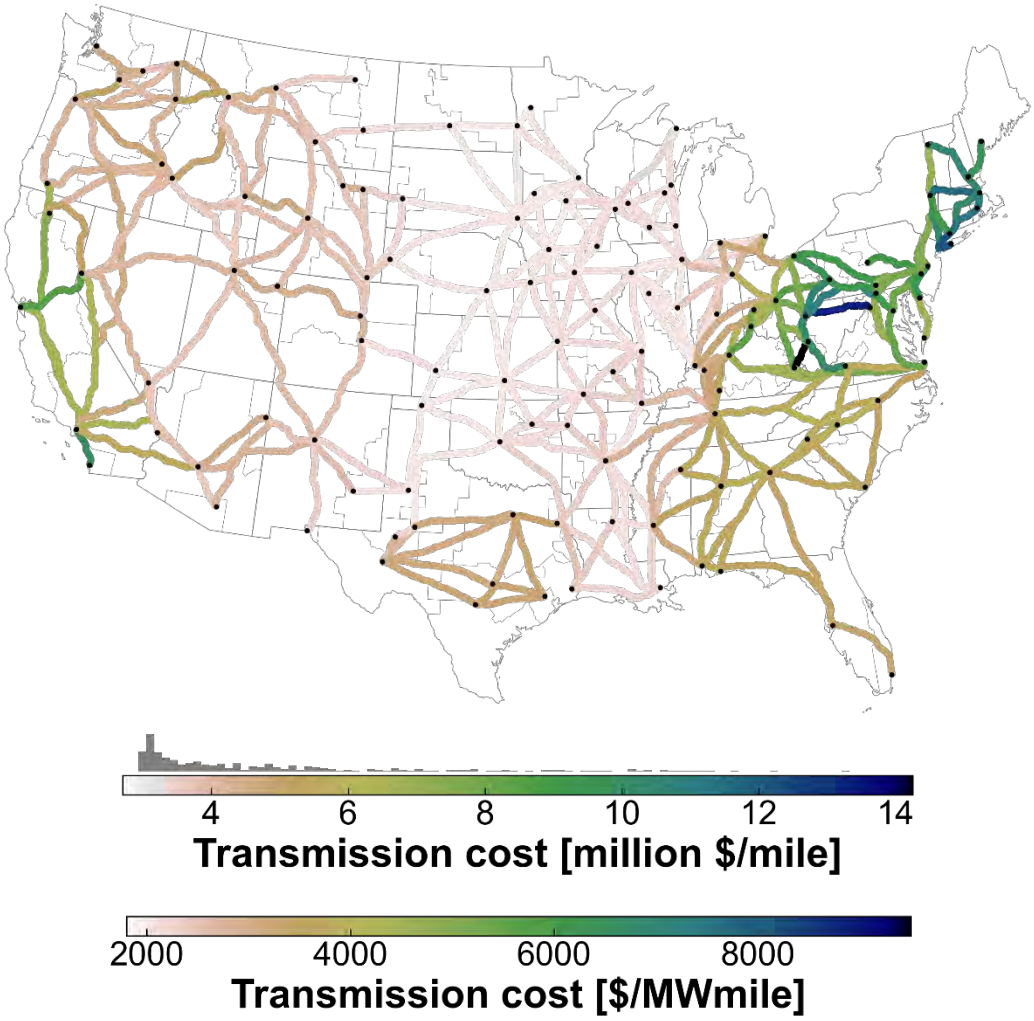


Figure A-1. Interzonal AC transmission cost assumptions

Direct current (DC) transmission line costs are assumed to be approximately 60% less than the $/MW-mile costs shown in Figure A-1 for AC transmission based on the MISO cost estimation guide (MISO 2021). However, DC transmission has the added cost of the converter stations. These are assumed to be $140/kW for line-commutated converters (LCCs) and back-to-back (B2B) interties and $180/kW for voltage source converters (VSC), also based on MISO (MISO 2021).

For the multiterminal (MT) framework, HVDC connection options are the same as those shown in Figure A-1 for AC transmission. For point-to-point (P2P), a new set of long-distance 195 candidate connections is included (Figure 2c). These are identified based on the highest wind resource and load centers in each region. Distances between these points are also based on the least-cost path estimation method.

Transmission losses are approximated based on distances between the zone "centers" (taken as the largest urban center when available, or a large transmission substation for zones without urban areas). Line losses are assumed to be 1% per 100 miles for AC transmission and 0.5% per 100 miles for DC. Losses are also modeled for the AC to DC conversion with 0.7% losses assumed for LCC technologies (used in the P2P framework) and 1.0% for VSC (used in the MT framework) (Alassi et al. 2019).

As a linear model, ReEDS considers continuous amounts of transmission capacity—with transmission costs in units of dollars per MW-mile—rather than discrete transmission circuits or projects. This simplification can lead to unrealistically sized transmission lines, particularly for HVDC transmission under the P2P and MT frameworks. To partially mitigate this, the analysis applies an iterative approach with two model runs for each of the scenarios under the HVDC (P2P and MT) frameworks. The first run uses all possible candidates. During the second, HVDC connections for which ReEDS builds less than 1.5 GW of capacity by 2050 are excluded.[43] This approach does not preclude small capacities but greatly reduces their number. ReEDS does not comprehensively account for additional upgrades or reinforcements for expansion of high-voltage DC or AC lines—e.g., that may be necessary to address voltage or stability issues—but estimated network reinforcement costs are included for new wind and solar development (see next section).

Under the Limited framework, a constraint is applied to the annual rate of transmission deployment. This rate is based on the maximum amount of transmission build in the United States over the past 10 years (2014–2023). Data from Federal Energy Regulatory Commission (FERC) collected by Lawrence Berkeley National Laboratory (LBNL) (Wiser et al. 2023) are used to estimate this maximum. The historical transmission data are reported by voltage and miles. To use this in ReEDS requires converting the voltage into capacity, and the following simple conversion factors are assumed: 400 MW for ≤230 kV, 750 MW for 345 kV, and 1500 MW for 500 kV. This approach results in 1.83 TW-mile/year of maximum annual transmission builds.

A.2 Wind and Solar Supply Curves

Assumptions for wind and solar developable potential, resource quality, and transmission access used in ReEDS are developed from the reV model (Maclaurin et al. 2021). reV is a high-resolution geospatial tool that considers renewable resources, land availability, hourly generation profiles, and transmission interconnection costs for approximately 60,000 potential sites across the contiguous United States. The most recent results and assumptions of the reV analysis for land-based wind and utility-scale solar photovoltaics (PV)[44] are documented by Lopez et al. (2024) and summarized below.

The technical resource potential for wind and solar is affected by the available land that could be developed. Land availability is estimated by considering siting suitability and

[43] For the scenarios translated for nodal modeling (Chapter 3), this iteration is also applied in 2035 instead of 2050 because the nodal modeling is conducted for 2035 systems.
[44] reV is also used similarly for offshore wind and concentrating solar power.

spatial exclusions from other uses. These siting considerations include terrain (e.g., slope, elevation), airspace and defense (e.g., airports, radar), environmental factors (e.g., endangered species habitat, wetlands, national parks and conservation areas), and siting regulations (e.g., setbacks from existing structures, roads, railroads, transmission lines, and pipelines). Default exclusion assumptions used for nearly all scenarios are based on the "Reference Access" case (Lopez et al. 2024). Under these assumptions, the total developable areas for wind and PV across the contiguous United States are 1.9 million square kilometers (km^2) and 2.6 million km^2, respectively. These land areas correspond to a technical potential of 11 TW of capacity potential for wind and 112 TW for PV; the higher PV potential is because of the relatively lower total land use requirements.[45] The developable potential for these resources is not spatially uniform with generally lower resource potential in locations with higher populations and associated built environment. Figure A-2a,c shows maps of the assumed resource potential for wind and solar, respectively, under the default assumptions. This available potential represents *options* that ReEDS could choose to deploy based on its optimization framework, which is much larger than the resulting buildout in the scenarios. ReEDS aggregates these available sites into its 134-zone structure but includes additional resource classes and transmission cost bins (Ho et al. forthcoming).

To capture the uncertainty associated with renewable energy siting over the next 3 decades, a Siting Limited sensitivity (Section 2.3.5) is included. For the Siting Limited sensitivity, the "Limited Access" siting regimes from Lopez et al. (2024) replace the Reference Access assumptions. Limited Access has more stringent exclusions, such as greater environmental exclusions and much larger setbacks that represent social challenges with siting. In this case, the developable area (and capacity) for wind is reduced to 800,000 km^2 (5.9 TW) and to 1.4 million km^2 (58 TW) for PV. As shown by Figure A-2b,d, the available resources are even more concentrated in the central regions of the country with lower population densities.

[45] The disturbed land area for these technologies differs, with <5% of the area of wind plants from roads, pads, and other infrastructure whereas approximately 90% of the area is covered by solar panels and other infrastructure.

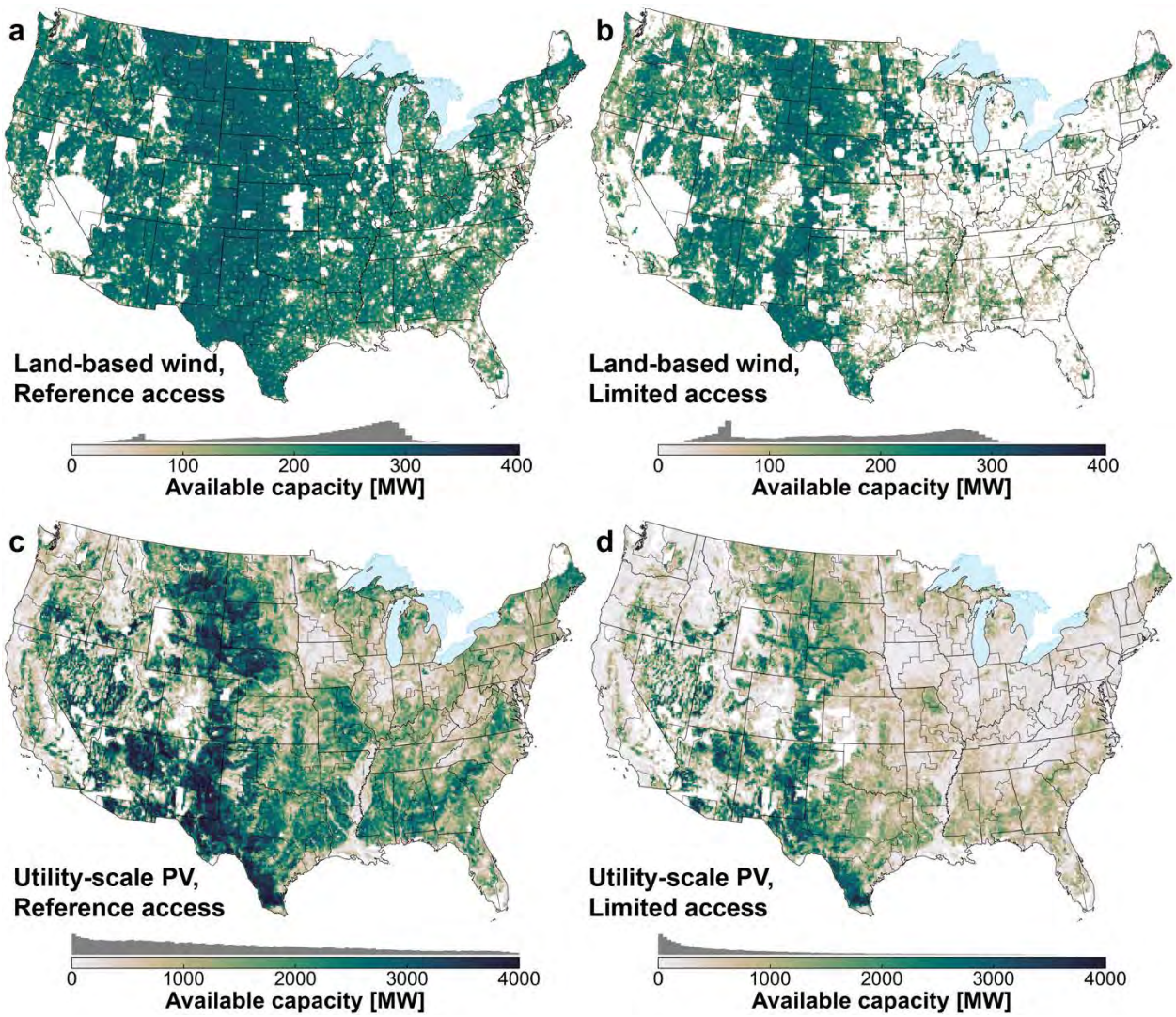


Figure A-2. Available land-based wind (a, b) and utility-scale PV (c, d) capacity under Reference Access (a, c) and Limited Access (b, d) assumptions

Histograms of available capacity by site are included above color bars. Note the difference in color scale limits between wind (a, b) and PV (c, d).

In addition to the developable potential, reV also estimates the performance (capacity factor) and generation profiles for each of the ~60,000 sites. Generation is modeled using the System Advisor Model[46] and based on meteorological data (e.g., wind speed, irradiance, temperature) from the 2-km resolution WIND Toolkit (Draxl et al. 2015) and 4-km resolution National Solar Radiation Database (Sengupta et al. 2018), including losses. Hourly generation is modeled for 7 weather years (2007–2013) for which coincident wind, solar, and demand data are available. The wind and solar technology assumptions are based on the Annual Technology Baseline (ATB) 2023 Moderate case for 2030.

[46] https://sam.nrel.gov/

Figure A-3 shows supply curves—the resource potential (in GW) ordered by lowest levelized cost of energy (LCOE)[47] in 2030—based on the land availability and performance assumptions from reV. The dashed lines show the supply curves without considering interconnection costs (Site LCOE). Interconnection costs as modeled in reV include spur lines to connect the renewable energy site to an existing substation that is the point of interconnection (POI), POI substation upgrade costs, and network reinforcements that represent other upgrades needed for the grid network. The underlying equipment costs and routing methods associated with these are based on the same sources used for interzonal transmission (Section A.1) but based on a wider range of voltages (Lopez et al. 2024). For network reinforcement costs, assumed per mile costs for upgrades are 50% of the cost of greenfield transmission and effective distance of upgrades based on the POI location and the largest load center in each of the 134 model zones (traced along the existing transmission system). This is a simplified approach to estimating interconnection costs but provides regionally varying costs that are approximately aligned with empirically observed costs (Seel et al. 2023). Figure A-3 shows how including interconnection costs (All-in LCOE, solid lines) is estimated to increase LCOEs by at least $5–$10/MWh for many locations. The modeling does not choose sites and technologies based on LCOE; LCOEs from Figure A-3 are shown to indicatively display the resource potential and quality assumed.

[47] ReEDS does not select resources based on LCOE. For example, options with higher LCOE can be chosen if their profiles are better aligned with system needs or the locations are preferred because of transmission congestion or for other reasons.

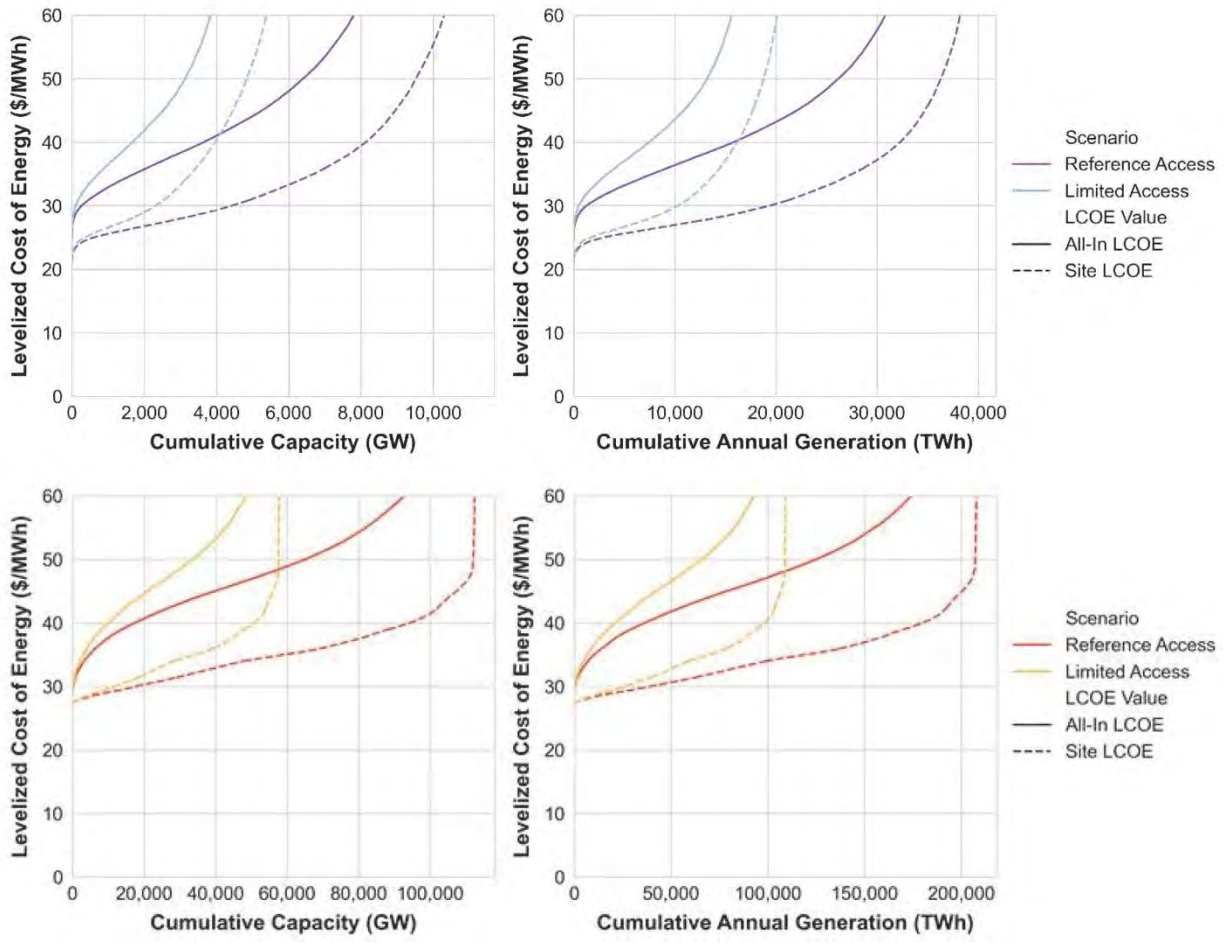


Figure A-3. LCOE supply curves for land-based wind (top) and solar PV (bottom)

Source: Adapted from Lopez et al. (2024). LCOEs are based on 2030 technology assumptions. Values above $60/MWh are not shown. "Site" LCOE excludes interconnection costs. "All-in" LCOE includes interconnection costs.

The interconnection costs modeled here are reflected in ReEDS, and these expenditures are tracked as local transmission investments. Local transmission distances and capacities—usually reported in MW-miles—also use the spur line distances and traced network upgrades.

A.3 Hydrogen Modeling

Hydrogen production and use for grid applications is endogenously modeled in ReEDS for the NTP Study. In other words, capacity for electrolyzers, hydrogen storage, and hydrogen-fueled generation are all decisions made by the model considering their assumed costs and constraints. For the NTP Study scenarios, hydrogen production is modeled via electrolysis only; steam methane reforming with or without carbon capture and storage (CCS) is not considered. In the default scenarios, electrolyzer costs are assumed to decline from $1,750/kW in 2022 to $550/kW in 2030 and remain constant after 2030 (DOE 2023b). In the Electrolyzer Low Cost sensitivity, electrolyzer costs decline to $157/kW by 2050 (DOE 2023b).

The model includes the electricity demand needed for electrolysis, which increases overall demand beyond the level shown in Figure 5 and Figure 6. Two forms of geological hydrogen storage—salt caverns and hard rock formations—are included as well as the ability to construct storage in underground pipe systems. Data on the availability of geological storage are taken from Lord et al. (2014) (Lord, Kobos, and Borns 2014). Costs for all three storage options are based on Papadias and Ahluwalia (2021) (Papadias and Ahluwalia 2021) and are approximately $40/kilogram of hydrogen (kg-H_2) for salt caverns, $65/kg-$H_2$ for hard rock, and $590/kg-$H_2$ for underground pipes. Electricity generation based on hydrogen is modeled to be from combustion turbines (CTs). These can be new greenfield H_2-CTs or can be retrofitted from existing natural gas (NG) power plants. The cost of greenfield H_2-CTs is assumed to be the same as that of new NG-CTs except with a 3% cost increase to account for adding a clutch to enable the CT to operate as a synchronous condenser (Denholm et al. 2022). Upgrades from NG-CT to H_2-CT are assumed to be 33% of the cost of a new plant, and upgrades from natural gas combined cycle (NG-CC) to H_2-CT are assumed to be 55% of the cost of a new plant because of the need to upgrade the steam turbine as well. Heat rates are assumed to be the same between H_2-CTs and NG-CTs.

Hydrogen storage levels are tracked chronologically over the modeled weather year at daily resolution within each model zone. In this way, the modeled hydrogen option is representative of seasonal storage and serves the primary purpose of supporting resource adequacy in the scenarios. Transport of hydrogen between zones is not allowed. Future work is needed to assess the relative trade-offs between hydrogen and electricity transmission. In addition, the scenarios do not include the use of hydrogen outside of the electricity sector, e.g., for use in industry and transportation. And, as noted in Section 2.3.2, hydrogen tax credits are not included in this study because the final policy was not released when the analysis was completed.

A.4 End-Use Emissions

The three electricity demand cases (Low, Mid, High) are based on different levels of electrification and associated reductions in end-use emissions as described in Section 2.3.3. Figure A-4 shows how direct emissions from the end-use sectors (e.g., vehicle tailpipe emissions for transportation, emissions from natural gas combustion in furnaces and water heaters in buildings, and emissions from heating and other processes in industry) vary across these cases. The power sector emissions results from ReEDS can be combined with these to estimate total energy emissions in the United States; however, care is needed to account for emissions from indirect electrification because consumption of hydrogen outside the power sector is not included.

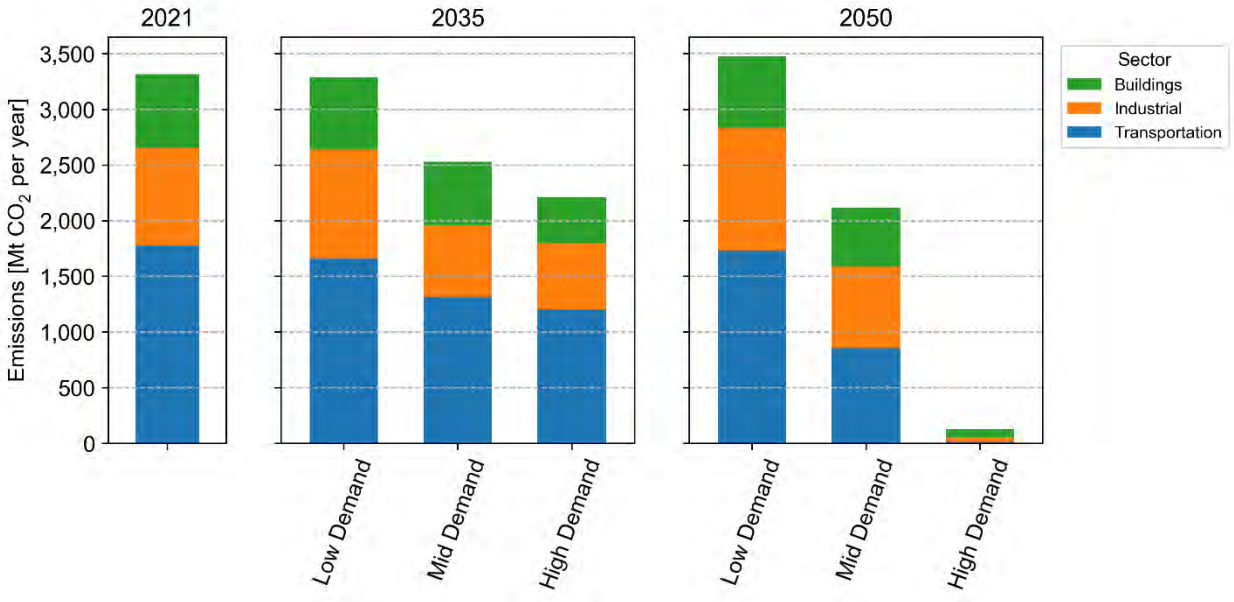


Figure A-4. End-use emissions for the three electricity demand cases

A.5 Climate Change Sensitivity

By default, ReEDS uses historical weather data for load and VRE generation profiles. Because future weather—and associated electricity demand patterns and generation performance—will likely differ from historical weather, a "Climate Change" case with a different set of assumptions is included as a sensitivity.

For this sensitivity, climate-change-impacted load and generation profiles were created from Super-Resolution for Renewable Energy Resource Data with Climate Change Impacts (Sup3rCC) (Buster et al. 2023). The Sup3rCC data are based on global climate model (GCM) data and use generative machine learning models to represent realistic spatiotemporal variability in wind, solar, and load profiles at a nominal 4-km hourly resolution. The Sup3rCC data used in this project are based on the climate model MRI-ESM-2.0 for the SSP5 Climate Change scenario with a climate forcing of 8.5 W/m^2 (Yukimoto et al. 2019). The projected weather data for 7 years (2050–2056) from this scenario are applied to all model years.[48]

Wind and solar PV generation profiles are created using the reV model with the Sup3rCC weather inputs and the same technology assumptions as used in ReEDS (Lopez et al. 2024). The climate-impacted load profiles are created using regression models that establish a relationship between state-level subsector loads (e.g., residential cooling loads for Colorado) and population-weighted hourly meteorological variables (e.g., air temperature, humidity, and irradiance). The regression models were trained on meteorological years 2007–2012 and validated in 2013. The validation results show low bias error, including during peak load hours, and demonstrate the

[48] In other words, the weather forecasted for 2050–2056 is applied to load, wind, and solar PV generation in all model years from 2020 to 2050. This is justified given the long-lived nature of most power system assets and the uncertainties with long-term load forecasts.

models' ability to extrapolate peak loads with nonhistorical temperature inputs (necessary to explore the impacts of climate change on high-stress events).

The climate-impacted load data show an increase in spring and fall demand during high-load periods, especially in the Southeast and the Pacific Northwest because of more frequent and intense heat events (Figure A-5). Summer peak loads generally increase within a state by 2%–8% in magnitude although there is significant spatial variability with some states exhibiting small decreases in load whereas others exhibit increases of up to 14%. Winter peak loads are highly dependent on weather year and region with most states in the East exhibiting a decrease in peak load and other states in the West exhibiting a slight increase in peak load. Because of the local nature of weather events that drive peak load events, the change in coincident peak load tends to decrease with larger spatial aggregations. For example, the coincident peak load across the contiguous United States increases only by 2%. The changes in peak load discussed here are based on isolated effects of weather. Load from both historical and future weather in these comparisons is based on end-use sector (i.e., electrification) assumptions from the 2050 model year in the High-Demand scenario. The impact of climate change on demand profiles is typically smaller in earlier years and for the lower electrification scenarios.

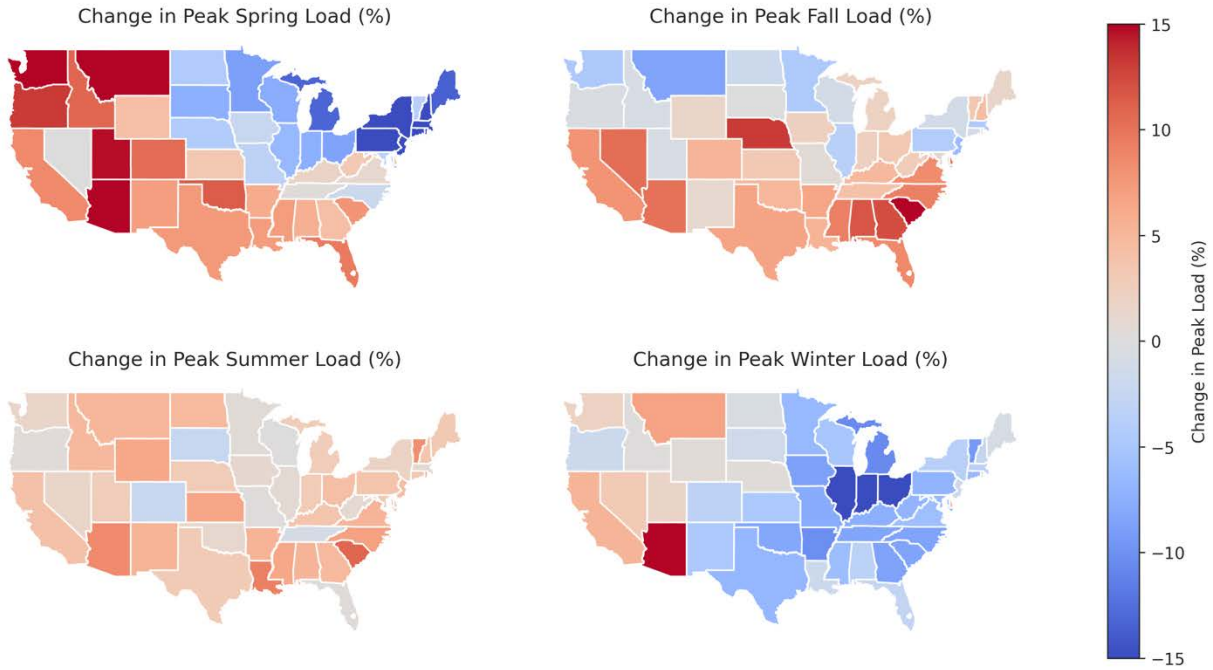


Figure A-5. Changes in seasonal all-sector peak load from historical weather (2007–2013) to future weather impacted by climate change (2050–2056)

The differences are based on the maximum hourly demand for each season across all 7 future weather years relative to the maximum during the 7 historical-weather-year period. This comparison is for the High-Demand case for the 2050 model year, which includes significant electrification.

The climate model and scenario used here do not project significant changes in renewable energy generation. Other GCMs have found larger changes to wind resources that could impact net load profiles and outcomes modeled (Martinez and Iglesias 2022). The Sup3rCC data used here are based on only 7 years (2050–2056) from a single climate model. Additional weather years would better represent the uncertainty from interannual variability. Alternative GCMs and scenarios would also yield different outcomes. Finally, because Sup3rCC is based on GCM data, it does not represent many important meteorological phenomena such as wildfires and hurricanes. Future work will study uncertainty from additional weather years, GCMs, and climate scenarios.

In addition to changes to demand, wind, and solar generation, the Climate Change sensitivity also includes adjustments to the potential contribution of hydropower, thermal resources, and transmission. Specifically, simple derate factors are applied to the summer capacity of these resources during both “representative” and “stress” periods modeled in ReEDS to represent various phenomena that could reduce the performance of these technologies or to reduce planners’ confidence in these resources for meeting system adequacy requirements.

To represent potential climate change impacts on hydropower resources, reservoir hydropower capacity is reduced by 20% during the modeled stress periods. This 20% reduction is applied for the 2050 model year with a simple linear ramp to this ultimate value starting in 2025. Derates are applied uniformly in all regions. The 20% value approximates impacts estimated by Turner et al. (2022) for hydropower facilities in WECC.

To represent climate change impacts on thermal cooling units, all available thermal generation capacity is derated during summer periods by 15% in 2050 with the same linear ramp starting from 2025. For thermal power plants, ReEDS uses summer capacity ratings, as reported for the EIA National Energy Modeling Systems data and supplemented with EIA form-860 data, for all nonwinter seasons. Summer capacity ratings are typically lower than winter or nameplate capacities, and the derate applied here is on top of this reduction as a proxy for higher temperatures and lower cooling water availability compared to historical summer periods.[49] This value is based on a 15% reduction in WECC thermal capacity driven by cooling water availability (Voisin et al. 2017). In addition, data from Electric Reliability Council of Texas (ERCOT) imply an 11% reduction in thermal capacity during summer (Electric Reliability Council of Texas 2022).

To represent climate change impacts on transmission, summer transmission capacity is derated by 5% by 2050 using a linear ramp starting from 2025. In ReEDS the transmission capacities are already based on summer ratings, so this reduction would be incremental to those driven by higher-than-historical temperatures during summer.

[49] Winter capacities are used for winter periods in ReEDS. All reported capacities in this study reflect summer ratings.

The 5% value is within the range estimated by Bartos et al. (2016). Another study for California suggests a 7% reduction (Sathaye et al. 2011).

Climate change impacts on demand, generation resources, and transmission are complex with significant uncertainties. Given the simple representation and proxy assumptions applied here, the results from the climate change sensitivity cases should be interpreted as indicative rather than definitive.

Appendix B. Integrated Capacity Expansion and Resource Adequacy Modeling

The Regional Energy Deployment System (ReEDS) and Probabilistic Resource Adequacy Suite (PRAS) models are operated in concert to analyze the scenarios presented in this chapter. Both models are summarized in Section 2.1. Appendix A provides more details about ReEDS; this appendix provides additional detail about PRAS and discusses how the models are integrated to help ensure the future portfolios analyzed are resource adequate. Mai et al. (forthcoming) provide further explanation about the combined modeling. Documentation for an earlier version of the PRAS model can be found in Stephen (2021), and the model is available open source.[50]

B.1 What Is PRAS?

PRAS is a probabilistic tool that simulates thermal generator outages and economic dispatch over a multiyear period to generate adequacy metrics for power system portfolios. It covers the same geographic extent (contiguous United States) with the same zonal spatial resolution (134 zones) as ReEDS. As described next, most of the data used in PRAS are passed directly from ReEDS. For example, hourly wind, solar, and load profiles are the same as those used in ReEDS. For this analysis, PRAS executes hourly simulations over 7 weather years (2007–2013).

PRAS models transmission in the same zonal manner as ReEDS and does not represent transmission outages. For thermal generators, the total capacity in each zone is disaggregated into individual units to facilitate the Monte Carlo assessment performed by PRAS. This disaggregation process uses data for existing units from the EIA National Energy Modeling System (NEMS) model (EIA 2023b) and, for new capacity, typical unit sizes from the 2023 Annual Technology Baseline (National Renewable Energy Laboratory 2023). Outage rates for thermal generators and storage are based on 2014–2018 data from the North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS) (NERC 2023b).

By using multiple years of hourly renewable energy and load possibilities along with thermal generator and storage outages, PRAS can provide statistical measures about the likelihood of unserved load. Reliability metrics estimated by PRAS include loss of load probability (LOLP), loss of load expectation (LOLE), and expected unserved energy (EUE). This can be used to assess system adequacy as well as when and where the system is likely to be stressed.

B.2 Integrated ReEDS-PRAS process

Figure B-1 shows how ReEDS and PRAS are used together. For a given solve period (e.g., 2035), ReEDS develops an initial system design that is passed on to PRAS. PRAS is then executed to estimate the total normalized expected unserved energy (NEUE)—where the normalization divides EUE by total contiguous U.S. load—and to

[50] https://www.nrel.gov/analysis/pras.html

identify the days of highest system stress (highest EUE). If a specified NEUE target is met, ReEDS proceeds to the next solve period (e.g., 2040). If the target is not met, ReEDS re-solves for the same solve period but with additional stress periods considered and the iterative process repeats. To limit computational runtimes, an iteration limit is also imposed, where ReEDS proceeds to the next solve period despite not meeting NEUE target; however, this seldom occurs in the scenarios.

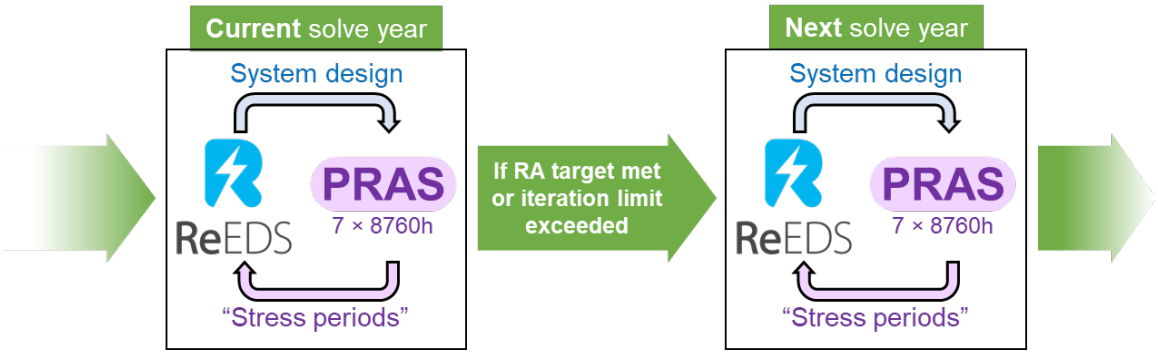


Figure B-1. Integrated capacity expansion and resource adequacy modeling

ReEDS models up to 30 stress periods, which are the periods with highest EUE as estimated by PRAS.[51] During the stress periods, ReEDS models dispatch in largely the same manner as the "representative periods." Important differences are that demand during these periods is elevated by the planning reserve margin (12%–18%), which is based on reference reserve margins from the 2021 NERC Long-Term Reliability Assessment (NERC 2021). Differences between this approach and a traditional planning reserve margin approach—including how it better addresses systems with higher VRE and transmission exchanges—are discussed by Mai et al. (forthcoming).

B.3 Planning Threshold

There are many metrics used to quantify resource adequacy (RA), with associated target reliability levels used in system planning. Most power systems in the United States quantify RA using LOLE, with a target of LOLE ≤1 day in 10 years (NERC 2023a). LOLE does not capture the severity of loss of load events; a power system that experiences a 1-day interconnection-wide blackout every 10 years and a power system that curtails 1 GW of industrial load on 1 day in 10 years would both satisfy the 1-in-10 LOLE target (Stenclik et al. 2021; Stephen et al. 2022). The EUE, measured in MWh, and load-normalized EUE (NEUE), measured as a percent or parts per million (ppm), metrics are volumetric rather than event-based, so the 1-blackout-in-10-years system would have much higher EUE and NEUE (and thus lower reliability) than the 1-industrial-load-shed-event-in-10-years system. Though NEUE-based system planning based has yet to become widespread, systems that do use NEUE-based planning tend to use NEUE targets in the range of 10 to 30 ppm (Alberta Electricity system Operator 2017; Electric Power Research Institute 2024; NERC 2024). In this study, the NEUE metric is used with a conservatively set threshold of 10 ppm. For context, if load were equally distributed across a year, 10 ppm would be equivalent to 5 minutes of complete

[51] The model is seeded with the highest demand period as a stress period to start.

load shedding (blackout) per year, 9% load shedding spread over a one-hour period, or 0.4% load shedding spread over a 24-hour day.

B.4 Caveats

The integrated ReEDS-PRAS formulation used here attempts to incorporate many of the practices recommended for evaluating systems with significant deployment of renewable energy, storage, and transmission (Stenclik 2023). However, as with any modeling analysis, there are limitations—and this section describes important caveats.

- **Reliability target.** The NEUE reliability metric is used in the scenario modeling for the reasons described previously, but this metric is not yet commonly adopted in practice. Another reliability metric could result in different outcomes. Moreover, because there are trade-offs between cost and reliability, different portfolio outcomes could result if the NEUE threshold assumption of 10 ppm were changed. The 10-ppm threshold is an upper bound in the model implementation; thus, the level of reliability can vary between 0 and 10 ppm across scenarios. Regional NEUE thresholds would also yield outcomes different from the national threshold used here.
- **Weather years.** Most scenarios consider 7 years of historical (2007–2013) weather in the PRAS modeling. Additional weather years would enable a more robust assessment of RA. Future weather conditions could also change and affect demand profiles and the contributions from weather-dependent resources.[52] The Climate Change sensitivity provides one sample of impacts from future weather (see Appendix A).
- **Outages.** PRAS simulates thermal generator and storage outages, but in the modeling these outage rates do not vary with time or weather conditions. In reality, thermal outages are correlated with extreme temperatures (S. Murphy, Sowell, and Apt 2019). PRAS also does not represent transmission outages, which could be a higher source of system risk in the scenarios with significantly expanded transmission.
- **Demand response.** The versions of ReEDS and PRAS used for this study do not include demand response. Demand response is used in some systems to provide RA capacity—e.g., 1.9 GW in CAISO in 2022, roughly 3%–4% of total RA capacity (CAISO 2023b). All unserved energy is included in the NEUE values discussed here, but in practice some of this unserved energy would be served by appropriately compensated demand response and would not be considered to contribute to “dropped load” events. If demand response for RA were included in the simulations, the resulting NEUE would be reduced.

[52] The impact of future electrification on demand profiles are reflected in the scenarios, but demand from the use of these new electrified end uses is based on historical weather in most scenarios.

Appendix C. Technology Cost Assumptions

The Regional Energy Deployment System (ReEDS) models a large suite of technologies, including electricity generation technologies, energy storage technologies, CO_2 capture and storage, and hydrogen-producing technologies.

C.1 Supply-Side Technologies

Table C-1 lists the electricity generation and storage technologies available in ReEDS and outlines which technologies are deployable under default assumptions in this study and which are included and excluded in various sensitivity cases.

Table C-1. Technologies Modeled in ReEDS

Technology	Expansion Allowed in Core Scenario	Included Sensitivity Cases	Excluded Sensitivity Cases
4-Hr Battery[a]	Yes		
8-Hr Battery[a]	Yes		
Bioenergy with CCS (BECCS)	Yes		
Biopower	Yes		
Concentrating Solar Power (CSP)	Yes		
Geothermal[b]	Yes		
Hydropower[b]	Yes		
Natural Gas Combined Cycle (NG-CC)	Yes		
Natural Gas Combustion Turbine (NG-CT)	Yes		
Land-Based Wind[b]	Yes		
Offshore Wind[b]	Yes		
Pumped Hydropower[b]	Yes		
Utility-Scale Solar PV[b]	Yes		
Coal + Carbon Capture and Storage (Coal-CCS)[d]	Yes		No CCS; No H_2 or CCS
Hydrogen Combustion Turbine (H_2-CT)[d]	Yes		No H_2; No H_2 or CCS; No H_2 or new nuclear

Technology	Expansion Allowed in Core Scenario	Included Sensitivity Cases	Excluded Sensitivity Cases
Technology	**Expansion Allowed in Core Scenario**	**Included Sensitivity Cases**	**Excluded Sensitivity Cases**
Natural Gas Combined Cycle with CCS (NG-CC-CCS)[d]	Yes		No CCS; No H_2 or CCS
Nuclear	Yes		No H_2 or new nuclear
Nuclear Small Modular Reactor (SMR)	No	+Nuclear SMR + DAC	
Coal[c]	No, existing capacity only		
Landfill Gas[c]	No, existing capacity only		
Oil-Gas-Steam[c]	No, existing capacity only		
Distributed PV[e]	Expansion is exogenously specified		

[a] ReEDS can model 2-, 4-, 6-, 8-, and 10-hour batteries, but only the 4-hour and 8-hour battery durations are modeled in this study to reduce computation time while allowing for both shorter-duration and longer-duration storage options.

[b] Plants of these types are modeled with a supply curve because these technologies have site-specific characteristics and multiple technology configurations. For land-based wind, offshore wind, and utility-scale solar PV, these supply curves and generation profiles are from the reV model.

[c] Existing plants of these types are included, but expanded capacity is not allowed in this analysis.

[d] Plants of these types can be greenfield builds or retrofits. More detail on retrofits can be found in Appendix C.2.

[e] Distributed PV deployment is exogenously specified based on simulations from NREL's Distributed Generation Market Demand (dGen) model (Sigrin et al. 2016). The same distributed PV projection featuring 130 GW of distributed PV capacity by 2035 is used for all scenarios and based on the Standard Scenarios 2023 Mid-case (Gagnon et al. 2024). Distributed PV cannot be curtailed in ReEDS.

Most scenarios use technology cost and performance assumptions from the 2023 ATB Moderate case. Capital, fixed operation and maintenance, and variable operation and maintenance cost data for the core scenarios are shown in Table C-2, Table C-3, and Table C-4, respectively. Costs for hydropower and geothermal options vary significantly by technology type and location and are therefore not shown in the tables. These costs are based on DOE's Hydropower Vision Report (DOE 2016) and the 2023 ATB (National Renewable Energy Laboratory 2023) for the two technologies, respectively. Other technology assumptions (e.g., heat rate, capacity factor improvements), as well as more conservative or advanced cost assumptions used in the cost sensitivity cases, can be found in the ATB.

Table C-2. Overnight Capital Costs ($/kW) in the Core Scenarios

Technology	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
4-Hr Battery	1,551	1,300	1,199	1,099	999	899
8-Hr Battery	2,790	2,282	2,093	1904	1,715	1,528
BECCS[a]	7,373	7,259	7,155	7,051	6,947	6,843
Coal-CCS	4,943	4,641	4,339	4,102	3,866	3,629
CSP[b]	4,529	3,658	3,528	3,397	3,266	3,136
NG-CC	1,174	1,122	1,070	1026	982	938
NG-CC-CCS	2,424	2,179	1934	1,823	1,713	1,602
NG-CT	1,057	1,014	971	928	885	843
H_2-CT[c]	1,088	1,044	1,000	956	912	868
Land-Based Wind	1,194	1,083	1,029	976	923	869
Nuclear	6,925	6,603	6,384	6,159	5,947	5,696
Nuclear SMR	7,563	7,213	6,974	6,729	6,500	6,227
Offshore Wind, Fixed-Bottom[d]	2,228	2048	1937	1,856	1,793	1,740
Offshore Wind, Floating Platform[d]	3,329	3,071	2,912	2,796	2,705	2,630
Utility-Scale Solar PV	1,300	1,082	864	795	727	659

[a] Costs shown assume a 90% emissions capture rate. BECCS cost and performance values are from Young (2020).

[b] Costs shown for CSP assume 8 hours of thermal energy storage (TES). ReEDS models four classes of CSP technologies, including various durations of TES.

[c] Hydrogen combustion turbine capital costs are not included in the ATB. Assumed costs for new H_2-CTs are 3% greater than for new NG-CTs (Denholm et al. 2022).

[d] Offshore wind costs shown for fixed-bottom technologies are for Wind Resource Class 3, and those shown for floating platform technologies are for Wind Resource Class 10. There are seven classes for each offshore wind technology in the ATB, and each class has different capital costs. See the 2023 ATB for more details (National Renewable Energy Laboratory 2023).

Table C-3. Fixed Operation and Maintenance Costs in $/(kW-year) in the Core Scenarios

Technology	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
4-Hr Battery	38.8	32.5	30.0	27.5	25.0	22.5
8-Hr Battery	69.8	57.1	52.3	47.6	42.9	38.2
BECCS	217	217	217	217	217	217
Coal-CCS	129	122	115	110	104	98.7
CSP	47.1	39.7	39.7	39.7	39.7	39.7
NG-CC	32.6	31.0	29.3	28.2	27.1	26.0
NG-CC-CCS	64.9	58.3	51.7	49.0	46.3	43.6
NG-CT	25.5	24.7	24.1	23.3	22.6	21.9
H_2-CT	23.7	23.7	23.7	23.7	23.7	23.7
Land-Based Wind	28.8	27.0	26.1	25.2	24.2	23.3
Nuclear	164	164	164	164	164	164
Nuclear SMR	128	128	128	128	128	128
Offshore Wind, Fixed-Bottom	107	97.6	91.3	86.5	82.7	79.5
Offshore Wind, Floating Platform	80.3	73.8	69.4	66.1	63.4	61.2
Utility-Scale Solar PV	22.1	19.4	16.8	16.0	15.3	14.6

Table C-4. Variable Operations and Maintenance Costs in $/MWh in the Core Scenarios

Technology	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
4-Hr Battery	0	0	0	0	0	0
8-Hr Battery	0	0	0	0	0	0
BECCS	22.3	22.3	22.3	22.3	22.3	22.3
Coal-CCS	15.4	14.7	14.0	13.7	13.5	13.2
CSP	2.6	2.3	2.3	2.3	2.3	2.3
NG-CC	2.1	2.0	1.9	1.9	1.8	1.7
NG-CC-CCS	4.8	4.4	4.0	3.9	3.7	3.6
NG-CT	7.0	7.0	7.0	7.0	7.0	7.0
H_2-CT	5.6	5.6	5.6	5.6	5.6	5.6
Land-Based Wind	0	0	0	0	0	0
Nuclear	2.7	2.7	2.7	2.7	2.7	2.7
Nuclear SMR	3.4	3.4	3.4	3.4	3.4	3.4
Offshore Wind, Fixed-Bottom	0	0	0	0	0	0
Offshore Wind, Floating Platform	0	0	0	0	0	0
Utility-Scale Solar PV	0	0	0	0	0	0

C.2 Retrofits With CCS

Existing fossil-fuel-fired capacity is allowed to retrofit with carbon capture and storage. Retrofits are allowed starting in 2030. Capital costs for retrofits and capacity derates are based on data from EIA NEMS assumptions (EIA 2023b) as described in Table C-5.

Table C-5. Retrofit Assumptions for Technologies in ReEDS

Original Technology	Retrofit Technology	Capital Costs	Capacity Derate
Coal	Coal-CCS	Uses NEMS retrofit capital cost data when available for existing plants. Otherwise, retrofit costs are from ATB where retrofit costs start at $3,100/kW in 2023 and decrease to $1,600/kW by 2050 (National Renewable Energy Laboratory 2023).	Uses NEMS heat rate data when available for existing plants to approximate capacity derate. Otherwise assumes a 29% derate after retrofitting.
NG-CC	NG-CC-CCS	Uses NEMS retrofit capital cost data when available for existing plants. Otherwise, retrofit costs are from ATB where retrofit costs start at $1,690/kW in 2023 and decrease to $1,010/kW by 2050 (National Renewable Energy Laboratory 2023).	Uses NEMS heat rate data when available for existing plants to approximate capacity derate. Otherwise assumes a 14% capacity derate after retrofitting.

C.3 Negative Emissions Technologies

ReEDS models two negative emissions technologies: bioenergy with CCS (BECCS) and direct air capture (DAC). BECCS is enabled by default in these scenarios and allowed to expand. The cost assumptions for BECCS are shown in Appendix C.1 because BECCS is also a supply-side technology. BECCS is assumed to have a 90% capture rare and an emissions rate of -0.060 metric tons CO_2 per MMBtu. DAC is turned off by default but enabled in the +Nuclear SMR + DAC scenario. The assumed levelized cost of DAC is between $300 and $400 per metric ton of CO_2 captured and sequestered based on Brown et al. (forthcoming).

The national CO_2(e) emissions constraint in ReEDS is modeled on a net basis, meaning negative emissions technologies can offset (positive) emissions to reach the desired target level. However, offsets of emissions are allowed only from fossil with CCS. Based on this definition, generation from fossil plants without CCS is not allowed when the requirement is net zero (e.g., after 2035 under the 100% by 2035 scenarios or after 2045 under the 90% by 2035 scenarios).

C.4 Financing and Retirement Assumptions

The economic lifetime assumptions for various technologies are shown in Table C-6. Most generators are assumed to have a 20-year economic lifetime whereas 15 years is assumed for batteries and electrolyzers and 40 years for transmission.

There are multiple ways plants can retire:

- **Announced retirements.** Plants that have announced their retirement date (EIA 2023b) are retired during that year.
- **Age-based retirements.** Plants must retire on or before their maximum age as shown in Table C-6. Utility-scale solar PV, distributed scale solar PV, land-based wind, and offshore wind can be repowered—with the associated new plant capital cost but without the need for new interconnection costs—once they reach their maximum age.
- **Endogenous retirements.** The model decides to retire capacity to avoid ongoing operation and maintenance and fuel costs if the plant does not receive sufficient value or revenue in the model. This is allowed only for fossil fuel plants.
- **Policy-based retirements.** Certain technologies in ReEDS regions and model years are forced to retire because of policy requirements.

Table C-6. Financing and Maximum Age Assumptions for Technologies in ReEDS

Technology	Economic Lifetime (years)	Maximum Age (years)
Hydropower	20	*
(Non-hydro) Renewable energy (wind, solar PV, geothermal, CSP)	20	30
Coal (with and without CCS)	20	70
NG-CC (with and without CCS)	20	55
NG-CTs and H_2-CTs	20	55
Nuclear	20	80
Nuclear SMR	20	80
Storage (pumped hydropower)	20	*
Storage (batteries)	15	15
Electrolyzer	15	*
Transmission	40	*

** No maximum age is modeled for these technologies.*

Appendix D. Additional Results

D.1 ReEDS Results for 2035

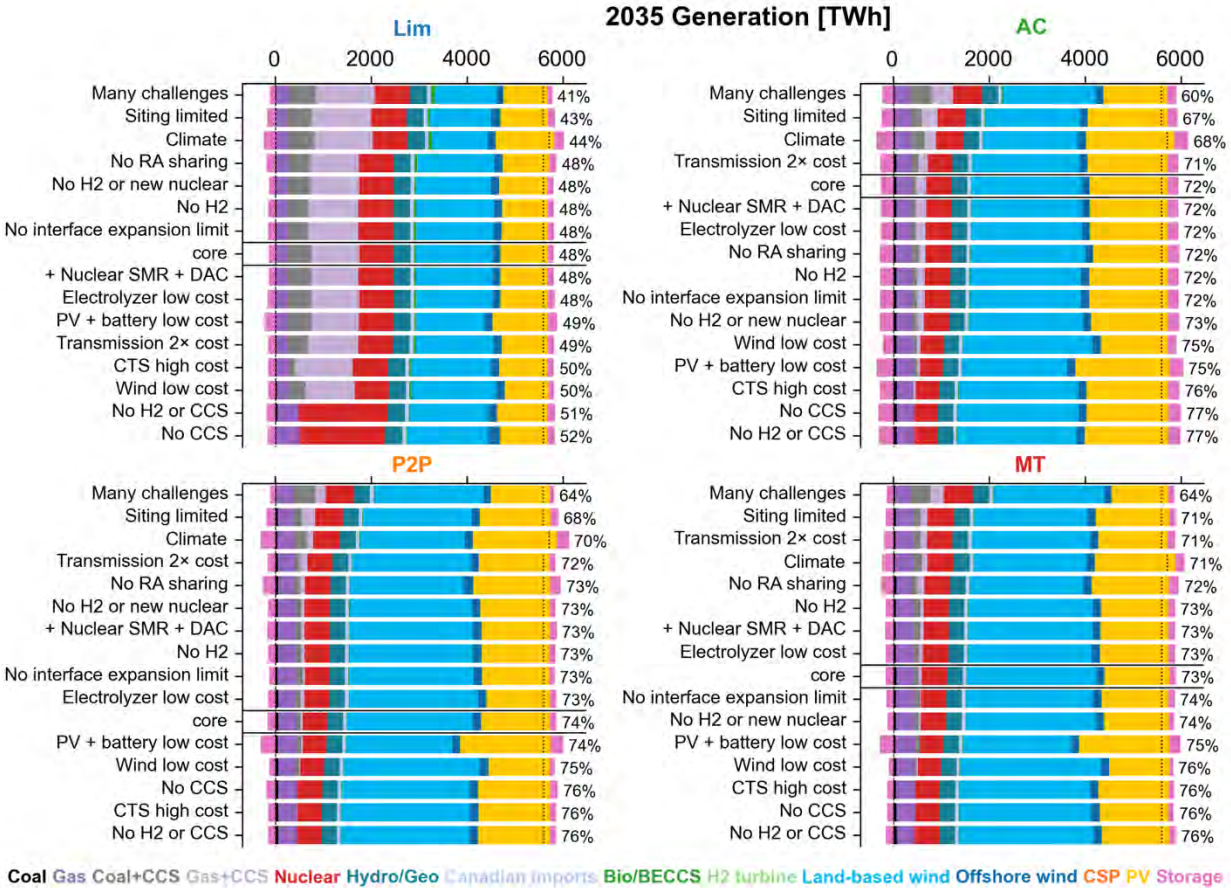


Figure D-1. National generation mix in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

Within each transmission framework, the sensitivity cases are sorted by 2035 VRE share (indicated by the percentage value to the right of each generation bar). Total generation is greater than end-use demand (vertical dotted line) because of transmission and distribution losses, storage losses, and generation for hydrogen production via electrolyzers. Total storage charging is shown as negative values and discharging as positive values.

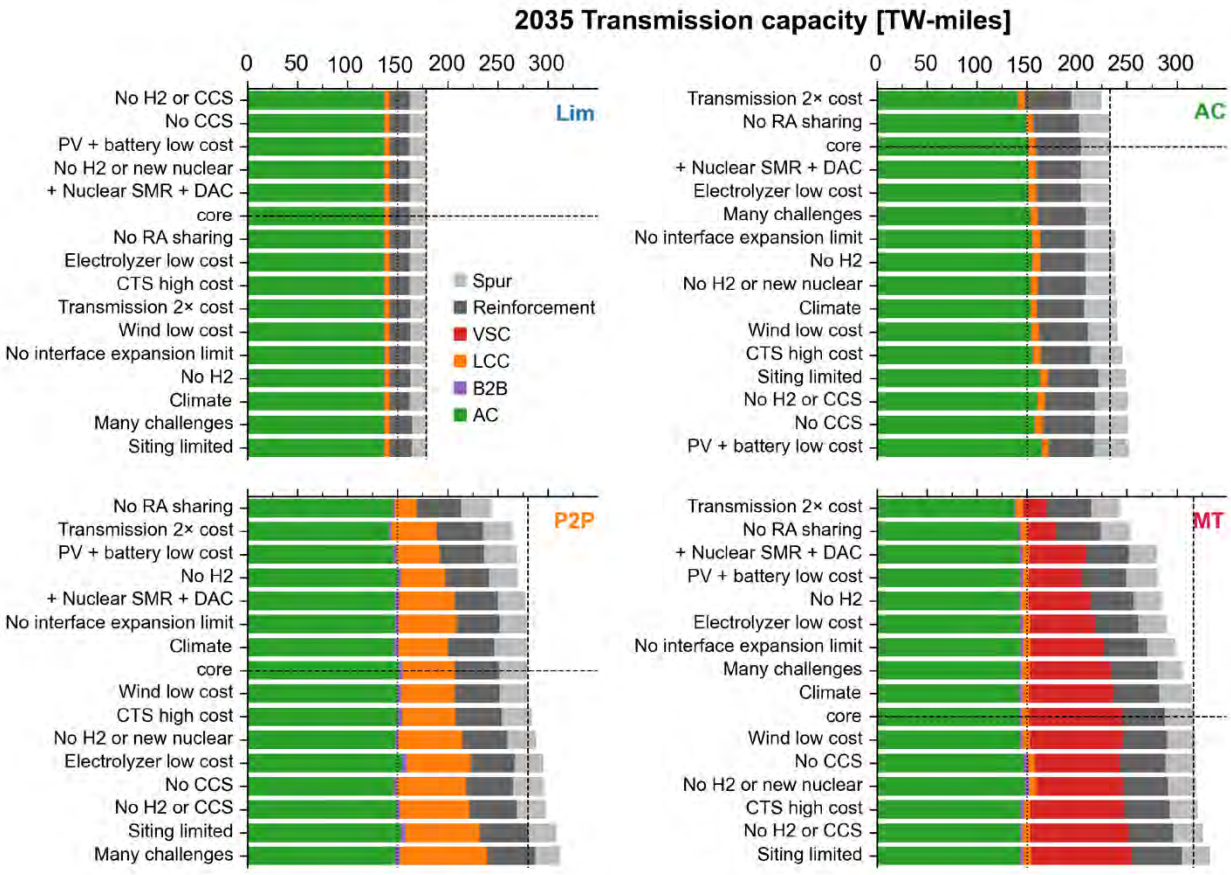


Figure D-2. Transmission capacity in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

Values for the core scenario for each transmission framework are marked by dashed black lines. Within each transmission framework, sensitivity cases are sorted by total transmission capacity in 2035. The 1.83 TW-mile/year limit on annual transmission additions is binding in all sensitivity cases for the Limited transmission framework, making 2035 transmission capacity the same in all sensitivity cases for this framework.

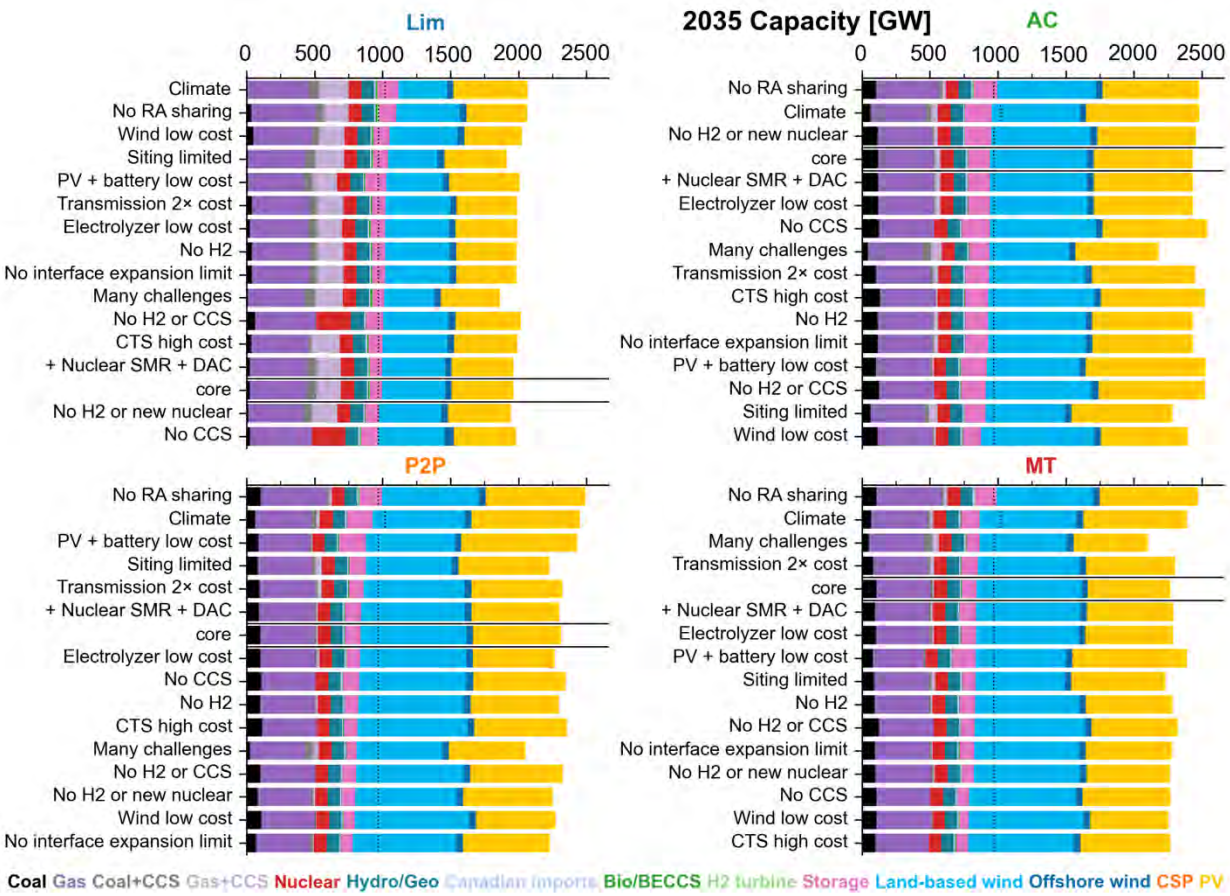


Figure D-3. National capacity mix in 2035 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

Within each transmission framework, the sensitivity cases are sorted by 2035 VRE capacity share. Peak coincident end-use demand is shown as vertical dotted lines.

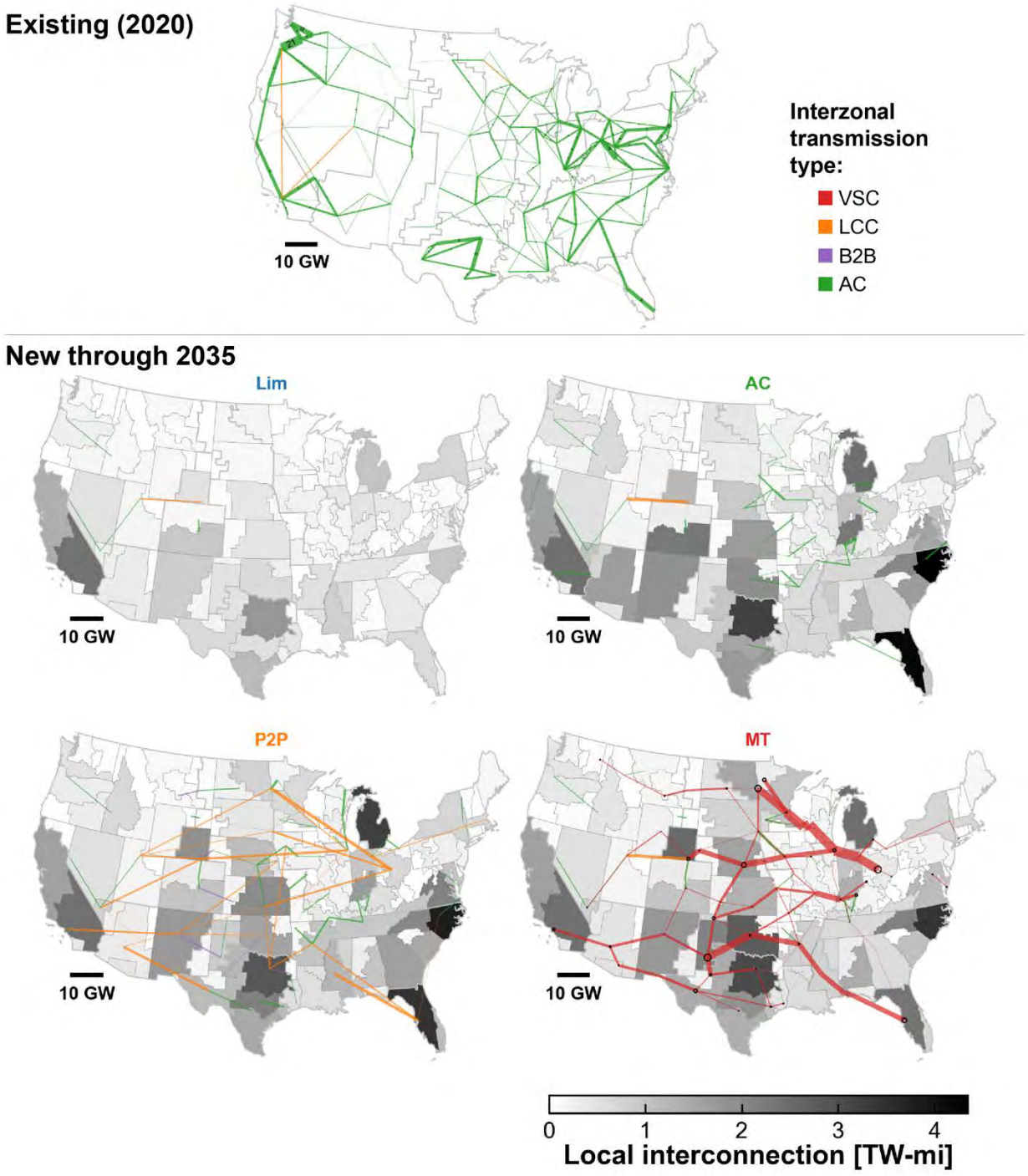


Figure D-4. New local and long-distance transmission through 2035 under Mid-Demand 90% by 2035 assumptions for each of the four transmission frameworks, with existing 2020 long-distance transmission capacity for context (top)

Interface transfer capability is indicated by the thickness of the lines connecting ReEDS zones. Converter capacity in the MT framework is indicated by the diameter of empty black circles, using the same length scale as the interface lines. The depiction of interzonal transmission capacity as straight lines between zone centers is a visual simplification; in practice, the interzonal transfer capacity would be spread across many transmission corridors for each interface.

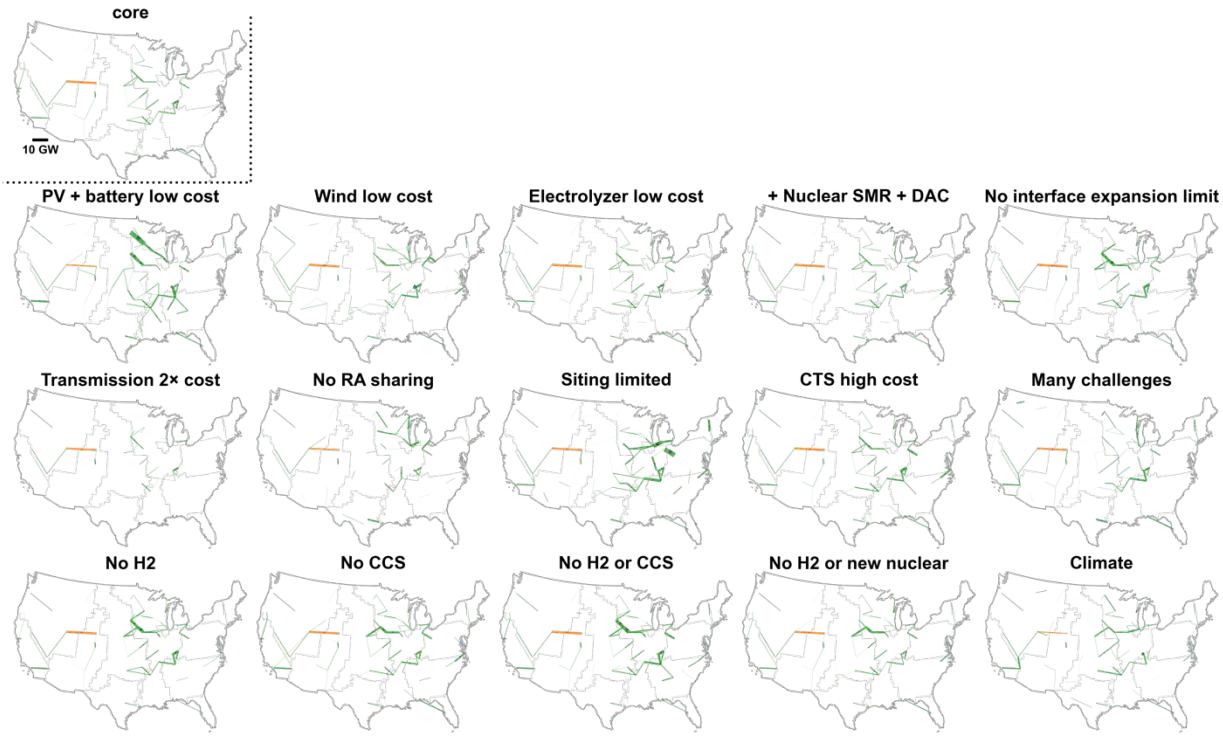


Figure D-5. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the AC transmission framework

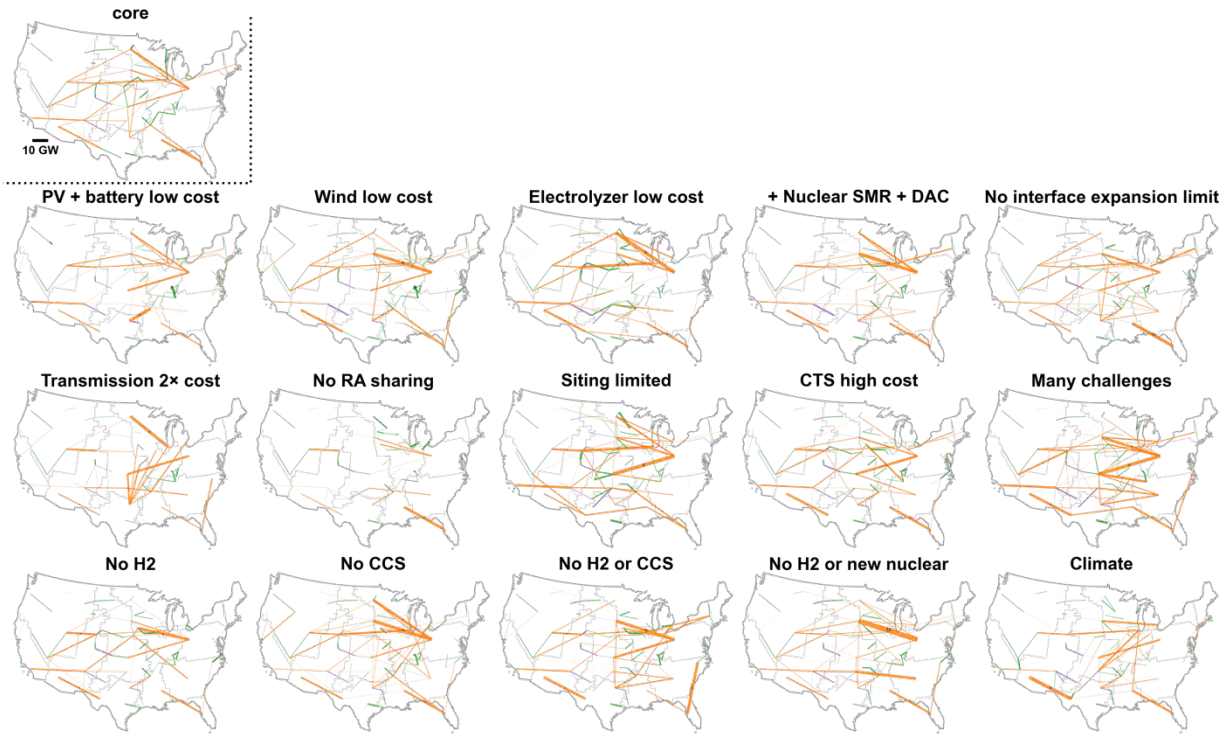


Figure D-6. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the P2P transmission framework

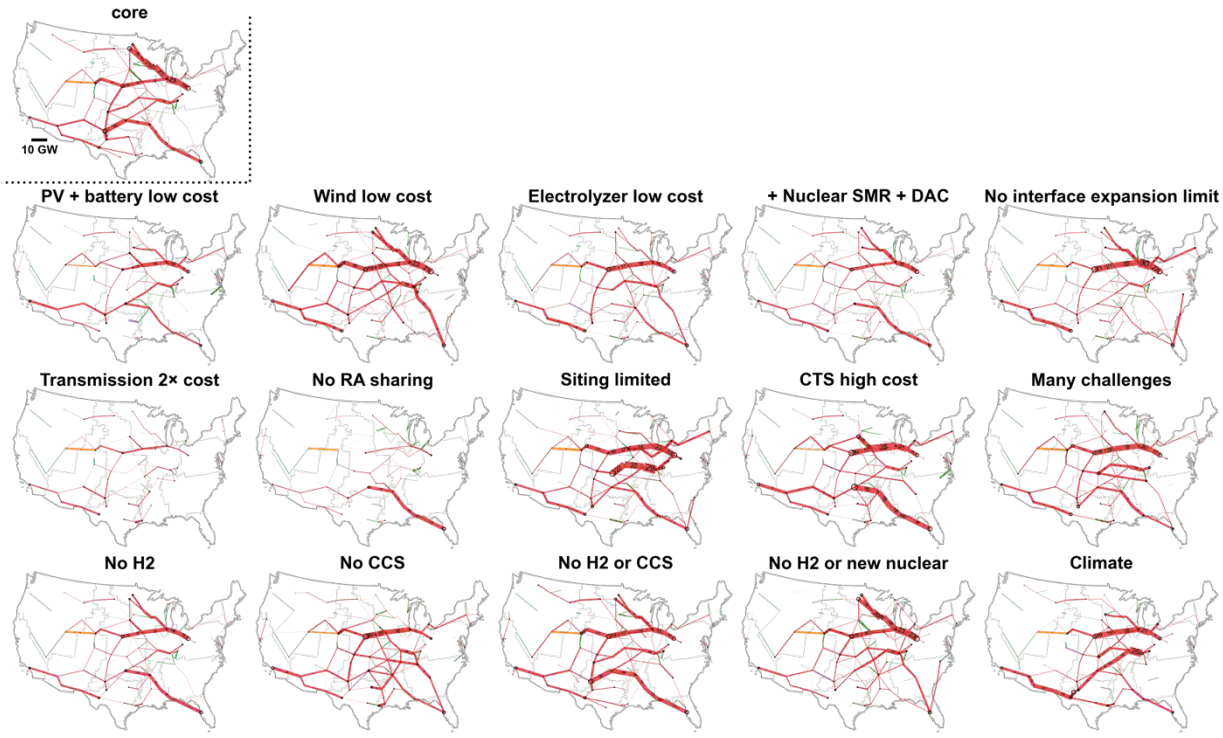


Figure D-7. New long-distance transmission additions through 2050 with Mid-Demand 90% by 2035 assumptions for each sensitivity case under the MT transmission framework

D.2 Additional Capacity Expansion Modeling Results Through 2050

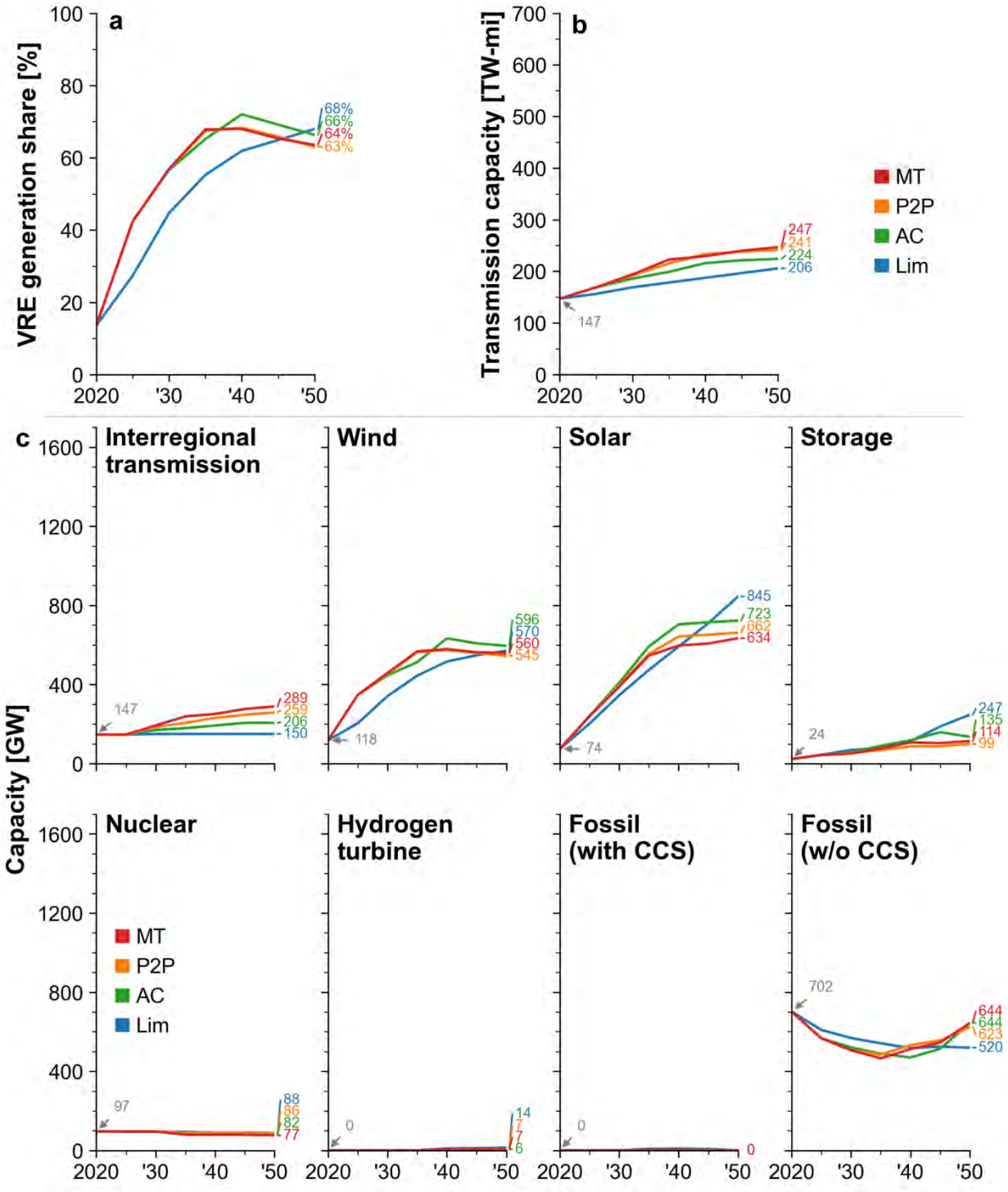


Figure D-8. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under Low-Demand Current Policies conditions

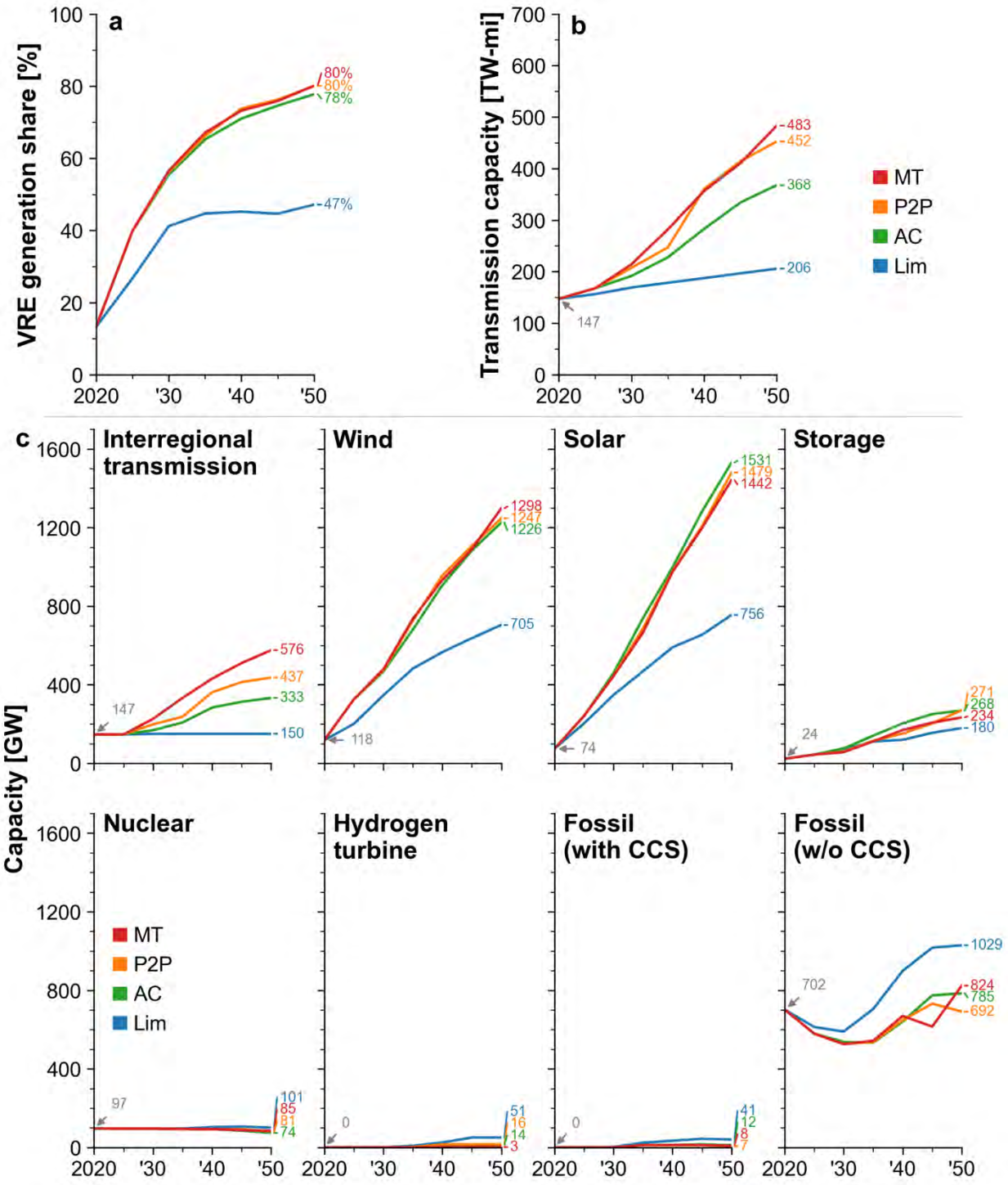


Figure D-9. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under High-Demand Current Policies conditions

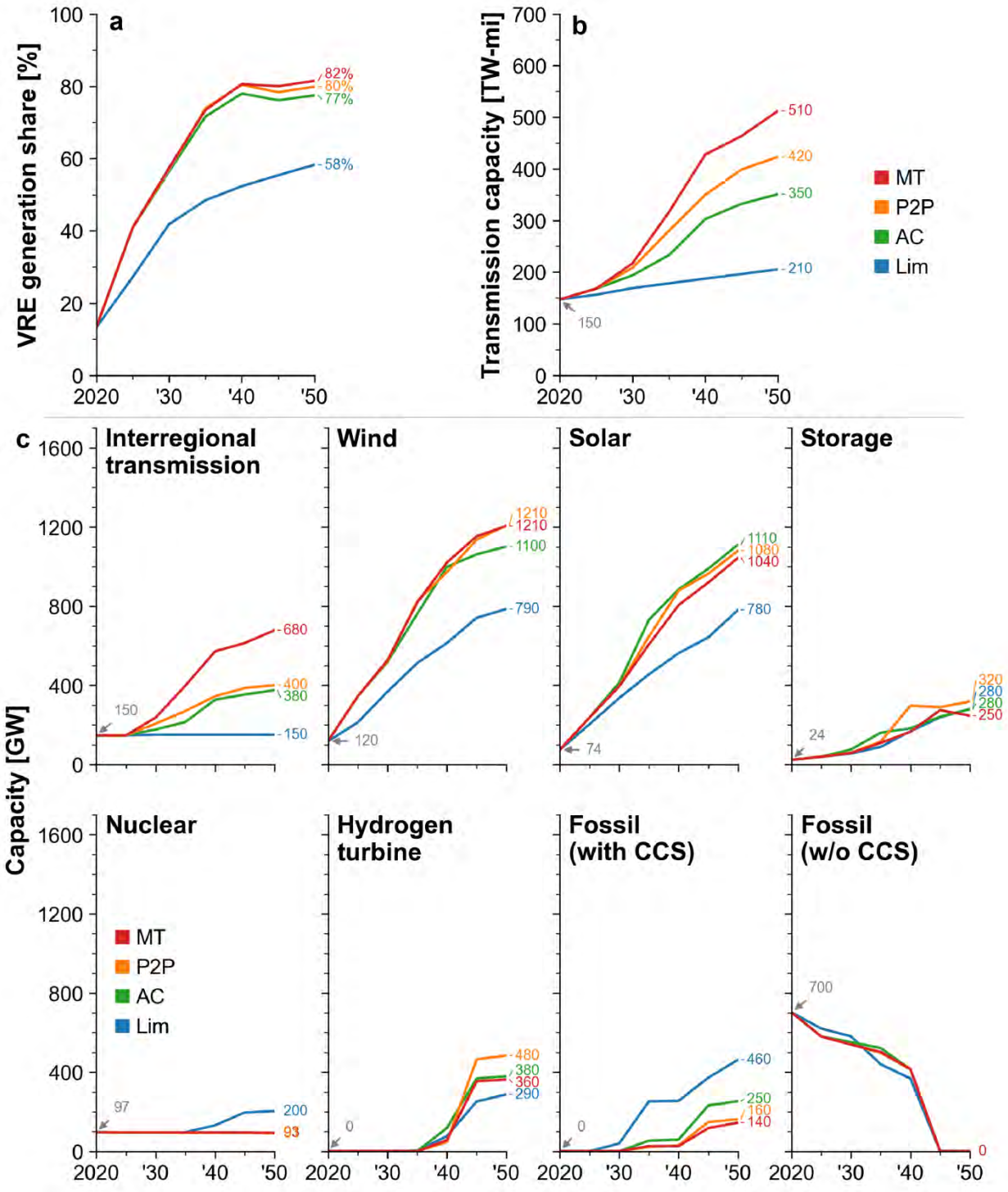


Figure D-10. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under Mid-Demand 90% by 2035 conditions

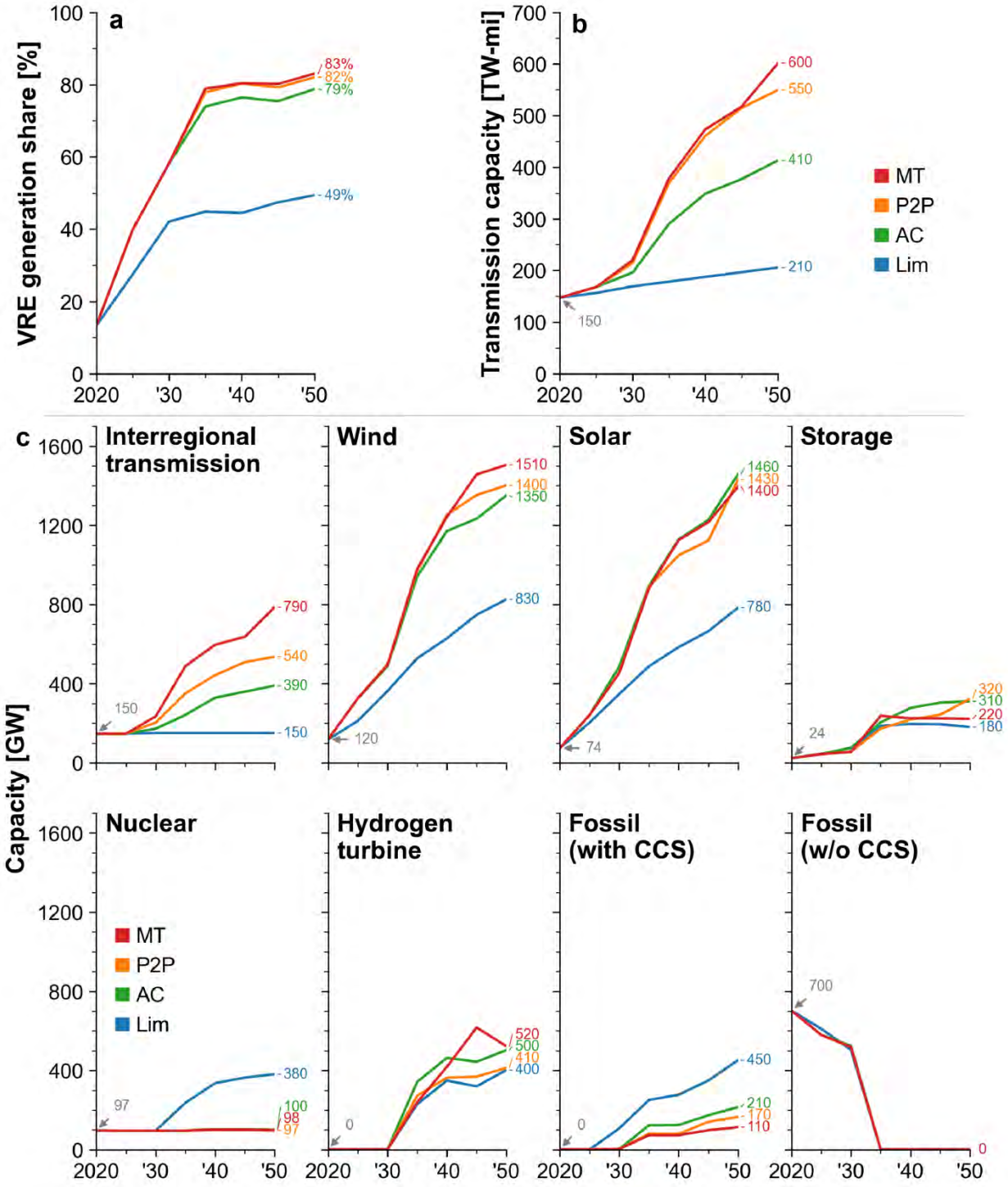


Figure D-11. Trajectories of VRE share (a), transmission capacity (b), and nameplate capacity (c) under High-Demand 100% by 2035 conditions

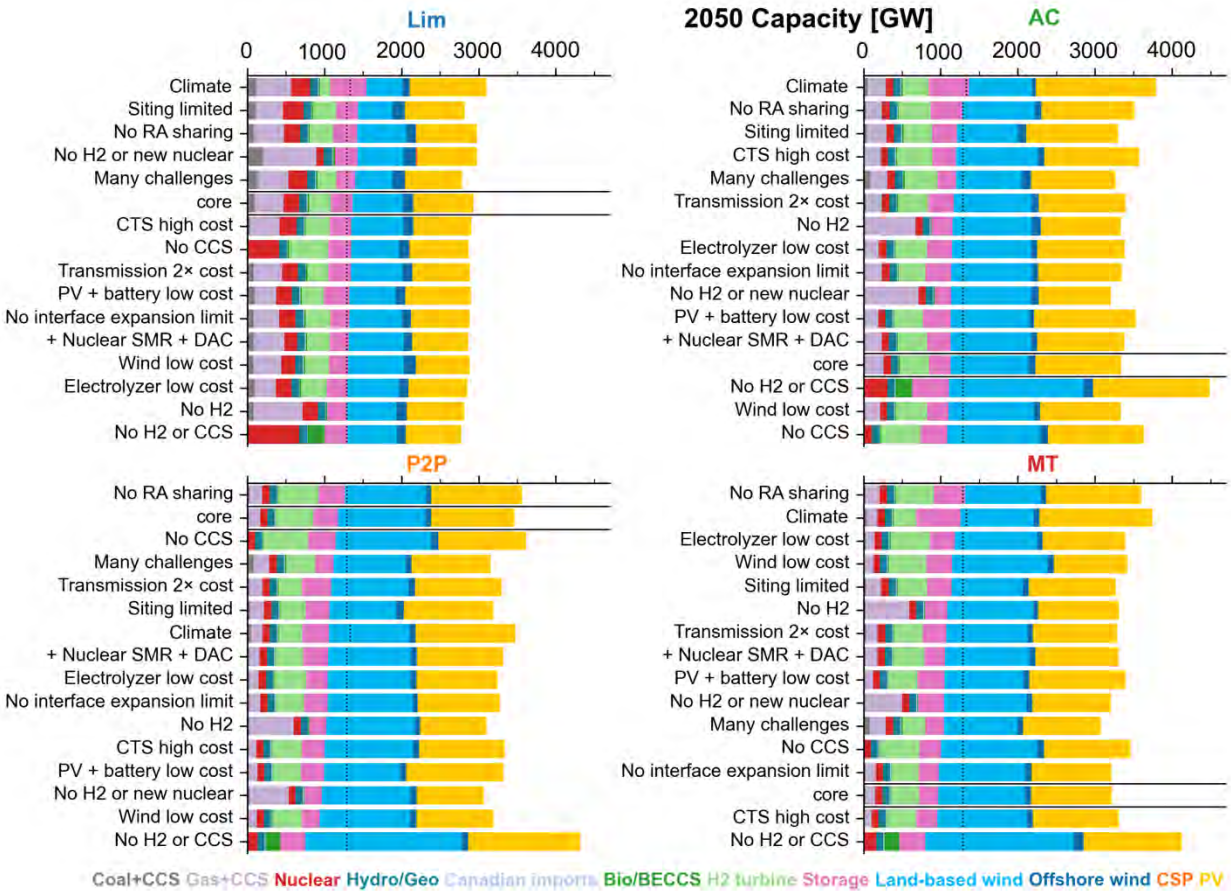


Figure D-12. National capacity mix in 2050 with Mid-Demand 90% by 2035 assumptions for each transmission framework and sensitivity case

Within each transmission framework, the sensitivity cases are sorted by 2050 VRE capacity share. Peak coincident end-use demand is shown as vertical dotted lines.

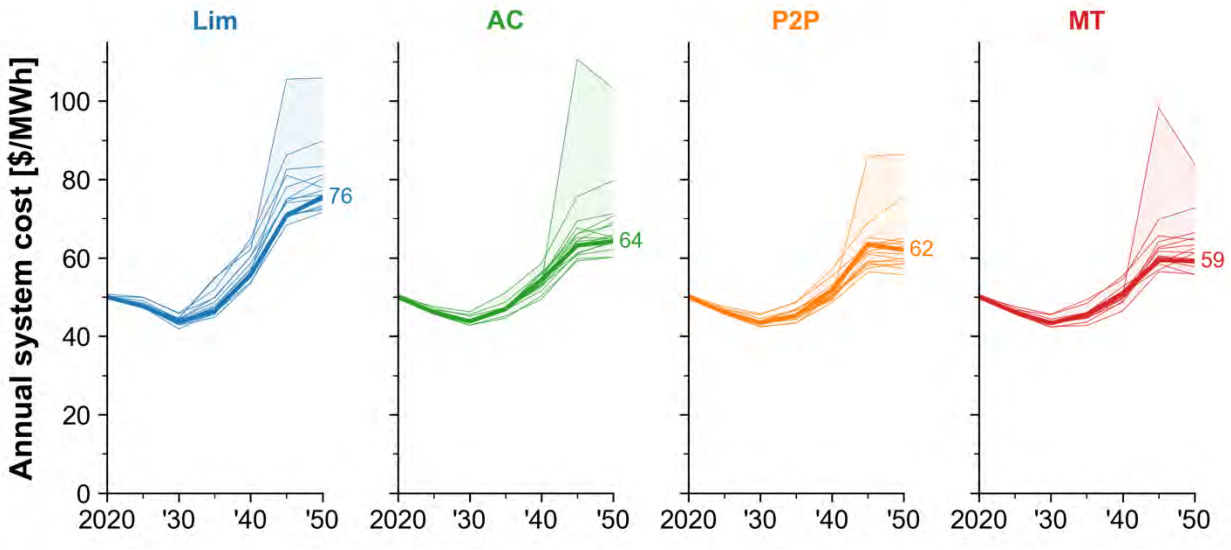


Figure D-13. Annual system cost ($/MWh) for the four transmission frameworks and all sensitivity cases under Mid-Demand 90% by 2035 conditions

Annual system cost is given by the sum of undiscounted annualized electricity system expenditures (fixed and operating) and tax credits, divided by annual end-use electricity demand (excluding induced demand from storage charging, H_2 production for use in H_2-CTs, and transmission losses).

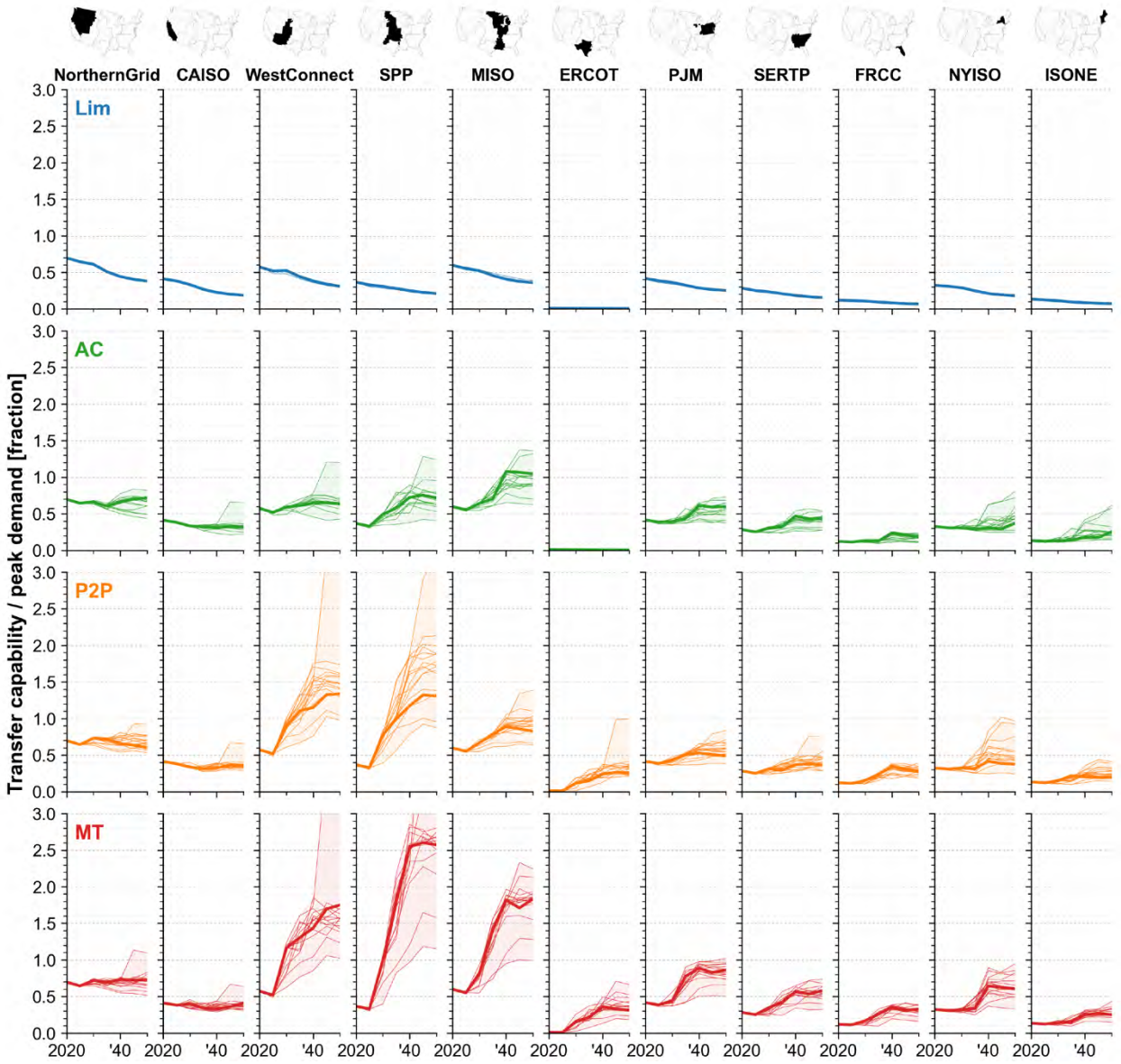


Figure D-14. Ratio of interregional transfer capability to peak demand for the 11 planning regions with Mid-Demand 90% by 2035 assumptions across the four transmission frameworks and all sensitivity cases

Interregional transfer capability for a given planning region is defined as the sum of import/export capacity between that planning region and other planning regions.

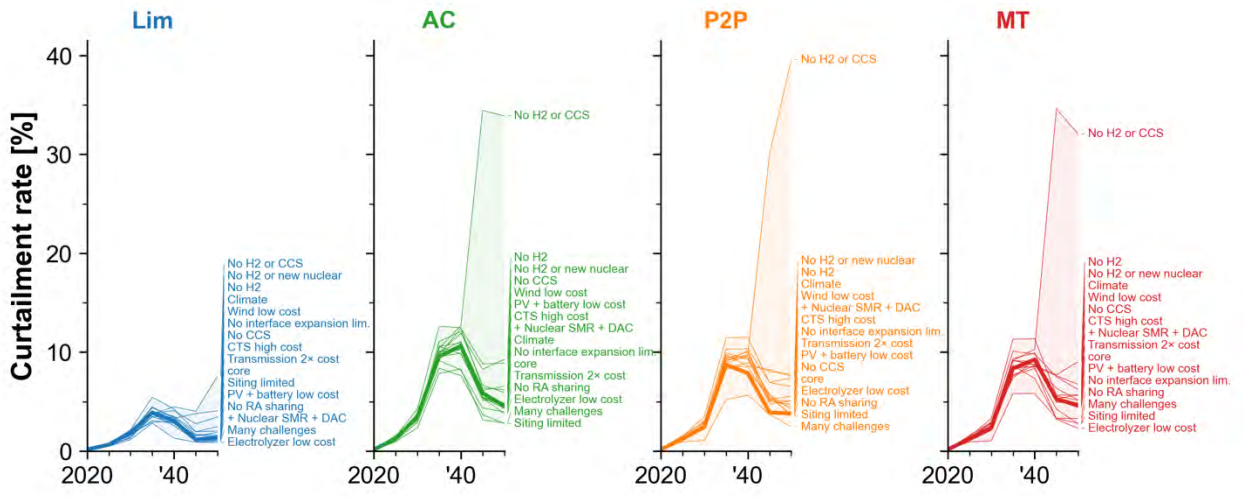


Figure D-15. National average VRE curtailment rate [$MWh_{curtailed}$ / $MWh_{available}$] with Mid-Demand 90% by 2035 assumptions for all sensitivity cases

D.3 Additional Resource Adequacy Results

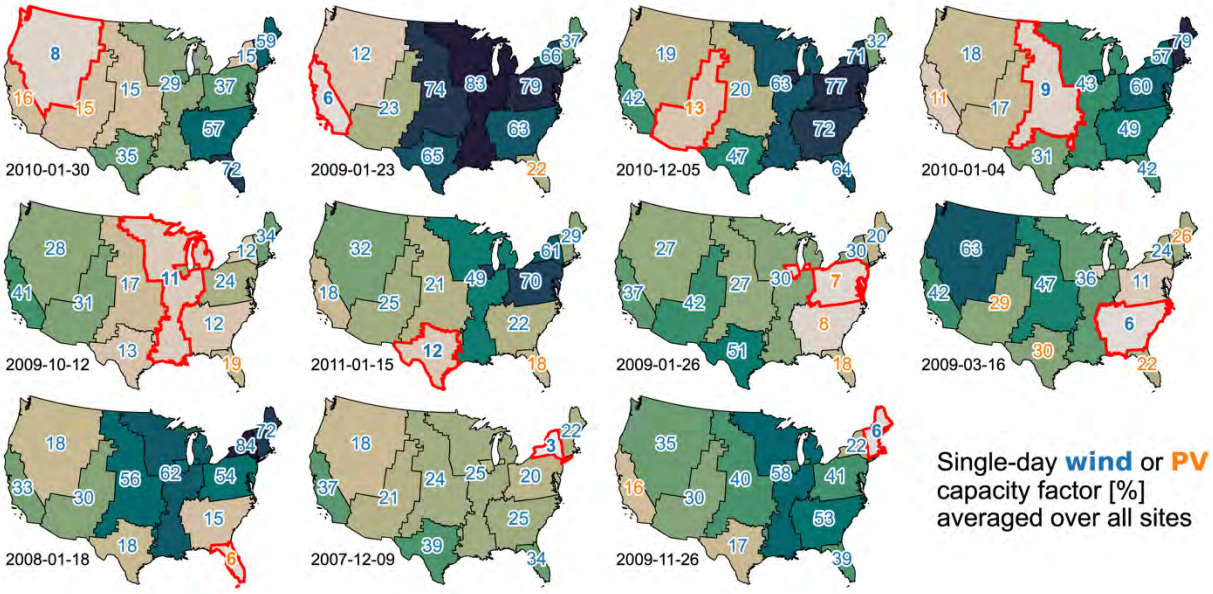


Figure D-16. Single-day wind (blue) or PV (orange) capacity factor on the least-windy/sunny day from 2007 to 2013 weather years in each planning region

For each map, the focused planning region is outlined in red, the date of the least-windy/sunny day in that region is given in the lower left, and the values and shading in each region represent the daily wind or PV capacity factor on that date, whichever is larger. (For example, on 2010-01-30, the wind capacity factor in NorthernGrid is 8% and the solar capacity factor is ≤8%; on the same day, the solar capacity factor in CAISO is 16%.) Planning region values are taken as the available-capacity-weighted average modeled capacity factor over all resource sites in the planning region. Capacity factors are modeled using the reV model as discussed in Appendix A.2. Most of these sites are never developed; if only developed or higher-quality resource sites in each planning region were included, the capacity factors would be higher than shown here.

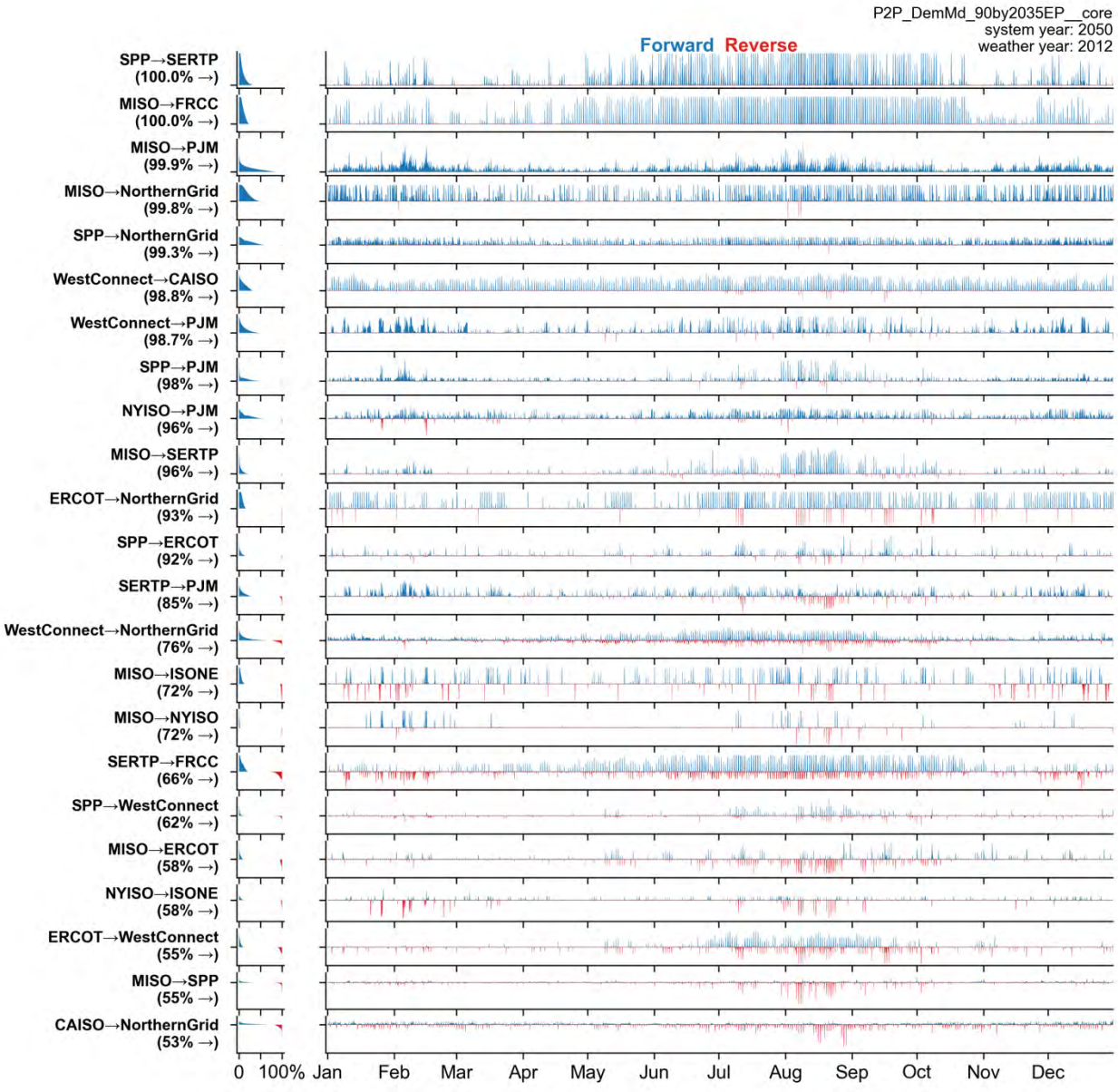


Figure D-17. Hourly interregional transmission flows for the P2P transmission framework in 2050 under Mid-Demand 90% by 2035 conditions as modeled by PRAS

Interfaces are labeled according to the predominant direction of flow. Flow in the predominant ("forward") direction is shown as positive blue values; flow in the "reverse" direction is shown as negative red values. Interfaces are sorted and labeled by the fraction of total flow in the "forward" direction on a MWh basis over the 7 weather years spanning 2007–2013. Distributions on the left include all weather years; hourly profiles on the right include only 2012 for clarity.

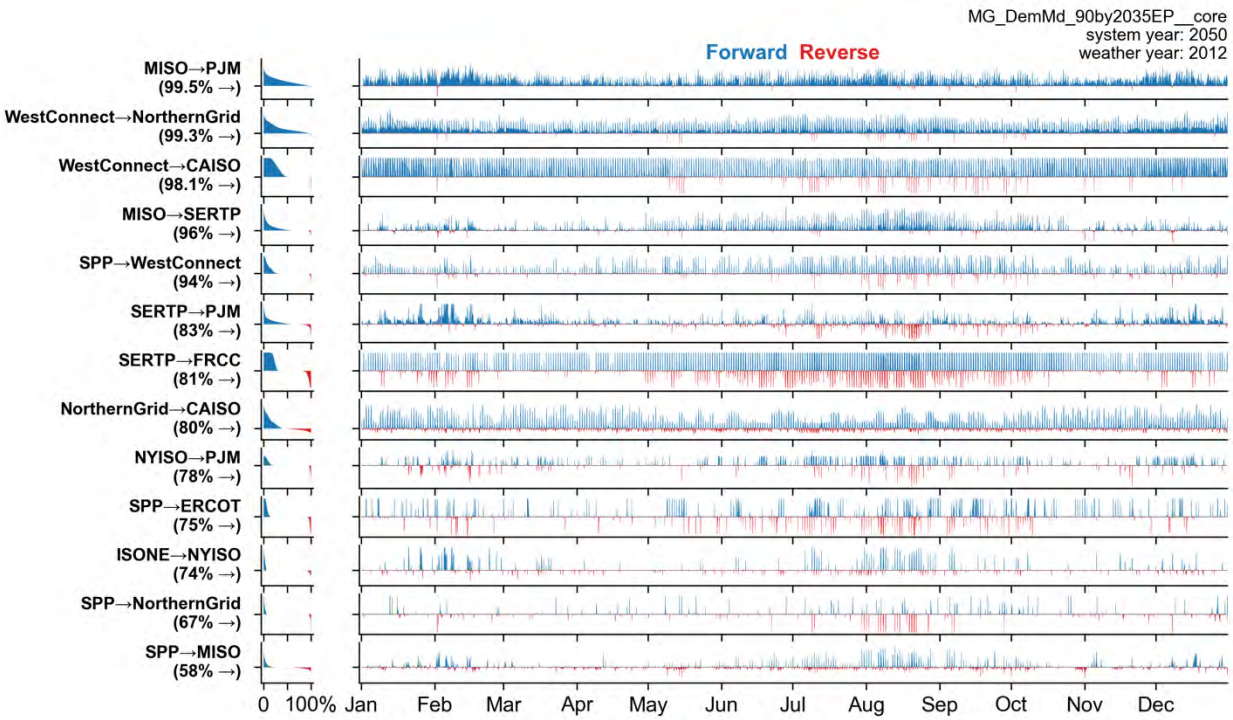


Figure D-18. Hourly interregional transmission flows for the MT transmission framework in 2050 under Mid-Demand 90% by 2035 conditions as modeled by PRAS

Data are presented in the same manner as Figure D-9.

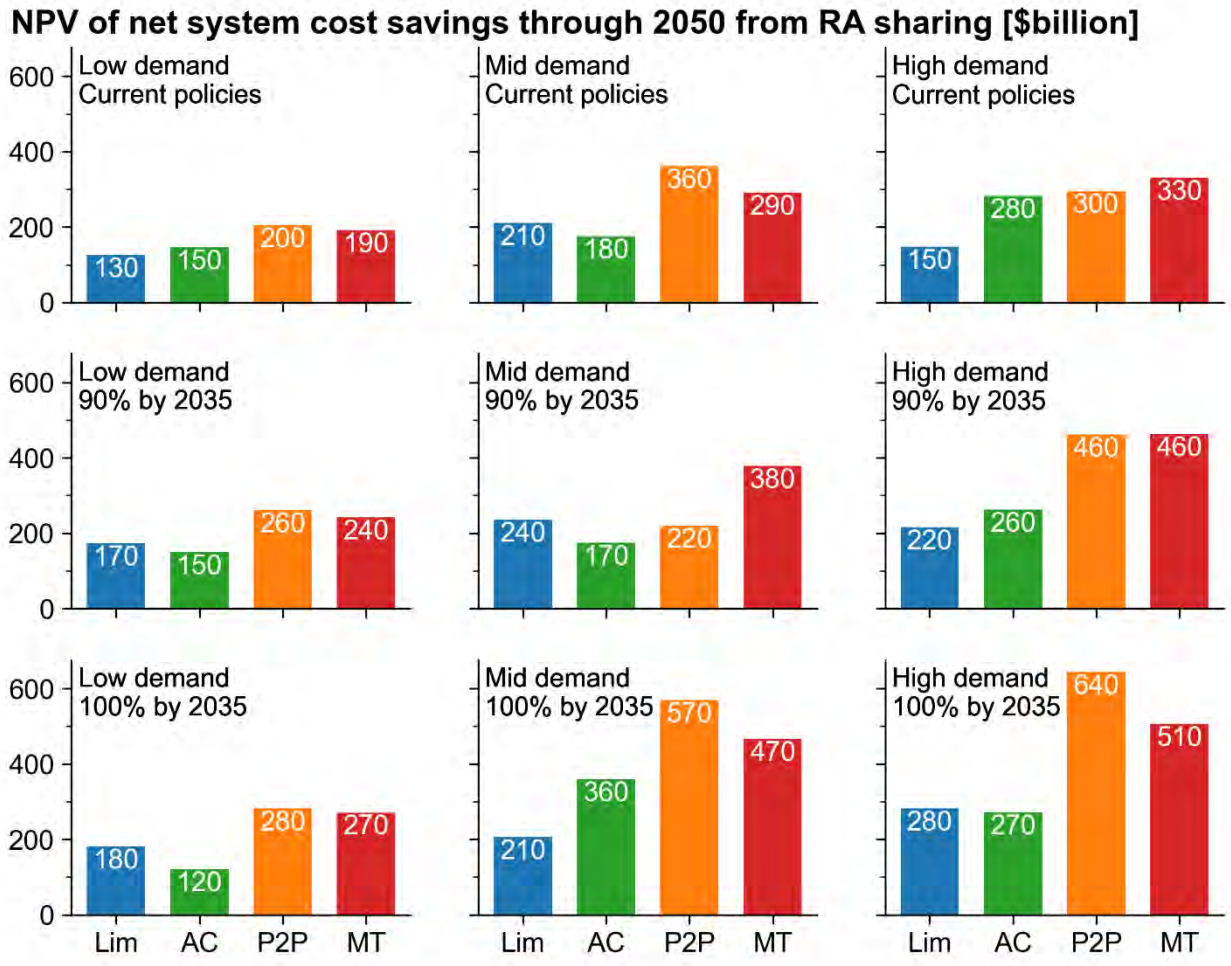


Figure D-19. Impact of the allowance of interregional RA sharing on system cost for each of the demand and emissions assumptions

Data are presented in the same manner as Figure 40a. The "No RA Sharing" sensitivity case was run for each set of demand and emissions assumptions to generate this figure.

D.4 Regional Economic Benefits

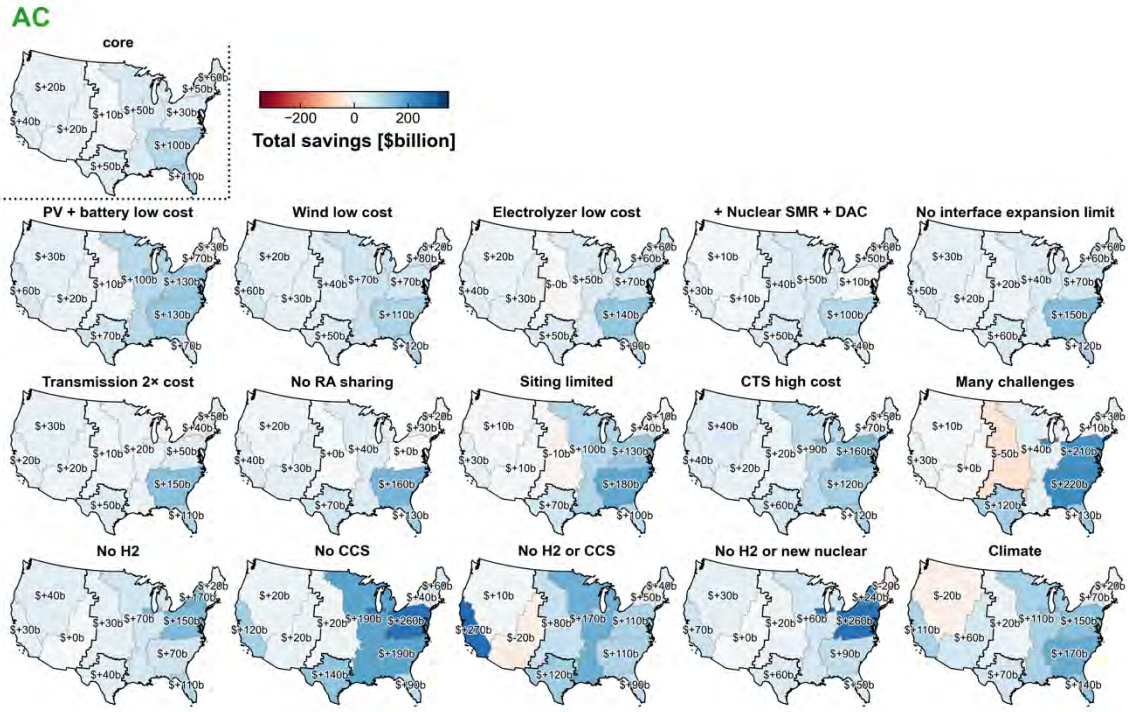


Figure D-20. Net present value of system savings in the AC transmission framework by region in $billion of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 scenario assumptions

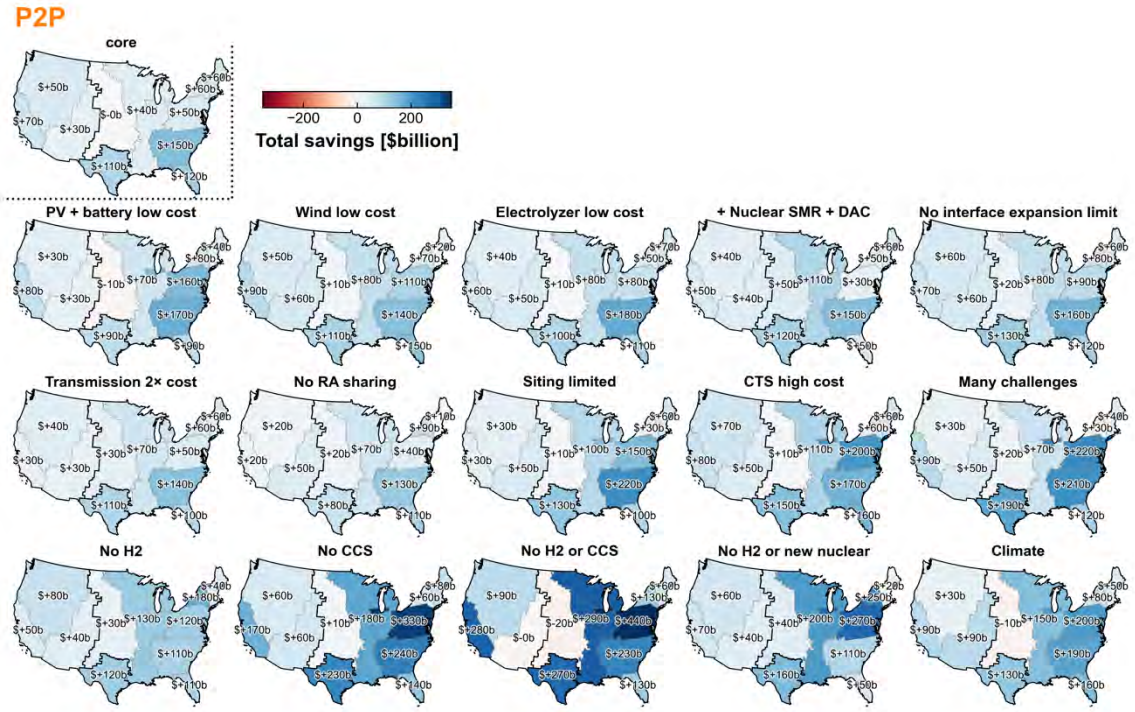


Figure D-21. Net present value of system savings in the P2P transmission framework by region in $billion of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 scenario assumptions

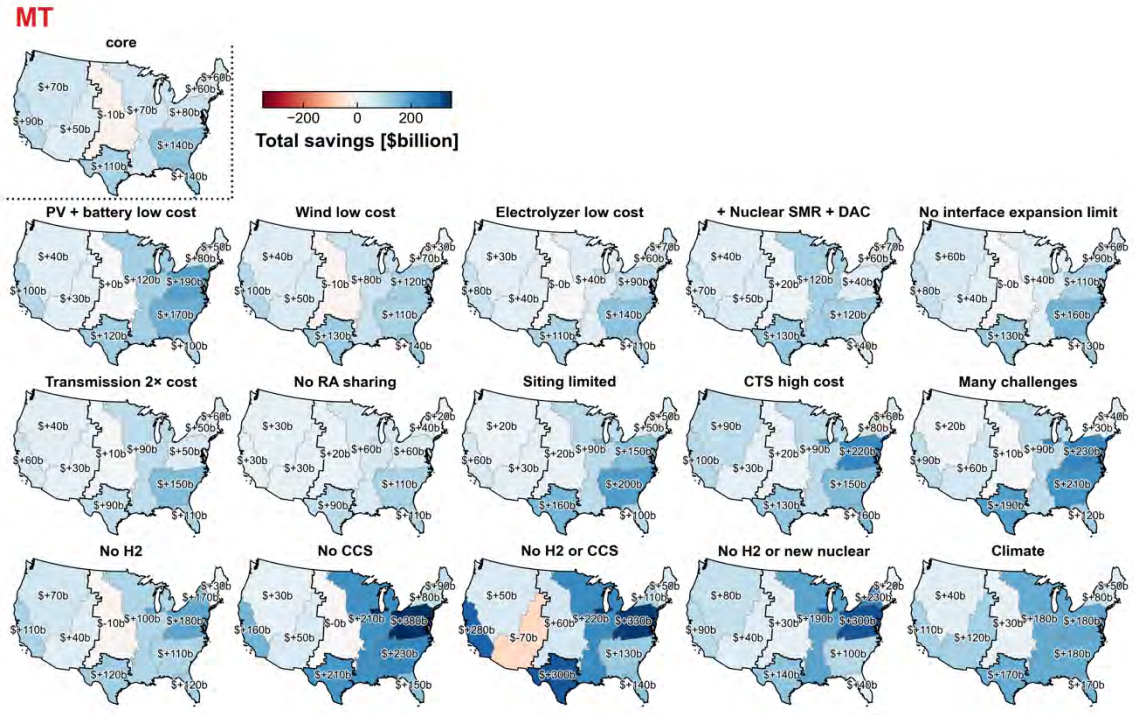


Figure D-22. Net present value of system savings in the MT transmission framework by region in $billion of avoided costs relative to the Limited framework under Mid-Demand 90% by 2035 scenario assumptions

Table D-1. Wind and Solar Capacity (GW) by State in the Core Mid-Demand 90% by 2035 Scenarios

	Land-based wind								Utility-scale solar							
	2035				2050				2035				2050			
	Lim	AC	P2P	MT	Lim	AC	P2P	MT	Lim	AC	P2P	MT	Lim	AC	P2P	MT
AL	3.7	8.6	7.3	12.4	8.1	12.6	24.3	16.8	3.2	23.2	17.1	16.5	18.3	50.5	31.1	43.6
AR	10.4	12.2	20.7	14.4	15.3	12.8	26.4	21.8	1.8	1.8	1.8	3.1	1.6	4.6	18	4.8
AZ	3.3	6.2	2.8	4.1	3.5	10.4	20.3	3.8	19.1	42.7	19	22.4	27.8	62.5	19.2	41
CA	7.5	8.1	7.8	8.9	8.9	12	12.2	10.3	28	32.5	33.5	33.6	25.7	40.5	46.1	47.9
CO	12.3	15.9	9.3	7.8	13.1	26.9	15	13.6	3.5	7.7	8.5	9.2	12	12.5	11.1	12.4
CT	0.6	0.7	0.7	0.7	0.6	1.3	1.1	1	0.5	0.5	0.5	0.5	0.3	0.3	0.3	0.3
DE	1.3	1.9	2.7	1.9	2.1	1.9	2.7	1.9	2.2	0.3	0.3	0.3	4.3	4.3	2.7	2.2
FL	3.2	17.7	12.2	6.7	3.6	27.4	15.6	17.7	18.2	56.8	54.1	44.5	35.8	103.7	82.8	74.8
GA	0	4.2	13.7	3.1	2.3	4.2	14.3	16.6	4.7	4.7	4.7	4.7	2.7	13.8	2.7	2.7
IA	15.9	13.4	16.1	13.4	19.2	7.7	15.3	40.6	2.3	6.9	0.3	0.3	2.3	6.9	1.9	7.6
ID	7.2	8.2	7.7	9.8	10.7	15.4	12.5	15.4	0.4	8.6	10.2	3.8	1.1	15.9	11.4	12.5
IL	18.5	22.2	17.7	16.8	24.9	19.5	31.9	39.7	9.3	11	5.8	5.3	11.9	10.9	7.8	10.2
IN	17.1	34.7	24.8	24.4	27.9	33.5	36.9	33	5.5	33.2	33	26.9	7.2	41.2	43.1	34.4
KS	10.6	14.9	18	13.1	11.5	14.9	19.4	19.7	2.8	22.1	26.4	19.4	5.3	26.4	30.6	31
KY	10.9	23.7	12.9	14.7	17.6	24.2	20.7	20.2	13.6	22.4	27	25.5	44.1	44.6	58.4	52
LA	9.3	17.9	18.3	17.9	14	23.9	29.1	25.6	7.5	7.7	4.9	4.4	13.1	18.1	8.4	10.2
MA	0.1	0.1	0.2	0.2	1.7	1	1.5	0.6	1.4	1.4	1.4	1.4	0.7	0.7	0.7	0.7
MD	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	3.9	3.1	3.1	3.1	5.8	5.4	5.5	5.4
ME	2.9	3.1	3.1	3.1	2.7	4.5	4.7	5.4	0.8	0.8	0.8	0.8	0.7	1.7	0.7	0.7
MI	22.3	38.8	52.3	38.8	26.1	73.9	53	46	5.6	10.2	2	4.7	9.7	34.3	8.9	9.8
MN	13.9	18.1	34.1	46.1	20.9	22.7	47.1	48.2	5.1	5.2	1.2	1.2	4.9	5.7	0.2	10.4
MO	15.9	19.8	23.6	16.2	29.8	30.6	27.3	61.2	15.4	10.6	6.2	8.5	21.8	11.2	17	9.7
MS	19.7	22.7	30.3	22.6	23.7	33.8	38.5	41.9	23.9	20.1	23.1	14	41.9	27	25.4	18.8
MT	7.9	7.2	5.5	9.4	10.2	10.9	6.4	9.5	0.9	1.2	1.9	0.8	1.3	1.2	3.3	2.8
NC	3.3	34.4	29.1	28.9	13.4	46.9	43.6	31.9	7.3	41.7	41.2	35.9	7.3	61.9	79.2	51.5
ND	11.9	13.5	24.7	36.3	13.6	37	28.3	46.2	0	6.4	0	0	0.7	11.4	12.6	13.3
NE	13.1	24.9	36.2	40.2	15.7	23.6	44.2	63.9	3	8.5	0.1	0.1	4.7	8.5	5	7.7
NH	0.2	0.5	0.5	0.5	2.2	4.3	2.3	4.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
NJ	0	0.7	1.8	0.7	0	0.7	1.8	0.7	1	1	1	1	0.6	0.6	0.6	0.6
NM	12.9	17.9	12.4	15.8	16.4	24.1	52.4	15	5.4	5.3	10.1	8.7	8.6	9.1	15.9	10.7
NV	0.2	0.4	0.4	0.4	0.3	4.2	2.7	2.5	8	21.5	17.2	17.6	27.9	25	20.9	20.6
NY	8.7	8.4	8.4	8.3	8.5	18.6	21.8	19.2	4.4	4.2	4.2	4.2	4.8	7.4	28.4	34.4
OH	9.7	20.4	19.3	10.9	30.2	20.3	30.2	10.5	4.4	4.6	4.4	4.4	8.4	4.5	4.4	4.4
OK	18.9	32.5	30.2	49.8	22.7	59.4	62.3	56.1	9.2	6.2	6.9	10.3	16.3	6.1	14.7	12.1
OR	9.1	9.7	10.8	5.4	8.5	12.2	11.9	16.3	1.6	1.6	1.6	1.6	2.8	8.4	5	1
PA	4.2	6.4	8.9	7.2	6.9	8.7	18.9	9	1.1	0.8	0.8	0.7	3.5	3.1	4.2	2.3
RI	0.9	0.8	0.8	0.8	1.2	1.2	1.2	1.2	0.3	0.3	0.3	0.3	3.3	3.4	1.4	2.4
SC	2.7	17.3	14.7	8.3	6.8	19.9	19.9	19.9	4.3	10.1	8.9	8.2	15.3	17.9	18	29.3
SD	3.3	9	9.7	14.4	5.2	8.3	13.7	16.8	0.3	0.1	0.1	0.1	1.3	0.1	0.9	0.8
TN	7.1	9.3	6.8	9.3	9.7	11.1	13.3	9.3	1.2	2.6	8.2	1.9	1.1	2.5	20.1	1.8
TX	88.9	109.6	128	136.6	110.2	147.9	164.3	175	66.8	116.1	96.1	109	120.7	159.4	163.5	190.2
UT	0.7	1	0.9	0.9	0.9	2.4	2	0.8	2.9	2.8	2.8	2.8	6.8	9.5	6.5	1.8
VA	5.7	18.9	24	16.4	14.6	21.6	29.6	30.8	16.5	21.7	20.8	10.8	35.6	36.3	45	17.8
VT	0.5	1	1.2	0.7	3.4	4.9	2.5	2.7	0.2	0.2	0.2	0.2	0.1	4.3	0.1	0.1
WA	10.4	15.4	12.3	15.1	13.6	26.7	29.7	19.4	0.4	0.4	0.4	0.4	13.1	0.6	7.2	6.2
WI	17.5	13.6	18.6	13.8	23.5	39.2	19.1	17	4.5	9.4	2.3	2.3	18.1	14.3	15	11
WV	0.9	0.9	0.9	0.9	3.4	0.7	0.7	0.4	0	0	0	0	0	0	0	0
WY	19	26.3	35	41.9	20.6	43	42.9	48.8	2.3	0.1	1.1	0.6	6.7	0	2.2	5.6

Appendix E. Transmission Value Analysis

The economic analysis presented here identifies and evaluates quantifiable benefits associated with transmission development across NTP Study zonal planning and operational analysis. The following sections outline the overall approach to quantify and regionally disaggregate the benefits of transmission applied to the NTP zonal scenarios.

E.1 Multivalue

This analysis considers a broad range of transmission benefits including reduced capital and operating costs, reduced cost of meeting reliability requirements, and increased capture of federal and state incentives. Using outputs from the zonal production cost model, the economic analysis includes six categories of transmission benefits (Figure 42). Annualized savings for capital investments are based on the equivalent annual cost assuming a 1.7% discount rate. Transmission assets are assumed to have a 40-year asset life; all other technologies are assumed to have a 20-year asset life.

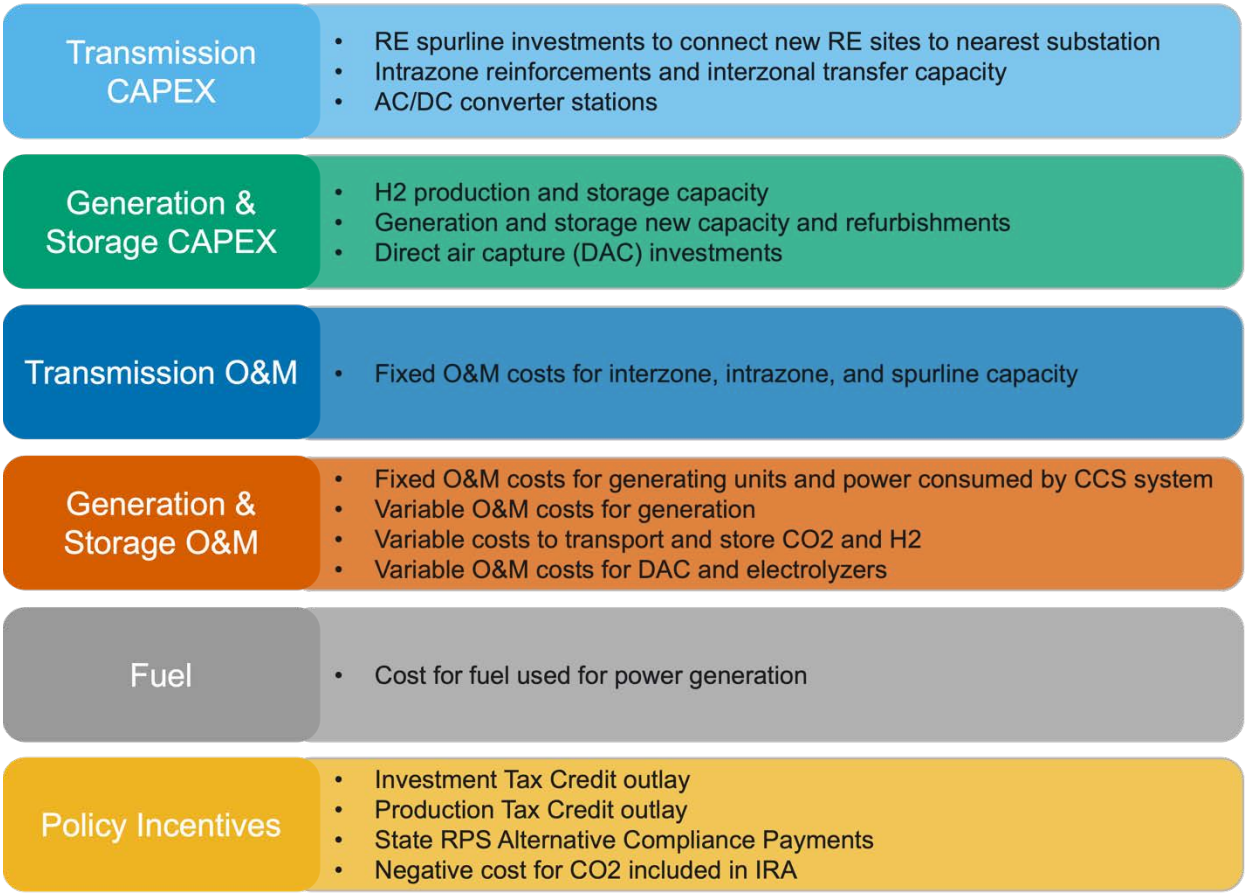


Figure E-1. System costs included in transmission valuation. Many benefits are correlated and not mutually exclusive.

E.2 System Perspective

The NTP Study evaluates transmission investments and operations across the entire contiguous United States. The economic analysis evaluates the value of transmission across this entire system as well as to a given region (e.g., ISONE, NYISO, CAISO). The analysis does not disaggregate the benefits experienced by different types of network users within each region (e.g., generators, consumers). In addition, no assumptions about how transmission cost recovery is allocated within a region or among customer classes are made.

E.3 Project Scope

This analysis evaluates the net benefits for the portfolio of transmission investments identified in NTP Study accelerated transmission frameworks rather than evaluating individual projects or transmission corridors. This approach reflects planning processes in place, such as MISO's multivalue project process that evaluates bundles of projects. It also aligns with the NTP Study approach, in which transmission investments and system operations are optimized on a multiregion scale. To isolate the impact of specific types of transmission development, the reference scenario (Limited) is compared with alternative "change" cases (AC, P2P, MT) that represent different types of transmission development.

E.4 Planning Horizon

The analysis considers an almost 30-year planning horizon, covering the period 2022–2050.[53] This extended planning horizon will inform how the benefits of transmission change over time as the underlying power system changes. It is also aligned with guidance under consideration by FERC to consider system needs and changes 20+ years in the future for transmission planning.

E.5 Uncertainty

The transmission valuation captures a range of possible future outcomes, drawing from the broad set of NTP Study sensitivity cases including macroeconomic drivers such as technology prices and availability as well as a range of system states such as different weather conditions. This analysis uses scenario-based comparisons to capture uncertainty system costs across a range of system futures.

E.6 Regional Disaggregation: Adjusted Production Cost

As interregional transmission enables more coordinated operation of low-cost generation resources, the distribution of operating costs within each region changes. For systemwide analysis, operating costs comprise variable operation and maintenance, fuel, and startup and shutdown. These metrics are sufficient to evaluate the change in operating costs for the entire system but, when evaluating the benefit distribution among regions, a further consideration is needed to capture the

[53] 2030 is the first year in which new interregional transmission can be commissioned in the NTP Study modeling.

transmission benefits of interregional trade to each region. The adjusted production cost (APC) metric is used to evaluate these benefits. The APC is the difference in total production costs adjusted for import costs and export revenues with and without a proposed transmission upgrade. This metric is used among independent system operators/regional transmission operators in the United States for transmission valuation and cost allocation including SPP, MISO, and PJM and is defined as follows:

$$\text{APC} = \text{Production Cost} + \text{Purchase Costs} - \text{Generator Revenue}$$

where

$$\text{Purchase Costs} = (\text{Hourly Consumer Load} + \text{Storage Charging} + \text{Imports}) \times \text{Locational Marginal Price}$$

$$\text{Generator Revenue} = \text{Hourly Generation} \times \text{Locational Marginal Price}$$

A key benefit of the APC when trying to disaggregate transmission benefits is that it does not strictly rely on the physical location where costs are incurred to estimate costs and benefits. As a simple example, a new transmission upgrade may enable the development of low-cost generation capacity in one region (Region A) that can serve additional load in a neighboring region (Region B). Strictly looking at where costs are occurring, the new transmission line will increase capital and operating costs in Region A because it is building more capacity and generating more. By contrast, capital and operating costs will decrease in Region B because it is building less capacity and relying on imports to meet its load. However, Region A is also benefiting through increased sales of power to its neighbors. In addition, Region B is not getting these imports for free; it incurs some cost to purchase imported energy. By including an adjustment for import costs and export revenues, the APC can capture these benefits. Figure E-1 shows the production cost adjustment (change in purchase cost – generator revenue) added to the transmission value for each region and topology for the core Mid-Demand 90% by 2035 scenarios.[54]

[54] For this study, the adjusted production cost is based on zonal marginal prices from the capacity expansion model based on the marginal price of meeting capacity, energy, and policy requirements in each balancing area. The capacity expansion model represents each modeled year with 33 representative days at 4-hr resolution, for a total of 198 modeled hours. Further study with full 8,760 hourly resolution at a nodal resolution can be used to refine the estimated adjusted production cost for each region.

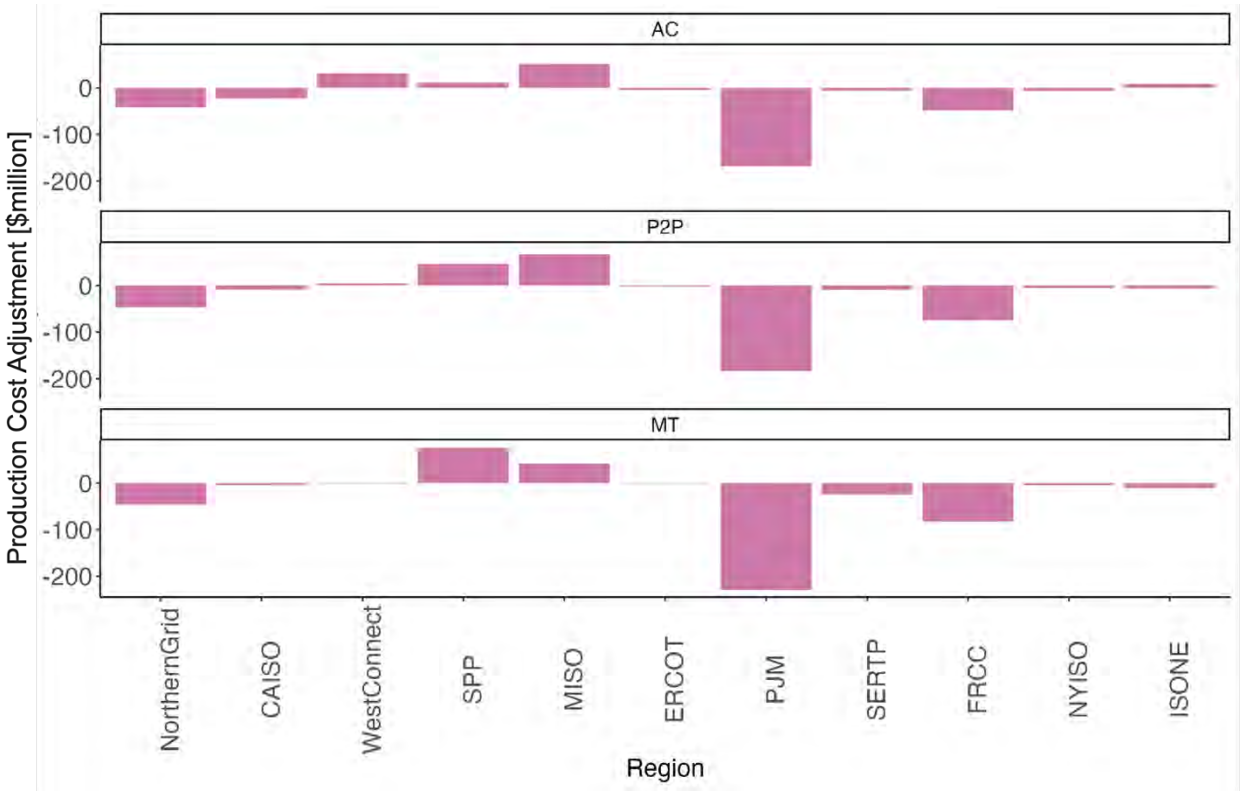


Figure E-2. Production cost adjustment for each transmission planning region and network topology for the core Mid-Demand 90% by 2035 scenarios ($million)

Appendix F. High Opportunity Transmission Interfaces: Regional Detail

The High Opportunity Transmission (HOT) analysis highlights robustly chosen transmission expansion opportunities for each of the 11 planning regions and each of the AC, P2P, MT transmission frameworks. The following maps show the interfaces with nearby planning regions and the 25th percentile of new transmission capacity built across those interfaces in the 16 sensitivity cases. These are the same data as shown in the national maps in the Text Box in Section 3.3 but provide a more granular view of transmission expansion in that planning region. The tables accompanying the maps show the 25th percentile as well as the 50th and 75th percentile results to inform more ambitious transmission development opportunities. Also included in the tables is the amount of existing transmission capacity across that interface. The interfaces are color coordinated to identify them in the table and map and across the other transmission framework maps. Three maps and associated tables are shown for each region showing the AC, P2P, and MT frameworks in that order. Some regions are grouped together when they have common borders (e.g., SERTP and FRCC; NYISO and ISONE).



CAISO

AC Framework

Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
Northern Grid S.	11	0.1	0.7	1.4
West Connect S.	5.3	3.6	4.0	4.7



P2P Framework

Interface Capacity (GW)

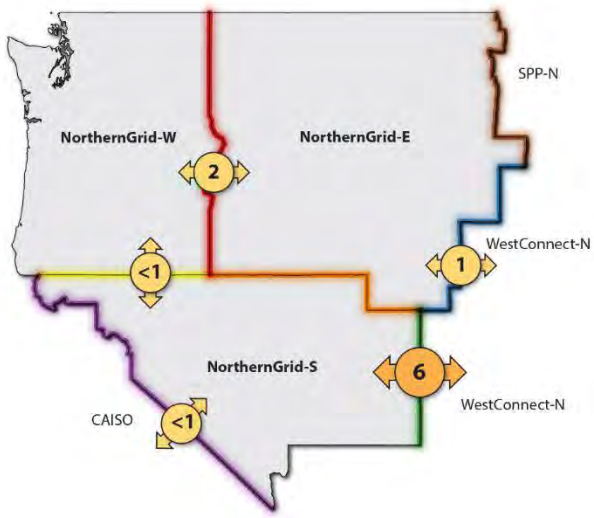
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
Northern Grid S.	11	0	0.1	0.4
West Connect S.	5.3	3.0	4.1	4.9



MT Framework

Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
Northern Grid S.	11	0	0.4	0.6
West Connect S.	5.3	6.2	6.8	9.1

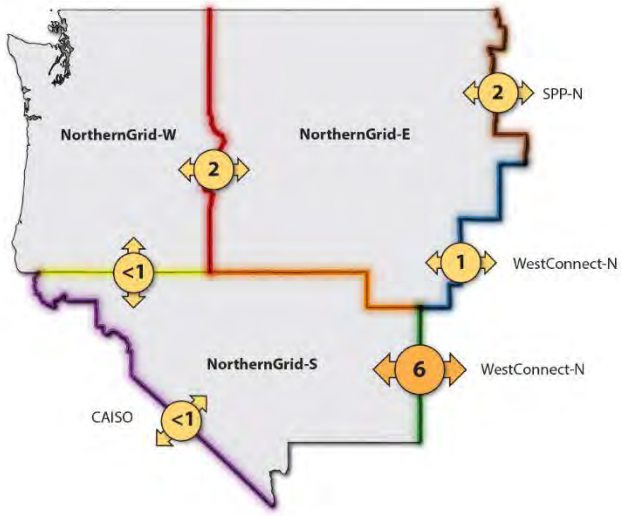


NorthernGrid

AC Framework

Interface Capacity (GW)

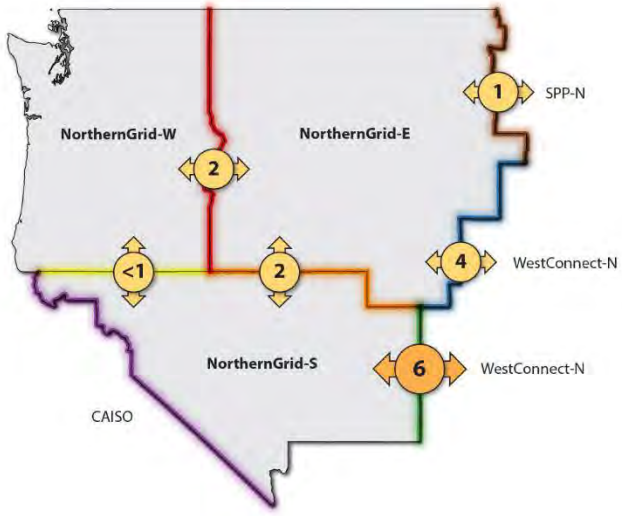
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
NG-W, NG-E	13.2	1.7	1.7	1.7
NG-E, SPP-N	0.2	0	0	0
NG-E, WC-N	4.0	1.1	1.2	1.8
NG-E, NG-S	3.1	0	0	0.6
NG-W, NG-S	0.5	0.1	0.4	1.2
NG-S, WC-N	2.4	6.3	7.1	7.2
NG-S, CAISO	11	0.1	0.7	1.4



P2P Framework

Interface Capacity (GW)

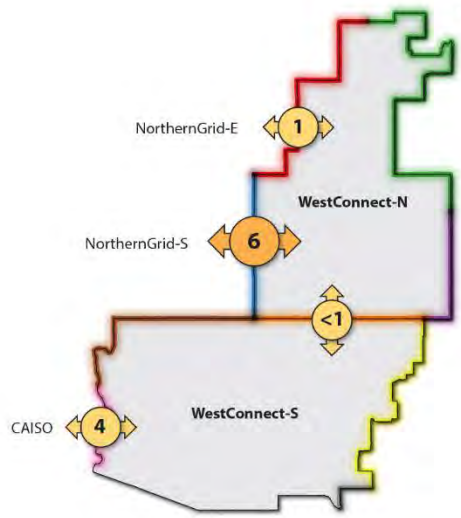
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
NG-W, NG-E	13.2	1.7	1.7	1.7
NG-E, SPP-N	0.2	1.8	2.2	2.5
NG-E, WC-N	4.0	1.4	2.1	2.5
NG-E, NG-S	3.1	0	0	0
NG-W, NG-S	0.5	0.1	0.3	0.5
NG-S, WC-N	2.4	5.8	7.0	7.9
NG-S, CAISO	11	0.1	0.4	0.3



MT Framework

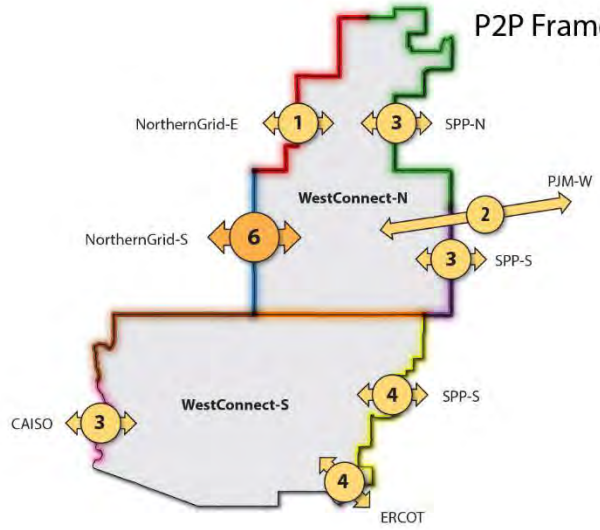
Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
NG-W, NG-E	13.2	1.7	1.7	1.7
NG-E, SPP-N	0.2	1.2	1.8	2.1
NG-E, WC-N	4.0	3.9	5.0	5.7
NG-E, NG-S	3.1	2.0	2.6	3.9
NG-W, NG-S	0.5	0.2	0.5	1.2
NG-S, WC-N	2.4	6.0	6.4	6.7
NG-S, CAISO	11	0	0.4	0.6



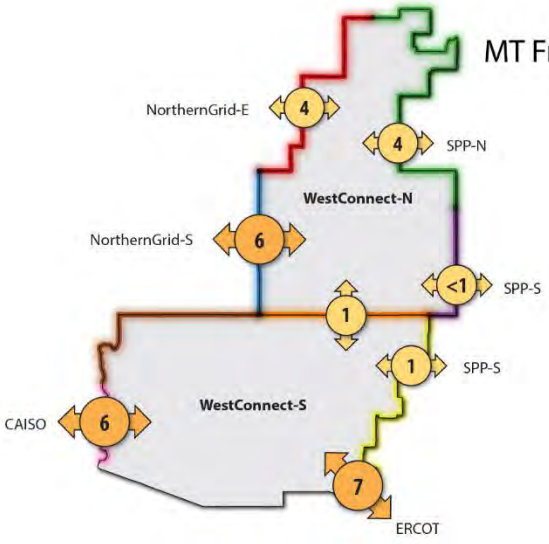
Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
WC-N, NG-E	4.0	1.1	1.2	1.8
WC-N, NG-S	2.4	6.3	7.1	7.2
WC-N, SPP-N	0.5	0	0	0
WC-N, SPP-S	0.2	0	0	0
WC-N, WC-S	1.4	0.1	0.7	0.8
WC-S, NG-S	7.3	0	0	0
WC-S, SPP-S	0.4	0	0	0
WC-S, ERCOT	0	0	0	0
WC-S, CAISO	5.3	3.6	4.0	4.7



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
WC-N, NG-E	4.0	1.4	2.1	2.5
WC-N, NG-S	2.4	5.8	7.0	7.9
WC-N, SPP-N	0.5	2.6	3.1	3.9
WC-N, SPP-S	0.2	2.7	3.1	3.9
WC-N, WC-S	1.4	0	0.1	0.3
WC-S, NG-S	7.3	0	0	0
WC-S, SPP-S	0.4	4.2	5.7	6.5
WC-S, ERCOT	0	4.1	5.7	7.3
WC-S, CAISO	5.3	3.0	4.1	4.9

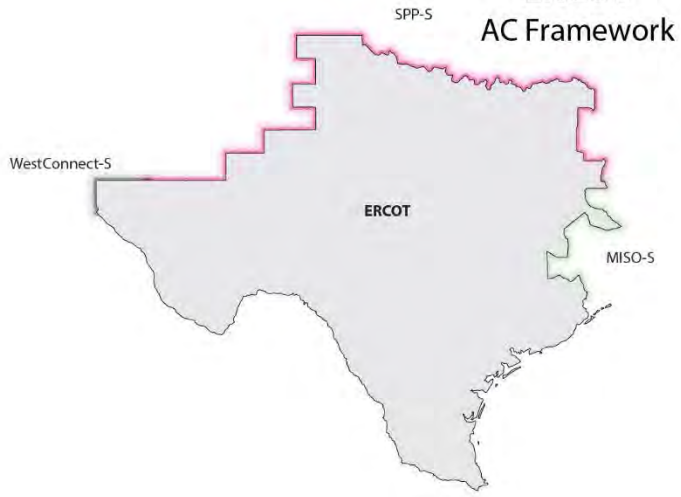


Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
WC-N, NG-E	4.0	3.9	5.0	5.7
WC-N, NG-S	2.4	6.0	6.4	6.7
WC-N, SPP-N	0.5	3.9	5.4	6.6
WC-N, SPP-S	0.2	0.5	0.9	1.5
WC-N, WC-S	1.4	1.0	1.6	2.4
WC-S, NG-S	7.3	0	0	0
WC-S, SPP-S	0.4	1.4	1.9	3.7
WC-S, ERCOT	0	6.5	7.1	9.5
WC-S, CAISO	5.3	6.2	6.8	9.1

ERCOT

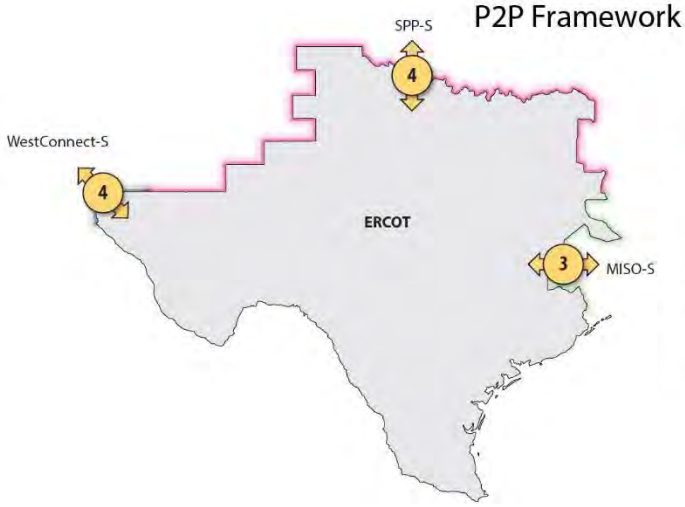
AC Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
ERCOT, SPP-S	0.8	**0**	0	0
ERCOT, WC-S	0	**0**	0	0
ERCOT, MISO-S	0	**0**	0	0

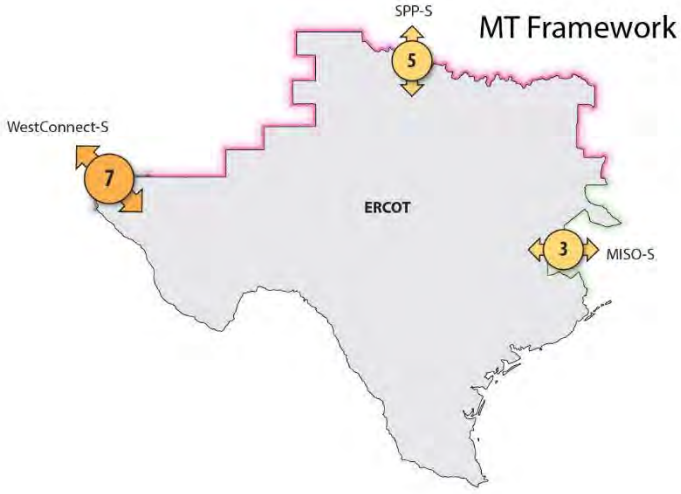
P2P Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
ERCOT, SPP-S	0.8	**4.1**	5.1	5.7
ERCOT, WC-S	0	**4.1**	5.7	7.3
ERCOT, MISO-S	0	**3.3**	4.4	4.9
Nonadjacent Region Interfaces				
ERCOT, MISO-N	0	**0**	0.2	1.3
ERCOT, NG-S	0	**0**	0	0.4
ERCOT, SPP-N	0	**0**	0	0.2
ERCOT, WC-N	0	**0**	0	0.3

MT Framework

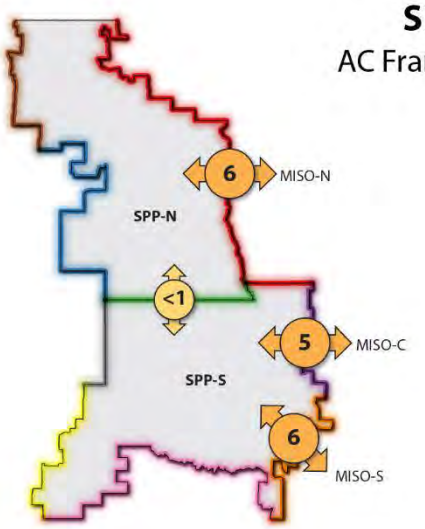


Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
ERCOT, SPP-S	0.8	**4.9**	6.3	12
ERCOT, WC-S	0	**6.5**	7.1	9.5
ERCOT, MISO-S	0	**2.6**	3.7	4.6

SPP

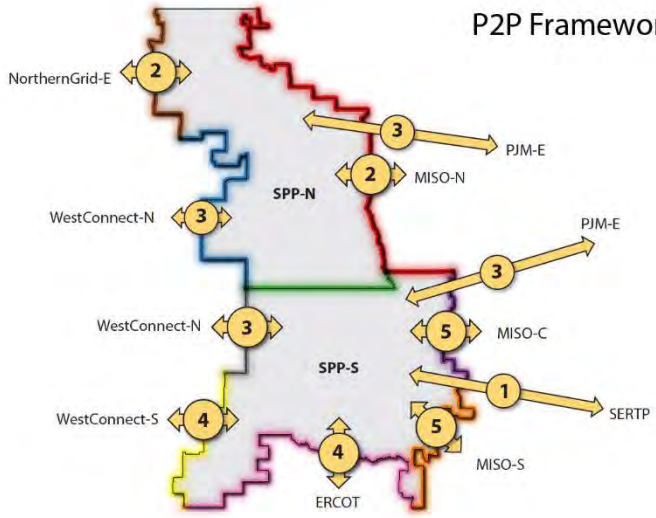
AC Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
SPP-N, NG-E	0.2	0	0	0
SPP-N, MISO-N	10.0	6.0	7.6	9.4
SPP-N, WC-N	0.5	0	0	0
SPP-N, SPP-S	5.4	0.2	0.3	0.4
SPP-S, MISO-C	2.0	4.7	6.0	6.0
SPP-S, MISO-S	3.3	5.8	6.4	7.0
SPP-S, WC-N	0.2	0	0	0
SPP-S, WC-S	0.4	0	0	0
SPP-S, ERCOT	0.8	0	0	0

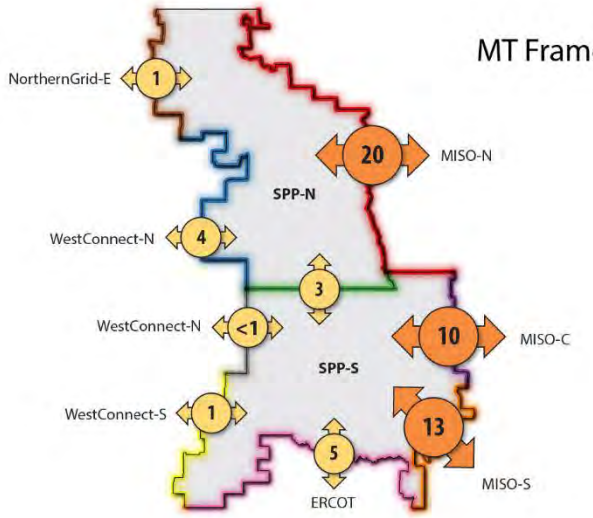
P2P Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
SPP-N, NG-E	0.2	1.8	2.2	2.5
SPP-N, MISO-N	10.0	1.7	2.6	3.8
SPP-N, WC-N	0.5	2.6	3.1	3.9
SPP-N, SPP-S	5.4	0	0.2	0.7
SPP-S, MISO-C	2.0	4.8	5.6	5.8
SPP-S, MISO-S	3.3	4.5	5.5	6.3
SPP-S, WC-N	0.2	2.7	3.1	3.9
SPP-S, WC-S	0.4	4.2	5.7	6.5
SPP-S, ERCOT	0.8	4.1	5.1	5.7
Nonadjacent Region Interfaces				
SPP-N, PJM-E	0	3.4	5.2	10
SPP-S, PJM-E	0	3.3	4.7	7.1
SPP-S, SRTP	0	1.0	2.5	4.6

MT Framework

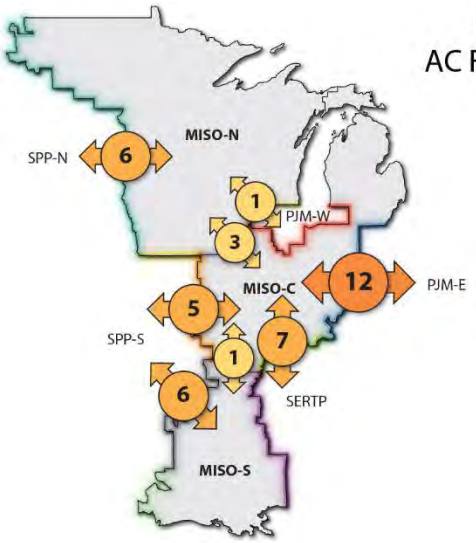


Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
SPP-N, NG-E	0.2	1.2	1.8	2.1
SPP-N, MISO-N	10.0	20.3	24.8	27.8
SPP-N, WC-N	0.5	3.9	5.4	6.6
SPP-N, SPP-S	5.4	3.4	5.8	7.5
SPP-S, MISO-C	2.0	9.9	13.8	16.8
SPP-S, MISO-S	3.3	12.6	16.5	18.1
SPP-S, WC-N	0.2	0.5	0.9	1.5
SPP-S, WC-S	0.4	1.4	1.9	3.7
SPP-S, ERCOT	0.8	4.9	6.3	12.0

MISO

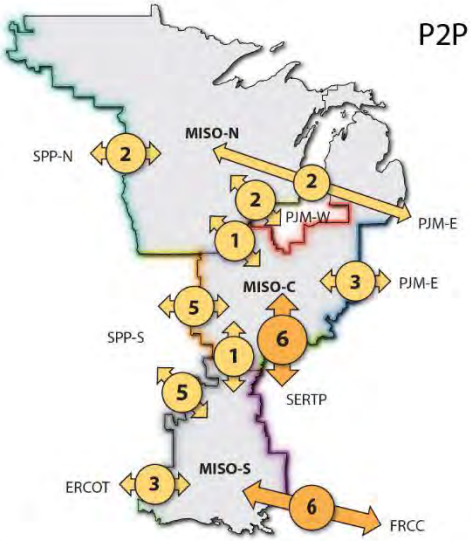
AC Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
MISO-N, SPP-N	10.0	6.0	7.6	9.4
MISO-N, PJM-W	5.0	1.4	2.9	4.9
MISO-N, MISO-C	5.5	2.6	4.3	5.1
MISO-C, PJM-W	15.1	0	0.7	1.0
MISO-N, SPP-S	1.1	0	0	0
MISO-C, PJM-E	28.3	11.7	14.4	16.1
MISO-C, SPP-S	2.0	4.7	6.0	6.0
MISO-C, SERTP	4.1	7.5	10.1	12.2
MISO-C, MISO-S	2.1	1.4	1.8	2.3
MISO-S, SPP-S	3.3	5.8	6.4	7.0
MISO-S, SERTP	11.0	0	0	0.1
MISO-S, ERCOT	0	0	0	0

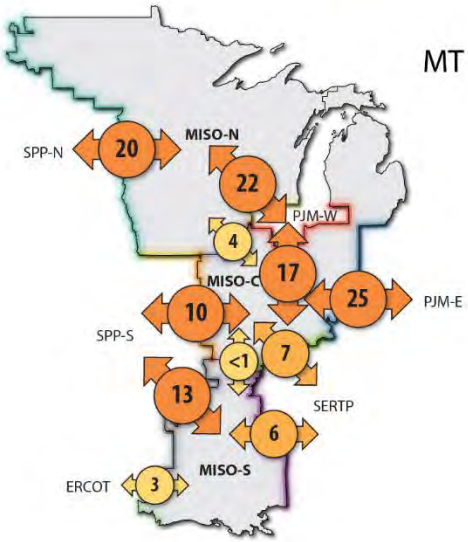
P2P Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
MISO-N, SPP-N	10.0	1.7	2.6	3.8
MISO-N, PJM-W	5.0	1.5	2.0	3.4
MISO-N, MISO-C	5.5	1.0	1.8	4.3
MISO-C, PJM-W	15.1	0	0	0
MISO-N, SPP-S	1.1	0	0	0
MISO-C, PJM-E	28.3	2.6	4.7	7.9
MISO-C, SPP-S	2.0	4.8	5.6	5.8
MISO-C, SERTP	4.1	5.6	6.8	7.7
MISO-C, MISO-S	2.1	1.2	1.8	2.7
MISO-S, SPP-S	3.3	4.5	5.5	6.3
MISO-S, SERTP	11.0	0	0	0
MISO-S, ERCOT	0	3.3	4.4	4.9
Nonadjacent Region Interfaces MISO-N, PJM-E	0	2.0	4.4	7.1
MISO-S, FRCC	0	6.2	7.3	8.6

MT Framework

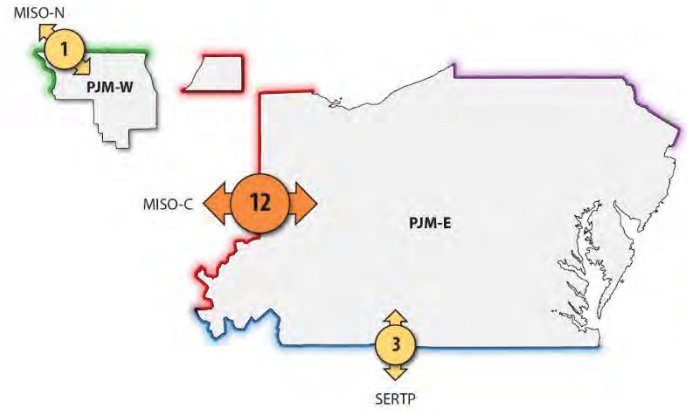


Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
MISO-N, SPP-N	10.0	20.3	24.8	27.8
MISO-N, PJM-W	5.0	21.8	23.4	27.5
MISO-N, MISO-C	5.5	3.8	5.0	5.5
MISO-C, PJM-W	15.1	16.5	19.7	22.8
MISO-N, SPP-S	1.1	0	0	0.1
MISO-C, PJM-E	28.3	24.7	28.0	32.6
MISO-C, SPP-S	2.0	9.9	13.8	16.8
MISO-C, SERTP	4.1	7.2	9.3	12.5
MISO-C, MISO-S	2.1	0.7	1.3	2.3
MISO-S, SPP-S	3.3	12.6	16.5	18.1
MISO-S, SERTP	11.0	5.8	9.7	11.1
MISO-S, ERCOT	0	2.6	3.7	4.6

PJM

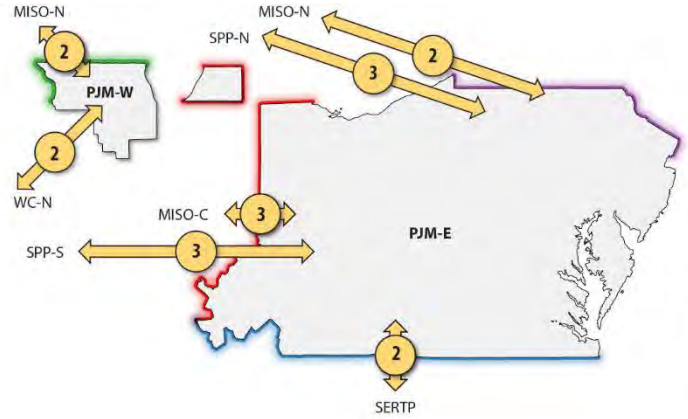
AC Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
PJM-W, MISO-N	5.0	1.4	2.9	4.9
PJM-E, MISO-C	28.3	11.7	14.4	16.1
PJM-E, SERTP	10.9	3.2	6.8	7.4
PJM-E, NYISO	6.6	0	0	0

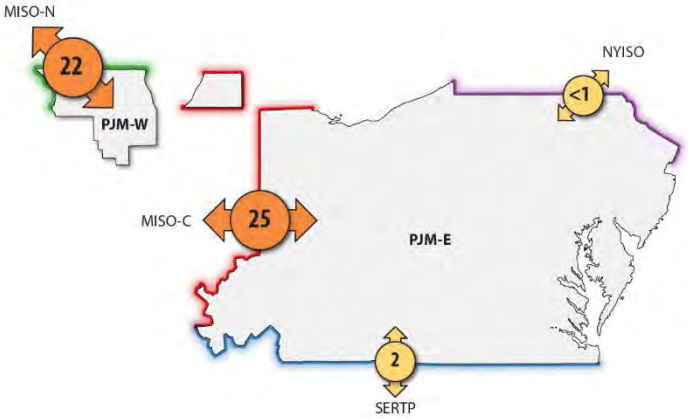
P2P Framework



Interface Capacity (GW)

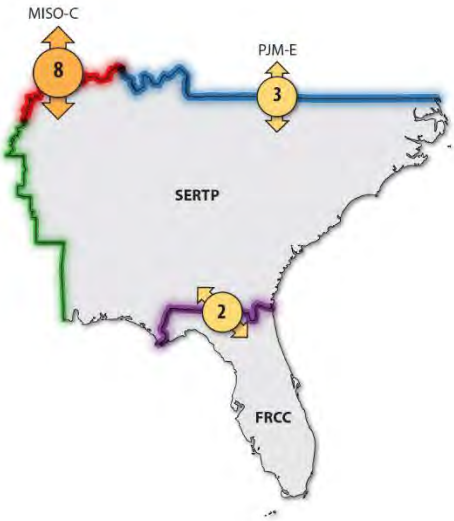
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
PJM-W, MISO-N	5.0	1.5	2.0	3.4
PJM-E, MISO-C	28.3	2.6	4.7	7.9
PJM-E, SERTP	10.9	2.2	5.0	6.3
PJM-E, NYISO	6.6	0	0	0
Nonadjacent Region Interfaces				
PJM-E, MISO-N	0	2.0	4.4	7.1
PJM-E, SPP-N	0	3.4	5.2	10.0
PJM-E, SPP-S	0	3.3	4.7	7.1
PJM-W, WC-N	0	2.2	3.1	4.9

MT Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
PJM-W, MISO-N	5.0	21.8	23.4	27.5
PJM-E, MISO-C	28.3	24.7	28.0	32.6
PJM-E, SERTP	10.9	1.6	3.8	5.7
PJM-E, NYISO	6.6	0.9	2.4	3.7

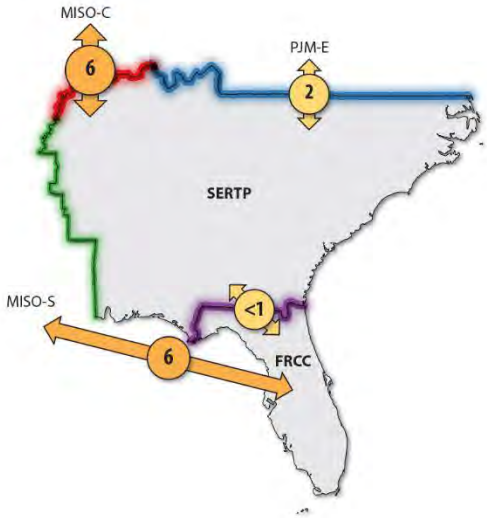


SERTP & FRCC

AC Framework

Interface Capacity (GW)

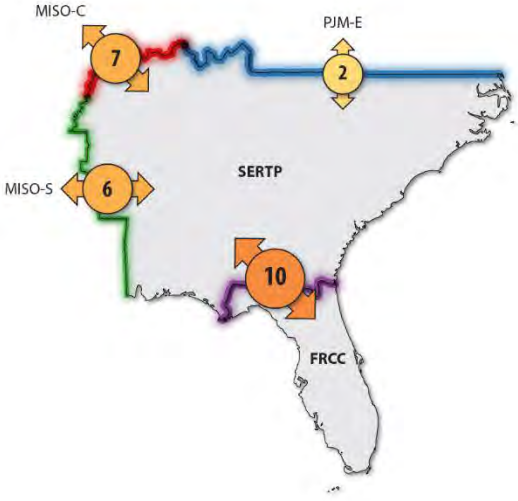
REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
SERTP, MISO-C	4.1	7.5	10.1	12.2
SERTP, PJM-E	10.9	3.2	6.8	7.4
SERTP, MISO-S	11.0	0	0	0.1
SERTP, FRCC	6.6	1.9	2.3	2.6



P2P Framework

Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
SERTP, MISO-C	4.1	5.6	6.8	7.7
SERTP, PJM-E	10.9	2.2	5.0	6.3
SERTP, MISO-S	11.0	0	0	0
SERTP, FRCC	6.6	0.1	0.8	1.7
Nonadjacent Region Interfaces				
FRCC, MISO-S	6.9	6.2	7.3	8.6



MT Framework

Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
SERTP, MISO-C	4.1	7.2	9.3	12.5
SERTP, PJM-E	10.9	1.6	3.8	5.7
SERTP, MISO-S	11.0	5.8	9.7	11.1
SERTP, FRCC	6.6	10.1	11.7	12.4

NYISO & ISONE

AC Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
NYISO, ISONE	3.5	**1.7**	1.8	2.5
NYISO, PJM-E	6.6	**0**	0	0

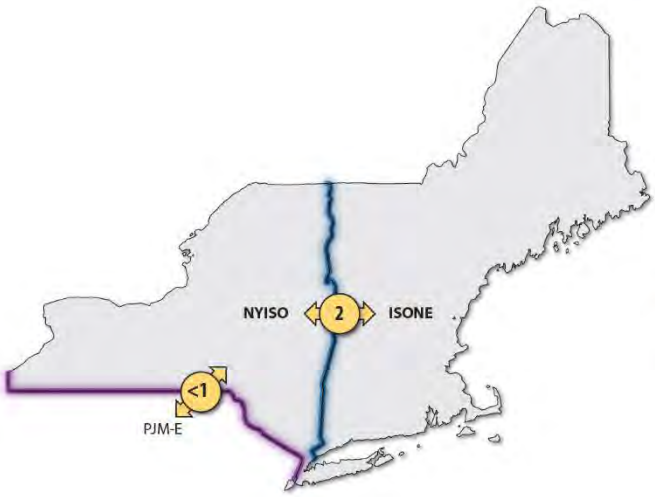
P2P Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
NYISO, ISONE	3.5	**1.4**	1.9	2.4
NYISO, PJM-E	6.6	**0**	0	0

MT Framework



Interface Capacity (GW)

REGION	EXISTING	Percentile of New Capacity 25TH	50TH	75TH
NYISO, ISONE	3.5	**1.6**	2.2	2.9
NYISO, PJM-E	6.6	**0.9**	2.4	3.7









DOE/GO-102024-6258 | October 2024

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 66

NERC 2024 Interregional Transfer Capability Study, Part 1

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interregional Transfer Capability Study (ITCS)

Strengthening Reliability Through the Energy Transformation

Transfer Capability Analysis (Part 1)

August 2024

RELIABILITY | RESILIENCE | SECURITY






3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

Statement of Purpose

Congress enacted legislation requiring an Interregional Transfer Capability Study (ITCS) to inform the potential need for more electric transmission capacity between regions for reliability. Signed into law in June 2023, section 322 of the Fiscal Responsibility Act of 2023[1] directs NERC, as the ERO under section 215 of the Federal Power Act[2] to conduct the ITCS:

> *The Electric Reliability Organization…in consultation with each regional entity…and each transmitting utility (as that term is defined in section 3(23) of such Act) that has facilities interconnected with a transmitting utility in a neighboring transmission planning region, shall conduct a study of total transfer capability as defined in section 37.6(b)(1)(vi) of title 18, Code of Federal Regulations, between transmission planning regions that contains the following:*
>
> *(1) Current total transfer capability, between each pair of neighboring transmission planning regions.*
> *(2) A recommendation of prudent additions to total transfer capability between each pair of neighboring transmission planning regions that would demonstrably strengthen reliability within and among such neighboring transmission planning regions.*
> *(3) Recommendations to meet and maintain total transfer capability together with such recommended prudent additions to total transfer capability between each pair of neighboring transmission planning regions.*

This congressional directive falls within the scope of NERC's obligation under section 215 to "conduct periodic assessments of the reliability and adequacy of the bulk power system in North America."[3] NERC and the six Regional Entities,[4] collectively called the ERO Enterprise, developed and executed the ITCS in collaboration with industry to address the congressional directive. The study must be filed with the Federal Energy Regulatory Commission (FERC) by December 2, 2024,[5] with a FERC public comment period to follow. This report, which builds on the *Overview of Study Need and Approach* (ITCS Overview) published in June 2024,[6] communicates the Part 1 study process details and the transfer capability analysis.

[1] H.R.3746 - 118th Congress (2023–2024): Fiscal Responsibility Act of 2023 | Congress.gov | Library of Congress
[2] 16 U.S.C. § 824o [hereafter section 215]
[3] Section 215(g). Such reliability assessments include the Long-Term Reliability Assessment, Summer Assessment, Winter Assessment, and special assessments.
[4] NERC's work with the Regional Entities is governed by Regional Delegation Agreements (RDA) on file with FERC and posted on NERC's website. See also section 215(e)(4).
[5] See Fiscal Responsibility Act (adding that, "Not later than 12 months after the end of the public comment period in subsection (b), the Federal Energy Regulatory Commission shall submit a report on its conclusions to Congress and include recommendations, if any, for statutory changes.").
[6] Readers are encouraged to review the ITCS Overview of Study Need and Approach, found here, for a more complete understanding of this Part 1 report.

Executive Summary

A Complex Grid

The North American grid is a complex machine that integrates a network of generation, transmission, and distribution systems across vast geographic areas that has evolved over many years.[7] A strong, flexible, and resilient transmission system is critical for the reliable delivery of electricity and is an essential component of grid reliability. As the ERO, NERC remains focused on assuring reliability throughout the ongoing energy transformation. Recent operational events[8] on the BPS show that more needs to be done to support energy adequacy to continuously meet customer demand. Ensuring sufficient transfer capability[9] of the transmission system to support energy adequacy[10] is the reliability gap that the ITCS seeks to address.

Study Need

NERC assessments[11] have identified the need for more transmission capacity to support the energy transformation and the ongoing electrification of the economy, including transportation, industry, and data centers. The situation is further compounded by more frequent extreme weather events. While always important, the need for reliable energy supply – in the interest of public health, safety, and security – becomes most pronounced under these conditions. The combination of these factors emphasizes the criticality of adequate and informed planning that will support future grid reliability. Transmission assessments, like the ITCS, are crucial to managing and mitigating future reliability risks. The ITCS will examine the extent of transfer capability, any prudent recommendations for additional transfer capability to strengthen reliability, and how to meet and maintain such capability as enhanced by any additions. Consistent with the ERO's mission, the ITCS focuses on reliability and will not include economic justification for new and/or upgraded transmission facilities.

KEY OBSERVATIONS

- Transfer capability varies seasonally and under different system conditions that limit transmission loading – it cannot be represented by a single number.
- Transfer capability varies widely across North America, with total import capability varying between 1% and 92% of peak load.
- Observed transfer capabilities are generally higher in the West Coast, Great Lakes, and mid-Atlantic areas, but relatively lower in the Mountain States, Great Plains, Southeast, and the Northeast regions. There is limited transfer capability between Interconnections.
- The magnitude of transfer capability is not itself a measure of energy adequacy. This will be evaluated in Part 2 of the study, which will recommend prudent additions where needed based on a holistic view of transmission and resource availability.

[7] An explanation of the electric power grid can be found here (Source: *Electricity Explained – U.S. Energy Information Administration*, *April 2024*).

[8] The ITCS Overview of Study Need and Approach includes examples of the critical role of transfer capability during the Western Interconnection Heatwave (2020), Winter Storm Uri (2021), and Winter Storm Elliott (2022).

[9] Transfer capability is the measure of the ability of interconnected electric systems to reliably move or transfer electric power from one area to another area by way of all transmission lines (or paths) between those areas under specific system conditions.

[10] Energy adequacy is the ability of the BPS to meet customer demand at all times.

[11] NERC's assessments can be found here.

The first ITCS document – *Overview of Study Need and Approach*[12] – was released in June 2024. It provides background and context on the study, including details regarding transfer capability calculations and the approach for recommending prudent additions, laying the foundation for the ITCS as a whole and its associated methods. As discussed therein, while an essential component of reliability is ensuring that a planned resource portfolio can deliver an adequate amount of energy at all hours of the year, the interconnected nature of the North American grid often results in energy transfers between neighboring regions. The fundamental question assessed by the ITCS is the ability of the BPS to reliably support these energy transfers.

This report – *Transfer Capability Analysis (Part 1)* – addresses the first part of the congressional directive, which mandated a transfer capability analysis between each pair of neighboring Transmission Planning Regions (TPR).[13] The results from this Part 1 analysis will be applied to Parts 2 and 3 of the study. Prudent Additions Recommendations (Part 2) of the ITCS will suggest increases to the transfer capability between neighboring TPRs to improve reliability during, for example, an extreme weather event. Meet and Maintain Recommendations (Part 3) will discuss how to meet and maintain transfer capability as enhanced by these prudent additions. Parts 2 and 3 will be issued together, and the final consolidated report will be submitted to FERC on or before December 2, 2024.

Significance of Transfer Capability

Adequate transfer capability is fundamental to the reliable operation of the BPS. Balancing Authorities may rely on their neighbors to supply energy for various purposes, including economic or policy reasons. Transfer capability is also essential under stressed operating conditions, allowing Balancing Authorities to maintain reliability by importing needed energy from their neighbors. As the resource mix becomes increasingly dependent on just-in-time and weather-dependent fuels, such as wind and solar, the ability to transfer electrical energy from areas of fuel adequacy to areas experiencing fuel constraints has become essential to maintaining reliable delivery of electricity to end-use customers. **Chapter 1** contains additional details regarding the calculation of transfer capability.

Recognizing the importance of transfer capability, there have been calls for industry regulators to require plans for a minimum transfer capability as a certain percentage of load. While the ITCS considered this approach, in practice, each TPR faces unique challenges such as its resource mix, each neighbor's resource mix, and probable weather impacts, each of which require careful consideration. As a result, a TPR with relatively low transfer capability may not experience resource deficiencies, while another TPR with relatively high transfer capability may experience resource deficiencies. A deliberate and holistic approach to coordinated resource and transmission planning will optimize the reliability provided by increased transfer capability. The recommendations for prudent additions in the Part 2 report will reflect a TPR-specific approach to transfer capability rather than a percentage-based minimum requirement.

Holistic Approach to Transfer Capability

A holistic view of the interconnected system and a thorough understanding of its behavior are essential when calculating or increasing transfer capability. When neighboring TPRs transfer energy over a highly interconnected system, the energy flows over many different lines based on the difficulty, or resistance, of traveling each route, unless there is specific equipment used to control flows. As a result, energy typically flows not only across the tie lines that directly connect the exporting (source) TPR to the importing (sink) TPR, but over many routes, some of which may be running through third-party systems. The way electrical energy flows has broad implications for calculating and using transfer capability in an interconnected system, especially when traveling over long distances. For example, maintaining and increasing transfer capability may be highly dependent on the system conditions within the source and sink TPRs as well as surrounding areas. Likewise, transfer capability does not correlate one-to-one with the rating of new or upgraded transmission facilities.

[12] The ITCS Overview of Study Need and Approach further explains transfer capability, calculation method, study assumptions, and other important study information.

[13] This is not a defined term in the NERC Glossary of Terms, but for the purposes of the ITCS, this term refers to the study regions that are described in the ITCS Overview and in **Chapter 1** of this report.

While the ITCS examines transfer capability as one side of the reliability equation, resource availability must also be considered. When extreme conditions challenge the BPS, they often impact a large geographic area. As a result, when one system is running short on resources, its neighboring systems may be facing the same dilemma simultaneously. System planners must consider various weather conditions impacting not only their own systems but also the neighboring systems they might rely on to transfer energy. Building transfer capability between systems that need more resources simultaneously will not enhance reliability during those extreme conditions. Only coordinated resource and transmission planning can ensure that the risks to the BPS are well understood and appropriately managed.

> The magnitude of transfer capability is not itself a measure of energy adequacy. This will be evaluated in Part 2 of the study, which will recommend prudent additions where needed based on a holistic view of transmission and resources.

Limitations of Transfer Capability

Planners must also carefully evaluate potential impacts of increased transfer capability. Increased transfers of energy between TPRs can benefit reliability in some situations, but large transfers also have reliability implications that must be considered. When a large amount of energy is transferred, certain aspects of reliable system operations, such as system stability, voltage control, and minimizing the potential for cascading outages, must also be considered, including the ability to withstand unplanned facility outages. This evaluation is crucial as an increased transfer capability may benefit neighboring TPRs under stressed conditions, but it can also potentially create some reliability issues that must be carefully considered in the planning process.

Finally, the transfer capability results in this report reflect the conditions studied and are not an exhaustive evaluation of the potential for energy transfers. The results are highly dependent on the assumptions, including load levels and dispatch of resources, both of which can vary significantly between seasons. For the same reasons, transfer capability can be different during non-peak periods than the peak conditions studied. This study used a set of cases representative of stressed system conditions most relevant for the Part 2 analysis. As such, the study did not attempt to maximize transfer capability values for each interface through optimal generation re-dispatch, system topology changes, or other operational measures. Consequently, higher transfer capabilities may be available under different conditions. Changes to future resource additions, resource retirements, load forecast changes, and/or transmission expansion plans have the potential to significantly alter the study results.

> Transfer capability varies seasonally and under different system conditions that limit transmission loading – it cannot be represented by a single number.

Transfer Capability Analysis (Part 1) Summary

The Part 1 transfer capability analysis between each pair of neighboring TPRs focused on two different base cases:[14]

- 2024 Summer
- 2024/25 Winter

These base cases were chosen from readily available seasonal peak load models and updated by industry to reflect future conditions. Further details regarding base case development can be found in **Chapter 1**. All electrically connected neighboring systems were evaluated, and results are presented by Interconnection proceeding from west to east as follows:

Transfer capability varies widely across North America, with total import capability varying between 1% and 92% of peak load.

- Western Interconnection (**Chapter 2**)
- Ties between the Western and Eastern Interconnections (**Chapter 3**)
- Ties between the Electric Reliability Council of Texas (ERCOT) and Eastern Interconnections (**Chapter 4**)
- Eastern Interconnection (**Chapter 5**)
- Ties between the Québec and Eastern Interconnections (**Chapter 6**)

Figure ES.1 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure ES.2** similarly depicts the results from the 2024/25 Winter case.

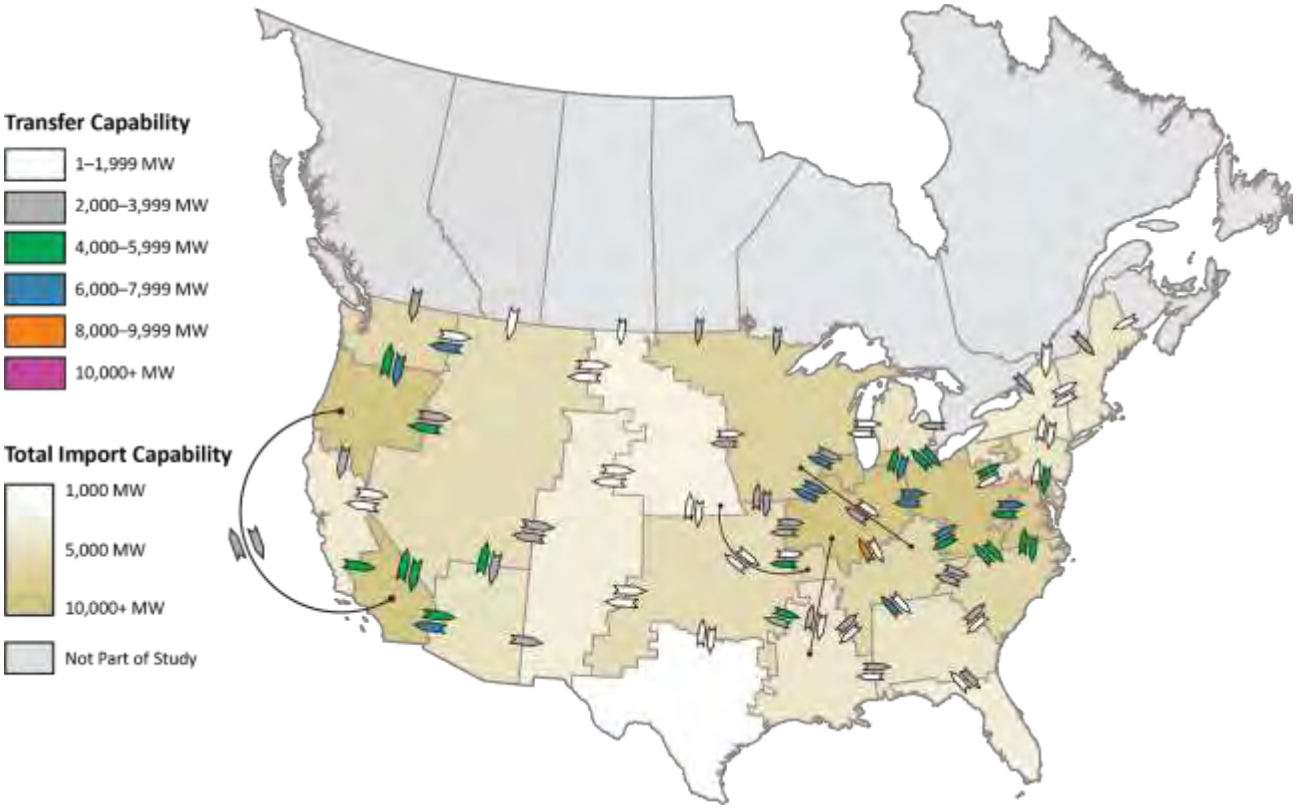


Figure ES.1: Transfer Capabilities (Summer)

[14] Base cases are computer models that simulate the behavior of the electrical system under various conditions.

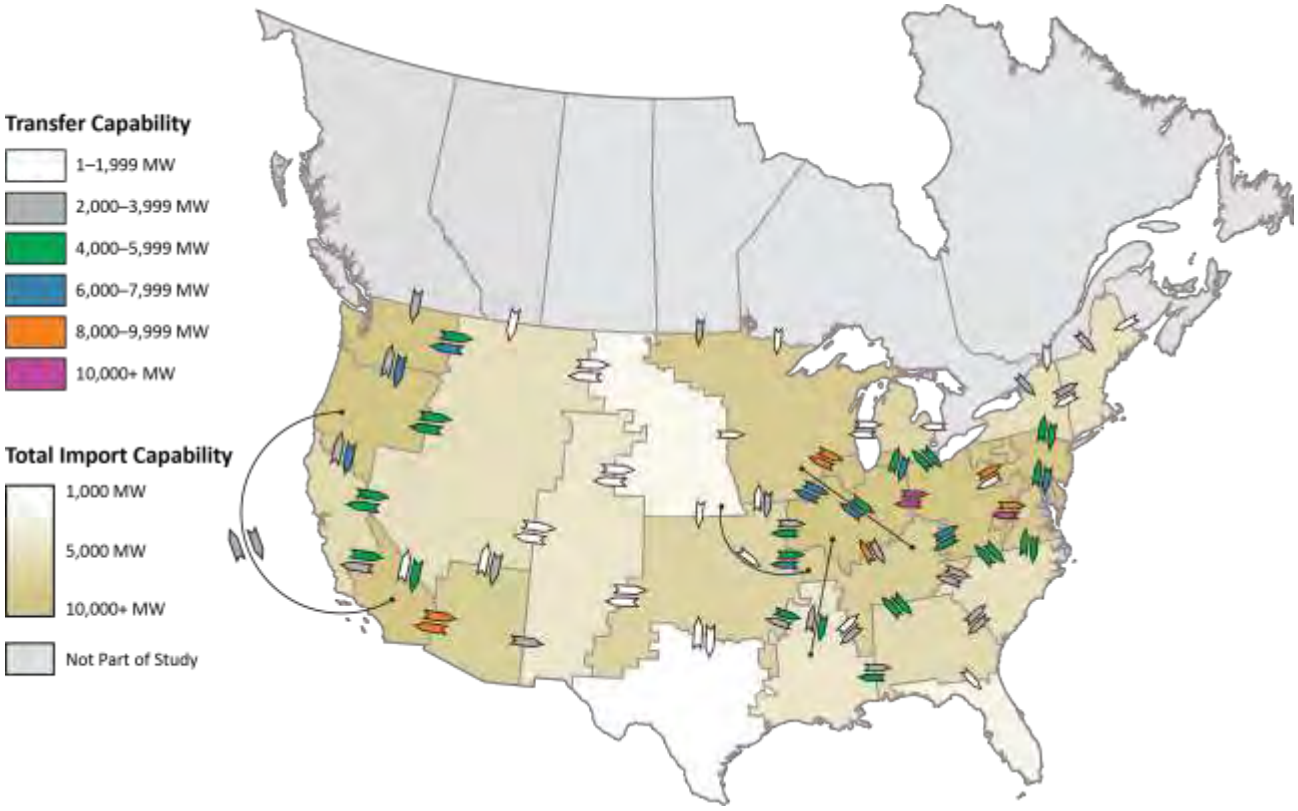


Figure ES.2: Transfer Capabilities (Winter)

Part 1 analysis also includes transfer capability between planning areas as defined by FERC's Order No. 1000.[15] Since the ITCS is being conducted under NERC's authority from section 215 and provides a more detailed reliability focus, these larger geographic areas will not be used to determine prudent additions.[16] Nonetheless, the current transfer capability results between these areas are provided for completeness in **Chapter 7**.

To more accurately reflect the ability of a TPR to simultaneously import energy from multiple neighbors, Part 1 also analyzed total import interfaces, which are provided in **Chapter 8** of this report. The use of these total import interfaces, while not part of the mandated evaluation of transfer capability between pairs of neighboring TPRs, is technically necessary to increase the accuracy of the Part 2 results by reducing the likelihood of overstating import capability.

This study is unique in terms of its geographic magnitude and overall approach to evaluating energy adequacy under extreme conditions. It revealed several challenges and highlighted associated opportunities to improve processes, data collection, and coordination for future studies. These key study opportunities are listed in **Appendix A**.

[15] More information can be found on FERC's website at www.ferc.gov.

[16] Order No. 1000 was issued by FERC in relation to Transmission Planning and Cost Allocation under FERC's authority under section 206 of the Federal Power Act. As a result, the Order No. 1000 planning regions do not, for example, include Texas.

Stakeholder Engagement and Reporting

To ensure a comprehensive and inclusive study, an ITCS Advisory Group of stakeholders was formed, including transmitting utilities across North America. Throughout the ITCS process, industry and stakeholders have been kept informed through regular updates posted on the ITCS web page, and through open project and Advisory Group meetings. To provide further opportunities for stakeholder engagement and consultation, the project has been divided into several stages, each with an accompanying report. In addition to this *Transfer Capability Analysis (Part 1)* report, the other documents are:

- ***Overview of Study Need and Approach***[17] **(completed)**: Provides background and context regarding transfer capability calculations and the approach for recommending prudent additions, laying the foundation for the ITCS as a whole and its associated methods. (published in June 2024)
- **Prudent Additions Recommendations (Part 2) and Meet and Maintain Recommendations (Part 3):** Identification of prudent additions to transfer capability between neighboring areas (Part 2) and the recommendations to meet and maintain transfer capability (Part 3). (November 2024)
- **Canadian Analysis:** A study of transfer capabilities from the United States to Canada and between Canadian provinces. While this part is outside the specific congressional directive,[18] the interconnectedness of the North American BPS[19] warrants analysis of Canada. (Q1 2025)

[17] The ITCS Overview of Study Need and Approach can be found here.

[18] H.R.3746 - 118th Congress (2023-2024): Fiscal Responsibility Act of 2023 | Congress.gov | Library of Congress

[19] The Western Interconnection includes the Canadian provinces of Alberta and British Columbia. Similarly, the Eastern Interconnection contains numerous transmission lines between the United States and Manitoba, New Brunswick, Ontario, and Saskatchewan, plus direct current (dc) connections with Québec.

Chapter 1: Part 1 Study Process Details

This section details the study design, tools, case development, and analysis parameters for calculating current transfer capability. The study details were reviewed by various industry groups, including the ITCS Advisory Group and Regional Entities' technical groups and committees.

Transmission Planning Regions

A set of interfaces was identified that included all pairs of neighboring TPRs so that transfer analysis from source (exporting) TPR to sink (importing) TPR and vice versa could be performed. In this context, only electrically connected neighboring systems were evaluated.

In general, this study's scope is interregional transfer capability analysis between source/sink TPRs.[20] As described in the ITCS Overview, during the process of defining TPRs for the purposes of this study, some areas defined in FERC's Order No. 1000,[21] which generally do not follow state boundaries, were sub-divided to provide more granular analysis of potential transfer capability limitations. The Canadian TPRs largely follow provincial boundaries. These TPRs, shown in **Figure 1.1**, have been carefully selected to identify key constraints to interregional transfer capability.

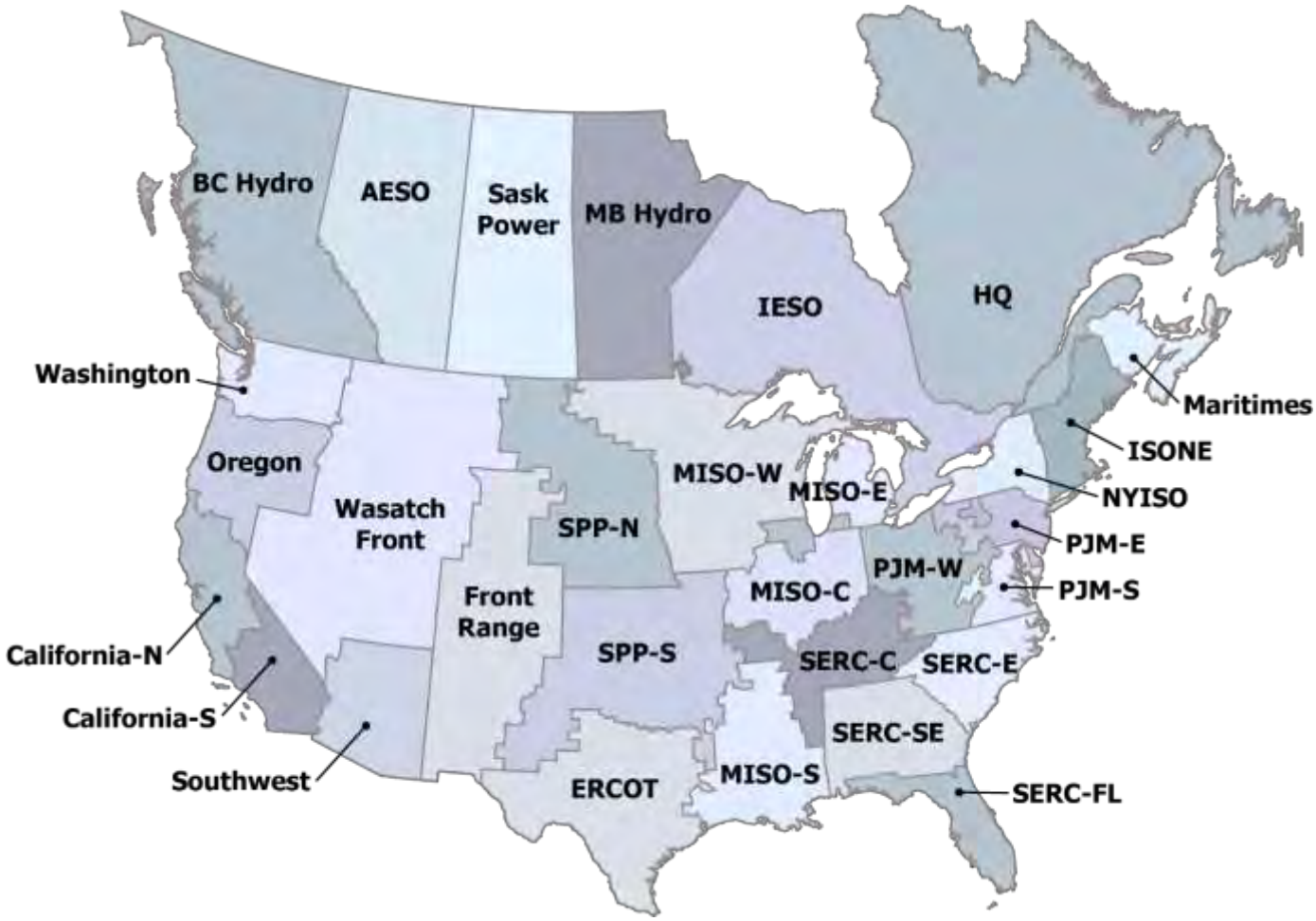


Figure 1.1: Transmission Planning Regions

[20] While the congressional directive applies to the United States, any analysis would be incomplete without a thorough understanding of the Canadian limits and available resources.

[21] More information can be found on FERC's website at www.ferc.gov.

Results for areas defined in FERC's Order No. 1000 are provided in **Chapter 7** of this report. These areas will not be part of the Part 2 Prudent Additions analysis, as the selected TPRs will provide more precise and meaningful recommendations for increases to transfer capability. While the Los Angeles Department of Water & Power (LADWP) is part of WestConnect, for the purposes of this study, LADWP was included as part of CAISO due to its geographic location within California.

To more accurately reflect the ability of a TPR to simultaneously import energy from multiple neighbors, Part 1 also analyzed total import capabilities of each TPR. Though not part of the mandate, which directed evaluation of transfer capability between neighboring TPRs, this evaluation is technically necessary to appropriately model system capability in Part 2 of the ITCS. Total import interface transfer capability results are reported in **Chapter 8**.

Canadian systems were included in this analysis to perform the transfer capability calculations from Canada to the United States. Analysis of transfer capability from the United States to Canada and between provinces will be performed subsequently, with the associated report expected to be published in the first quarter of 2025.

Total Transfer Capability

As described further in the ITCS Overview, Total Transfer Capability (TTC) is calculated as the sum of the Base Transfer Level (BTL) and First Contingency Incremental Transfer Capability (FCITC). In other words, **TTC = BTL + FCITC**. This enables a consistent calculation method across the entire study area, although TTC calculations are different than path limits which are used by some entities.

The BTL for each interface was derived, where available, from the scheduled interchange tables provided with each of the study cases. This was compared to the desired interchange for each area provided in the study cases to cross-check. Where required, adjustments were made to account for additional schedules and market re-dispatch based on load ratio where a Balancing Authority spanned multiple TPRs. For each area in the study cases where the detailed scheduled interchange tables were unavailable, BTL was approximated using the actual line flow across each interface and cross-checked against the scheduled interchange. This approach was endorsed by the ITCS Advisory Group.

The transfer analysis, which calculates the FCITC, involves simulating an incremental increase in transfers from source to sink while applying relevant contingencies and monitoring criteria (both described later), until a criteria violation is found. PowerGEM's Transmission Adequacy and Reliability Assessment (TARA) software was used for this transfer analysis. The last incremental step prior to finding a criteria violation is reported as the FCITC. A voltage screening was performed for each transfer analysis to validate the FCITC limit found. Models reflecting this transfer amount were created and screened for voltage violations using applicable contingencies. If a voltage violation was found, the FCITC was reduced, and the process repeated until the voltage violation was resolved. All results were vetted by the Regional Entities through the respective Planning Coordinators.

Base Case Development

The current transfer capability calculation was performed using relevant Eastern Interconnection and Western Interconnection base cases with consistent criteria and assumptions. Base cases are not required for the ERCOT and Québec Interconnections for this study, as they are only tied with the Eastern Interconnection via dc ties. Also, the dc ties from the Electric Reliability Council of Texas (ERCOT) to Mexico are treated as static, and the ERCOT-Mexico interface is not included in the scope of this analysis. More information can be found in the Part 1 scoping document.[22]

[22] ITCS Transfer Study Scope Part 1 (nerc.com)

System models representing Eastern and Western Interconnections were created to perform the analysis via base cases created through the MOD-032[23] process as a starting point for the following seasons:

- 2024 Summer
- 2024/25 Winter

Planning Coordinators and Transmission Planners were requested to review these cases and to supply updates, including:

- New generation – At a minimum, generation with a signed Interconnection Service Agreement was included in the applicable cases.
- Planned retirements – Generation that has retired or has announced retirement was removed from the applicable cases.
- Load forecast adjustments – Cases were updated to use the most current load forecasts.
- Resource dispatch – Changes to reflect the most current resource plans were included.
- Facility ratings – Rating changes received, including enhancements since the cases were built, were included in the cases.
- Expected long-term facility outages – Facilities expected to be out of service were removed from the applicable cases.
- Transmission system topology updates – Changes to topology, including new facility construction, were included in the cases.
- Base transfers (interchange) – New or updated firm transfers were accounted for in the cases.

Contingencies

The transfer analysis simulated contingencies, namely the unplanned outage of system elements, to ensure that the system would remain reliable during the energy transfer. The following NERC Reliability Standard TPL-001-5.1[24] category P1 contingencies (100kV and above) were used for the transfer studies, namely:

- P1-1: Loss of individual generators,
- P1-2: Loss of a single transmission line operating at 100 kV or above, and
- P1-3: Loss of a single transformer with a low-side voltage of 100 kV or above

All contingencies meeting the above criteria within the source and sink TPRs were included in each transfer study, along with all contingencies within five buses from either the source or sink TPR.

Monitored Facilities and Thresholds

Facility monitoring criteria and thresholds were established to prevent undue limitation of transfer capability results based on heavily loaded, electrically distant elements. These practices followed industry-accepted methods to ensure that transmission facilities only minimally participating in an interregional transfer do not artificially constrain the transfer limits. Additional detail regarding these criteria can be found in the Part 1 scoping document.[25] Some entities performed additional studies while monitoring lower voltage facilities to ensure there were no significant differences.

[23] MOD-032-1 (nerc.com)
[24] TPL-001-5.1 (nerc.com)
[25] ITCS Transfer Study Scope Part 1 (nerc.com)

Modeling of Transfer Participation

Transfers were simulated by scaling up the available generation in the source TPR in proportion to each unit's remaining availability, namely the difference between maximum generating capacity (P_{MAX}) and its modeled output (P_{GEN}), while scaling down the generation in the sink TPR proportional to its modeled output. Each transfer was simulated until a valid thermal limit was reached while enforcing the source system's maximum generation capacity. If the transfer did not report any transfer limits, meaning that the source TPR was resource-limited, the transfer was repeated without enforcing the source TPR's maximum generation capacity. Invalid limits, such as overloads on generating plant outlets due to not respecting these P_{MAX} values, were ignored.

Special Interface Considerations

Several interfaces have known operating procedures or other special circumstances. In many cases, these are remedial action schemes and/or flow control devices, e.g., phase angle regulators (PAR) or dc lines. The project team worked closely with industry subject matter experts to ensure that these situations were fully understood and properly reflected in the study results.

Power flows over dc lines do not change during transfer analysis; however, these lines are typically designed to carry large quantities of energy over long distances and across asynchronous Interconnections. Where an interface consists solely of dc tie lines, the TTC was calculated as the sum of the dc tie line ratings except where limitations on the ac system near the dc terminals are known to be more restrictive. Where an interface includes one or more dc tie lines as well as ac tie lines, the transfer analysis was conducted with the dc lines at the flow levels in the base cases.

Similarly, many interfaces include one or more PARs. For example, the PJM East to New York Interface is partially controlled by several PARs. Operating manuals describe how transfers across this interface are controlled, including the target percentage of flows across each line. This flow distribution was modeled in the base case development and transfer analysis to reflect the operating agreements between PJM and the New York Independent System Operator (NYISO).

Finally, there are several situations where one or more units at a power plant can connect to two different Interconnections. These units were modeled as provided in the base cases. The associated capacity was not added to the interface TTC, as this could lead to an overstatement of transfer capability, such as when the units are offline.

Study Results

As noted earlier, the TTC values below will be used in Parts 2 and 3 of the ITCS. Part 2 will recommend prudent additions to the amount of energy that can be moved or transferred between neighboring TPRs, while Part 3 will provide recommendations on how to meet and maintain transfer capability as enhanced by any prudent additions.

TTC results are highly dependent on the precise operating conditions, including dispatch, topology, load patterns, and facility ratings. This study did not attempt to optimize dispatch or topology to maximize TTC values. Observed transfer capability may be higher or lower depending on the operational conditions.

Results are presented by Interconnection for each season, proceeding from west to east as follows:

- Western Interconnection
- Ties between the Western and Eastern Interconnections
- Ties between the ERCOT and Eastern Interconnections
- Eastern Interconnection
- Ties between the Québec and Eastern Interconnections

Within the Western and Eastern Interconnections, results are generally presented from west to east, then north to south. A list of the interfaces and their ordering is included at the outset of each section.

Chapter 2: Western Interconnection Results

TTC results for the following interfaces are presented in this section:

- W1: British Columbia -> Washington
- W2: Washington <-> Oregon
- W3: Washington <-> Wasatch Front
- W4: Oregon <-> California North
- W5: Oregon <-> Wasatch Front
- W6: California North <-> California South
- W7: California North <-> Wasatch Front
- W8: California South <-> Wasatch Front
- W9: California South <-> Southwest
- W10: Alberta -> Wasatch Front
- W11: Wasatch Front <-> Southwest
- W12: Wasatch Front <-> Front Range
- W13: Southwest <-> Front Range
- W14: Oregon <-> Southern California (dc)

The interface between British Columbia and Saskatchewan will be covered in the Canadian Analysis.

Figure 2.1 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 2.2** similarly depicts the results from the 2024/25 Winter case.



Figure 2.1: Transfer Capabilities for Western Interconnection Interfaces (Summer)



Figure 2.2: Transfer Capabilities for Western Interconnection Interfaces (Winter)

Interface W1: British Columbia -> Washington



Interface Direction	2024 Summer	2024/25 Winter
British Columbia -> Washington	2,358 MW	2,170 MW

Interface W2: Washington <-> Oregon



Interface Direction	2024 Summer	2024/25 Winter
Washington -> Oregon	7,085 MW	7,496 MW
Oregon -> Washington	4,103 MW	2,713 MW

Interface W3: Washington <-> Wasatch Front



Interface Direction	2024 Summer	2024/25 Winter
Washington -> Wasatch Front	1,925 MW	4,498 MW
Wasatch Front -> Washington	7,377 MW	7,030 MW

Interface W4: Oregon <-> California North



Interface Direction	2024 Summer	2024/25 Winter
Oregon -> California North	3,972 MW	6,175 MW
California North -> Oregon	0 MW	2,548 MW

Explanatory Note: Flows from south to north (California North to Oregon) are not typical under summer peak conditions, and generation dispatch optimization would be required to reverse the flows. Previous studies have shown a south to north transfer of ~3,675 MW.

Interface W5: Oregon <-> Wasatch Front



Interface Direction	2024 Summer	2024/25 Winter
Oregon -> Wasatch Front	2,525 MW	5,339 MW
Wasatch Front -> Oregon	4,748 MW	5,079 MW

Interface W6: California North <-> California South



Interface Direction	2024 Summer	2024/25 Winter
California North -> California South	4,647 MW	5,676 MW
California South -> California North	0 MW	3,861 MW

Explanatory Note: Flows from south to north (California South to California North) are not typical under summer peak conditions, and generation dispatch optimization would be required to reverse the flows. Previous studies have shown a south to north transfer of ~3,000 MW.

Interface W7: California North <-> Wasatch Front



Interface Direction	2024 Summer	2024/25 Winter
California North -> Wasatch Front	1,961 MW	4,980 MW
Wasatch Front -> California North	116 MW	5,388 MW

Interface W8: California South <-> Wasatch Front



Interface Direction	2024 Summer	2024/25 Winter
California South -> Wasatch Front	5,965 MW	984 MW
Wasatch Front -> California South	5,419 MW	5,568 MW

Interface W9: California South <-> Southwest



Interface Direction	2024 Summer	2024/25 Winter
California South -> Southwest	5,247 MW	8,470 MW
Southwest -> California South	7,667 MW	8,752 MW

Interface W10: Alberta -> Wasatch Front



Interface Direction	2024 Summer	2024/25 Winter
Alberta -> Wasatch Front	957 MW	1,280 MW

Interface W11: Wasatch Front <-> Southwest



Interface Direction	2024 Summer	2024/25 Winter
Wasatch Front -> Southwest	2,351 MW	2,095 MW
Southwest -> Wasatch Front	5,821 MW	1,295 MW

Interface W12: Wasatch Front <-> Front Range



Interface Direction	2024 Summer	2024/25 Winter
Wasatch Front -> Front Range	2,032 MW	1,984 MW
Front Range -> Wasatch Front	2,437 MW	477 MW

Interface W13: Southwest <-> Front Range



Interface Direction	2024 Summer	2024/25 Winter
Southwest -> Front Range	3,284 MW	3,751 MW
Front Range -> Southwest	0 MW	0 MW

Interface W14: Oregon <-> California South



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Oregon -> California South	3,220 MW	3,220 MW
California South -> Oregon	3,100 MW	3,100 MW

Chapter 3: Western – Eastern Interconnection Results

TTC results for the following interfaces are presented in this section:

- WE1: Wasatch Front <-> SPP North (dc)
- WE2: Front Range <-> SPP North (dc)
- WE3: Front Range <-> SPP South (dc)

The interface between Alberta and Saskatchewan will be covered in the Canadian Analysis.

Figure 3.1 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 3.2** similarly depicts the results from the 2024/25 Winter case.



Figure 3.1: Transfer Capability Between Western and Eastern Interconnections (Summer)



Figure 3.2: Transfer Capability Between Western and Eastern Interconnections (Winter)

Interface WE1: Wasatch Front <-> SPP North



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Wasatch Front -> SPP North	150 MW	150 MW
SPP North -> Wasatch Front	200 MW	200 MW

Interface WE2: Front Range <-> SPP North



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Front Range -> SPP North	510 MW	510 MW
SPP North -> Front Range	510 MW	510 MW

Interface WE3: Front Range <-> SPP South



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Front Range -> SPP South	410 MW	410 MW
SPP South -> Front Range	410 MW	410 MW

Chapter 4: ERCOT – Eastern Interconnection Results

TTC results for the following interfaces are presented in this section:

- TE1: ERCOT <-> SPP South (dc)

Figure 4.1 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 4.2** similarly depicts the results from the 2024/25 Winter case.



Figure 4.1: Transfer Capability Between ERCOT and Eastern Interconnections (Summer)

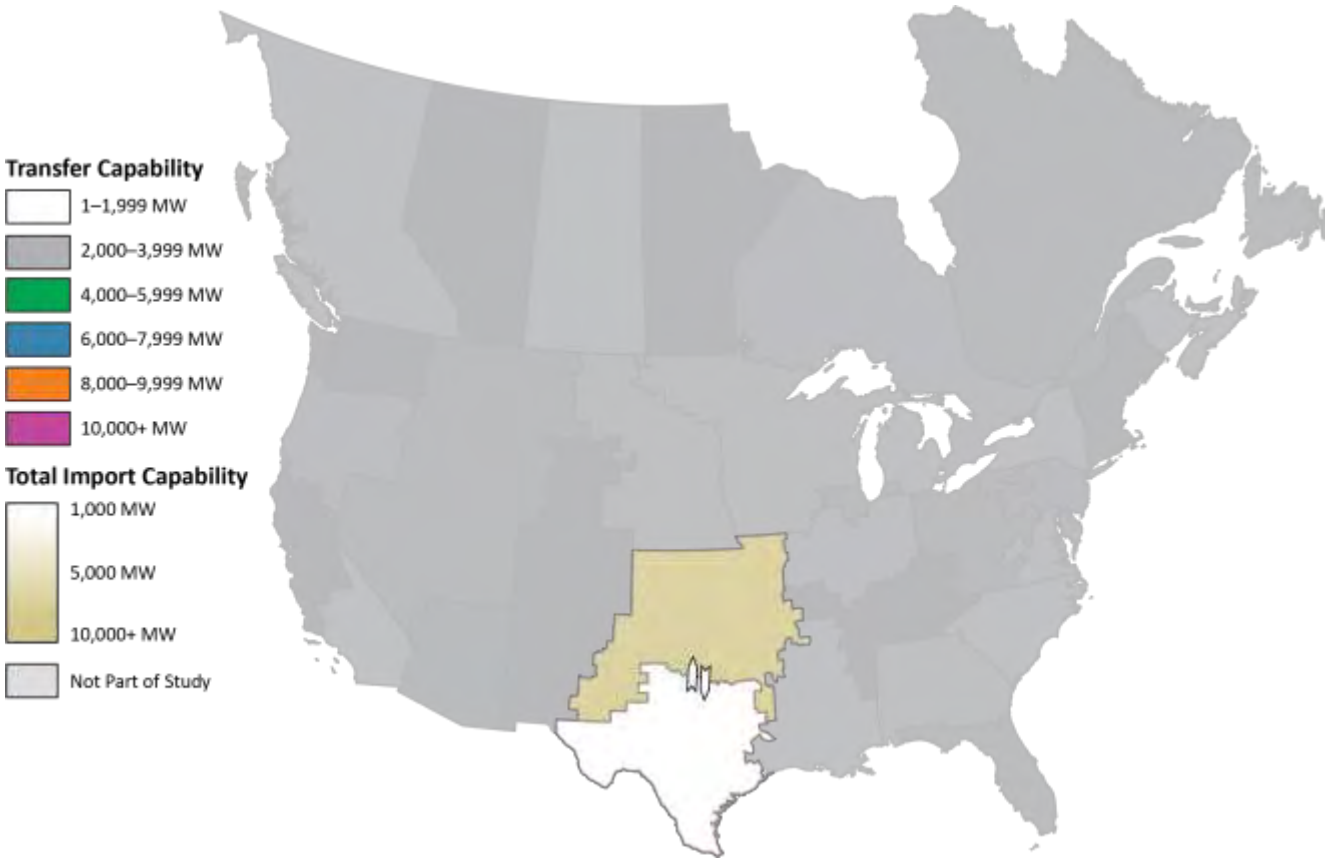


Figure 4.2: Transfer Capability Between ERCOT and Eastern Interconnections (Winter)

Interface TE1: ERCOT <-> SPP South



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
ERCOT -> SPP South	820 MW	820 MW
SPP South -> ERCOT	820 MW	820 MW

Chapter 5: Eastern Interconnection Results

TTC results for the following interfaces are presented in this section:

- E1: Saskatchewan -> SPP North
- E2: SPP North <-> SPP South
- E3: SPP North <-> SERC Central
- E4: SPP North <-> MISO West
- E5: SPP South <-> MISO West
- E6: SPP South <-> MISO Central
- E7: SPP South <-> SERC Central
- E8: SPP South <-> MISO South
- E9: Manitoba -> MISO West
- E10: Ontario -> MISO West
- E11: MISO West <-> MISO East (dc)
- E12: MISO West <-> PJM West
- E13: MISO West <-> MISO Central
- E14: MISO West <-> SERC Central
- E15: MISO Central <-> MISO East
- E16: MISO Central <-> PJM West
- E17: MISO Central <-> SERC Central
- E18: MISO Central <-> MISO South
- E19: MISO South <-> SERC Central
- E20: MISO South <-> SERC Southeast
- E21: Ontario -> MISO East
- E22: MISO East <-> PJM West
- E23: SERC Central <-> PJM West
- E24: SERC Central <-> SERC East
- E25: SERC-Central <-> SERC Southeast
- E26: SERC Southeast <-> SERC Florida
- E27: SERC Southeast <-> SERC East
- E28: SERC East <-> PJM West
- E29: SERC East <-> PJM South
- E30: PJM West <-> PJM East
- E31: PJM West <-> PJM South
- E32: PJM East <-> PJM South
- E33: PJM East <-> New York
- E34: Ontario -> New York
- E35: New York <-> New England
- E36: Maritimes -> New England

Interfaces between Saskatchewan and Manitoba, and between Manitoba and Ontario will be covered in the Canadian Analysis.

Figure 5.1 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 5.2** similarly depicts the results from the 2024/25 Winter case.

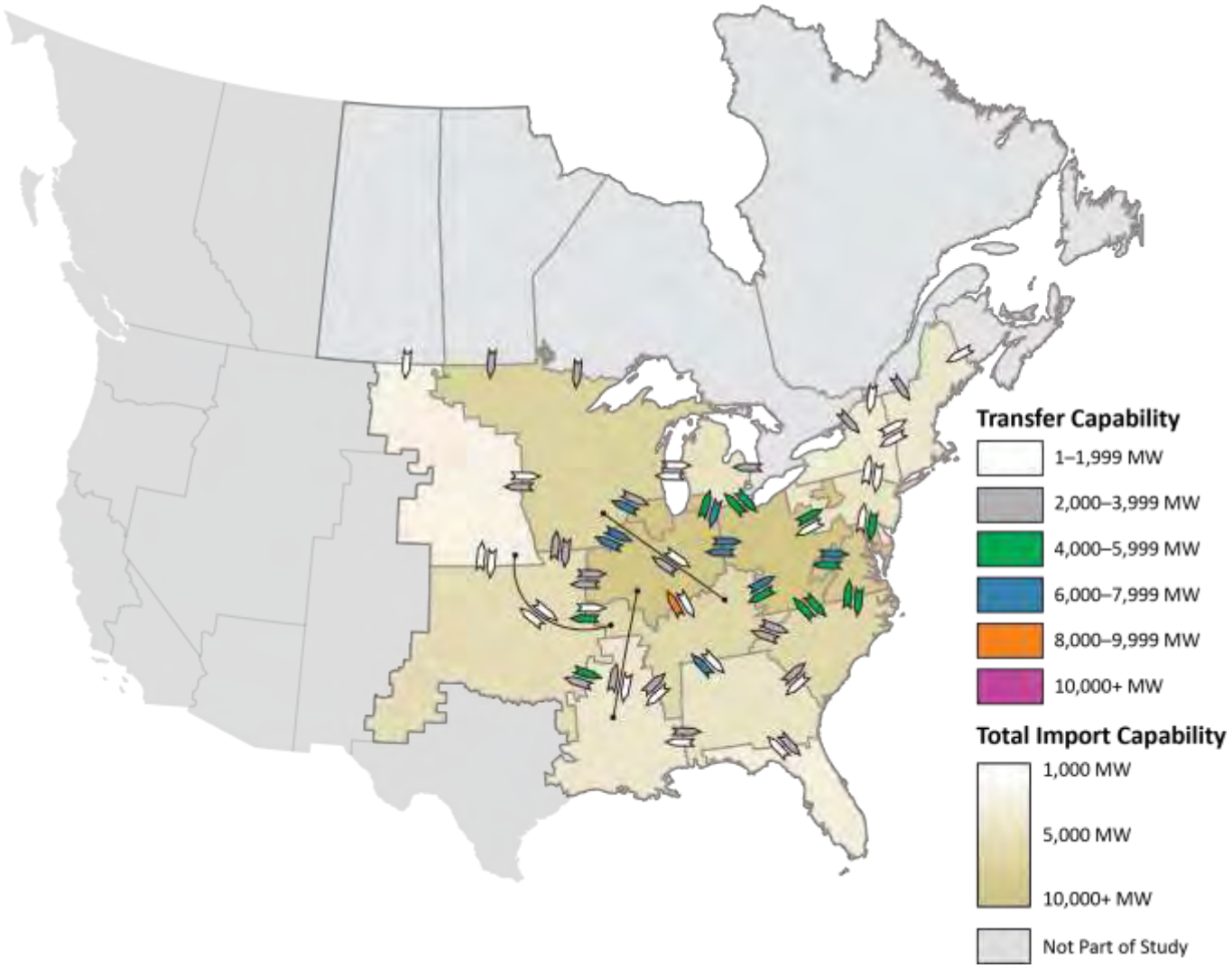


Figure 5.1: Transfer Capabilities of Eastern Interconnection Interfaces (Summer)

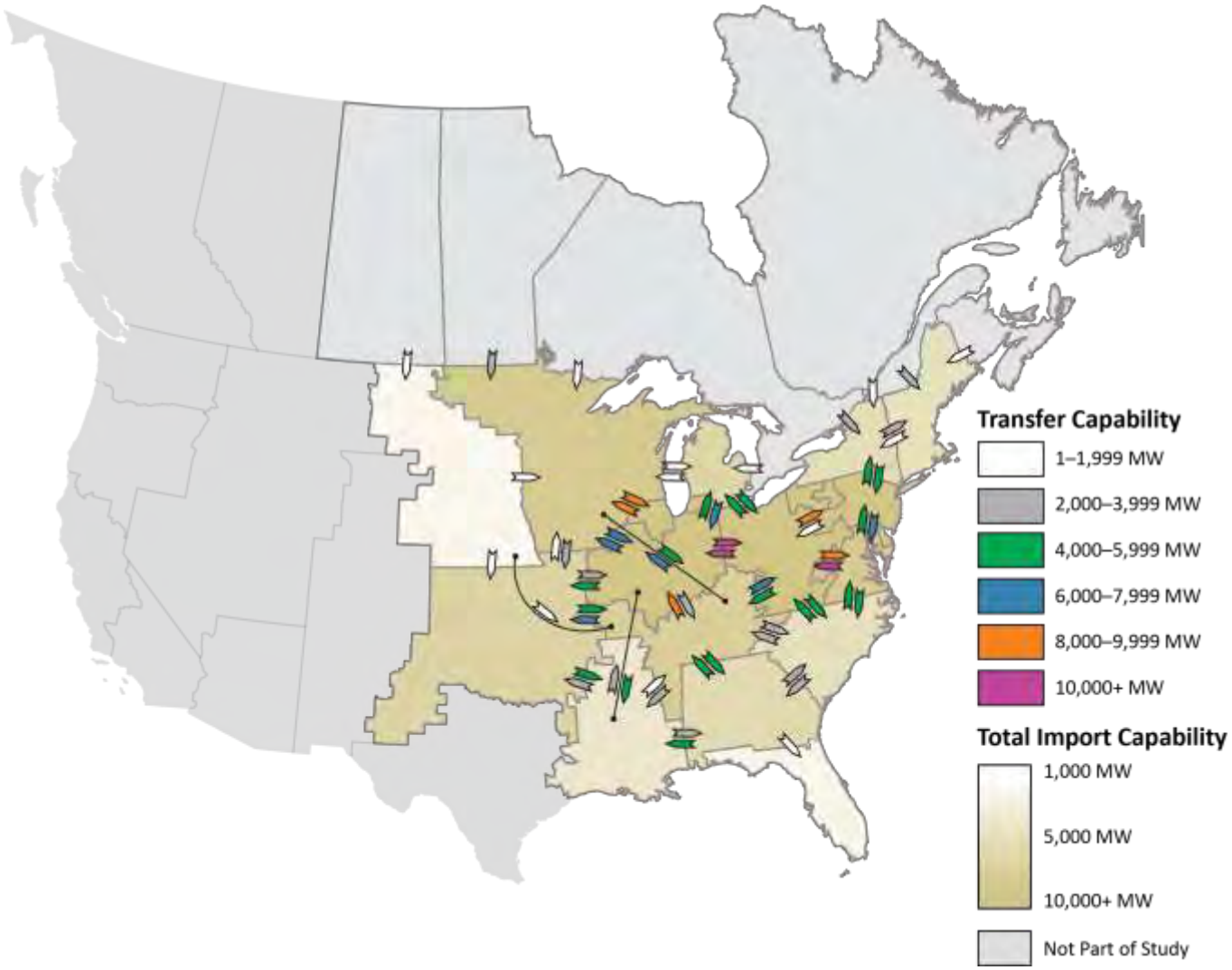


Figure 5.2: Transfer Capabilities of Eastern Interconnection Interfaces (Winter)

Interface E1: Saskatchewan -> SPP North



Interface Direction	2024 Summer	2024/25 Winter
Saskatchewan -> SPP North	165 MW	663 MW

Interface E2: SPP North <-> SPP South



Interface Direction	2024 Summer	2024/25 Winter
SPP North -> SPP South	1,501 MW	1,785 MW
SPP South -> SPP North	1,705 MW	0 MW

Explanatory Note: Under the studied winter peak conditions, transfers from SPP South to SPP North were limited by a constraint that will be relieved by a new construction project expected to be in-service in late 2024 or early 2025.

Interface E3: SPP North <-> SERC Central



Interface Direction	2024 Summer	2024/25 Winter
SPP North -> SERC Central	128 MW	1,102 MW
SERC Central -> SPP North	1,183 MW	0 MW

Explanatory Note: Under the studied winter peak conditions, transfers from SERC Central to SPP North were limited by a constraint that will be relieved by a new construction project expected to be in-service in late 2024 or early 2025.

Interface E4: SPP North <-> MISO West



Interface Direction	2024 Summer	2024/25 Winter
SPP North -> MISO West	623 MW	778 MW
MISO West -> SPP North	2,209 MW	0 MW

Explanatory Note: Under the studied winter peak conditions, transfers from MISO West to SPP North were limited by a constraint that will be relieved by a new construction project expected to be in-service in late 2024 or early 2025.

Interface E5: SPP South <-> MISO West



Interface Direction	2024 Summer	2024/25 Winter
SPP South -> MISO West	3,323 MW	1,196 MW
MISO West -> SPP South	2,086 MW	3,801 MW

Interface E6: SPP South <-> MISO Central



Interface Direction	2024 Summer	2024/25 Winter
SPP South -> MISO Central	2,481 MW	2,420 MW
MISO Central -> SPP South	3,873 MW	5,635 MW

Interface E7: SPP South <-> SERC Central



Interface Direction	2024 Summer	2024/25 Winter
SPP South -> SERC Central	859 MW	5,591 MW
SERC Central -> SPP South	5,042 MW	6,445 MW

Interface E8: SPP South <-> MISO South



Interface Direction	2024 Summer	2024/25 Winter
SPP South -> MISO South	4,295 MW	4,336 MW
MISO South -> SPP South	3,033 MW	3,878 MW

Interface E9: Manitoba -> MISO West



Interface Direction	2024 Summer	2024/25 Winter
Manitoba -> MISO West	3,772 MW	3,633 MW

Interface E10: Ontario -> MISO West



Interface Direction	2024 Summer	2024/25 Winter
Ontario -> MISO West	2,424 MW	1,862 MW

Interface E11: MISO West <-> MISO East



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
MISO West -> MISO East	160 MW	160 MW
MISO East -> MISO West	160 MW	160 MW

Interface E12: MISO West <-> PJM West



Interface Direction	2024 Summer	2024/25 Winter
MISO West -> PJM West	2,518 MW	8,011 MW
PJM West -> MISO West	7,791 MW	9,086 MW

Interface E13: MISO West <-> MISO Central



Interface Direction	2024 Summer	2024/25 Winter
MISO West -> MISO Central	6,199 MW	7,306 MW
MISO Central -> MISO West	7,602 MW	7,341 MW

Interface E14: MISO West <-> SERC Central



Interface Direction	2024 Summer	2024/25 Winter
MISO West -> SERC Central	150 MW	4,141 MW
SERC Central -> MISO West	3,671 MW	6,877 MW

Interface E15: MISO Central <-> MISO East



Interface Direction	2024 Summer	2024/25 Winter
MISO Central -> MISO East	4,864 MW	5,585 MW
MISO East -> MISO Central	6,344 MW	6,531 MW

Interface E16: MISO Central <-> PJM West



Interface Direction	2024 Summer	2024/25 Winter
MISO Central -> PJM West	6,572 MW	10,790 MW
PJM West -> MISO Central	6,986 MW	20,449 MW

Interface E17: MISO Central <-> SERC Central



Interface Direction	2024 Summer	2024/25 Winter
MISO Central -> SERC Central	235 MW	3,903 MW
SERC Central -> MISO Central	8,288 MW	8,441 MW

Interface E18: MISO Central <-> MISO South



Interface Direction	2024 Summer	2024/25 Winter
MISO Central -> MISO South	1,797 MW	4,067 MW
MISO South -> MISO Central	2,117 MW	1,093 MW

Interface E19: MISO South <-> SERC Central



Interface Direction	2024 Summer	2024/25 Winter
MISO South -> SERC Central	2,468 MW	1,361 MW
SERC Central -> MISO South	1,457 MW	3,342 MW

Interface E20: MISO South <-> SERC Southeast



Interface Direction	2024 Summer	2024/25 Winter
MISO South -> SERC Southeast	3,600 MW	3,392 MW
SERC Southeast -> MISO South	1,638 MW	4,028 MW

Interface E21: Ontario -> MISO East



Interface Direction	2024 Summer	2024/25 Winter
Ontario -> MISO East	2,348 MW	1,649 MW

Interface E22: MISO East <-> PJM West



Interface Direction	2024 Summer	2024/25 Winter
MISO East -> PJM West	5,603 MW	5,940 MW
PJM West -> MISO East	4,345 MW	5,608 MW

Interface E23: SERC Central <-> PJM West



Interface Direction	2024 Summer	2024/25 Winter
SERC Central -> PJM West	6,646 MW	6,710 MW
PJM West -> SERC Central	5,444 MW	5,786 MW

Interface E24: SERC Central <-> SERC East



Interface Direction	2024 Summer	2024/25 Winter
SERC Central -> SERC East	2,419 MW	3,311 MW
SERC East -> SERC Central	3,257 MW	2,675 MW

Interface E25: SERC Central <-> SERC Southeast



Interface Direction	2024 Summer	2024/25 Winter
SERC Central -> SERC Southeast	1,095 MW	5,387 MW
SERC Southeast -> SERC Central	6,579 MW	4,639 MW

Interface E26: SERC Southeast <-> SERC Florida



Interface Direction	2024 Summer	2024/25 Winter
SERC Southeast -> SERC Florida	2,958 MW	1,807 MW
SERC Florida -> SERC Southeast	1,322 MW	0 MW

Explanatory Note: Flows from South to North (SERC Florida to SERC Southeast) are not typical under winter peak conditions.

Interface E27: SERC Southeast <-> SERC East



Interface Direction	2024 Summer	2024/25 Winter
SERC Southeast -> SERC East	2,397 MW	3,669 MW
SERC East -> SERC Southeast	1,703 MW	3,536 MW

Interface E28: SERC East <-> PJM West



Interface Direction	2024 Summer	2024/25 Winter
SERC East -> PJM West	5,185 MW	4,448 MW
PJM West -> SERC East	5,318 MW	4,286 MW

Interface E29: SERC East <-> PJM South



Interface Direction	2024 Summer	2024/25 Winter
SERC East -> PJM South	4,596 MW	4,963 MW
PJM South -> SERC East	4,665 MW	5,463 MW

Interface E30: PJM West <-> PJM East



Interface Direction	2024 Summer	2024/25 Winter
PJM West -> PJM East	4,762 MW	9,815 MW
PJM East -> PJM West	1,443 MW	166 MW

Interface E31: PJM West <-> PJM South



Interface Direction	2024 Summer	2024/25 Winter
PJM West -> PJM South	7,041 MW	9,035 MW
PJM South -> PJM West	5,347 MW	10,942 MW

Interface E32: PJM East <-> PJM South



Interface Direction	2024 Summer	2024/25 Winter
PJM East -> PJM South	5,094 MW	6,770 MW
PJM South -> PJM East	1,605 MW	4,166 MW

Interface E33: PJM East <-> New York



Interface Direction	2024 Summer	2024/25 Winter
PJM East -> New York	1,356 MW	4,814 MW
New York -> PJM East	913 MW	4,019 MW

Interface E34: Ontario -> New York



Interface Direction	2024 Summer	2024/25 Winter
Ontario -> New York	2,286 MW	2,719 MW

Interface E35: New York <-> New England



Interface Direction	2024 Summer	2024/25 Winter
New York -> New England	1,303 MW	2,432 MW
New England -> New York	1,660 MW	1,359 MW

Interface E36: Maritimes -> New England



Interface Direction	2024 Summer	2024/25 Winter
Maritimes -> New England	1,127 MW	1,265 MW

Chapter 6: Québec – Eastern Interconnection Results

TTC results for the following interfaces are presented in this section:

- QE1: Québec -> New York (dc)
- QE2: Québec -> New England (dc)

Interfaces between Québec and Ontario and between Québec and the Maritimes will be covered in the Canadian Analysis.

Figure 6.1 depicts the calculated transfer capabilities for the 2024 Summer case. **Figure 6.2** similarly depicts the results from the 2024/25 Winter case.



Figure 6.1: Transfer Capability Between Québec and Eastern Interconnections (Summer)



Figure 6.2: Transfer Capability Between Québec and Eastern Interconnections (Winter)

Interface QE1: Québec -> New York



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Québec -> New York	1,000 MW	1,000 MW

Interface QE2: Québec -> New England



Special Information: dc-only interface

Interface Direction	2024 Summer	2024/25 Winter
Québec -> New England	2,225 MW	2,225 MW

Chapter 7: Supplemental Results Between Order 1000 Areas

The ITCS analyzed an additional set of transfers between areas defined in FERC's Order 1000 (see **Figure 7.1**). While these larger geographic areas will not be used for the purpose of determining prudent additions, the current transfer capability results are provided for completeness. Where results were previously presented, they are not repeated here. TTC results for the following interfaces are presented in this section:

- W1001: British Columbia -> Northern Grid
- W1002: Alberta -> Northern Grid
- W1003: Northern Grid <-> California ISO
- W1004: Northern Grid <-> West Connect
- W1005: California ISO <-> West Connect
- E1001: Saskatchewan -> SPP
- E1002: SPP <-> MISO
- E1003: SPP <-> SERTP
- E1004: Manitoba -> MISO
- E1005: Ontario -> MISO
- E1006: MISO <-> PJM
- E1007: MISO <-> SERTP
- E1008: SERTP <-> PJM
- E1009: SERTP <-> SCRTP
- E1010: SERTP <-> FRCC
- E1011: PJM <-> New York

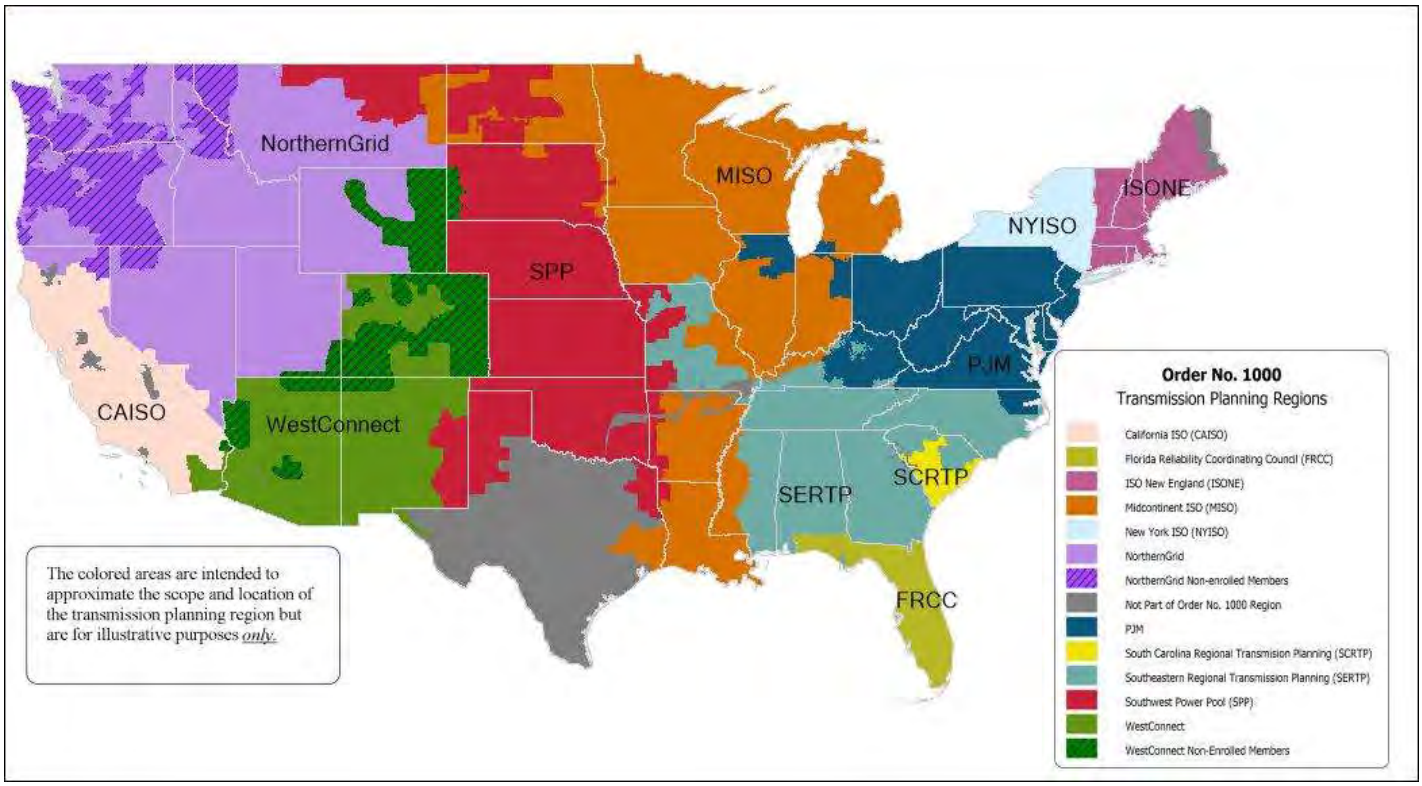


Figure 7.1: Areas Defined in FERC Order 1000

Interface W1001: British Columbia -> Northern Grid

Interface Direction	2024 Summer	2024/25 Winter
British Columbia -> Northern Grid	2,435 MW	2,164 MW

Interface W1002: Alberta -> Northern Grid

Interface Direction	2024 Summer	2024/25 Winter
Alberta -> Northern Grid	981 MW	1,286 MW

Interface W1003: Northern Grid <-> California ISO

Interface Direction	2024 Summer	2024/25 Winter
Northern Grid -> California ISO	4,140 MW	8,705 MW
California ISO -> Northern Grid	1,985 MW	5,208 MW

Interface W1004: Northern Grid <-> West Connect

Interface Direction	2024 Summer	2024/25 Winter
Northern Grid -> West Connect	2,842 MW	3,326 MW
West Connect -> Northern Grid	5,710 MW	1,865 MW

Interface W1005: California ISO <-> West Connect

Interface Direction	2024 Summer	2024/25 Winter
California ISO -> West Connect	2,534 MW	2,375 MW
West Connect -> California ISO	2,967 MW	3,912 MW

Interface E1001: Saskatchewan -> SPP

Interface Direction	2024 Summer	2024/25 Winter
Saskatchewan -> SPP	0 MW	665 MW

Interface E1002: SPP <-> MISO

Interface Direction	2024 Summer	2024/25 Winter
SPP -> MISO	7,058 MW	1,513 MW
MISO -> SPP	5,308 MW	6,403 MW

Interface E1003: SPP <-> SERTP

Interface Direction	2024 Summer	2024/25 Winter
SPP -> SERTP	4,857 MW	2,814 MW
SERTP -> SPP	2,822 MW	6,324 MW

Interface E1004: Manitoba -> MISO

Interface Direction	2024 Summer	2024/25 Winter
Manitoba -> MISO	3,058 MW	3,058 MW

Interface E1005: Ontario -> MISO

Interface Direction	2024 Summer	2024/25 Winter
Ontario -> MISO	2,419 MW	1,834 MW

Interface E1006: MISO <-> PJM

Interface Direction	2024 Summer	2024/25 Winter
MISO -> PJM	5,593 MW	12,552 MW
PJM -> MISO	9,146 MW	10,771 MW

Interface E1007: MISO <-> SERTP

Interface Direction	2024 Summer	2024/25 Winter
MISO -> SERTP	6,976 MW	9,543 MW
SERTP -> MISO	0 MW	9,801 MW

Interface E1008: SERTP <-> PJM

Interface Direction	2024 Summer	2024/25 Winter
SERTP -> PJM	8,609 MW	9,782 MW
PJM -> SERTP	7,704 MW	7,905 MW

Interface E1009: SERTP <-> SCRTP

Interface Direction	2024 Summer	2024/25 Winter
SERTP -> SCRTP	1,767 MW	1,948 MW
SCRTP -> SERTP	2,415 MW	2,335 MW

Interface E1010: SERTP <-> FRCC

Interface Direction	2024 Summer	2024/25 Winter
SERTP -> FRCC	2,918 MW	1,803 MW
FRCC -> SERTP	1,058 MW	0 MW

Interface E1011: PJM <-> New York

Interface Direction	2024 Summer	2024/25 Winter
PJM -> New York	635 MW	858 MW
New York -> PJM	3,136 MW	3,394 MW

Chapter 8: Supplemental Total Import Interface Limits

The ITCS also analyzed an additional set of transfers into each TPR. These total import interfaces analyze the simultaneous transfers into a TPR from all its neighbors. In instances where the calculated total import interface transfer capability was lower than that from any neighboring TPR, the highest neighbor-to-neighbor results were reported to avoid understating the total import capability. The definitions of these interfaces exclude connections via dc-only interfaces, which can typically be scheduled independently. TTC results for the following interfaces are presented in this section:

- WTI01: Into Washington
- WTI02: Into Oregon
- WTI03: Into California North
- WTI04: Into California South
- WTI05: Into Wasatch Front
- WTI06: Into Southwest
- WTI07: Into Front Range
- ETI01: Into SPP North
- ETI02: Into SPP South
- ETI03: Into MISO West
- ETI04: Into MISO Central
- ETI05: Into MISO South
- ETI06: Into MISO East
- ETI07: Into SERC Central
- ETI08: Into SERC Southeast
- ETI09: Into SERC Florida
- ETI10: Into SERC East
- ETI11: Into PJM West
- ETI12: Into PJM East
- ETI13: Into PJM South
- ETI14: Into New York
- ETI15: Into New England

Interface WTI01: Into Washington



Interface Direction	2024 Summer	2024/25 Winter
Into Washington TTC	7,377 MW[26]	10,297 MW
Percentage of Peak Load	43%	50%

Interface WTI02: Into Oregon



Interface Direction	2024 Summer	2024/25 Winter
Into Oregon TTC	8,004 MW	7,534 MW
dc-only interfaces	3,100 MW	3,100 MW
Total of TTC and dc-only interfaces	11,104 MW	10,634 MW
Percentage of Peak Load	92%	89%

[26] Value is from the Wasatch Front to Washington interface, as the total import interface calculation was more limiting.

Interface WTI03: Into California North



Interface Direction	2024 Summer	2024/25 Winter
Into California North TTC	3,972 MW[27]	6,631 MW
Percentage of Peak Load	14%	29%

Interface WTI04: Into California South



Interface Direction	2024 Summer	2024/25 Winter
Into California South TTC	7,829 MW	11,288 MW
dc-only interfaces	3,220 MW	3,220 MW
Total of TTC and dc-only interfaces	11,049 MW	14,508 MW
Percentage of Peak Load	28%	69%

[27] Value is from the Oregon to California North interface, as the total import interface calculation was more limiting.

Interface WTI05: Into Wasatch Front



Interface Direction	2024 Summer	2024/25 Winter
Into Wasatch Front TTC	5,965 MW[28]	5,558 MW
dc-only interfaces	200 MW	200 MW
Total of TTC and dc-only interfaces	6,165 MW	5,758 MW
Percentage of Peak Load	23%	35%

Interface WTI06: Into Southwest



Interface Direction	2024 Summer	2024/25 Winter
Into Southwest TTC	5,247 MW[29]	8,470 MW[30]
Percentage of Peak Load	22%	66%

[28] Value is from the California South to Wasatch Front interface, as the total import interface calculation was more limiting.
[29] Value is from the California South to Southwest interface, as the total import interface calculation was more limiting.
[30] Value is from the California South to Southwest interface, as the total import interface calculation was more limiting.

Interface WTI07: Into Front Range



Interface Direction	2024 Summer	2024/25 Winter
Into Front Range TTC	3,284 MW[31]	3,751 MW [32]
dc-only interfaces	920 MW	920 MW
Total of TTC and dc-only interfaces	4,204 MW	4,671 MW
Percentage of Peak Load	21%	30%

[31] Value is from the Southwest to Front Range interface, as the total import interface calculation was more limiting.
[32] Value is from the Southwest to Front Range interface, as the total import interface calculation was more limiting.

Interface ETI01: Into SPP North



Interface Direction	2024 Summer	2024/25 Winter
Into SPP North TTC	2,209 MW[33]	663 MW[34]
dc-only interfaces	660 MW	660 MW
Total of TTC and dc-only interfaces	2,869 MW	1,323 MW
Percentage of Peak Load	21%	11%

[33] Value is from the MISO West to SPP North interface, as the total import interface calculation was more limiting.
[34] Value is from the Saskatchewan to SPP North interface, as the total import interface calculation was more limiting.

Interface ETI02: Into SPP South



Interface Direction	2024 Summer	2024/25 Winter
Into SPP South TTC	5,042 MW[35]	6,445 MW[36]
dc-only interfaces	1,230 MW	1,230 MW
Total of TTC and dc-only interfaces	6,272 MW	7,675 MW
Percentage of Peak Load	13%	20%

[35] Value is from the SERC Central to SPP South interface, as the total import interface calculation was more limiting.
[36] Value is from the SERC Central to SPP South interface, as the total import interface calculation was more limiting.

Interface ETI03: Into MISO West



Interface Direction	2024 Summer	2024/25 Winter
Into MISO West TTC	7,791 MW[37]	9,086 MW[38]
dc-only interfaces	160 MW	160 MW
Total of TTC and dc-only interfaces	7,951 MW	9,246 MW
Percentage of Peak Load	19%	26%

Interface ETI04: Into MISO Central



Interface Direction	2024 Summer	2024/25 Winter
Into MISO Central TTC	12,714 MW	20,449 MW[39]
Percentage of Peak Load	35%	63%

[37] Value is from the PJM West to MISO West interface, as the total import interface calculation was more limiting.
[38] Value is from the PJM West to MISO West interface, as the total import interface calculation was more limiting.
[39] Value is from the PJM West to MISO Central interface, as the total import interface calculation was more limiting.

Interface ETI05: Into MISO South



Interface Direction	2024 Summer	2024/25 Winter
Into MISO South TTC	4,295 MW[40]	4,336 MW[41]
Percentage of Peak Load	12%	13%

Interface ETI06: Into MISO East



Interface Direction	2024 Summer	2024/25 Winter
Into MISO East TTC	5,139 MW	7,019 MW
dc-only interfaces	160 MW	160 MW
Total of TTC and dc-only interfaces	5,299 MW	7,179 MW
Percentage of Peak Load	25%	44%

[40] Value is from the SPP South to MISO South interface, as the total import interface calculation was more limiting.
[41] Value is from the SPP South to MISO South interface, as the total import interface calculation was more limiting.

Interface ETI07: Into SERC Central



Interface Direction	2024 Summer	2024/25 Winter
Into SERC Central TTC	6,878 MW	8,443 MW
Percentage of Peak Load	15%	18%

Interface ETI08: Into SERC Southeast



Interface Direction	2024 Summer	2024/25 Winter
Into SERC Southeast TTC	4,900 MW	6,525 MW
Percentage of Peak Load	11%	15%

Interface ETI09: Into SERC Florida



Interface Direction	2024 Summer	2024/25 Winter
Into SERC Florida TTC	2,958 MW	1,807 MW
Percentage of Peak Load	6%	4%

Interface ETI10: Into SERC East



Interface Direction	2024 Summer	2024/25 Winter
Into SERC East TTC	6,959 MW	5,463 MW[42]
Percentage of Peak Load	16%	12%

[42] Value is from PJM South to SERC East interface, as the total import interface calculation was more limiting.

Interface ETI11: Into PJM West



Interface Direction	2024 Summer	2024/25 Winter
Into PJM West TTC	21,773 MW	10,942 MW[43]
Percentage of Peak Load	28%	16%

Interface ETI12: Into PJM East



Interface Direction	2024 Summer	2024/25 Winter
Into PJM East TTC	4,762 MW[44]	9,815 MW[45]
Percentage of Peak Load	11%	28%

[43] Value is from the PJM South to PJM West interface, as the total import interface calculation was more limiting.
[44] Value is from the PJM West to PJM East interface, as the total import interface calculation was more limiting.
[45] Value is from the PJM West to PJM East interface, as the total import interface calculation was more limiting.

Interface ETI13: Into PJM South



Interface Direction	2024 Summer	2024/25 Winter
Into PJM South TTC	9,578 MW	9,035 MW[46]
Percentage of Peak Load	28%	27%

Interface ETI14: Into New York



Interface Direction	2024 Summer	2024/25 Winter
Into New York TTC	2,802 MW	4,814 MW[47]
dc-only interfaces	1,000 MW	1,000 MW
Total of TTC and dc-only interfaces	3,802 MW	5,814 MW
Percentage of Peak Load	12%	24%

[46] Value is from the PJM West to PJM South interface, as the total import interface calculation was more limiting.
[47] Value is from the PJM East to New York interface, as the total import interface calculation was more limiting.

Interface ETI15: Into New England



Interface Direction	2024 Summer	2024/25 Winter
Into New England TTC	2,313 MW	3,033 MW
dc-only interfaces	2,225 MW	2,225 MW
Total of TTC and dc-only interfaces	4,538 MW	5,258 MW
Percentage of Peak Load	19%	25%

Chapter 9: Acknowledgements

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Appendix A: Key Study Opportunities

Observation 1: There is an opportunity to develop guidance for subdividing large areas and standardizing data sources for future studies.
One challenge was selecting appropriately sized and electrically connected TPRs. It is essential to strike the right balance to identify significant limitations of interregional transfers. As the BPS evolves, these TPRs should be reviewed and modified as appropriate. In a few instances where Balancing Authorities are split into multiple TPRs, there are opportunities to enhance available data to more efficiently account for each TPR, improving the data quality in future studies.

Observation 2: There is an opportunity to improve coordination with NERC's Long-Term Reliability Assessment (LTRA) process.
Some differences in load forecasts and resource assumptions were noted when comparing study cases to LTRA data. Standardizing case-building processes and associated content could ensure consistency and improve the efficiency of future studies.

Observation 3: Future studies may need special cases to study additional conditions.
This transfer analysis used cases designed for transmission planning assessments.[48] This study revealed a potential need to develop additional cases, such as to study heavy transfers in both directions of an interface.

Observation 4: Future studies should include stability analysis.
Part 1 studies included power flow analysis, voltage screening, and known stability limits. Future studies should include more expansive stability analysis to identify potentially more restrictive limits, especially because stability limitations can become more prominent when there is increased reliance on heavy transfers across large areas.

Observation 5: A future study evaluation schedule is needed.
The study results are highly dependent on the point-in-time information used to develop the cases. Since generation construction and retirement, transmission expansion plans, and load forecasts are constantly evolving, it would be beneficial to repeat this transfer analysis on a regular basis. Further, given the long lead time required for transmission additions, consideration should be given to future study horizons.[49]

[48] For example, TPL-001-5 (nerc.com)
[49] The study horizon for ITCS Part 2 is 2024 and 2033.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 67

August 20 Order

Order No. 202-25-7

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

Order No. 202-25-3

J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, MI. In 2021, Consumers announced that it planned to implement a "speed closure" of the Campbell Plant fifteen years before the end of its scheduled design life.[1] Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant's retirement and discontinue its operations on May 31, 2025.

Order No. 202-25-3, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until August 21, 2025. That order was based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO). Specifically, I determined that MISO likely faced tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. I determined that the continued operation of the Campbell Plant would provide additional generation capacity during these periods which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety. I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability. My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[2] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply

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[1] *See Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation*, Consumers Energy (June 23, 2021), https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation. As a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline.

[2] *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, at 16 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf (NERC 2025 Summer Reliability Assessment).

shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.[3]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[4] Additionally, EIA stated, "[t]ypically, Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[5] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it was not projected to be available during the peak demand period this summer.[6]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts and Consumers acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."[7]

Fourth, MISO's Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[8] While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and these results "reinforce the need to increase capacity."[9]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-3 continue, both in the near and long term. The summer season has not yet ended, and the production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO this summer. That need is evidenced by the fact that the Campbell Plant was called on by MISO to generate large amounts of electricity during the heat wave that hit MISO this past June. According

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[3] *Id.*
[4] *Michigan State Profile and Energy Estimates*, U.S. Energy Info. Admin. (Oct. 17, 2024), https://www.eia.gov/state/print.php?sid=MI.
[5] *Id.*
[6] The start-up of Palisades is scheduled for the fourth quarter of 2025.
[7] NERC 2025 Summer Reliability Assessment at 16.
[8] *Planning Resource Auction—Results for Planning Year 2025–2026,* Midcontinent Independent System Operator, Inc., 13 (May 29, 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf. (MISO Planning Resource Auction – Results for Planning Year 2025-26).
[9] *Id*. at 2,12.

to the U.S. Environmental Protection Agency's data, over the month of June, the Campbell Plant generated approximately 664,000 MWh, running at 61% capacity.[10] In fact, between June 11 and August 18, MISO issued dozens of alerts to manage grid reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits. MISO issued alerts for the Central Region on at least 40 of the 69 days between June 11 and August 18. In June, MISO issued alerts affecting the Central Region on 18 days, including an Energy Emergency Alert (EEA) level 1 ("Max Gen Step 1b") on June 23 to enable MISO to take emergency action to ensure grid stability, including bringing additional resources online.[11] The Central Region had alerts on 21 days in July, including one Max Generation Warning on July 29 and two Max Generation Alerts on July 28 and 29.[12] Two Capacity Advisory Initiate alerts have been issued in August to date.[13] Moreover, the May 2025 NERC Summer Reliability Assessment referenced a Seasonal Outlook issued by the National Oceanic and Atmospheric Administration (NOAA), which estimates that much of the Midwest has a 33%-40% chance to experience above-normal temperatures this summer.[14] The Seasonal Outlook released by NOAA on July 17, 2025, increased this estimate for much of the region to a 40%-50% chance.[15]

MISO's resource adequacy problems are not limited to the summer. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[16] MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round

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[10] *See, Custom Data Download, EPA CAMPD (Clean Air Markets Program Data),* https://campd.epa.gov/data/custom-data-download *(search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >>Apply >>"2025" and "June." The data can then be filtered to only include the Campbell Plant.)*

[11] An Energy Emergency Alert is an alert declared by the Transmission Provider in accordance with the NERC Operating Manual associated with the Transmission Provider's inability to provide for the Energy and Operating Reserve requirements of the MISO Balancing Authority Area. For more information, see MISO, FERC Electric Tariff, Module A, § 1.E (Definitions) (92.0.0). For more information on Energy Emergency Alert levels, see North American Electric Reliability Corporation. (n.d.). *EOP-011-1 Emergency Operations*. https://www.nerc.com/pa/stand/reliability%20standards/eop-011-1.pdf.

[12] A Max Gen Alert occurs when MISO is forecasting a potential capacity shortage. A Max Gen Warning is a warning to prepare for a possible Max Gen Event. *See* MISO Operating Procedures, https://efis.psc.mo.gov/Document/Display/9379 (20180920).

[13] A Capacity Advisory alert is an advisory issued based on the potential for limited operating capacity margins (<5%) in the following 2-3 days. *See* MISO Operating Procedures, https://efis.psc.mo.gov/Document/Display/9379 (20180920).

[14] NERC 2025 Summer Assessment at 9.

[15] *Seasonal Outlook*, NOAA Climate Prediction Ctr., (July 17, 2025), https://www.cpc.ncep.noaa.gov/products/predictions/long_range/seasonal.php?lead=1.

[16] M*idcontinent Independent System Operator, Inc.*, FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. Midcontinent Independent System Operator, Inc., 180 FERC ¶ 61,141 (2022).

concern."[17] MISO noted that over 60 percent of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[18]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[19] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projects that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[20]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative.*"[21] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[22]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Michigan.[23]

On June 6, 2025, subsequent to the issuance of Order No. 202-25-3, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy

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[17] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).
[18] *Id.* at 3-4.
[19] *Attributes Roadmap*, MISO (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[20] *Id.* at 11.
[21] *MISO's Response to the Reliability Imperative*, MISO (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.
[22] *Id.* at 12.
[23] MISO Planning Resource Auction – Results for Planning Year 2025-26 at 13.

planning reserve margin requirements.[24] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[25] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[26] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[27]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[28] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[29]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[30] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three year grace period to commence commercial operations.[31] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[32] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

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[24] *2025 OMS-MISO Survey Results*, OMS and MISO (Updated June 6, 2025) https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.
[25] *Id.* at 2.
[26] *Id.* at 7.
[27] *Id.* at 9.
[28] *Id.* at 7, 9.
[29] *Id.*
[30] M*idcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).
[31] 192 FERC ¶ 61,064 at P 84.
[32] *See generally, US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P Global (May 2025), US gas-fired turbine wait times as much as seven years; costs up sharply | S&P Global. "With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."

Order 202-25-3 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[33] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[34] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[35]

The Department's July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[36] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[37] In addition, as just one example, Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[38]

Grid operators—including MISO itself—have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the

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[33] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

[34] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[35] *Id*.

[36] *See also Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy (July 2025), at 1, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[37] Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan*, (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

[38] *See Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center*, Data Center Dynamics (August 05, 2025), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-to-provide-1gw-of-power-to-new-hyperscale-data-center/ (quoting Consumers Energy CEO Garrick Rochow).

changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[39] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[40] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[41]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[42] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and accelerated retirements of generation facilities supporting the issuance of Order No. 202-25-3 will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest under FPA section 202(c).

To ensure the Campbell Plant will be available if needed to address emergency conditions, the Campbell Plant shall remain in operation until November 19, 2025.[43]

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[39] Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce, Subcommittee on Energy, 119th Cong. (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), at 5, https://democrats-energycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-media-document/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf.

[40] *Id.* at 6.

[41] *Id.* at 7.

[42] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b) (2018).

[43] 16 U.S.C. § 824a(c)(4).

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

A. From August 21, 2025, MISO and Consumer Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

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

D. By September 4, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

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

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Campbell Plant shall not be considered a capacity resource.

H. This Order shall be effective from 00:00 Eastern Daylight Time (EDT) on August 21, 2025, and shall expire at 00:00 EDT on November 19, 2025, with the exception of applicable compliance obligations in paragraph D.

I. Issued in Norfolk, Virginia at 8:50pm Eastern Daylight Time on this 20th day of August 2025.

Chris Wright
Secretary of Energy

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

Michigan Public Service Commissioners
Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 68

Grid Strategies September Report

A Review of DOE's Second 202(c) Order for the Campbell Coal Plant

Michael Goggin

September 2025

This report responds to DOE's August 2025 order[1] mandating that the Campbell coal plant in Michigan be kept online, overriding decisions to retire the plant by the utility, Michigan utility regulators, and the regional grid operator. Our June report, *A Review of DOE's 202(c) Order for the Campbell Coal Plant,* responded to DOE's first order[2] for the Campbell plant, which was issued in May. This report reaffirms and incorporates the June report. As explained there, utility, state, regional, and national regulatory requirements already ensure Michigan and MISO have enough power plant capacity to keep the lights on. This report focuses on rebutting new arguments in DOE's August 2025 order.

1. There is no evidence MISO needs Campbell this fall.

DOE's May order for Campbell argues that "NERC anticipates that the near-term period of highest capacity shortfall for MISO will occur in August,"[3] and repeatedly claims that summer was the primary risk period. DOE's new order now proposes to keep the plant online for 90 more days, through almost the entire fall season.

To support this new order, DOE cites, among other sources, to a theoretical modeling report MISO published in 2023, the *Attributes Roadmap*. That report actually found minimal fall risk under both MISO's current generation mix and expected 2032 generation mix, and only identified potential fall risk under another theoretical future generation mix, for 2027.[4] The potential future generation mix that generates equivalent fall and summer risk includes 22 GW of coal capacity, 49 GW of wind, and 44 GW of solar.[5] As of June 2025, MISO has around 47 GW of coal capacity, 32 GW of wind, and 18 GW of solar, close to the current generation mix that

[1] U.S. Dep't of Energy ("DOE"), *Order No. 202-25-7* (Aug. 2025), *available at* https://www.energy.gov/sites/default/files/2025-08/MISO%20Order%20No.%20202-25-7.pdf (*hereinafter* "*Order No. 202-25-7*").
[2] DOE, *Order No. 202-25-3* (May 2025), *available at* https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf (*hereinafter* "*Order No. 202-25-3*").
[3] *Id.* at 1.
[4] Midcontinent Indep. Sys. Operator, Inc. ("MISO"), *Attributes Roadmap: A Reliability Imperative Report* (Dec. 2023), at 11, *available at* https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[5] MISO, *MISO Futures Report: Series 1A* (Nov. 1, 2023), at 75, *available at* https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

MISO's report found did not have fall risk.[6] Thus, the MISO report cited by DOE actually confirms there is minimal fall risk associated with today's generation mix.

Contrary to DOE's unsupported claim of fall resource adequacy risk, MISO's data show it has surplus generating capacity this fall. MISO uses detailed probabilistic resource adequacy modeling, described in more detail in my June report, to confirm that it has sufficient resources to meet electricity demand in all seasons. The June report explains that MISO uses the industry standard criteria of a 1-day-in-10-year Loss of Load Expectation ("LOLE") to determine the optimal amount of capacity needed to meet demand without burdening ratepayers with the cost of surplus capacity. MISO explains that it ensures that:

> [T]he annual LOLE is at 1 day in 10 years, or 0.1 LOLE for the Summer season, and for the off seasons, values of LOLH [Loss of Load Hours] and EUE [Expected Unserved Energy] are calculated at the point where the seasonal LOLE is at 1 day in 100 years, or 0.01 LOLE.[7]

In other words, for this fall, MISO targeted a reserve margin that meets a level of reliability that is 10 times more stringent than the industry standard.

Moreover, MISO's capacity auction for this fall produced a large capacity surplus above even the level needed for the unduly stringent 1-day-in-100 years target. Without Campbell, MISO's capacity auction for this fall cleared at a reserve margin of 17.5%, well above the 14.9% target needed to meet the 1-day-in-100-years target.[8] Retaining Campbell only further adds to that capacity surplus, burdening MISO ratepayers with the cost of retaining capacity that is not needed.

The zonal results from MISO's 2025/26 capacity auction also confirm there is no resource adequacy shortfall this fall in Zone 7, which is the MISO footprint in Michigan's Lower Peninsula. Without Campbell, Zone 7 has 337.5 MW of supplies above the Local Clearing Requirement, which is the amount of capacity that MISO has concluded must come from within Zone 7 after accounting for transmission constraints.[9] And MISO also studied Campbell's retirement and determined that it could retire without causing a reliability concern on the local (sub-Zone 7) transmission system. If MISO had identified an unmet reliability need, it could have retained Campbell under a System Support Resource designation.

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[6] MISO, *Fact Sheet* (July 2025) (last visited Sept. 4, 2025), https://www misoenergy.org/meet-miso/media-center/corporate-fact-sheet/.
[7] MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report* (2025), at 9, *available at* https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401 (*hereinafter* "PY 2025−2026 LOLE Study Report").
[8] MISO, *Planning Resource Auction: Results for Planning Year 2025-26 (Corrections)* (May 29, 2025), at 4−5, https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.
[9] *Id.* at 19.

2. There is no evidence Campbell was needed during this year's summer heat wave.

DOE claims that there are "[c]ontinuing [e]mergency [c]onditions" and that Campbell will "continue to be a critical asset to maintain reliability in MISO this summer" because MISO issued one Max Generation Warning on July 29, Max Generation Alerts on July 28 and 29, and reached a Maximum Generation Event Step 1b on June 23.[10] All of these events are operating practices well within MISO's established processes for periods of high electricity demand, and do not indicate that Campbell was actually needed to maintain reliability. In fact, Step 1b is part of Event Step 1, which is only the first step out of five in MISO's toolkit for addressing maximum generation events,[11] as shown below. The July Max Generation Alerts and Warning that DOE highlights did not even reach that first step in MISO's event hierarchy.

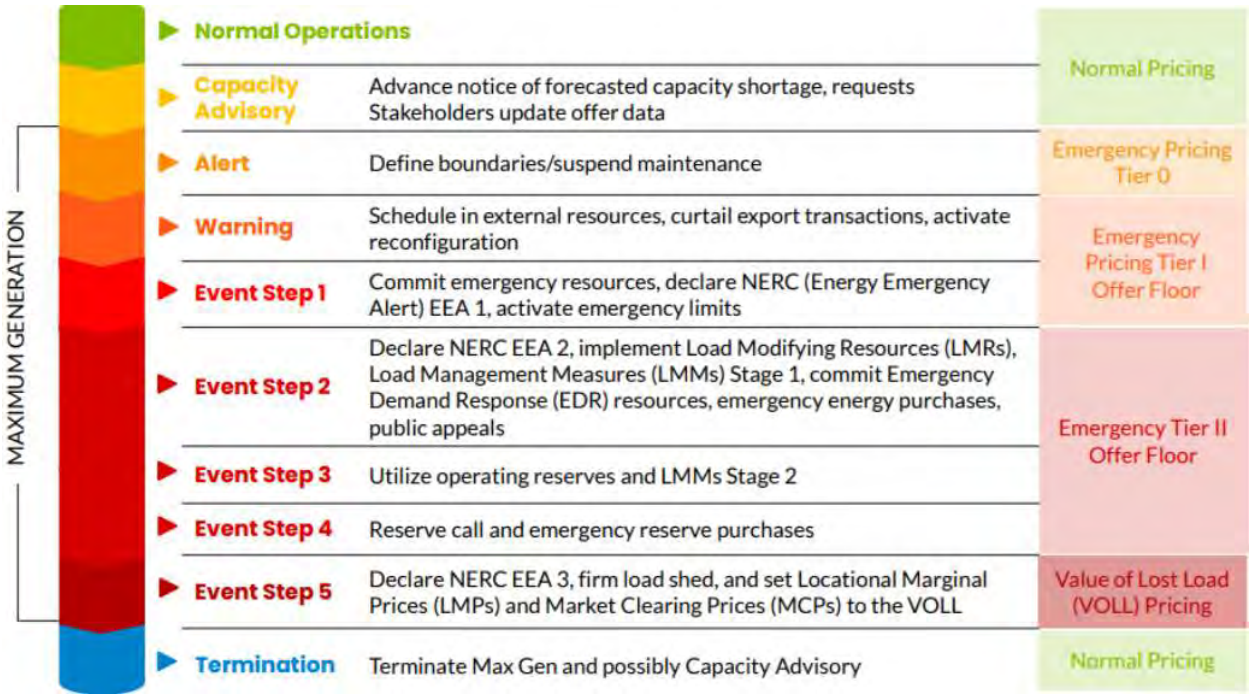


Figure 1: MISO chart showing its steps for Maximum Generation Events

Our June report documented these and other tools MISO has available and uses when electricity demand is high. As the June report explained, the additional tools MISO can deploy if an event progresses past Step 1b include "activating additional tiers of demand response resources, issuing public conservation requests, procuring emergency energy, and directing resources with environmental de-rates to request waivers, all before load is shed."[12] As additional indication that

[10] *Order No. 202-25-7*, *supra* note 1, at 2–3.
[11] MISO, *Maximum Generation Emergency Declarations through June 2024* (updated Aug. 30, 2024), at 2, *available at* https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/Capacity_Emergency_Historical_Information.pdf (*hereinafter* "MISO Capacity Emergency Historical Information").
[12] *Motion to Intervene and Request for Rehearing and Stay of Public Interest Organizations: Exhibit 2, Grid Strategies Report* (June 18, 2025), at 38–39.

1b events are routine, MISO North/Central experienced one 2a event, one step beyond 1b, in each of 2021, 2022, and 2023.

MISO North/Central experienced seven Maximum Generation warnings or full events from 2020 through June 2024: three during the summer, three during the winter, and one during the spring.[13] None were in the fall, confirming that fall is not a period of significant loss of load risk for MISO. And none of those warnings or events resulted in a loss of load in MISO North/Central.[14]

Federal government data show that the Campbell plant had poor availability this summer, including during these seven MISO peak demand events in 2020−2024, and the June 2025 Step 1b event that DOE's order highlights.[15] In the majority of those events, at least one of the three generating units at Campbell was offline, as shown in Table 1 below. On average, only two of three Campbell units were available during these seven events, reducing the plant's output during the events by 30% on average. For comparison, on average MISO coal plants have an outage rate of less than 8% for smaller units and less than 10% for larger units.[16]

Table 1: Campbell Availability During Recent MISO North/Central Maximum Generation Events

Event	Units offline	Maximum output (MW)	Plant availability
July 6-7, 2020, 1a	2	334	22%
Feb 16, 2021, 1b	0	1,426	94%
June 10, 2021, 2a	0	1,514	100%
Jan 7, 2022, warning	2	902	60%
May 12-13, 2022, warning	0	1,434	95%
Dec 23, 2022, 2a	1	1,203	79%
Aug 23-24, 2023, 2a	1	898	59%
June 23, 2025, 1b	2	760	50%
Average	**1**	**1,059**	**70%**

[13] MISO Capacity Emergency Historical Information, *supra* note 11, at 2 (details on MISO's designation of warning, 1a, 1b, and 2a events).
[14] MISO did shed 700 MW of firm load in MISO South during Winter Storm Uri, but none in MISO North/Central. *See* Fed. Energy Regulatory Comm'n ("FERC"), et al., *The February 2021 Cold Weather Outages in Texas and the South Central United States* (last updated Dec. 8, 2021), at 151, *available at* https://ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.
[15] U.S. Environmental Protection Agency ("EPA"), *Continuous Emission Monitoring Systems (CEMS) Data* (last visited Sept. 4, 2025), https://campd.epa.gov/data/custom-data-download. Data for Campbell plant output during the July 2025 MISO max gen warning event are not yet available. EPA Continuous Emission Monitoring Systems data report gross generation before subtracting plant consumption and losses, so all figures here are gross generation. The "maximum output" column reports the maximum gross generation of the plant during the event, and the "plant availability" column reports this maximum output as a percent of the maximum gross generation of 1,514 MW during the event on June 10, 2021.
[16] PY 2025−2026 LOLE Study Report, *supra* note 7, at 26.

During the peak demand period of the June 23, 2025, Step 1b event that DOE's order highlights, Campbell Units 1 and 2 provided zero output. As shown in Figure 2 below, Unit 2 had been offline for more than a month at that point, while Unit 1's output abruptly dropped to zero midday on June 23, before peak demand that evening.

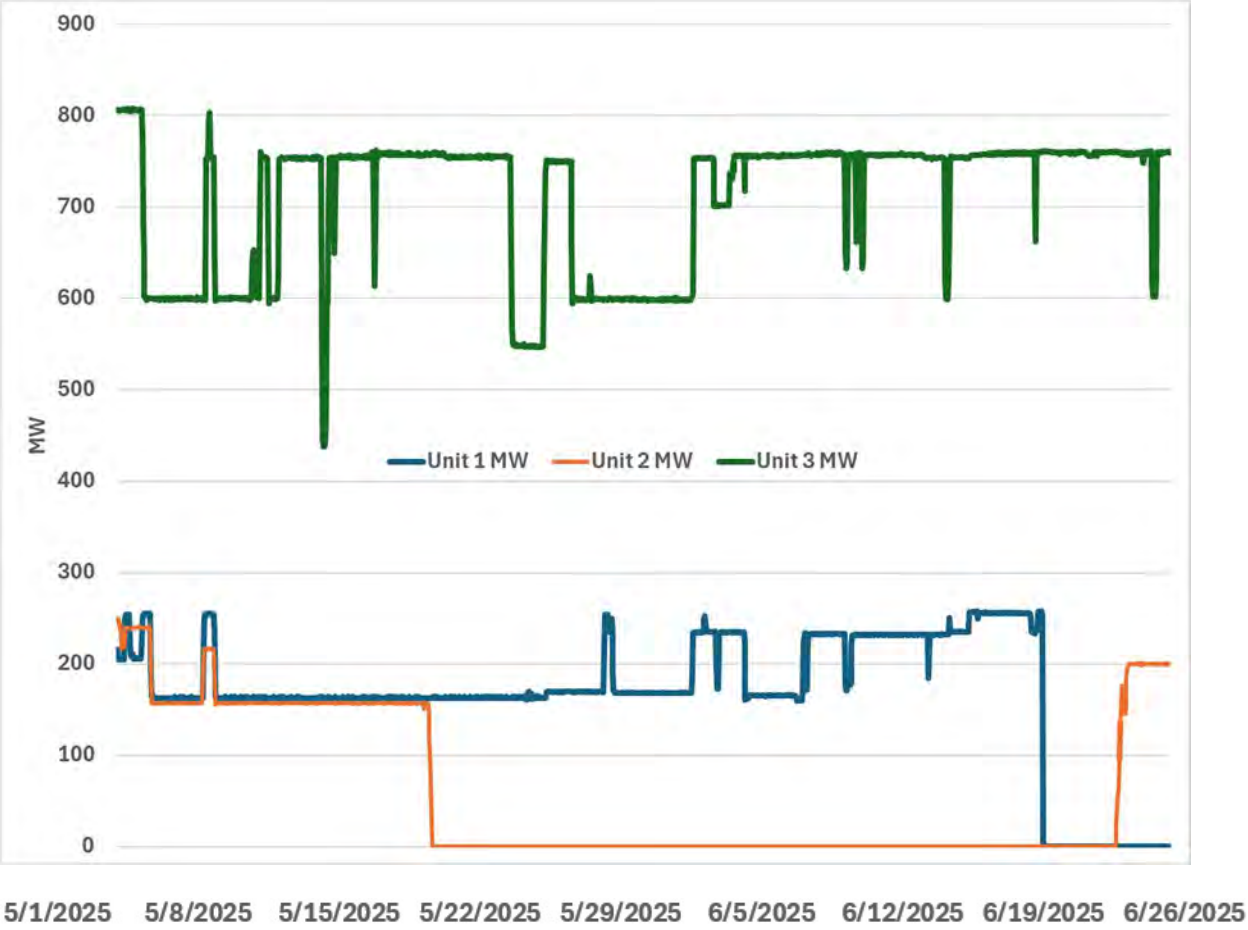


Figure 2: Campbell unit output over May and June 2025, from EPA CEMS dataset

3. Campbell's high costs make it uneconomic even during high demand periods

Public data indicate that Campbell's fuel and operating and maintenance costs exceed $40/MWh, which makes it an uneconomic source of generation. Specifically, DOE's Energy Information Administration ("EIA") data show Campbell paid an average of $3.36 per million British thermal units ("MMBtu") for coal purchased in June 2025, representing a more than 25% cost increase from the previous month; this translates into a cost of $34.15/MWh based on Campbell's fuel consumption and electricity generation in June.[17] Data filed with the Federal Energy Regulatory Commission ("FERC") show that Campbell incurred over $54 million in non-fuel operations and

[17] Energy Info. Admin. ("EIA"), *Form EIA-923 detailed data with previous form data* (Aug. 2025, last visited Sept. 4, 2025), (data for June 2025), https://www.eia.gov/electricity/data/eia923/xls/f923_2025.zip.

maintenance ("O&M") costs in 2024,[18] which corresponds to an additional $6.59/MWh in average cost per MWh generated in 2024, for total operating costs of $40.74/MWh.[19]

These costs are higher than average prices in the MISO market during a typical year, and even during high demand periods like MISO experienced in June 2025. Over the one-year period from July 2024 through June 2025, the MISO Day-Ahead price at the Campbell market node exceeded $40.74/MWh in only 21% of hours.[20] Thus, in 79% of hours, Campbell could not earn enough to cover its operational costs.

Campbell's operating costs exceeded the market price at the Campbell node over 70% of the time from May 24−June 30, 2025;[21] during those hours, the plant clearly operated at a loss. Combining this MISO price data with the Campbell hourly generation data presented above confirms that the plant operated at a net loss in the MISO market over those 38 days, with losses from the plant operating during periods of low prices more than offsetting profits during higher-priced hours. This indicates that the plant operated at an overall loss even during a high-demand summer period that included the June 23 event, which is consistent with Consumers Energy reporting that it incurred net costs of $29 million over that time period due to DOE's Campbell order.[22]

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[18] *Consumers Energy Company submits FERC Form 1 report for 2024/Q4*, Docket No. EL25-90 (Mar. 20, 2025), Accession No. 20250320-8006, at 402, *available at* https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250320-8006. Fuel costs in row 20 were subtracted from total production expenses in row 34 to arrive at non-fuel O&M costs. The non-fuel O&M costs for Unit 3 were then divided by .9331 to calculate the total non-fuel O&M costs for Unit 3, reflecting that the cost figures in Form 1 only report Consumers Energy's costs for its 93.31% share of Unit 3.

[19] Form 1 does not distinguish between variable O&M costs that are incurred as a function of generating MWh and fixed O&M costs that are incurred simply by keeping the plant open. However, given that both types of costs will be incurred as a result of DOE mandating that the Campbell plant remain open, and the plant's ongoing capacity factor is unlikely to drastically change from its capacity factor in 2024, expressing O&M costs in $/MWh accurately reflects the ongoing costs of operating the plant. Dollar-per-MWh costs were calculated based on EIA Form 923 generation for 2024.

[20] MISO, *Historical Annual Day-Ahead LMPs* (July 3, 2025) (last visited Sept. 4, 2025), https://www misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AHistorical%20LMP%2FMarketReportName%3AHistorical%20Annual%20Day-Ahead%20LMPs%20(zip)&t=10&p=0&s=MarketReportPublished&sd=desc. Coal plants typically sell their output in the Day-Ahead market instead of the Real-Time market due to their inflexibility, so this analysis is based on Day-Ahead market prices.

[21] This period was chosen because DOE issued the 202c order late on May 23, and EPA data showing the hourly generation of Campbell is currently only available through the end of June 2025.

[22] U.S. Sec. and Exch. Comm'n ("SEC"), *Form 10-Q* (July 31, 2025), (report for Consumers Energy for the second quarter of 2025, filed July 2025), *available at* https://d18rn0p25nwr6d.cloudfront net/CIK-0000201533/10a900b7-263b-4ccd-82a0-4162ba7ae5f2.pdf.

4. DOE's July 2025 Resource Adequacy report is based on flawed inputs

DOE's order briefly mentions a report it issued on July 7, 2025,[23] entitled *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*. That report has been widely criticized,[24] including for vastly overstating the need for resources by using assumptions for nationwide generator retirements, capacity additions, and load growth that are drastically higher than other data and projections from EIA, the DOE entity tasked with "independent statistics and analysis." As summarized in Table 2 below, in total DOE's report overstates the need for resources by around 200 GW relative to other DOE sources. If those inputs were used instead, the report would not even have found a 2030 need because 109 GW of resource additions would more than meet the 92 GW of need created by 40 GW of load growth plus 52 GW of retirements.

Table 2: Assumptions in DOE's July 2025 report vs other DOE data, GW by 2030

	DOE July 2025 report	Other DOE data/projections	Overstatement of need for resources
Capacity retirements	104 GW firm	52 GW nameplate[25]	52 GW
Resource additions	22 GW firm	109 GW[26]	87 GW
Load growth	101 GW	40 GW in high growth case[27]	61 GW
Total overstatement of need for resources			**200 GW**

5. Conclusion

This report builds on the points made in our June report. DOE's two Campbell orders are both unnecessary and costly market interventions.

6. Qualifications of Michael Goggin

Michael Goggin has worked on electricity market and reliability issues for over 20 years. At Grid Strategies he serves as an expert on those topics for a range of clients including state utility

[23] DOE, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, (July 7, 2025), at 1, *available at* https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[24] For example, *see* Ric O'Connell, *GridLab Analysis: Department of Energy Resource Adequacy Report* (July 11, 2025), *available at* https://gridlab.org/gridlab-analysis-department-of-energy-resource-adequacy-report/; *see also* Jennifer Danis, et al., *Enough Energy: A Review of DOE's Resource Adequacy Methodology* (July 2025), *available at* https://policyintegrity.org/files/publications/IPI_EnoughEnergy_FinalReport.pdf.

[25] EIA, *EIA-860M* (June 2025), (data for May 2025), https://www.eia.gov/electricity/data/eia860m/.

[26] *Id.* To be conservative, the tally of 109 GW of planned resource additions includes only thermal and battery resources and does not account for the significant resource adequacy contributions from planned wind and solar resources. The 22 GW figure for the July 2025 DOE report is based on the statement on page 1 that for capacity additions by 2030, "only 22 GW would come from firm baseload generation sources."

[27] EIA Annual Energy Outlook high growth case assumes 6% growth through 2030, versus 15% assumed in DOE's July 2025 report.

regulators, grid operators, and non-profit organizations. He has testified as an expert in dozens of proceedings before state utility commissions in Arizona, Colorado, Georgia, Iowa, Illinois, Indiana, Wisconsin, Louisiana, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, South Carolina, Virginia, Washington, and Wisconsin, as well as before FERC.

For the preceding ten years Michael worked at the American Wind Energy Association (now known as the American Clean Power Association), where he provided technical analysis regarding renewable energy, transmission, and wholesale electricity markets, including directing the organization's research and analysis team from 2014-2018. Prior to the American Wind Energy Association, he worked at a firm serving as a consultant to DOE, and at two environmental groups.

7. Sources

The principal documents I relied on in preparing this report include the materials listed below and in footnotes. To the extent feasible, relevant documents are included in the Appendix of the Request for Rehearing.

-DOE, *Order No. 202-25-7* (Aug. 2025), *available at* https://www.energy.gov/sites/default/files/2025-08/MISO%20Order%20No.%20202-25-7.pdf

-DOE, *Order No. 202-25-3* (May 2025), *available at* https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf

-MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report*, *available at* https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401

-MISO, *Planning Resource Auction Results for Planning Year 2025-26 (Corrections, reposted May 29, 2025)*, *available at* https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf

-MISO, *Attributes Roadmap* (Dec. 2023), *available at* https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf

-MISO, *MISO Market Capacity Emergency*, *available at* https://cdn.misoenergy.org/SO-P-EOP-11-002%20Rev%2021%20MISO%20Market%20Capacity%20Emergency683501.pdf

MISO, *Historical Annual Day-Ahead LMPs*, *available at* https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AHistorical%20LMP%2FMarketReportName%3AHistori

cal%20Annual%20Day-Ahead%20LMPs%20(zip)&t=10&p=0&s=MarketReportPublished&sd=desc

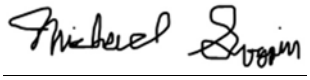
-FERC, *Consumers Energy Company submits FERC Form 1 report for 2024/Q4* (Mar. 2025), *available at* https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250320-8006

-U.S. EPA, *Continuous Emission Monitoring Systems: Custom Data Download*, *available at* https://campd.epa.gov/data/custom-data-download

-U.S. DOE, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (July 2025), *available at* https://www.energy.gov/sites/default/files/202507/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf

-DOE Energy Information Administration, *Form EIA-923 June 2025* (Aug. 2025), *available at* https://www.eia.gov/electricity/data/eia923/

-DOE Energy Information Administration, *Form EIA-860M*, (data for May 2025, published June 2025), *available at* https://www.eia.gov/electricity/data/eia860m/



Michael Goggin
Vice President
Grid Strategies, L.L.C.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 69

Powers Sept. Decl.

DECLARATION OF BILL POWERS, P.E.

I, Bill Powers, P.E., declare as follows:

1. I am the principal of Powers Engineering, an engineering firm that consults on issues related to the operation of, and control of pollution from, power plants, including coal-fired power plants. My office is located in San Diego, California.

2. My professional and educational experience is set forth in the curriculum vitae attached to this declaration (Attachment A) and in the declaration I prepared on the U.S. Department of Energy's and Secretary of Energy Christopher Wright's ("DOE") May 23, 2025 order regarding Consumers Energy Company's ("Consumers") J.H. Campbell coal-fired power plant (Order No. 202-25-3) ("May Order"). That declaration, attached here as Attachment B, was filed with DOE on June 18, 2025 as an attachment to the Request for Rehearing of the May Order filed by 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, Ecology Center, and Urban Core Collective ("Public Interest Organizations").

3. My June 18 declaration provides my opinion on: (A) the extent to which Campbell can operate reliably after May 31, 2025; (B) whether Campbell can operate effectively as a peaking unit; and (C) easily attainable steps DOE can require to ensure Campbell's operations are consistent with environmental requirements and minimize adverse environmental impacts. I did not opine on the claimed energy emergency described in the Order, nor did I opine on alternatives to Campbell that are available to DOE to effectively address the circumstances described in the Order.

4. I am familiar with DOE's August 20, 2025 order regarding Consumers' Campbell plant (Order No. 202-25-7) ("August Order"). I have been asked by the Public Interest Organizations to opine on: (A) the continued validity of the opinion I provided in my June 18 declaration; (B) the extent to which Campbell can reliably operate in light of any new information that has emerged since my June 18 declaration; and (C) environmental implications of Campbell's continued operation, including adverse environmental impacts and consistency with environmental requirements.

A. <u>The continued validity of the opinion I provided in my June 18 declaration.</u>

5. The opinion I provided in my June 18 declaration continues to be valid. I am not aware of any new information that weakens or undermines my June 18 declaration. In fact, as I discuss below, I am aware of new information that reinforces my opinion. Thus, I fully reaffirm and incorporate here my June 18 declaration.

6. Additionally, I do not identify anything in the August Order that responds to my June 18 declaration. I also do not identify in the August Order material that addresses the types of matters addressed in my June 18 declaration.

B. <u>The extent to which Campbell can reliably operate in light of any new information that has emerged since my June 18 declaration.</u>

7. In my professional opinion, it is unlikely that Campbell can be depended upon to operate reliably in its current state as of August 2025. This is especially true if the plant is required to run for extended periods of time; is required to stop and start numerous times; or attempts to start up at an accelerated rate in response to extreme demand conditions. The reasons for that opinion are set forth in my June 18 declaration at pages 4–17 (which, again, I incorporate here).

8. As I explained in my June 18 declaration, each of Campbell's three units suffered outages in 2023 and 2024 that tended to be long, recurrent, and due to the types of failures that are the predictable result of old equipment, minimal capital spending, and minimal major maintenance spending.[1] The record evidence shows that, in the 2022-2025 period, Consumers significantly cut back on capital expenditures and major maintenance on Campbell Units 1, 2, and 3:

- **Capital spending:** Consumers reduced its capital spending by approximately **91 percent** across all three units compared to the amount the company projected to spend if Units 1-2 operated until 2031 and Unit 3 operated until 2039.[2]
- **Major maintenance spending:** Consumers reduced its major maintenance spending by approximately **62-78 percent** across all three units compared to the amount the company projected to spend if Units 1-2 operated until 2031 and Unit 3 operated until 2039.[3]

The reductions in Consumers' capital and major maintenance spending on Units 1-3 that followed the Integrated Resource Plan (IRP) that established a May 2025 retirement date are summarized in the following table:

Capital spending	Pre-IRP projected spend 2022-25 ($MM)	Post-IRP actual/projected spend 2022-25 ($MM)	% reduction
Units 1&2	60.6	4.1	93
Unit 3	85.5	8.4	90
Major maintenance spending			
Units 1&2	14.4	5.5	62
Unit 3	23.5	5.1	78

[1] Attachment B (June 18 declaration), pp. 4-5.
[2] Ibid, pp. 5-6.
[3] Ibid.

9. Further, Consumers recently confirmed that it did "not record[] any capital expenditures at the Campbell plant in the two-year period prior to May 31, 2025."[4] Consumers' lack of capital expenditures in that two-year period is consistent with the opinion in my June 18 declaration that Consumers has been transitioning from a preventive capital spending and maintenance structure to a reactive, "fix it if it breaks" approach.[5]

10. Campbell will continue to degrade in 2025 to the extent there is a continued lack of capital spending and minimal major maintenance spending. *Id.* at 5.

11. I am not aware of any calculations or itemizations of costs that Consumers has incurred since the May Order.[6]

12. It is my opinion that if Campbell's ability to operate reliably has improved since my June 18 declaration, it is likely the result of Consumers making capital expenditures or performing major maintenance that it had cancelled after Campbell's May 31, 2025 retirement date was established in the 2021 Integrated Resource Plan settlement. I identified those foregone capital expenditures and major maintenance projects in my June 18 declaration.[7] The table below identifies a subset of those cancelled capital and major maintenance projects that are the minimum that would likely be necessary to improve Campbell's ability to operate reliably.[8]

[4] RFR Exhibit 101, Consumers, Informal Response to Michigan AG Campbell Questions, June 10, 2025, Question 1 ("Consumers June Responses to AG").
[5] Attachment B (June 18 declaration), pp. 15-16.
[6] RFR Exhibit 101 (Consumers June Responses to AG), Question 2 (stating that Consumers "has not performed any calculations to determine any amounts it could or would include in a request for cost recovery" to comply with the May Order).
[7] Attachment B (June 18 declaration), pp. 8-14.
[8] Ibid.

Unit 1	Unit 2	Unit 3
Replacement of: • Pulse Jet Fabric Filter (PJFF) bags • Boiler components • Superheat outlet pendant • Air preheater baskets	**Replacement of:** • Horizontal reheat • Selective Catalytic Reduction (SCR) catalyst • Burner assemblies • Turbine reheat stop valve • Boiler components	**Two major maintenance projects:** • Boiler feedwater pump inspection • Turbine overhaul **Replacement of:** • PJFF bags • High pressure feedwater heater 8A • SCR catalyst

13. New information reinforces my opinion that it is unlikely Campbell can be depended upon to operate reliably. For example, during June 2025—the first full calendar month of operation under the May Order—Unit 1 experienced an outage on June 23 and remained offline the rest of the month.[9]

14. In addition, Unit 2 was largely offline in June 2025, producing power on only four days in a 30-day month. It produced significant amounts of power on only three days, June 28-30, and then operating only at approximately 50 percent of its rated capacity when online.[10] Multiple operational issues contributed to Unit 2's poor performance. On July 17, 2025, Consumers informed Michigan's environmental agency that:

> [Campbell] Unit 2 was offline on May 19, 2025 and there was no immediate plan as of May 27, 2025 to bring it back online. But after further evaluation and interpretation of the DOE order . . . it has been determined that it is necessary to attempt to repair and operate Unit 2 . . . .[11]

[9] RFR Exhibit 102, EPA, Clean Air Markets Program Data (CAMPD), June daily emissions data by unit for the Campbell Plant, available at https://campd.epa.gov/data/custom-data-download. Select "emissions" from the "data type" menu; select "daily emissions" from the "data subtype" menu; and then select "apply." On the next screen, set 06/01/2025 as the start date and 06/30/2025 as the end date; search for and select "J H Campbell" from the "facility" menu; and then select "apply." Select "preview data." ("CAMPD daily emissions data").
[10] Ibid.
[11] RFR Exhibit 103, Joseph Firlit, Consumers, email to April Lazzaro, EGLE, July 17, 2025 ("July 17 email from Consumers to EGLE").

Unit 2 was "out of service due to needed boiler tube repairs and other balance of plant work"[12] when the 90-day period covered by the May Order began on May 23.[13] At the time, the estimated return to service was June 27, 2025.[14] Unit 2 then operated briefly between June 25 and July 4, 2025 before going back offline to address a water intake issue.[15]

15. Unit 2's poor performance in June 2025 is consistent with its recent operational performance. Unit 2 had very high forced outage rates in 2023 and 2024, 57.32 percent and 48.07 percent respectively, caused by worn, obsolete, and difficult to repair components.[16]

16. In my opinion, Unit 2 is suffering from chronic component operational deficiencies that severely impair its reliability.

17. Even if it were available to operate, Unit 2 takes approximately 36 hours to start up from a cold condition. Unit 2 could not be relied upon to provide any power, much less peaking power to meet high demand summer load conditions, during the June – August 2025 period covered by the May Order. The approximate number of hours required for startup from a cold condition for each Campbell unit are shown in the table below.[17] These startup times are very long, even for coal units. In contrast, peaking gas turbines can start up in 10 minutes or less.[18]

Unit 1	Unit 2	Unit 3
24 hours	36 hours	72 hours

[12] Petrotech, *Balance of Plant in Power Generation*, webpage accessed on August 31, 2025: https://petrotechinc.com/balance-of-plant-in-power-generation/. "Coal and thermal plants require extensive BoP (balance of plant) systems to handle ash removal, feedwater management, as well as pollution control."
[13] RFR Exhibit 101 (Consumers June Responses to AG), Question 4.
[14] Ibid.
[15] RFR Exhibit 103 (July 17 email from Consumers to EGLE).
[16] Attachment B (June 18 declaration), pp. 4-5.
[17] RFR Exhibit 101 (Consumers June Responses to AG), Question 5.
[18] Attachment B (June 18 declaration), p. 17.

18. The problems with Campbell Units 1 and 2 reaffirm my opinion that it is unlikely Campbell can be depended upon to operate reliably, including because Consumers transitioned from a preventative to a reactive approach to plant maintenance in recent years. As I explain in my June 18 declaration, it is reasonable to assume that much of the $161 million in planned capital and major maintenance projects that Consumers cancelled at Campbell in recent years was necessary to ensure continued, nominally reliable plant operations. Campbell can no longer operate reliably due to the lack of capital and major maintenance investment in recent years. This reality contradicts a basic premise of the August Order, which claims there is an ongoing need for Campbell—to assure grid reliability—at least through 2030.[19]

19. Campbell is a 1,560 MW power plant.[20] Campbell operated well below its capacity in June 2025, with output between approximately 800 MW and 1,000 MW.[21] Campbell was in partial outage throughout the month, with one or two of the three units, either Unit 1 or Unit 2 or both, offline at any given time.[22] The statement in DOE's Order that the Campbell units must operate continuously to reliably produce power is in error.[23] Units 1 and 2 demonstrated they cannot stay online continuously in June 2025 and that they must stop and start, with long outages between stops, due to their unreliable condition.

20. The Campbell outages that occurred in June 2025 were predictable due to the lack of the necessary capital and major maintenance expenditures in recent years. Neither Unit 1 nor

[19] August Order, p. 5. "The (MISO) 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."
[20] May Order, p. 1.
[21] RFR Exhibit 102 (CAMPD daily emissions data) (numbers derived by dividing the "Gross Load MWh" values by 24 (hours)).
[22] Ibid.
[23] August Order, p. 1, footnote 1: "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."

Unit 2 could reliably provide power throughout the first full calendar month of the May Order. The unreliability of the Campbell units will likely increase if these units continue to operate.

C. The extent to which Campbell's operations are consistent with environmental requirements and minimize adverse environmental impacts in light of any new information that has emerged since my June 18 declaration.

21. Burning coal produces pollutants. These pollutants include nitrogen oxide ("NO_x"), sulfur dioxide ("SO_2"), and particulate matter, among others.

22. Large quantities of these pollutants will enter the atmosphere if uncontrolled.

23. Coal-burning power plants must include air emission control equipment to reduce the pollutants in the coal boiler exhaust gas stream. The equipment still allows some level of pollution to enter the atmosphere, but it reduces the amount of pollutants entering the atmosphere.

24. Some of that air cleaning equipment includes pulse jet fabric filters and SCR catalysts. Pulse jet fabric filters remove particulate matter from the boiler exhaust gas. Pulse jet fabric filter bags are degraded over time by fly ash erosion and plugging, resulting in particulate "bleed through" and potentially bag rupture, which would result in increased particulate matter emissions.[24] The SCR catalysts are used to reduce NO_x emissions. Over time the catalyst is poisoned by trace metals and fouled by fly ash.[25] NO_x emissions increase as the catalyst degrades.

[24] Power Engineering, *Real World Performance Results of Fabric Filters on Utility Coal-Fired Boilers*, August 1, 2012: https://www.power-eng.com/environmental-emissions/real-world-performance-results/.
[25] Power Engineering, *Selective Catalytic Reduction: Operational Issues and Guidelines*, November 1, 2011: https://www.power-eng.com/environmental-emissions/selective-catalytic-reduction-operational-issues-and-guidelines/.

25. In order for air cleaning equipment like pulse jet fabric filters and SCR catalysts to do the job they are supposed to do, they must be kept in good working order. They also must be replaced when at their end of life.

26. The Campbell units depend on pulse jet fabric filters and SCR catalysts to reduce the units' air pollution emissions.

27. In my June 18 declaration, I explained the hazards if Campbell's pulse jet fabric filters and SCR catalysts are not in good working order.[26] These hazards include releases of particulate matter and NO_x. I further explained that DOE should require any Campbell unit that exceeds air permit limits for opacity, NO_x, or SO_2 during operation of Units 1 -2—as registered on the continuous monitors installed on each unit—to shut down. My opinion remains the same following review of new information available since the June 18 declaration.

28. Campbell's SCR catalysts are past their end of life. According to Consumers, "Campbell Unit 2 and Campbell Unit 3 selective catalytic reduction catalysts [were] at end of life" as of June 10.[27] The company further recognized on June 10 that new catalyst is needed should DOE continue preventing Campbell's retirement.[28] Consumers' estimate for one layer of catalyst at Campbell Unit 2 is $3 million and at Campbell Unit 3 is $5 million.[29] The company also noted that catalyst purchases "typically require six-to-twelve-month lead time."[30]

29. In addition, according to Consumers, "Campbell Unit 3 is overdue for [pulse jet fabric filter] bag changeout."[31] Consumers cancelled a prior changeout "due to expected site

[26] Attachment B (June 18 declaration), pp. 19-20.
[27] RFR Exhibit 101 (Consumers June Responses to AG), Question 2.
[28] Ibid (stating that the SCR catalysts for Campbell Units 2 and 3 "are expected to perform adequately for the next 90 days, however additional extensions beyond this will eventually require catalyst addition").
[29] Ibid.
[30] Ibid.
[31] Ibid, Question 15.

closure."[32] Consumers acknowledged on June 10 that continued operation of Campbell beyond August 2025 "may negatively impact [] performance" of the Unit 3 pulse jet fabric filter.[33] Consumers' rough estimate for Campbell Unit 3 pulse jet fabric filter full bag changeout (24 compartments with 28,272 bags total) is $7 million to $10 million.[34]

30. The Consumers air permit requires that "[a]ny air cleaning device shall be installed, maintained, and operated in a satisfactory manner and in accordance with the Michigan Air Pollution Control rules and existing law."[35]

31. In my professional opinion, and based on the available information, Campbell's SCR catalysts and pulse jet fabric filter bags are air cleaning devices that are not installed, maintained, and operated in a satisfactory manner at this time. A SCR catalyst at its end of life cannot do its job to remove NO_x in a satisfactory manner. Nor can a pulse jet fabric filter overdue for bag replacement do its job to effectively remove particulate from the boiler exhaust gas.

32. In my professional opinion, including because of the state of the SCR catalysts and pulse jet fabric filters, it appears that operating Campbell violates the air permit, or at minimum may be in serious conflict with the permit.

33. I also opined in my June 18 declaration that there are alternatives to running Campbell to meet an extreme peak demand that would produce far less environmental harm. The new emissions and discharge information since filing my June 18 declaration reinforces my opinion.

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[32] Ibid.
[33] Ibid.
[34] Ibid.
[35] Attachment C, Consumers Energy, J.H. Campbell Generating Complex, Renewable Operating Permit, Permit Number: MI-ROP-B2835-2020b, p. 6.

34. U.S. EPA's Clean Air Markets Program Data ("CAMPD") show that, between June 1 and June 30, 2025, Campbell emitted approximately 694,696 pounds of SO_2 and 483,868 pounds of NO_x. Campbell also emitted 1,453,247,200 pounds of carbon dioxide in the same time period.[36] NO_x is a lung irritant and a precursor to ozone formation.[37] SO_2 can harm the respiratory system and contribute to the formation of acid rain.[38]

35. Campbell is located in Ottawa County, Michigan. The counties adjacent to Ottawa County—Muskegon County to the north and Allegan County to the south—have been identified by the EPA as ozone non-attainment areas.[39] Campbell Units 1-3, when operational, emit ozone precursors that form ozone in the atmosphere, which is carried to surrounding areas and could contribute to ozone non-attainment in Muskegon and Allegan counties.

36. Discharge Monitoring Reports that Consumers filed with Michigan's environmental agency show that, between June 1 and July 31, 2025, Campbell withdrew and discharged approximately 40 billion gallons of cooling water to Lake Michigan.[40] The primary environmental impacts of this cooling water usage is (1) degradation of marine fauna being run through cooling water circulation pumps and (2) the deleterious impacts on marine fauna of the 20°F or more increase in water temperature at the point of cooling water discharge.

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[36] RFR Exhibit 102 (CAMPD daily emissions data).
[37] U.S. EPA, *Basic Information about NO_2*, webpage accessed August 31, 2025: https://www.epa.gov/no2-pollution/basic-information-about-no2.
[38] U.S. EPA, *Sulfur Dioxide Basics*, webpage accessed August 31, 2025: https://www.epa.gov/so2-pollution/sulfur-dioxide-basics.
[39] U.S. EPA., Michigan Nonattainment/Maintenance Status for Each County by Year for All Criteria Pollutants, webpage accessed September 3, 2025: https://www3.epa.gov/airquality/greenbook/anayo_mi html.
[40] See Campbell DMR reports for June and July 2025, available at https://mienviro michigan.gov/nsite/map/results/detail/6241586858212305105/documents. To access the July report, search for "MI0001422_2025-07-01_to_2025-07-31_DMR.pdf" in the "File" bar. The date of the entry is 8/13/2025. To access the June report, search for "MI0001422_2025-06-01_to_2025-06-30_DMR.pdf" in the "File" bar. The date of the entry is 7/14/2025.

37. In my professional opinion, and based on my 40 years of experience in coal boiler air emissions assessment and utility resource planning (as further discussed in Attachments A and B), the above-discussed emissions and discharge data show substantial and unnecessary environmental impact caused by operation of Campbell when lower-emitting, lower cost alternatives are available.

38. Thus, it continues to be my opinion that a coal unit would be the last alternative to consider for a peaking power application due in part to its high environmental impact.

I declare under penalty of perjury under the laws of the United States, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 3rd day of September 2025, in San Diego, California.



Bill Powers, P.E.
Powers Engineering
4452 Park Blvd., Suite 209
San Diego, CA 92116

Attachment A

BILL POWERS, P.E.

PROFESSIONAL HISTORY

Powers Engineering, San Diego, CA 1994-
ENSR Consulting and Engineering, Camarillo, CA 1989-93
Naval Energy and Environmental Support Activity, Port Hueneme, CA 1982-87
U.S. Environmental Protection Agency, Research Triangle Park, NC 1980-81

EDUCATION

Bachelor of Science – Mechanical Engineering, Duke University
Master of Public Health – Environmental Sciences, University of North Carolina

PROFESSIONAL AFFILIATIONS

Registered Professional Mechanical Engineer, California (Certificate M24518)
Registered Professional Engineer, Missouri (Certificate 2018039156)
American Society of Mechanical Engineers
Institute of Electrical and Electronics Engineers

TECHNICAL SPECIALTIES

Forty years of experience in:

- Air quality and utility commission proceedings - expert witness
- Distributed solar photovoltaics (PV) siting and regional renewable energy planning
- Power plant cooling system conversion and air emission control assessments
- Combustion equipment permitting, testing and monitoring
- Air pollution control equipment retrofit design/performance testing
- Petroleum refinery air engineering and testing
- Latin America environmental project experience

RECENT AIR QUALITY AND UTILITY COMMISSION PROCEEDINGS

Compressor Station Gas Turbine Air Emission Controls. Assessed the air emission controls and siting issues related to two proposed pipeline compressor station projects in the vicinity of Nashville, Tennessee utilizing Solar Turbines, Inc Titan gas turbines. The result, based on application of a Reasonably Available Control Technology (RACT) requirement, was the reduction of the proposed air permit nitrogen oxides (NOx) emission limit from 25 parts per million (ppm) to 9 ppm.

Combined Heat and Power Plant Gas Turbine Air Emission Controls. Evaluated the air emission controls proposed for a combined heat and power (CHP) plant at Duke University that would utilize Solar Turbines, Inc Titan gas turbine. Applicant proposed a 25 ppm NO_x limit using dry low-NO_x combustion as Best Available Control Technology (BACT) in its Certificate of Public Convenience and Necessity (CPCN) application to the North Carolina Utilities Commission. Argued that NO_x BACT for the CHP plant should be use of selective catalytic reduction (SCR) to achieve a 2 ppm NO_x emission limit. Applicant withdrew its CPCN application.

SDG&E 36-Inch Transmission Pipeline. Expert witness for non-profit client advocating that existing 16-inch pipeline did not require replacement with new $600 million 36-inch pipeline. Underscored in testimony that SDG&E had recently completed extensive inline inspection of existing 16-inch pipeline and found that pipeline was in good condition for long-term operation at 512 psig transmission pressure. Demonstrated that reduction of pressure to 320 psig would not increase safety of existing pipeline, as ILI could no longer be done periodically at lower pressure. Commission accepted this reasoning and denied SDG&E's application.

Cove Point LNG Export Terminal. Expert witness in two separate administrative proceedings before the Maryland Public Service Commission, in 2014 and 2017, regarding air permit conditions for the proposed Cove Point LNG export. The plant site is located in a non-attainment area for ozone. Testimony addressed deficiencies in the proposed air emission limits and proposed control technology for combustion equipment – including gas turbines, auxiliary boilers, and flares, fugitive emission sources, and marine loading vapor recovery systems.

Corpus Christi LNG Expert Terminal. Expert witness in Texas Commission on Environmental Quality contested air permit proceeding in 2013 before the State Office of Administrative Hearings. Testimony addressed deficiencies in the proposed control technology for compressor-drive gas turbines, flares, and fugitive emission sources, and marine loading vapor recovery systems.

DISTRIBUTED SOLAR PV SITING AND REGIONAL RENEWABLE ENERGY PLANNING

Roadmap to 100 Percent Local Solar by 2030 in the City of San Diego. Author of the May 2020 *Roadmap to 100 Percent Local Solar Build-Out by 2030 in the City of San Diego* strategic energy plan for San Diego. The *Roadmap* outlines a strategy to maximize the use of solar energy and battery storage in the City of San Diego (City) to provide 100 percent clean electricity to all San Diegans by 2030. The City's Climate Action Plan sets a mandatory target of 100 percent clean electricity by 2035. The *Roadmap* describes how the City can best deliver lower-cost electricity and provide local job growth by choosing local solar power paired with battery storage, complemented by smart energy efficiency and demand response programs, to reach 100 percent clean energy.

North Carolina Clean Path 2025 Plan. Author of the August 2017 *North Carolina Clean Path 2025* strategic energy plan for North Carolina. *NC Clean Path 2025* implements local solar power, battery storage, and energy efficiency measures to rapidly replace fossil fuel-generated electricity in the state. The plan is substantially less costly than the $40 billion expansion of natural gas infrastructure, nuclear power, and transmission infrastructure being planned for North Carolina. Implementation of *NC Clean Path 2025* would reduce power generated by coal- and natural gas-fired plants by about 60 percent by 2025, and 100 percent by 2030. All in-state coal-fired plants would be closed and gas-fired plants would be used only for backup supply. Existing transmission and distribution infrastructure would be maintained and not expanded.

Bay Area Smart Energy 2020 Plan. Author of the March 2012 *Bay Area Smart Energy 2020* strategic energy plan for the nine-county region surrounding San Francisco Bay. This plan uses the zero net energy building targets in the *California Energy Efficiency Strategic Plan* as a framework to achieve a 60 percent reduction in GHG emissions from Bay Area electricity usage, and a 50 percent reduction in peak demand for grid electricity, by 2020. The 2020 targets in the plan include: 25 percent of detached homes and 20 percent of commercial buildings achieving zero net energy, adding 200 MW of community-scale microgrid battery storage and 400 MW of utility-scale battery storage, reduction in air conditioner loads by 50 percent through air conditioner cycling and targeted incentive funds to assure highest efficiency replacement units, and cooling system modifications to increase power output from The Geysers geothermal production zone in Sonoma County.

Solar PV technology selection and siting for SDG&E Solar San Diego project. Served as PV technology expert in California Public Utilities Commission proceeding to define PV technology and sites to be used in San Diego Gas & Electric (SDG&E) $250 million "Solar San Diego" project. Recommendations included: 1) prioritize use of roof-mounted thin-film PV arrays similar to the SCE urban PV program to maximize the installed PV capacity, 2) avoid tracking ground-mounted PV arrays due to high cost and relative lack of available land in the urban/suburban core, 3) and incorporate limited storage in fixed rooftop PV arrays to maximizing output during peak demand periods. Suitable land next to SDG&E substations capable of supporting 5 to 40 MW of PV (each) was also identified by Powers Engineering as a component of this project.

Rooftop PV alternative to natural gas-fired peaking gas turbines, Chula Vista. Served as PV technology expert in California Energy Commission (CEC) proceeding regarding the application of MMC Energy to build a 100 MW peaking gas turbine power plant in Chula Vista. Presented testimony that 100 MW of PV arrays in the Chula Vista area could provide the same level of electrical reliability on hot summer days as an equivalent amount of peaking gas turbine capacity at approximately the same cost of energy. The final decision issued by the CEC in the case denied the application in part due to failure of the applicant or CEC staff to thoroughly evaluate the PV alternative to the proposed turbines.

San Diego Smart Energy 2020 Plan. Author of October 2007 *San Diego Smart Energy 2020*, an energy plan that focuses on meeting the San Diego region's electric energy needs through accelerated integration of renewable and non-renewable distributed generation, in the form of combined heat and power (CHP) systems and solar photovoltaic (PV) systems. PV would meet approximately 28 percent of the San Diego region's electric energy demand in 2020. Annual energy demand would drop 20 percent in 2020 relative to 2003 through use all cost-effective energy efficiency measures. Existing utility-scale gas-fired generation would continue to be utilized to provide power at night, during cloudy weather, and for grid reliability support.

COOLING SYSTEM CONVERSION AND POWER PLANT EMISSION CONTROL ASSESSMENTS

Closed-Cycle Cooling Alternative at California Nuclear Plant.
Lead engineer on review of Bechtel assessment of wedgewire screens and closed-cycle cooling for Diablo Canyon nuclear plant. Demonstrated that wedgewire screens were not likely to be effective in substantially reducing entrainment at the site, and that lower cost closed-cycle retrofit alternatives could be utilized to allow a "cost reasonable" cooling tower retrofit. Plume-abated back-to-back cooling towers located in secondary parking lots to the southeast of the turbine building were identified as the most cost-effective alternative.

Closed-Cycle Cooling Alternative at Florida Nuclear Plant.
Evaluated closed cycle cooling tower feasibility assessment for Turkey Point Nuclear Units 3 and 4. Closed-cycle cooling would replace the existing closed-cycle cooling canals. Wet cooling towers for Units 3 and 4 are feasible and could be operational within four years of submittal of applications for the necessary permits.

Utility Boilers – Conversion of Existing Once-Through Cooled Boilers to Wet Towers, Parallel Wet-Dry Cooling, or Dry Cooling. Provided expert testimony and preliminary design for the conversion of four natural gas and/or coal-fired utility boilers (Unit 4, 235 MW; Unit 3, 135 MW; Unit 2, 65 MW; and Unit 1,65 MW) from once-through river water cooling to wet cooling towers, parallel wet-dry cooling, and dry cooling. Major design constraints were available land for location of retrofit cooling systems and need to maintain maximum steam turbine backpressure at or below 5.5 inches mercury to match performance capabilities of existing equipment. Approach temperatures of 12 ^{o}F and 13 ^{o}F were used for the wet towers. SPX Cooling Technologies F-488 plume-abated wet cells with six feet of packing were used to achieve approach temperatures of 12 ^{o}F and 13 ^{o}F. Annual energy penalty of wet tower retrofit designs is approximately 1 percent. Parallel wet-dry or dry cooling was determined to be technically feasible for Unit 3 based on straightforward access to the Unit 3 surface condenser and available land adjacent to the boiler.

Utility Boiler – Assessment of Air Cooling and Integrated Gasification/Combined Cycle for Proposed 500 MW Coal-Fired Plant. Provided expert testimony on the performance of air-cooling and IGCC relative to the conventional closed-cycle wet cooled, supercritical pulverized coal boiler proposed by the applicant. Steam Pro™ coal-fired power plant design software was used to model the proposed plant and evaluate the impacts on performance of air cooling and plume-abated wet cooling. Results indicated that a conservatively designed air-cooled condenser could maintain rated power output at the design ambient temperature of 90 ^{o}F. The IGCC comparative analysis indicated that unit reliability comparable to a conventional pulverized coal unit could be achieved by including a spare gasifier in the IGCC design, and that the slightly higher capital cost of IGCC was offset by greater thermal efficiency and reduced water demand and air emissions.

Utility Boiler – Assessment of Closed-Cycle Cooling Retrofit Cost for 1,200 MW Oil-Fired Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 1,200 MW Roseton Generating Station. Determined that the cost to retrofit the Roseton plant with plume-abated closed-cycle wet cooling was well established based on cooling tower retrofit studies performed by the original owner (Central Hudson Gas & Electric Corp.) and subsequent regulatory agency critique of the cost estimate. Also determined that elimination of redundant and/or excessive budgetary line items in owners cost estimate brings the closed-cycle retrofit in line with expected costs for comparable new or retrofit plume-abated cooling tower applications.

Nuclear Power Plant – Assessment of Closed-Cycle Cooling Retrofit Cost for 2,000 MW Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 2,000 MW Indian Point Generating Station. Determined that the most appropriate arrangement for the hilly site would be an inline plume-abated wet tower instead of the round tower configuration analyzed by the owner. Use of the inline configuration would allow placement of the towers at numerous sites on the property with little or need for blasting of bedrock, greatly reducing the cost of the retrofit. Also proposed an alternative circulating cooling water piping configuration to avoid the extensive downtime projected by the owner for modifications to the existing discharge channel.

Power Plant Dry Cooling Symposium – Chair and Organizer. Chair and organizer of the first symposium held in the U.S. (May 2002) that focused exclusively on dry cooling technology for power plants. Sessions included basic principles of wet and dry cooling systems, performance capabilities of dry cooling systems, case studies of specific installations, and reasons why dry cooling is the predominant form of cooling specified in certain regions of North America (Massachusetts, Nevada, northern Mexico).

Ameren Missouri Coal Units – Causes of Opacity and Opacity Reduction Alternatives. Lead engineer to assess the root causes of opacity exceedances and evaluate potential alternatives to eliminate opacity violations from the Labadie, Meramec, and Rush Island power plants.

Utility Boilers – Evaluation of Correlation Between Opacity and PM_{10} Emissions at Coal-Fired Plant. Provided expert testimony on whether correlation existed between mass PM_{10} emissions and opacity during opacity excursions at large coal-fired boiler in Georgia. EPA and EPRI technical studies were reviewed to assess the correlation of opacity and mass emissions during opacity levels below and above 20 percent. A strong correlation between opacity and mass emissions was apparent at a sister plant at opacities less than 20 percent. The correlation suggests that the opacity monitor correlation underestimates mass emissions at opacities greater than 20 percent, but may continue to exhibit a good correlation for the component of mass emissions in the PM_{10} size range.

IGCC as BACT for Air Emissions from Proposed 960 MW Coal Plant. Presented testimony on IGCC as BACT for air emissions reduction from 960 MW coal plant. Applicant received air permit for a pulverized coal plant to be equipped with a baghouse, wet scrubber, and wet ESP for air emissions control. Use of IGCC technology at the emission rates permitted for two recently proposed U.S. IGCC projects, and demonstrated in practice at a Japanese IGCC plant firing Chinese bituminous coal, would substantially reduce potential emissions of NO_x, SO_2, and PM. The estimated control cost-effectiveness of substituting IGCC for pulverized coal technology in this case was approximately $3,000/ton.

Analysis of Proposed Air Emission Limits for 600 MW Pulverized Coal Plant. Project engineer tasked with evaluating sufficiency of air emissions limits and control technologies for proposed 600 MW coal plant Arkansas. Determined that the applicant had: 1) not properly identified SO_2, sulfuric acid mist, and PM BACT control levels for the plant, and 2) improperly utilized an incremental cost effectiveness analysis to justify air emission control levels that did not represent BACT.

Eight Pulverized Coal Fired 900 MW Boilers – IGCC Alternative with Air Cooling. Provided testimony on integrated gasification combined cycle (IGCC) as a fully commercial coal-burning alternative to the pulverized coal (PC) technology proposed by TXU for eight 900 MW boilers in East Texas, and East Texas as an ideal location for CO2 sequestration due to presence of mature oilfield CO2 enhanced oil recovery opportunities and a deep saline aquifer underlying the entire region. Also presented testimony on the major increase in regional consumptive water use that would be caused by the evaporative cooling towers proposed for use in the PC plants, and that consumptive water use could be lowered by using IGCC with evaporative cooling towers or by using air-cooled condensers with PC or IGCC technology. TXU ultimately dropped plans to build the eight PC plants as a condition of a corporate buy-out.

Utility Boilers – Retrofit of SCR and FGD to Existing Coal-Fired Units.
Expert witness in successful effort to compel an existing coal-fired power plant located in Massachusetts to meet an accelerated NO_x and SO_2 emission control system retrofit schedule. Plant owner argued the installation of advanced NO_x and SO_2 control systems would generate > 1 ton/year of ancillary emissions, such as sulfuric acid mist, and that under Massachusetts Dept. of Environmental Protection regulation ancillary emissions > 1 ton/year would require a BACT evaluation and a two-year extension to retrofit schedule. Successfully demonstrated that no ancillary emissions would be generated if the retrofit NO_x and SO_2 control systems were properly sized and optimized. Plant owner committed to accelerated compliance schedule in settlement agreement.

Utility Boilers – Retrofit of SCR to Existing Natural Gas-Fired Units.
Lead engineer in successful representation of interests of California coastal city to prevent weakening of an existing countywide utility boiler NO_x rule. Weakening of NO_x rule would have allowed a merchant utility boiler plant located in the city to operate without installing selective catalytic reduction (SCR) NO_x control systems. This project required numerous appearances before the county air pollution control hearing board to successfully defend the existing utility boiler NO_x rule.

Biomass Plant NO_x and CO Air Emissions Control Evaluation. Lead engineer for evaluation of available nitrogen oxide (NO_x) and carbon monoxide (CO) controls for a 45 MW Aspen Power biomass plant in Texas where proponent had identified selective non-catalytic reduction (SNCR) for NO_x and good combustion practices for CO as BACT. Identified the use of tail-end SCR for NO_x control at several operational U.S. biomass plants, and oxidation catalyst in use at two of these plants for CO and VOC control, as BACT for the proposed biomass plant. Administrative law judge concurred in decision that SCR and oxidation catalyst is BACT. Developer added SCR and oxidation catalyst to project in subsequent settlement agreement.

Biomass Plant Air Emissions Control Consulting. Lead expert on biomass air emissions control systems for landowners that will be impacted by a proposed 50 MW biomass to be built by the local East Texas power cooperative. Public utility agreed to meet current BACT for biomass plants in Texas, SCR for NO_x and oxidation catalyst for CO, in settlement agreement with local landowners.

Combined-Cycle Power Plant Startup and Shutdown Emissions. Lead engineer for analysis of air permit startup and shutdown emissions minimization for combined-cycle power plant proposed for the San Francisco Bay Area. Original equipment was specified for baseload operation prior to suspension of project in early 2000s. Operational profile described in revised air permit was load following with potential for daily start/stop. Recommended that either fast start turbine technology be employed to minimize start/stop emissions or that "demonstrated in practice" operational and control software modifications be employed to minimize startup/shutdown emissions.

NON-WIRES ALTERNATIVES TO TRANSMISSION LINES

Ameren Missouri Mark Twain 345 kV Transmission Line. Responsible for evaluating: 1) the expected peak load growth of Ameren Missouri (MO) in general and in Northeast MO specifically over the next decade, 2) the likelihood of wind projects moving forward in the Northeast MO over the next decade, 3) the feasibility and cost of reconductoring with high capacity composite conductors the three 161 kV line segments that would experience NERC violations if 450 to 500 MW of wind power was constructed in Northeast MO, and 4) the feasibility and cost-effectiveness of substituting local solar for wind power to allow Ameren MO to meet its 2021 Renewable Portfolio Standard (RPS) obligation without building the proposed 345 kV transmission line or upgrading the three existing 161 kV lines interconnecting at the Adair Substation.

American Transmission Corporation Badger-Coulee 345 kV Line. Responsible for evaluating: 1) the expected peak load growth of Wisconsin utilities over the next decade, and 2) the feasibility and cost-effectiveness of alternatives including load management, energy efficiency, local solar, biogas, and energy storage as viable no-wires alternatives to the proposed ATC Badger-Coulee 345 kV transmission line.

San Diego Gas & Electric Wood Pole to Steel Pole Replacement Project.
Lead engineer assessing need and alternatives to replacement of existing wooden 69 kV poles with larger steel 69 kV poles as a response to the fire hazard potential of wooden poles in rural, high fire risk areas. Wooden poles in good condition and not a source of fire ignition. Utility would continue to shut off power to customers during low humidity, high wind conditions. Prepared alternative, solar with batteries for the ~10,000 affected customer meters, to allow customers to ride-through high fire hazard preventive grid power shut-offs at far less cost than replacing wood poles with steel poles.

San Diego Gas & Electric 500 kV Sunrise Transmission Line.
Lead engineer assessing the validity of load growth forecasts used by the utility to justify the need for the 500 kV line, and for developing a no-wires alternative, net-metered solar power with some battery support, to meet the identified reliability need at little or no net cost to the utility customer base.

COMBUSTION EQUIPMENT PERMITTING, TESTING AND MONITORING

EPRI Gas Turbine Power Plant Permitting Documents – Co-Author.
Co-authored two Electric Power Research Institute (EPRI) gas turbine power plant siting documents. Responsibilities included chapter on state-of-the-art air emission control systems for simple-cycle and combined-cycle gas turbines, and authorship of sections on dry cooling and zero liquid discharge systems.

Air Permits for 50 MW Peaker Gas Turbines – Six Sites Throughout California.
Responsible for preparing all aspects of air permit applications for five 50 MW FT-8 simple-cycle turbine installations at sites around California in response to emergency request by California state government for additional peaking power. Units were designed to meet 2.0 ppm NO_x using standard temperature SCR and innovative dilution air system to maintain exhaust gas temperature within acceptable SCR range. Oxidation catalyst is also used to maintain CO below 6.0 ppm.

Kauai 27 MW Cogeneration Plant – Air Emission Control System Analysis. Project manager to evaluate technical feasibility of SCR for 27 MW naphtha-fired turbine with once-through heat recovery steam generator. Permit action was stalled due to questions of SCR feasibility. Extensive analysis of the performance of existing oil-fired turbines equipped with SCR, and bench-scale tests of SCR applied to naphtha-fired turbines, indicated that SCR would perform adequately. Urea was selected as the SCR reagent given the local availability of urea. Unit is first known application of urea-injected SCR on a naphtha-fired turbine.

Microturbines – Ronald Reagan Library, Ventura County, California.
Project manager and lead engineer or preparation of air permit applications for microturbines and standby boilers. The microturbines drive the heating and cooling system for the library. The microturbines are certified by the manufacturer to meet the 9 ppm NO_x emission limit for this equipment. Low-NO_x burners are BACT for the standby boilers.

Hospital Cogeneration Microturbines – South Coast Air Quality Management District.
Project manager and lead engineer for preparation of air permit application for three microturbines at hospital cogeneration plant installation. The draft Authority To Construct (ATC) for this project was obtained two weeks after submittal of the ATC application. 30-day public notification was required due to the proximity of the facility to nearby schools. The final ATC was issued two months after the application was submitted, including the 30-day public notification period.

Gas Turbine Cogeneration – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for two 5.5 MW gas turbines in cogeneration configuration for county government center. The turbines are equipped with selective catalytic reduction (SCR) and oxidation catalyst to comply with SCAQMD BACT requirements. Aqueous urea is used as the SCR reagent to avoid trigger hazardous material storage requirements. The NO_x and CO continuous emissions monitoring systems are covered by a separate permit.

Peaker Gas Turbines – Evaluation of NO_x Control Options for Installations in San Diego County.
Lead engineer for evaluation of NO_x control options available for 1970s vintage simple-cycle gas turbines proposed for peaker sites in San Diego County. Dry low-NO_x (DLN) combustors, catalytic combustors, high-temperature SCR, and NO_x absorption/conversion ($SCONO_x$) were evaluated for each candidate turbine make/model. High-temperature SCR was selected as the NOx control option to meet a 5 ppm NO_x emission requirement.

Hospital Cogeneration Plant Gas Turbines – San Joaquin Valley Unified Air Pollution Control District.
Project manager and lead engineer for preparation of air permit application and Best Available Control Technology (BACT) evaluation for hospital cogeneration plant installation. The BACT included the review of DLN combustors, catalytic combustors, high-temperature SCR and $SCONO_x$. DLN combustion followed by high temperature SCR was selected as the NO_x control system for this installation. The high temperature SCR is located upstream of the heat recovery steam generator (HRSG) to allow the diversion of exhaust gas around the HRSG without compromising the effectiveness of the NO_x control system.

1,000 MW Coastal Combined-Cycle Power Plant – Feasibility of Dry Cooling.
Expert witness in on-going effort to require use of dry cooling on proposed 1,000 MW combined-cycle "repower" project at site of an existing 1,000 MW utility boiler plant. Project proponent argued that site was two small for properly sized air-cooled condenser (ACC) and that use of ACC would cause 12-month construction delay. Demonstrated that ACC could easily be located on the site by splitting total of up to 80 cells between two available locations at the site. Also demonstrated that an ACC optimized for low height and low noise would minimize or eliminate proponent claims of negative visual and noise impacts.

Industrial Cogeneration Plant Gas Turbines – Upgrade of Turbine Power Output.
Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for proposed gas turbine upgrade. The BACT included the review of DLN combustors, catalytic combustors, high-, standard-, and low-temperature SCR, and $SCONO_x$. Successfully negotiated air permit that allowed facility to initially install DLN combustors and operate under a NO_x plantwide "cap." Within two major turbine overhauls, or approximately eight years, the NO_x emissions per turbine must be at or below the equivalent of 5 ppm. The 5 ppm NO_x target will be achieved through technological in-combustor NO_x control such as catalytic combustion, or SCR or SCR equivalent end-of-pipe NO_x control technologies if catalytic combustion is not available.

Gas Turbines – Modification of RATA Procedures for Time-Share CEM.
Project manager and lead engineer for the development of alternate CO continuous emission monitor (CEM) Relative Accuracy Test Audit (RATA) procedures for time-share CEM system serving three 7.9 MW turbines located in San Diego. Close interaction with San Diego APCD and EPA Region 9 engineers was required to

receive approval for the alternate CO RATA standard. The time-share CEM then passed the annual RATA without problems as a result of changes to some CEM hardware and the more flexible CO RATA standard.

Gas Turbines – Evaluation of NO_x Control Technology Performance. Lead engineer for performance review of dry low-NO_x combustors, catalytic combustors, high-, standard-, and low-temperature selective catalytic reduction (SCR), and NO_x absorption/conversion ($SCONO_x$). Major turbine manufacturers and major manufacturers of end-of-pipe NO_x control systems for gas turbines were contacted to determine current cost and performance of NO_x control systems. A comparison of 1993 to 1999 "$/kwh" and "$/ton" cost of these control systems was developed in the evaluation.

Lead engineer for evaluation for proposed combined cycle gas turbine NO_x and CO control systems. Project was in litigation over contract terms, and there was concern that the GE Frame 7FA turbine could not meet the 3 ppm NO_x permit limit using a conventional combustor with water injection followed by SCR. Operations personnel at GE Frame 7FA installatins around the country were interviewed, along with principal SCR vendors, to corroborate that the installation could continuously meet the 3 ppm NO_x limit.

Gas Turbines – Title V "Presumptively Approvable" Compliance Assurance Monitoring Protocol. Project manager and lead engineer for the development of a "presumptively approval" NO_x parametric emissions monitoring system (PEMS) protocol for industrial gas turbines. "Presumptively approvable" means that any gas turbine operator selecting this monitoring protocol can presume it is acceptable to the U.S. EPA. Close interaction with the gas turbine manufacturer's design engineering staff and the U.S. EPA Emissions Measurement Branch (Research Triangle Park, NC) was required to determine modifications necessary to the current PEMS to upgrade it to "presumptively approvable" status.

Environmental Due Diligence Review of Gas Turbine Sites – Mexico. Task leader to prepare regulatory compliance due diligence review of Mexican requirements for gas turbine power plants. Project involves eleven potential sites across Mexico, three of which are under construction. Scope involves identification of all environmental, energy sales, land use, and transportation corridor requirements for power projects in Mexico. Coordinator of Mexican environmental subcontractors gathering on-site information for each site, and translator of Spanish supporting documentation to English.

Development of Air Emission Standards for Gas Turbines - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian gas turbine power plants. All major gas turbine power plants in Peru are currently using water injection to increase turbine power output. Recommended that 42 ppm on natural gas and 65 ppm on diesel (corrected to 15% O_2) be established as the NO_x limit for existing gas turbine power plants. These limits reflect NO_x levels readily achievable using water injection at high load. Also recommended that new gas turbine sources be subject to a BACT review requirement.

Gas Turbines – Title V Permit Templates. Lead engineer for the development of standardized permit templates for approximately 100 gas turbines operated by the oil and gas industry in the San Joaquin Valley. Emissions limits and monitoring requirements were defined for units ranging from GE Frame 7 to Solar Saturn turbines. Stand-alone templates were developed based on turbine size and NO_x control equipment. NO_x utilized in the target turbine population ranged from water injection alone to water injection combined with SCR.

Gas Turbines – Evaluation of NO_x, SO_2 and PM Emission Profiles. Performed a comparative evaluation of the NO_x, SO_2 and particulate (PM) emission profiles of principal utility-scale gas turbines for an independent power producer evaluating project opportunities in Latin America. All gas turbine models in the 40 MW to 240 MW range manufactured by General Electric, Westinghouse, Siemens and ABB were included in the evaluation.

Stationary Internal Combustion Engine (ICE) RACT/BARCT Evaluation. Lead engineer for evaluation of retrofit NO_x control options available for the oil and gas production industry gas-fired ICE population in the San Joaquin Valley affected by proposed RACT and BARCT emission limits. Evaluation centered on lean-burn compressor engines under 500 bhp, and rich-burn constant and cyclically loaded (rod pump) engines under 200 bhp. The results of the evaluation indicated that rich burn cyclically-loaded rod pump engines comprised 50 percent of the affected ICE population, though these ICEs accounted for only 5 percent of the uncontrolled gas-fired stationary ICE NO_x emissions. Recommended retrofit NO_x control strategies included: air/fuel ratio adjustment for rod pump ICEs, Non-selective catalytic reduction (NSCR) for rich-burn, constant load ICEs, and "low emission" combustion modifications for lean burn ICEs.

Development of Air Emission Standards for Stationary ICEs - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian stationary ICE power plants. Draft 1997 World Bank NO_x and particulate emission limits for stationary ICE power plants served as the basis for proposed MEM emission limits. A detailed review of ICE emissions data provided in PAMAs submitted to the MEM was performed to determine the level of effort that would be required by Peruvian industry to meet the proposed NO_x and particulate emission limits. The draft 1997 WB emission limits were revised to reflect reasonably achievable NO_x and particulate emission limits for ICEs currently in operation in Peru.

Air Toxics Testing of Natural Gas-Fired ICEs. Project manager for test plan/test program to measure volatile and semi-volatile organic air toxics compounds from fourteen gas-fired ICEs used in a variety of oil and gas production applications. Test data was utilized by oil and gas production facility owners throughout California to develop accurate ICE air toxics emission inventories.

AIR ENGINEERING/AIR TESTING PROJECT EXPERIENCE – GENERAL

Reverse Air Fabric Filter Retrofit Evaluation – Coal-Fired Boiler. Lead engineer for upgrade of reverse air fabric filters serving coal-fired industrial boilers. Fluorescent dye injected to pinpoint broken bags and damper leaks. Corrosion of pneumatic actuators serving reverse air valves and inadequate insulation identified as principal causes of degraded performance.

Pulse-Jet Fabric Filter Performance Evaluation – Gold Mine. Lead engineer on upgrade of pulse-jet fabric filter and associated exhaust ventilation system serving an ore-crushing facility at a gold mine. Fluorescent dye used to identify bag collar leaks, and modifications were made to pulse air cycle time and duration. This marginal source was in compliance at 20 percent of emission limit following completion of repair work.

Pulse-Jet Fabric Filter Retrofit - Gypsum Calciner. Lead engineer on upgrade of pulse-jet fabric filter controlling particulate emissions from a gypsum calciner. Recommendations included a modified bag clamping mechanism, modified hopper evacuation valve assembly, and changes to pulse air cycle time and pulse duration.

Wet Scrubber Retrofit – Plating Shop. Project engineer on retrofit evaluation of plating shop packed-bed wet scrubbers failing to meet performance guarantees during acceptance trials, due to excessive mist carryover. Recommendations included relocation of the mist eliminator (ME), substitution of the original chevron blade ME with a mesh pad ME, and use of higher density packing material to improve exhaust gas distribution. Wet scrubbers passed acceptance trials following completion of recommended modifications.

Electrostatic Precipitator (ESP) Retrofit Evaluation – MSW Boiler. Lead engineer for retrofit evaluation of single field ESP on a municipal solid waste (MSW) boiler. Recommendations included addition of automated power controller, inlet duct turning vanes, and improved collecting plate rapping system.

ESP Electric Coil Rapper Vibration Analysis Testing - Coal-Fired Boiler. Lead engineer for evaluation of ESP rapper effectiveness test program on three field ESP equipped with "magnetically induced gravity return" (MIGR) rappers. Accelerometers were placed in a grid pattern on ESP collecting plates to determine maximum

instantaneous plate acceleration at a variety of rapper power setpoints. Testing showed that the rappers met performance specification requirements.

Aluminum Remelt Furnace Particulate Emissions Testing. Project manager and lead engineer for high temperature (1,600 ºF) particulate sampling of a natural gas-fired remelt furnace at a major aluminum rolling mill. Objectives of test program were to: 1) determine if condensable particulate was present in stack gases, and 2) to validate the accuracy of the in-stack continuous opacity monitor (COM). Designed and constructed a customized high temperature (inconel) PM_{10}/Mtd 17 sampling assembly for test program. An onsite natural gas-fired boiler was also tested to provide comparative data for the condensable particulate portion of the test program. Test results showed that no significant levels of condensable particulate in the remelt furnace exhaust gas, and indicated that the remelt furnace and boiler had similar particulate emission rates. Test results also showed that the COM was accurate.

Aluminum Remelt Furnace CO and NO_x Testing. Project manager and lead engineer for continuous week-long testing of CO and NO_x emissions from aluminum remelt furnace. Objective of test program was to characterize CO and NO_x emissions from representative remelt furnace for use in the facility's criteria pollution emissions inventory. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system.

PETROLEUM REFINERY AIR ENGINEERING/TESTING EXPERIENCE

Big West Refinery Expansion EIS. Lead engineer on comparative cost analysis of proposed wet cooling tower and fin-fan air cooler for process cooling water for the proposed clean fuels expansion project at the Big West Refinery in Bakersfield, California. Selection of the fin-fin air-cooler would eliminate all consumptive water use and wastewater disposal associated with the cooling tower. Air emissions of VOC and PM_{10} would be reduced with the fin-fan air-cooler even though power demand of the air-cooler is incrementally higher than that of the cooling tower. Fin-fan air-coolers with approach temperatures of 10 ºF and 20 ºF were evaluated. The annualized cost of the fin-fin air-cooler with a 20 ºF approach temperature is essentially the same as that of the cooling tower when the cost of all ancillary cooling tower systems are considered.

Criteria and Air Toxic Pollutant Emissions Inventory for Proposed Refinery Modifications. Project manager and technical lead for development of baseline and future refinery air emissions inventories for process modifications required to produce oxygenated gasoline and desulfurized diesel fuel at a California refinery. State of the art criteria and air toxic pollutant emissions inventories for refinery point, fugitive and mobile sources were developed. Point source emissions estimates were generated using onsite criteria pollutant test data, onsite air toxics test data, and the latest air toxics emission factors from the statewide refinery air toxics inventory database. The fugitive volatile organic compound (VOC) emissions inventories were developed using the refinery's most recent inspection and maintenance (I&M) monitoring program test data to develop site-specific component VOC emission rates. These VOC emission rates were combined with speciated air toxics test results for the principal refinery process streams to produce fugitive VOC air toxics emission rates. The environmental impact report (EIR) that utilized this emission inventory data was the first refinery "Clean Fuels" EIR approved in California.

Development of Air Emission Standards for Petroleum Refinery Equipment - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian petroleum refineries. The sources included in the scope of this project included: 1) SO_2 and NO_x refinery heaters and boilers, 2) desulfurization of crude oil, particulate and SO_2 controls for fluid catalytic cracking units (FCCU), 3) VOC and CO emissions from flares, 4) vapor recovery systems for marine unloading, truck loading, and crude oil/refined products storage tanks, and 5) VOC emissions from process fugitive sources such as pressure relief valves, pumps, compressors and flanges. Proposed emission limits were developed for new and existing refineries based on a thorough evaluation of the available air emission control technologies for the affected refinery sources. Leading vendors of refinery control technology, such as John Zink and Exxon Research, provided estimates of retrofit costs for the largest Peruvian refinery, La Pampilla,

located in Lima. Meetings were held in Lima with refinery operators and MEM staff to discuss the proposed emission limits and incorporate mutually agreed upon revisions to the proposed limits for existing Peruvian refineries.

Air Toxic Pollutant Emissions Inventory for Existing Refinery. Project manager and technical lead for air toxic pollutant emissions inventory at major California refinery. Emission factors were developed for refinery heaters, boilers, flares, sulfur recovery units, coker deheading, IC engines, storage tanks, process fugitives, and catalyst regeneration units. Onsite source test results were utilized to characterize emissions from refinery combustion devices. Where representative source test results were not available, AP-42 VOC emission factors were combined with available VOC air toxics speciation profiles to estimate VOC air toxic emission rates. A risk assessment based on this emissions inventory indicated a relatively low health risk associated with refinery operations. Benzene, 1,3-butadiene and PAHs were the principal health risk related pollutants emitted.

Air Toxics Testing of Refinery Combustion Sources. Project manager for comprehensive air toxics testing program at a major California refinery. Metals, Cr^{+6}, PAHs, H_2S and speciated VOC emissions were measured from refinery combustion sources. High temperature Cr^{+6} stack testing using the EPA Cr^{+6} test method was performed for the first time in California during this test program. Representatives from the California Air Resources Board source test team performed simultaneous testing using ARB Method 425 (Cr^{+6}) to compare the results of EPA and ARB Cr^{+6} test methodologies. The ARB approved the test results generated using the high temperature EPA Cr^{+6} test method.

Air Toxics Testing of Refinery Fugitive Sources. Project manager for test program to characterize air toxic fugitive VOC emissions from fifteen distinct process units at major California refinery. Gas, light liquid, and heavy liquid process streams were sampled. BTXE, 1,3-butadiene and propylene concentrations were quantified in gas samples, while BTXE, cresol and phenol concentrations were measured in liquid samples. Test results were combined with AP-42 fugitive VOC emission factors for valves, fittings, compressors, pumps and PRVs to calculate fugitive air toxics VOC emission rates.

OIL AND GAS PRODUCTION AIR ENGINEERING/TESTING EXPERIENCE

Air Toxics Testing of Oil and Gas Production Sources. Project manager and lead engineer for test plan/test program to determine VOC removal efficiency of packed tower scrubber controlling sulfur dioxide emissions from a crude oil-fired steam generator. Ratfisch 55 VOC analyzers were used to measure the packed tower scrubber VOC removal efficiency. Tedlar bag samples were collected simultaneously to correlate BTX removal efficiency to VOC removal efficiency. This test was one of hundreds of air toxics tests performed during this test program for oil and gas production facilities from 1990 to 1992. The majority of the volatile air toxics analyses were performed at in-house laboratory. Project staff developed thorough familiarity with the applications and limitations of GC/MS, GC/PID, GC/FID, GC/ECD and GC/FPD. Tedlar bags, canisters, sorbent tubes and impingers were used during sampling, along with isokinetic tests methods for multiple metals and PAHs.

Air Toxics Testing of Glycol Reboiler – Gas Processing Plant. Project manager for test program to determine emissions of BTXE from glycol reboiler vent at gas processing facility handling 12 MM/cfd of produced gas. Developed innovative test methods to accurately quantify BTXE emissions in reboiler vent gas.
Air Toxics Emissions Inventory Plan. Lead engineer for the development of generic air toxics emission estimating techniques (EETs) for oil and gas production equipment. This project was performed for the Western States Petroleum Association in response to the requirements of the California Air Toxics "Hot Spots" Act. EETs were developed for all point and fugitive oil and gas production sources of air toxics, and the specific air toxics associated with each source were identified. A pooled source emission test methodology was also developed to moderate the cost of source testing required by the Act.

Fugitive NMHC Emissions from TEOR Production Field. Project manager for the quantification of fugitive Nonmethane hydrocarbon (NMHC) emissions from a thermally enhanced oil recovery (TEOR) oil production field in Kern County, CA. This program included direct measurement of NMHC concentrations in storage tank

vapor headspace and the modification of available NMHC emission factors for NMHC-emitting devices in TEOR produced gas service, such as wellheads, vapor trunklines, heat exchangers, and compressors. Modification of the existing NMHC emission factors was necessary due to the high concentration of CO_2 and water vapor in TEOR produced gases.

Fugitive Air Emissions Testing of Oil and Gas Production Fields. Project manager for test plan/test program to determine VOC and air toxics emissions from oil storage tanks, wastewater storage tanks and produced gas lines. Test results were utilized to develop comprehensive air toxics emissions inventories for oil and gas production companies participating in the test program.

Oil and Gas Production Field – Air Emissions Inventory and Air Modeling. Project manager for oil and gas production field risk assessment. Project included review and revision of the existing air toxics emission inventory, air dispersion modeling, and calculation of the acute health risk, chronic non-carcinogenic risk and carcinogenic risk of facility operations. Results indicated that fugitive H_2S emissions from facility operations posed a potential health risk at the facility fenceline.

TITLE V PERMIT APPLICATION/MONITORING PLAN EXPERIENCE

Title V Permit Application – San Diego County Industrial Facility. Project engineer tasked with preparing streamlined Title V operating permit for U.S. Navy facilities in San Diego. Principal emission units included chrome plating, lead furnaces, IC engines, solvent usage, aerospace coating and marine coating operations. For each device category in use at the facility, federal MACT requirements were integrated with District requirements in user friendly tables that summarized permit conditions and compliance status.

Title V Permit Application Device Templates - Oil and Gas Production Industry. Project manager and lead engineer to prepare Title V permit application "templates" for the Western States Petroleum Association (WSPA). The template approach was chosen by WSPA to minimize the administrative burden associated with listing permit conditions for a large number of similar devices located at the same oil and gas production facility. Templates are being developed for device types common to oil and gas production operations. Device types include: boilers, steam generators, process heaters, gas turbines, IC engines, fixed-roof storage tanks, fugitive components, flares, and cooling towers. These templates will serve as the core of Title V permit applications prepared for oil and gas production operations in California.

Title V Permit Application - Aluminum Rolling Mill. Project manager and lead engineer for Title V permit application prepared for largest aluminum rolling mill in the western U.S. Responsible for the overall direction of the permit application project, development of a monitoring plan for significant emission units, and development of a hazardous air pollutant (HAP) emissions inventory. The project involved extensive onsite data gathering, frequent interaction with the plant's technical and operating staff, and coordination with legal counsel and subcontractors. The permit application was completed on time and in budget.

Title V Model Permit - Oil and Gas Production Industry. Project manager and lead engineer for the comparative analysis of regional and federal requirements affecting oil and gas production industry sources located in the San Joaquin Valley. Sources included gas turbines, IC engines, steam generators, storage tanks, and process fugitives. From this analysis, a model applicable requirements table was developed for a sample device type (storage tanks) that covered the entire population of storage tanks operated by the industry. The U.S. EPA has tentatively approved this model permit approach, and work is ongoing to develop comprehensive applicable requirements tables for each major category of sources operated by the oil and gas industry in the San Joaquin Valley.

Title V Enhanced Monitoring Evaluation of Oil and Gas Production Sources. Lead engineer to identify differences in proposed EPA Title V enhanced monitoring protocols and the current monitoring requirements for oil and gas production sources in the San Joaquin Valley. The device types evaluated included: steam generators, stationary ICEs, gas turbines, fugitives, fixed roof storage tanks, and thermally enhanced oil recovery (TEOR) well vents. Principal areas of difference included: more stringent Title V O&M requirements

for parameter monitors (such as temperature, fuel flow, and O_2), and more extensive Title V recordkeeping requirements.

RACT/BARCT/BACT EVALUATIONS

RACT/BARCT Reverse Jet Scrubber/Fiberbed Mist Eliminator Retrofit Evaluation. Project manager and lead engineer on project to address the inability of existing wet electrostatic precipitators (ESPs) and atomized mist scrubbers to adequately remove low concentration submicron particulate from high volume recovery boiler exhaust gas at the Alaska Pulp Corporation mill in Sitka, AK. The project involved thorough on-site inspections of existing control equipment, detailed review of maintenance and performance records, and a detailed evaluation of potential replacement technologies. These technologies included a wide variety of scrubbing technologies where manufacturers claimed high removal efficiencies on submicron particulate in high humidity exhaust gas. Packed tower scrubbers, venturi scrubbers, reverse jet scrubbers, fiberbed mist eliminators and wet ESPs were evaluated. Final recommendations included replacement of atomized mist scrubber with reverse jet scrubber and upgrading of the existing wet ESPs. The paper describing this project was published in the May 1992 TAPPI Journal.

Aluminum Smelter RACT Evaluation - Prebake. Project manager and technical lead for CO and PM_{10} RACT evaluation for prebake facility. Retrofit control options for CO emissions from the anode bake furnace, potline dry scrubbers and the potroom roof vents were evaluated. PM_{10} emissions from the coke kiln, potline dry scrubbers, potroom roof vents, and miscellaneous potroom fugitive sources were addressed. Four CO control technologies were identified as technologically feasible for potline CO emissions: potline current efficiency improvement through the addition of underhung busswork and automated puncher/feeders, catalytic incineration, recuperative incineration and regenerative incineration. Current efficiency improvement was identified as probable CO RACT if onsite test program demonstrated the effectiveness of this approach. Five PM_{10} control technologies were identified as technologically feasible: increased potline hooding efficiency through redesign of shields, the addition of a dense-phase conveying system, increased potline air evacuation rate, wet scrubbing of roof vent emissions, and fabric filter control of roof vent emissions.

RACT/BACT Testing/Evaluation of PM_{10} Mist Eliminators on Five-Stand Cold Mill. Project manager and lead engineer for fiberbed mist eliminator and mesh pad mist eliminator comparative pilot test program on mixed phase aerosol (PM_{10})/gaseous hydrocarbon emissions from aluminum high speed cold rolling mill. Utilized modified EPA Method 5 sampling train with portion of sample gas diverted (after particulate filter) to Ratfisch 55 VOC analyzer. This was done to permit simultaneous quantification of aerosol and gaseous hydrocarbon emissions in the exhaust gas. The mesh pad mist eliminator demonstrated good control of PM_{10} emissions, though test results indicated that the majority of captured PM_{10} evaporated in the mesh pad and was emitted as VOC.

Aluminum Remelt Furnace/Rolling Mill RACT Evaluations. Lead engineer for comprehensive CO and PM_{10} RACT evaluation for the largest aluminum sheet and plate rolling mill in western U.S. Significant sources of CO emissions from the facility included the remelt furnaces and the coater line. The potential CO RACT options for the remelt furnaces included: enhanced maintenance practices, preheating combustion air, installation of fully automated combustion controls, and energy efficiency modifications.

BARCT Low NO_x Burner Conversion – Industrial Boilers. Lead engineer for evaluation of low NO_x burner options for natural gas-fired industrial boilers. Also evaluated methanol and propane as stand-by fuels to replace existing diesel stand-by fuel system. Evaluated replacement of steam boilers with gas turbine co-generation system.

BACT Packed Tower Scrubber/Mist Eliminator Performance Evaluations. Project manager and lead engineer for Navy-wide plating shop air pollution control technology evaluation and emissions testing program. Mist eliminators and packed tower scrubbers controlling metal plating processes, which included hard chrome, nickel, copper, cadmium and precious metals plating, were extensively tested at three Navy plating shops.

Chemical cleaning and stripping tanks, including hydrochloric acid, sulfuric acid, chromic acid and caustic, were also tested. The final product of this program was a military design specification for plating and chemical cleaning shop air pollution control systems. The hydrochloric acid mist sampling procedure developed during this program received a protected patent.

BACT Packed Tower Scrubber/UV Oxidation System Pilot Test Program. Technical advisor for pilot test program of packed tower scrubber/ultraviolet (UV) light VOC oxidation system controlling VOC emissions from microchip manufacturing facility in Los Angeles. The testing was sponsored in part by the SCAQMD's Innovative Technology Demonstration Program, to demonstrate this innovative control technology as BACT for microchip manufacturing operations. The target compounds were acetone, methylethylketone (MEK) and 1,1,1-trichloroethane, and compound concentrations ranged from 10-100 ppmv. The single stage packed tower scrubber consistently achieved greater than 90% removal efficiency on the target compounds. The residence time required in the UV oxidation system for effective oxidation of the target compounds proved significantly longer than the residence time predicted by the manufacturer.

BACT Pilot Testing of Venturi Scrubber on Gas/Aerosol VOC Emission Source. Technical advisor for project to evaluate venturi scrubber as BACT for mixed phase aerosol/gaseous hydrocarbon emissions from deep fat fryer. Venturi scrubber demonstrated high removal efficiency on aerosol, low efficiency on VOC emissions. A number of VOC tests indicated negative removal efficiency. This anomaly was traced to a high hydrocarbon concentration in the scrubber water. The pilot unit had been shipped directly to the jobsite from another test location by the manufacturer without any cleaning or inspection of the pilot unit.

Pulp Mill Recovery Boiler BACT Evaluation. Lead engineer for BACT analysis for control of SO_2, NO_x, CO, TNMHC, TRS and particulate emissions from the proposed addition of a new recovery furnace at a kraft pulp mill in Washington. A "top down" approach was used to evaluate potential control technologies for each of the pollutants considered in the evaluation.

Air Pollution Control Equipment Design Specification Development. Lead engineer for the development of detailed Navy design specifications for wet scrubbers and mist eliminators. Design specifications were based on field performance evaluations conducted at the Long Beach Naval Shipyard, Norfolk Naval Shipyard, and Jacksonville Naval Air Station. This work was performed for the U.S. Navy to provide generic design specifications to assist naval facility engineering divisions with air pollution control equipment selection. Also served as project engineer for the development of Navy design specifications for ESPs and fabric filters.

CONTINUOUS EMISSION MONITOR (CEM) PROJECT EXPERIENCE

Process Heater CO and NO_x CEM Relative Accuracy Testing. Project manager and lead engineer for process heater CO and NO_x analyzer relative accuracy test program at petrochemical manufacturing facility. Objective of test program was to demonstrate that performance of onsite CO and NO_x CEMs was in compliance with U.S. EPA "Boiler and Industrial Furnace" hazardous waste co-firing regulations. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system. One of the two process heater CEM systems tested failed the initial test due to leaks in the gas conditioning system. Troubleshooting was performed using O_2 analyzers, and the leaking component was identified and replaced. This CEM system met all CEM relative accuracy requirements during the subsequent retest.

Performance Audit of NO_x and SO_2 CEMs at Coal-Fired Power Plant. Lead engineer on system audit and challenge gas performance audit of NO_x and SO_2 CEMs at a coal-fired power plant in southern Nevada. Dynamic and instrument calibration checks were performed on the CEMs. A detailed visual inspection of the CEM system, from the gas sampling probes at the stack to the CEM sample gas outlet tubing in the CEM trailer, was also conducted. The CEMs passed the dynamic and instrument calibration requirements specified in EPA's Performance Specification Test - 2 (NO_x and SO_2) alternative relative accuracy requirements.

LATIN AMERICA ENVIRONMENTAL PROJECT EXPERIENCE

Assessment of operational deficiencies of Camisa pipeline – Peru. Project leader of multi-year assessment of root causes of ruptures on Camisea 14-inch natural gas liquids pipeline for non-profit client. Determined that primary causes of hurried construction in difficult and unstable terrain, unstable right-of-way in the jungle sector due to inadequate erosion control practices, and inadequate pipe wall thickness to withstand external lateral forces. Two assessments were developed during the course of the project documenting deficiencies and recommending remedial actions.

Evaluation of U.S.-Mexico Border Region Copper Smelter Compliance with Treaty Obligations – Mexico. Project manager and lead engineer to evaluate compliance of U.S. and Mexican border region copper smelters with the SO_2 monitoring, recordkeeping and reporting requirements in Annex IV [Copper Smelters] of the La Paz Environmental Treaty. Identified potential problems with current ambient and stack monitoring practices that could result in underestimating the impact of SO_2 emissions from some of these copper smelters. Identified additional source types, including hazardous waste incinerators and power plants, that should be considered for inclusion in the La Paz Treaty process.

Development of Air Emission Limits for ICE Cogeneration Plant - Panamá. Lead engineer assisting U.S. cogeneration plant developer to permit an ICE cogeneration plant at a hotel/casino complex in Panama. Recommended the use of modified draft World Bank NO_x and PM limits for ICE power plants. The modification consisted of adding a thermal efficiency factor adjustment to the draft World Bank NO_x and PM limits. These proposed ICE emission limits are currently being reviewed by Panamanian environmental authorities.

Mercury Emissions Inventory for Stationary Sources in Northern Mexico. Project manager and lead engineer to estimate mercury emissions from stationary sources in Northern Mexico. Major potential sources of mercury emissions include solid- and liquid-fueled power plants, cement kilns co-firing hazardous waste, and non-ferrous metal smelters. Emission estimates were provided for approximately eighty of these sources located in Northern Mexico. Coordinated efforts of two Mexican subcontractors, located in Mexico City and Hermosillo, to obtain process throughput data for each source included in the inventory.

Translation of U.S. EPA Scrap Tire Combustion Emissions Estimation Document – Mexico. Evaluated the Translated a U.S. EPA scrap tire combustion emissions estimation document from English to Spanish for use by Latin American environmental professionals.

Environmental Audit of Aluminum Production Facilities – Venezuela. Evaluated the capabilities of existing air, wastewater and solid/hazardous waste control systems used by the aluminum industry in eastern Venezuela. This industry will be privatized in the near future. Estimated the cost to bring these control systems into compliance with air, wastewater and solid/hazardous waste standards recently promulgated in Venezuela. Also served as technical translator for team of U.S. environmental engineers involved in the due diligence assessment.

Assessment of Environmental Improvement Projects – Chile and Peru. Evaluated potential air, water, soil remediation and waste recycling projects in Lima, Peru and Santiago, Chile for feasibility study funding by the U.S. Trade and Development Agency. Project required onsite interaction with in-country decisionmakers (in Spanish). Projects recommended for feasibility study funding included: 1) an air quality technical support project for the Santiago, Chile region, and 2) soil remediation/metals recovery projects at two copper mine/smelter sites in Peru.

Air Pollution Control Training Course – Mexico. Conducted two-day Spanish language air quality training course for environmental managers of assembly plants in Mexicali, Mexico. Spanish-language course manual prepared by Powers Engineering. Practical laboratory included training in use of combustion gas analyzer, flame ionization detector (FID), photoionization detector (PID), and occupational sampling.

Stationary Source Emissions Inventory – Mexico. Developed a comprehensive air emissions inventory for stationary sources in Nogales, Sonora. This project requires frequent interaction with Mexican state and federal environmental authorities. The principal Powers Engineering subcontractor on this project is a Mexican firm located in Hermosillo, Sonora.

VOC Measurement Program – Mexico. Performed a comprehensive volatile organic compound (VOC) measurements program at a health products fabrication plant in Mexicali, Mexico. An FID and PID were used to quantify VOCs from five processes at the facility. Occupational exposures were also measured. Worker exposure levels were above allowable levels at several points in the main assembly area.

Fluent in Spanish. Studied at the Universidad de Michoacán in Morelia, Mexico, 1993, and at the Colegio de España in Salamanca, Spain, 1987-88. Have lectured (in Spanish) on air monitoring and control equipment at the Instituto Tecnológico de Tijuana. Maintain contact with Comisión Federal de Electricidad engineers responsible for operation of wind and geothermal power plants in Mexico, and am comfortable operating in the Mexican business environment.

PUBLICATIONS

Bill Powers, "*More Distributed Solar Means Fewer New Combustion Turbines*," Natural Gas & Electricity Journal, Vol. 29, Number 2, September 2012, pp. 17-20.

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Bill Powers, "*Today's California Renewable Energy Strategy—Maximize Complexity and Expense*," Natural Gas & Electricity Journal, Vol. 27, Number 2, September 2010, pp. 19-26.

Bill Powers, "*Environmental Problem Solving Itself Rapidly Through Lower Gas Costs*," Natural Gas & Electricity Journal, Vol. 26, Number 4, November 2009, pp. 9-14.

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Bill Powers, "*Unused Turbines, Ample Gas Supply, and PV to Solve RPS Issues*," Natural Gas & Electricity Journal, Vol. 26, Number 2, September 2009, pp. 1-7.

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Bill Powers, "*Energy, the Environment, and the California – Baja California Border Region*," Electricity Journal, Vol. 18, Issue 6, July 2005, pp. 77-84.

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W.E. Powers, R. Wydrum, P. Morris, *"Design and Performance of Optimized Air-Cooled Condenser at Crockett Cogeneration Plant,"* presented at EPA Symposium on Technologies for Protecting Aquatic Organisms from Cooling Water Intake Structures, Washington, DC, May 2003.

P. Pai, D. Niemi, W.E. Powers, *"A North American Anthropogenic Inventory of Mercury Emissions,"* presented at Air & Waste Management Association Annual Conference in Salt Lake City, UT, June 2000.

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W.E. Powers, et. al., *"Hazardous Air Pollutant Emission Inventory for Stationary Sources in Nogales, Sonora, Mexico ,"* presented at 1995 AWMA/EPA Emissions Inventory Specialty Conference, RTP, NC, October 1995.

W.E. Powers, *"Develop of a Parametric Emissions Monitoring System to Predict NO_x Emissions from Industrial Gas Turbines,"* presented at 1995 AWMA Golden West Chapter Air Pollution Control Specialty Conference, Ventura, California, March 1995.

W. E. Powers, et. al., *"Retrofit Control Options for Particulate Emissions from Magnesium Sulfite Recovery Boilers,"* presented at 1992 TAPPI Envr. Conference, April 1992. Published in *TAPPI Journal*, July 1992.

S. S. Parmar, M. Short, W. E. Powers, *"Determination of Total Gaseous Hydrocarbon Emissions from an Aluminum Rolling Mill Using Methods 25, 25A, and an Oxidation Technique,"* presented at U.S. EPA Measurement of Toxic and Related Air Pollutants Conference, May 1992.

N. Meeks, W. E. Powers, *"Air Toxics Emissions from Gas-Fired Internal Combustion Engines,"* presented at AIChE Summer Meeting, August 1990.

W. E. Powers, *"Air Pollution Control of Plating Shop Processes,"* presented at 7th AES/EPA Conference on Pollution Control in the Electroplating Industry, January 1986. Published in *Plating and Surface Finishing* magazine, July 1986.

H. M. Davenport, W. E. Powers, *"Affect of Low Cost Modifications on the Performance of an Undersized Electrostatic Precipitator,"* presented at 79th Air Pollution Control Association Conference, June 1986.

AWARDS

Engineer of the Year, 1991 – ENSR Consulting and Engineering, Camarillo
Engineer of the Year, 1986 – Naval Energy and Environmental Support Activity, Port Hueneme
Productivity Excellence Award, 1985 – U. S. Department of Defense

PATENTS

Sedimentation Chamber for Sizing Acid Mist, Navy Case Number 70094

Attachment B

DECLARATION OF BILL POWERS, P.E.

I, Bill Powers, P.E., declare as follows:

1. I am the principal of Powers Engineering, an engineering firm that consults on issues related to the operation of, and control of pollution from, power plants, including coal-fired power plants. My office is located in San Diego, California. My professional and educational experience is summarized in the curriculum vitae attached to this declaration (Attachment A).

2. I received a Bachelor of Science degree from Duke University in Mechanical Engineering and a Master of Public Health degree in Environmental Sciences from the University of North Carolina. I am a registered engineer in the state of California.

3. I have been an independent engineering consultant with a focus on power systems since 1994. In prior employment, I received "Engineer of the Year" awards from ENSR Consulting and Engineering in 1991 (before ENSR merged with AECOM) and from the Naval Energy and Environmental Support Activity ("NEESA") office within the U.S. Navy in 1986 (before NEESA was subsumed by the Naval Facilities Engineering Service Center). I also received a "Productivity Award of Excellence" from the U.S. Department of Defense in 1985. I worked extensively on Navy and Marine Corps shore installation of coal-fired power plants in the 1980s as a Navy civilian engineer.

4. I have over 40 years of experience in the fields of power plant operations and environmental engineering. My technical specialties include, among others: combustion equipment permitting, testing, and monitoring; air emission control assessments; air pollution control equipment retrofit design/performance; and power plant cooling system conversion.

5. I have served as an engineering expert for a wide array of clients, including private companies, non-profits, and government entities, including the cities of Carlsbad, California and Houston and Dallas, Texas. In this role, I have provided expert testimony, conducted feasibility studies, and consulted on power plant engineering issues in a number of states, including Arkansas, California, Connecticut, Florida, Georgia, Kentucky, Maryland, Missouri, Nevada, North Carolina, New York, and Tennessee.

6. I have extensive experience with coal-fired power plants. For example, in 2022 I provided expert testimony before the North Carolina Public Utility Commission regarding Duke Energy's proposed plan to maintain coal-fired units in its electric supply portfolio—a proposal that was justified in part on the company's belief that those units were necessary to meet winter peak demand. Throughout my career, I have consulted on the operation of, and control of pollution from, coal-fired power plants. Examples include serving as the lead engineer on a system and performance audit of continuous emissions monitoring systems at a coal-fired power plant in Nevada, and on a project to assess and address the root causes of opacity exceedances at Ameren Missouri's Labadie, Meramec, and Rush Island coal-fired power plants. I have also frequently provided expert testimony on coal-fired power plants. For example, I testified on air pollution controls at a coal-fired power plant in Massachusetts, and on the correlation between a Georgia coal-fired power plant's particulate matter emissions and opacity excursions, among other issues. I also served as a testifying expert on an evaluation of the air emissions limits and control technologies for a proposed coal-fired power plant in Arkansas.

7. I am very familiar with "peaking" units that are intended to ramp up and provide electricity during times of peak demand, such as during hot summer months. For example, in 2001, I prepared all aspects of the air permit applications for five 50 MW simple-cycle gas

turbine installations in response to an emergency request by the California state government for additional peaking power.

8. I am familiar with the U.S. Department of Energy's ("DOE") May 23, 2025 order regarding Consumers Energy Company's ("CECo") J.H. Campbell coal-fired power plant (Order No. 202-25-3) ("Order").

9. The J.H. Campbell coal-fired power plant ("Campbell") consists of three coal-fired generating units. The in-service dates for Units 1, 2, and 3 are 1962, 1967, and 1980 respectively.[1] The nameplate capacity for Unit 1 is 265.2 MW; for Unit 2 is 378.8 MW; and for Unit 3 is 916.8 MW.[2] Under CECo's 2021 integrated resource plan ("IRP"), which was approved with modifications by the Michigan Public Service Commission ("Michigan PSC") in 2022, the Campbell units were scheduled to retire on or before May 31, 2025.

10. I was asked by Earthjustice to develop an opinion on: (A) the extent to which Campbell can operate reliably after May 31, 2025; (B) whether Campbell can operate effectively as a peaking unit; and (C) easily attainable steps DOE can require to ensure Campbell's operations are consistent with environmental requirements and minimize adverse environmental impacts. A list of materials I reviewed in developing my opinion is attached (Attachment B).

11. While there may be alternatives to Campbell available to DOE to address the circumstances DOE describes in the Order, I do not opine on these alternatives. I also do not opine on the claimed energy emergency described in the Order.

[1] Michigan PSC Case No. U-21585, Direct Testimony of Richard T. Blumenstock on Behalf of CECo, p. 7, Tbl. 1 (May 2024).
[2] EIA, Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860) (Apr. 2025), https://www.eia.gov/electricity/data/eia860m/ (showing nameplate capacity).

A. The extent to which Campbell can operate reliably beginning June 1, 2025

12. In my professional opinion, it is unlikely that Campbell can be depended upon to operate reliably in its current state as of June 2025.[3] This is especially true if the plant is required to run for extended periods of time; is required to stop and start numerous times; or attempts to start up at an accelerated rate in response to extreme demand conditions.

13. Even before the scheduled retirement date of May 31, 2025, Campbell suffered from poor reliability. Nationally, the average coal unit forced outage rate in 2023 was 12.0 percent.[4] In contrast, Campbell Units 1-3 had forced outage rates in 2024 of 14.84 percent, 48.07 percent, and 19.25 percent, respectively[5]—well above the average coal unit forced outage rate. The forced outage rates in 2023 were similarly high: Units 1-3 had forced outage rates of 18.66 percent, 57.32 percent, and 22.41 percent, respectively.[6]

14. "Availability" is a measure of the percent of time a unit is not in planned or forced outage and is available to generate electricity. Campbell has lower availability than coal units of comparable size. When CECo compared the availability of the Campbell units in 2019-2023 to similarly sized and fueled generating units, the company found that "[t]he availability of Campbell Units 1, 2, and 3 were all below the five-year comparisons."[7]

15. The nature of the Unit 1-3 outages in 2023 and 2024 reflects the impact of worn and difficult-to-repair or replace coal unit components on operational reliability. Outages tended to be long and recurrent. Tables 1 and 2 document the longest Unit 1-3 outages by description and duration in 2024 and 2023, respectively. The long outages on Units 1 and 2, and the types of

[3] CECo filed testimony regarding Campbell on June 2, 2025, in its most recent rate case before the Michigan PSC.
[4] NERC, *2024 State of Reliability*, p. 59 (June 2024).
[5] Michigan PSC Case No. U-21424, Direct Testimony of Nathan J. Hoffman on Behalf of CECo, Ex. A-15 (Mar. 2025).
[6] Michigan PSC Case No. U-21258, Direct Testimony of Nathan J. Hoffman on Behalf of CECo, Ex. A-14 (Mar. 2024).
[7] U-21424, Hoffman Direct Testimony, p. 22 & Ex. A-16.

failures, are the predictable result of old equipment, no capital investment, and minimal maintenance.

Table 1. Longest 2024 Outages by Type, Units 1-3 - Description and Duration[8]

Unit	Outage description	Total duration (hours)
1	• degraded governing valve (3 outages) • worn leaking superheater tube (1 outage)	911 491
2	• obsolete boiler feedwater pump failure (1 outage) • degraded valve(s) malfunction (3 outages) • worn equipment leaks, various (4 outages)	1,417 1,723 854
3	• worn/failed turbine turning gear[9] (1 outage) • worn tube leak (1 outage)	1,104 356

Table 2. Longest 2023 Outages by Type, Units 1-3 - Description and Duration[10]

Unit	Outage description	Total duration (hours)
1	• worn leaking valve and superheater tube (2 outages)	661
2	• obsolete boiler feedwater pump failure (4 outages) • worn equipment leaks (3 outages)	3,445 571
3	• worn leaking boiler/superheater tubes (3 outages) • worn/vibrating turbine bearings (1 outage)	1,857 426

16. In my professional opinion, Campbell will continue to degrade in 2025 due to the continued lack of capital investment and minimal major maintenance spending.

17. CECo dramatically reduced capital and major maintenance spending on Units 1-3 following the IRP that established a May 2025 retirement date. CECo reduced its capital spending on the units in the 2022-2025 period by approximately 91 percent compared to the amount the company projected to spend in the same period if Units 1-2 operated until 2031 and Unit 3 operated until 2039 (the retirement dates CECo originally proposed in its IRP). Likewise, CECo reduced its major maintenance spending on the units in the 2022-2025 period by 62-78

[8] U-21424, Hoffman Direct Testimony, Ex. A-11.
[9] *Ibid.*, Ex. A-13. The stated scope of the turbine turning gear repair was to "[f]abricate replacement planetary gears and drive shaft to allow for unit operation until the planned retirement in 2025."
[10] U-21258, Hoffman Direct Testimony, Ex. A-10.

percent (approximately 72% total across all three units). The reductions in capital and major maintenance spending are summarized in Table 3.[11]

Table 3. Reductions in CECo Capital and Major Maintenance Spending on Campbell Units 1-3, 2022-2025

Capital spending	Pre-IRP projected spend 2022-25 ($MM)	Post-IRP actual/projected spend 2022-25 ($MM)	% reduction
Units 1&2	60.6	4.1	93
Unit 3	85.5	8.4	90
Major maintenance spending			
Units 1&2	14.4	5.5	62
Unit 3	23.5	5.1	78

18. Some of the capital and major maintenance projects that CECo cancelled in 2022-2025 were reliability projects, while others were air emission control system projects. Regarding the reliability projects that CECo originally planned to carry out (before deciding to retire Units 1-3 in May 2025), CECo likely believed they were necessary to maintain adequate unit reliability and that failure to carry out the projects could compromise that reliability. But CECo then determined that those projects were unnecessary with the May 2025 retirement. Therefore, it is unlikely that Campbell can reliably dispatch given this deferred capital and major maintenance spending.

19. A detailed listing of the 2022-2025 capital projects that CECo projected carrying out before deciding to retire the units in May 2025 is shown in the left-hand column of Tables 4a (Units 1 and 2) and 4b (Unit 3).[12] As can be seen from the middle column in these tables,[13] CECo did not carry out most of those projects.

[11] Table 3 summarizes the information presented in Tables 4a, 4b, 5a, and 5b, which are based on CECo filings with the Michigan PSC.
[12] Information in the left-hand column is from witness Kapala's testimony in CECo's 2021 IRP case. *See* Michigan PSC Case No. U-21090, Revised Direct Testimony of Norman J. Kapala, pp. 13-18 (Oct. 2021).
[13] Information in the middle column is from witness Blumenstock's testimony in CECo's 2023-2025 rate cases. *See* Ex. A-12 to the Direct Testimony of Richard T. Blumenstock in Michigan PSC Case Nos. U-21389 (May 2023), U-21585 (May 2024), and U-21870 (June 2025).

20. Table 4a compares (i) the capital projects CECo proposed carrying out for Units 1 and 2 before deciding to retire those units in May 2025 with (ii) those projects CECo has actually carried out, or plans to carry out, after making that retirement decision. Capital spending dropped by two-thirds on Units 1 and 2 in 2022, from the proposed $12.6 million to $4.1 million. No capital spending occurred in 2023-2024, and no capital spending has yet occurred or is expected to occur in 2025 as of CECo's June 2025 rate case filing. Cancelled capital projects with a direct impact on unit reliability include, among others, partial replacement of the Unit 1 superheat outlet pendant and replacement of the Unit 2 burner assemblies and horizontal reheat system.

Table 4a. Units 1&2 Capital Spend: CECo pre-IRP projection vs. post-IRP actuals/projections

Pre-IRP projection	Post-IRP actuals/projections	Difference
2022 projected spend (in 2021): $12,556,500 $7,300,000 at Campbell Unit 1, including: • PJFF Bag Replacement ($1,578,000) • Superheat Outlet Pendant – partial replacement ($3,490,000) • Five additional projects totaling $2,232,000 $5,256,500 at Campbell Unit 2, including: • Catalyst Management ($1,120,000) • Replace Burner Assemblies ($1,350,000) • Six additional projects totaling $2,786,500	**2022 actual expenditure: $4,067,000** The 2022 actual capital expenditure primarily consisted of two projects, both on Unit 1: air preheater baskets and seals ($1,819,000), and pulse jet fabric filter bags ($1,040,000).	**$8,489,500**
2023 projected spend (in 2021): $16,686,700 $7,214,680 at Campbell Unit 1, including: • PJFF Filter Bag Replacement ($1,514,100) • Replace Air Preheater Baskets and Seals ($1,113,400) • Distributed Control System and Simulator Upgrade ($1,500,000) • Ashpit Rebuild ($1,000,000) • Twelve additional projects totaling $2,087,180 $9,472,020 at Campbell Unit 2, including: • Horizontal Reheat Replacement ($5,053,000) • SCR Reactor Catalyst Replacement ($2,000,000) • Nine additional projects totaling $2,419,020	**2023 actual expenditure: $0** The precise value reported in CECo's filing is negative (-$1,479,000). This is likely due to accounting treatment. For purposes of this analysis, I treat negative investment as $0.	**$16,686,700**
2024 projected spend (in 2021): $21,005,000 $9,753,000 at Campbell Unit 1, including: • Replace Burners Corner 1-8 ($2,700,000) • Replace Air Preheater Baskets and Seals ($1,137,100) • Boiler Component Replacement ($3,000,000) • Balance of Plant Equipment Replacement ($1,500,000) • Six additional projects totaling $1,415,900 $11,252,000 at Campbell Unit 2, including: • Horizontal Reheat Replacement ($7,952,000) • Distributed Control System and Simulator Upgrade ($1,500,000) • Four additional projects totaling $1,800,000	**2024 actual expenditure: $0** The precise value reported in CECo's filing is negative (-$1,510,000). This is likely due to accounting treatment. For purposes of this analysis, I treat negative investment as $0, which is consistent with 2024 testimony from CECo witness Blumenstock stating that the company did not plan to invest any capital in the Campbell units in 2024.[14]	**$21,005,000**
2025 projected spend (in 2021): $10,350,000 $2,550,000 at Campbell Unit 1, including four projects that do not exceed $669,000 individually $7,800,000 at Campbell Unit 2, including: • Replace turbine right side Reheat Stop Valve body ($1,850,000) • Boiler Component Replacement ($3,000,000) • Five additional projects totaling $2,950,000	**2025 projected expenditure: $0** CECo projected no capital expenditures at Unit 1 or Unit 2 in 2025.	**$10,350,000**
	TOTAL	**$56,531,200**

[14] *See* U-21585, Blumenstock Direct Testimony, p. 62.

21. Table 4b compares the capital projects CECo proposed carrying out for Unit 3 before deciding to retire that unit in May 2025 with those projects CECo has actually carried out, or plans to carry out, after making that retirement decision. Capital spending dropped by more than half on Unit 3 in 2022, from a proposed $17.1 million to $7.9 million, and dropped almost entirely in 2023, from a proposed $20.5 million to less than $0.5 million. No capital spending occurred in 2024, and no capital spending has yet occurred or is expected to occur in 2025 as of CECo's June 2025 rate case filing. Cancelled Unit 3 capital projects with a direct impact on unit reliability include, among others, complete coal mill overhauls, boiler wall panel replacements, and fuel handling repairs.

Table 4b. Unit 3 Capital Spend: CECo pre-IRP projection vs. post-IRP actuals/projections

Pre-IRP projection	Post-IRP actuals/projections	Difference
2022 projected spend (in 2021): $17,125,333 • PJFF Bag & Cleaning Air Manifold Replacement ($3,994,601) • SCR Reactor Catalyst Management ($1,866,200) • Complete Mill Overhauls ($1,264,800) • Replace CO-O2 Monitors ($967,400) • Design and Install New Large Particle Ash Screen ($1,485,100) • Fuel Handling & Infrastructure Repairs ($1,500,000) • Sixteen additional projects totaling $6,047,032	**2022 actual expenditure: $7,935,000** The 2022 actual capital expenditure included three projects: air compressor replacement ($1,207,000); selective catalytic reduction catalyst management ($1,196,000); and diesel generator controls ($1,172,000). The actual expenditure represented about 46 percent of the pre-IRP projection.	**$9,190,333**
2023 projected spend (in 2021): $20,478,187 • PJFF Bag & Cleaning Air Manifold Replacement ($3,263,331) • Complete Mill Overhauls ($1,295,300) • Design and Install New Large Particle Ash Screen ($1,008,700) • Secondary Air Heater basket & seal replacement ($2,425,000) • High Pressure Feedwater Heater 8A replacement ($5,039,800) • Fuel Handling & Infrastructure Repairs ($1,500,000) • Seventeen additional projects totaling $6,954,257	**2023 actual expenditure: $456,000** The actual capital expenditure represented about 2 percent of the pre-IRP projection.	**$20,022,187**
2024 projected spend (in 2021): $33,395,569 • SCR Reactor Catalyst Management ($1,959,510) • Turbine Drain Modifications ($2,535,000) • Superheat Terminal Drain Replacement ($3,023,100) • Replace Boiler Sidewall Panels ($2,425,000) • Replace Boiler Front And Rear Wall Panels ($2,482,900) • Secondary Air Heater basket & seal replacement ($1,562,000) • Fuel Handling & Infrastructure Repairs ($1,500,000) • Cell Construction and Permitting ($5,482,830) • and twenty-one additional projects totaling $12,425,229	**2024 actual expenditure: $0** The precise value reported in Consumers' filing is negative (-$1,264,000). This is likely due to accounting treatment. For purposes of this analysis, I treat negative investment as $0, which is consistent with 2024 testimony from CECo witness Blumenstock stating that the company did not plan to invest any capital in the Campbell units in 2024.	**$33,395,569**
2025 projected spend (in 2021): $14,512,045 • GSU Replacement ($6,485,045) • SCR Reactor Catalyst Management ($3,000,000) • AQCS Equipment repair/replacement ($1,000,000) • Cell Construction and Permitting ($2,000,000) • and four additional projects totaling $2,027,000	**2025 projected expenditure: $0** CECo projected no Unit 3 capital budget in 2025.	**$14,512,045**
	TOTAL	**$77,120,134**

22. A detailed listing of the 2022-2025 major maintenance projects that CECo projected carrying out before deciding in 2022 to retire the units in May 2025 is shown in the left-hand column of Tables 5a (Units 1 and 2) and 5b (Unit 3).[15] As can be seen from the middle column in these tables,[16] CECo did not carry out most of those projects.

23. Table 5a compares the major maintenance projects CECo proposed carrying out for Units 1 and 2 before deciding to retire those units in May 2025 with those projects CECo has actually carried out, or plans to carry out, after making that retirement decision. Major maintenance spending declined by a total of 62 percent across 2022-2025, from a proposed total of $14.4 million to $5.5 million. CECo does not specify the nature of most of its major maintenance projects in its rate case filings. However, one cancelled major maintenance project with a direct impact on unit reliability is the Unit 2 turbine valve inspection project.

[15] Information in the left-hand column is from witness Kapala's testimony in CECo's 2021 IRP case. *See* Michigan PSC Case No. U-21090, Revised Direct Testimony of Norman J. Kapala, pp. 28-30 (Oct. 2021).
[16] Information in the middle column is from witness Blumenstock's testimony in CECo's 2023-2025 rate cases. *See* Ex. A-41 to the Direct Testimony of Richard T. Blumenstock in Michigan PSC Case No. U-21389 (May 2023) and Ex. A-43 to witness Blumenstock's testimony in Case Nos. U-21585 (May 2024), and U-21870 (June 2025).

Table 5a. Units 1&2 Major Maintenance Spend: CECo pre-IRP projection vs. post-IRP actuals/projections

Pre-IRP projection	Post-IRP actuals/projections	Difference
2022 projected spend (in 2021): $3,537,000 • Campbell 1 and 2 Periodic Outage Maintenance ($1,248,000) • Thirteen additional projects totaling $2,289,000	**2022 actual expenditure: $3,307,000** The 2022 actual maintenance expenditure was slightly less than the Unit 1&2 maintenance budget projected by CECo in 2021.	**$230,000**
2023 projected spend (in 2021): $2,905,000 • Covering 10 projects	**2023 actual expenditure: $1,054,000** The 2023 actual maintenance expenditure was approximately one-third the Unit 1&2 maintenance budget proposed for 2023 by CECo in 2021.	**$1,851,000**
2024 projected spend (in 2021): $3,405,167 • Covering 12 projects	**2024 actual expenditure: $903,000** The 2024 actual maintenance expenditure was approximately 27 percent of the Unit 1&2 maintenance budget proposed for 2024 by CECo in 2021.	**$2,502,167**
2025 projected spend (in 2021): $4,569,000 • Campbell 2 Turbine Valve Inspection ($1,300,000) • Seven additional projects totaling $3,269,000	**2025 projected expenditure:**[17] **$268,000** The 2025 projected maintenance expenditure was approximately 6 percent of the Unit 1&2 maintenance budget proposed for 2025 by CECo in 2021.	**$4,301,000**
	TOTAL	**$8,884,167**

[17] *See* U-21585, Ex. A-43 to Blumenstock Direct Testimony. This exhibit shows the "Projected Test Year 12 Months Ending 02/28/26." This 12-month cost projection covers most of the 5-month 2025 operational period (1/1/25 – 5/31/25) for Campbell Units 1&2 as well as the additional months those units would not be operational. From the information I reviewed, this is the best source of information regarding CECo's actual and projected 2025 major maintenance spending.

24. Table 5b compares the major maintenance projects CECo proposed carrying out for Unit 3 before deciding to retire that unit in May 2025 with those projects CECo has actually carried out, or plans to carry out, after making that retirement decision. Major maintenance spending declined by a total of 78 percent across 2022-2025, from a proposed total of $23.5 million to $5.1 million. CECo does not specify most of its major maintenance projects in its rate case filings. However, as discussed in more detail below, one cancelled major maintenance project with a direct impact on unit reliability is the $7.9 million Unit 3 turbine overhaul project. The project was originally scheduled to take place in 2024. The turbine failed in April 2024 resulting in a 46-day forced outage.[18]

[18] *See infra* Tbl. 1.

Table 5b. Unit 3 Major Maintenance Spend: CECo pre-IRP projection vs. post-IRP actuals/projections

Pre-IRP projection	Post-IRP actuals/projections	Difference
2022 projected spend (in 2021): $4,208,040 • Boiler Feed Pump Turbine Inspection ($1,680,000) • Fourteen additional projects totaling $2,528,040	**2022 actual expenditure: $3,196,000** The 2022 actual maintenance expenditure was sufficient to do about 75 percent of the Unit 3 maintenance projects budgeted for 2022 by CECo in 2021.	**$1,012,040**
2023 projected spend (in 2021): $2,523,970 • Covering 12 projects	**2023 actual expenditure: $995,000** The actual expenditure represented about 40 percent of the pre-IRP projection.	**$1,528,970**
2024 projected spend (in 2021): $12,954,250 • Campbell 3 Turbine Overhaul ($7,931,350) • Campbell 3 Boiler Chemical Cleaning ($1,429,000) • Campbell 3 Base Outage Boiler and Critical Maintenance ($1,000,000) • Campbell 3 Periodic Outage Maintenance ($933,100) • Eight additional projects totaling $1,660,800	**2024 actual expenditure: $591,000** The 2024 projected actual maintenance expenditure was sufficient to do about 5 percent of the Unit 3 maintenance projects budgeted for 2024 by CECo in 2021. The highest cost proposed 2024 project, the Campbell 3 Turbine Overhaul ($7,931,350), was not carried out. The turbine failed in April 2024 resulting in a 46-day forced outage.	**$12,363,250**
2025 projected spend (in 2021): $3,810,600 • Campbell 3 Turbine Valve Inspection ($1,200,000) • Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000) • Six additional projects totaling $1,410,600	**2025 projected expenditure:**[19] **$277,000** The actual expenditure represented about 7 percent of the pre-IRP projection.	**$3,533,600**
	TOTAL	**$18,437,860**

[19] *See* U-21585, Ex. A-43 to Blumenstock Direct Testimony. This exhibit shows the "Projected Test Year 12 Months Ending 02/28/26." This 12-month cost projection covers most of the 5-month 2025 operational period (1/1/25 – 5/31/25) for Campbell Unit 3 as well as the additional months that unit would not be operational. From the information I reviewed, this is the best source of information regarding CECo's actual and projected 2025 major maintenance spending.

25. It is unlikely that Campbell can reliably dispatch given this deferred capital and major maintenance spending.

26. Moreover, Campbell Units 1 and 2 were built in the 1960s. Units 1 and 2 are beyond both a typical coal unit economic design life of 30-40 years and a typical operational lifetime of 40-50 years.[20,21]

27. Replacement parts are not readily available or do not exist for Units 1 and 2, as described by CECo witness Hoffman: "Some of these units were built in the 1960s, and given the ages and designs of the systems, replacement parts are not always readily available. In some instances, replacement parts do not exist at all. The start-up boiler feed pump ("SUBFP") at Campbell Unit 2 is one of those systems. Keeping spare parts on hand is neither cost effective nor practical since replacements do not exist."[22]

28. CECo witness Blumenstock states that CECo discontinued capital investment in Units 1-3 in 2023 and is only doing sufficient maintenance to keep Units 1-3 operable through May 2025: "The Company does not plan to invest any capital in the Campbell units during the bridge period [2024 and early 2025] or test year . . . [T]he Company has projected modest amounts of major maintenance to ensure that these units are able to operate through their retirement date of May 31, 2025."[23] Witness Blumenstock also indicates that Unit 1 would be retired early, on April 1, 2025.[24]

29. In my professional opinion, witness Blumenstock is describing CECo's transition from a preventative capital investment and maintenance structure, intended to maintain the

[20] M. Hafner, G. Luciani, *The Palgrave Handbook of International Energy Economics*, p. 127 (2022).
[21] International Energy Agency, *The role of CCUS in low-carbon power systems*, p. 18 (2020).
[22] U-21424, Hoffman Direct Testimony, p.6.
[23] U-21585, Blumenstock Direct Testimony, p. 62.
[24] *Ibid*., p. 20.

Campbell units' long-term reliability, to a reactive, "fix it if breaks" approach to operating Units 1-3. CECo's objective shifted from maintaining long-term reliability to keeping the units operating—to the extent possible with little or no spending—*up until* May 31, 2025 *and no longer.* CECo's objective was *not* to achieve the high level of Unit 1-3 reliability that would be necessary for the units to ramp up and work reliably under emergency demand conditions.

30. A case in point is the cancelled $7.9 million Unit 3 turbine overhaul project that was originally scheduled for 2024.[25] In late April 2024, the Unit 3 turbine suffered a turning gear failure that resulted in a 1,104-hour (46 day) forced outage.[26] The turbine turning gear was repaired to achieve the limited objective of allowing Unit 3 to continue to operate until the planned retirement in (May) 2025.[27] It is reasonable to assume that the turning gear failure would not have occurred if the Unit 3 turbine had already been overhauled. This failure incident calls into question how many other Unit 3 components are vulnerable to near-term failure due to lack of investment and preventative maintenance by CECo. Given the limited maintenance, it would be unreasonable for DOE to assume that Unit 3 can run much longer without CECo doing a substantial amount of deferred maintenance.

31. While it is not possible based on publicly available information to put an exact price tag on the cost of ensuring that Campbell could reliably operate at full capacity, CECo cancelled **approximately $161 million** in planned capital and major maintenance projects at Campbell over the past four years ($133.6 million in capital projects; $27.3 million in major maintenance projects). It is reasonable to assume that much of this investment was necessary to ensure continued, nominally reliable operation of Campbell. It is also reasonable to assume that

[25] U-21090, Kapala Revised Direct Testimony, p. 29.
[26] U-21424, Ex. A-11 to Hoffman Direct Testimony.
[27] *Ibid*., Ex. A-13.

some of this investment was necessary to ensure compliance with environmental requirements, as discussed more below. Those capital and major maintenance investments are what *CECo determined* in 2021 that it would need to spend on a year-to-year basis to operate the Campbell units reliably and in conformance with environmental requirements in 2022-2025, if these units were to continue to operate past May 2025 (i.e. until 2031 for Units 1 and 2 and until 2039 for Unit 3).

B. Whether Campbell can operate effectively as a peaking unit

32. In my opinion, Campbell cannot operate effectively as a peaking unit that would be dispatched with only a few hours of notice to meet an extreme demand condition.

33. Coal units generally, and Campbell's three units specifically, cannot serve as peaking units that respond to extreme peak demand on short notice. Coal units are designed for baseload, round-the-clock operation.[28] Coal units started "cold" (room temperature) typically take approximately 12 hours to reach full load operation.[29] The ramp rate is slow to avoid excessive thermal stress on components exposed to heat. In contrast, utility-scale battery storage can dispatch from a cold start to full power in a matter of seconds.[30] Similarly, combustion gas turbines, designed for fast-response peaking duty, can go from a cold start to full power in 5 to 10 minutes.[31]

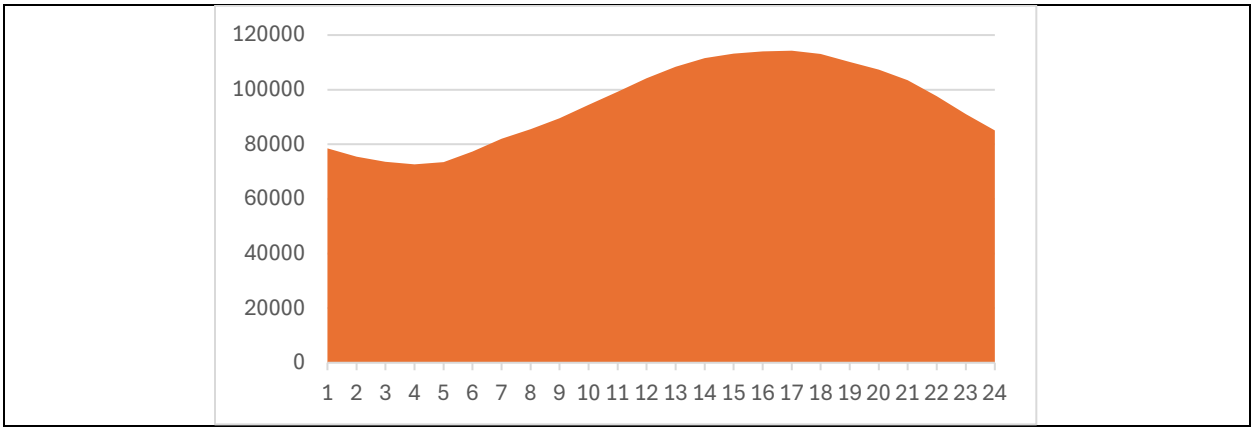
34. Coal units cannot respond to extreme demand events unless they are fully online several hours before the high demand situation occurs. In other words, coal units need

[28] U-21258, Hoffman Direct Testimony, pp. 4-5.
[29] IEA Clean Coal Centre, *Increasing the flexibility of coal-fired power plants*, p. 26 (Sept. 2014).
[30] NERC, *Energy Storage: Overview of Electrochemical Storage*, p. 1 (Feb. 2021). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Master_ESAT_Report.pdf ("BESS are a well suited technology to provide short-term grid contingency support (tens of seconds) . . . .").
[31] General Electric, *Get to know the LM6000* (webpage) (2025), https://www.gevernova.com/gas-power/products/gas-turbines/lm6000. ("With around five minutes to ramp up from start-up to full power . . . .").

substantial lead time to be fully operational at or before an extreme peak demand is reached. They cannot be dispatched from an offline "cold" status to address extreme emergency demand if an emergency is declared only a few hours before the demand must be met.

35. Grid demand often increases rapidly on peak demand days. MISO may have only a few hours of notice that an extreme peak demand day is developing. The need to bring on additional generation resources to meet an extreme peak may be uncertain until the period immediately prior to the actual peak. An example of this can be seen in Figure 1, which shows a 24-hour demand curve for the MISO control area on the high demand summer day of September 5, 2023.[32] MISO actual demand was rising as fast as 5,000 MW per hour during the day, adding the equivalent of Campbell's 1,561 MW capacity every 20 minutes to meet demand.

Figure 1. MISO 24-hour demand curve (MW), September 5, 2023



36. Bringing Campbell from a cold start condition to full output to meet extreme demand would also be expensive. According to the National Association of Regulatory Utility Commissioners, the estimated cost to "cold start" a coal-fired power plant is $417 per MW of capacity.[33] The total nameplate capacity of Campbell Units 1-3 is 1,561 MW. Therefore, the

[32] Figure 1 was developed using data from U.S. EIA, csv dataset, "MISO_load-temp_hr_2023" (accessed June 13, 2025).
[33] NARUC, *Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices*, p. 16 (Jan. 2020).

estimated cost to start up Campbell from a cold start condition would be approximately $650,000. (1,561 MW × $417 per MW = $650,937).

37. Alternatively, instead of starting cold, CECo could be forced to run Campbell for hours unnecessarily solely to be prepared for a potential near-term high-peak demand. That approach would be expensive and polluting.

C. Easily attainable steps DOE can require to ensure Campbell's operations are consistent with environmental requirements and minimize adverse environmental impacts

38. In my opinion, for DOE's order to be consistent with environmental requirements, CECo must demonstrate, prior to restarting Units 1-3, that (1) the pulse jet fabric filters on Units 1-3 are in sound, leak-free condition, and (2) the SCRs on Units 2 and 3 have sufficient remaining catalyst life to adequately control NO_x emissions.

39. As noted above, some of the capital and major maintenance projects cancelled in 2022-2025 were air emission control system projects. Cancelled capital projects with a direct impact on maintaining environmental compliance included, among others, PJFF filter bag(s) replacement on Unit 1 (for particulate/opacity control); SCR reactor catalyst replacement on Unit 2 (for nitrogen oxide control); and replacement of PJFF filter bag(s), "cleaning air manifold," and SCR reactor catalyst on Unit 3.[34] These projects were planned likely because CECo believed they were necessary to maintain adequate air emission control system performance and that failure to carry out the projects could compromise that performance.

40. Table 6 shows the multiple air emission control system capital projects that were cancelled in 2022-2025. The implications of these cancelled air quality control system projects are: (1) degraded fabric filter performance on Units 1 and 3, potentially resulting in particulate

[34] *See infra* Tables 4a and 4b.

and/or opacity exceedances, and (2) degraded performance of nitrogen oxide (NO_x) control systems (SCR) on Units 2 and 3, potentially resulting in NO_x exceedances. Degraded fabric filter performance, caused by torn or improperly secured filter bags, could lead to elevated levels of opacity and particulate emissions. A degraded SCR catalyst could lead to poor NO_x conversion and elevated NO_x emissions at the stack.

Table 6. Cancelled 2022-2025 Campbell Unit 1-3 air quality control capital projects

Year	Unit	Project[35]	Budget ($)
2022	2 3	• (SCR) catalyst management • Fabric filter bag(s) & cleaning air manifold replacement	1,120,000 3,994,601
2023	1 2 3	• Fabric filter bag replacement • SCR reactor catalyst replacement • Fabric filter bag(s) & cleaning air manifold replacement	1,514,100 2,000,000 3,263,331
2025	3	• SCR reactor catalyst management • Air quality control system (AQCS) equipment repair/replacement	3,000,000 1,000,000

41. In light of these cancelled projects, DOE should require that CECo demonstrate that the Campbell Unit 1-3 pulse jet fabric filters are currently leak free prior to authorizing further operation. DOE also should require that CECo provide records demonstrating that the catalysts in the Units 2 and 3 SCRs have sufficient remaining useful life to reasonably assure compliance with NO_x limits.

42. It is my opinion that DOE should require verification of the good working order of the Unit 1-3 air emission control systems before authorizing Campbell to operate under extreme demand conditions. DOE should also require that any Campbell unit that exceeds air permit limits for opacity, NO_x, or SO_2 that occur during operation of Units 1-3, as registered on the continuous opacity, NO_x, or SO_2 monitors installed on each unit, be shut down.

[35] *See* U-21090, Kapala Revised Direct Testimony; U-21389, Blumenstock Direct Testimony, Ex. A-12 (not listed as carried-out); U-21585, Blumenstock Direct Testimony, A-12 (not listed as carried-out).

43. It is also my opinion that there are alternatives to running Campbell to meet an extreme peak demand that would produce far less environmental harm.

44. Any air emissions that result from running Campbell would not occur if the plant is retired. Additionally, according to its NPDES wastewater discharge permit, Campbell is cooled with ~1 billion gallons per day of Lake Michigan water in a once-through cooling configuration (NPDES permit). Therefore, the plant will use up to 1 billion gallons per day if called to operate. That is a potentially significant impact on Lake Michigan marine fauna that does not occur if Campbell is retired. Finally, any coal burned will produce coal ash that will have to be stored/disposed of onsite. That is another impact that would not occur if Campbell is retired.

45. In my opinion, a coal unit would be the last alternative to consider for a peaking power application due to its slow ramp time and high environmental impact.

I declare under penalty of perjury under the laws of the United States, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 15th day of June 2025, in San Diego, California.

Bill Powers, P.E.

Bill Powers, P.E.
Powers Engineering
4452 Park Blvd., Suite 209
San Diego, CA 92116

Attachment C

MICHIGAN DEPARTMENT OF ENVIRONMENT, GREAT LAKES, AND ENERGY
AIR QUALITY DIVISION

EFFECTIVE DATE: February 4, 2020
REVISION DATES: September 3, 2020, July 2, 2021

ISSUED TO

Consumers Energy, J.H. Campbell Generating Complex

State Registration Number (SRN): B2835

LOCATED AT

17000 Croswell, West Olive, Ottawa County, Michigan 49460

RENEWABLE OPERATING PERMIT

Permit Number: MI-ROP-B2835-2020b

Expiration Date: February 4, 2025

Administratively Complete ROP Renewal Application
Due Between August 4, 2023 and August 4, 2024

This Renewable Operating Permit (ROP) is issued in accordance with and subject to Section 5506(3) of Part 55, Air Pollution Control, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended (Act 451). Pursuant to Rule 210(1) of the administrative rules promulgated under Act 451, this ROP constitutes the permittee's authority to operate the stationary source identified above in accordance with the general conditions, special conditions and attachments contained herein. Operation of the stationary source and all emission units listed in the permit are subject to all applicable future or amended rules and regulations pursuant to Act 451 and the federal Clean Air Act.

SOURCE-WIDE PERMIT TO INSTALL

Permit Number: MI-PTI-B2835-2020b

This Permit to Install (PTI) is issued in accordance with and subject to Section 5505(1) of Act 451. Pursuant to Rule 214a of the administrative rules promulgated under Act 451, the terms and conditions herein, identified by the underlying applicable requirement citation of Rule 201(1)(a), constitute a federally enforceable PTI. The PTl terms and conditions do not expire and remain in effect unless the criteria of Rule 201(6) are met. Operation of all emission units identified in the PTI is subject to all applicable future or amended rules and regulations pursuant to Act 451 and the federal Clean Air Act.

Michigan Department of Environment, Great Lakes, and Energy

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Heidi Hollenbach, Grand Rapids District Supervisor

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AUTHORITY AND ENFORCEABILITY

For the purpose of this permit, the **permittee** is defined as any person who owns or operates an emission unit at a stationary source for which this permit has been issued. The **department** is defined in Rule 104(d) as the Director of the Michigan Department of Environment, Great Lakes, and Energy (EGLE) or his or her designee.

The permittee shall comply with all specific details in the permit terms and conditions and the cited underlying applicable requirements. All terms and conditions in this ROP are both federally enforceable and state enforceable unless otherwise footnoted. Certain terms and conditions are applicable to most stationary sources for which an ROP has been issued. These general conditions are included in Part A of this ROP. Other terms and conditions may apply to a specific emission unit, several emission units which are represented as a flexible group, or the entire stationary source which is represented as a Source-Wide group. Special conditions are identified in Parts B, C, D and/or the appendices.

In accordance with Rule 213(2)(a), all underlying applicable requirements are identified for each ROP term or condition. All terms and conditions that are included in a PTI are streamlined, subsumed and/or is state-only enforceable will be noted as such.

In accordance with Section 5507 of Act 451, the permittee has included in the ROP application a compliance certification, a schedule of compliance, and a compliance plan. For applicable requirements with which the source is in compliance, the source will continue to comply with these requirements. For applicable requirements with which the source is not in compliance, the source will comply with the detailed schedule of compliance requirements that are incorporated as an appendix in this ROP. Furthermore, for any applicable requirements effective after the date of issuance of this ROP, the stationary source will meet the requirements on a timely basis, unless the underlying applicable requirement requires a more detailed schedule of compliance.

Issuance of this permit does not obviate the necessity of obtaining such permits or approvals from other units of government as required by law.

This permit does not relieve the permittee from any responsibilities or obligations imposed on the permittee, at the source under Consent Decree U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014, entered in 2014 between the USEPA and the permittee.

A. GENERAL CONDITIONS

Permit Enforceability

- All conditions in this permit are both federally enforceable and state enforceable unless otherwise noted. **(R 336.1213(5))**

- Those conditions that are hereby incorporated in a state-only enforceable Source-Wide PTI pursuant to Rule 201(2)(d) are designated by footnote one. **(R 336.1213(5)(a), R 336.1214a(5))**

- Those conditions that are hereby incorporated in a federally enforceable Source-Wide PTI pursuant to Rule 201(2)(c) are designated by footnote two. **(R 336.1213(5)(b), R 336.1214a(3))**

General Provisions

1. The permittee shall comply with all conditions of this ROP. Any ROP noncompliance constitutes a violation of Act 451, and is grounds for enforcement action, for ROP revocation or revision, or for denial of the renewal of the ROP. All terms and conditions of this ROP that are designated as federally enforceable are enforceable by the Administrator of the United States Environmental Protection Agency (USEPA) and by citizens under the provisions of the federal Clean Air Act (CAA). Any terms and conditions based on applicable requirements which are designated as "state-only" are not enforceable by the USEPA or citizens pursuant to the CAA. **(R 336.1213(1)(a))**

2. It shall not be a defense for the permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this ROP. **(R 336.1213(1)(b))**

3. This ROP may be modified, revised, or revoked for cause. The filing of a request by the permittee for a permit modification, revision, or termination, or a notification of planned changes or anticipated noncompliance does not stay any ROP term or condition. This does not supersede or affect the ability of the permittee to make changes, at the permittee's own risk, pursuant to Rule 215 and Rule 216. **(R 336.1213(1)(c))**

4. The permittee shall allow the department, or an authorized representative of the department, upon presentation of credentials and other documents as may be required by law and upon stating the authority for and purpose of the investigation, to perform any of the following activities: **(R 336.1213(1)(d))**
   a. Enter, at reasonable times, a stationary source or other premises where emissions-related activity is conducted or where records must be kept under the conditions of the ROP.
   b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of the ROP.
   c. Inspect, at reasonable times, any of the following:
      i. Any stationary source.
      ii. Any emission unit.
      iii. Any equipment, including monitoring and air pollution control equipment.
      iv. Any work practices or operations regulated or required under the ROP.
   d. As authorized by Section 5526 of Act 451, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the ROP or applicable requirements.

5. The permittee shall furnish to the department, within a reasonable time, any information the department may request, in writing, to determine whether cause exists for modifying, revising, or revoking the ROP or to determine compliance with this ROP. Upon request, the permittee shall also furnish to the department copies of any records that are required to be kept as a term or condition of this ROP. For information which is claimed by the permittee to be confidential, consistent with the requirements of the 1976 PA 442, MCL §15.231 et seq., and known as the Freedom of Information Act, the person may also be required to furnish the records directly to the USEPA together with a claim of confidentiality. **(R 336.1213(1)(e))**

6. A challenge by any person, the Administrator of the USEPA, or the department to a particular condition or a part of this ROP shall not set aside, delay, stay, or in any way affect the applicability or enforceability of any other condition or part of this ROP. **(R 336.1213(1)(f))**

7. The permittee shall pay fees consistent with the fee schedule and requirements pursuant to Section 5522 of Act 451. **(R 336.1213(1)(g))**

8. This ROP does not convey any property rights or any exclusive privilege. **(R 336.1213(1)(h))**

Equipment & Design

9. Any collected air contaminants shall be removed as necessary to maintain the equipment at the required operating efficiency. The collection and disposal of air contaminants shall be performed in a manner so as to minimize the introduction of contaminants to the outer air. Transport of collected air contaminants in Priority I and II areas requires the use of material handling methods specified in Rule 370(2).[2] **(R 336.1370)**

10. Any air cleaning device shall be installed, maintained, and operated in a satisfactory manner and in accordance with the Michigan Air Pollution Control rules and existing law. **(R 336.1910)**

Emission Limits

11. Unless otherwise specified in this ROP, the permittee shall comply with Rule 301, which states, in part, "Except as provided in Subrules 2, 3, and 4 of this rule, a person shall not cause or permit to be discharged into the outer air from a process or process equipment a visible emission of a density greater than the most stringent of the following:"[2] **(R 336.1301(1))**
    a. A 6-minute average of 20% opacity, except for one 6-minute average per hour of not more than 27% opacity.
    b. A limit specified by an applicable federal new source performance standard.

    The grading of visible emissions shall be determined in accordance with Rule 303.

12. The permittee shall not cause or permit the emission of an air contaminant or water vapor in quantities that cause, alone or in reaction with other air contaminants, either of the following:
    a. Injurious effects to human health or safety, animal life, plant life of significant economic value, or property.[1] **(R 336.1901(a))**
    b. Unreasonable interference with the comfortable enjoyment of life and property.[1] **(R 336.1901(b))**

Testing/Sampling

13. The department may require the owner or operator of any source of an air contaminant to conduct acceptable performance tests, at the owner's or operator's expense, in accordance with Rule 1001 and Rule 1003, under any of the conditions listed in Rule 1001(1).[2] **(R 336.2001)**

14. Any required performance testing shall be conducted in accordance with Rule 1001(2), Rule 1001(3) and Rule 1003. **(R 336.2001(2), R 336.2001(3), R 336.2003(1))**

15. Any required test results shall be submitted to the Air Quality Division (AQD) in the format prescribed by the applicable reference test method within 60 days following the last date of the test. **(R 336.2001(5))**

Monitoring/Recordkeeping

16. Records of any periodic emission or parametric monitoring required in this ROP shall include the following information specified in Rule 213(3)(b)(i), where appropriate. **(R 336.1213(3)(b))**
    a. The date, location, time, and method of sampling or measurements.
    b. The dates the analyses of the samples were performed.
    c. The company or entity that performed the analyses of the samples.
    d. The analytical techniques or methods used.
    e. The results of the analyses.
    f. The related process operating conditions or parameters that existed at the time of sampling or measurement.

17. All required monitoring data, support information and all reports, including reports of all instances of deviation from permit requirements, shall be kept and furnished to the department upon request for a period of not less than 5 years from the date of the monitoring sample, measurement, report or application. Support information includes all calibration and maintenance records and all original strip-chart recordings, or other original data records, for continuous monitoring instrumentation and copies of all reports required by the ROP. **(R 336.1213(1)(e), R 336.1213(3)(b)(ii))**

Certification & Reporting

18. Except for the alternate certification schedule provided in Rule 213(3)(c)(iii)(B), any document required to be submitted to the department as a term or condition of this ROP shall contain an original certification by a Responsible Official which state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. **(R 336.1213(3)(c))**

19. A Responsible Official shall certify to the appropriate AQD District Office and to the USEPA that the stationary source is and has been in compliance with all terms and conditions contained in the ROP except for deviations that have been or are being reported to the appropriate AQD District Office pursuant to Rule 213(3)(c). This certification shall include all the information specified in Rule 213(4)(c)(i) through (v) and shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the certification are true, accurate, and complete. The USEPA address is: USEPA, Air Compliance Data - Michigan, Air and Radiation Division, 77 West Jackson Boulevard, Chicago, Illinois 60604-3507. **(R 336.1213(4)(c))**

20. The certification of compliance shall be submitted annually for the term of this ROP as detailed in the special conditions, or more frequently if specified in an applicable requirement or in this ROP. **(R 336.1213(4)(c))**

21. The permittee shall promptly report any deviations from ROP requirements and certify the reports. The prompt reporting of deviations from ROP requirements is defined in Rule 213(3)(c)(ii) as follows, unless otherwise described in this ROP. **(R 336.1213(3)(c))**
    a. For deviations that exceed the emissions allowed under the ROP, prompt reporting means reporting consistent with the requirements of Rule 912 as detailed in Condition 25. All reports submitted pursuant to this paragraph shall be promptly certified as specified in Rule 213(3)(c)(iii).
    b. For deviations which exceed the emissions allowed under the ROP and which are not reported pursuant to Rule 912 due to the duration of the deviation, prompt reporting means the reporting of all deviations in the semiannual reports required by Rule 213(3)(c)(i). The report shall describe reasons for each deviation and the actions taken to minimize or correct each deviation.
    c. For deviations that do not exceed the emissions allowed under the ROP, prompt reporting means the reporting of all deviations in the semiannual reports required by Rule 213(3)(c)(i). The report shall describe the reasons for each deviation and the actions taken to minimize or correct each deviation.

22. For reports required pursuant to Rule 213(3)(c)(ii), prompt certification of the reports is described in Rule 213(3)(c)(iii) as either of the following: **(R 336.1213(3)(c))**
    a. Submitting a certification by a Responsible Official with each report which states that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.
    b. Submitting, within 30 days following the end of a calendar month during which one or more prompt reports of deviations from the emissions allowed under the ROP were submitted to the department pursuant to Rule 213(3)(c)(ii), a certification by a Responsible Official which states that; "based on information and belief formed after reasonable inquiry, the statements and information contained in each of the reports submitted during the previous month were true, accurate, and complete." The certification shall include a listing of the reports that are being certified. Any report submitted pursuant to Rule 213(3)(c)(ii) that will be certified on a monthly basis pursuant to this paragraph shall include a statement that certification of the report will be provided within 30 days following the end of the calendar month.

23. Semiannually for the term of the ROP as detailed in the special conditions, or more frequently if specified, the permittee shall submit certified reports of any required monitoring to the appropriate AQD District Office. All instances of deviations from ROP requirements during the reporting period shall be clearly identified in the reports. **(R 336.1213(3)(c)(i))**

24. On an annual basis, the permittee shall report the actual emissions, or the information necessary to determine the actual emissions, of each regulated air pollutant as defined in Rule 212(6) for each emission unit utilizing the emissions inventory forms provided by the department. **(R 336.1212(6))**

25. The permittee shall provide notice of an abnormal condition, start-up, shutdown, or malfunction that results in emissions of a hazardous or toxic air pollutant which continue for more than one hour in excess of any applicable standard or limitation, or emissions of any air contaminant continuing for more than two hours in excess of an applicable standard or limitation, as required in Rule 912, to the appropriate AQD District Office. The notice shall be provided not later than two business days after the start-up, shutdown, or discovery of the abnormal conditions or malfunction. Notice shall be by any reasonable means, including electronic, telephonic, or oral communication. Written reports, if required under Rule 912, must be submitted to the appropriate AQD District Supervisor within 10 days after the start-up or shutdown occurred, within 10 days after the abnormal conditions or malfunction has been corrected, or within 30 days of discovery of the abnormal conditions or malfunction, whichever is first. The written reports shall include all of the information required in Rule 912(5) and shall be certified by a Responsible Official in a manner consistent with the CAA.[2] **(R 336.1912)**

Permit Shield

26. Compliance with the conditions of the ROP shall be considered compliance with any applicable requirements as of the date of ROP issuance if either of the following provisions is satisfied. **(R 336.1213(6)(a)(i), R 336.1213(6)(a)(ii))**
    a. The applicable requirements are included and are specifically identified in the ROP.
    b. The permit includes a determination or concise summary of the determination by the department that other specifically identified requirements are not applicable to the stationary source.

    Any requirements identified in Part E of this ROP have been identified as non-applicable to this ROP and are included in the permit shield.

27. Nothing in this ROP shall alter or affect any of the following:
    a. The provisions of Section 303 of the CAA, emergency orders, including the authority of the USEPA under Section 303 of the CAA. **(R 336.1213(6)(b)(i))**
    b. The liability of the owner or operator of this source for any violation of applicable requirements prior to or at the time of this ROP issuance. **(R 336.1213(6)(b)(ii))**
    c. The applicable requirements of the acid rain program, consistent with Section 408(a) of the CAA. **(R 336.1213(6)(b)(iii))**

d. The ability of the USEPA to obtain information from a source pursuant to Section 114 of the CAA. **(R 336.1213(6)(b)(iv))**

28. The permit shield shall not apply to provisions incorporated into this ROP through procedures for any of the following:
    a. Operational flexibility changes made pursuant to Rule 215. **(R 336.1215(5))**
    b. Administrative Amendments made pursuant to Rule 216(1)(a)(i)-(iv). **(R 336.1216(1)(b)(iii))**
    c. Administrative Amendments made pursuant to Rule 216(1)(a)(v) until the amendment has been approved by the department. **(R 336.1216(1)(c)(iii))**
    d. Minor Permit Modifications made pursuant to Rule 216(2). **(R 336.1216(2)(f))**
    e. State-Only Modifications made pursuant to Rule 216(4) until the changes have been approved by the department. **(R 336.1216(4)(e))**

29. Expiration of this ROP results in the loss of the permit shield. If a timely and administratively complete application for renewal is submitted not more than 18 months, but not less than 6 months, before the expiration date of the ROP, but the department fails to take final action before the end of the ROP term, the existing ROP does not expire until the renewal is issued or denied, and the permit shield shall extend beyond the original ROP term until the department takes final action. **(R 336.1217(1)(c), R 336.1217(1)(a))**

Revisions

30. For changes to any process or process equipment covered by this ROP that do not require a revision of the ROP pursuant to Rule 216, the permittee must comply with Rule 215. **(R 336.1215, R 336.1216)**

31. A change in ownership or operational control of a stationary source covered by this ROP shall be made pursuant to Rule 216(1). **(R 336.1219(2))**

32. For revisions to this ROP, an administratively complete application shall be considered timely if it is received by the department in accordance with the time frames specified in Rule 216. **(R 336.1210(10))**

33. Pursuant to Rule 216(1)(b)(iii), Rule 216(2)(d) and Rule 216(4)(d), after a change has been made, and until the department takes final action, the permittee shall comply with both the applicable requirements governing the change and the ROP terms and conditions proposed in the application for the modification. During this time period, the permittee may choose to not comply with the existing ROP terms and conditions that the application seeks to change. However, if the permittee fails to comply with the ROP terms and conditions proposed in the application during this time period, the terms and conditions in the ROP are enforceable. **(R 336.1216(1)(c)(iii), R 336.1216(2)(d), R 336.1216(4)(d))**

Reopenings

34. A ROP shall be reopened by the department prior to the expiration date and revised by the department under any of the following circumstances:
    a. If additional requirements become applicable to this stationary source with three or more years remaining in the term of the ROP, but not if the effective date of the new applicable requirement is later than the ROP expiration date. **(R 336.1217(2)(a)(i))**
    b. If additional requirements pursuant to Title IV of the CAA become applicable to this stationary source. **(R 336.1217(2)(a)(ii))**
    c. If the department determines that the ROP contains a material mistake, information required by any applicable requirement was omitted, or inaccurate statements were made in establishing emission limits or the terms or conditions of the ROP. **(R 336.1217(2)(a)(iii))**
    d. If the department determines that the ROP must be revised to ensure compliance with the applicable requirements. **(R 336.1217(2)(a)(iv))**

Renewals

35. For renewal of this ROP, an administratively complete application shall be considered timely if it is received by the department not more than 18 months, but not less than 6 months, before the expiration date of the ROP. **(R 336.1210(9))**

Stratospheric Ozone Protection

36. If the permittee is subject to Title 40 of the Code of Federal Regulations (CFR), Part 82 and services, maintains, or repairs appliances except for motor vehicle air conditioners (MVAC), or disposes of appliances containing refrigerant, including MVAC and small appliances, or if the permittee is a refrigerant reclaimer, appliance owner or a manufacturer of appliances or recycling and recovery equipment, the permittee shall comply with all applicable standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F.

37. If the permittee is subject to 40 CFR Part 82 and performs a service on motor (fleet) vehicles when this service involves refrigerant in the MVAC, the permittee is subject to all the applicable requirements as specified in 40 CFR Part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners. The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed by the original equipment manufacturer. The term MVAC as used in Subpart B does not include the air-tight sealed refrigeration system used for refrigerated cargo or an air conditioning system on passenger buses using Hydrochlorofluorocarbon-22 refrigerant.

Risk Management Plan

38. If subject to Section 112(r) of the CAA and 40 CFR Part 68, the permittee shall register and submit to the USEPA the required data related to the risk management plan for reducing the probability of accidental releases of any regulated substances listed pursuant to Section 112(r)(3) of the CAA as amended in 40 CFR 68.130. The list of substances, threshold quantities, and accident prevention regulations promulgated under 40 CFR Part 68, do not limit in any way the general duty provisions under Section 112(r)(1).

39. If subject to Section 112(r) of the CAA and 40 CFR Part 68, the permittee shall comply with the requirements of 40 CFR Part 68, no later than the latest of the following dates as provided in 40 CFR 68.10(a):
    a. June 21, 1999,
    b. Three years after the date on which a regulated substance is first listed under 40 CFR 68.130, or
    c. The date on which a regulated substance is first present above a threshold quantity in a process.

40. If subject to Section 112(r) of the CAA and 40 CFR Part 68, the permittee shall submit any additional relevant information requested by any regulatory agency necessary to ensure compliance with the requirements of 40 CFR Part 68.

41. If subject to Section 112(r) of the CAA and 40 CFR Part 68, the permittee shall annually certify compliance with all applicable requirements of Section 112(r) as detailed in Rule 213(4)(c)). **(40 CFR Part 68)**

Emission Trading

42. Emission averaging and emission reduction credit trading are allowed pursuant to any applicable interstate or regional emission trading program that has been approved by the Administrator of the USEPA as a part of Michigan's State Implementation Plan. Such activities must comply with Rule 215 and Rule 216. **(R 336.1213(12))**

Permit to Install (PTI)

43. The process or process equipment included in this permit shall not be reconstructed, relocated, or modified unless a PTI authorizing such action is issued by the department, except to the extent such action is exempt from the PTI requirements by any applicable rule.[2] **(R 336.1201(1))**

44. The department may, after notice and opportunity for a hearing, revoke PTI terms or conditions if evidence indicates the process or process equipment is not performing in accordance with the terms and conditions of the PTI or is violating the department's rules or the CAA.[2] **(R 336.1201(8), Section 5510 of Act 451)**

45. The terms and conditions of a PTI shall apply to any person or legal entity that now or hereafter owns or operates the process or process equipment at the location authorized by the PTI. If a new owner or operator submits a written request to the department pursuant to Rule 219 and the department approves the request, this PTI will be amended to reflect the change of ownership or operational control. The request must include all of the information required by Subrules (1)(a), (b) and (c) of Rule 219. The written request shall be sent to the appropriate AQD District Supervisor, EGLE.[2] **(R 336.1219)**

46. If the installation, reconstruction, relocation, or modification of the equipment for which PTI terms and conditions have been approved has not commenced within 18 months of the original PTI issuance date, or has been interrupted for 18 months, the applicable terms and conditions from that PTI, as incorporated into the ROP, shall become void unless otherwise authorized by the department. Furthermore, the person to whom that PTI was issued, or the designated authorized agent, shall notify the department via the Supervisor, Permit Section, EGLE, AQD, P. O. Box 30260, Lansing, Michigan 48909, if it is decided not to pursue the installation, reconstruction, relocation, or modification of the equipment allowed by the terms and conditions from that PTI.[2] **(R 336.1201(4))**

Footnotes:
[1]This condition is state-only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

B. SOURCE-WIDE CONDITIONS

Part B outlines the Source-Wide Terms and Conditions that apply to this stationary source. The permittee is subject to these special conditions for the stationary source in addition to the general conditions in Part A and any other terms and conditions contained in this ROP.

The permittee shall comply with all specific details in the special conditions and the underlying applicable requirements cited. If a specific condition type does not apply to this source, NA (not applicable) has been used in the table. If there are no Source-Wide Conditions, this section will be left blank.

C. EMISSION UNIT SPECIAL CONDITIONS

Part C outlines terms and conditions that are specific to individual emission units listed in the Emission Unit Summary Table. The permittee is subject to the special conditions for each emission unit in addition to the General Conditions in Part A and any other terms and conditions contained in this ROP.

The permittee shall comply with all specific details in the special conditions and the underlying applicable requirements cited. If a specific condition type does not apply, NA (not applicable) has been used in the table. If there are no conditions specific to individual emission units, this section will be left blank.

EMISSION UNIT SUMMARY TABLE

The descriptions provided below are for informational purposes and do not constitute enforceable conditions.

Emission Unit ID	Emission Unit Description (Including Process Equipment & Control Device(s))	Installation Date/ Modification Date	Flexible Group ID
EUPARTSCLEANERS	Multiple individual cleaning units that are subject to the same applicable requirements. The cleaning units are used in support of facility operations.	01-01-1994/ NA	FGPARTSCLEANERS
EUBOILER1	A 2490 MMBTU per hour dry bottom, tangential fired boiler with fuel oil startup capabilities. Emissions are currently controlled by low-NOx burners, sorbent injection (ACI) (activated carbon or other sorbent for mercury control), dry sorbent injection (DSI) (hydrated lime or other sorbent), and a pulse-jet fabric filter (PJFF) baghouse.	01-01-1958/ 04 23-2015	FGMATS_U12 FGBOILER12
EUBOILER2	A 3560 MMBTU per hour wall-fired (converted from cell burner) boiler with fuel oil startup capability. Emissions are controlled by low-NOx burners, selective catalytic reduction (SCR), sorbent injection (ACI) (activated carbon or other sorbent for mercury control), DSI (hydrated lime or other sorbent), and a PJFF baghouse.	01-01-1963/ 04-23-2015	FGMATS_U12 FGBOILER12
EUBOILER3	An 8240 MMBTU per hour dry bottom, wall-fired boiler with fuel oil startup capability. Emissions are controlled by low-NOx burners, SCR, sorbent injection (ACI) (activated carbon or other sorbent for mercury control), spray dry absorber (SDA), and PJFF baghouse.	02-01-1974/ 04-23-2015	FGMATS_U3
EUCOALHAND	Coal handling facility. Particulate emissions are controlled by 11 baghouses, enclosures, and dust suppression.	01-01-1958	NA

Emission Unit ID	Emission Unit Description (Including Process Equipment & Control Device(s))	Installation Date/ Modification Date	Flexible Group ID
EUSDA_U3	Lime preparation operations for Boiler 3 that support the SDA including storage silos, vertical ball mills, lime slurry transfer and product tanks. Emissions are controlled by bin vent filters and spray scrubbers (mill scrubbers). SDA operations for Boiler 3 includes lime slurry atomizer head tanks, recycle silos, recycle mix tanks, and recycle slurry storage tanks. Emissions are controlled by bin vent filters and a spray scrubber (recycle mix tank).	04-23-2015	NA
EUDSI_U12	Dry Sorbent Injection Material Handling for Boilers 1 and 2. Includes sorbent silos (hydrated lime or other sorbent) and pneumatic transfer; bin vent filters.	04-23-2015	NA
EUACI_U123	Activated carbon (or other sorbent) material handling including silos for Boiler Units 1, 2 and 3; with bin vent filters.	04-23-2015	NA
EUBYPRODUCT	There are three separate byproduct handling systems (one for each boiler). The system transfers the byproduct from the fabric filters (ash, spent lime, and sorbent) to the disposal silos. The equipment includes conveyance piping and byproduct transfer tanks, filter separator, vacuum exhausters, and conveying blowers from transfer tanks to flyash storage/disposal silos. Dry flyash handling facility is located at the landfill and is common to Boilers 1, 2, and 3 and consists of three flyash storage/disposal silos; with flyash truck dry load outs. Emissions control: The transfer tanks' byproduct vacuum exhauster filter separators exhaust to the boiler pulse-jet fabric filters (except as noted in the emission unit requirements); bin vent filters on the byproduct transfer tanks and flyash silos. Water added for flyash conditioning before flyash truck loading for disposal.	04-23-2015	NA
EUAUXBLR12	A 17 MMBTU/hr fuel oil-fired firetube auxiliary boiler servicing EUBOILER1 and EUBOILER2. This boiler is a limited use boiler.	01-01-1958	NA
EUAUXBLR3B	A 9.8 MMBTU/hr fuel oil fired auxiliary boiler providing heat to Plant 3.	11-2011	FGAUXBLRS3
EUAUXBLR3C	A 9.8 MMBTU/hr fuel oil fired auxiliary boiler providing heat to Plant 3.	11-2011	FGAUXBLRS3
EUCAT3DIESEL	A diesel-powered, stationary internal combustion engine rated at 9.3 MMBTU/hr heat input.	02-01-1974	NA

Emission Unit ID	Emission Unit Description (Including Process Equipment & Control Device(s))	Installation Date/ Modification Date	Flexible Group ID
EUWPDIESEL	Water Pump for EUSDA_U3 emergency flush certified to NSPS IIII Tier 3 requirements. A diesel-powered, stationary internal combustion engine rated at 130 HP (97 kW).	07-2016	FGNEWCIRICE
EUCATFIREPUMP3	A diesel-powered, stationary internal combustion Caterpillar 3406 model engine rated at 2.8 MMBTU/hr heat input; used as a fire pump.	01-2017	FGEXISTINGRICE
EUHPHSWP15001	A diesel-powered, stationary internal combustion engine rated at 3.05 MMBTU/hr heat input; Emergency Diesel Generator #1.	01-01-1958	FGEXISTINGRICE
EUHPHSWP15002	A diesel-powered, stationary internal combustion engine rated at 3.05 MMBTU/hr heat input; Emergency Diesel Generator #2.	01-01-1958	FGEXISTINGRICE
EUHPHSWP3000	A diesel-powered, stationary internal combustion engine rated at 2.58 MMBTU/hr heat input; Emergency Diesel Generator.	01-01-1958	FGEXISTINGRICE
EUCATDIESEL12	A 2,000-kilowatt (kW) diesel-fueled emergency engine manufactured in 2007 or later.	10-12-2012	NA
EUTRNCNTRDIESEL	A diesel-powered, stationary internal combustion engine rated at 1193 BHP; Emergency Diesel Generator.	08-2013	FGNEWCIRICE
EUGUARDSHK_ENG	A natural-gas, stationary internal combustion engine rated at 40 HP; Emergency Generator for the guard shack.	08-2015	NA

EUBOILER1
EMISSION UNIT CONDITIONS

DESCRIPTION

A 2490 MMBTU/hr dry bottom, tangential fired boiler with fuel oil startup capability. This emission unit is subject to 40 CFR Part 63, Subpart UUUUU (MATS) and 40 CFR Part 64 (CAM). All CAM requirements are in FGBOILER12 and all MATS requirements are in FGMATS_U12.

Flexible Group ID: FGBOILER12 and FGMATS_U12

POLLUTION CONTROL EQUIPMENT

Low-NOx burners,
Sorbent injection (ACI) (activated carbon or other sorbent for mercury control),
Dry sorbent injection (DSI) (hydrated lime or other sorbent), and
Pulse-jet fabric filter (PJFF) baghouse.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Particulate matter (PM)	0.16 pound per 1,000 pounds exhaust gas, corrected to 50% excess air[2]	Hourly	EUBOILER1	SC V.1 (FGBOILER12, SC VI.1, COMS)	**R 336.1331(1)(c)**
2. NO_x	0.220 pound per MMBTU heat input[2,3,4]	Based on a 365-day Rolling Average Emission Rate[2,3,4]	EUBOILER1	SC VI.1	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 76; Act 451, Section 324.5503(b)**
3. SO_2	0.350 pounds per MMBTU heat input[2,3,4]	Based on a 30-day Rolling Average Emission Rate[2,3,4]	EUBOILER1	SC VI.1 SC VI.2	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 113; Act 451, Section 324.5503(b)**

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
4. SO_2	0.290 pound per MMBTU heat input[2,3,4]	Based on a 90-day Rolling Average Emission Rate[2,3,4]	EUBOILER1	SC VI.1 SC VI.2	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 113; Act 451, Section 324.5503(b)**
5. PM	0.015 pound per MMBTU heat input[2,3,4]	Hourly[2,3,4]	EUBOILER1	SC V.2 (FGBOILER12, SC VI.1, COMS)	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 144; Act 451, Section 324.5503(b)**
6. Opacity	20%[2,3,4]	Per 6-minute period except for one 6-minute period per hour of not more than 27%[2,3,4]	EUBOILER1	SC VI.4	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 151; Act 451, Section 324.5503(b)**
7. SO_2	1.67 pounds per MMBTU heat input[2]	Monthly average, based on the average of the 31 previous operating days	EUBOILER1	SC VI.3	**R 336.1401(3), Table 41**

8. The permittee shall comply with the System-Wide Annual NOx Tonnage Limitations and System-Wide Annual SO_2 Tonnage Limitations specified in Appendix 11-A. Emissions from EUBOILER1 shall be counted toward the system-wide total emissions.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 98 & 129, Act 451, Section 324.5503(b))**

9. The permittee shall comply with the SO_2 and NO_x allowance surrender and super-compliance allowance provisions listed in Appendix 11-B: Allowance Provisions.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 101-109 and 132-140, Act 451, Section 324.5503(b))**

See Appendices 11-A and 11-B

II. MATERIAL LIMIT(S)

Material	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Coal – sulfur content	1.0% by weight, at a heat content of 12,000 BTU/lb[2]	Monthly average, based on the average of the 31 previous operating days	EUBOILER1	SC VI.3	**R 336.1401(3), Table 41**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate EUBOILER1 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for the emission control equipment (PJFF baghouse, ACI, DSI) is implemented and maintained. The MAP shall, at a minimum, specify the following:

   a. A complete preventative maintenance program including identification of the supervisory personnel responsible for overseeing the inspection, maintenance, and repair of air-cleaning devices, a description of the items or conditions that shall be inspected, the frequency of the inspections or repairs, and an identification of the major replacement parts that shall be maintained in inventory for quick replacement.

   b. An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction or failure, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.

   c. A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits.

   If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days, if new equipment is installed or upon request from the District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1910, R 336.1911)**

2. The permittee shall continuously operate the PM Control Device for EUBOILER1 and use good air pollution control practices to maximize the PM emission reductions at all times when the unit is in operation. The requirements of Appendix 3-F shall be met.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 141, Act 451, Section 324.5503(b))**

3. The permittee shall not operate the boiler, including startup and shutdown, unless the corresponding PJFF baghouse is installed and operating properly, in accordance with safe operating practices.[2] **(R 336.1910)**

4. The permittee shall not burn freeze conditioning/dust suppression agents unless PJFF baghouses are installed and operating properly, in accordance with safe operating practices.[2] **(R 336.1910)**

See Appendix 3-F

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate EUBOILER1 unless the low-NOx burners, the DSI, the ACI sorbent injection (for mercury control), and PJFF baghouse are installed, maintained, and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approvable MAP for EUBOILER1 control equipment as required in SC III.1.[2] **(R 336.1910)**

2. The permittee shall not operate EUBOILER1 unless the low-NO_x burners, including over fire air processes, are Continuously Operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 75, Act 451, Section 324.5503(b))**

3. The permittee shall not operate EUBOILER1 unless the DSI system is Continuously Operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 113, Act 451, Section 324.5503(b))**

4. The permittee shall not operate EUBOILER1 unless the PJFF baghouse unit is Continuously Operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 144, Act 451, Section 324.5503(b))**

5. The permittee shall continuously operate the PM control devices being vented to a combined stack associated with FGBOILER12.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 142, Act 451, Section 324.5503(b))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Every three (3) years, or more frequently upon request of the AQD, the permittee shall verify PM emission rates from EUBOILER1 by testing at the owner's expense, in accordance with the Department requirements. Testing shall be performed using an approved USEPA Method listed in 40 CFR Part 60, Appendix A, Reference Method 17 (Determination of Particulate Emissions from Stationary Sources (In-stack Filtration Method)), Reference Method 5 or "MATS" 5, or other acceptable test method(s). An alternate method, or a modification to the approved USEPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.[2] **(R 336.1213(3), R 336.2001, R 336.2003, R 336.2004)**
2. The permittee shall conduct a stack test for PM pursuant to the provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements. Subsequent stack tests for PM shall be conducted pursuant to the schedule and provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 153, Act 451, Section 324.5503(b))**

3. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted.[2] **(R 336.2001(3))**

4. The permittee shall assess opacity using USEPA Reference Method 9 - "Visual Determination of the Opacity of Emissions from Stationary Sources," upon the request of AQD.[2] **(R 336.1301)**

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. For purposes of determining compliance with the Rolling Average Emission Rates for NO_x and SO_2 as found in SC I.2, I.3, and I.4, the permittee shall install and operate CEMS in accordance with the procedures of 40 CFR Part 75, except that the NO_x and SO_2 emissions data need not be bias adjusted and the missing data substitution procedures of 40 CFR Part 75 shall not apply. If applicable, diluent capping (i.e., 5% CO_2) will be applied to the NO_x emission rate for any hours where the measured CO_2 concentration is less than 5% following the procedures in 40 CFR Part 75, Appendix F, Section 3.3.4.1.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 99 and 130, Act 451, Section 324.5503(b))**

2. The permittee shall monitor unit level SO_2 concentrations and gas flow, using CEMS, as installed, maintained, and operated in accordance with 40 CFR Part 75.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 116, Act 451, Section 324.5503(b))**

3. The permittee shall monitor gas flow, SO_2, CO_2, and NOx emissions using CEMS, as installed, maintained, and operated in accordance with the provisions of 40 CFR Part 75.[2] **(R 336.1401, R 336.2101)**

4. The permittee shall monitor and record the opacity from each boiler using a Continuous Opacity Monitoring System (COMS), installed, operated and maintained in accordance with 40 CFR Part 60, Appendix B.[2] **(R 336.1301, R 336.2101)**

See Appendices 3-A, 3-B, and 3-D

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit any performance test reports, including RATA reports, to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVBLR12	228[2]	400[2]	**R 336.1225** **R 336.2803** **R 336.2804** **40 CFR 52.21 (c) and (d)**

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the acid rain permitting provisions of 40 CFR Part 72.1 to 72.94, as outlined in a complete Phase II, Acid Rain Permit issued by the AQD. Phase II, Acid Rain Permit No. MI-AR-1710-2020is hereby incorporated into this ROP as Appendix 9. **(R 336.1902(1)(q))**

2. The permittee shall not allow the emission of an air pollutant to exceed the amount of any emission allowances that an affected source lawfully holds as of the allowance transfer deadline pursuant to R 336.1902(1)(q) and 40 CFR Part 72.9(c)(1)(i). **(R 336.1213(10))**

3. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_X Annual Trading Program, as specified in 40 CFR Part 97, Subpart AAAAA, and identified in Appendix 10. **(40 CFR Part 97, Subpart AAAAA)**

4. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_X Ozone Season Group 2 Trading Program, as specified in 40 CFR Part 97, Subpart EEEEE, and identified in Appendix 10. **(40 CFR Part 97, Subpart EEEEE)**

5. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule SO_2 Group 1 Trading Program, as specified in 40 CFR Part 97, Subpart CCCCC, and identified in Appendix 10. **(40 CFR Part 97, Subpart CCCCC)**

6. The permittee shall comply with applicable provisions of Act 451 Part 15 EMISSION LIMITATIONS AND PROHIBITIONS-MERCURY.[2] **(R 336.2503(1))**

7. The permittee shall comply with all applicable requirements of 40 CFR Part 64 as specified in FGBOILER12. **(40 CFR Part 64)**

8. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units, as specified in FGMATS_U12.[2] **(40 CFR Part 63, Subpart UUUUU)**

Footnotes:
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).
[3]This condition is federally enforceable and was originally established in the consent decree settling, "U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" and also pursuant to Act 451, Section 324.5503(b), and will remain in effect after termination of the consent decree.
[4]Definitions specific to this condition may be found in Appendix 1-B: Definitions Applicable to Specified Permit Conditions.

EUBOILER2
EMISSION UNIT CONDITIONS

DESCRIPTION

A 3560 MMBTU/hr wall-fired boiler with fuel oil startup capability. This emission unit is subject to 40 CFR Part 64 (CAM) and 40 CFR Part 63, Subpart UUUUU (MATS). All CAM requirements are in FGBOILER12, and all MATS requirements are in FGMATS_U12.

Flexible Group ID: FGBOILER12 and FGMATS_U12

POLLUTION CONTROL EQUIPMENT

Low-NOx burners,
Selective catalytic reduction (SCR),
Sorbent injection (ACI) (activated carbon or other sorbent for mercury control),
Dry sorbent injection (DSI) (hydrated lime or other sorbent), and
Pulse-jet fabric filter (PJFF) baghouse.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Particulate matter (PM)	0.15 pound per 1,000 pounds exhaust gas, corrected to 50% excess air[2]	Hourly	EUBOILER2	SC V.1 (FGBOILER12, SC VI.1, COMS)	**R 336.1331(1)(c)**
2. NO_x	0.100 pound per MMBTU heat input[2,3,4]	Based on a 30-day Rolling Average Emission Rate[2,3,4]	EUBOILER2	SC VI.1	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 78; Act 451, Section 324.5503(b)**
3. NO_x	0.080 pound per MMBTU heat input[2,3,4]	Based on a 90-day Rolling Average Emission Rate[2,3,4]	EUBOILER2	SC VI.1	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 79; Act 451, Section 324.5503(b)**

	Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
4.	SO_2	0.320 pound per MMBTU heat input[2,3,4]	Based on a 365-day Rolling Average Emission Rate[2,3,4]	EUBOILER2	SC VI.1 SC VI.2	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 114; Act 451, Section 324.5503(b)**
5.	PM	0.015 pound per MMBTU heat input[2,3,4]	Hourly[2,3,4]	EUBOILER2	SC V.2 (FGBOILER12, SC VI.1, COMS)	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 145; Act 451, Section 324.5503(b)**
6.	SO_2	1.67 pounds per MMBTU heat input[2]	Monthly average, based on the average of the 31 previous operating days	EUBOILER2	SC VI.3	**R 336.1401(3), Table 41**
7.	Opacity	20%[2,3,4]	Per 6-minute period except for one 6-minute period per hour of not more than 27%[2,3,4]	EUBOILER2	SC VI.4	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 151; Act 451, Section 324.5503(b)**

8. The permittee shall comply with the System-Wide Annual NOx Tonnage Limitations and System-Wide Annual SO_2 Tonnage Limitations specified in Appendix 11-A. Emissions from EUBOILER2 shall be counted toward the system-wide total emissions.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 98 & 129, Act 451, Section 324.5503(b))**

9. The permittee shall comply with the SO_2 and NO_x allowance surrender and super-compliance allowance provisions listed in Appendix 11-B: Allowance Provisions.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 101-109 and 132-140, Act 451, Section 324.5503(b))**

See Appendices 11-A and 11-B

II. MATERIAL LIMIT(S)

	Material	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1.	Coal – sulfur content	1.0% by weight, at a heat content of 12,000 BTU/lb[2]	Monthly average, based on the average of the 31 previous operating days	EUBOILER2	SC VI.3	**R 336.1401(3), Table 41**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate EUBOILER2 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for the emission control equipment (PJFF baghouse, ACI, DSI, and SCR) is implemented and maintained. The MAP shall, at a minimum, specify the following:

   a. A complete preventative maintenance program including identification of the supervisory personnel responsible for overseeing the inspection, maintenance, and repair of air-cleaning devices, a description of the items or conditions that shall be inspected, the frequency of the inspections or repairs, and an identification of the major replacement parts that shall be maintained in inventory for quick replacement.

   b. An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction or failure, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.

   c. A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits.

   If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days if new equipment is installed or upon request from the District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1910, R 336.1911)**

2. The permittee shall continuously operate the PM Control Device for EUBOILER2 and use good air pollution control practices to maximize the PM emission reductions at all times when the unit is in operation. The requirements of Appendix 3-F shall be met.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 141, Act 451, Section 324.5503(b))**

3. The permittee shall not operate the boiler, including startup and shutdown, unless the corresponding PJFF baghouse is installed and operating properly, in accordance with safe operating practices.[2] **(R 336.1910)**

4. The permittee shall not burn freeze conditioning/dust suppression agents unless PJFF baghouses are installed and operating properly, in accordance with safe operating practices.[2] **(R 336.1910)**

See Appendix 3-F

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate EUBOILER2 unless the low-NOx burners, the SCR, DSI, ACI sorbent injection (for mercury control), and PJFF baghouse are installed, maintained, and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approvable MAP for EUBOILER2 as required in SC III.1.[2] **(R 336.1910)**

2. The permittee shall not operate EUBOILER2 unless the SCR and PJFF baghouse are continuously operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraphs 77 and 145, Act 451, Section 324.5503(b))**

3. The permittee shall not operate EUBOILER2 unless the DSI system is continuously operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 114, Act 451, Section 324.5503(b))**

4. The permittee shall continuously operate the PM control devices being vented to a combined stack associated with FGBOILER12.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 142, Act 451, Section 324.5503(b))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Every three (3) years, or more frequently upon request of the AQD, the permittee shall verify PM emission rates from EUBOILER2 by testing at the owner's expense, in accordance with the Department requirements. Testing shall be performed using an approved USEPA Method listed in 40 CFR Part 60, Appendix A Reference Method 17 (Determination of Particulate Emissions from Stationary Sources (In-stack Filtration Method)), Reference Method 5, "MATS" Reference Method 5, or other acceptable test method(s). An alternate method, or a modification to the approved USEPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.[2] **(R 336.1213(3), R 336.1201(3), R 336.2001, R 336.2003, R 336.2004)**

2. The permittee shall conduct a stack test for PM pursuant to the provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements. Subsequent stack tests for PM shall be conducted pursuant to the schedule and provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 153, Act 451, Section 324.5503(b))**

3. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor no less than 7 days prior to the anticipated test date.[2] **(R 336.2001(3))**

4. The permittee shall assess opacity using USEPA Reference Method 9 - "Visual Determination of the Opacity of Emissions from Stationary Sources", upon the request of AQD.[2] **(R 336.1301)**

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. For purposes of determining compliance with the Rolling Average Emission Rates for NO_x and SO_2 as found in SC I.2, I.3, and I.4., the permittee shall install and operate CEMS in accordance with the procedures of 40 CFR Part 75, except that the NO_x and SO_2 emissions data need not be bias adjusted and the missing data substitution procedures of 40 CFR Part 75 shall not apply. If applicable, diluent capping (i.e., 5% CO_2) will be applied to the NO_x emission rate for any hours where the measured CO_2 concentration is less than 5% following the procedures in 40 CFR Part 75, Appendix F, Section 3.3.4.1.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 99 and 130, Act 451, Section 324.5503(b))**

2. The permittee shall monitor SO_2 concentrations and gas flow using CEMS, as installed, maintained, and operated in accordance with 40 CFR Part 75.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 116, Act 451, Section 324.5503(b))**

3. The permittee shall monitor gas flow, SO_2, CO_2, and NOx emissions using CEMS, as installed, maintained, and operated in accordance with the provisions of 40 CFR Part 75.[2] **(R 336.1401, R 336.2101)**

4. The permittee shall monitor and record the opacity from each boiler using a Continuous Opacity Monitoring System (COMS), installed, operated and maintained in accordance with 40 CFR Part 60, Appendix B.[2] **(R 336.1301, R 336.2101)**

See Appendices 3-A, 3-B, and 3-D

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit any performance test reports, including RATA reports to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVBLR12	228[2]	400[2]	**R 336.1225** **R 336.2803** **R 336.2804** **40 CFR 52.21 (c) and (d)**

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the acid rain permitting provisions of 40 CFR 72.1 to 72.94, as outlined in a complete Phase II, Acid Rain Permit issued by the AQD. Phase II, Acid Rain Permit No. MI-AR-1710-2020 is hereby incorporated into this ROP as Appendix 9. **(R 336.1902(1)(q))**

2. The permittee shall not allow the emission of an air pollutant to exceed the amount of any emission allowances that an affected source lawfully holds as of the allowance transfer deadline pursuant to R 336.1902(1)(q) and 40 CFR 72.9(c)(1)(i). **(R 336.1213(10))**

3. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_X Annual Trading Program, as specified in 40 CFR Part 97, Subpart AAAAA, and identified in Appendix 10. **(40 CFR Part 97, Subpart AAAAA)**

4. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_X Ozone Season Group 2 Trading Program, as specified in 40 CFR Part 97, Subpart EEEEE, and identified in Appendix 10. **(40 CFR Part 97, Subpart EEEEE)**

5. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule SO_2 Group 1 Trading Program, as specified in 40 CFR Part 97, Subpart CCCCC, and identified in Appendix 10. **(40 CFR Part 97, Subpart CCCCC)**

6. The permittee shall comply with applicable provisions of Act 451 Part 15 EMISSION LIMITATIONS AND PROHIBITIONS—MERCURY.[2] **(R 336.2503(1))**

7. The permittee shall comply with all applicable requirements of 40 CFR Part 64 as specified in FGBOILER12. **(40 CFR Part 64)**

8. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units, as specified in FGMATS_U12.[2] **(40 CFR Part 63, Subpart UUUUU)**

See Appendices 11-A and 11-B

Footnotes:
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).
[3]This condition is federally enforceable and was originally established in the consent decree settling, "U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" and also pursuant to Act 451, Section 324.5503(b), and will remain in effect after termination of the consent decree.
[4]Definitions specific to this condition may be found in Appendix 1-B: Definitions Applicable to Specified Permit Conditions.

EUBOILER3
EMISSION UNIT CONDITIONS

DESCRIPTION

An 8240 MMBTU/hr dry bottom, wall-fired boiler with fuel oil startup capability. This emission unit is subject to 40 CFR Part 63, Subpart UUUUU (MATS). The MATS requirements are in FGMATS_U3.

Flexible Group ID: FGMATS_U3

POLLUTION CONTROL EQUIPMENT

Low-NOx burners,
Selective catalytic reduction (SCR),
Sorbent injection (ACI) (activated carbon or other sorbent for mercury control),
Spray dry absorber (SDA), and
Pulse-jet fabric filter (PJFF) baghouse.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Opacity	20%[2]	Per 6-minute period except for one 6-minute period per hour of not more than 27%	EUBOILER3	SC VI.2	**40 CFR 60.42(a)(2), R 336.1301**
2. Opacity	20%[2,3,4]	Per 6-minute period except for one 6-minute period per hour of not more than 27%	EUBOILER3	SC VI.2	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 151; Act 451, Section 324.5503(b)**
3. PM	0.10 pound per MMBTU heat input[2]	Hourly	EUBOILER3	SC V.1 SC VI.2 SC VI. 4	**40 CFR 60.42(a)(1)**
4. PM	370 pounds per hour[2]	Hourly	EUBOILER3	SC V.1 SC VI.2 SC VI.4	**R 336.1205(3)**
5. PM	1,080 tons per year[2]	Based on a 12-month rolling time period as determined at the end of each calendar month	EUBOILER3	SC V.1 SC VI.2 SC VI.4	**R 336.1205(3)**

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
6. PM	0.015 pound per MMBTU heat input[2,3,4]	Based on a 3-hr rolling average in accordance with SC V.4 and SC VI.4[2,3,4]	EUBOILER3	SC V.3, SC V.4 (if applicable) SC VI.4	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 146; Act 451, Section 324.5503(b)**
7. SO_2	1.2 pounds per MMBTU heat input[2]	Continuous	EUBOILER3	SC VI.1	**40 CFR 60.43(a)(2)**
8. SO_2	10,500 pounds per hour[2]	Based on a daily average	EUBOILER3	SC VI.1	**R 336.1205(3)**
9. SO_2	31,650 tons per year[2]	Based on a 12-month rolling time period as determined at the end of each calendar month	EUBOILER3	SC VI.1	**R 336.1205(3)**
10. SO_2	0.085 pound per MMBTU heat input[2,3,4]	Based on a 30-day Rolling Average[2,3,4]	EUBOILER3	SC VI.3	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 112; Act 451, Section 324.5503(b)**
11. SO_2	0.070 pound per MMBTU heat input[2,3,4]	Based on a 365-day Rolling Average Emission Rate[2,3,4]	EUBOILER3	SC VI.3	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 112; Act 451, Section 324.5503(b)**
12. NOx	0.70 pound per MMBTU heat input[2]	Per 3-hour rolling time period, as determined each hour the boiler operates	EUBOILER3	SC VI.1	**40 CFR 60.44(a)(3)**
13. NOx	6,130 pounds per hour[2]	Based on a daily average	EUBOILER3	SC VI.1	**R 336.1205(3)**
14. NOx	18,750 tons per year[2]	Based on a 12-month rolling time period as determined at the end of each calendar month	EUBOILER3	SC VI.1	**R 336.1205(3)**

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
15. NOx	0.100 pound per MMBTU heat input[2,3,4]	Based on a 30-day Rolling Average Emission Rate[2,3,4]	EUBOILER3	SC VI.3	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 81; Act 451, Section 324.5503(b)**
16. NOx	0.080 pound per MMBTU heat input[2,3,4]	Based on a 90-day Rolling Average Emission Rate[2,3,4]	EUBOILER3	SC VI.3	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 82; Act 451, Section 324.5503(b)**

17. The permittee shall comply with the System-Wide Annual NOx Tonnage Limitations and System-Wide Annual SO_2 Tonnage Limitations specified in Appendix 11-A. Emissions from EUBOILER3 shall be counted toward the system-wide total emissions.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 98 & 129, Act 451, Section 324.5503(b))**

18. The permittee shall comply with the SO_2 and NO_x allowance surrender and super-compliance allowance provisions listed in Appendix 11-B: Allowance Provisions.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 101-109 and 132-140, Act 451, Section 324.5503(b))**

See Appendix 11-A and Appendix 11-B

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not burn freeze conditioning/dust suppression agents unless the boiler and corresponding particulate control device are operating properly.[2] **(R 336.1910)**

2. The permittee shall not operate the boiler, including startup and shutdown, unless the corresponding PJFF baghouse is installed and operating properly, in accordance with safe operating practices.[2] **(R 336.1910)**

3. The permittee shall not operate EUBOILER3 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for emission control equipment (PJFF baghouse, ACI, SDA, and SCR) is implemented and maintained. The MAP shall, at a minimum, specify the following:

   a. A complete preventative maintenance program including identification of the supervisory personnel responsible for overseeing the inspection, maintenance, and repair of air-cleaning devices, a description of the items or conditions that shall be inspected, the frequency of the inspections or repairs, and an identification of the major replacement parts that shall be maintained in inventory for quick replacement.

b. An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction or failure, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.

c. A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits.

If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days if new equipment is installed or upon request from the District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1910, R 336.1911)**

4. The permittee shall comply with all provisions of the federal Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced after August 17, 1971, as specified in 40 CFR Part 60, Subparts A and D, as they apply to EUBOILER3.[2] **(40 CFR Part 60, Subparts A and D)**

5. The permittee shall continuously operate the PM Control Device for EUBOILER3 and use good air pollution control practices to maximize the PM emission reductions at all times when the unit is in operation. The requirements of Appendix 3-F shall be met.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 141, Act 451, Section 324.5503(b))**

See Appendix 3-F

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate EUBOILER3 unless the low-NOx burners, the SCR, SDA, ACI sorbent injection (for mercury control), and PJFF baghouse are installed, maintained, and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approvable MAP for EUBOILER3 as required in SC III.5.[2] **(R 336.1910)**

2. The permittee shall not operate EUBOILER3 unless the SCR is Continuously Operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 80, Act 451, Section 324.5503(b))**

3. The permittee shall not operate EUBOILER3 unless the SDA and PJFF baghouse units are Continuously Operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraphs 112 and 146, Act 451, Section 324.5503(b))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Every three (3) years, or more frequently upon request of the AQD, the permittee shall verify PM emission rates from EUBOILER3 by testing at the owner's expense, in accordance with the Department requirements. Testing shall be performed using an approved USEPA Method listed in 40 CFR Part 60, Appendix A, Reference Method 17 (Determination of Particulate Emissions from Stationary Sources (in-stack Filtration Method) Reference Method 5, "MATS" Reference Method 5, or other acceptable test method(s). An alternate method, or a modification to the approved USEPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.[2] **(R 336.2001, R 336.2003, R 336.2004)**

2. The permittee shall notify the AQD no less than 7 days prior to the anticipated test date.[2] **(R 336.2001(3))**

3. The permittee shall conduct a stack test for PM pursuant to the provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements. Subsequent stack tests for PM shall be conducted pursuant to the schedule and provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 153, Act 451, Section 324.5503(b))**

4. As an alternative to the requirements of SC V.3 PM stack testing, the permittee may forego stack testing and instead demonstrate continuous compliance with SC I.7 PM filterable emission limit by using the PM CEMS pursuant to conditions contained in Appendix 5: PM Emissions Testing and Monitoring Requirements, and Appendix 3-E: PM CEMS.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 157, Act 451, Section 324.5503(b))**

See Appendices 3-E and 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall monitor gas flow, SO_2, CO_2, and NOx emissions using CEMS, as installed, maintained, and operated in accordance with the provisions of 40 CFR Part 75.[2] **(R 336.1205(3), R 336.2101, 40 CFR Part 60)**

2. The permittee shall monitor and record the opacity from the boiler using a Continuous Opacity Monitoring System (COMS), installed, operated and maintained in accordance with 40 CFR Part 60, Appendix B.[2] **(R 336.1301, R 336.2101, 40 CFR 60.42(a)(2))**

3. For purposes of determining compliance with the Rolling Average Emission Rates for NO_x and SO_2 as found in SC I.10, I.11, I.15, and I.16, the permittee shall install and operate CEMS in accordance with the procedures of 40 CFR Part 75, except that the NO_x and SO_2 emissions data need not be bias adjusted and the missing data substitution procedures of 40 CFR Part 75 shall not apply. If applicable, diluent capping (i.e., 5% CO_2) will be applied to the NO_x emission rate for any hours where the measured CO_2 concentration is less than 5% following the procedures in 40 CFR Part 75, Appendix F, Section 3.3.4.1.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 99 and 130, Act 451, Section 324.5503(b))**

4. The permittee shall install and continuously operate a PM CEMS pursuant to the conditions contained in Appendix 3-E: PM CEMS.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 159, 163, Act 451, Section 324.5503(b))**

See Appendices 3-A through 3-F

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit any performance test reports, including RATA reports to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

5. Quarterly reporting of monthly excess sulfur dioxide, and nitrogen oxide emissions (including the nature and cause of the periods of excess emissions), and of the dates and times of the monitoring systems being inoperative. Each quarterly report is due within 30 days of the calendar quarter reporting period. **(R 336.2170)**

6. Quarterly reporting of excess opacity emissions (including the nature and cause of the periods of excess emissions), and of the dates and times of the monitoring systems being inoperative. Each quarterly report is due within 30 days of the calendar quarter reporting period. **(R 336.2170)**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVBLR3	327[2]	642[2]	**R 336.1201(3)**

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the acid rain permitting provisions of 40 CFR 72.1 to 72.94, as outlined in a complete Phase II, Acid Rain Permit issued by the AQD. Phase II, Acid Rain Permit No. MI-AR-1710-2020 is hereby incorporated into this ROP as Appendix 9. **(R 336.1902(1)(q))**

2. The permittee shall not allow the emission of an air pollutant to exceed the amount of any emission allowances that an affected source lawfully holds as of the allowance transfer deadline pursuant to R 336.1902(1)(q) and 40 CFR 72.9(c)(1)(i). **(R 336.1213(10))**

3. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_X Annual Trading Program, as specified in 40 CFR Part 97, Subpart AAAAA, and identified in Appendix 10. **(40 CFR Part 97, Subpart AAAAA)**

4. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_X Ozone Season Group 2 Trading Program, as specified in 40 CFR Part 97, Subpart EEEEE, and identified in Appendix 10. **(40 CFR Part 97, Subpart EEEEE)**

5. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule SO_2 Group 1 Trading Program, as specified in 40 CFR Part 97, Subpart CCCCC, and identified in Appendix 10. **(40 CFR Part 97, Subpart CCCCC)**

6. The permittee shall comply with applicable provisions of Act 451 Part 15 EMISSION LIMITATIONS AND PROHIBITIONS—MERCURY.[2] **(R 336.2503(1))**

7. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units as specified in FGMATS_U3.[2] **(40 CFR Part 63, Subpart UUUUU)**

Footnotes:

[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).

[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

[3]This condition is federally enforceable and was originally established in the consent decree settling, "U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" and also pursuant to Act 451, Section 324.5503(b), and will remain in effect after termination of the consent decree.

[4]Definitions specific to this condition may be found in Appendix 1-B: Definitions Applicable to Specified Permit Conditions.

EUCOALHAND
EMISSION UNIT CONDITIONS

DESCRIPTION

The coal handling facility consists of: (2) dumper buildings, transfer conveyors, transfer building, breaker house, bunker rooms, and the coal pile storage area itself.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

Enclosures, 11 baghouses, dust suppression, telescopic spouts. The Dust Collectors serving the Unit 1 and 2 (DC10), and Unit 3 (DC1) dumper houses, and Coal yard dust hopper (DC11) are subject to 40 CFR Part 64 (CAM).

Dust collectors serving the breaker house (DC4), bunker houses (DC 5, 6, 7) and the reclaim hopper (DC9) are subject to the New Source Performance Standard 40 CFR Part 60, Subpart Y. (Initial performance testing has been completed.)

Dust collectors serving the reclaim (DC2) and transfer house (DC3A, DC3B) are subject to Michigan Rule 336.1301.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. PM	0.10 pound per 1,000 pounds exhaust gas, on a dry basis	At all times, as verifiable through any requested stack testing	Each discharge point	SC IV.1 SC VI.1 Through SC VI.8 (Proper maintenance and operation of the baghouses)	**R 336.1331(1)(a), Table 31(j)**
2. Opacity	20%	6-minute average	Discharge points for dust collectors DC4, DC5, DC6, DC7, and DC9	SC IV.1 SC VI.1 Through SC VI.8 (Proper maintenance and operation of the baghouses)	**40 CFR 60.252(c) (NSPS, Subpart Y)**
3. Opacity	20%	6-minute average	Discharge points for dust collectors DC1, DC2, DC3A, DC3B, DC10, and DC11,	SC IV.1 SC VI.1 Through SC VI.8 (Proper maintenance and operation of the baghouses)	**R 336.1301(1)(a)**

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate a process portion unless the particulate matter control device controlling the portion is installed and operating properly. **(R 336.1910)**

2. The permittee shall operate all coal handling equipment in accordance with the most recent facility Fugitive Dust Control Plan as approvable by the AQD District Supervisor. **(R 336.1213(3))**

3. The permittee shall not operate EUCOALHAND unless a malfunction abatement plan (MAP) as described in Rule 911(2), for emission control equipment is implemented and maintained. The MAP shall, at a minimum, specify the following:

   a. A complete preventative maintenance program including identification of the supervisory personnel responsible for overseeing the inspection, maintenance, and repair of air-cleaning devices, a description of the items or conditions that shall be inspected, the frequency of the inspections or repairs, and an identification of the major replacement parts that shall be maintained in inventory for quick replacement.

   b. An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction or failure, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.

   c. A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits.

   If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days if new equipment is installed or upon request from the District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits. **(R 336.1910, R 336.1911)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. Each particulate matter control device shall be equipped with pressure drop measurement devices and associated alarm system.[2] **(R 336.1201(3), R 336.1213(3))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall assess opacity using USEPA Reference Method 9 - “Visual Determination of the Opacity of Emissions from Stationary Sources”, upon the request of AQD. **(R 336.1213(3))**

2. Upon request of the AQD District Supervisor, the permittee shall verify PM emission rates from EUCOALHAND by testing at the owner’s expense, in accordance with the Department requirements. Testing shall be performed using an approved USEPA Method listed in 40 CFR Part 60, Appendix A; Part 10 of the Michigan Air Pollution Control Rules. An alternate method, or a modification to the approved USEPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test. **(R 336.1213(3), R 336.2001, R 336.2003, R 336.2004)**

3. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted. **(R 336.1213(3))**

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall conduct and record non-certified visible emissions observations for the dust collectors servicing EUBOILER 1, EUBOILER2 (DC10) and EUBOILER3 (DC1) dumper houses and Coal Yard dust hopper DC(11) once per day when operating, as the primary indicator of the proper functioning of each fabric filter dust collector. If visible emissions are observed, the permittee shall document the visible emissions, including the duration, and continue to observe the source of the visible emissions until no visible emissions are observed. The permittee shall initiate corrective actions as quickly as possible upon the detection of visible emissions. If there is a break in the visible emissions observations, it will be assumed that visible emissions continue to occur during any break in observations. The appropriate range of visible emissions defining proper functioning of each fabric filter dust collector is no visible emissions. **(40 CFR 64.6(c)(1)(i), (ii), and (iii))**

2. An excursion is the observation of visible emissions for the dust collectors serving EUBOILER1 and EUBOILER2 (DC10) or EUBOILER3 (DC1) dumper house or the coal yard dust hopper (DC11) for a duration exceeding one (1) hour. **(40 CFR 64.6(c)(2))**

3. The permittee shall properly maintain the monitoring system, including keeping necessary parts for routine repair of the monitoring equipment. **(40 CFR 64.7(b))**

4. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions or other measures as specified in the MAP. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). **(40 CFR 64.7(d))**

5. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. **(40 CFR 64.6(c)(3), 40 CFR 64.7(c))**

6. Any formal compliance determinations with the opacity limit established in 40 CFR 60.252(c) shall utilize Method 9 and the procedures in 40 CFR 60.11. **(40 CFR 60.254(b)(2))**

7. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan and any activities undertaken to implement a quality improvement plan, and other information such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions. **(40 CFR 64.9(b)(1))**

8. The permittee shall perform, and document non-certified visible emissions observations from dust collectors DC4, DC5, DC6, DC7, and DC9 as required in I.2 on a daily basis when EUCOALHAND is operating. If during the observation there are any visible emissions detected from an emission point, then corrective procedures as defined in the MAP shall be implemented. Records of the non-certified visible emissions observations, USEPA Method 9 observations that are performed, the reason for any visible emissions observed, and any corrective actions taken, shall be kept on file and in a format acceptable to the AQD. **(R 336.1213(3))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. Each semiannual report of monitoring deviations shall include summary information on the number, duration, and cause of exceedances/excursions in the reporting period; and the corrective actions taken in response. If there were no excursions and/or exceedances in the reporting period, then this report shall include a statement that there were no excursions and/or exceedances. **(40 CFR 64.9(a)(2)(i))**

5. Each semiannual report of monitoring deviations shall include summary information on monitor downtime. If there were no periods of monitor downtime in the reporting period, then this report shall include a statement that there were no periods of monitor downtime. **(40 CFR 64.9(a)(2)(ii))**

6. Each semiannual report of monitoring deviations shall include a description of the actions taken to implement a Quality Improvement Plan (QIP) during the reporting period, if appropriate. If a QIP has been completed, the report shall include documentation that the QIP has been implemented, and a discussion pertaining to whether the QIP implementation has reduced the likelihood of excursions or exceedances. **(40 CFR 64.9(a)(2)(iii))**

7. The permittee shall submit any performance test reports, except for Method 9, to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. The permittee shall otherwise comply with the applicable requirements of 40 CFR Part 60 (“Standards of Performance for New Stationary Sources”), Subparts A (“General Provisions’) and Y (“Standards of Performance for Coal Preparation Plants”). **(40 CFR Part 60, Subparts A and Y)**

2. The permittee shall comply with all applicable requirements of 40 CFR Part 64. **(40 CFR Part 64)**

3. If the permittee identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the permittee shall promptly notify the AQD and if necessary, submit a proposed modification of the ROP and CAM Plan to address the necessary monitoring changes. Such a modification may include but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters. **(40 CFR 64.7(e))**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUSDA_U3
EMISSION UNIT CONDITIONS

DESCRIPTION

Lime preparation operations for Boiler 3 that support the SDA including storage silos, vertical ball mills, and lime slurry transfer and product tanks.

SDA operations for Boiler 3 including lime slurry atomizer head tanks, recycle silos, recycle mix tanks, and recycle slurry storage tanks. The two recycle silos are subject to 40 CFR Part 64 Compliance Assurance Monitoring (CAM).

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

Silos are controlled by bin vent filters.
Ball mills emissions controlled by spray scrubbers (mill scrubbers).
Recycle mix tank emissions controlled by a spray scrubber.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Opacity	5%[2]	6-Minute average	Each bin vent filter in EUSDA_U3	SC VI.1	**R 336.1301(1)(c)**
2. Opacity	5%[2]	6-Minute average	Each spray scrubber in EUSDA_U3	SC VI.1	**R 336.1301(1)(c)**
3. PM	0.004 gr / dscf of exhaust gases[2]	Hourly	Each bin vent filter in EUSDA_U3	SC III.2 SC IV.1 SC V.1	**R 336.1331(1)(c)**
4. PM	0.01 gr / dscf of exhaust gases[2]	Hourly	Each spray scrubber in EUSDA_U3	SC III.2 SC IV.1 SC V.1	**R 336.1331(1)(c)**
5. PM10	0.03 pph[2]	Hourly	Each of the following bin vent filter emission points: SVLSS-BV3A SVLSS-BV3B SVLSS-BV3C	SC III.2 SC IV.1 SC V.1	**R 336.2803** **R 336.2804**
6. PM2.5	0.03 pph[2]	Hourly	Each of the following bin vent filter emission points: SVLSS-BV3A SVLSS-BV3B SVLSS-BV3C	SC III.2 SC IV.1 SC V.1	**R 336.2803** **R 336.2804**
7. PM10	0.021 pph[2]	Hourly	Each of the following spray scrubber emission points: SVVM-SS3A SVVM-SS3B SVVM-SS3C	SC III.2 SC IV.1 SC V.1	**R 336.2803** **R 336.2804**

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
8. PM2.5	0.021 pph[2]	Hourly	Each of the following spray scrubber emission points: SVVM-SS3A SVVM-SS3B SVVM-SS3C	SC III.2 SC.IV.1 SC V.1	**R 336.2803 R 336.2804**
9. PM10	0.02 pph[2]	Hourly	Each of the following bin vent filter emission points: SVRS-BV3A SVRS-BV3B (CAM Subject)	SC III.2 SC IV.1 SC V.1 SC VI.1 SC VI.2	**R 336.2803 R 336.2804**
10. PM2.5	0.02 pph[2]	Hourly	Each of the following bin vent filter emission points: SVRS-BV3A SVRS-BV3B (CAM Subject)	SC III.2 SC IV.1 SC V.1 SC VI.1 SC VI.2	**R 336.2803 R 336.2804**
11. PM10	0.024 pph[2]	Hourly	Each of the following spray scrubber emission points: SVMT-SS3A1 SVMT-SS3B1 SVMT-SS3A2 SVMT-SS3B2	SC III.2 SC IV.1 SC V.1	**R 336.2803 R 336.2804**
12. PM2.5	0.024 pph[2]	Hourly	Each of the following spray scrubber emission points: SVMT-SS3A1 SVMT-SS3B1 SVMT-SS3A2 SVMT-SS3B2	SC III.2 SC IV.1 SC V.1	**R 336.2803 R 336.2804**

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The Campbell Complex fugitive dust plan shall be updated as necessary and kept at the facility. If at any time the fugitive dust control program fails to address or inadequately addresses a dusting event, the permittee shall amend the fugitive dust control program within 45 days after such an event occurs. The permittee shall also amend the fugitive dust control program within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the fugitive dust control program and any amendments to the fugitive dust control program to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the fugitive dust control program or amended fugitive dust control program shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1372, R 336.2803, R 336.2804, Act 451, Section 324.5524)**

2. The permittee shall not operate EUSDA_U3 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for operation of the process and emission control equipment, is implemented updated as necessary, and kept at the facility. If at any time the MAP fails to address or inadequately addresses an event that meets

the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1910, R 336.1911)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate any portion of EUSDA_U3 unless the associated enclosures, bin vent filters and spray scrubbers are installed, maintained and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approved MAP for EUSDA_U3 as required in SC III.2.[2] **(R 336.1910, R 336.1911, R 336.2803, R 336.2804)**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Upon request of the AQD District Supervisor, the permittee shall verify PM, PM10, and PM2.5 emission rates from EUSDA_U3 by testing at owner's expense, in accordance with the Department requirements. Testing shall be performed using an approved USEPA Method listed in:

Pollutant	Test Method Reference
PM	40 CFR Part 60, Appendix A; Part 10 of the Michigan Air Pollution Control Rules
PM10/PM2.5	40 CFR Part 51, Appendix M

An alternate method, or a modification to the approved USEPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test. **(R 336.1213(3), R 336.2001, R 336.2003, R 336.2004)**

The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted. **(R 336.1213(3))**

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall perform, and document non-certified visible emissions observations as required in SC I.1 and I.2 on a daily basis when EUSDA_U3 is operating. If during the observation there are any visible emissions detected from an emission point, then corrective procedures as defined in the MAP shall be implemented. Records of the non-certified visible emissions observations, USEPA Method 9 observations that are performed, the reason for any visible emissions observed, and any corrective actions taken, shall be kept on file and in a format acceptable to the AQD.[2] **(R 336.1301(1)(c)**

2. The permittee shall conduct and record non-certified visible emissions observations the Recycle Silo bin vent filters (SVRS-BV3A, SVRS-BV3B) once per day when operating, as the primary indicator of the proper functioning of each bin vent filter for EUSDA_U3. If visible emissions are observed, the permittee shall document the visible emissions, including duration, and continue to observe the source of the visible emissions until no visible emissions are observed. The permittee shall initiate corrective actions as quickly as possible upon the detection of visible emissions. If there is a break in the visible emissions observations, it will be assumed that visible emissions continue to occur during any break in observations. The appropriate range of visible emissions defining proper functioning of each bin vent filter is no visible emissions. **(40 CFR 64.6(c)(1)(i), (ii), and (iii))**

3. An excursion is the observation of visible emissions for a duration exceeding one (1) hour. **(40 CFR 64.6(c)(2))**

4. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions or in accordance with the MAP. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). **(40 CFR 64.7(d))**

5. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. **(40 CFR 64.6(c)(3), 40 CFR 64.7(c))**

6. The permittee shall properly maintain the monitoring system, including keeping necessary parts for routine repair of the monitoring equipment. **(40 CFR 64.7(b))**

7. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan and any activities undertaken to implement a quality improvement plan, and other information such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions. **(40 CFR 64.9(b)(1))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

2. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

3. Each semiannual report of monitoring and deviations shall include summary information on the number, duration and cause of excursions and/or exceedances and the corrective actions taken. If there were no excursions and/or exceedances in the reporting period, then this report shall include a statement that there were no excursions and/or exceedances. **(40 CFR 64.9(a)(2)(i))**

4. Each semiannual report of monitoring and deviations shall include summary information on monitor downtime. If there were no periods of monitor downtime in the reporting period, then this report shall include a statement that there were no periods of monitor downtime. **(40 CFR 64.9(a)(2)(ii))**

5. Each semiannual report shall include a Quality Improvement Plan (QIP) during the reporting period, if appropriate. If a QIP has been completed, the report shall include documentation that the QIP has been implemented, and a discussion pertaining to whether the QIP implementation has reduced the likelihood of excursions or exceedances. **(40 CFR 64.9(a)(2)(iii))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVLSS-BV3A	4.3[2]	135[2]	**R 336.2803** **R 336.2804**
2. SVLSS-BV3B	4.3[2]	135[2]	**R 336.2803** **R 336.2804**
3. SVLSS-BV3C	4.3[2]	135[2]	**R 336.2803** **R 336.2804**
4. SVVM-SS3A	11.4[2]	52[2]	**R 336.2803** **R 336.2804**
5. SVVM-SS3B	11.4[2]	52[2]	**R 336.2803** **R 336.2804**
6. SVVM-SS3C	11.4[2]	52[2]	**R 336.2803** **R 336.2804**
7. SVRS-BV3A	6.1[2]	126[2]	**R 336.2803** **R 336.2804**
8. SVRS-BV3B	6.1[2]	126[2]	**R 336.2803** **R 336.2804**
9. SVMT-SS3A1	6.1[2]	58[2]	**R 336.2803** **R 336.2804**
10. SVMT-SS3B1	6.1[2]	58[2]	**R 336.2803** **R 336.2804**
11. SVMT-SS3A2	6.1[2]	58[2]	**R 336.2803** **R 336.2804**
12. SVMT-SS3B2	6.1[2]	58[2]	**R 336.2803** **R 336.2804**

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with all applicable requirements of 40 CFR Part 64. **(40 CFR Part 64)**

2. If the permittee identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the permittee shall promptly notify the AQD and if necessary, submit a proposed modification of the ROP and CAM Plan to address the necessary monitoring changes. Such a modification may include but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters. **(40 CFR 64.7(e))**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUDSI_U12
EMISSION UNIT CONDITIONS

DESCRIPTION

Dry Sorbent Injection (DSI) Material Handling for Boilers 1 and 2. Includes sorbent silos (hydrated lime or other sorbent) and pneumatic transfer.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

Bin vent filters

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Opacity	5%[2]	6- Minute Average	Each bin vent filter in EUDSI_U12	SC VI.1	**R 336.1301(1)(c)**
2. PM	0.004 gr / dscf of exhaust gases[2]	Hourly	Each bin vent filter in EUDSI_U12	SC III.2 SC VI.1	**R 336.1331(1)(c)**
3. PM10	0.08 pph[2]	Hourly	Each of the following bin vent filter emission points: SVLSS-BV1A SVLSS-BV1B SVLSS-BV1C SVLSS-BV2A SVLSS-BV2B SVLSS-BV2C	SC III.2 SC VI.1	**R 336.2803** **R 336.2804**
4. PM2.5	0.08 pph[2]	Hourly	Each of the following bin vent filter emission points: SVLSS-BV1A SVLSS-BV1B SVLSS-BV1C SVLSS-BV2A SVLSS-BV2B SVLSS-BV2C	SC III.2 SC VI.1	**R 336.2803** **R 336.2804**

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The Campbell Complex fugitive dust plan shall be updated as necessary and kept at the facility. If at any time the fugitive dust control program fails to address or inadequately addresses a dusting event, the permittee shall amend the fugitive dust control program within 45 days after such an event occurs. The permittee shall also amend the fugitive dust control program within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the fugitive dust control program and any amendments to the fugitive dust control program to the AQD District Supervisor for review and approval. If the AQD does not

notify the permittee within 90 days of submittal, the fugitive dust control program or amended fugitive dust control program shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1372, R 336.2803, R 336.2804, Act 451, Section 324.5524)**

2. The permittee shall not operate EUDSI_U12 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for operation of the process and emission control equipment, is implemented updated as necessary, and kept at the facility. If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1910, R 336.1911)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate any portion of EUDSI_U12 unless the associated enclosures and bin vent filters are installed, maintained and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approved MAP for EUDSI_U12 as required in SC III.2.[2] **(R 336.1910, R 336.1911, R 336.2803, R 336.2804)**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall perform, and document non-certified visible emissions observations as required in SC I.1 on a daily basis when EUDSI_U12 is operating. If during the observation there are any visible emissions detected from an emission point, then corrective procedures as defined in the MAP shall be implemented. Records of the non-certified visible emissions observations, USEPA Method 9 observations that are performed, the reason for any visible emissions observed, and any corrective actions taken, shall be kept on file and in a format acceptable to the AQD.[2] **(R 336.1301(1)(c))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit any performance test reports to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVLSS-BV1A	14[2]	140[2]	**R 336.2803** **R 336.2804**
2. SVLSS-BV1B	14[2]	140[2]	**R 336.2803** **R 336.2804**
3. SVLSS-BV1C	14[2]	140[2]	**R 336.2803** **R 336.2804**
4. SVLSS-BV2A	14[2]	140[2]	**R 336.2803** **R 336.2804**
5. SVLSS-BV2B	14[2]	140[2]	**R 336.2803** **R 336.2804**
6. SVLSS-BV2C	14[2]	140[2]	**R 336.2803** **R 336.2804**

IX. OTHER REQUIREMENT(S)

NA

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUACI_U123
EMISSION UNIT CONDITIONS

DESCRIPTION

Activated carbon (or other sorbent) material handling including four (4) silos for Boiler Units 1, 2, and 3.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

Bin vent filters

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Opacity	5%[2]	6- Minute Average	Each bin vent filter in EUACI_U123	SC VI.1	**R 336.1301(1)(c)**
2. PM	0.004 gr / dscf of exhaust gases[2]	Hourly	Each bin vent filter in EUACI_U123	SC III.2 SC VI.1	**R 336.1331(1)(c)**
3. PM10	0.045 pph[2]	Hourly	Each of the following bin vent filter emission points: SVACI-BV1A SVACI-BV2A	SC III.2 SC VI.1	**R 336.2803** **R 336.2804**
4. PM2.5	0.045 pph[2]	Hourly	Each of the following bin vent filter emission points: SVACI-BV1A SVACI-BV2A	SC III.2 SC VI.1	**R 336.2803** **R 336.2804**
5. PM10	0.041 pph[2]	Hourly	Each of the following bin vent filter emission points: SVACI-BV3A SVACI-BV3B	SC III.2 SC VI.1	**R 336.2803** **R 336.2804**
6. PM2.5	0.041 pph[2]	Hourly	Each of the following bin vent filter emission points: SVACI-BV3A SVACI-BV3B	SC III.2 SC VI.1	**R 336.2803** **R 336.2804**

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The Campbell Complex fugitive dust plan shall be updated as necessary and kept at the facility. If at any time the fugitive dust control program fails to address or inadequately addresses a dusting event, the permittee shall amend the fugitive dust control program within 45 days after such an event occurs. The permittee shall also amend the fugitive dust control program within 45 days, if new equipment is installed or upon request from the

AQD District Supervisor. The permittee shall submit the fugitive dust control program and any amendments to the fugitive dust control program to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the fugitive dust control program or amended fugitive dust control program shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1372, R 336.2803, R 336.2804, Act 451, Section 324.5524)**

2. The permittee shall not operate EUACI_U123 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for operation of the process and emission control equipment, is implemented updated as necessary, and kept at the facility. If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1910, R 336.1911)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate any portion of EUACI_U123 unless the associated enclosures and bin vent filters are installed, maintained and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approved MAP for EUACI_U123 as required in SC III.2.[2] **(R 336.1910, R 336.1911, R 336.2803, R 336.2804)**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall perform, and document non-certified visible emissions observations as required in SC I.1 on a daily basis when EUACI_U123 is operating. If during the observation there are any visible emissions detected from an emission point, then corrective procedures as defined in the MAP shall be implemented. Records of the non-certified visible emissions observations, USEPA Method 9 observations that are performed, the reason for any visible emissions observed, and any corrective actions taken, shall be kept on file and in a format acceptable to the AQD.[2] **(R 336.1301(1)(c))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVACI-BV1A	14[2]	60[2]	**R 336.2803** **R 336.2804**
2. SVACI-BV2A	14[2]	60[2]	**R 336.2803** **R 336.2804**
3. SVACI-BV3A	12[2]	80[2]	**R 336.2803** **R 336.2804**
4. SVACI-BV3B	12[2]	80[2]	**R 336.2803** **R 336.2804**

IX. OTHER REQUIREMENT(S)

NA

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUBYPRODUCT
EMISSION UNIT CONDITIONS

DESCRIPTION

Flyash and byproduct handling system that transports flyash and byproduct from the plant to the disposal silos. The Unit 3 Transfer Tanks A and B (SVTT-BV3A and SVTT-BV3B) as well as Landfill Silo's A, B, and C (SVDCASS-BVA, SVDCASS-BVB, and SVDCASS-BVC) are subject to 40 CFR Part 64 (CAM).

Unit 3 System

- A large portion of PJFF flyash/byproduct is recycled back to the SDA via the SDA Recycle Flyash System and the remainder is conveyed to the Unit 3 Dry Flyash Byproduct System (for resale or landfill). The SDA Byproduct System consists of the following major equipment: two transfer towers [[TT3A and TT3B], three vacuum exhausters [two in operation and one spare], and three disposal silos [Flyash Silos A, B, and C]. Each transfer tower includes two filter separators (F/S) and a single transfer tank. Each transfer tank and each disposal silo are equipped with a bin vent filter. TT3A, TT3B and the three associated vacuum exhausters located at Boiler 3 are regulated under EUBYPRODUCT.

- The vacuum conveyance system pulls flyash from the PJFF hoppers and transports the flyash in hard piping through a F/S and into a transfer tank where the conveyance air is then discharged through a vacuum exhauster (two F/S's per transfer tank. Transfer tank displacement air is released through a bin vent filter to atmosphere. Flyash and byproduct materials collected in the transfer tanks are periodically conveyed to disposal silos A, B, or C where the material is loaded onto trucks for shipment as either byproduct or waste.

Unit 1 and 2 System

- The Dry Flyash Handling System services both Unit 1 and Unit 2 and consists of the following major equipment: three transfer towers [TT1, TT2 and TT3], five vacuum exhausters [three in operation and two spares], and two disposal silos [DSA, DSB]. Each transfer tower includes a filter separator and transfer tank. Each transfer tank and each disposal silo are equipped with a bin vent filter.

- TT1 and TT2 and the three associated vacuum exhausters located at Boiler 1&2 are regulated under EUBYPRODUCT. TT3 and the remaining two associated vacuum exhausters that solely support Unit 2 are not regulated by EUBYPRODUCT and are exempt from permitting under Michigan Rule 284(k).

- The vacuum conveyance system pulls flyash from each Boiler Unit's PJFF hoppers and transports the flyash in hard piping through a filter separator and into a transfer tank where the conveyance air is then discharged through a vacuum exhauster. The three vacuum exhausters that serve TT1 and TT2 normally discharge to the Unit 1 PJFF inlet ductwork. The two vacuum exhausters that serve TT3 can only discharge to the Unit 2 PJFF inlet duct. Transfer tank displacement air is released through a bin vent filter to atmosphere. Flyash and byproduct materials collected in the transfer tanks are periodically conveyed to disposal silos DSA and DSB where the material is loaded onto trucks for shipment as either byproduct or waste.

- When Boiler 1 and its associated PJFF are not in operation, then the vacuum exhausters associated with TT1 and TT2 will be redirected and one vacuum exhauster may intermittently discharge controlled emissions to atmosphere through a dedicated stack (bypassing the Boiler 1 PJFF). The operation of TT3 and its associated vacuum exhausters would remain unchanged; discharging into the Unit 2 inlet PJFF ductwork.

Common

- 3 Disposal Silos (A, B, & C) – located at the landfill, and store the byproduct/flyash until disposed in licensed landfill.
- Truck loading – each disposal silo has a loading bay under the silo where trucks are loaded with byproduct/flyash for transport to the landfill or for beneficial re-use. "B" silo also employs an exterior load-out chute.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

Transfer tank: Each tank has as a filter separator that breaks the vacuum of the conveyance air to separate the transported material (the flyash byproduct) from the conveyance air. The filter separator is the fabric filter control for the conveyance air. The displacement air from the byproduct dropping into the tank is controlled by a bin vent filter.

Vacuum exhausters: Although the conveyance air from the vacuum exhausters are already controlled by the filter separator (with 0.004 gr/dscf PM emission guarantee), the normal vacuum exhauster discharge configuration is to the PJFF inlet breeching ducts (for either Unit 1, 2, or 3). There are limited times when the Unit 1 PJFF is offline for maintenance or other purposes, at which time the filter separator serving Unit 2 and/or in-plant dust systems will discharge to atmosphere through a vacuum exhauster. Emissions are still controlled via the filter separator (upgraded in PTI No. 18-15) and will be monitored through bag leak dust detectors and visible emission observations under this limited operating scenario.

Disposal Silos: The Disposal Silos A, B and C are controlled by bin vent filter dust collectors.

Truck Loading: Each disposal silo has a dust collector and/or dust suppressant system in the truck loading bay under the silos to control particulate matter during truck loading. The byproduct headed for landfill disposal is sufficiently wetted/conditioned through a pin-paddle mixer prior to loading and transport. The dry load-out chutes minimize fugitive emissions by proper seating of the telescopic chute to or over the truck hatch. Emissions during transfer activity are vacuumed to discharge back into the storage silo, which is controlled by the bin vent filters.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period / Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Opacity	5%[2]	6- Minute Average	Each of the following bin vent filter emission points: SVTT12-BV1 SVTT12-BV2 SVTT12-FSVE SVTT3-BV3A SVTT3-BV3B SVDCASS-BVA SVDCASS-BVB SVDCASS-BVC	SC VI.1 SC VI.2	**R 336.1301(1)(c)**
2. PM	0.004 gr / dscf of exhaust gases[2]	Hourly	Each of the following bin vent filter emission points: SVTT12-BV1 SVTT12-BV2 SVTT3-BV3A SVTT3-BV3B SVDCASS-BVA SVDCASS-BVB SVDCASS-BVC	SC III.2 SC VI.2	**R 336.1331(1)(c)**
3. PM	0.004 gr / dscf of exhaust gases[2]	Hourly	Byproduct transfer tank vacuum exhauster SVTT12-FSVE	SC III.2 SC VI.2	**R 336.1331(1)(c)**

Pollutant	Limit	Time Period / Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
4. PM10	0.03 pph^2	Hourly	Each of the following bin vent filter emission points: SVTT12-BV1 SVTT12-BV2	SC III.2 SC VI.2	**R 336.2803 R 336.2804**
5. PM2.5	0.03 pph^2	Hourly	Each of the following bin vent filter emission points: SVTT12-BV1 SVTT12-BV2	SC III.2 SC VI.2	**R 336.2803 R 336.2804**
6. PM10	0.05 pph^2	Hourly	Each of the following bin vent filter emission points: SVTT3-BV3A SVTT3-BV2B (CAM Subject)	SC III.2 SC VI.1 SC VI.2	**R 336.2803 R 336.2804**
7. PM2.5	0.05 pph^2	Hourly	Each of the following bin vent filter emission points: SVTT3-BV3A SVTT3-BV3B (CAM Subject)	SC III.2 SC VI.1 SC VI.2	**R 336.2803 R 336.2804**
8. PM10	0.55 pph^2	Hourly	Each of the following bin vent filter emission points: SVDCASS-BVA SVDCASS-BVB SVDCASS-BVC (CAM Subject)	SC III.2 SC VI.1 SC VI.2	**R 336.2803 R 336.2804**
9. PM2.5	0.55 pph^2	Hourly	Each of the following bin vent filter emission points: SVDCASS-BVA SVDCASS-BVB SVDCASS-BVC (CAM Subject)	SC III.2 SC VI.1 SC VI.2	**R 336.2803 R 336.2804**
10. PM10	0.10 pph^2	Hourly	Byproduct transfer tank vacuum exhauster: SVTT12-FSVE	SC III.2 SC VI.2	**40 CFR 52.21(c) and (d)**
11. PM2.5	0.10 pph^2	Hourly	Byproduct transfer tank vacuum exhauster: SVTT12-FSVE	SC III.2 SC VI.2	**40 CFR 52.21(c) and (d)**
12. PM	0.10 lbs per 1,000 lbs. exhaust gas	Hourly	Unit 2 dry flyash transfer tower – including the transfer tank, hoppers, and vacuum exhauster	SC III.2 SC VI.2	**R 336.1331**

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The Campbell Complex fugitive dust plan shall be updated as necessary and kept at the facility. If at any time the fugitive dust control program fails to address or inadequately addresses a dusting event, the permittee shall amend the fugitive dust control program within 45 days after such an event occurs. The permittee shall also amend the fugitive dust control program within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the fugitive dust control program and any amendments to the fugitive dust control program to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the fugitive dust control program or amended fugitive dust control program shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1372, R 336.2803, R 336.2804, Act 451, Section 324.5524)**

2. The permittee shall not operate EUBYPRODUCT unless a malfunction abatement plan (MAP) as described in Rule 911(2), for operation of the process and emission control equipment, is implemented updated as necessary, and kept at the facility. If at any time the MAP fails to address or inadequately addresses an event that meets the characteristics of a malfunction, the permittee shall amend the MAP within 45 days after such an event occurs. The permittee shall also amend the MAP within 45 days, if new equipment is installed or upon request from the AQD District Supervisor. The permittee shall submit the MAP and any amendments to the MAP to the AQD District Supervisor for review and approval. If the AQD does not notify the permittee within 90 days of submittal, the MAP or amended MAP shall be considered approved. Until an amended plan is approved, the permittee shall implement corrective procedures or operational changes to achieve compliance with all applicable emission limits.[2] **(R 336.1910, R 336.1911)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate any portion of EUBYPRODUCT unless the associated enclosures and bin vent filters and filter separators are installed, maintained and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approved MAP for EUBYPRODUCT as required in SC III.2.[2] **(R 336.1910, R 336.1911, R 336.2803, R 336.2804)**

2. The permittee shall not operate each byproduct transfer tank vacuum exhauster unless the associated filter separator exhaust gases discharge to an associated PJFF baghouse on either EUBOILER1, EUBOILER2, or EUBOILER3, except as allowed in SC IV.3.[2] **(R 336.1205, R 336.1331, R 336.2803, R 336.2804)**

3. The exhaust from the filter/separator associated with EUBOILER2 shall be routed back to the PJFF for EUBOILER1, except at times when the PJFF for EUBOILER1 is not operating.[2] **(R 336.1205, R 336.1331, 40 CFR 52.21(c) and (d))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall perform, and document non-certified visible emissions observations on all exhausts to the atmosphere as required in SC I.1 on a daily basis when EUBYPRODUCT is operating. If during the observation there are any visible emissions detected from an emission point, then corrective procedures as defined in the MAP shall be implemented. Records of the non-certified visible emissions observations, USEPA Method 9

observations that are performed, the reason for any visible emissions observed, and any corrective actions taken, shall be kept on file and in a format acceptable to the AQD.[2] **(R 336.1301(1)(c))**

2. The permittee shall conduct and record non-certified visible emissions observations from the bin vent filters servicing the EUBOILER3 Transfer Tanks (SVTT-BV3A, SVTT-BV3B) and the Landfill Silos (SVDCASS-BVA, SVDCASS-BVB, and SVCASSS-BVC) once per day when operating, as the primary indicator of the proper functioning of each bin vent filter for EUBYPRODUCT. If visible emissions are observed, the permittee shall document the visible emissions, including duration, and continue to observe the source of the visible emissions until no visible emissions are observed. The permittee shall initiate corrective actions as quickly as possible upon the detection of visible emissions. If there is a break in the visible emissions observations, it will be assumed that visible emissions continue to occur during any break in observations. The appropriate range of visible emissions defining proper functioning of each bin vent filter is no visible emissions. **(40 CFR 64.6(c)(1)(i), (ii), and (iii))**

3. The permittee shall utilize visible emissions as the primary indicator of the proper functioning of each PM control device. The appropriate range of visible emissions defining proper functioning of the PM Control Device is no visible emissions.[2] **(R 336.1201(3), 40 CFR 64.6(c)(1)(i) and (ii))**

4. The permittee shall keep, in a satisfactory manner, all records necessary to show that the Campbell Complex fugitive dust plan required by SC III.1 is being implemented.[2] **(R 336.1372, R 336.2803, R 336.2804, Act 451, Section 324.5524)**

5. The permittee shall keep, in a satisfactory manner, all records necessary to show that the MAP required by SC III.2 is being implemented.[2] **(R 336.1910, R 336.1911)**

6. The permittee shall keep, in a satisfactory manner, visible emissions records for the times that the filter/separator associated with EUBOILER2 is routed to SVTT12-FSVE instead of the PJFF for EUBOILER1.[2] **(R 336.1205, R 336.1331, 40 CFR 52.21(c) and (d), R 336.1213(3))**

7. The permittee shall restore operation of the emission unit, control device, and associated pollutant capture system equipment to normal/compliant operation as quickly as possible in response to any noted exceedance or excursion. **(40 CFR 64.7(d))**

8. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions or as specified by the MAP. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). **(40 CFR 64.7(d))**

9. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. **(40 CFR 64.6(c)(3), 40 CFR 64.7(c))**

10. The permittee shall properly maintain the monitoring system, including keeping necessary parts for routine repair of the monitoring equipment. **(40 CFR 64.7(b))**

11. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan and any activities undertaken to implement a quality improvement plan, and

other information such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions. **(40 CFR 64.9(b)(1))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. Each semiannual report of monitoring and deviations shall include summary information on the number, duration and cause of excursions and/or exceedances and the corrective actions taken. If there were no excursions and/or exceedances in the reporting period, then this report shall include a statement that there were no excursions and/or exceedances. **(40 CFR 64.9(a)(2)(i))**

5. Each semiannual report shall include a Quality Improvement Plan (QIP) during the reporting period, if appropriate. If a QIP has been completed, the report shall include documentation that the QIP has been implemented, and a discussion pertaining to whether the QIP implementation has reduced the likelihood of excursions or exceedances. **(40 CFR 64.9(a)(2)(iii))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack and Vent ID	Maximum Exhaust Diameter/Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVTT12-BV1	9^2	32^2	**R 336.2803** **R 336.2804**
2. SVTT12-BV2	9^2	32^2	**R 336.2803** **R 336.2804**
3. SVTT12-FSVE	20^2	40^2	**R 336.2803** **R 336.2804**
4. SVTT3-BV3A	14^2	70^2	**R 336.2803** **R 336.2804**
5. SVTT3-BV3B	14^2	70^2	**R 336.2803** **R 336.2804**
6. SVDCASS-BVA	$24x60^2$	141^2	**R 336.2803** **R 336.2804**
7. SVDCASS-BVB	$24x60^2$	141^2	**R 336.2803** **R 336.2804**
8. SVDCASS-BVC	$24x60^2$	136^2	**R 336.2803** **R 336.2804**
9. SVBLR12	228^2	400^2	**R 336.2803** **R 336.2804**
10. SVBLR3	327^2	642^2	**R 336.2803** **R 336.2804**

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with all applicable requirements of 40 CFR Part 64. **(40 CFR Part 64)**

2. If the permittee identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the permittee shall promptly notify the AQD and if necessary, submit a proposed modification of the ROP and CAM Plan to address the necessary monitoring changes. Such a modification may include but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters. **(40 CFR 64.7(e))**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUAUXBLR12
EMISSION UNIT CONDITIONS

DESCRIPTION

The common auxiliary boiler for Units 1 and 2 is an oil-fired fire-tube boiler rated at 17 MMBTU/hr. This boiler is a limited use boiler, which is defined in 40 CFR 63.7575 as any boiler that burns any amount of solid, liquid, or gaseous fuels and has a federally enforceable average annual capacity factor of no more than 10%. This unit is subject to the provisions of 40 CFR Part 63, Subpart DDDDD.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

Material	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Fuel Oil	0.5% sulfur by weight based on a higher heating value of 18,000 BTU/lb[2]	Applicable at all times	EUAUXBLR12	SC VI.1	**R 336.1401(1), Table 41**
2. #2 Fuel Oil (Note A)	10% annual capacity factor of oil (Note B)[2]	Calendar Year	EUAUXBLR12	SC VI.4	**40 CFR 63.7555(a)(3)**

Note A: This limit is to satisfy the Federally Enforceable capacity factor limit associated with the limited use definition under 40 CFR Part 63, Subpart DDDDD, 40 CFR 63.7575.

Note B: Annual capacity factor means the ratio between the actual heat input to a boiler from the fuels burned during a calendar year to the potential heat input to the boiler had it been operated for 8,760 hours during a year at the maximum steady state design heat input capacity. (40 CFR 63.7575)

3. The permittee shall only burn fuels as allowed in the Unit designed to burn gas under light liquid subcategory definition in 40 CFR 63.7575. **(40 CFR 63.7575, R336.1213(3))**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. To demonstrate continuous compliance, the permittee shall conduct a tune-up of the boiler every 5 years (within 61 months) of the date of the last tune up. If the boiler is not operating on the required date for tune-up, the tune-up must be conducted within 30 calendar days of startup.[2] **(40 CFR 63.7500(a), 40 CFR 63.7515(d), 40 CFR 63.7540(12) and (13))**

2. The permittee shall conduct tune up of the boiler as specified in the following:[2] **(40 CFR 63.7540(a)(12))**

   a. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the permittee may delay the burner inspection until the next unit shutdown).

   b. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern.

c. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next unit shutdown).

d. Optimize total emissions of CO.

e. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made.

f. Maintain on-site and submit, if requested by the Administrator, a report containing the information below:
   i. The concentrations of CO in the effluent stream in parts per million by volume, and oxygen content in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater.
   ii. A description of any corrective actions taken as part of the tune-up.

3. At all times, the permittee must operate and maintain any affected source (as defined in 40 CFR 63.7490, stated in SC IX.1), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. **(40 CFR 63.700(a)(3))**

4. Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in 40 CFR 63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart. **(40 CFR 63.7500(c))**

5. The permittee shall install a fuel meter.[2] **(R 336.1201(3))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

NA

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall maintain sufficient records to demonstrate that the sulfur content for each shipment of fuel oil received is less than 0.5% by weight.[2] **(R 336.1201(3))**

2. The permittee shall conduct and maintain records of a daily (non-certified) visual observation for opacity in order to verify proper firing, whenever a boiler is in use for 24 consecutive hours or more. **(R 336.1213(3))**

3. The permittee shall keep a record of the following on a monthly basis:[2] **(R 336.1201(3))**
   a. Total fuel usage
   b. Sulfur content of fuel oil
   c. Higher Heating Value of fuel oil

4. The permittee shall keep fuel use records for the days the boiler was operating.[2] **(40 CFR 63.7525(k))**

5. The permittee shall maintain a complete record of fuel oil specifications and/or fuel analysis for each delivery, or storage tank, of fuel oil used for the auxiliary boiler. These records may include purchase records for ASTM specification fuel oil, specifications or analyses provided by the vendor at the time of delivery, analytical results from laboratory testing, or any other records adequate to demonstrate compliance with the percent sulfur limit in fuel oil.[2] **(R 336.1201(3))**

6. The permittee shall keep records of compliance demonstrations.[2] **(R°336.1201(3))**

7. For each unit that meets the definition of limited-use boiler or process heater, the permittee must keep fuel use records for the days the boiler or process heater was operating. **(40 CFR 63.7525(k))**

8. The permittee must keep records according to paragraphs (a)(1) and (2) of 40 CFR 63.7555. **(40 CFR 63.7555(a))**
   a. A copy of each notification and report that is submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that permittee submitted, according to the requirements in 40 CFR Part 63.10(b)(2)(xiv). **(40 CFR 63.7555(a)(1))**
   b. Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in 40 CFR Part 63.10(b)(2)(viii). **(40 CFR 63.7555(a)(2))**

9. For units in the limited use subcategory, the permittee must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating. **(40 CFR 63.7555(a)(3))**

10. Records must be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). **(40 CFR 63.7560(a))**

11. As specified in 40 CFR 63.10(b)(1), the permittee must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. **(40 CFR 63.7560(b))**

12. The permittee must keep each record on site, or they must be accessible from on-site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1). The permittee can keep the records off site for the remaining 3 years. **(40 CFR 63.7560(c))**

See Appendix 3-C (Fuel Oil Sulfur Monitoring)

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**
4. The permittee must meet the notification requirements in 40 CFR 63.7545 according to the schedule in 40 CFR 63.7545 and in Subpart A of 40 CFR Part 63. **(40 CFR 63.7495(d))**

5. The permittee must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 40 CFR 63.7545(e). **(40 CFR 63.7530(f))**

6. The permittee must submit to the Administrator all of the notifications in 40 CFR 63.7(b) and (c); 40 CFR 63.8(e), (f)(4) and (6); and 40 CFR 63.9(b) through (h) that apply by the dates specified. **(40 CFR 63.7545(a))**

7. Unless the USEPA Administrator has approved a different schedule for submission of reports under 40 CFR Part 63.10(a), the permittee must submit each report, according to paragraph (h) of 40 CFR 63.7550, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of 40 CFR 63.7550 as stated below. **(40 CFR 63.7550(b))**

a. Each semi-annual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31. **(40 CFR 63.7550(b)(3))**

b. Each semi-annual compliance report must be postmarked or submitted no later than September 15 or March 15, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than March 15. **(40 CFR 63.7550(b)(4), 40 CFR 63.7550(b)(5))**

8. A compliance report must contain the information below depending on how the facility chooses to comply with the limits set in this rule. **(40 CFR 63.7550(c))**
   a. If the facility is subject to the requirements of a tune-up, permittee must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (xiv) and (xvii) of 40 CFR 63.7550, and paragraph (c)(5)(iv) of 40 CFR 63.7550 for limited-use boiler or process heater. **(40 CFR 63.7550(c)(1))**
   b. 40 CFR 63.7550(c)(5) is as follows:
      i. Company and Facility name and address. **(40 CFR 63.7550(c)(5)(i))**
      ii. Process unit information, emissions limitations, and operating parameter limitations. **(40 CFR 63.7550(c)(5)(ii))**
      iii. Date of report and beginning and ending dates of the reporting period. **(40 CFR 63.7550(c)(5)(iii))**
      iv. The total operating time during the reporting period. **(40 CFR 63.7550(c)(5)(iv))**
      v. Include the date of the most recent tune-up for each unit subject to only the requirement to conduct a 5-year tune-up according to 40 CFR 63.7540(a)(12). Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown. **(40 CFR 63.7550(c)(5)(xiv))**
      vi. Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. **(40 CFR 63.7550(c)(5)(xvii))**

9. The permittee must submit all reports required by Table 9 of 40 CFR Part 63, Subpart DDDDD electronically to the USEPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the USEPA's CDX.) The permittee must use the appropriate electronic report in CEDRI for 40 CFR Part 63, Subpart DDDDD. Instead of using the electronic report in CEDRI for 40 CFR Part 63, Subpart DDDDD, the permittee may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to 40 CFR Part 63, Subpart DDDDD is not available in CEDRI at the time that the report is due, the permittee must submit the report to the Administrator at the appropriate address listed in 40 CFR 63.13. The permittee must begin submitting reports via CEDRI no later than 90-days after the form becomes available in CEDRI. **(40 CFR 63.7550(h)(3))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVAUXBLR12	30[2]	153[2]	NA

IX. OTHER REQUIREMENT(S)

1. 40 CFR Part 63, Subpart DDDDD applies to new or reconstructed affected sources as described in paragraph (a)(2) of 40 CFR 63.7490, as listed below. **(40 CFR 63.7490(a))**
   a. The affected source of 40 CFR Part 63, Subpart DDDDD is each new or reconstructed industrial, commercial, or institutional boiler or process heater, as defined in 40 CFR 63.7575, located at a major source. **(40 CFR 63.7490(a)(2))**

2. A boiler or process heater is:
   a. New if the permittee commences construction of the boiler or process heater after June 4, 2010, and the permittee meets the applicability criteria at the time the permittee commences construction. **(40 CFR 63.7490(b))**
   b. Reconstructed if the permittee meets the reconstruction criteria as defined in 40 CFR 63.2, the permittee commences reconstruction after June 4, 2010, and the permittee meets the applicability criteria at the time the permittee commence reconstruction. **(40 CFR 63.7490(c))**
3. For affected sources (as defined in 40 CFR 63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration no later than 180 days after the re-start of the affected source and according to the applicable provisions in 40 CFR 63.7(a)(2) as cited in Table 10 to 40 CFR Part 63, Subpart DDDDD. You must complete a subsequent tune-up by following the procedures described in 40 CFR 63.7540(a)(10)(i) through (vi) and within 30 calendar days of startup for units that are not operating at the time of their scheduled tune-up. **(40 CFR 63.7515(g))**

4. The permittee shall comply with the General Provisions in 40 CFR 63.1 through 63.15 that apply to this source as indicated in Table 10 of 40 CFR Part 63, Subpart DDDDD. **(40 CFR 63.7565, Table 10)**

5. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. **(40 CFR Part 63, Subpart DDDDD)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUCAT3DIESEL
EMISSION UNIT CONDITIONS

DESCRIPTION

On-site, stationary, diesel-fired internal combustion engine, 9.4 MMBTU/hr heat input; emergency use only. This unit is subject to the provisions of 40 CFR Part 63, Subpart ZZZZ.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

Material	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Fuel Oil – sulfur content	1.0% by weight at 18,000 BTU/lb	Instantaneous; at all times	EUCAT3DIESEL	SC VI.6 (Use of No. 2 Fuel Oil, which by definition contains <0.5% Sulfur by weight; see **Appendix 3-C-1**)	**R 336.1401(1), Table 41**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall:
   a. Change oil and filter every 500 hours of operation or annually, whichever comes first, except as allowed in SC III.2;
   b. Inspect the air filter every 1,000 hours of operation or annually, whichever comes first, and replace as necessary; and
   c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

   If the emergency engine is being operated during an emergency and it is not possible to shut down the engine to perform the work practice standards on the schedule required, the work practice standard can be delayed until the emergency is over. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State or local law has been abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law or which the risk was deemed unacceptable. **(40 CFR 63.6602, 40 CFR Part 63, Subpart ZZZZ, Table 2c, Item 1)**

2. The permittee may utilize an oil analysis program in order to extend the specified oil change requirement. The oil analysis must be performed at the same frequency as oil changes are required. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c of 40 CFR Part 63, Subpart ZZZZ. **(40 CFR 63.6625(i))**

3. The permittee shall install, maintain and operate EUCAT3DIESEL and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. **(40 CFR 63.6605, 40 CFR 63.6625(e))**

4. The permittee shall minimize the time spent at idle during startup and minimize the startup time EUCAT3DIESEL to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup apply. **(40 CFR 63.6625(h))**

5. There is no time limit on the use of emergency stationary RICE in emergency situations. **(40 CFR 63.6640(f)(1))**

6. The permittee may operate EUCAT3DIESEL for no more than 100 hours per calendar year for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The permittee may petition the Department for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. **(40 CFR 63.6640(f)(2))**

7. EUCAT3DIESEL may operate up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing as provided in 40 CFR 63.6640(f)(2). The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for the permittee to supply non-emergency power as part of a financial arrangement with another entity. **(40 CFR 63.6640(f)(3))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall install a non-resettable hour meter on each engine in EUCAT3DIESEL. **(40 CFR 63.6625(f))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. If using the oil analysis program, the permittee must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30% of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20% from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine. **(40 CFR 63.6625(i))**

See Appendix 3-C

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall keep in a satisfactory manner, records of the occurrence and duration of each malfunction of operation or the air pollution control monitoring equipment. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(a)(2), 40 CFR 63.6660)**

2. The permittee shall keep in a satisfactory manner, records of actions taken during periods of malfunction to minimize emissions, including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(a)(5), 40 CFR 63.6660)**

3. The permittee shall keep in a satisfactory manner, records to demonstrate continuous compliance with the operating limitations. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(d), 40 CFR 63.6660)**

4. The permittee shall keep in a satisfactory manner, records of the maintenance conducted to demonstrate that the engine and after-treatment control device (if any) were operated and maintained according to the developed maintenance plan. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(e), 40 CFR 63.6660)**

5. The permittee shall monitor and record the total hours of operation for EUCAT3DIESEL per calendar year, recorded through the non-resettable hours meter, in a manner acceptable to the AQD District Supervisor. The permittee shall document how many hours are spent for emergency operation; including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in 40 CFR 63.6640(f)(4)(ii), the permittee must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation. **(40 CFR 63.6655(f))**

6. The permittee shall maintain sufficient records to demonstrate that the sulfur content for each shipment of fuel oil received is less than 1.0% by weight. **(R 336.1213(3))**

7. The permittee shall conduct and maintain records of a daily (non-certified) visual observation for opacity in order to verify proper firing, whenever an engine is in use for 24 consecutive hours or more. **(R 336.1213(3))**

8. The permittee shall maintain a record of the applicability determination for each Reciprocating Internal Combustion Engine (RICE) relative to the requirements of 40 CFR Part 63, Subparts A and ZZZZ. **(40 CFR Part 63, Subpart A, Section 63.10(b)(3))**

See Appendix 3-C (Fuel Oil Sulfur Monitoring)

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit to the AQD District Supervisor, a semiannual compliance report, as specified in 40 CFR 63.6650, which contains all deviations during the reporting period from any applicable emission limitation or operating limitation. If there are no deviations from any applicable emission limitations or operating limitations, the report shall contain a statement that there were no deviations during the reporting period. The first report shall cover the period beginning on the applicable compliance date specified in 40 CFR 63.6595 and ending on June 30 (postmarked or delivered by July 31) or December 31 (postmarked or delivered by January 31), whichever date is the first date following the end of the first calendar half after the applicable compliance date. Each subsequent report must cover the semiannual period from January 1 through June 30, or from July 1 through December 31. The subsequent reports must be postmarked or delivered by July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period, except as allowed in 40 CFR 63.6650(b)(5). The compliance report must also contain the following information, as specified in 40 CFR 63.6650(c) and (d):
   a. Company name and address.
   b. Certification of the report by a responsible official.
   c. Date of report and beginning and ending dates of the reporting period.
   d. The number of malfunctions, including a brief description of each event, that occurred during the reporting period and a demonstration that the Malfunction Plan was followed during such events.
   e. The total operating time of the RICE at which the deviation occurred during the reporting period.
   f. The number, duration, and cause of deviations and the corrective action taken.

   A copy of the compliance report shall be kept on file for a period of at least five years (at least two years at the site) and made available to the Department upon request. **(40 CFR 63.6640(b), 40 CFR 63.6650(b),(c),(d), 40 CFR 63.6660)**

5. Each affected source that has obtained a Title V operating permit pursuant to 40 CFR Part 70 or 71 must report all deviations as defined in 40 CFR Part 63, Subpart ZZZZ in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of 40 CFR Part 63, Subpart ZZZZ along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in 40 CFR Part 63, Subpart ZZZZ, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority. **(40 CFR 63.6650(f))**

6. For any engine that is an emergency stationary engine with a site rating of more than 100 brake hp that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in 40 CFR 63.6640(f)(4)(ii), you must submit an annual report according to the requirements below and as specified in 40 CFR 63.6650(h): **(40 CFR 63.6650(h), 40 CFR 63.6660)**

   a. The report must contain the following information:
      i. Company name and address where the engine is located.
      ii. Date of the report and beginning and ending dates of the reporting period.
      iii. Engine site rating and model year.
      iv. Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.
      v. Hours operated for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii).
      vi. Number of hours the engine is contractually obligated to be available for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii).

vii. Hours spent for operation for the purpose specified in 40 CFR 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

viii. If there were no deviations from the fuel requirements in 40 CFR 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

ix. If there were deviations from the fuel requirements in 40 CFR 63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

b. The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in 40 CFR 63.13.

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the provisions of the National Emission Standards for Hazardous Air Pollutants, as specified in 40 CFR Part 63, Subparts A and ZZZZ, as they apply to EUCAT3DIESEL. **(40 CFR Part 63, Subparts A and ZZZZ)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUCATDIESEL12
EMISSION UNIT CONDITIONS

DESCRIPTION

A 2,000-kilowatt (kW) diesel-fueled emergency engine manufactured in 2007 or later. This unit is subject to the provisions of 40 CFR Part 60, Subpart IIII and 40 CFR Part 63, Subpart ZZZZ.
Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period / Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. NMHC + NOx	6.4 g/kW-hr[2]	Hourly	EUCATDIESEL12	SC V.1 SC VI.2	**40 CFR 60.4205(b)**
2. CO	3.5 g/kW-hr[2]	Hourly	EUCATDIESEL12	SC V.1 SC VI.2	**40 CFR 60.4205(b)**
3. PM	0.20 g/kW-hr[2]	Hourly	EUCATDIESEL12	SC V.1 SC VI.2	**40 CFR 60.4205(b)**

II. MATERIAL LIMIT(S)

1. The permittee shall burn only diesel fuel, in EUCATDIESEL12, with a sulfur content not to exceed 15 ppm (0.0015%) by weight.[2] **(R 336.1205(3), R 336.1402(1), 40 CFR 60.4207, 40 CFR 80.510(b))**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate EUCATDIESEL12 for more than 500 hours per year on a 12-month rolling time period basis as determined at the end of each calendar month. The 500 hours includes the 100 hours for the purpose of necessary maintenance checks and readiness testing as described in SC III.2.[2] **(R 336.1205(3), R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, 40 CFR 52.21(c) & (d))**

2. The permittee may operate EUCATDIESEL12 for no more than 100 hours per calendar year, as determined at the end of each calendar month, for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. The permittee may petition the Department for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. EUCATDIESEL12 may operate up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing. The 50 hours per calendar year for non-emergency situations may not be used for peak shaving or to generate income for a facility to supply non-emergency power as part of a financial arrangement with another entity.[2] **(40 CFR 60.4211(f), 40 CFR 63.6640(f)**

3. The permittee shall install, maintain, and operate EUCATDIESEL12 according to the manufacturer emissions-related written instructions, or procedures developed by the owner/operator and approved by the engine manufacturer, over the entire life of the engine.[2] **(R 336.1205(3), R 336.1225, R 336.1911, R 336.2803, R 336.2804, 40 CFR 52.21(c) & (d), 40 CFR 60.4206, 40 CFR 60.4211)**

4. There is no time limit on the use of emergency stationary RICE in emergency situations. **(40 CFR 60.4211(f)(1), 40 CFR 63.6640(f)(1)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall equip and maintain EUCATDIESEL12 with a non-resettable hours meter to track the operating hours.[2] **(R 336.1205(3), R 336.1225, 40 CFR 60.4209(a), 40 CFR 63.6625(f))**

2. The nameplate capacity of EUCATDIESEL12 shall not exceed 2,000 kW, as certified by the equipment manufacturer.[2] **(R 336.1205(3))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall conduct an initial performance test for EUCATDIESEL12 within one year after startup of the engine to demonstrate compliance with the emission limits in 40 CFR 60.4205 unless the engine has been certified by the manufacturer and the permittee maintains the engine as required by 40 CFR Part 60, Subpart IIII. If a performance test is required, the performance tests shall be conducted at the owner's expense, in accordance with Department requirements and according to 40 CFR 60.4212. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.[2] **(40 CFR 60.4211)**

2. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted. **(R 336.1213(3))**

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall complete all required calculations in a format acceptable to the AQD District Supervisor by the last day of the calendar month, for the previous calendar month, unless otherwise specified in any monitoring/recordkeeping special condition.[2] **(R 336.1205(3), R 336.2803, R 336.2804, 40 CFR 52.21 (c) & (d))**

2. The permittee shall keep, in a satisfactory manner, a record of testing required in SC V.1 or manufacturer certification documentation indicating that EUCATDIESEL12 meets the applicable emission limitations contained in the federal Standards of Performance for New Stationary Sources 40 CFR Part 60, Subpart IIII. The permittee shall keep all records on file and make them available to the Department upon request.[2] **(40 CFR 60.4211)**

3. The permittee shall monitor and record the total hours of operation and the hours of operation during non-emergencies for EUCATDIESEL12, on a monthly and 12-month rolling time period basis, in a manner acceptable to the AQD District Supervisor. The permittee shall document how many hours are spent for emergency operation of EUCATDIESEL12, including what classified the operation as emergency and how many hours are spent for maintenance or readiness testing and non-emergency operation.[2] **(R 336.1205(3), R 336.2803, R 336.2804, 40 CFR 60.4211(f), 40 CFR 60.4214(b))**

4. The permittee shall keep, in a satisfactory manner, fuel supplier certification records or fuel sample test data, for each delivery of diesel fuel oil used in EUCATDIESEL12, demonstrating that the fuel sulfur content meets the requirement of 40 CFR 80.510(b). The certification or test data shall include the name of the oil supplier or laboratory, and the sulfur content of the fuel oil.[2] **(R 336.1205(3), R 336.1402(1), 40 CFR 80.510(b))**

See Appendix 3-C

VII. REPORTING

1. The permittee shall submit all applicable notifications specified in 40 CFR 63.7(b) and (c), 40 CFR 63.8 (e), (f)(4), and (f)(6), and 40 CFR 63.9(b) through (e), (g), and (h) by the dates specified.[2] **(40 CFR 63.6645(a)(3) and (f))**

2. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

3. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

4. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

5. The permittee shall submit any performance test reports to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Diameter/ Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVCATDIESEL12	18[2]*	47[2]	**R 336.1225** **R 336.2803** **R 336.2804** **40 CFR 52.21 (c) & (d)**

* The maximum diameter applies to the exhaust stack itself and does not apply to any no-loss rain sleeve that may be in use.

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60, Subparts A and IIII, as they apply to EUCATDIESEL12.[2] **(40 CFR Part 60, Subparts A & IIII,)**

2. The permittee shall comply with the provisions of the National Emission Standards for Hazardous Air Pollutants, as specified in 40 CFR Part 63, Subparts A and ZZZZ, as they apply to EUCATDIESEL12 upon startup.[2] **(40 CFR Part 63, Subparts A and ZZZZ, 40 CFR 63.6595)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUGUARDSHK_ENG
EMISSION UNIT CONDITIONS

DESCRIPTION

A natural-gas, stationary internal combustion engine rated at 40 HP; Emergency Generator for the guard shack. This unit is subject to the provisions of 40 CFR Part 60, Subpart JJJJ and 40 CFR Part 63, Subpart ZZZZ.

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. NOx + Hc	10 g/kW-hr g/hp-hr	Hourly	EUGUARDSHK_ENG	SC VI.2	**40 CFR 60.6233(d)**
2. 2. CO	387 g/hp-hr	Hourly	EUGUARDSHK_ENG	SC VI.2	**40 CFR 60.6233(d)**

II. MATERIAL LIMIT(S)

1. The permittee shall burn only field or pipeline quality natural gas, in each engine in EUGUARDSHK_ENG. **(40 CFR 60.4230, R 336.1213(3))**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. There is no time limit on the use of emergency stationary RICE in emergency situations. **(40 CFR 60.4243(d)(1))**

2. The permittee may operate EUGUARDSHK_ENG for no more than 100 hours per calendar year for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The permittee may petition the Department for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. **(40 CFR 60.4243(d)(2), 40 CFR 63.6640(f))**

3. EUGUARDSHK_ENG may operate up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing as provided in 40 CFR 60.4243(d)(2). The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for the permittee to supply non-emergency power as part of a financial arrangement with another entity. **(40 CFR 60.4243(d)(3), 40 CFR 63.6640(f))**

4. The permittee shall operate and maintain EUGUARDSHK_ENG such that it meets the emission limits in SC I.1, and I.2 over the entire life of the engine. **(40 CFR 60.4234, 40 CFR 60.4243(b))**

5. If the permittee purchased a certified engine, according to procedures specified in 40 CFR Part 60, Subpart JJJJ, for the same model year, the permittee shall meet the following requirements for EUGUARDSHK_ENG:

   a. Operate and maintain the certified engine and control device according to the manufacturer's emission-related written instructions;

b. Keep a maintenance plan and the permittee may only change those engine settings that are permitted by the manufacturer. If you do not operate and maintain the certified engine and control device according to the manufacturer's emission-related written instructions, the engine will be considered a non-certified engine; and

c. Meet the requirements as specified in 40 CFR Part 1068, Subparts A through D.

If the permittee does not operate and maintain the certified engine and control device according to the manufacturer's emission-related written instructions, the engine will be considered a non-certified engine and be subject to SC III.5. **(40 CFR 60.4243(b)(1))**

6. If the permittee purchased a non-certified engine or a certified engine operating in a non-certified manner, the permittee shall keep a maintenance plan for EUGUARDSHK_ENG and shall, to the extent practicable, maintain and operate each engine in a manner consistent with good air pollution control practice for minimizing emissions. **(40 CFR 60.4243(b)(2))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. EUGUARDSHK_ENG shall be certified to meet the applicable emission standard of 40 CFR 60.4233. The permittee shall install and configure each engine according to the manufacturer's specifications. **(40 CFR 60.4243)**

2. The permittee shall equip and maintain EUGUARDSHK_ENG with non-resettable hours meters to track the operating hours. **(40 CFR 60.4237, 40 CFR 63.6655(f))**

3. The nameplate capacity of EUGUARDSHK_ENG shall not exceed 500 BHP, as certified by the equipment manufacturer. **(40 CFR 63.6590(c)(4))**

V. TESTING/SAMPLING

1. The permittee shall conduct an initial performance test for EUGUARDSHK_ENG within one year after startup of the engine to demonstrate compliance with the emission limits in 40 CFR 60.4231 unless the engine has been certified by the manufacturer and the permittee maintains the engine as required by 40 CFR Part 60, Subpart JJJJ. If a performance test is required, the performance test shall be conducted at the owner's expense, in accordance with Department requirements and according to 40 CFR 60.4244. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.[2] **(40 CFR 60.4244)**

2. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted. **(R 336.1213(3))**

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall keep in a satisfactory manner, records of all maintenance conducted on EUGUARDSHK_ENG. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 60.4245(a)(2))**

2. The permittee shall keep, in a satisfactory manner, a record of testing required in SC V.1 or manufacturer certification documentation indicating that EUGUARDSHK_ENG meets the applicable emission limitations contained in the federal Standards of Performance for New Stationary Sources 40 CFR Part 60, Subpart JJJJ. The permittee shall keep all records on file and make them available to the Department upon request. **(40 CFR 60.4245)**

3. The permittee shall monitor and record the hours of operation of EUGUARDSHK_ENG during emergencies and non-emergencies, on a calendar year basis, in a manner acceptable to the AQD District Supervisor. The permittee shall record the time of operation of EUGUARDSHK_ENG and the reason it was in operation during that time. **(40 CFR 60.4243)**

See Appendix 4

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60, Subparts A and JJJJ, as they apply to EUGUARDSHK_ENG. **(40 CFR Part 60, Subparts A and JJJJ)**

2. The permittee shall comply with all applicable provisions of the National Emission Standards for Hazardous Air Pollutants, as specified in 40 CFR Part 63, Subparts A and ZZZZ, for Stationary Reciprocating Internal Combustion Engines by the initial compliance date. **(40 CFR 63.6595, 40 CFR Part 63, Subparts A and ZZZZ)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

D. FLEXIBLE GROUP SPECIAL CONDITIONS

Part D outlines the terms and conditions that apply to more than one emission unit. The permittee is subject to the special conditions for each flexible group in addition to the General Conditions in Part A and any other terms and conditions contained in this ROP.

The permittee shall comply with all specific details in the special conditions and the underlying applicable requirements cited. If a specific condition type does not apply, NA (not applicable) has been used in the table. If there are no special conditions that apply to more than one emission unit, this section will be left blank.

FLEXIBLE GROUP SUMMARY TABLE

The descriptions provided below are for informational purposes and do not constitute enforceable conditions.

Flexible Group ID	Flexible Group Description	Associated Emission Unit IDs
FGBOILER12	The common 40 CFR Part 64 (CAM) requirements for these emission units are in this flexible group.	EUBOILER1 EUBOILER2
FGMATS_U12	Common applicable Mercury and Air Toxics Standard requirements for EUBOILER1 and EUBOILER2.	EUBOILER1 EUBOILER2
FGMATS_U3	Mercury and Air Toxics Standard requirements for EUBOILER3.	EUBOILER3
FGEXISTINGRICE	Onsite, stationary diesel-fired internal combustion engines. Engines used as a source of emergency power or water supply that are subject to the RICE MACT.	EUCATFIREPUMP3 EUHPHSWP15001 EUHPHSWP15002 EUHPHSWP3000
FGAUXBLRS3	Distillate oil fired auxiliary boilers less than 10 MMBTU.	EUAUXBLR3B EUAUXBLR3C
FGNEWCIRICE	New stationary diesel-fired internal combustion, compression ignition engines. Engines used as a source of emergency power or water supply that are subject to the RICE MACT.	EUWPDIESEL EUTRNCNTRDIESEL
FGPARTSCLEANERS	Any cold cleaner that is grandfathered or exempt from Rule 201 pursuant to Rule 278, 278a and Rule 281(2)(h) or Rule 285(2)(r)(iv). Existing cold cleaners were placed into operation prior to July 1, 1979. New cold cleaners were placed into operation on or after July 1, 1979.	EUPARTSCLEANERS

FGBOILER12
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

The common 40 CFR Part 64 (CAM) requirements for these emission units are in this flexible group.

Emission Units: EUBOILER1, EUBOILER2

POLLUTION CONTROL EQUIPMENT

Pollution control equipment is described for each unit in EUBOILER1 and EUBOILER2.

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

NA

IV. DESIGN/EQUIPMENT PARAMETER(S)

NA

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall assess opacity using USEPA Reference Method 9 - "Visual Determination of the Opacity of Emissions from Stationary Sources", upon the request of AQD.[2] **(R 336.1301)**

See Appendices 3-A and 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall utilize COMS-recorded opacity as an indicator of the emission unit's compliance with the particulate matter limit, except during periods of monitoring and system malfunction, system repairs or QA/QC activities. The appropriate range of opacity defining proper function of the PJFF is 0-20% opacity. An excursion is defined as any two (2) or more consecutive 1-hour block average opacity values greater than 15%. **(40 CFR 64.6(c)(1)(i) and (ii))**

2. The permittee shall continuously monitor and record any alarms and corrective actions taken. **(40 CFR 64.6(c)(1)(i) and (ii))**

3. The permittee shall properly maintain the COMS, including completing daily COMS zero and calibration tests; conduct necessary preventative maintenance; maintaining necessary parts for routine repairs of the monitoring equipment; and demonstrating adequate performance through an annual monitor audit. **(40 CFR 64.6(c)(1)(iii), 40 CFR 64.7(b))**

4. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. The permittee shall operate the COMS during all required periods when the coal-fired boiler is operating. Data recorded during monitoring malfunctions, repair activities and QA/QC operations shall not be used for 40 CFR Part 64 compliance. **(40 CFR 64.6(c)(3), 40 CFR 64.7(c))**

5. The permittee shall conduct all required monitoring per the CAM Plan and otherwise satisfy the requirements specified in 40 CFR 64.7 through 40 CFR 64.9. **(40 CFR 64.6(c)(3), 40 CFR 64.7(a))**

6. The required COMS shall collect data for all required intervals when the emission unit is operating. **(40 CFR 64.7(c)(1)(iii))**

7. The permittee shall restore operation of the emission unit, control device, and associated pollutant capture system equipment to normal/compliant operation as quickly as possible, in accordance with good air pollution control practices for minimizing emissions in response to any noted exceedance or excursion. Excursions shall trigger an internal investigation, corrective action(s) per the MAP, and a CAM excursion summary reporting requirement. Necessary response shall include minimizing the period of any startup, shutdown or malfunction and taking necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of the excursion or exceedance (other than those caused by excused startup or shutdown conditions). **(40 CFR 64.7(d))**

8. If the permittee identifies a failure to achieve compliance with an emission limitation or standard for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the permittee shall promptly notify the AQD and if necessary, submit a proposed modification of the ROP and CAM Plan to address the necessary monitoring changes. Such a modification may include but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters. **(40 CFR 64.7(e))**

See Appendices 3-A, 3-B and 3-D

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. Quarterly reporting of monthly excess sulfur dioxide emissions (including the nature and cause of the periods of excess emissions), and of the dates and times of the monitoring systems being inoperative. Each quarterly report is due within 30 days of the calendar quarter reporting period. **(R 336.2170)**

5. Quarterly reporting of excess opacity emissions (including the nature and cause of the periods of excess emissions), and of the dates and times of the monitoring systems being inoperative. Each quarterly report is due within 30 days of the calendar quarter reporting period. **(R 336.2170)**

6. Each semiannual report of monitoring deviations shall include summary information on the number, duration, and cause of exceedances/excursions in the reporting period; and the corrective actions taken in response. If there were no excursions and/or exceedances in the reporting period, then this report shall include a statement that there were no excursions and/or exceedances. **(40 CFR 64.9(a)(2)(i))**

7. Each semiannual report of monitoring deviations shall include summary information on monitor downtime in the reporting period. If there were no periods of monitor downtime in the reporting period, then this report shall include a statement that there were no periods of monitor downtime. **(40 CFR 64.9(a)(2)(ii))**

8. Each semiannual report of monitoring deviations shall include a description of the actions taken to implement a Quality Improvement Plan (QIP) during the reporting period, if appropriate. If a QIP has been completed, the report shall include documentation that the QIP has been implemented, and a discussion pertaining to whether the QIP implementation has reduced the likelihood of excursions or exceedances. **(40 CFR 64.9(a)(2)(iii))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVBLR12	228[2]	400[2]	**R 336.1225** **R 336.2803** **R 336.2804** **40 CFR 52.21(c) and (d)**

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with all applicable requirements of 40 CFR Part 64. **(40 CFR Part 64)**

Footnotes:
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).
[3]This condition is federally enforceable and was originally established in the consent decree settling, "U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" and also pursuant to Act 451, Section 324.5503(b), and will remain in effect after termination of the consent decree.
[4]Definitions specific to this condition may be found in Appendix 1-B: Definitions Applicable to Specified Permit Conditions.

FGMATS_U12
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

40 CFR Part 63, Subpart UUUUU (Mercury and Air Toxics Standards or MATS) requirements for existing coal-fired electric utility steam generating unit(s) (EGU) rated more than 25 megawatts electric (MWe) that serve(s) a generator producing electricity for sale and designed to burn coal that is not low rank virgin coal (calorific value of ≥ 8,300 BTU/pound).

Emission Units: EUBOILER1 and EUBOILER2

POLLUTION CONTROL EQUIPMENT

EUBOILER1:
Low-NOx burners,
Sorbent injection (ACI) (activated carbon or other sorbent) for mercury control,
Dry sorbent injection (DSI) (hydrated lime or other sorbent) for acid gas control,
Pulse-jet fabric filter (PJFF) baghouse for PM control.

EUBOILER2:
Low-NOx burners,
Selective catalytic reduction (SCR),
Sorbent injection (ACI) (activated carbon or other sorbent) for mercury control,
Dry sorbent injection (DSI) (hydrated lime or other sorbent) for acid gas control,
Pulse-jet fabric filter (PJFF) baghouse for PM control.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Filterable PM (per boiler)	0.030 lb/MMBTU*	Quarterly or Triennial Stack Test+	EUBOILER1 EUBOILER2	SC V.1	**40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.a**
2. Hydrogen chloride (HCl) (per boiler)	0.0020 lb/MMBTU*	Quarterly or Triennial Stack Test+	EUBOILER1 EUBOILER2	SC V.2	**40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.b**
3. Mercury (Hg) (per boiler)	1.2 lb/TBTU*	30-boiler operating day rolling arithmetic average updated at the end of each new boiler operating day	EUBOILER1 EUBOILER2	SC V.3 SC VI.3	**40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.c**

* The emission limits apply at all times except during startup and shutdown.
+ If the unit(s) no longer meets the requirement for LEE status, the unit(s) will comply by stack testing quarterly until a continuous monitoring system has been installed, certified, and is operating.

4. If the permittee uses the provisions for low emitting EGU (LEE) status for any pollutant except Hg, performance test data must be collected showing average emissions less than 50% the of the applicable standard. **(40 CFR 63.10005(h)(1)(i))**

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall conduct a tune-up of each emission unit of FGMATS_U12 burner(s) and combustion controls, as applicable, at least every 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in 40 CFR 63.10021(e). **(40 CFR 63.10000(e), 40 CFR 63.10006(i), 40 CFR 63.10021(e))**

2. For the startup of any emission unit of FGMATS_U12 which will comply using paragraph (1) of the definition of ''startup'' in 40 CFR 63.10042, the permittee must use clean fuels as defined in 40 CFR 63.10042 for ignition. Once the emission unit(s) of FGMATS_U12 convert(s) to firing coal, residual oil, or solid oil-derived fuel, the permittee must engage all the applicable control technologies except dry scrubber and SCR. The permittee must start the dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. The permittee must comply with all applicable emission limits at all times except for periods that meet the applicable definitions of startup and shutdown in 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10042, 40 CFR Part 63, Subpart UUUUU, Table 3)**

3. During shutdown of any emission unit of FGMATS_U12 while firing coal, residual oil, or solid oil-derived fuel, the permittee must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the applicable emission unit(s) of FGMATS_U12 and for as long as possible thereafter considering operational and safety concerns. In any case, the permittee must operate their controls when necessary to comply with other standards made applicable to the FGMATS_U12 by a permit limit or a rule other than 40 CFR Part 63, Subpart UUUUU and that require operation of the control devices. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in 40 CFR 63.10042 and must be used to the maximum extent possible taking into account considerations such as not compromising boiler or control device integrity. **(40 CFR 63.10042, 40 CFR Part 63, Subpart UUUUU, Table 3)**

4. The emission limits and operating limits in 40 CFR Part 63, Subpart UUUUU apply at all times except during periods of startup and shutdown; however, the applicable work practice requirements, which are specified in items 3 and 4 of Table 3 of 40 CFR Part 63, Subpart UUUUU must be met during periods of startup or shutdown. **(40 CFR 63.10000(a), 40 CFR Part 63, Subpart UUUUU, Table 3, 40 CFR 63.10022(a)(4))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall operate and maintain all associated air pollution control equipment and monitoring equipment necessary for compliance with 40 CFR Part 63, Subpart UUUUU in a manner consistent with safety and good air pollution control practices for minimizing emissions. **(40 CFR 63.10000(b))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall verify the filterable PM emission rates from each emission unit by testing at owner's expense, in accordance with 40 CFR 63.10007 and Table 5 to 40 CFR Part 63, Subpart UUUUU. The permittee must complete the test once every calendar quarter and at least 45 days since the previous performance test if not a LEE for PM. The permittee may skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year. **(40 CFR 63.10006(f), 40 CFR 63.10007, 40 CFR 63.10021(d)(1) and (2), 40 CFR Part 63, Subpart UUUUU, Table 5)**

2. The permittee shall verify the HCl emission rates from each emission unit by testing at owner's expense, in accordance with 40 CFR 63.10007 and Table 5 to 40 CFR Part 63, Subpart UUUUU. The permittee must complete the test once every calendar quarter and at least 45 days since the previous performance test if not a LEE for HCl. The permittee may skip performance testing in those quarters during which less than 168 boiler operating hours occur, except that a performance test must be conducted at least once every calendar year. **(40 CFR 63.10006(f), 40 CFR 63.10007, 40 CFR 63.10021(d)(1) and (2), 40 CFR Part 63, Subpart UUUUU, Table 5)**

3. If the permittee uses the provisions for LEE status for any pollutant except for Hg, the permittee shall verify each LEE pollutant emission rate from the applicable emission unit(s) of FGMATS_U12 by testing at owner's expense, in accordance with 40 CFR 63.10007 and Table 5 to 40 CFR Part 63, Subpart UUUUU. The permittee must complete the test once every 36 months and at least 1,050 days since the previous performance test to demonstrate continued LEE status. If a performance test deadline is missed due to the EGU being inoperative and 168 or more boiler operating hours occur in the next test period, an additional performance test shall be completed in the next test period, with at least 350 calendar days separating the performance tests conducted in the same 3-year period. **(40 CFR 63.10006(b), 40 CFR 63.10006(f), 40 CFR 63.10007, 40 CFR Part 63, Subpart UUUUU, Table 5)**

4. Unless an alternate schedule has been approved by the AQD, no less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing. The protocol shall describe the test method(s) and the maximum routine operating conditions, including targets for key operational parameters associated with air pollution control equipment to be monitored and recorded during testing, as applicable. **(40 CFR 63.7, 40 CFR 63.10007, 40 CFR 63.10030(a))**

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. During startup, as defined by paragraph (1) of the definition of "startup" in 40 CFR 63.10042, the permittee must operate all Continuous Monitoring Systems (CMS). Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). The permittee must comply with the applicable emission limits at all times except for startup and shutdown periods unless the permittee chooses to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, then the permittee must comply with the applicable Hg emission limit at all times. The permittee must collect monitoring data during startup periods, as specified in 40 CFR 63.10020(a) and (b). The permittee must keep records during startup periods, as provided in 40 CFR 63.10032 and 40 CFR 63.10021(h). Any fraction of an hour in which startup occurs constitutes a full hour of startup. **(40 CFR Part 63, Subpart UUUUU, Table 3)**

2. The permittee must operate all CMS during shutdown. The permittee must also collect appropriate data, and the permittee must calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. The permittee must collect monitoring data during shutdown periods, as specified in 40 CFR 63.10020(a). The permittee must keep records during shutdown periods, as provided in 40 CFR 63.10032 and 40 CFR 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. **(40 CFR Part 63, Subpart UUUUU, Table 3)**

3. For any emission unit not relying on the LEE provisions for Hg, the permittee shall install, calibrate, maintain and operate a device to monitor and record the Hg concentration from each emission unit on a continuous basis. The permittee shall install and operate the Hg CEMS or sorbent trap monitoring system to meet the timelines, requirements and reporting detailed in Appendix A of 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10000(c)(1)(vi))**

4. If required to convert measured pollutant concentrations to the units of the applicable mass per heat input emission limit(s) or for routine operation of a sorbent trap monitoring system, the permittee shall install, calibrate, maintain and operate a device to monitor and record the oxygen (O_2) or carbon dioxide (CO_2) exhaust gas content, exhaust gas flow rate and/or moisture from each emission unit on a continuous basis. The monitor shall be operated in accordance with procedures outlined in 40 CFR Part 75, Appendices A and B. As an alternative

to moisture monitoring, the permittee may elect to use appropriate fuel-specific default moisture values from 40 CFR 75.11(b) for coal-fired units or a default moisture value for non-coal-fired units as established via petition to the Administrator under 40 CFR 75.66. **(40 CFR 63.10010(b)-(d), 40 CFR Part 63, Subpart UUUUU, Table 5)**

5. For any emission unit not relying on the LEE provisions for Hg, the permittee shall keep, in a satisfactory manner, hourly (if applicable) and 30-day rolling average Hg emission rate records for each emission unit **OR** (30-day (or 90-day if emission averaging (as applicable)) rolling weighted average Hg emission rate records for the combination of units participating in an averaging plan) excluding periods of startup and shutdown. **(40 CFR 63.10010, 40 CFR 63.10021, 40 CFR Part 63, Subpart UUUUU, Table 7)**

6. The permittee must operate the required monitoring system(s) and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see 40 CFR 63.8(c)(7) of 40 CFR Part 63, Subpart A), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. The permittee is required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable. **(40 CFR 63.10020(b))**

7. The permittee may not use data recorded during startup or shutdown in calculations used to report emissions, except as otherwise provided in 40 CFR 63.10000(c)(1)(vi)(B) and 40 CFR 63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. The permittee must use all of the quality-assured data collected during all other periods in assessing the operation of the control device and associated control system. **(40 CFR 63.10020(c))**

8. Failure to collect required data is a deviation from the monitoring requirements except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments. **(40 CFR 63.10020(d))**

9. If the permittee uses CEMS to measure SO_2, PM, HCl, HF, or Hg emissions (or sorbent trap monitoring system), except as otherwise provided in 40 CFR 63.10020(c), the permittee must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and other required monitoring systems to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, a 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 in 40 CFR 63.10021(b) to determine the 30- or 90-boiler operating day rolling average. **(40 CFR 63.10021(a) and (b))**

10. The permittee must keep the following records:

    a. A copy of each notification and report that has been submitted to comply with 40 CFR Part 63, Subpart UUUUU, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that has been submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv). **(40 CFR 63.10032(a)(1))**

    b. Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in 40 CFR 63.10(b)(2)(viii). **(40 CFR 63.10032(a)(2))**

    c. For each CEMS and CPMS, the permittee must keep the following records:

        i. Records described in 40 CFR 63.10(b)(2)(vi) through (xi). **(40 CFR 63.10032(b)(1))**

        ii. Previous (i.e., superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3). **(40 CFR 63.10032(b)(2))**

        iii. Request for alternatives to relative accuracy test for CEMS as required in 40 CFR 63.8(f)(6)(i). **(40 CFR 63.10032(b)(3))**

        iv. The date and time that each deviation started and stopped and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period. **(40 CFR 63.10032(b)(4))**

v. If the permittee continuously monitors Hg and/or HCl and/or HF emissions, the permittee must also keep the records required under Appendix A and/or Appendix B of 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10032(a))**

d. For each emission unit subject to an emission limit:

i. The permittee shall keep the monthly fuel use by each emission unit, including the type(s) of fuel and amount(s) used. **(40 CFR 63.10032(d)(1))**

ii. If the permittee combusts non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), the permittee must keep a record which documents how the secondary material meets each of the legitimacy criteria. If the permittee combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), the permittee must keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), the permittee must keep a record which documents how the fuel satisfies the requirements of the petition process. **(40 CFR 63.10032(d)(2))**

iii. For an emission unit that qualifies as a LEE under 40 CFR 63.10005(h), the permittee shall keep annual records that document that the emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year. **(40 CFR 63.10032(d)(3))**

e. Regarding startup periods or shutdown periods:

i. If the permittee chooses to rely on paragraph (1) of the definition of ''startup'' in 40 CFR 63.10042 for the emission unit(s), the permittee shall keep records of the occurrence and duration of each startup or shutdown. **(40 CFR 63.10032(f)(1))**

ii. The type(s) and amount(s) of fuel used during each startup or shutdown. **(40 CFR 63.10032(i))**

f. The occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment. **(40 CFR 63.10032(g))**

g. Actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. **(40 CFR 63.10032(h))**

h. If the permittee elects to average emissions consistent with 40 CFR 63.10009, the permittee shall keep a copy of the emissions averaging implementation plan required in 40 CFR 63.10009(g), all calculations required under 40 CFR 63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with 40 CFR 63.10022. **(40 CFR 63.10032(e))**

11. The permittee shall keep all records in a form suitable and readily available for expeditious review and for at least 5 years after the date of each occurrence, corrective action, report, or record. The records must be kept onsite for at least 2 years and may be kept offsite for the remaining 3 years. **(40 CFR 63.10(b)(1), 40 CFR 63.10033)**

12. The permittee shall maintain on site and submit, if requested by the Administrator, an annual report of periodic performance tune-ups containing the information required by 40 CFR 63.10021(e)(8). The reports shall be in a format acceptable to the Administrator. If requested by the AQD District Supervisor, the permittee shall also submit an annual report with the results of the performance tune-ups. **(40 CFR 63.10021(e)(8))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. Semiannual reporting of the information required in 40 CFR 63.10031(c)(1) through (9), (d), and (e) as applicable. The report shall be postmarked or received by the Administrator by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. The report shall include the following:

   a. The information required by the Continuous Monitoring Summary Report located in 40 CFR 63.10(e)(3)(vi). **(40 CFR 63.10031(c)(1))**

   b. The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by USEPA or the basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure. **(40 CFR 63.10031(c)(2))**

   c. Indicate whether any emission unit in FGMATS_U12 burned new types of fuel during the reporting period. If new types of fuel were burned, include the date of the performance test where that fuel was in use. **(40 CFR 63.10031(c)(3))**

   d. Include the date of the most recent tune-up for each emission unit. The date of the tune-up is the date the tune-up provisions specified in 40 CFR 63.10021(e)(6) and (7) were completed. **(40 CFR 63.10031(c)(4))**

   e. Report emergency bypass information annually from units with LEE status. **(40 CFR 63.10031(c)(6))**

   f. A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during the test, if applicable. If the permittee is conducting stack tests once every 3 years to maintain LEE status, consistent with 40 CFR 63.10006(b), the report shall include the date of each stack test conducted during the previous 3 years, a comparison of emission level the permittee achieved in each stack test conducted during the previous 3 years to the 50% emission limit threshold required in 40 CFR 63.10005(h)(1)(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions. **(40 CFR 63.10031(c)(7))**

   g. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to FGMATS_U12 and there are no deviations from the requirements for work practice standards in Table 3 to 40 CFR Part 63, Subpart UUUUU that apply to FGMATS_U12, the report shall include a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in 40 CFR 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period. **(40 CFR Part 63, Subpart UUUUU, Table 8)**

   h. If there is a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain a brief description of the deviation, the duration of the deviation, the cause of the deviation, and the information in 40 CFR 63.10031(d). If there were periods during which the CMS's, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in 40 CFR 63.8(c)(7), the report must contain the information in 40 CFR 63.10031(e). **(40 CFR 63.10031(c)(1) through (9), (d), and (e), 40 CFR 63.10031(a), 40 CFR 63.10031(c)(9), 40 CFR Part 63, Subpart UUUUU, Table 8)**

   i. If the affected source submits a compliance report pursuant to Table 8 in 40 CFR Part 63, Subpart UUUUU, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in 40 CFR Part 63, Subpart UUUUU, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report required by SC VII.2. **(40 CFR 63.10031(e))**

5. The permittee must submit any of the following applicable notifications by the dates specified within the specific citation: 40 CFR 63.7(b) and (c) Notification of performance test and Quality assurance program; 40 CFR 63.8(e) Performance evaluation of continuous monitoring systems; 40 CFR 63.8(f)(4) Request to use alternative monitoring methods; 40 CFR 63.8(f)(6) Alternative to the relative accuracy test; 40 CFR 63.9(b) Initial

notifications; 40 CFR 63.9(c) Request for extension of compliance; 40 CFR 63.9(d) Notification that source is subject to special compliance requirements; 40 CFR 63.9(e) Notification of performance test, which shall be submitted at least 30 days before the performance test is scheduled to begin; 40 CFR 63.9(f) Notification of opacity and visible emission observations; 40 CFR 63.9(g) Additional notification requirements for sources with continuous monitoring systems; and 40 CFR 63.9(h) Notification of compliance status. **(40 CFR 63.10030(a))**

6. On or after July 1, 2020, within 60 days after the date of completing each performance test, the permittee must submit the performance test reports required by this subpart to USEPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of USEPA's Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/index.html). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. At the discretion of the AQD, the permittee must also submit these reports, one to the Technical Programs Unit Supervisor and one to the AQD District Supervisor, in a format approved by the AQD. **(40 CFR 63.10031(f))**

7. On or after July 1, 2020, within 60 days after the date of completing each CEMS (SO2, PM, HCl, HF, and Hg) performance evaluation test, as defined in 40 CFR 63.2, the permittee must submit the relative accuracy test audit (RATA) data (or, for PM CEMS, RCA and RRA data) required by this subpart to USEPA's WebFIRE database by using CEDRI that is accessed through USEPA's CDX (www.epa.gov/cdx). The RATA data shall be submitted in the file format generated through use of USEPA's Electronic Reporting Tool (ERT) (http://www.epa.gov/ttn/chief/ert/index.html). Only RATA data compounds listed on the ERT Web site are subject to this requirement. At the discretion of the AQD, the permittee must also submit these RATA reports to the AQD District Supervisor in a format approved by the AQD. Owners or operators shall submit calibration error testing, drift checks, and other information required in the performance evaluation as described in 40 CFR 63.2 and as required in this chapter. **(40 CFR 63.10031(f)(1))**

8. On or after July 1, 2020, for a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31, June 30, September 30, and December 31, the permittee must submit quarterly reports to USEPA's WebFIRE database by using the CEDRI that is accessed through USEPA's CDX (www.epa.gov/cdx). The permittee must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with USEPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the CEMS and PM CPMS. **(40 CFR 63.10031(f)(2))**

9. Reports for a SO_2 CEMS, a Hg CEMS or sorbent trap monitoring system, a HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in 40 CFR Part 63, Subpart UUUUU, Appendices A and B and 40 CFR 63.10021(f). **(40 CFR 63.10031(f)(3))**

10. On or after July 1, 2020, the permittee must submit all reports required by 40 CFR 63.10031 (c) and (d) electronically using CEDRI that is accessed through the USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). The permittee must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with USEPA's reporting form output format. If requested by the AQD, the permittee must also submit these reports to the AQD District Supervisor in a format approved by the AQD. **(40 CFR 63.10031(f)(4))**

11. Prior to July 1, 2020, all reports subject to electronic submittal in SC VII.6, VII.7, VII.8 and VII.10 shall be submitted to the USEPA at the frequency specified in those paragraphs in electronic portable document format (PDF) using the ECMPS Client Tool. Each PDF version of a submitted report must include sufficient information to assess compliance and to demonstrate that the testing was done properly. The data elements listed at 40 CFR 63.10031(f)(6)(i)-(xii) must be entered into the ECMPS Client Tool at the time of submission of each PDF file. **(40 CFR 63.10031(f)(6))**

12. If requested by the Administrator, the permittee must submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already

undergone a performance evaluation that meets the requirements of 40 CFR 63.10010 (e.g., if the CMS was previously certified under another program). **(40 CFR 63.10000(d)(3))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. For each emission unit or emissions averaging group complying with an emission limit as specified in Table 2 of 40 CFR Part 63, Subpart UUUUU, the permittee may request to switch from a mass per heat input to a mass per gross output limit (or vice versa).
   a. The permittee may switch from a mass per heat input to a mass per gross output limit (or vice-versa), provided that:
      i. The permittee submits a request that identifies for each emission unit or emissions averaging group involved in the proposed switch both the current and proposed emission limit. **(40 CFR 63.10030(e)(7)(iii)(A)(1))**
      ii. The request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur. **(40 CFR 63.10030(e)(7)(iii)(A)(2))**
      iii. The request demonstrates through performance stack test results completed within 30 days prior to the submission, compliance for each emission unit or emissions averaging group with both the mass per heat input and mass per gross output limits. **(40 CFR 63.10030(e)(7)(iii)(A)(3))**
      iv. The permittee revises and submits all other applicable plans, e.g., monitoring and emissions averaging, with the request. **(40 CFR 63.10030(e)(7)(iii)(A)(4))**
      v. The permittee maintains records of all information regarding the choice of emission limits. **(40 CFR 63.10030(e)(7)(iii)(A)(5))**
   b. The permittee may begin to use the revised emission limits starting in the next reporting period, after receipt of written acknowledgement from the Administrator of the switch. **(40 CFR 63.10030(e)(7)(iii)(B))**
   c. From the submission of the request until start of the next reporting period after receipt of written acknowledgement from the Administrator of the switch, the permittee shall demonstrate compliance with both the mass per heat input and mass per gross output emission limits for each pollutant for each emission unit or emissions averaging group. **(40 CFR 63.10030(e)(7)(iii)(C))**

2. If using a CMS to demonstrate continuous compliance with an emission limit or operating limit, the permittee must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before the initial performance evaluation (where applicable) of the CMS. This requirement also applies to the permittee if the permittee petitions the Administrator for alternative monitoring parameters under 40 CFR 63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under Appendix B of 40 CFR Part 60 or 40 CFR Part 75, and that meet the requirements of 40 CFR 63.10010. Using the process described in 40 CFR 63.8(f)(4), the permittee may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in the site-specific monitoring plan. The monitoring plan must address the following provisions: **(40 CFR 63.10000(d), 40 CFR 63.10010)**
   a. Installation of the CMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device). See 40 CFR 63.10010(a) for further details. For PM CPMS installations, follow the procedures in 40 CFR 63.10010(h).

b. Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

c. Schedule for conducting initial and periodic performance evaluations.

d. Performance evaluation procedures and acceptance criteria (e.g., calibrations), including the quality control program in accordance with the general requirements of 40 CFR 63.8(d).

e. On-going operation and maintenance procedures, in accordance with the general requirements of 40 CFR 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).

f. Conditions that define a CMS that is out of control consistent with 40 CFR 63.8(c)(7)(i) and for responding to out of control periods consistent with 40 CFR 63.8(c)(7)(ii) and (c)(8).

g. On-going recordkeeping and reporting procedures, in accordance with the general requirements of 40 CFR 63.10(c), (e)(1), and (e)(2)(i), or as specifically required under 40 CFR Part 63, Subpart UUUUU.

h. Alternatively, the requirements are considered to be met for a particular CMS or sorbent trap monitoring system if:

   i. The CMS or sorbent trap monitoring system is installed, certified, maintained, operated, and quality-assured either according to 40 CFR Part 75, or Appendix A or B of 40 CFR Part 63, Subpart UUUUU; and

   ii. The recordkeeping and reporting requirements of 40 CFR Part 75, or Appendix A or B of 40 CFR Part 63, Subpart UUUUU, which pertain to the CMS, are met.

3. If the permittee chooses to reapply for LEE status, the permittee must demonstrate all performance tests and CEMS or sorbent trap monitoring system data over a consecutive 3-year period show compliance with the LEE criteria. **(40 CFR 63.10006(b)(2) and (h))**

4. If any emission unit(s) cease(s) to operate in a manner that causes the unit(s) to meet the definition of an EGU subject to 40 CFR Part 63, Subpart UUUUU, the permittee must submit the notification in 40 CFR 63.10000(i)(2) no less than 30 days prior to when the EGU will cease complying with 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10000(i)(2), 40 CFR 63.10030(f))**

5. The permittee shall comply with all provisions of the National Emission Standards for Hazardous Air Pollutants as specified in 40 CFR Part 63, Subparts A and UUUUU. **(40 CFR Part 63, Subparts A and UUUUU)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FGMATS_U3
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

40 CFR Part 63, Subpart UUUUU (Mercury and Air Toxics Standards or MATS) requirements for existing coal-fired electric utility steam generating unit(s) (EGU) rated more than 25 megawatts electric (MWe) that serve(s) a generator producing electricity for sale and designed to burn coal that is not low rank virgin coal (calorific value of ≥ 8,300 BTU/pound).

Emission Unit: EUBOILER3

POLLUTION CONTROL EQUIPMENT

Low-NOx burners,
Selective catalytic reduction (SCR),
Sorbent injection (ACI) (activated carbon or other sorbent for mercury control),
Spray dry absorber (SDA) for acid gas control,
Pulse-jet fabric filter (PJFF) baghouse for PM control.

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Filterable PM	0.030 lb/MMBTU*	30-day boiler operating day rolling arithmetic average updated at the end of each new boiler operating day	EUBOILER3	SC VI.3 SC VI.7 SC VI.8	**40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.a**
2. SO_2	0.20 lb/MMBTU*	30-boiler operating day rolling arithmetic average updated at the end of each new boiler operating day	EUBOILER3	SC VI.2 SC VI.6 SC VI.7 SC VI.10 SC VI.14	**40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.b**
3. Mercury (Hg)	1.2 lb/TBTU*	30-boiler operating day rolling arithmetic average updated at the end of each new boiler operating day	EUBOILER3	SC V.1 SC VI.4 SC VI.7 SC VI.9 SC VI.14	**40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.c**

* The emission limits apply at all times except during startup and shutdown

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall conduct a tune-up of each emission unit of FGMATS_U3 burner(s) and combustion controls, as applicable, at least every 36 calendar months, or each 48 calendar months if neural network combustion

optimization software is employed, as specified in 40 CFR 63.10021(e). **(40 CFR 63.10000(e), 40 CFR 63.10006(i), 40 CFR 63.10021(e))**

2. For the startup of any emission unit of FGMATS_U3 which will comply using paragraph (1) of the definition of ''startup'' in 40 CFR 63.10042, the permittee must use clean fuels as defined in 40 CFR 63.10042 for ignition. Once the emission unit(s) of FGMATS_U3 convert(s) to firing coal, residual oil, or solid oil-derived fuel, the permittee must engage all the applicable control technologies except dry scrubber and SCR. The permittee must start the dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. The permittee must comply with all applicable emission limits at all times except for periods that meet the applicable definitions of startup and shutdown in 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10042, 40 CFR Part 63, Subpart UUUUU, Table 3)**

3. During shutdown of any emission unit of FGMATS_U3 while firing coal, residual oil, or solid oil-derived fuel, the permittee must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the applicable emission unit(s) of FGMATS_U3 and for as long as possible thereafter considering operational and safety concerns. In any case, the permittee must operate their controls when necessary to comply with other standards made applicable to the FGMATS_U3 by a permit limit or a rule other than 40 CFR Part 63, Subpart UUUUU and that require operation of the control devices. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in 40 CFR 63.10042 and must be used to the maximum extent possible taking into account considerations such as not compromising boiler or control device integrity. **(40 CFR 63.10042, 40 CFR Part 63, Subpart UUUUU, Table 3)**

4. The emission limits and operating limits in 40 CFR Part 63, Subpart UUUUU apply at all times except during periods of startup and shutdown; however, the applicable work practice requirements, which are specified in items 3 and 4 of Table 3 of 40 CFR Part 63, Subpart UUUUU must be met during periods of startup or shutdown. **(40 CFR 63.10000(a), 40 CFR Part 63, Subpart UUUUU, Table 3)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall operate and maintain all associated air pollution control equipment and monitoring equipment necessary for compliance with 40 CFR Part 63, Subpart UUUUU in a manner consistent with safety and good air pollution control practices for minimizing emissions. **(40 CFR 63.10000(b))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. During startup, as defined by paragraph (1) of the definition of ''startup'' in 40 CFR 63.10042, the permittee must operate all Continuous Monitoring Systems (CMS). Startup means either the first-ever firing of fuel in a boiler for the purpose of producing electricity, or the firing of fuel in a boiler after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on site use). The permittee must comply with the applicable emission limits at all times except for startup and shutdown periods unless the permittee chooses to use just one set of sorbent traps to demonstrate compliance with the applicable Hg emission limit, then the permittee must comply with the applicable Hg emission limit at all times. The permittee must collect monitoring data during startup periods, as specified in 40 CFR 63.10020(a) and (b). The permittee must keep records during startup periods, as provided in 40 CFR 63.10032 and 40 CFR 63.10021(h). Any fraction of an hour in which startup occurs constitutes a full hour of startup. **(40 CFR Part 63, Subpart UUUUU, Table 3)**

2. The permittee must operate all CMS during shutdown. The permittee must also collect appropriate data, and the permittee must calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. The permittee must collect monitoring data during shutdown periods, as specified in 40 CFR 63.10020(a). The permittee must keep records during shutdown periods, as provided in 40 CFR 63.10032 and 40 CFR 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. **(40 CFR Part 63, Subpart UUUUU, Table 3)**

3. The permittee shall install, calibrate, maintain and operate a device to monitor and record the PM concentration of the exhaust gas from each emission unit on a continuous basis. The permittee shall install and operate the PM CEMS to meet the timelines, requirements and reporting detailed in Performance Specification 11 in 40 CFR Part 60, Appendix B and Procedure 2 in 40 CFR Part 60, Appendix F. **(40 CFR 63.10010(i), 40 CFR Part 63, Subpart UUUUU, Table 5)**

4. The permittee shall install, calibrate, maintain and operate a device to monitor and record the Hg concentration from each emission unit on a continuous basis. The permittee shall install and operate the Hg CEMS or sorbent trap monitoring system to meet the timelines, requirements and reporting detailed in Appendix A of 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10000(c)(1)(vi))**

5. The permittee shall install, maintain, and operate a device(s) to monitor and record the SO_2 concentration of the exhaust gas from each emission unit on a continuous basis. The permittee shall install and operate each CEMS to meet the timelines, requirements and reporting detailed in 40 CFR Part 75, Appendices A and B. **(40 CFR 63.10000(c)(1)(v))**

6. If required to convert measured pollutant concentrations to the units of the applicable mass per heat input emission limit(s) or for routine operation of a sorbent trap monitoring system, the permittee shall install, calibrate, maintain and operate a device to monitor and record the oxygen (O_2) or carbon dioxide (CO_2) exhaust gas content, exhaust gas flow rate and/or moisture from each emission unit on a continuous basis. The monitor shall be operated in accordance with procedures outlined in 40 CFR Part 75, Appendices A and B. As an alternative to moisture monitoring, the permittee may elect to use appropriate fuel-specific default moisture values from 40 CFR 75.11(b) for coal-fired units or a default moisture value for non-coal-fired units as established via petition to the Administrator under 40 CFR 75.66. **(40 CFR 63.10010(b)-(d), 40 CFR Part 63, Subpart UUUUU, Table 5)**

7. If the permittee elects to use a PM CEMS or participate in an averaging plan for PM, total non-Hg HAP metals, or individual metals, the permittee shall keep, in a satisfactory manner, hourly (if applicable) and 30-day rolling average PM, total non-Hg HAP metals, or individual metals (as applicable) emission rate records for each emission unit excluding periods of startup and shutdown. **(40 CFR 63.10010, 40 CFR 63.10021, 40 CFR Part 63, Subpart UUUUU, Table 7)**

8. For any emission unit not relying on the LEE provisions for Hg, the permittee shall keep, in a satisfactory manner, hourly (if applicable) and 30-day rolling average Hg emission rate records for each emission unit excluding periods of startup and shutdown. **(40 CFR 63.10010, 40 CFR 63.10021, 40 CFR Part 63, Subpart UUUUU, Table 7)**

9. The permittee shall keep, in a satisfactory manner, hourly and 30-day rolling average SO_2 emission rate records for each emission unit excluding periods of startup and shutdown. **(40 CFR 63.10010, 40 CFR 63.10021, 40 CFR Part 63, Subpart UUUUU, Table 7)**

10. The permittee must operate the required monitoring system(s) and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see 40 CFR 63.8(c)(7) of 40 CFR Part 63, Subpart A), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. The permittee is required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable. **(40 CFR 63.10020(b))**

11. The permittee may not use data recorded during startup or shutdown in calculations used to report emissions, except as otherwise provided in 40 CFR 63.10000(c)(1)(vi)(B) and 40 CFR 63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. The permittee must use all of the quality-assured data collected during all other periods in assessing the operation of the control device and associated control system. **(40 CFR 63.10020(c))**

12. Failure to collect required data is a deviation from the monitoring requirements except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments. **(40 CFR 63.10020(d))**

13. If the permittee uses CEMS to measure SO_2, PM, HCl, HF, or Hg emissions (or sorbent trap monitoring system), except as otherwise provided in 40 CFR 63.10020(c), the permittee must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and other required monitoring systems to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, a 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 in 40 CFR 63.10021(b) to determine the 30- or 90-boiler operating day rolling average. **(40 CFR 63.10021(a) and (b))**

14. The permittee must keep the following records:

    a. A copy of each notification and report that has been submitted to comply with 40 CFR Part 63, Subpart UUUUU, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that has been submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv). **(40 CFR 63.10032(a)(1))**

    b. Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in 40 CFR 63.10(b)(2)(viii). **(40 CFR 63.10032(a)(2))**

    c. For each CEMS and CPMS, the permittee must keep the following records:

        i. Records described in 40 CFR 63.10(b)(2)(vi) through (xi). **(40 CFR 63.10032(b)(1))**

        ii. Previous (i.e., superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3). **(40 CFR 63.10032(b)(2))**

        iii. Request for alternatives to relative accuracy test for CEMS as required in 40 CFR 63.8(f)(6)(i). **(40 CFR 63.10032(b)(3))**

        iv. The date and time that each deviation started and stopped and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period. **(40 CFR 63.10032(b)(4))**

        v. If the permittee continuously monitors Hg and/or HCl and/or HF emissions, the permittee must also keep the records required under Appendix A and/or Appendix B of 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10032(a))**

    d. For each emission unit subject to an emission limit:

        i. The permittee shall keep the monthly fuel use by each emission unit, including the type(s) of fuel and amount(s) used. **(40 CFR 63.10032(d)(1))**

        ii. If the permittee combusts non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), the permittee must keep a record which documents how the secondary material meets each of the legitimacy criteria. If the permittee combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), the permittee must keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), the permittee must keep a record which documents how the fuel satisfies the requirements of the petition process. **(40 CFR 63.10032(d)(2))**

e. Regarding startup periods or shutdown periods:

i. If the permittee chooses to rely on paragraph (1) of the definition of ''startup'' in 40 CFR 63.10042 for the emission unit(s), the permittee shall keep records of the occurrence and duration of each startup or shutdown. **(40 CFR 63.10032(f)(1))**

ii. The type(s) and amount(s) of fuel used during each startup or shutdown. **(40 CFR 63.10032(i))**

f. The occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment. **(40 CFR 63.10032(g))**

g. Actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. **(40 CFR 63.10032(h))**

15. The permittee shall keep all records in a form suitable and readily available for expeditious review and for at least 5 years after the date of each occurrence, corrective action, report, or record. The records must be kept onsite for at least 2 years and may be kept offsite for the remaining 3 years. **(40 CFR 63.10(b)(1), 40 CFR 63.10033)**

16. The permittee shall maintain on site and submit, if requested by the Administrator, an annual report of periodic performance tune-ups containing the information required by 40 CFR 63.10021(e)(8). The reports shall be in a format acceptable to the Administrator. If requested by the AQD District Supervisor, the permittee shall also submit an annual report with the results of the performance tune-ups. **(40 CFR 63.10021(e)(8))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. Semiannual reporting of the information required in 40 CFR 63.10031(c)(1) through (9), (d), and (e) as applicable. The report shall be postmarked or received by the Administrator by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. The report shall include the following:

a. The information required by the Continuous Monitoring Summary Report located in 40 CFR 63.10(e)(3)(vi). **(40 CFR 63.10031(c)(1))**

b. The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by USEPA or the basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure. **(40 CFR 63.10031(c)(2))**

c. Indicate whether any emission unit in FGMATS_U3 burned new types of fuel during the reporting period. If new types of fuel were burned, include the date of the performance test where that fuel was in use. **(40 CFR 63.10031(c)(3))**

d. Include the date of the most recent tune-up for each emission unit. The date of the tune-up is the date the tune-up provisions specified in 40 CFR 63.10021(e)(6) and (7) were completed. **(40 CFR 63.10031(c)(4))**

e. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to FGMATS_U3 and there are no deviations from the requirements for work practice standards in Table 3 to 40 CFR Part 63, Subpart UUUUU that apply to FGMATS_U3, the report shall include a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in 40 CFR 63.8(c)(7), a statement

that there were no periods during which the CMSs were out-of-control during the reporting period. **(40 CFR Part 63, Subpart UUUUU, Table 8)**

f. If there is a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain a brief description of the deviation, the duration of the deviation, the cause of the deviation, and the information in 40 CFR 63.10031(d). If there were periods during which the CMS's, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in 40 CFR 63.8(c)(7), the report must contain the information in 40 CFR 63.10031(e). **(40 CFR 63.10031(c)(1) through (9), (d), and (e), 40 CFR 63.10031(a), 40 CFR 63.10031(c)(9), 40 CFR Part 63, Subpart UUUUU, Table 8)**

g. If the affected source submits a compliance report pursuant to Table 8 in 40 CFR Part 63, Subpart UUUUU, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in 40 CFR Part 63, Subpart UUUUU, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report required by SC VII.2. **(40 CFR 63.10031(e))**

5. The permittee must submit any of the following applicable notifications by the dates specified within the specific citation: 40 CFR 63.7(b) and (c) Notification of performance test and Quality assurance program; 40 CFR 63.8(e) Performance evaluation of continuous monitoring systems; 40 CFR 63.8(f)(4) Request to use alternative monitoring methods; 40 CFR 63.8(f)(6) Alternative to the relative accuracy test; 40 CFR 63.9(b) Initial notifications; 40 CFR 63.9(c) Request for extension of compliance; 40 CFR 63.9(d) Notification that source is subject to special compliance requirements; 40 CFR 63.9(e) Notification of performance test, which shall be submitted at least 30 days before the performance test is scheduled to begin; 40 CFR 63.9(f) Notification of opacity and visible emission observations; 40 CFR 63.9(g) Additional notification requirements for sources with continuous monitoring systems; and 40 CFR 63.9(h) Notification of compliance status. **(40 CFR 63.10030(a))**

6. On or after July 1, 2020, within 60 days after the date of completing each performance test, the permittee must submit the performance test reports required by this subpart to USEPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of USEPA's Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/index.html). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. At the discretion of the AQD, the permittee must also submit these reports, one to the Technical Programs Unit Supervisor and one to the AQD District Supervisor, in a format approved by the AQD. **(40 CFR 63.10031(f))**

7. On or after July 1, 2020, for a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31, June 30, September 30, and December 31, the permittee must submit quarterly reports to USEPA's WebFIRE database by using the CEDRI that is accessed through USEPA's CDX (www.epa.gov/cdx). The permittee must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with USEPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the CEMS and PM CPMS. **(40 CFR 63.10031(f)(2))**

8. Reports for a SO_2 CEMS, a Hg CEMS or sorbent trap monitoring system, a HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in 40 CFR Part 63, Subpart UUUUU, Appendices A and B and 40 CFR 63.10021(f). **(40 CFR 63.10031(f)(3))**

9. On or after July 1, 2020, the permittee must submit all reports required by 40 CFR 63.10031 (c) and (d) electronically using CEDRI that is accessed through the USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). The permittee must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with USEPA's reporting form output format. If requested by the AQD, the permittee must also submit these reports, to the AQD District Supervisor in a format approved by the AQD. **(40 CFR 63.10031(f)(4))**

10. Prior to July 1, 2020, all reports subject to electronic submittal in SC VII.6, VII.7, and VII.9 shall be submitted to the USEPA at the frequency specified in those paragraphs in electronic portable document format (PDF) using the ECMPS Client Tool. Each PDF version of a submitted report must include sufficient information to assess compliance and to demonstrate that the testing was done properly. The data elements listed at 40 CFR 63.10031(f)(6)(i)-(xii) must be entered into the ECMPS Client Tool at the time of submission of each PDF file. **(40 CFR 63.10031(f)(6))**

11. If requested by the Administrator, the permittee must submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already undergone a performance evaluation that meets the requirements of 40 CFR 63.10010 (e.g., if the CMS was previously certified under another program). **(40 CFR 63.10000(d)(3))**

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. For each emission unit or emissions averaging group complying with an emission limit as specified in Table 2 of 40 CFR Part 63, Subpart UUUUU, the permittee may request to switch from a mass per heat input to a mass per gross output limit (or vice versa).
   a. The permittee may switch from a mass per heat input to a mass per gross output limit (or vice-versa), provided that:
      i. The permittee submits a request that identifies for each emission unit or emissions averaging group involved in the proposed switch both the current and proposed emission limit. **(40 CFR 63.10030(e)(7)(iii)(A)(1))**
      ii. The request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur. **(40 CFR 63.10030(e)(7)(iii)(A)(2))**
      iii. The request demonstrates through performance stack test results completed within 30 days prior to the submission, compliance for each emission unit or emissions averaging group with both the mass per heat input and mass per gross output limits. **(40 CFR 63.10030(e)(7)(iii)(A)(3))**
      iv. The permittee revises and submits all other applicable plans, e.g., monitoring and emissions averaging, with the request. **(40 CFR 63.10030(e)(7)(iii)(A)(4))**
      v. The permittee maintains records of all information regarding the choice of emission limits. **(40 CFR 63.10030(e)(7)(iii)(A)(5))**
   b. The permittee may begin to use the revised emission limits starting in the next reporting period, after receipt of written acknowledgement from the Administrator of the switch. **(40 CFR 63.10030(e)(7)(iii)(B))**
   c. From the submission of the request until start of the next reporting period after receipt of written acknowledgement from the Administrator of the switch, the permittee shall demonstrate compliance with both the mass per heat input and mass per gross output emission limits for each pollutant for each emission unit or emissions averaging group. **(40 CFR 63.10030(e)(7)(iii)(C))**

2. If using a CMS to demonstrate continuous compliance with an emission limit or operating limit, the permittee must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before the initial performance evaluation (where applicable) of the CMS. This requirement also applies to the permittee if the permittee petitions the Administrator for alternative monitoring parameters under 40 CFR 63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under Appendix B of 40 CFR Part 60 or 40 CFR Part 75, and that meet the requirements of 40 CFR 63.10010. Using the process described in 40 CFR 63.8(f)(4), the permittee may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in the

site-specific monitoring plan. The monitoring plan must address the following provisions: **(40 CFR 63.10000(d), 40 CFR 63.10010)**

a. Installation of the CMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device). See 40 CFR 63.10010(a) for further details. For PM CPMS installations, follow the procedures in 40 CFR 63.10010(h).

b. Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

c. Schedule for conducting initial and periodic performance evaluations.

d. Performance evaluation procedures and acceptance criteria (e.g., calibrations), including the quality control program in accordance with the general requirements of 40 CFR 63.8(d).

e. On-going operation and maintenance procedures, in accordance with the general requirements of 40 CFR 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).

f. Conditions that define a CMS that is out of control consistent with 40 CFR 63.8(c)(7)(i) and for responding to out of control periods consistent with 40 CFR 63.8(c)(7)(ii) and (c)(8).

g. On-going recordkeeping and reporting procedures, in accordance with the general requirements of 40 CFR 63.10(c), (e)(1), and (e)(2)(i), or as specifically required under 40 CFR Part 63, Subpart UUUUU.

h. Alternatively, the requirements are considered to be met for a particular CMS or sorbent trap monitoring system if:

   i. The CMS or sorbent trap monitoring system is installed, certified, maintained, operated, and quality-assured either according to 40 CFR Part 75, or Appendix A or B of 40 CFR Part 63, Subpart UUUUU; and

   ii. The recordkeeping and reporting requirements of 40 CFR Part 75, or Appendix A or B of 40 CFR Part 63, Subpart UUUUU, which pertain to the CMS, are met.

3. If any emission unit(s) cease(s) to operate in a manner that causes the unit(s) to meet the definition of an EGU subject to 40 CFR Part 63, Subpart UUUUU, the permittee must submit the notification in 40 CFR 63.10000(i)(2) no less than 30 days prior to when the EGU will cease complying with 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10000(i)(2), 40 CFR 63.10030(f))**

4. The permittee shall comply with all provisions of the National Emission Standards for Hazardous Air Pollutants as specified in 40 CFR Part 63, Subparts A and UUUUU. **(40 CFR Part 63, Subparts A and UUUUU)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FGEXISTINGRICE
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

Existing Emergency Engines located at a Major Source < 500 HP, Commenced Construction or Reconstruction before June 12, 2006.

These four (4) existing stationary diesel-fired reciprocating compression ignition internal combustion engines are emergency generators subject to 40 CFR Part 63, Subpart ZZZZ (National Emission Standard for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (RICE).

Emission Units: EUCATFIREPUMP3, EUHPHSWP15001, EUHPHSWP15002, EUHPHSWP3000.

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMITS

NA

II. MATERIAL LIMIT(S)

Material	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Fuel Oil – sulfur content	1.0% by weight at 18,000 BTU/lb	Instantaneous; at all times	EUCATFIREPUMP3 EUHPHSWP15001 EUHPHSWP15002 EUHPHSWP3000	SC VI.5	**R 336.1401(1), Table 41**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. Each engine in FGEXISTINGRICE shall be installed, maintained, and operated in a satisfactory manner. A list of recommended work practice standards as specified in 40 CFR 63.6602 and Table 2c, Item 1 or the permittee may petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices. The following are the recommended work practices specified in 40 CFR Part 63, Subpart ZZZZ, Table 2c:

   a. Change oil and filter every 500 hours of operation or annually, whichever comes first, except as allowed in SC III.3.
   b. Inspect the air cleaner every 1,000 hours of operation or annually, whichever comes first; and replace as necessary.
   c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

   If the emergency engine is being operated during an emergency and it is not possible to shut down the engine to perform the work practice standards on the schedule required the work practice standard can be delayed until the emergency is over. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State or local law has been abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law or which the risk was deemed unacceptable. **(40 CFR 63.6602, 40 CFR Part 63, Subpart ZZZZ, Table 2c, Item 6)**

2. The permittee may utilize an oil analysis program in order to extend the specified oil change requirement. The oil analysis must be performed at the same frequency as oil changes are required. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c of 40 CFR Part 63, Subpart ZZZZ. **(40 CFR 63.6625(i))**

3. The permittee shall maintain and operate each engine in FGEXISTINGRICE per the manufacturer's emission related written instructions or develop a maintenance plan which must provide for the maintenance and operation of the engine in a manner consistent with good air pollution control practices for minimizing emissions. **(40 CFR 63.6625(e), 40 CFR 63.6640(a), 40 CFR Part 63, Subpart ZZZZ, Table 6 Item 9)**

4. The permittee shall minimize the time spent at idle during startup and minimize the startup time of each engine in FGEXISTINGRICE to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup apply. **(40 CFR 63.6625(h))**

5. There is no time limit on the use of emergency stationary RICE in emergency situations. **(40 CFR 63.6640(f)(1))**

6. The permittee may not operate each engine in FGEXISTINGRICE for more than 100 hours per calendar year for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The permittee may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. **(40 CFR 63.6640(f)(2))**

7. The permittee may operate each engine in FGEXISTINGRICE for up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing as provided in 40 CFR 63.6640 (f)(2). The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income to supply non-emergency power as part of a financial arrangement with another entity, except as allowed in 40 CFR 63.6640(f)(4)(ii). **(40 CFR 63.6640(f)(4))**

8. If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable. **(40 CFR Part 63, Table 2c, Footnote 1)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall equip and maintain with a non-resettable hour meter to track the number of hours each engine operates. **(40 CFR 63.6625(f))**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. If using the oil analysis program in order to extend the specified oil change requirement in 40 CFR Part 63, Subpart ZZZZ, Table 2d, the permittee must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20% from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner

or operator must change the oil within 2 business days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 business days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine. **(40 CFR 63.6625(j))**

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. For each engine in FGEXISTINGRICE, the permittee shall keep in a satisfactory manner, records of the occurrence and duration of each malfunction of operation or the air pollution control monitoring equipment. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(a)(2), 40 CFR 63.6660)**

2. For each engine in FGEXISTINGRICE, the permittee shall keep in a satisfactory manner, records of actions taken during periods of malfunction to minimize emissions, including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(a)(5), 40 CFR 63.6660)**

3. For each engine in FGEXISITINGRICE, the permittee shall keep in a satisfactory manner, maintenance records to demonstrate compliance with SC III.1 and the written maintenance plan. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(d), 40 CFR 63.6655(e), 40 CFR 63.6660)**

4. The permittee shall monitor and record the total hours of operation for each engine in FGEXISTINGRICE per calendar year, recorded through the non-resettable hours meter, in a manner acceptable to the District Supervisor, Air Quality Division. The permittee shall document how many hours are spent for emergency operation; including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in 40 CFR 63.6640(f)(4)(ii), the permittee must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation. **(40 CFR 63.6655(f))**

5. The permittee shall maintain sufficient records to demonstrate that the sulfur content for each shipment of fuel oil received is less than 1.0% by weight. **(R 336.1213(3))**

6. The permittee shall conduct and maintain records of a daily (non-certified) visual observation for opacity in order to verify proper firing, whenever an engine is in use for 24 consecutive hours or more. **(R 336.1213(3))**

7. The permittee shall maintain a record of the applicability determination for each engine in FGEXISTINGRICE relative to the requirements of 40 CFR Part 63, Subparts A and ZZZZ. **(40 CFR Part 63, Subpart A, Section 63.10(b)(3))**

See Appendix 3-C

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit to the AQD District Supervisor, a semiannual compliance report, as specified in 40 CFR 63.6650, which contains all deviations during the reporting period from any applicable emission limitation or operating limitation. If there are no deviations from any applicable emission limitations or operating limitations, the report shall contain a statement that there were no deviations during the reporting period. The first report shall cover the period beginning on the applicable compliance date specified in 40 CFR 63.6595 and ending on June 30 (postmarked or delivered by July 31) or December 31 (postmarked or delivered by January 31), whichever date is the first date following the end of the first calendar half after the applicable compliance date. Each subsequent report must cover the semiannual period from January 1 through June 30, or from July 1 through December 31. The subsequent reports must be postmarked or delivered by July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period, except as allowed in 40 CFR 63.6650(b)(5). The compliance report must also contain the following information, as specified in 40 CFR 63.6650(c) and (d):

   a. Company name and address.

   b. Certification of the report by a responsible official.

   c. Date of report and beginning and ending dates of the reporting period.

   d. The number of malfunctions, including a brief description of each event, that occurred during the reporting period and a demonstration that the Malfunction Plan was followed during such events.

   e. The total operating time of the RICE at which the deviation occurred during the reporting period.

   f. The number, duration, and cause of deviations and the corrective action taken.

   A copy of the compliance report shall be kept on file for a period of at least five years (at least two years at the site) and made available to the Department upon request. **(40 CFR 63.6640(b), 40 CFR 63.6650(b),(c),(d), 40 CFR 63.6660)**

5. Each affected source that has obtained a Title V operating permit pursuant to 40 CFR Part 70 or 71 must report all deviations as defined in 40 CFR Part 63, Subpart ZZZZ in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of 40 CFR Part 63, Subpart ZZZZ along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in 40 CFR Part 63, Subpart ZZZZ, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority. **(40 CFR 63.6650(f))**

   c. For each engine in FGEXISTINGRICE that is an emergency stationary engine with a site rating of more than 100 brake hp that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in 40 CFR 63.6640(f)(4)(ii), you must submit an annual report according to the requirements below and as specified in 40 CFR 63.6650(h). **(40 CFR 63.6650(h), 40 CFR 63.6660)**

   a. The report must contain the following information:
      i. Company name and address where the engine is located.
      ii. Date of the report and beginning and ending dates of the reporting period.
      iii. Engine site rating and model year.
      iv. Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.
      v. Hours operated for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii).
      vi. Number of hours the engine is contractually obligated to be available for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii).

vii. Hours spent for operation for the purpose specified in 40 CFR 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.
viii. If there were no deviations from the fuel requirements in 40 CFR 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.
ix. If there were deviations from the fuel requirements in 40 CFR 63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

b. The permittee shall submit annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in 40 CFR 63.13.
See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with all applicable provisions of the National Emission Standards for Hazardous Air Pollutants, as specified in 40 CFR Part 63, Subparts A and ZZZZ, for Stationary Reciprocating Internal Combustion Engines by the initial compliance date of May 3, 2013. **(40 CFR 63.6595(a)(1), 40 CFR, Part 63, Subparts A and ZZZZ)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FGNEWCIRICE
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

EUWPDIESEL: A Water Pump for EUSDA_U3 emergency flush certified to NSPS IIII Tier 3 requirements. A diesel-powered, stationary internal combustion engine rated at 130 HP (97 kW).

EUTRNCNTRDIESEL: An emergency generator for the Training Center with diesel engine certified to NSPS IIII Tier 3 requirements. A diesel-powered, stationary internal combustion engine rated at 1,193 bHP.

These units are subject to the provisions of 40 CFR Part 60, Subpart IIII and 40 CFR Part 63, Subpart ZZZZ.

Emission Units: EUWPDIESEL, EUTRNCNTRDIESEL

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. NMHC + NOx	4.0 g/kW-hr[2]	Hourly	EUWPDIESEL	SC V.1 SC VI.2	**40 CFR 60.4205(b), 40 CFR 89.112(a) Table 1**
2. CO	5.0 g/kW-hr[2]	Hourly	EUWPDIESEL	SC V.1 SC VI.2	**40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 89.112(a) Table 1**
3. PM	0.30 g/kW-hr[2]	Hourly	EUWPDIESEL	SC V.1 SC VI.2	**40 CFR 60.4202(a)(2), 40 CFR 60.4205(b), 40 CFR 89.112(a) Table 1**
4. NMHC + NOx	6.4 g/kW-hr[2]	Hourly	EUTRNCNTRDIESEL	SC V.1 SC VI.2	**40 CFR 60.4205(c)**
5. CO	3.5 g/kW-hr[2]	Hourly	EUTRNCNTRDIESEL	SC V.1 SC VI.2	**40 CFR 60.4205(c)**
6. PM	0.20 g/kW-hr[2]	Hourly	EUTRNCNTRDIESEL	SC V.1 SC VI.2	**40 CFR 60.4205(c)**

II. MATERIAL LIMIT(S)

1. The permittee shall burn only diesel fuel, in EUWPDIESEL and EUTRNCNTRDIESEL with the maximum sulfur content of 15 ppm (0.0015%) by weight and a minimum Cetane index of 40 or a maximum aromatic content of 35 volume percent.[2] **(R 336.1205(1)(a), R 336.1402(1), 40 CFR 60.4207(b), 40 CFR 80.510(b))**

   See Appendix 3-C

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate EUWPDIESEL for more than 100 hours per year on a 12-month rolling time period basis as determined at the end of each calendar month. The 100 hours includes the hours for the purpose

of emergency operation, necessary maintenance checks and readiness testing as described in SC III.2.[2] **(R 336.1205(1)(a), R 336.1225, R 336.1702(a))**

2. The permittee may operate not either EUWPDIESEL or EUTRNCNTRDIESEL for no more than 100 hours per calendar year for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. The permittee may petition the Department for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. EUWPDIESEL may operate up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing.[2] **(40 CFR 60.4211(f))**

3. If EUWPDIESEL and/or EUTRNCNTRDIESEL is a certified engine, the permittee shall meet the following requirements:
   a. Operate and maintain the certified engine and control device according to the manufacturer's emission-related written instructions;
   b. Change only those emission-related settings that are permitted by the manufacturer; and
   c. Meet the requirements as specified in 40 CFR 89, 94, and/or 1068, as they apply to each engine in FGNEWCIRICE.

   If you do not operate and maintain the certified engine and control device according to the manufacturer's emission-related written instructions, the engine may be considered a non-certified engine.[2] **(40 CFR 60.4211(a))**

4. If EUWPDIESEL and/or EUTRNCNTRDIESEL is a non-certified engine or a certified engine operating in a non-certified manner, the permittee shall keep a maintenance plan and records of conducted maintenance for EUWPDIESEL and must, to the extent practicable, maintain and operate each engine in FGNEWCIRICE in a manner consistent with good air pollution control practice for minimizing emissions.[2] **(40 CFR 60.4211(g)(2))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall equip and maintain EUWPDIESEL and EUTRNCNTRDIESEL with a non-resettable hours meter to track the operating hours.[2] **(R 336.1205(1)(a), R 336.1225, 40 CFR 60.4209)**

2. The nameplate capacity of EUWPDIESEL shall not exceed 130 hp, as certified by the equipment manufacturer.[2] **(R 336.1205(1)(a), R 336.1225, 40 CFR 60.4202, 40 CFR 89.112(a))**

3. The nameplate capacity of EUTRNCNTRDIESEL shall not exceed the capacity restrictions (560<kW<=2237) as certified by the equipment manufacturer. **(40 CFR 60.4202)**

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. Unless EUWPDIESEL and/or EUTRNCNTRDIESEL has been certified by the manufacturer as required by 40 CFR Part 60, Subpart IIII and the permittee maintains the engine as required by 40 CFR 60.4211, the permittee shall conduct an initial performance test to demonstrate compliance with the emission limits in SC I.1 – I.3 for each diesel engine, within one year after startup, or within 1 year after either diesel engine is no longer configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after the permittee changes emission-related settings in a way that is not permitted by the manufacturer, to demonstrate compliance with the emission limits in 40 CFR 60.4205(b). If a performance test is required, the performance test shall be conducted according to 40 CFR 60.4212. No less than 30 days prior to testing, a complete test plan shall be submitted to the AQD. The final plan must be approved by the AQD prior to testing. After conducting the initial performance test, the permittee shall conduct subsequent performance testing, for non-certified engines, every 8,760 hours or 3 years, whichever comes first. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted. Verification of emission rates

includes the submittal of a complete report of the test results to the AQD within 60 days following the last date of the test.[2] **(R 336.2001, R 336.2003, R 336.2004, 40 CFR 60.4211(g)(2), 40 CFR 60.4212)**

2. Upon request of the AQD District Supervisor, the permittee shall verify NOx, CO, PM10, and PM2.5 emission rates from EUWPDIESEL or EUTRNCNTRDIESEL by testing at owner's expense, in accordance with the Department requirements. Testing shall be performed using an approved USEPA Method listed in:

Pollutant	Test Method Reference
PM10/PM2.5	40 CFR Part 51, Appendix M
NOx	40 CFR Part 60, Appendix A
CO	40 CFR Part 60, Appendix A

An alternate method, or a modification to the approved USEPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.[2] **(R 336.1205, R 336.1225, R 336.2001, R 336.2003, R 336.2004)**

See Appendix 5

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall complete all required calculations in a format acceptable to the AQD District Supervisor by the 30th day of the calendar month, for the previous calendar month, unless otherwise specified in any monitoring/recordkeeping special condition.[2] **(R 336.1205(1)(a))**

2. The permittee shall keep, in a satisfactory manner, records of testing required in SC V.1 or manufacturer certification documentation indicating that EUWPDIESEL and EUTRNCNTRDIESEL meets the applicable requirements contained in the federal Standards of Performance for New Stationary Sources 40 CFR Part 60, Subpart IIII. If EUWPDIESEL or EUTRNCNTRDIESEL becomes uncertified then the permittee must also keep records of a maintenance plan and maintenance activities. The permittee shall keep all records on file and make them available to the Department upon request.[2] **(40 CFR 60.4211(g)(2))**

3. The permittee shall monitor and record the total hours of operation and the hours of operation during non-emergencies for EUWPDIESEL and EUTRNCNTRDIESEL, on a monthly and 12-month rolling time period basis, in a manner acceptable to the AQD District Supervisor. The permittee shall document how many hours are spent for emergency operation of EUWPDIESEL and EUTRNCNTRDIESEL, including what classified the operation as emergency and how many hours are spent maintenance or readiness testing and for non-emergency operation.[2] **(R 336.1205(1)(a), 40 CFR 60.4211, 40 CFR 60.4214(b))**

4. The permittee shall keep, in a satisfactory manner, fuel supplier certification records or fuel sample test data, for each delivery of diesel fuel oil used in EUWPDIESEL and EUTRNCNTRDIESEL, demonstrating that the fuel meets the requirement of 40 CFR 80.510(b). The certification or test data shall include the name of the oil supplier or laboratory, the sulfur content, and cetane index or aromatic content of the fuel oil.[2] **(R 336.1205(1)(a), R 336.1402(1), 40 CFR 80.510(b))**

See Appendices 3, 4, and 7

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit any performance test reports to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

The exhaust gases from the stacks listed in the table below shall be discharged unobstructed vertically upwards to the ambient air unless otherwise noted:

Stack & Vent ID	Maximum Exhaust Dimensions (inches)	Minimum Height Above Ground (feet)	Underlying Applicable Requirements
1. SVWPDIESEL	14[2]	16[2]	**40 CFR 52.21(c) & (d)**

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60, Subparts A and IIII, as they apply to EUWPDIESEL and EUTRNCNTRDIESEL.[2] **(40 CFR Part 60, Subparts A & IIII, 40 CFR 63.6590)**

2. The permittee shall comply with the provisions of the National Emission Standards for Hazardous Air Pollutants, as specified in 40 CFR Part 63, Subparts A and ZZZZ, as they apply to EUWPDIESEL and EUTRNCNTRDIESEL.[2] **(40 CFR Part 63, Subparts A and ZZZZ, 40 CFR 63.6595)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FGAUXBLRS3
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

Two (2) distillate oil fired boilers rated at 9.8 MMBTU heat input, providing heat to Plant 3. These units are subject to the provisions of 40 CFR Part 63, Subpart DDDDD.

Emission Units: EUAUXBLR3B, EUAUXBLR3C (Both are 9.8 MMBTU/hr, Diesel fuel)

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

Material	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Fuel Oil – sulfur content	0.4% by weight at 18,000 BTU/lb	Instantaneous; at all times	EUAUXBLR3B EUAUXBLR3C	SC VI.1	**R 336.1282 (b)(ii)**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee must meet the tune-up and energy assessment work practice standards for each applicable boiler or process heater at the source. **(40 CFR 63.7500(a)(1), 40 CFR Part 63, Subpart DDDDD, Table 3, Nos. 1-4)**

2. The permittee must operate and maintain affected sources in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the AQD that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. **(40 CFR 63.7500(a)(3))**

3. The permittee may obtain approval from the USEPA Administrator to use an alternative to the tune-up and energy assessment work practice standards. **(40 CFR 63.7500(b))**

4. The permittee must conduct a biennial performance tune-up according to 40 CFR 63.7540(a)(11) as stated in SC III.5, respectively. Each biennial tune-up specified in 40 CFR 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. **(40 CFR 63.7515(d))**

5. Boilers or process heaters with a heat input capacity of less than 10 million BTU per hour must conduct a biennial tune-up of the boiler or process heater. **(40 CFR 63.7540(a)(11), 40 CFR 63.7500(e))**

6. The permittee shall conduct the tune-up within 30 days of startup, if the unit is not operating on the required date for a tune-up. **(40 CFR 63.7540(a)(12))**

7. The permittee must demonstrate continuous compliance with the tune-up requirement by completing the following: **(40 CFR 63.7540(a)(10))**

a. Inspect the burner, and clean or replace any components of the burner as necessary (the permittee may delay the burner inspection until the next scheduled unit shutdown). At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment. **(40 CFR 63.7540(a)(10)(i))**

b. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available. **(40 CFR 63.7540(a)(10)(ii))**

c. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection. **(40 CFR 63.7540(a)(10)(iii))**

d. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NOx requirement to which the unit is subject. **(40 CFR 63.7540(a)(10)(iv))**

e. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer. **(40 CFR 63.7540(a)(10)(v))**

f. Maintain on-site and submit, if requested by the AQD, the most recent periodic report containing the information as listed below. **(40 CFR 63.7540(a)(10)(vi))**

   i. The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater. **(40 CFR 63.7540(a)(10)(vi)(A))**

   ii. A description of any corrective actions taken as a part of the tune-up. **(40 CFR 63.7540(a)(10)(vi)(B))**

   iii. The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit. **(40 CFR 63.7540(a)(10)(vi)(C))**

8. The permittee must complete the Initial tune ups on all affected units except as provided in 40 CFR 63.7510(j) and 40 CFR 63.7540(a)(13). **(40 CFR 63.7510(e))**

9. For affected sources (as defined in 40 CFR 63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, the permittee must complete a subsequent tune-up within 30 days of startup by following the procedures described in SC III.7.a through SC III.7.f. **(40 CFR 63.7515(9))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

NA

V. TESTING/SAMPLING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. The permittee shall maintain sufficient records to demonstrate that the sulfur content for each shipment of fuel oil received is less than 0.4% by weight. **(R 336.1213(3))**

2. The permittee must keep a copy of each notification and report submitted to comply with 40 CFR Part 63, Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that the permittee submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv). **(40 CFR 63.7555(a)(1))**

3. The permittee must keep each record on site, or they must be accessible from on-site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. The permittee can keep the records off site for the remaining 3 years. **(40 CFR 63.7560(a), (b), and (c))**

See Appendix 3-C (Fuel Oil Sulfur Monitoring)

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee must submit boiler tune-up compliance reports. Compliance reports must be postmarked or submitted by March 15 of the year following the tune-up and must cover the applicable 1, 2, or 5-year period starting from January 1 of the year following the previous tune-up to December 31 (of the latest tune-up year). Compliance reports must be submitted using the Compliance and Emissions Data Reporting Interface (CEDRI) which is accessed through the USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). If the reporting form is not available in CEDRI at the time the compliance report is due, a hardcopy of the compliance report shall be submitted to the state and USEPA Region 5. At the discretion of the Administrator, the permittee must submit these reports in the format specified by the Administrator. **(40 CFR 63.7550(b), 40 CFR 63.10(a)(5), 40 CFR 63.7550(h)(3))**

5. Unless the USEPA Administrator has approved a different schedule for submission of reports under 40 CFR 63.10(a), the permittee must submit each report, according to paragraph (h) of 40 CFR 63.7550, stated in SC VII.5, by the date in Table 9 of 40 CFR Part 63, Subpart DDDDD and according to the requirements in paragraphs (b)(1) through (4) of 40 CFR 63.7550, as listed below. For units that are subject only to a requirement to conduct a 5-year tune-up according to 40 CFR 63.7540(a)(12), stated in SC IX.5.b, and not subject to emission limits or operating limits, the permittee may submit only a 5-year compliance report, as specified in paragraphs (b)(1) through (4) of 40 CFR 63.7550, as listed below, instead of a semi-annual compliance report. **(40 CFR 63.7550(a) & (b))**
   a. Each semi-annual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. 5-year compliance reports must cover the 5-year period from January 1 to December 31. **(40 CFR 63.7550(b)(3))**
   b. Each semi-annual compliance report must be postmarked or submitted no later than September 15 or March 15, whichever date is the first date following the end of the semiannual reporting period. 5-year compliance reports must be postmarked or submitted no later than March 15. **(40 CFR 63.10(a)(5), 40 CFR 63.7550(b)(4), 40 CFR 63.7550(b)(5))**

6. The permittee must include the following information in the compliance report. **(40 CFR 63.7550(a) & (c))**
   a. If the facility is subject to the requirements of a tune up the permittee must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (xiv), and (xvii) of 40 CFR 63.7550. **(40 CFR 63.7550(c)(1))**
   b. 40 CFR 63.7550(c)(5) is as follows:
      i. Company and Facility name and address. **(40 CFR 63.7550(c)(5)(i))**
      ii. Process unit information, emissions limitations, and operating parameter limitations. **(40 CFR 63.7550(c)(5)(ii))**
      iii. Date of report and beginning and ending dates of the reporting period. **(40 CFR 63.7550(c)(5)(iii))**
      iv. Include the date of the most recent tune-up for each unit subject to only the requirement to conduct a 5-year tune-up according to 40 CFR 63.7540(a)(12), stated in SC IX.5.b. Include the date of the most recent burner inspection if it was not done on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown. **(40 CFR 63.7550(c)(5)(xiv))**
      v. Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. **(40 CFR 63.7550(c)(5)(xvii))**

7. The permittee must submit the reports according to the procedures specified in paragraph (h)(3) of 40 CFR 63.7550, as listed below. **(40 CFR 63.7550(h))**
   a. The permittee must submit all reports required by Table 9 of 40 CFR Part 63, Subpart DDDDD electronically to the USEPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the USEPA's CDX.) The permittee must use the appropriate electronic report in CEDRI for 40 CFR Part 63, Subpart DDDDD. Instead of using the electronic report in CEDRI for 40 CFR Part 63, Subpart DDDDD, the permittee may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to 40 CFR Part 63, Subpart DDDDD is not available in CEDRI at the time that the report is due, the permittee must submit the report to the Administrator at the appropriate address listed in 40 CFR 63.13. The permittee must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI. **(40 CFR 63.7550(h)(3))**

8. The permittee must report each instance in which the permittee did not meet each applicable operating limit in Tables 3 and 4 to 40 CFR Part 63, Subpart DDDDD. These instances are deviations from the operating limits, respectively, in 40 CFR Part 63, Subpart DDDDD. These deviations must be reported according to the requirements in Section 63.7550. **(40 CFR 63.7540(b))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. **(40 CFR Part 63, Subparts A and DDDDD)**

2. The permittee must be in compliance with the work practice standards (tune ups, energy assessment) in 40 CFR Part 63, Subpart DDDDD. **(40 CFR 63.7505(a))**

3. The permittee shall comply with the General Provisions in 40 CFR 63.1 through 40 CFR 63.15 apply to this source as indicated in Table 10 of 40 CFR Part 63, Subpart DDDDD. **(40 CFR 63.7565, Table 10)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FGPARTSCLEANERS
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

Any cold cleaner that is grandfathered or exempt from Rule 201 pursuant to Rule 278, 278a and Rule 281(2)(h) or Rule 285(2)(r)(iv). Existing cold cleaners were placed into operation prior to July 1, 1979. New cold cleaners were placed into operation on or after July 1, 1979.

Emission Unit: EUPARTSCLEANERS

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

1. The permittee shall not use cleaning solvents containing more than five % by weight of the following halogenated compounds: methylene chloride, perchloroethylene, trichloroethylene, 1,1,1-trichloroethane, carbon tetrachloride, chloroform, or any combination thereof. **(R 336.1213(2))**

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. Cleaned parts shall be drained for no less than 15 seconds or until dripping ceases. **(R 336.1611(2)(b), R 336.1707(3)(b))**

2. The permittee shall perform routine maintenance on each cold cleaner as recommended by the manufacturer. **(R 336.1213(3))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The cold cleaner must meet one of the following design requirements:

   a. The air/vapor interface of the cold cleaner is no more than ten square feet. **(R 336.1281(2)(h))**

   b. The cold cleaner is used for cleaning metal parts and the emissions are released to the general in-plant environment. **(R 336.1285((2)(r)(iv))**

2. The cold cleaner shall be equipped with a device for draining cleaned parts. **(R 336.1611(2)(b), R 336.1707(3)(b))**

3. All new and existing cold cleaners shall be equipped with a cover and the cover shall be closed whenever parts are not being handled in the cold cleaner. **(R 336.1611(2)(a), R 336.1707(3)(a))**

4. The cover of a new cold cleaner shall be mechanically assisted if the Reid vapor pressure of the solvent is more than 0.3 psia or if the solvent is agitated or heated. **(R 336.1707(3)(a))**

5. If the Reid vapor pressure of any solvent used in a new cold cleaner is greater than 0.6 psia; or, if any solvent used in a new cold cleaner is heated above 120 degrees Fahrenheit, then the cold cleaner must comply with at least one of the following provisions:

a. The cold cleaner must be designed such that the ratio of the freeboard height to the width of the cleaner is equal to or greater than 0.7. **(R 336.1707(2)(a))**

b. The solvent bath must be covered with water if the solvent is insoluble and has a specific gravity of more than 1.0. **(R 336.1707(2)(b))**

c. The cold cleaner must be controlled by a carbon adsorption system, condensation system, or other method of equivalent control approved by the AQD. **(R 336.1707(2)(c))**

V. TESTING/SAMPLING

NA

VI. MONITORING/RECORDKEEPING

Records shall be maintained on file for a period of five years. **(R 336.1213(3)(b)(ii))**

1. For each new cold cleaner in which the solvent is heated, the solvent temperature shall be monitored and recorded at least once each calendar week during routine operating conditions. **(R 336.1213(3))**

2. The permittee shall maintain the following information on file for each cold cleaner: **(R 336.1213(3))**

   a. A serial number, model number, or other unique identifier for each cold cleaner.

   b. The date the unit was installed, manufactured or that it commenced operation.

   c. The air/vapor interface area for any unit claimed to be exempt under Rule 281(2)(h).

   d. The applicable Rule 201 exemption.

   e. The Reid vapor pressure of each solvent used.

   f. If applicable, the option chosen to comply with Rule 707(2).

3. The permittee shall maintain written operating procedures for each cold cleaner. These written procedures shall be posted in an accessible, conspicuous location near each cold cleaner. **(R 336.1611(3), R 336.1707(4))**

4. As noted in Rule 611(2)(c) and Rule 707(3)(c), if applicable, an initial demonstration that the waste solvent is a safety hazard shall be made prior to storage in non-closed containers. If the waste solvent is a safety hazard and is stored in non-closed containers, verification that the waste solvent is disposed of so that not more than 20%, by weight, is allowed to evaporate into the atmosphere shall be made on a monthly basis. **(R 336.1213(3), R 336.1611(2)(c), R 336.1707(3)(c))**

VII. REPORTING

1. Prompt reporting of deviations pursuant to General Conditions 21 and 22 of Part A. **(R 336.1213(3)(c)(ii))**

2. Semiannual reporting of monitoring and deviations pursuant to General Condition 23 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. **(R 336.1213(3)(c)(i))**

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

NA

E. NON-APPLICABLE REQUIREMENTS

At the time of the ROP issuance, the AQD has determined that no non-applicable requirements have been identified for incorporation into the permit shield provision set forth in the General Conditions in Part A pursuant to Rule 213(6)(a)(ii).

APPENDICES

Appendix 1-A. Acronyms and Abbreviations

Common Acronyms		Pollutant / Measurement Abbreviations	
AQD	Air Quality Division	acfm	Actual cubic feet per minute
BACT	Best Available Control Technology	BTU	British Thermal Unit
CAA	Clean Air Act	°C	Degrees Celsius
CAM	Compliance Assurance Monitoring	CO	Carbon Monoxide
CEM	Continuous Emission Monitoring	CO_2e	Carbon Dioxide Equivalent
CEMS	Continuous Emission Monitoring System	dscf	Dry standard cubic foot
CFR	Code of Federal Regulations	dscm	Dry standard cubic meter
COM	Continuous Opacity Monitoring	°F	Degrees Fahrenheit
Department/ department	Michigan Department of Environment, Great Lakes, and Energy	gr	Grains
		HAP	Hazardous Air Pollutant
EGLE	Michigan Department of Environment, Great Lakes, and Energy	Hg	Mercury
		hr	Hour
EU	Emission Unit	HP	Horsepower
FG	Flexible Group	H_2S	Hydrogen Sulfide
GACS	Gallons of Applied Coating Solids	kW	Kilowatt
GC	General Condition	lb	Pound
GHGs	Greenhouse Gases	m	Meter
HVLP	High Volume Low Pressure*	mg	Milligram
ID	Identification	mm	Millimeter
IRSL	Initial Risk Screening Level	MM	Million
ITSL	Initial Threshold Screening Level	MW	Megawatts
LAER	Lowest Achievable Emission Rate	NMOC	Non-methane Organic Compounds
MACT	Maximum Achievable Control Technology	NO_x	Oxides of Nitrogen
MAERS	Michigan Air Emissions Reporting System	ng	Nanogram
MAP	Malfunction Abatement Plan	PM	Particulate Matter
MSDS	Material Safety Data Sheet	PM10	Particulate Matter equal to or less than 10 microns in diameter
NA	Not Applicable		
NAAQS	National Ambient Air Quality Standards	PM2.5	Particulate Matter equal to or less than 2.5 microns in diameter
NESHAP	National Emission Standard for Hazardous Air Pollutants	pph	Pounds per hour
		ppm	Parts per million
NSPS	New Source Performance Standards	ppmv	Parts per million by volume
NSR	New Source Review	ppmw	Parts per million by weight
PS	Performance Specification	%	Percent
PSD	Prevention of Significant Deterioration	psia	Pounds per square inch absolute
PTE	Permanent Total Enclosure	psig	Pounds per square inch gauge
PTI	Permit to Install	scf	Standard cubic feet
RACT	Reasonable Available Control Technology	sec	Seconds
ROP	Renewable Operating Permit	SO_2	Sulfur Dioxide
SC	Special Condition	TAC	Toxic Air Contaminant
SCR	Selective Catalytic Reduction	Temp	Temperature
SNCR	Selective Non-Catalytic Reduction	THC	Total Hydrocarbons
SRN	State Registration Number	tpy	Tons per year
TEQ	Toxicity Equivalence Quotient	µg	Microgram
USEPA/EPA	United States Environmental Protection Agency	µm	Micrometer or Micron
		VOC	Volatile Organic Compounds
VE	Visible Emissions	yr	Year

*For HVLP applicators, the pressure measured at the gun air cap shall not exceed 10 psig.

Appendix 1-B. Definitions Related to the Consent Agreement.

The following definitions apply to permit conditions originally established in the consent decree settling, "U.S. v Consumers Energy Company, Civil Action No. 14-13580, E.D. Mich., 2014." This Appendix is also federally enforceable pursuant to Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, Rule 201(1)(a), and Rule 214a, and will remain in effect after termination of the consent decree. **(Act 451, Section 324.5503(b))**

- For the purposes of the Consent Decree, every term expressly defined by this Appendix shall have the meaning given that term herein. Every other term used in the Consent Decree that is also a term used under the Act or in a federal regulation implementing the Act shall mean in the Consent Decree what such term means under the Act or those regulations. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 4)**
- A "30-Day Rolling Average Emission Rate" for a Unit shall be expressed in lb/MMBTU and calculated in accordance with the following procedure: first, sum the total pounds of NO_x or SO_2 emitted from the Unit during the current Unit Operating Day and the previous 29 Unit Operating Days; second, sum the total heat input to the Unit in MMBTU during the current Unit Operating Day and the previous 29 Unit Operating Days; and third, divide the total number of pounds of NO_x or SO_2 emitted during the 30 Unit Operating Days by the total heat input during the 30 Unit Operating Days. A new 30-Day Rolling Average Emission Rate shall be calculated for each new Unit Operating Day. Each 30-Day Rolling Average Emission Rate shall include all emissions that occur during all periods within any Unit Operating Day, including emissions from startup, shutdown, and malfunction. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 5)**
- A "90-Day Rolling Average Emission Rate" for a Unit shall be expressed in lb/MMBTU and calculated in accordance with the following procedure: first, sum the total pounds of NO_x or SO_2 emitted from the Unit during the current Unit Operating Day and the previous 89 Unit Operating Days; second, sum the total heat input to the Unit in MMBTU during the current Unit Operating Day and the previous 89 Unit Operating Days; and third, divide the total number of pounds of NO_x or SO_2 emitted during the 90 Unit Operating Days by the total heat input during the 90 Unit Operating Days. A new 90-Day Rolling Average Emission Rate shall be calculated for each new Unit Operating Day. Each 90-Day Rolling Average Emission Rate shall include all emissions that occur during all periods within any Unit Operating Day, including emissions from startup, shutdown, and malfunction. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 6)**
- A "365-Day Rolling Average Emission Rate" for a Unit shall be expressed in lb/MMBTU and calculated in accordance with the following procedure: first, sum the pounds of the pollutant in question emitted from the Unit during the most recent Unit Operating Day and the previous 364 Unit Operating Days; second, sum the total heat input to the Unit in MMBTU during the most recent Unit Operating Day and the previous 364 Unit Operating Days; and third, divide the total number of pounds of the pollutant emitted during the 365 Unit Operating Days by the total heat input during the 365 Unit Operating Days. A new 365-Day Rolling Average Emission Rate shall be calculated for each new Unit Operating Day. Each 365-Day Rolling Average Emission Rate shall include all emissions that occur during all periods of operation, including startup, shutdown, and malfunction. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 7)**
- "Baghouse" means a full stream (fabric filter or membrane) particulate emissions control device. Full stream is defined as capturing the entire stream of exhaust gas with no concurrent by-pass. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 8)**
- "Campbell" means Consumers' J.H. Campbell Generating Plant consisting of three electric utility steam-generating units designated as Unit l (260 MW), Unit 2 (360 MW), and Unit 3 (835 MW) and related equipment, located in West Olive, Ottawa County, Michigan. Campbell Unit 3 is co-owned by Consumers (approximately 93%) along with Wolverine Power Supply Cooperative and the Michigan Public Power Association. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 10)**
- "CEMS" or "Continuous Emission Monitoring System," means, for obligations involving the monitoring of NO_x and SO_2 emissions under the Consent Decree, the devices defined in 40 CFR 72.2 and installed and

maintained as required by 40 CFR Part 75. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 12)**

- "Clean Air Act" or "CAA" or "Act" means the federal Clean Air Act, 42 U.S.C. §§ 7401-7671q, and it's implementing regulations. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 13)**
- "Cobb" means, for purposes of the Consent Decree, Consumers' B.C. Cobb Generating Plant consisting of two electric utility steam-generating units designated as Unit 4 (160 MW) and Unit 5 (160 MW) and related equipment, located in Muskegon, Muskegon County, Michigan. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 14)**
- "Consent Decree" means Consent Decree ("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014") and its Appendices. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 15)**
- "Consumers" means Consumers Energy Company. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 16)**
- "Consumers System" means the Campbell, Cobb, Karn, Weadock, and Whiting facilities as defined herein. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 17)**
- "Continuously Operate" or "Continuous Operation" means that when a pollution control technology or combustion control is required to be used at a Unit pursuant to the Consent Decree (including, but not limited to, SCR, FGD, DSI, ESP, Baghouse, or Low NOx Combustion System), it shall be operated at all times that the Unit it serves is in operation, except the SCRs on Campbell Units 2 and 3 need not be operated during scheduled maintenance on the applicable Unit's Urea Based Ammonia System and consistent with the technological limitations, manufacturers' specifications, good engineering and maintenance practices (including Campbell Unit 2 and Unit 3 scheduled Urea Based Ammonia System outages), and good air pollution control practices for minimizing emissions (as defined in 40 CFR 60.11(d)), as applicable, for such equipment and the Unit. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 18)**
- "Date of Entry" means the date the Consent Decree was signed by the United States District Court Judge (i.e. November 4, 2014). **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 19)**
- "Day" means calendar day unless otherwise specified in the Consent Decree. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 21)**
- "Dry Sorbent Injection" or "DSI" means a process in which a sorbent is pneumatically injected into the ducting downstream of where the coal is combusted and flue gas is produced, and upstream of the PM Control Device. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 22)**
- "Electrostatic Precipitator" or "ESP" means a device for removing particulate matter from combustion gases by imparting an electric charge to the particles and then attracting them to a metal plate or screen of opposite charge before the combustion gases are exhausted to the atmosphere. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 23)**
- "Emission Rate" for a given pollutant means the number of pounds of that pollutant emitted per million British Thermal Units of heat input (lb/MMBTU), calculated in accordance with each applicable 30, 90 or 365-Day Rolling Average Emission Rate definition. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 24)**
- "Flue Gas Desulfurization System" or "FGD" means a pollution control device that employs flue gas desulfurization technology, including an absorber or absorbers utilizing lime or limestone, or a sodium based material, for the reduction of SO_2 emissions. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 27)**
- "Fossil Fuel" means any hydrocarbon fuel, including coal, petroleum coke, petroleum oil, or natural gas. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 29)**
- "Full Stream Operation" is defined as the design configuration of a control device such that it captures the

entire stream of exhaust gas with no concurrent by-pass. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 30)**

- "Karn," for purposes of the Consent Decree, means Consumers' D.E. Karn Generating Plant consisting of two electric utility steam-generating units designated as Unit 1 (255 MW) and Unit 2 (260 MW) and related equipment, located in Essexville, Bay County, Michigan. Karn does not include the oil-fired electricity generating units designated as Karn Units 3 and 4, also located in Essexville, Bay County, Michigan. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 34)**
- "Karn Units 3 and 4" means Consumers' oil-fired Units 3 and 4, in Essexville, Bay County, Michigan. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 35)**
- "KW" means Kilowatt or one thousand watts net. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 36)**
- "lb/MMBTU" means one pound per million British Thermal Units. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 37)**
- "Low NOx Combustion System" means burners and associated combustion air control equipment, including Over Fire Air if specified, which control mixing characteristics of Fossil Fuel and oxygen, thus restraining the formation of NO_x during combustion of fuel in the boiler. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 38)**
- "Malfunction" means a failure to operate in a normal or usual manner by any air pollution control equipment, process equipment, or a process, which is sudden, infrequent, and not reasonably preventable. Failures that are caused in part by poor maintenance or careless operation are not malfunctions. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 39)**
- "Michigan SIP" means the Michigan State Implementation Plan, and any amendments thereto, as approved by USEPA pursuant to Section 110 of the Act, 42 U.S.C. § 7410. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 40)**
- "MW" means a megawatt or one million watts net. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 41)**
- "NO_x" means oxides of nitrogen, measured in accordance with the provisions of the Consent Decree. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 45)**
- "NO_x Allowance" means an authorization to emit a specified amount of NO_x that is allocated or issued under an emissions trading or marketable permit program of any kind established under the Clean Air Act or the Michigan SIP; provided, however, that with respect to any such program that first applies to emissions occurring after December 31, 2011, a "NO_x Allowance" shall include an allowance created and allocated to a Consumers System Unit under such program only for control periods starting on or after November 4, 2018. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 46)**
- "Operating Day" means any calendar day on which a Unit fires Fossil Fuel. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 49)**
- "Over Fire Air" or "OFA" mean an in-furnace staged combustion control to reduce NO_x emissions. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 51)**
- "PM" means total filterable particulate matter, measured in accordance with the provisions of the Consent Decree. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 53)**
- "PM Continuous Emission Monitoring System" or "PM CEMS" means, for obligations involving the monitoring of PM emissions under the Consent Decree, the equipment that samples, analyzes, measures, and provides, by readings taken at frequent intervals, an electronic and/or paper record of PM emissions. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 54)**
- "PM Control Device" means any device, including an ESP or Baghouse, which reduces emissions of PM. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 55)**
- "PM Emission Rate" means the number of pounds of PM emitted per million BTU of heat input (lb/MMBTU). **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 56)**

- "Selective Catalytic Reduction" or "SCR" means an air pollution control device for reducing NO_x emissions in which ammonia ("NH_3") is added to the flue gas and then passed through layers of a catalyst material. The ammonia and NO_x in the flue gas stream react on the surface of the catalyst, forming nitrogen ("N_2") and water vapor. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 61)**
- "SO_2" means sulfur dioxide, measured in accordance with the provisions of the Consent Decree. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 62)**
- "SO_2 Allowance" means an authorization to emit a specified amount of SO_2 that is allocated or issued under an emissions trading or marketable permit program of any kind established under the Clean Air Act or the Michigan SIP; provided, however, that with respect to any such program that first applies to emissions occurring after December 31, 2011, an "SO_2 Allowance" shall include an allowance created and allocated to a Consumers System Unit under such program only for control periods starting on or after November 4, 2018. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 63)**
- "State" means the State of Michigan. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 64)**
- "State Implementation Plan" or "SIP" means regulations and other materials promulgated by a state for purposes of meeting the requirements of the Act that have been approved by USEPA pursuant to Section IIO of the Act, 42 U.S.C. § 74IO. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 65)**
- "Surrender" or "Surrender of Allowances" means, for purposes of SO_2 or NO_x allowances, permanently surrendering allowances from the accounts administered by USEPA and Michigan for all Units in the Consumers System, so that such allowances can never be used thereafter to meet any compliance requirements under the Act, a SIP, or the Consent Decree. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 66)**
- "System-Wide Annual NO_x Tonnage Limitation" means the limitations, as specified in the Consent Decree, on the number of tons of NO_x that may be emitted from Campbell, Cobb, Kam, Weadock, and Whiting, collectively, during the relevant calendar year (i.e., January 1 through December 31), and shall include all emissions of NO_x during all periods of operations, including startup, shutdown, and malfunction. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 67)**
- "System-Wide Annual SO_2 Tonnage Limitation" means the limitations, as specified in the Consent Decree, on the number of tons of SO_2 that may be emitted from Campbell, Cobb, Kam, Weadock, and Whiting, collectively, during the relevant calendar year (i.e., January 1 through December 31), and shall include all emissions of SO_2 during all periods of operations, including startup, shutdown, and malfunction. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 68)**
- "Title V Permit" means the permit required of Consumers' major sources pursuant to Subchapter V of the Act, 42 U.S.C. §§ 7661-7661e. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 69)**
- "Unit" means collectively, the coal pulverizer, stationary equipment that feeds coal to the boiler, the boiler that produces steam for the steam turbine, the steam turbine, the generator, the equipment necessary to operate the generator, steam turbine, and boiler, and all ancillary equipment, including pollution control equipment and systems necessary for production of electricity. An electric steam generating station may comprise one or more Units. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 70)**
- "Urea Based Ammonia System" or "UBAS" means a type of ammonia feed system for SCRs where solid urea pellets are stored in a silo. Upon use,the solid urea is heated to liquid, thermally decomposed to ammonia, and injected into the SCR as the reagent for the NO_x reduction reaction. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 71)**
- "Weadock" means, for purposes of the Consent Decree, Consumers' J.C. Weadock Generating Plant consisting of two electric utility steam-generating Units designated as Unit 7 (155 MW) and Unit 8 (155 MW) and related equipment, located in Essexville, Bay County, Michigan. **("U.S. v Consumers Energy**

Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 72)

- "Whiting" means, for purposes of the Consent Decree, Consumers' Whiting Generation Station consisting of three electric utility steam-generating Units designated as Unit 1 (102 MW), Unit 2 (102 MW), and Unit 3 (124 MW) and related equipment, located in Luna Pier, Monroe County, Michigan. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 73)**

Appendix 2. Schedule of Compliance

The permittee certified in the ROP application that this stationary source is in compliance with all applicable requirements and the permittee shall continue to comply with all terms and conditions of this ROP. A Schedule of Compliance is not required. **(R 336.1213(4)(a), R 336.1119(a)(ii))**

Appendix 3. Monitoring Requirements

Appendix 3-A. Continuous Opacity Monitoring Systems

(This section applies to each boiler.)

The Continuous Opacity Monitoring System (COMS) performance specifications defined in 40 CFR Part 60, Appendix B, are adopted.

Cycling time for opacity: complete a minimum of one cycle of sampling/analysis for each successive 10-second period and one cycle of data recording for each successive 6-minute period. **(R 336.2152)**

Zero and Drift: The COMS must be subject to the manufacturer's zero and span check at least once daily. **(R 336.2153)**

Location: The location of the COMS or the monitoring devices must be such that representative measurement of emissions or process parameters are obtained. **(R 336.2155)**

Alternative Systems: AQD may approve the use of an alternative monitoring system if one is available that meets COMS objectives and if, because of physical limitations or other reasons, COMS cannot be installed or give accurate measurements. **(R 336.2159)**

Monitoring and reporting requirements shall not apply during any period of monitoring system malfunction if it can be demonstrated to the satisfaction of AQD that: the cause of the malfunction could not have been avoided by any reasonable action and necessary repairs are being made as expeditiously as practicable. **(R 336.2190)**

Appendix 3-B. Continuous Emissions Monitoring System (Title IV; Gas Flow, SO2 , CO2, NOx)

(This section applies to each boiler.)

The CEMS performance specifications defined in 40 CFR Part 75, Appendix B, are adopted.

Methods of measurement, frequency of measurement and recordkeeping methods for CEMS required under 40 CFR 75 are outlined in the most recent version of the Acid Rain Program - J. H. Campbell Plant Monitoring Plan, originally dated July 19, 1993.

Data Reporting: the AQD may approve alternative data reporting or reduction procedures if it can be demonstrated that such procedures are at least as accurate as the procedures identified in R 336.2175.

Appendix 3-C. Fuel Oil Sulfur Monitoring

Maintain a complete record of fuel oil specifications and/or a fuel analysis for each delivery, or storage tank, of fuel oil. These records may include purchase records for ASTM specification fuel oil, specifications or analyses provided by the vendor at the time of delivery, analytical results from laboratory testing, or any other records adequate to demonstrate compliance with the percent sulfur limit in fuel oil.

Appendix 3-D. Continuous Emission Monitoring Systems (SO2/CO2)

(This section applies to Units 1 and 2.)

The Continuous Emissions Monitoring Systems (CEMS) performance specifications defined in 40 CFR Part 75, Appendix B, are adopted. The Certified SO_2 and CO_2 monitors will be used to determine sulfur dioxide emissions. The data reduction procedures defined in R 336.2175 will be used to determine SO_2 lbs/MMBTU. On the last day of each calendar month, the CEMS data recording system will generate and record an "operating monthly average" as the average of the previous 31 operating days.

Appendix 3-E. PM CEMS

This Appendix is federally enforceable and was established pursuant to Rule 201(1)(a). This Appendix was originally established in the consent decree settling, "U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" and also pursuant Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, and will remain in effect after termination of the consent decree. Definitions specific to this Appendix may be found in Appendix 1-B: Definitions. **(Act 451, Section 324.5503(b))**

- Consumers shall install, correlate, maintain, and operate a PM CEMS on Campbell Unit 3 as specified below. The PM CEMS shall comprise a continuous particle mass monitor measuring particulate matter concentration, directly or indirectly, on an hourly average basis and a diluent monitor used to convert the concentration to units expressed in lb/MMBTU. The PM CEMS installed must be appropriate for the anticipated stack conditions and capable of measuring PM concentrations on an hourly average basis. Consumers shall maintain, in an electronic database, the hourly average emission values of the PM CEMS in lb/MMBTU. Except for periods of monitor malfunction, maintenance, calibration, or repair, Consumers shall continuously operate the PM CEMS at all times when the Unit it serves is operating. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 159)**
- In developing both the plan for installation and correlation of the PM CEMS and the QA/QC protocol, Consumers shall use the criteria set forth in 40 CFR Part 60, Appendix B, Performance Specification 11, and Appendix F, Procedure 2. Following USEPA's approval of the plan described in Paragraph 160 of the Consent Decree and the QA/QC protocol described in Paragraph 161 of the Consent Decree, Consumers shall thereafter operate the PM CEMS in accordance with the approved plan and QA/QC protocol. Notwithstanding any other provision of the Consent Decree, exceedances of the PM Emission Rate that occur as a result of de-optimizing emission controls and/or spiking the exhaust gas with excess particulate required to achieve the high level PM test runs during the correlation testing shall not be a violation of the requirements of the Consent Decree (or credible evidence thereof); provided, however, that Consumers shall make best efforts to keep the high level PM test runs during such correlation testing below the applicable PM Emission Rate. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 162)**
- Consumers shall, correlate, maintain, and commence Continuous Operation of the PM CEMS approved by EGLE at Campbell Unit 3, conduct performance specification tests on the PM CEMS, and demonstrate compliance with the PM CEMS installation and correlation plans submitted to and approved by EGLE. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 163)**
- Except as approved pursuant to Paragraph 157 of the Consent Decree, stack testing shall be used to determine compliance with the PM Emission Rates established by the Consent Decree. Data from PM

CEMS shall be used, at a minimum, to provide information to operators on PM emissions rate trends on a continuous basis. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 164)**

- The data recorded by the PM CEMS shall be expressed in lb/MMBTU on a rolling average 3-hour basis to identify any PM emission rates in excess of the applicable PM Emission Rate and shall be available in electronic format. **(U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 163)**

Appendix 3-F. Optimization of Baghouses

This Appendix is federally enforceable and was established pursuant to Rule 201(1)(a). This Appendix was originally established in the consent decree settling, "U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" and also pursuant Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, and will remain in effect after termination of the consent decree. Definitions specific to this Appendix may be found in Appendix 1-B: Definitions. **(Act 451, Section 324.5503(b))**

Consumers shall:

a) At a minimum, to the extent practicable: (i) operate each compartment of the Baghouse as designed for Full Stream Operation for each Unit, where applicable (regardless of whether those actions are needed to comply with opacity limits); (ii) maintain and replace bags on each Baghouse as needed to maximize collection efficiency, where applicable; and
b) During the next planned Unit outage (or unplanned outage of sufficient length), optimize the PM controls on that Unit by inspecting for and repairing any failed Baghouse compartment.

The above requirements are found in **"U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 141.**

Appendix 4. Recordkeeping

Specific recordkeeping requirement formats and procedures are detailed in Part A or the appropriate Source-Wide, Emission Unit and/or Flexible Group Special Conditions. Therefore, this appendix is not applicable.

Appendix 5. Testing Procedures

This Appendix is federally enforceable and was established pursuant to Rule 201(1)(a). This Appendix was originally established in the consent decree settling, "U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" and also pursuant Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, and will remain in effect after termination of the consent decree. Definitions specific to this Appendix may be found in Appendix 1-B: Definitions. **(Act 451, Section 324.5503(b))**

Specific testing requirement plans, procedures and averaging times are detailed in the appropriate Requirement Tables. Moreover, the permittee shall use the following approved test plans, procedures and averaging times to measure the pollutant emissions for the applicable requirements referenced in Table EUBOILER3 (see below). Alternative test plans, procedures, or averaging must be approved by the AQD District Supervisor.

Test Methods and Procedures for Boiler #3

In conducting the performance test as required in 40 CFR 60.8, the owner or operator shall use the reference methods, procedures and test methods in 40 CFR Part 60, Appendix A or other methods and procedures specified in Section 60.46(d), except as provided in Section 60.8(b).

1. Particulate Matter: Method 17 at a facility without wet flue gas desulfurization system and Method 5B shall be used after flue gas desulfurization system. Method 5 and MATS method 5 shall also be used.

2. Opacity: Method 9.

3. SO_2: Method 6C shall be in the same sample site selected for particulate sample. The emission rate correction factor, integrated sampling and analysis procedure of Method 3A shall be used to determine the O_2 or CO_2 concentration, and shall be taken simultaneously and in the same point as the SO_2 sample.

2. NO_x: Method 7E shall be in the same sample site selected for particulate sample. The emission rate correction factor, integrated sampling and analysis procedure of Method 3A shall be used to determine the O_2 or CO_2 concentration, and shall be taken simultaneously and in the same point as the NO_x sample.

PM Emissions Testing and Monitoring Requirements

- Annually unless a Unit is Retired or Refueled to Natural Gas, Consumers shall conduct a stack test for PM pursuant to Paragraph 154 of the Consent Decree. The annual performance test requirement imposed on Consumers by this paragraph may be satisfied by stack tests conducted by Consumers as may be required by other conditions in its ROP for any year that such stack tests are required. Consumers may perform testing every other year, rather than every year, provided that two of the most recently completed test results from tests conducted in accordance with the methods and procedures specified above demonstrate that the PM emissions are equal to or less than 0.010 lb/MMBTU. Consumers shall perform testing every year, rather than every other year, beginning in the year immediately following any test result demonstrating that the PM emissions are greater than 0.010 lb/MMBTU.. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 153)**

- To determine compliance with the PM Emission Rate established in Subsections VI.B (Unit-Specific PM Requirements at Campbell Units 1 and 2), Consumers shall use the applicable reference methods and procedures (filterable portion only) specified in its ROP and the Michigan SIP for Campbell Units 1 and 2. Each test shall consist of three separate runs performed under representative operating conditions not including periods of startup, shutdown, or malfunction. The sampling time for each run associated with a Unit controlled by a Baghouse shall be at least 120 minutes and the volume of each run shall be at least 1.70 dry standard cubic meters (60 dry standard cubic feet). Consumers shall calculate the PM Emission Rate from the stack test results in accordance with 40 CFR 60.8(f). The results of each PM stack test shall be submitted to EGLE within 60 Days of completion of each test. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 154)**

- As an alternative to the PM testing required in this Appendix (PM Emissions Testing and Monitoring Requirements; beginning at paragraph 153) of the Consent Decree, following the installation and operation of PM CEMS as required by Appendix 3-E (PM CEMS), Consumers, at its sole discretion, may seek USEPA approval pursuant to Section XIII (Review and Approval of Submittals; beginning at paragraph 193) of the Consent Decree to forego stack testing and instead demonstrate continuous compliance with an applicable filterable PM Emission Rate by using the PM CEMS data on a 3-hour rolling average basis. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 157)**

  Note: JHC EUBOILER3 was approved by USEPA to use the PM CEMS alternative to testing per letter dated January 20, 2020 and mailed on February 3, 2020 this PM CEMS approval letter is available upon request.

Appendix 6. Permits to Install

The following table lists any PTIs issued or ROP revision applications received since the effective date of the previously issued ROP No. MI-ROP-B2835-2013. Those ROP revision applications that are being issued concurrently with this ROP renewal are identified by an asterisk (*). Those revision applications not listed with an asterisk were processed prior to this renewal.

Source-Wide PTI No MI-PTI-B2835-2013 is being reissued as Source-Wide PTI No. MI-PTI-B2835-2020b.

Permit to Install Number	ROP Revision Application Number	Description of Equipment or Change	Corresponding Emission Unit(s) or Flexible Group(s)
142-12	201500412	PTI No. 141-12 incorporated EUCATDIESEL12.	EUCATDIESEL12
18-15	201500412	Incorporated USEPA Consent Decree conditions and to bridge the conditions with PTI No. 39-15. It also incorporated updates to control equipment that had been installed.	EUBYPRODUCT EUACIU123 EUDSI_U12 UESDA_U3
39-15	201500061	Incorporated Conditions of the USEPA Consent Decree that states: "The following must be included in the permit: a schedule for all unit-specific, plant-specific, and system-specific performance, operational, maintenance, and control technology requirements established by this Consent Decree including, but not limited to, any (a) 30-Day, 90-Day and 365-Day Rolling Average Emission Rates, (b) System-Wide Annual NOx and SO2 Tonnage Limitations, (c) the requirements pertaining to the Surrender of NOx and SO2 Allowances, (d) PM Emission Rate and annual stack test requirements, and (e) PM CEMS monitoring requirements."	EUBOILER1 EUBOILER2 EUBOILER3 Appendices 1, 3, 5, 7, and 10
18-15A	201800102*	Ash and byproduct handling system that transports ash and byproduct from the plant to the disposal silos. Unit 3 System: • 2 Transfer tanks each with a built in filter separator • 5 Vacuum Exhausters – exhaust to the Unit 3 PJFF Inlet Unit 1 and 2 System: • 2 Transfer tanks each with a built in filter separator • 3 Vacuum Exhausters – normally discharge to the Unit 1 PJFF inlet except for times when the Unit 1 PJFF is unavailable Common: • 3 Disposal Silos (A, B & C) • Truck loading	EUBYPRODUCT

The following table lists the ROP amendments or modifications issued after the effective date of ROP No. MI-ROP-B2835-2020.

Permit to Install Number	ROP Revision Application Number - Issuance Date	Description of Equipment or Change	Corresponding Emission Unit(s) or Flexible Group(s)
50-20	202000099 / September 3, 2020	Incorporate PTI 50-20 into the ROP, which was to correct emission limits for the water pump EUWPDIESEL. The change was due to an incorrect emission limit cited from 40 CFR Part 60 Subpart IIII in the previous permit but the correct emission limit was	EUWPDIESEL EUTRNCNTRDIESEL FGNEWCIRICE

Permit to Install Number	ROP Revision Application Number - Issuance Date	Description of Equipment or Change	Corresponding Emission Unit(s) or Flexible Group(s)
		used in the permit review. This correction was considered administrative and not subject to New Source Review during permitting. Additionally, the company identified two other errors in their ROP. The errors were related to the other engine in the flexible group, EUTRNCNTRDIESEL, which was not originally permitted through a PTI but was grouped with the fire pump engine EUWPDIESEL in the ROP. These errors were related to what federal subpart was/was not applicable to that engine. It appears that EUTRNCTRDIESEL was accidently included in FGNEWCIRICE Special Condition III. 1 at same time that EUTRNCNTRDIESEL was accidently excluded from FGNEWCIRICE Special Condition III. 2. These emission units were corrected in FGNEWCIRICE. PTI 50-20 was not required to go through the public participation process.	
39-15A	202100070 / July 1, 2021	Incorporate PTI No. 39-15A into the ROP, which was for administrative updates to permitted conditions to reflect the termination of a Consent Decree between the USEPA and Consumers Energy. PTI No. 39-15A previously allowed Boiler #1 and #2 to have individual stacks or meet certain requirements if using a shared stack. The option and associated requirements for having a shared stack are also removed during this minor modification. It should be noted that PTI No. 39-15A had some errors that were corrected during this Modification. During the last ROP Renewal, the Company requested that the conditions common to boilers 1 and 2 housed in FGBOILER12 be separated and put into their respective boiler emission unit. This was done with the exception of all of the CAM requirements being kept in FGBOILERS12. Additionally, a separate FGMATSU12 table was created to house all of the common MATS requirements for the boilers. All requirements for EDTA and citrosolve have been removed as the units no longer burn any waste. The Conditions related to FGBOILER12 were accidentally added back into PTI No. 39-15A as well in	EUBOILER1, EUBOILER2 EUBOILER3, EUBYPRODUCT, FGBOILER12 Appendices 1-B, 3, 5

Permit to Install Number	ROP Revision Application Number - Issuance Date	Description of Equipment or Change	Corresponding Emission Unit(s) or Flexible Group(s)
		the associated Emission Units, so the Conditions were duplicative. AQD removed the duplicative and obsolete Conditions that were present in PTI No. 39-15A during this minor modification. During the Company's review, the Company requested to clarify in Appendix 3-E. PM CEMS, PM specification tests will be sent in the future to EGLE. This change would also allow updates to the installation and correlation plans to be submitted to and approved by EGLE.	

Appendix 7. Emission Calculations

Determination of Unit Specific NOx or SO_2 Mass Emissions for Those Units Where 40 CFR Part 75 NOx or SO_2 Mass Emissions Are Measured at a Common Stack

This Appendix is federally enforceable and was established pursuant to Rule 201(1)(a). This Appendix was originally established in the consent decree settling, "U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" and also pursuant Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, and will remain in effect after termination of the consent decree. Definitions specific to this Appendix may be found in Appendix 1-B: Definitions. **(Act 451, Section 324.5503(b))**

For J.H. Campbell Units 1 and 2, NO_x mass emission rates are monitored at the associated common stacks via the use of NO_x concentration and flow CEMS. In addition, each of the preceding individual units are equipped with duct-level NO_x and diluent (i.e., CO_2) concentration CEMS to permit the determination of unit specific NO_x lb/MMBTU emission rates. The following procedures shall be used to calculate unit level NO_x mass emission rates for purposes of conducting rolling average NO_x lb/MMBTU calculations. If Campbell Units EUBOILER1 and EUBOILER2 elect to install unit level SO_2 CEMS only in lieu of installing both unit level SO_2 CEMS and Flow CEMS, the same procedure shall be followed for calculating unit level SO_2 mass emissions except that the value of K in Paragraph c. shall equal 1.660 x 10-7 (lb/scf)/ppm.

a. From 40 CFR Part 75, Appendix F, equation F-15 (already calculated and reported under Part 75), common stack heat input shall be calculated as follows:

$$HI = Q_w \times \frac{1}{F_c} \times \frac{\%CO_{2w}}{100}$$

Where,

HI = *Common stack hourly heat input rate during unit operation, MMBTU/hr*
Q_w = *Hourly average volumetric flow rate during unit operation, wet basis, scfh*
F_c = *Carbon-based F-factor, listed in 40 CFR 75, Appendix A, Section 3.3.5 for each fuel, scf/MMBTU*
$\%\ CO_{2w}$ = *Hourly concentration of CO_2 during unit operation, percent CO_2*

b. From 40 CFR Part 75, Appendix F, Equation F-21a (already calculated and reported under Part 75), individual unit heat input shall be calculated as follows:

$$HI_i = HI_{CS} \times \frac{T_{CS}}{t_i} \times \left[\frac{MW_i \times t_i}{\sum_{i=1}^{n} MW_i \times t_i}\right]$$

Where,

HI_i = *Heat input rate for a unit, MMBTU/hr*
HI_{CS} = *Heat input rate at the common stack, MMBTU/hr*
MW_i = *Gross electrical output, MWe*
t_c = *Unit operating time, hour or fraction of an hour*
t_{CS} = *Common stack or common pipe operating time, hour or fraction of an hour*
n = *Total number of units using the common stack*
i = *Designation of a particular unit*

c. From 40 CFR Part 75, Appendix F, Equation F-6 (already calculated and reported under Part 75), individual unit NO_x lb/MMBTU emission rates shall be calculated as follows:

$$E = K \times C_h \times F_c \times \frac{100}{\%CO_2}$$

Where,

E = *Pollutant emission rate during unit operation, lb/MMBTU*
K = *$1.194x10^{-7}$ for NO_x (lb/scj)/ppm*
C_h = *Hourly average NO_x concentration during unit operation, ppm*
F_c = *Carbon-based F-factor, listed in 40 CFR 75, Appendix A, Section 3.3.5 for each fuel, scf/MMBTU*
$\%CO_2$ = *Hourly concentration of CO_2 during unit operation, percent CO_2*

d. To calculate unit level NO_x mass emissions in each operating hour (not calculated or reported under Part 75), the following calculation shall be performed:

$$\boldsymbol{E_{(NOx)h} = E \times HI_i}$$

Where,

$E_{(NOx)h}$ = *NO_x mass emission rate for hour "h", in lbs/hr*
E = *Pollutant emission rate during unit operation, lb/MMBTU*
HI_i = *Heat input rate for a unit, MMBTU/hr*

$$\boldsymbol{M_{(NOx)h} = E_{(NOx)h} \times t_h}$$

Where,

$M_{(NOx)h}$ = *NO_x mass emissions for hour "h", lbs*
$E_{(NOx)h}$ = *NO_x mass emission rate for hour "h", in lbs/hr*
t_h = *Unit operating time for hour "h", in hours or fraction of an hour*

e. The preceding unit specific NO_x mass emissions data shall then be used in accordance with Paragraphs 5, 6, and 7 of the CD (refer to Appendix 1-B) to calculate 30-day rolling, 90-day rolling and 365-day rolling NO_x lb/MMBTU emission rates, respectively (as applicable).

Appendix 8. Reporting

A. Annual, Semiannual, and Deviation Certification Reporting

The permittee shall use the EGLE, AQD, Report Certification form (EQP 5736) and EGLE, AQD, Deviation Report form (EQP 5737) for the annual, semiannual and deviation certification reporting referenced in the Reporting Section of the Source-Wide, Emission Unit and/or Flexible Group Special Conditions. Alternative formats must meet the provisions of Rule 213(4)(c) and Rule 213(3)(c)(i), respectively, and be approved by the AQD District Supervisor.

B. Other Reporting

The permittee shall use the following approved formats and procedures for the reporting requirements referenced in. EUBOILER3, EUCOALHAND, FGMATS_U12, and FGMATS_U3. For other reporting requirements, specific reporting requirement formats and procedures are detailed in Part A or the appropriate Requirement Tables. Alternative formats must be approved by the AQD District Supervisor.

Standards of Performance for New Sources (NSPS) reporting requirements for EUBOILER3 and EUCOALHAND include, but are not necessarily limited to, the following:

Notification requirements per Section 60.7 of 40 CFR Part 60, Subpart A;

60.7(a)(1)	Notification of the date of construction or reconstruction of an affected facility is commenced, postmarked no later than 30 days after such date.
60.7(a)(2)	Notification of the date or anticipated date of the initial startup of an affected facility, postmarked not more than 60 nor less than 30 days prior to such date.
60.7(a)(3)	Notification of the actual date of initial startup of an affected facility, postmarked within 15 days after such date.
60.7(a)(4)	Notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in Section 60.14(e). This notice shall be postmarked 60 days (or as soon as practicable) before the change is commenced.

Notifications of reconstruction activities per Section 60.15 of 40 CFR, Part 60, Subpart A; and

60.15(d)	If an owner or operator of an existing facility proposes to replace components and the fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable entirely new facility, notification of the proposed replacements, postmarked 60 days (or as soon as practicable) before the construction of the replacements is commenced.

Reporting requirements per 40 CFR Part 60, Subpart D.

Excess emission (EE) reports and monitoring system performance (MSP) reports shall be submitted every quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. Each EE and MSP report shall include the information required in Section 60.7(c). Periods of excess emission and monitoring system downtime that shall be reported are defined as followed:

1. Opacity: EE are defined as any 6-minute period during which the average opacity of emissions exceeds 20% opacity, except that one 6-minute average per hour of up to 27% need not be reported.

2. SO_2: EE are defined as any 3-hour period during which the average emissions (arithmetic average of 3 contiguous one-hour periods) of SO_2 as measured by a CEMS exceeded the applicable standard under Section 60.43, per Section 60.45(g)(2).

3. NO_x: EE are defined as any 3-hour period during which the average emissions (arithmetic average of 3 contiguous one-hour periods) of NO_x as measured by a CEMS exceeded the applicable standard under Section 60.44, Section 60.45(g)(3).

Appendix 9. Acid Rain Permit

PHASE II ACID RAIN PERMIT
Permit No. MI-AR-1710-2020

Permittee	Consumers Energy – J.H. Campbell Plant
Address	17000 Croswell, West Olive, MI
SRN	B2835
ORIS Code	1710
Issue Date	February 4, 2020
Effective	Issuance date of this facility's Renewable Operating Permit at the facility in accordance with 40 CFR 72.73.
Expiration	This permit shall expire when the facility's Renewable Operating Permit expires, in accordance with 40 CFR 72.73.
ROP No.	MI-ROP-B2835-2020

The Acid Rain Permit Contents

1. A statement of basis prepared by the Air Quality Division (AQD) containing:

   References to statutory and regulatory authorities, and with comments, notes, and justification that apply to the source in general;

2. Terms and conditions including:

   A table of sulfur dioxide allowances to be allocated during the term of the permit, if applicable, authorized by this permit during Phase II. Unless they are subject to Sections 405(g)(2) or (3) of the federal Clean Air Act, new units are not allocated allowances in 40 CFR Part 73 and must obtain allowances by other means (Section 403(e) of the federal Clean Air Act);

   Comments, notes and justifications regarding permit decisions and changes made to the permit application forms during the review process, and any additional requirements; and,

   Any applicable nitrogen oxides compliance plan. Unless they are coal fired utility units regulated pursuant to Sections 404, 405, or 409 of the federal Clean Air Act, new units are not subject to the acid rain nitrogen oxides requirements (40 CFR 76.1(a)).

3. The permit application that this source submitted, as corrected by the AQD. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application.

Statement of Basis

Statutory and Regulatory Authorities.

In accordance with the Natural Resources and Environmental Protection Act, 1994 PA 451 and Titles IV and V of the federal Clean Air Act, the Michigan Department of Environment, Great Lakes, and Energy, Air Quality Division (AQD), issues this permit pursuant to the provisions of R 336.1210 to R 336.1218, and R 336.1299(d).

For further information contact:

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State Office Building, 4th Floor
301 East Louis B. Glick Highway
Jackson, Michigan 49201-1556

Telephone: 517-416-4631
Facsimile: 517-780-7855

There are no comments, notes and/or justification that apply to the source in general for this section.

Terms and Conditions:

Phase II Sulfur Dioxide Allowance Allocation and Nitrogen Oxides Requirements for each affected unit.

		2020	2021	2022	2023	2024
Unit 1	SO_2 allowances	8113	8113	8113	8113	8113
	NOx Emission Limits	Pursuant to 40 CFR part 76, the State of Michigan Department of Environment, Great Lakes, and Energy, Air Quality Division approves a NOx standard emissions limitation compliance plan for unit 1. The NOx compliance plan is effective beginning 2017. Under the NOx compliance plan, this unit's annual average NOx emissions rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under 40 CFR 76.7(a)(2), of **0.45 lb/MMBTU** for Phase I tangentially fired boilers. In addition to the described NOx compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NOx compliance plan and requirements covering excess emissions.				

		2020	2021	2022	2023	2024
Unit 2	SO_2 allowances	9702	9702	9702	9702	9702
	NOx Emission Limits	Pursuant to 40 CFR part 76, the State of Michigan Department of Environment, Great Lakes, and Energy, Air Quality Division approves a NOx standard emissions limitation compliance plan for unit 2. The NOx compliance plan is effective beginning 2017. Under the NOx compliance plan, this unit's annual average NOx emissions rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under 40 CFR 76.7(a)(2), of **0.68 lb/MMBTU** for cell burner boilers. In addition to the described NOx compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NOx compliance plan and requirements covering excess emissions.				

Terms and Conditions (cont.):

		2020	2021	2022	2023	2024
Unit 3	SO_2 allowances	27529	27529	27529	27529	27529
	NOx Emission Limits	Pursuant to 40 CFR part 76, the State of Michigan Department of Environment, Great Lakes, and Energy, Air Quality Division approves a NOx standard emissions limitation compliance plan for unit 3. The NOx compliance plan is effective beginning 2017. Under the NOx compliance plan, this unit's annual average NOx emissions rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under 40 CFR 76.7(a)(2), of **0.46 lb/MMBTU** for Phase II dry bottom wall-fired boilers. In addition to the described NOx compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NOx compliance plan and requirements covering excess emissions.				

Comments, notes and justifications regarding permit decisions, and changes made to the permit application forms during the review process:

Permit Application: (attached)

Acid Rain Permit Application submitted February 27, 2018
Acid Rain NOx Compliance Plan submitted July 5, 2017

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2018

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ new ☐ revised ☒ for ARP permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

J.H. Campbell Plant Facility (Source) Name	MI State	1710 Plant Code

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a Unit ID#	b Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
Unit 1	Yes
Unit 2	Yes
Unit 3	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

EPA Form 7610-16 (Revised 12-2016)

J.H. Campbell Plant
Facility (Source) Name (from STEP 1)

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit.
(2) The owners and operators of each affected source and each affected unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
(ii) Have an Acid Rain Permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Nitrogen Oxides Requirements

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

J.H. Campbell Plant
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.

(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:

(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and

(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator or permitting authority:

(i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply;

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

(iv) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR part 72 subpart I and 40 CFR part 75.

Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.

(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.

(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.

(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit.

(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

J.H. Campbell Plant
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Effect on Other Authorities

No provision of the Acid Rain Program, an Acid Rain permit application, an Acid Rain permit, or an exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a source can hold; *provided*, that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

STEP 4
Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

John P. Broschak, Designated Representative Name	
Signature: John P. Broschak	1-24-18 Date

EPA Form 7610-16 (Revised 12-2016)

EPA

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2018

Acid Rain NO_X Compliance Plan

For more information, see instructions and refer to 40 CFR 76.9

Page 1

This submission is: ☐ New ☒ Revised

Page 1 of 1

STEP 1
Indicate plant name, State, and Plant code from the current Certificate of Representation covering the facility.

Plant Name	State	Plant Code
J.H. Campbell	MI	1710

STEP 2

Identify each affected Group 1 and Group 2 boiler using the unit IDs from the current Certificate of Representation covering the facility. Also indicate the boiler type: "CB" for cell burner, "CY" for cyclone, "DBW" for dry bottom wall-fired, "T" for tangentially fired, "V" for vertically fired, and "WB" for wet bottom, and select the compliance option for each unit by making an 'X' in the appropriate row and column.

	ID# 1 Type T	ID# 2 Type CB	ID# 3 Type DBW	ID# Type	ID# Type	ID# Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)						
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)	X					
(c) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)			X			
(d) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)						
(e) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)		X				
(f) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)						
(g) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)						
(h) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)						
(i) NO_2 Averaging Plan (include NO_X Averaging form)						
(j) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)						
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_2 Averaging (check the NO_2 Averaging Plan box and include NO_X Averaging Form))						
(l) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17(a)(2)(i)(C), (a)(2)(ii)(B), or (b)(2)						

EPA Form 7610-28 (Revised 12-2016)

J.H. Campbell
Plant Name (from Step 1)

STEP 3
Identify the first calendar year in which this plan will apply.

January 1, 2017

STEP 4
Read the special provisions and certification, enter the name of the designated representative, sign and date.

Special Provisions

General

This source is subject to the standard requirements in 40 CFR 72.9. These requirements are listed in this source's Acid Rain Permit.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name John P. Broschak

Signature John P. Broschak Date 6/29/17

EPA Form 7610-28 (Revised 12-2016)

Appendix 10: Cross State Air Pollution Rule (CSAPR) Trading Program Title V Requirements

Description of CSAPR Monitoring Provisions

The CSAPR subject units, and the unit-specific monitoring provisions, at this source are identified in the following tables. These units are subject to the requirements for the CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, and CSAPR SO_2 Group 1 Trading Program, which are included below as Sections I, II, and III, respectively.

Each unit will use one of the following as the monitoring methodology for each parameter as provided below and shall comply with the general monitoring, recordkeeping, reporting and other requirements in conditions 1 through 5 below and in paragraph (b) of Sections I, II, and III:

- Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B (for SO_2 monitoring) or 40 CFR Part 75, Subpart H (for NO_X monitoring)
- Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR Part 75, Appendix D
- Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR Part 75, Appendix E
- Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19
- USEPA-approved alternative monitoring system requirements pursuant to 40 CFR Part 75, Subpart E

Unit ID: 1	
Parameter	Monitoring Methodology
SO_2	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B
NO_X	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart H
Heat Input	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B (for SO2 monitoring) or 40 CFR Part 75, Subpart H (for NOX monitoring)

Unit ID: 2	
Parameter	Monitoring Methodology
SO_2	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B
NO_X	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart H
Heat Input	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B (for SO2 monitoring) or 40 CFR Part 75, Subpart H (for NOX monitoring)

Unit ID: 3	
Parameter	Monitoring Methodology
SO_2	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B
NO_X	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart H
Heat Input	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B (for SO2 monitoring) or 40 CFR Part 75, Subpart H (for NOX monitoring)

1. The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (CSAPR NO_X Annual Trading Program), 97.830 through 97.835 (CSAPR NO_X Ozone Season Group 2 Trading Program), and 97.630 through 97.635 (CSAPR SO_2 Group 1 Trading Program). The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable CSAPR trading programs.

2. Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the USEPA's website at https://www.epa.gov/airmarkets/clean-air-markets-monitoring-plans-part-75-sources.

3. Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR Part 75, Subpart E and 40 CFR 75.66 and 97.435 (CSAPR NO_X Annual Trading Program), 97.835 (CSAPR NO_X Ozone Season Group 2 Trading Program), and/or 97.635 (CSAPR SO_2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the USEPA's website at https://www.epa.gov/airmarkets/part-75-petition-responses.

4. Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (CSAPR NO_X Annual Trading Program), 97.830 through 97.834 (CSAPR NO_X Ozone Season Group 2 Trading Program), and/or 97.630 through 97.634 (CSAPR SO_2 Group 1 Trading Program) must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (CSAPR NO_X Annual Trading Program), 97.835 (CSAPR NO_X Ozone Season Group 2 Trading Program), and/or 97.635 (CSAPR SO_2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on the USEPA's website at https://www.epa.gov/airmarkets/part-75-petition-responses.

5. The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (CSAPR NO_X Annual Trading Program), 97.830 through 97.834 (CSAPR NO_X Ozone Season Group 2 Trading Program), and 97.630 through 97.634 (CSAPR SO_2 Group 1 Trading Program), and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add or change this unit's monitoring system description.

SECTION I: CSAPR NO_X Annual Trading Program requirements (40 CFR 97.406)

(a) Designated representative requirements.
The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.413 through 97.418.

(b) Emissions monitoring, reporting, and recordkeeping requirements.
(1) The owners and operators, and the designated representative, of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.430 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.431 (initial monitoring system certification and recertification procedures), 97.432 (monitoring system out-of-control periods), 97.433 (notifications concerning monitoring), 97.434 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.435 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).
(2) The emissions data determined in accordance with 40 CFR 97.430 through 97.435 shall be used to calculate allocations of CSAPR NO_X Annual allowances under 40 CFR 97.411(a)(2) and (b) and 97.412 and to determine compliance with the CSAPR NO_X Annual emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.430 through 97.435 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NO_X emissions requirements.
(1) CSAPR NO_X Annual emissions limitation.
(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall hold, in the source's compliance account, CSAPR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.424(a) in an amount not less than the tons of total NO_X emissions for such control period from all CSAPR NO_X Annual units at the source.

(ii). If total NO_X emissions during a control period in a given year from the CSAPR NO_X Annual units at a CSAPR NO_X Annual source are in excess of the CSAPR NO_X Annual emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A). The owners and operators of the source and each CSAPR NO_X Annual unit at the source shall hold the CSAPR NO_X Annual allowances required for deduction under 40 CFR 97.424(d); and

(B). The owners and operators of the source and each CSAPR NO_X Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart AAAAA and the Clean Air Act.

(2) CSAPR NO_X Annual assurance provisions.

(i). If total NO_X emissions during a control period in a given year from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state and Indian country within the borders of such State exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.425(b), of multiplying— (A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state and Indian country within the borders of such state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and (B) The amount by which total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state and Indian country within the borders of such state for such control period exceed the state assurance level.

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

(iii). Total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the State and Indian country within the borders of such state during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the state NO_X Annual trading budget under 40 CFR 97.410(a) and the state's variability limit under 40 CFR 97.410(b).

(iv). It shall not be a violation of 40 CFR Part 97, Subpart AAAAA or of the Clean Air Act if total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the State and Indian country within the borders of such State during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state and Indian country within the borders of such state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold CSAPR NO_X Annual allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

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

(B). Each CSAPR NO_X Annual allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart AAAAA and the Clean Air Act.

(3) Compliance periods.

(i). A CSAPR NO_X Annual unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(ii). A CSAPR NO_X Annual unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A CSAPR NO_X Annual allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR NO_X Annual allowance that was allocated for such control period or a control period in a prior year.

(ii). A CSAPR NO_X Annual allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a CSAPR NO_X Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR NO_X Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart AAAAA.

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

(i). Such authorization shall only be used in accordance with the CSAPR NO_X Annual Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR Part 97, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR NO_X Annual allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_X Annual allowances in accordance with 40 CFR Part 97, Subpart AAAAA.

(2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.430 through 97.435, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR Part 75, Subparts B and H), an excepted monitoring system (pursuant to 40 CFR Part 75, Appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR Part 75, Subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.406(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.416 for the designated representative for the source and each CSAPR NO_X Annual unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR Part 97, Subpart AAAAA.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NO_X Annual Trading Program.

(2) The designated representative of a CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall make all submissions required under the CSAPR NO_X Annual Trading Program, except as provided in 40 CFR 97.418. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR Parts 70 and 71.

(f) Liability.

(1) Any provision of the CSAPR NO_X Annual Trading Program that applies to a CSAPR NO_X Annual source or the designated representative of a CSAPR NO_X Annual source shall also apply to the owners and operators of such source and of the CSAPR NO_X Annual units at the source.

(2) Any provision of the CSAPR NO_X Annual Trading Program that applies to a CSAPR NO_X Annual unit or the designated representative of a CSAPR NO_X Annual unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

No provision of the CSAPR NO_X Annual Trading Program or exemption under 40 CFR 97.405 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_X Annual source or CSAPR NO_X Annual unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

(h) Effect on units in Indian country.

Notwithstanding the provisions of paragraphs (a) through (g) above, paragraphs (a) through (g) shall be deemed not to impose any requirements on any source or unit, or any owner, operator, or designated representative with regard to any source or unit, in Indian country within the borders of the state.

SECTION II: CSAPR NO_X Ozone Season Group 2 Trading Program Requirements (40 CFR 97.806)

(a) Designated representative requirements.

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.813 through 97.818.

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

(1) The owners and operators, and the designated representative, of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.830 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.831 (initial monitoring system certification and recertification procedures), 97.832 (monitoring system out-of-control periods), 97.833 (notifications concerning monitoring), 97.834 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.835 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.830 through 97.835 shall be used to calculate allocations of CSAPR NO_X Ozone Season Group 2 allowances under 40 CFR 97.811(a)(2) and (b) and 97.812 and to determine compliance with the CSAPR NO_X Ozone Season Group 2 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.830 through 97.835 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NO_X emissions requirements.

(1) CSAPR NO_X Ozone Season Group 2 emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall hold, in the source's compliance account, CSAPR NO_X Ozone Season Group 2 allowances available for deduction for such control period under 40 CFR 97.824(a) in an amount not less than the tons of total NO_X emissions for such control period from all CSAPR NO_X Ozone Season Group 2 units at the source.

(ii). If total NO_X emissions during a control period in a given year from the CSAPR NO_X Ozone Season Group 2 units at a CSAPR NO_X Ozone Season Group 2 source are in excess of the CSAPR NO_X Ozone Season Group 2 emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A). The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall hold the CSAPR NOX Ozone Season Group 2 allowances required for deduction under 40 CFR 97.824(d); and

(B). The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart EEEEE and the Clean Air Act.

(2) CSAPR NO_X Ozone Season Group 2 assurance provisions.

(i). If total NO_X emissions during a control period in a given year from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state and Indian country within the borders of such state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_X Ozone Season Group 2 allowances available for deduction for such control period under 40 CFR 97.825(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.825(b), of multiplying—

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

(B). The amount by which total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state and Indian country within the borders of such state for such control period exceed the state assurance level.

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

(iii). Total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state and Indian country within the borders of such state during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season Group 2 trading budget under 40 CFR 97.810(a) and the state's variability limit under 40 CFR 97.810(b).

(iv). It shall not be a violation of 40 CFR Part 97, Subpart EEEEE or of the Clean Air Act if total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state and Indian country within the borders of such state during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state and Indian country within the borders of such state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold CSAPR NO_X Ozone Season Group 2 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

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

(B). Each CSAPR NO_X Ozone Season Group 2 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart EEEEE and the Clean Air Act.

(3) Compliance periods.

(i). A CSAPR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter.

(ii). A CSAPR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A CSAPR NOX Ozone Season Group 2 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR NO_X Ozone Season Group 2 allowance that was allocated for such control period or a control period in a prior year.

(ii). A CSAPR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a CSAPR NO_X Ozone Season Group 2 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR NO_X Ozone Season Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart EEEEE.

(6) Limited authorization. A CSAPR NO_X Ozone Season Group 2 allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the CSAPR NO_X Ozone Season Group 2 Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR Part 97, Subpart EEEEE, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR NO_X Ozone Season Group 2 allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_X Ozone Season Group 2 allowances in accordance with 40 CFR Part 97, Subpart EEEEE.

(2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.830 through 97.835, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR Part 75, Subparts B and H), an excepted monitoring system (pursuant to 40 CFR Part 75, Appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR Part 75, Subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.806(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.816 for the designated representative for the source and each CSAPR NO_X Ozone Season Group 2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.816 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR Part 97, Subpart EEEEE.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NO_X Ozone Season Group 2 Trading Program.

(2) The designated representative of a CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall make all submissions required under the CSAPR NO_X Ozone Season Group 2 Trading Program, except as provided in 40 CFR 97.818. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR Parts 70 and 71.

(f) Liability.

(1) Any provision of the CSAPR NO_X Ozone Season Group 2 Trading Program that applies to a CSAPR NO_X Ozone Season Group 2 source or the designated representative of a CSAPR NO_X Ozone Season Group 2 source shall also apply to the owners and operators of such source and of the CSAPR NO_X Ozone Season Group 2 units at the source.

(2) Any provision of the CSAPR NO_X Ozone Season Group 2 Trading Program that applies to a CSAPR NO_X Ozone Season Group 2 unit or the designated representative of a CSAPR NO_X Ozone Season Group 2 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

No provision of the CSAPR NO_X Ozone Season Group 2 Trading Program or exemption under 40 CFR 97.805 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR NO_X Ozone Season Group 2 source or CSAPR NO_X Ozone Season Group 2 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

(h) Effect on units in Indian country.

Notwithstanding the provisions of paragraphs (a) through (g) above, paragraphs (a) through (g) shall be deemed not to impose any requirements on any source or unit, or any owner, operator, or designated representative with regard to any source or unit, in Indian country within the borders of the state.

SECTION III: CSAPR SO_2 Group 1 Trading Program requirements (40 CFR 97.606)

(a) Designated representative requirements.

The owners and operators shall comply with the requirement to have a designated representative, and may have an alternate designated representative, in accordance with 40 CFR 97.613 through 97.618.

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

(1) The owners and operators, and the designated representative, of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.630 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.631 (initial monitoring system certification and recertification procedures), 97.632 (monitoring system out-of-control periods), 97.633 (notifications concerning monitoring), 97.634 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.635 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of CSAPR SO_2 Group 1 allowances under 40 CFR 97.611(a)(2) and (b) and 97.612 and to determine compliance with the CSAPR SO_2 Group 1 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) SO_2 emissions requirements.

(1) CSAPR SO_2 Group 1 emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO2 Group 1 unit at the source shall hold, in the source's compliance account, CSAPR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all CSAPR SO_2 Group 1 units at the source.

(ii). If total SO_2 emissions during a control period in a given year from the CSAPR SO_2 Group 1 units at a CSAPR SO_2 Group 1 source are in excess of the CSAPR SO_2 Group 1 emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A). The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall hold the CSAPR SO_2 Group 1 allowances required for deduction under 40 CFR 97.624(d); and

(B). The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation 40 CFR Part 97, Subpart CCCCC and the Clean Air Act.

(2) CSAPR SO_2 Group 1 assurance provisions.

(i). If total SO_2 emissions during a control period in a given year from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state and Indian country within the borders of such state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO_2 emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.625(b), of multiplying—

(A). The quotient of the amount by which the common designated representative's share of such SO_2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state and Indian country within the borders of such state for such control period, by which each common designated representative's share of such SO_2 emissions exceeds the respective common designated representative's assurance level; and

(B). The amount by which total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state and Indian country within the borders of such state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the CSAPR SO_2 Group 1 allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state and Indian country within the borders of such state during a control period in a given year exceed the state assurance level if such total SO_2 emissions exceed the sum, for such control period, of the state SO_2 Group 1 trading budget under 40 CFR 97.610(a) and the state's variability limit under 40 CFR 97.610(b).

(iv). It shall not be a violation of 40 CFR Part 97, Subpart CCCCC or of the Clean Air Act if total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state and Indian country within the borders of such state during a control period exceed the state assurance level or if a common designated representative's share of total SO_2 emissions from the CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state and Indian country within the borders of such state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold CSAPR SO_2 Group 1 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

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

(B). Each CSAPR SO_2 Group 1 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart CCCCC and the Clean Air Act.

(3) Compliance periods.

(i). A CSAPR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(ii). A CSAPR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR SO_2 Group 1 allowance that was allocated for such control period or a control period in a prior year.

(ii). A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a CSAPR SO_2 Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR SO_2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart CCCCC.

(6) Limited authorization. A CSAPR SO_2 Group 1 allowance is a limited authorization to emit one ton of SO_2 during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the CSAPR SO_2 Group 1 Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR Part 97, Subpart CCCCC, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR SO_2 Group 1 allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR SO_2 Group 1 allowances in accordance with 40 CFR Part 97, Subpart CCCCC.

(2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.630 through 97.635, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR Part 75, Subparts B and H), an excepted monitoring system (pursuant to 40 CFR Part 75, Appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR Part 75, Subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.606(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.616 for the designated representative for the source and each CSAPR SO_2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.616 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR Part 97, Subpart CCCCC.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR SO_2 Group 1 Trading Program.

(2) The designated representative of a CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall make all submissions required under the CSAPR SO_2 Group 1 Trading Program, except as provided in 40 CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR Parts 70 and 71.

(f) Liability.

(1) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 source or the designated representative of a CSAPR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the CSAPR SO_2 Group 1 units at the source.

(2) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 unit or the designated representative of a CSAPR SO_2 Group 1 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

No provision of the CSAPR SO_2 Group 1 Trading Program or exemption under 40 CFR 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR SO_2 Group 1 source or CSAPR SO_2 Group 1 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

(h) Effect on units in Indian country.

Notwithstanding the provisions of paragraphs (a) through (g) above, paragraphs (a) through (g) shall be deemed not to impose any requirements on any source or unit, or any owner, operator, or designated representative with regard to any source or unit, in Indian country within the borders of the state.

Appendix 11-A. System Wide Tonnage Limitations

This Appendix is federally enforceable and was established pursuant to Rule 201(1)(a). Appendix 11-A and Appendix 11-B were originally established in the consent decree settling, "U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" and also pursuant Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, and will remain in effect after termination of the consent decree. Definitions specific to this Appendix may be found in Appendix 1-B: Definitions. **(Act 451, Section 324.5503(b))**

System-Wide Annual NOx Tonnage Limitations

The Consumers System, collectively, shall operate so as not to exceed the following System-Wide Annual NO_x Tonnage Limitations:

For the Calendar Year Specified Below:	System-Wide Annual NO_x Tonnage Limitation:
2017 and continuing each calendar year thereafter	6,600

("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 98)

- For purposes of calculating the System-Wide Annual NOx Tonnage Limitations, Consumers shall use CEMS in accordance with the procedures specified in 40 CFR Part 75, which includes the requirements associated with the concepts of bias adjustments and missing data substitution. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 100)**

System-Wide Annual SO_2 Tonnage Limitations

The Consumers System, collectively, shall operate so as not to exceed the following System-Wide Annual SO_2 Tonnage Limitations:

For the Calendar Year Specified Below:	System-Wide Annual SO_2 Tonnage Limitation:
2017 and continuing each calendar year thereafter	10,900

("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 129)

- For purposes of calculating the System-Wide Annual SO_2 Tonnage Limitations, Consumers shall use CEMS in accordance with the procedures specified in 40 CFR Part 75, which includes the requirements associated with the concepts of bias adjustments and missing data substitution. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 131)**

Appendix 11-B. Allowance Provisions

This Appendix is federally enforceable and was established pursuant to Rule 201(1)(a). This Appendix was originally established in the consent decree settling, "U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" and also pursuant Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, and will remain in effect after termination of the consent decree. Definitions specific to this Appendix may be found in Appendix 1-B: Definitions. **(Act 451, Section 324.5503(b))**

Use and Surrender of NOx Allowances

- Consumers shall not use NOx Allowances to comply with any requirement of the Consent Decree, as enumerated in this permit, including by claiming compliance with any emission limitation required by the Consent Decree, as provided in this permit, by using, tendering, or otherwise applying NOx Allowances to offset any excess emissions. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 101)**

- Except as provided by Appendix 11-B: Allowance Provisions, Consumers shall not sell, bank, trade, or transfer any NOx Allowances allocated to the Consumers System Units. Nothing in the Consent Decree shall restrict Consumers' ability to transfer NOx Allowances among its own facility or general accounts. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 102)**

- Beginning with the year 2014 compliance period, and continuing each year thereafter, Consumers shall Surrender all NOx Allowances allocated to the Consumers System for that year's compliance period that Consumers does not need in order to meet its own federal and/or state CAA regulatory requirements for the Consumers System Units. However, NOx Allowances allocated to the Consumers System may be used by Consumers to meet its own federal and/or state CAA regulatory requirements for such Units. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 103)**

- Nothing in Appendix 11-B: Allowance Provisions, shall prevent Consumers from purchasing or otherwise obtaining NOx Allowances from another source for purposes of complying with federal and/or state CAA regulatory requirements to the extent otherwise allowed by law. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 104)**

Super-Compliant NOx Allowances

- Beginning with the year 2014 and continuing in each calendar year thereafter, Consumers may sell, bank, use, trade, or transfer NOx Allowances made available in that year's compliance period solely as a result of:
  a. the installation and operation of any NOx pollution control that is not otherwise required by, or necessary to maintain compliance with, any provision of the Consent Decree as provided in this permit, and is not otherwise required by law;
  b. the use of SCR prior to the date established by the Consent Decree; or
  c. achievement and maintenance of an Emission Rate below a 365-Day Rolling Average Emission Rate for NO_x at the following Units: (i) at Campbell Unit 1: 0.200 lb/MMBTU; (ii) at Campbell Unit 2: 0.070 lb/MMBTU; (iii) at Campbell Unit 3: 0.070 lb/MMBTU;

  provided that Consumers is also in compliance for that calendar year with all emission limitations for NO_x set forth in the Consent Decree as provided in this permit. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014"paragraph 106)**

Method for Surrender of NOx Allowances

- Consumers shall Surrender, or transfer to a non-profit third-party selected by Consumers for Surrender, all NOx Allowances required to be Surrendered pursuant to Appendix 11-B: Allowance Provisions by June 30 of the immediately following calendar year. Such Surrender need not include the specific NOx Allowances that were allocated to Consumers System Units, so long as Consumers Surrenders NO_x Allowances that are from the same year or an earlier year and that are equal to the number required to be Surrendered under the Consent Decree as provided in this permit. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 107)**

- If any NOx Allowances required to be Surrendered under Appendix 11-B: Allowance Provisions are transferred directly to a non-profit third-party, Consumers shall include a description of such transfer in the next report submitted to USEPA pursuant to the Periodic Reporting provisions of the Consent Decree (beginning at paragraph 188 of the Consent Decree). Such report shall: (a) identify the non-profit third-party recipient(s) of the NOx Allowances and list the serial numbers of the transferred NOx Allowances; and (b) include a certification by the third-party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the NOx Allowances and will not use any of the NOx Allowances to meet any obligation imposed by any environmental law. No later than the third periodic report due after the transfer of any NOx Allowances, Consumers shall include a statement that the third-party recipient(s) Surrendered the NOx Allowances for permanent Surrender to USEPA in accordance with the provisions of Appendix 11-B, "Method for Surrender of NOx Allowances," within one year after Consumers transferred the NOx Allowances to them. Consumers shall not have complied with the NOx

Allowance Surrender requirements of Appendix 11-B, "Method for Surrender of NOx Allowances," until all third-party recipient(s) have actually Surrendered the transferred NOx Allowances to USEPA. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 108)**

- For all NOx Allowances required to be Surrendered, Consumers or the third-party recipient(s) (as the case may be) shall first submit a NOx Allowance transfer request to USEPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of such NOx Allowances to the USEPA Enforcement Surrender Account or to any other USEPA account that USEPA may direct in writing. Such NOx Allowance transfer requests may be made in an electronic manner using USEPA's Clean Air Markets Division Business System or similar system provided by USEPA. As part of submitting these transfer requests, Consumers or the third-party recipient(s) shall irrevocably authorize the transfer of these NO_x Allowances and identify – by name of account and any applicable serial or other identification numbers or station names – the source and location of the NOx Allowances being Surrendered. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 109)**

Use and Surrender of SO_2 Allowances

- Consumers shall not use SO_2 Allowances to comply with any requirement of the Consent Decree, as enumerated in this permit, including by claiming compliance with any emission limitation required by the Consent Decree, as enumerated in this permit, by using, tendering, or otherwise applying SO_2 Allowances to offset any excess emissions. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 132)**

- Except as provided in Appendix 11-B: Allowance Provisions, Consumers shall not sell, bank, trade, or transfer any SO_2 Allowances allocated to the Consumers System Units. Nothing in Appendix 11-B: Allowance Provisions, shall restrict Consumers' ability to transfer SO_2 Allowances among its own facility or general accounts. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 133)**

- Beginning with the year 2014 compliance period, and continuing each year thereafter, Consumers shall Surrender all SO_2 Allowances allocated to the Consumers System for that year's compliance period that Consumers does not need in order to meet its own federal and/or state CAA regulatory requirements for the Consumers System Units. However, SO_2 Allowances allocated to the Consumers System Units may be used by Consumers to meet its own federal and/or state CAA regulatory requirements for such Units. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 134)**

- Nothing in Appendix 11-B: Allowance Provisions, shall prevent Consumers from purchasing or otherwise obtaining SO_2 Allowances from another source for purposes of complying with federal and/or state CAA regulatory requirements to the extent otherwise allowed by law. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 135)**

Super-Compliant SO_2 Allowances

- Beginning with the year 2014 and continuing in each calendar year thereafter, Consumers may sell, bank, use, trade, or transfer SO_2 Allowances made available in that year's compliance period solely as a result of:
  a. the installation and operation of any SO_2 pollution control that is not otherwise required by, or necessary to maintain compliance with, any provision of the Consent Decree, and is not otherwise required by law;
  b. the use of FGD or DSI prior to the date established by the Consent Decree; or
  c. achievement and maintenance of an Emission Rate below a 365-Day Rolling Average Emission Rate for SO_2 at the following Units: (i) at Campbell Units 1 and 2: 0.260 lb/MMBTU; (ii) at Campbell Unit 3: 0.060 lb/MMBTU

  provided that Consumers is also in compliance for that calendar year with all emission limitations for SO_2 set forth in the Consent Decree as provided in this permit. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 137)**

Method for Surrender of SO_2 Allowances

- Consumers shall Surrender, or transfer to a non-profit third party selected by Consumers for Surrender, all SO_2 Allowances required to be Surrendered pursuant to Appendix 11-B: Allowance Provisions, by June 30 of the immediately following calendar year. Such Surrender need not include the specific SO_2 Allowances that were allocated to Consumers System Units, so long as Consumers Surrenders SO_2 Allowances that are from the same year or an earlier year and that are equal to the number required to be Surrendered under Appendix 11-B:

Allowance Provisions. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 138)**

- If any SO_2 Allowances required to be Surrendered under Appendix 11-B, "Use and Surrender of SO2 Allowances," are transferred directly to a non-profit third party, Consumers shall include a description of such transfer in the next report submitted to USEPA pursuant to the Periodic Reporting provisions of the Consent Decree (beginning at paragraph 188 of the Consent Decree). Such report shall: (a) identify the non-profit third-party recipient(s) of the SO_2 Allowances and list the serial numbers of the transferred SO_2 Allowances; and (b) include a certification by the non-profit third-party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the allowances and will not use any of the SO_2 Allowances to meet any obligation imposed by any environmental law. No later than the third periodic report due after the transfer of any SO_2 Allowances, Consumers shall include a statement that the non-profit third-party recipient(s) Surrendered the SO_2 Allowances for permanent Surrender to USEPA in accordance with the provisions of the following Paragraph 140 Appendix 11-B, "Method for Surrender of SO2 Allowances," within one year after Consumers transferred the SO_2 Allowances to them. Consumers shall not have complied with the SO_2 Allowance Surrender requirements of this Appendix 11-B, "Method for Surrender of SO2 Allowances," until all third-party recipient(s) have actually Surrendered the transferred SO_2 Allowances to USEPA. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 139)**
- For all SO_2 Allowances required to be Surrendered, Consumers or the third-party recipient(s) (as the case may be) shall first submit an SO_2 Allowance transfer request to USEPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of such SO_2 Allowances to the USEPA Enforcement Surrender Account or to any other USEPA account that USEPA may direct in writing. Such SO_2 Allowance transfer requests may be made in an electronic manner using USEPA's Clean Air Markets Division Business System or similar system provided by USEPA. As part of submitting these transfer requests, Consumers or the third-party recipient(s) shall irrevocably authorize the transfer of these SO_2 Allowances and identify – by name of account and any applicable serial or other identification numbers or station names – the source and location of the SO_2 Allowances being Surrendered. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 140)**

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 70

Konidena Decl.

DECLARATION OF RAO KONIDENA

I, Rao Konidena, declare as follows:

1. I am an electrical engineer and the principal of Rakon Energy LLC, an engineering firm that consults on energy markets such as the Midcontinent Independent System Operator (MISO).

2. I spent 15 years at MISO forecasting resource adequacy and working on policy matters, including in management and in public-facing roles. I have extensive experience on engineering and planning issues associated with distributed energy resources, storage, and transmission planning, advising state commissions, consumer advocates, and clean energy developers nationwide.

3. In my professional opinion, for the reasons discussed below, neither MISO's alerts and operating conditions during June 2025 nor MISO's seasonal capacity market structure provide a factual basis for the Order's findings of a shortage of electric energy and a shortage of facilities for the generation of electricity in portions of the Midwest region of the United States. The MISO alerts and operating conditions cited by the DOE are not evidence of an actual shortage of electric energy because MISO had sufficient tools and authority to keep the lights on and almost certainly would have maintained reliability and kept the lights on absent J.H. Campbell's continued operation. Even at peak demand on June 23, 2025, MISO had a surplus more than ten times greater than the amount of power Campbell was providing. Meanwhile, the seasonal capacity market structure reflects a forward-looking reform to improve the accuracy of crediting generators in non-summer seasons, align obligations with actual seasonal risks, and protect consumers from unnecessary costs.

A. Education and Experience

4. My office is located in Roseville, Minneapolis-St. Paul Metro area, Minnesota. My professional and educational experience is summarized in the curriculum vitae attached to this declaration (Attachment A).

5. I received a Bachelor of Engineering in Electrical and Electronics Engineering from Bangalore University, a Master of Science in Electrical Engineering from the University of Texas at Arlington, and a Master of Business Administration from the University of Minnesota.

6. I have more than two decades of experience in U.S. wholesale electricity markets, distribution system planning, and the integration of distributed energy resources. As Principal of Rakon Energy LLC, I have provided expert testimony before state commissions and FERC on issues involving resource adequacy, transmission planning, distributed energy resources (DERs), and energy storage. My clients have included retail customer aggregators, state attorneys general, generation developers, consumer advocates, and environmental organizations. Through this work, I have analyzed and advised on the implications of utility distribution system plans, distributed energy resource tariffs, interconnection rules, and the evolving seasonal capacity constructs of organized wholesale markets.

7. From 2003 to 2018, I served at MISO in roles ranging from resource forecasting to policy studies. At MISO, I led studies on demand response, energy efficiency, distributed generation potential, and grid-scale storage, as well as independent load forecasting and economic transmission planning. I represented MISO in national and international forums, including the Department of Energy's U.S. DRIVE technical team and the GO-15 group of global grid operators. This combination of independent consulting and ISO experience provides me with a deep understanding of how MISO's market structures, its planning processes, and its operational practices affect reliability, investment, and consumer costs.

B. Purpose of Declaration

8. I am familiar with the U.S. Department of Energy's and Energy Secretary Chris Wright's ("DOE") August 20, 2025 order to MISO and Consumers Energy Company (Order No. 202-25-7) ("Order").

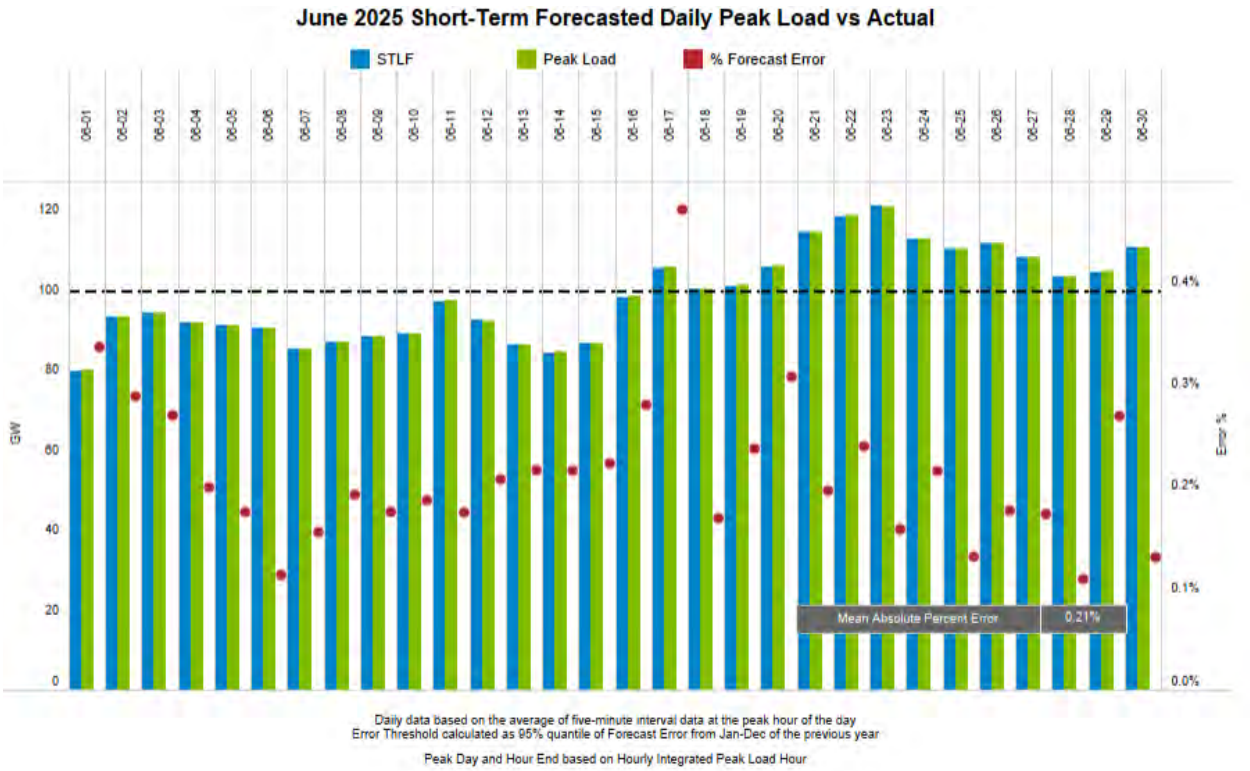
9. I was asked by Earthjustice, Sierra Club, Natural Resources Defense Council, and Environmental Defense Fund to develop an opinion on (A) whether MISO's alerts and operating conditions during June 2025 provide a factual basis for the Order's findings of a shortage of electric energy and a shortage of facilities for the generation of electricity in portions of the Midwest region of the United States; and (B) whether MISO's seasonal capacity market structure provides a factual basis for the Order's findings of a shortage of electric energy and a shortage of facilities for the generation of electricity in portions of the Midwest region of the United States.

C. Whether MISO's Alerts During June 2025 Provide a Factual Basis for the Order's Findings.

10. In my professional opinion, MISO's June 2025 operating conditions do not support DOE's claim of a shortage of electric energy or a shortage of facilities for the generation of electricity. While demand was high, it was not unprecedented compared to prior years. As I show below, demand peaked in June 2025 between 4PM and 5PM eastern on June 23, yet MISO maintained surplus resources more than ten times greater than the amount of power being supplied by Campbell. MISO has a variety of tools available during tight conditions, including flexible demand response resources that can be called on to reduce load and maintain reliability, as well as the authority to manage generators' planned outages, reschedule them if needed, and even direct generators to return from outage. As a result, MISO had sufficient tools and authority to keep the lights on, meaning that high demand, large outages, or DOE's cited alerts were not evidence of an actual shortage of electric energy.

11. During June 2025, electricity demand (i.e., "load") ranged from around 80,000 MW to close to 120,000 MW.[1] Demand reached its highest points between June 20 and June 24, and peaked at 119,300 MW between 4PM to 5PM Eastern on June 23, 2025.[2] Figure 1 shows MISO's short-term forecasts of daily peak load (in blue) and its actual daily peak loads (in green) during June 2025.

Figure 1: MISO's June 2025 Forecasted and Actual Loads



Source: MISO Monthly Operations Report: June 2025 at 25.

12. MISO has successfully dealt with higher levels of demand in recent years. In August 2024, MISO had a peak demand of 122,000 MW.[3] Similarly, as indicated in MISO's chart reproduced below as Figure 2, there were 110 hours with load greater than 100,000 MW in

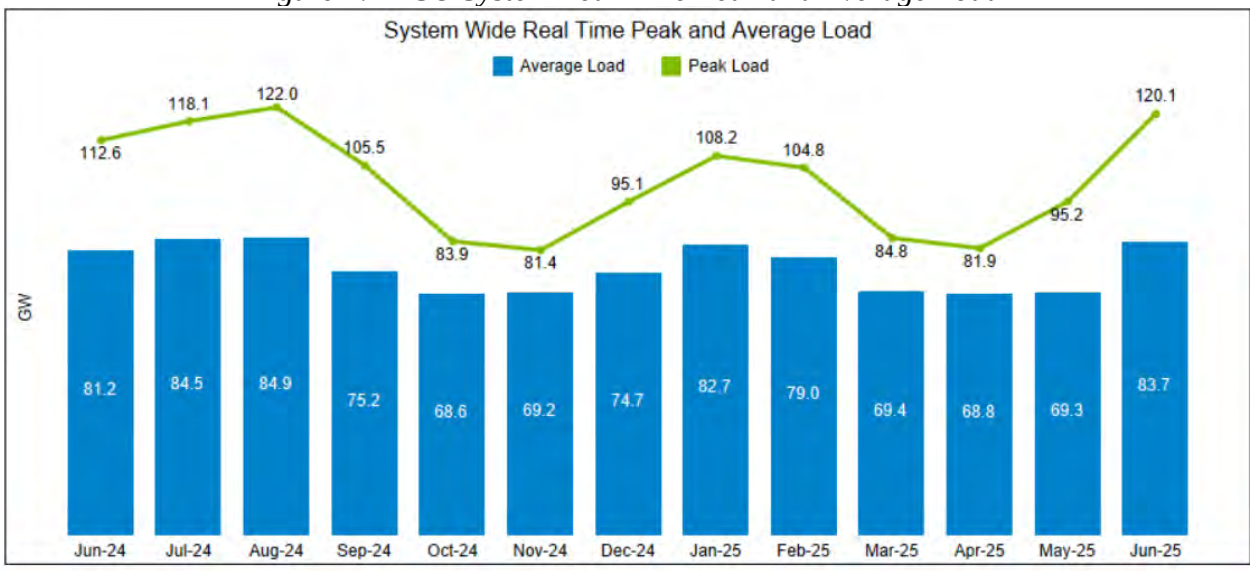
[1] MISO Monthly Operations Report: June 2025 at 25, https://cdn.misoenergy.org/202506%20Market%20and%20Operations%20Report709571.pdf.

[2] "Historical Regional Forecast and Actual Load " Report available at Market Reports, Summary folder. https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=.

[3] MISO Monthly Operations Report: June 2025 at 23.

June 2025 compared to 67 hours in June 2024. This means that June 2025 saw more frequent high-load conditions than the prior year, but those conditions were not unprecedented or beyond what MISO had already managed successfully.

Figure 2: MISO System Real Time Peak and Average Load



System Wide Load Weighted Temperature

	Jun-24	May-25	Jun-25
Average	77°F	63°F	76°F
Maximum	93°F	83°F	100°F
Minimum	55°F	47°F	52°F

Load Weighted Heating & Cooling Degree Days

	Average HDD	Std Dev HDD	Average CDD	Std Dev CDD
Jun-25	0.14	0.94	14.60	8.60
May-25	2.30	3.41	3.73	4.90
Jun-24	0.07	0.56	14.60	7.77

Hours with Load Greater than:

	100 GW	80 GW	60 GW
Jun-25	110	415	709
May-25	0	62	653
Jun-24	67	364	695

Source: MISO Monthly Operations Report: June 2025 at 23.

13. In order to meet demand, MISO runs markets in which generators offer their supply at various prices. MISO receives these offers shortly before the generators are to supply the power. Offered supply therefore provides a reliable and conservative indicator of available resources.

14. MISO had more than enough offered supply to meet the peak load of 119,312 MW. According to MISO data, there was 122,635 MW of offered supply.[4] That means

[4] MISO Real-Time Expanded Report with Published Date of 06/23/25. Available at MISO Market Reports – Real-Time – Real-Time Expanded Report. https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#t=10&p=0&s=MarketReportPublished&sd=desc .

MISO had 3,300 MW of offered supply over and above its peak load. This is shown in the calculations below.

	Offered Supply	122,635 MW
-	Peak Load	119,312 MW
=	Surplus	3,323 MW

15. As a regular practice, MISO ensures it has more generation in reserve than needed to meet demand. It does so to cover contingencies, such as the loss of a transmission line or the loss of its largest generator. Specifically, MISO maintains operating reserves of 2,710 MW.[5] And at the peak load on June 23, MISO had more than enough resources to meet peak demand *and* maintain its operating reserve.

16. Meanwhile, MISO was not limited to only the offered supply of 122,635 MW. MISO had access to emergency headroom totaling 7,328 MW.[6] This headroom is composed of two pieces. MISO had 3,946 MW of committed emergency headroom—resources instantaneously available to MISO operators if needed—and 3,382 MW of uncommitted supply—resources available to MISO with some notice, most of which require less than 4 hours of notice. Emergency headroom (committed and uncommitted) is provided by generators that can meet the grid's needs by surpassing a limit placed for economic purposes.[7] With the emergency headroom, MISO had an even greater surplus available at the time of peak demand. Its available resources totaled 129,963 MW (122,635 MW + 3,946 MW + 3,382 MW =

[5] MISO Multiday Operating Margin Forecast Report with Published Date of 06/22/25. Available at MISO Market Reports – Summary – Multiday Operating Margin Forecast Report. https://www misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#t=10&p=0&s=MarketReportPublished&sd=desc .

[6] Ibid.

[7] See Exhibit 4-11: Dispatch Limits, Page 93 of 319. Energy and Operating Reserve Markets Business Practices Manual, BPM-002-r25, Effective Date: SEP-30-2024.

129,963). That is 7,941 MW greater than the peak load plus operating reserve. The calculations are shown below.

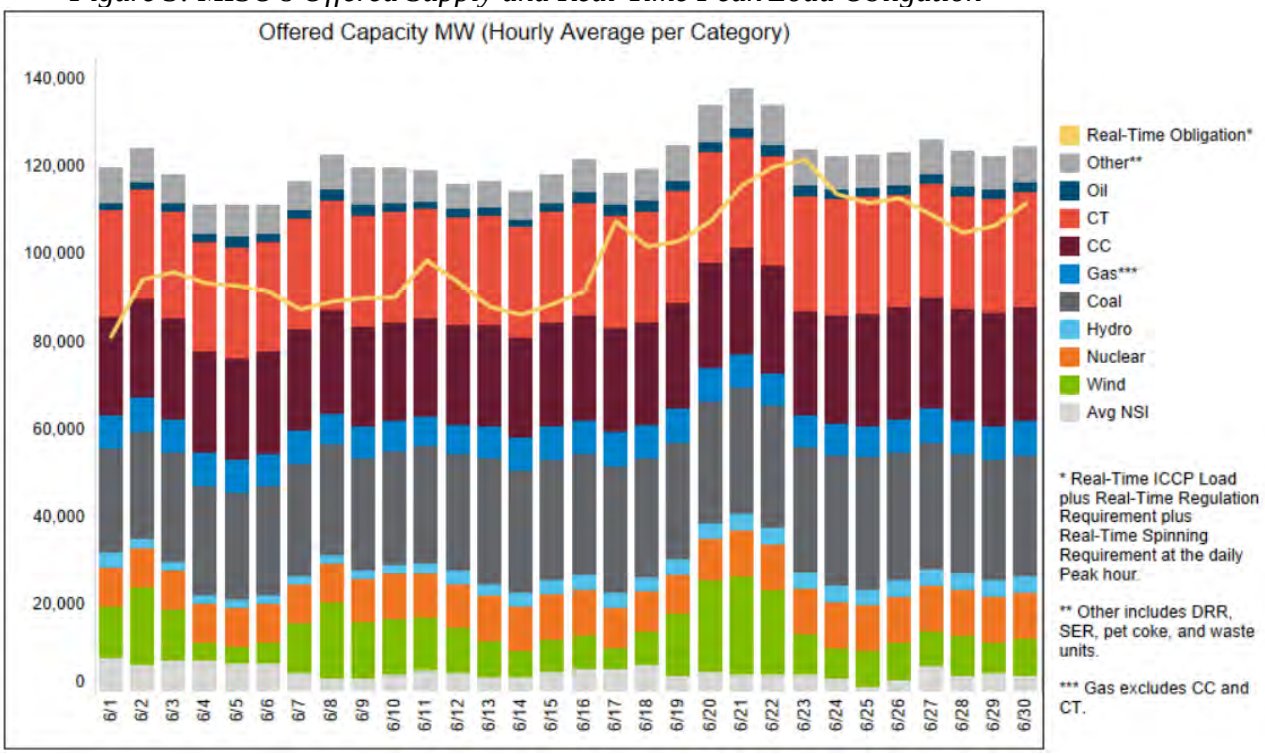
	Offered Supply	122,635 MW
+	Committed Emergency Headroom	3,946 MW
+	Uncommitted Emergency Headroom	3,382 MW
-	Peak Load	119,312 MW
-	Operating Reserve	2,710 MW
=	**Surplus**	**7,941 MW**

17. MISO's surplus of 7,941 MW was over 10 times greater than 760 MW, the amount of power Campbell was providing at the time.[8] (7,941 MW ÷ 760 MW = 10.44). Thus, at peak demand, MISO did not need Campbell to have sufficient supply to maintain reliability for the region.

18. MISO's surplus can also be presented graphically. In Figure 3 below, the vertical bars show the offered supply on each day in June at the hour of that day when demand peaked. The vertical bars *do not* include emergency headroom. On June 23, the offered supply is 122,635 MW. The yellow line shows the peak demand on each day, and does not include operating reserves. Thus, this chart gives a clear visual comparison of how much offered supply was available and whether the system had adequate offered supply to meet demand. As shown in Figure 3, even during the high-load period in June 2025, on every day in the month MISO had more supply available than it needed to meet demand. On June 23, the offered supply was 122,635 MW and peak load was 119,312 MW.

[8] EPA, Clean Air Markets Program Data (CAMPD), June hourly emissions data by unit for the Campbell Plant, available at https://campd.epa.gov/data/custom-data-download. Select "emissions" from the "data type" menu; select "hourly emissions" from the "data subtype" menu; and then select "apply." On the next screen, set 06/01/2025 as the start date and 06/30/2025 as the end date; search for and select "J H Campbell" from the "facility" menu; and then select "apply." Select "preview data."

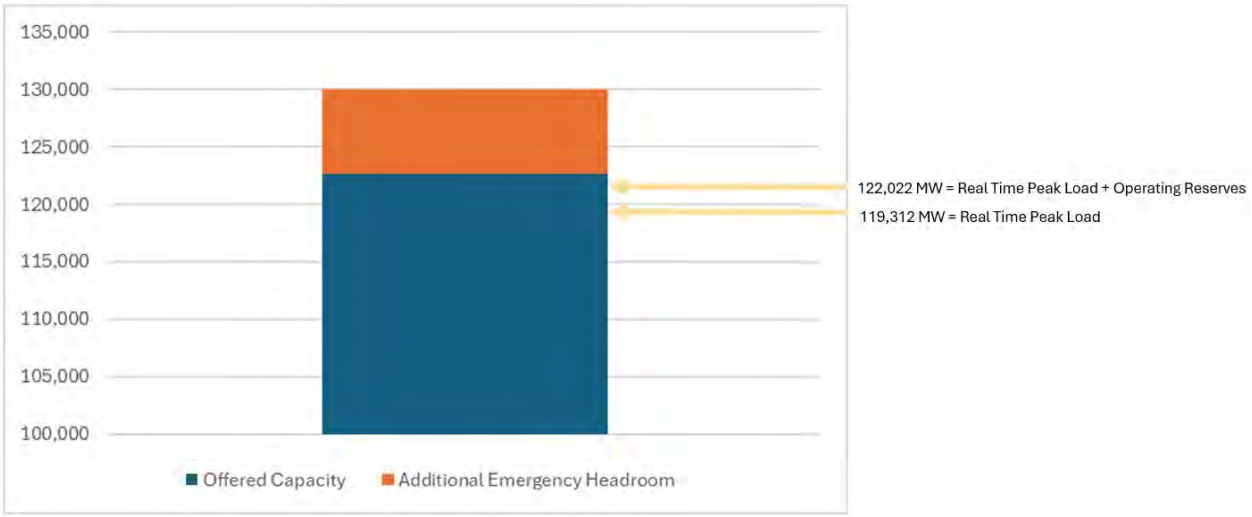
Figure 3: MISO's Offered Supply and Real-Time Peak Load Obligation



Source: MISO Monthly Operations Report: June 2025 at 33.

19. As already discussed, on top of the offered supply, MISO had another 7,328 MW of emergency headroom available to it. Thus, MISO had 129,963 MW of available resources. Additionally, to protect against contingencies, MISO keeps an operating reserve of 2,710 MW. As calculated above, MISO had surplus of 7,941 MW at the peak demand of June 23. I show this visually in Figure 4 (using the same sources indicated above).

Figure 4: Offered Supply and Emergency Headroom at Peak Load on June 23, 2025



20. It is also important to note that MISO, like other FERC-jurisdictional Regional Transmission Organizations (RTOs), has processes to manage generator outages. While generators typically submit planned outages for approval, MISO can deny or reschedule those outages if system reliability would be jeopardized.[9] In addition, MISO can request or direct a generator to return from outage sooner if conditions tighten.[10] The speed with which MISO can bring a unit back depends on how it is listed in the Outage Scheduler (e.g., "Deration" vs. "Out of Service"/"Economy") and the generator's declared recall/return-to-service time.[11] These

[9] MISO coordinates and reviews all generation outage schedules for reliability impacts. If MISO's studies show a reasonable expectation of an Emergency or other circumstances that compromise reliability, MISO may request rescheduling of planned generation outages consistent with Good Utility Practice. If voluntary rescheduling is not agreed upon, MISO has the authority to re-prioritize or reschedule the outage, and if necessary, develop Operating Guides or even revoke contributing transmission outages to maintain reliability. Source: Section 4.3. Coordination of Generation Outages, MISO Outage Operations Business Practices Manual, BPM-008-r23, Effective Date: September 1, 2024. Available at https://www misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/.

[10] See "4.3.3 Max Gen Event Step 1a - MISO Stakeholder Actions - 1. WHEN notified by MISO, THEN START applicable off-line AME Generation Resources." For the Generation Plant Owner. AME is Available Max Emergency. Page 22 of 41, MISO Market Capacity Emergency, SO-P-EOP-11-002 Rev: 21, Information Use Public. Available at https://cdn misoenergy.org/SO-P-EOP-11-002%20Rev%2021%20MISO%20Market%20Capacity%20Emergency683501.pdf.

[11] Page 19 of 82, MISO Outage Operations Business Practices Manual, BPM-008-r23, Effective Date: September 1, 2024.

oversight measures mean that outage levels are managed within a reliability framework, rather than being an uncontrolled signal of scarcity. Thus, even when tens of thousands of megawatts are offline, MISO still has the authority and tools to ensure enough power is available. Outages alone are not proof of shortage.

21. Notably, between 4PM to 5PM Eastern on June 23, among the resources available to MISO were 8,610 MW of demand response programs called Load Modifying Resources. This basket of resources includes traditional demand response programs that reduce peak demand by, for example, cycling air conditioning loads and using behind-the-meter generators. In essence, MISO has established a process whereby it can pay Load Modifying Resources to reduce demand. The Load Modifying Resources provide MISO with significant flexibility to address tight conditions.

22. Not all Load Modifying Resources had the same notification times – meaning that the entire 8,610 MW did not require either a 1-hour notice to reduce peak demand or a 6-hour notice. That gives MISO flexibility. MISO can first activate the resources that require longer notification times, while keeping in reserves the faster resources as conditions develop.[12] The Load Modifying Resources' notification times are shown in Figure 5.

[12] See "Due to the dynamic nature of the Bulk Electric System (BES) these preliminary declarations and instructions may be canceled prior to the actual start time of the forecasted Alert, Warning, Event or EEA as conditions warrant." Attachment 5 – Additional Information, Page 36 of 41, MISO Market Capacity Emergency, SO-P-EOP-11-002 Rev: 21, Information Use Public. Available at https://cdn.misoenergy.org/SO-P-EOP-11-002%20Rev%2021%20MISO%20Market%20Capacity%20Emergency683501.pdf. MISO's deployment of Load Modifying Resources and other Emergency Demand Response during emergencies is governed by Schedule 30 of the MISO Tariff (https://docs.misoenergy.org/miso12-legalcontent/Schedule_30_-_Emergency_Demand_Response_Initiative.pdf) and Business Practice Manual No. 26: Demand Response, BPM-026-r12, Effective Date: Nov. 7, 2024 (https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals).

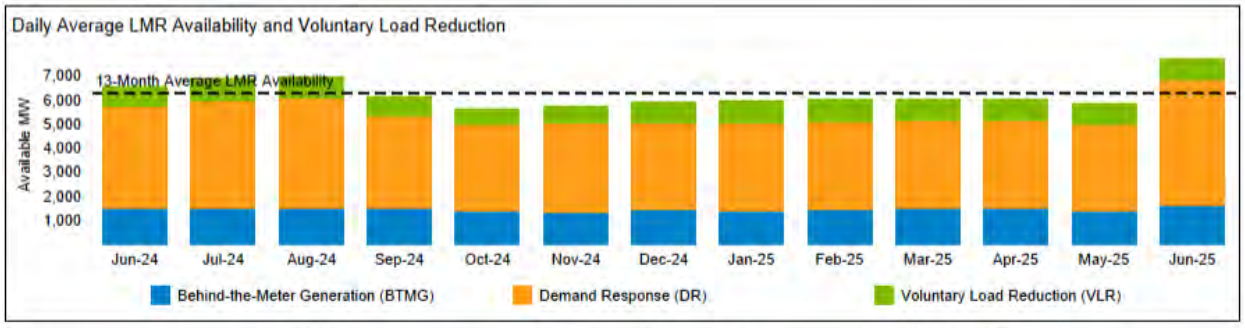
Figure 5: MISO's Available Load-Modifying Resources at Peak Load on June 23, 2025

Notification Time (Hours)	Demand Response (MW)	Behind the Meter Generation (MW)	Total
1	761	457	**1,218**
2	1,854	1,282	**3,136**
4	1,507	211	**1,718**
6	2,011	527	**2,538**
Total	**6,133**	**2,477**	**8,610**

Source: MISO Monthly Operations Report: June 2025 at 27.

23. MISO also had access to Voluntary Load Reduction, in addition to the registered Load Modifying Resources. This means that MISO had a large and flexible toolset to reduce demand during tight conditions, which helped avoid an actual shortage even during high-load days in June 2025. Figure 6 shows Load Modifying Resources and Voluntary Load Reduction available to MISO in June 2025 and for the last year.

Figure 6: Daily Average Load Modifying Resource Availability and Voluntary Load Reduction



PRA Auction	BTMG (MW)	DR (MW)	Total BTMG and DR (MW)
Summer 2024	4,144	8,109	12,253
Summer 2025	4,283	9,004	13,287

Source: MISO Monthly Operations Report: June 2025 at 27.

D. Whether MISO's Seasonal Capacity Market Structure Provides a Factual Basis for the Order's Findings.

24. In my professional opinion, MISO's transition to a seasonal capacity market structure does not provide a factual basis for DOE's claim of capacity shortages in Fall 2025. Rather, it reflects a forward-looking reform to improve the accuracy of crediting generators in

non-summer seasons, align obligations with actual seasonal risks, and protect consumers from unnecessary costs.

25. MISO's seasonal capacity market structure was primarily motivated by a drive to improve| the accuracy of generator availability, not to address generator capacity shortages. As MISO's then Senior Director for Real Time Operations and Operations Planning, Mr. Jameson Smith, explained to FERC, "when system conditions begin to get tight in the Winter, a resource may offer as available but, in reality, cannot perform when needed. The current annual Resource Adequacy construct may overstate availability throughout the year and does not properly incentivize resources to be available when most needed."[13] In other words, the seasonal capacity accreditation[14] process was designed to better align capacity credit with actual seasonal performance, ensuring that resources were credited only when they could truly deliver. DOE's reliance on the existence of this reform as proof of present shortages misconstrues its purpose: the reform was forward-looking, to enhance planning certainty, not a sign of existing scarcity.

26. The DOE Order 202-25-7 misinterpreted MISO's 2025 Planning Resource Auction results as a sign of capacity shortage.[15] In fact, as MISO's then Executive Director for Market Development and Design, Mr. Scott Wright, explained in testimony to FERC, "[h]istorically, approximately 92% of [MISO Utilities] either submitted a [Resource Plan] or

[13] Page 5-6, Jameson Smith Testimony (Nov. 30, 2021), FERC Docket No. ER22-495-000. https://elibrary ferc.gov/eLibrary/filelist?accession_number=20211130-5166.

[14] A capacity accreditation rating is how much of a generator's nameplate capacity counts toward meeting its obligations to serve load in the annual capacity auction. For example, a 100 MW unit might be credited as 90 MW, giving it a 90% capacity credit. Seasonal capacity accreditation means this value is based on a unit's demonstrated seasonal performance, rather than relying solely on summer performance year-round. For instance, a 100 MW unit might receive 90 MW of credit in summer but only 5 MW in winter due to operating limitations in colder conditions.

[15] DOE Order Page 4. https://www.energy.gov/sites/default/files/2025-08/MISO%20Order%20No.%20202-25-7.pdf.

participated by self-scheduling[16] in the [Capacity Auction]; only about 8% of [Zonal Resource Credits] have been offered economically in the [Capacity Auction]."[17] In other words, 92% of the MISO utilities that have the obligation to serve load do not meaningfully participate in the Planning Resource Auction. As Mr. Wright explains later in his testimony, MISO's seasonal capacity construct is all about MISO as a market operator sending the right price signals to generators to become available when the capacity is "tight" in the future.[18] The higher prices in the 2025 Capacity Auction, therefore, provided the intended signal without indicating a present shortage.

27. Against this backdrop, DOE further misstates the purpose of seasonality as proof of year-round shortages. In fact, when the Federal Energy Regulatory Commission approved the seasonal market structure, it emphasized that the reform aimed to improve the accuracy of capacity availability and reduce consumer costs, rather than addressing capacity scarcity. The Commission found that the seasonal capacity market structure "better align[s] resource adequacy requirements with periods of increased risks," and that it would ensure MISO utilities are not required to procure capacity beyond what is necessary in a given season.[19]

[16] Self-Scheduling is when a MISO utility commits its generation to run regardless of the market price, rather than offering it economically into the auction.

[17] Page 9, Lines 14-16. Scott Wright Testimony (Nov. 30, 2021), FERC Docket No. ER22-495-000. https://elibrary ferc.gov/eLibrary/filelist?accession_number=20211130-5166.

[18] "When capacity is **tight**, MISO's operators make reliability commitments to address the uncertainty of resource availability in place of reliance on price signals in the market." Page 19, Lines 11-13. Also, "As the resource fleet has evolved, the MISO Region has become more reliant on uncertain, uncommitted resources during **tight** operating periods." Page 22, Lines 7-8. Finally, "Such resources are accredited based on historic contributions during past system peaks, but there is no assurance that the accredited capacity will be available during **tight** grid conditions or a particular emergency event." Page 23, Lines 9-12. Scott Wright Testimony.

[19] "Further, by providing a more granular assessment of seasonal resource adequacy needs, MISO's proposal will ensure that LSEs are not required to procure capacity beyond what is necessary to ensure resource adequacy in a given Season." Paragraph 77, Order Accepting Proposed Tariff Revisions Subject to Revision re Midcontinent Independent System Operator, Inc. (Aug. 31, 2022) under FERC Docket No. ER22-495-000. https://elibrary ferc.gov/eLibrary/filelist?accession_number=20220831-3093.

28. As MISO explained to FERC, "its models indicate that the move to seasonal Auctions will result in nearly double the amount of uncleared [Zonal Resource Credits[20]] in non-Summer Seasons, providing liquidity to the market for replacement capacity."[21] In plain terms, the seasonal framework creates more available capacity (i.e., Zonal Resource Credits) that utilities can procure if one of their designated resources becomes unavailable, ensuring that the seasonal capacity market structure expands supply options rather than signaling a shortage.

29. Likewise, the Commission highlighted that "MISO has demonstrated that its proposal will result in lower Reserve Requirements for non-Summer Seasons, at the MISO-wide level, which should in and of itself reduce costs to customers."[22] MISO's seasonal capacity market structure is thus a refinement to improve risk alignment and consumer protection, not evidence that MISO lacks sufficient resources outside the summer peak.

I declare under penalty of perjury under the laws of the United States, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 3rd day of September 2025, in Roseville, Minnesota.

Rao Konidena

Rao Konidena
Rakon Energy LLC
2309 Auerbach St, Roseville, MN 55113

[20] Zonal Resource Credits (ZRCs) can be traded between utilities and other MISO market participants. For example, if a utility holds surplus ZRCs beyond what it needs to meet its load-serving obligations, it can sell or transfer those ZRCs to another entity that is deficient.

[21] "It is reasonable to expect that bilateral trading for replacement capacity will be much more robust under the proposal than it is today. Additionally, the move to seasonal auctions with seasonal PRMR targets based on seasonal peaks has been modeled to result in nearly double the amounts of uncleared ZRCs outside the summer Season, providing liquidity to the market for replacement capacity." Page 28, MISO Deficiency Letter Response (Apr. 8, 2022) under Docket No. ER22-495-000. https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20220408-5195 Note that "Replacement capacity" is the additional capacity a MISO utility must procure to meet its load obligation when a designated resource cannot provide its committed Zonal Resource Credits (ZRCs), such as when a generating unit is on outage, derated, or otherwise unavailable.

[22] Paragraph 88, Order Accepting Proposed Tariff Revisions Subject to Revision re Midcontinent Independent System Operator, Inc. under ER22-495.

Attachment A

RAO KONIDENA

ENERGY MARKET EXPERTISE IN DISTRIBUTED ENERGY RESOURCES

Roseville, MN 55113 Cell: 612-594-9257 · rkonidena76@gmail.com

Rao Konidena brings deep experience in distribution system planning and integration of distributed energy resources. His regulatory testimonies across the U.S. have informed utility distribution planning, storage deployment strategies, and DER tariff design. At MISO, Rao led studies on demand-side potential and DER impacts on long-term planning. His consulting work spans utility-scale and customer-sited solutions, with a consistent focus on how DERs shape the future of distribution systems.

Rao is on the Board of Ever Green Energy and President of the Board at the Center for Renewables Integration.

EXPERIENCE

RAKON ENERGY® LLC, Roseville, MN
President & Chief Executive Officer (CEO) May 2018 – Present

Testimonies filed before state regulatory agencies and related work.

- The Colorado Office of the Utility Consumer Advocate engaged Rakon Energy LLC to provide expert testimony before the Colorado Public Utilities Commission on a utility distribution system plan. Proceeding No. 24A-0547E Public Utilities Commission

- Engleman Fallon, PLLC engaged Rakon Energy LLC to provide expert testimony before the Federal Energy Regulatory Commission on behalf of the Kentucky Public Service Commission regarding a transmission cost allocation complaint. FERC Docket No. EL25-67-000. eLibrary | File List

- Citizens Utility Board and Environmental Defense Fund engaged Rakon Energy to provide testimony before the Illinois Commerce Commission (Docket No. 24-0088) in the Ameren Transmission Company of Illinois and Ameren Illinois Company d/b/a Ameren Illinois in the Joint Petition for a Certificate of Public Convenience and Necessity proceeding. https://icc.illinois.gov/docket/P2024-0088/documents/356793

- San Louis Obispo Mothers For Peace engaged Rakon Energy in the Application of Pacific Gas and Electric Company to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant from September 1, 2023 through December 31, 2025 and for Approval of Planned Expenditure of 2025 Volumetric Performance Fees (U 39 E) docket before the California Public Utilities Commission Proceeding A.24-03-018. https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2403018/7629/537498256.pdf

- The Massachusetts Attorney General's Office, Office of Ratepayer Advocacy, engaged the Center for Renewables Integration to provide expert testimony before the Massachusetts Department of Public Utilities regarding Eversource (DPU 23-126), National Grid (DPU 23-115) and Unitil's (DPU 23-117) Energy Storage Tariffs. Rakon Energy is part of the Center for Renewables Integration expert witness team. https://eeaonline.eea.state ma.us/DPU/Fileroom/dockets/bynumber

- The Commonwealth of Pennsylvania's Office of Consumer Advocate engaged Rakon Energy LLC to provide expert testimony before the Pennsylvania Public Utilities Commission on a utility rate case. Docket No. R-2024-3047068 https://www.puc.pa.gov/pcdocs/1835234.pdf

- Rakon Energy is engaged on behalf of the Environmental Law & Policy Center and the Citizens Utility Board to provide testimony before the Illinois Commerce Commission (Docket No. P2023-0658) in the Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois - Joint Petition for a Certificate of Public Convenience and Necessity proceeding. https://icc.illinois.gov/docket/P2023-0658/documents/349330

- Rakon Energy is engaged by NC WARN, a nonprofit organization, for testimony before the North Carolina Utilities

Commission (Docket No. E-100, SUB 190) in Duke Energy Carolina Biennial Consolidated Carbon Plan and Integrated Resource Plan.
https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=34aaef8f-5012-48aa-b319-77861e016436

- Rakon Energy was engaged by NC WARN, a nonprofit organization, for testimony before the North Carolina Utilities Commission (Docket No. E-7, SUB 1276) in Duke Energy Carolina Rate Case.
https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=eff4d6f7-4a43-4c25-8784-2f5718375204

- The Office of People's Counsel in State of Maryland engaged Rakon Energy LLC to provide expert testimony before the Maryland Public Service Commission on a transmission line rebuild project. PSC Case No: 9698. Submitted date – September 13, 2023. https://webpsc.psc.state.md.us/DMS/case/9698

- San Louis Obispo Mothers For Peace engaged Rakon Energy in the Proposed Extension of the Diablo Canyon Power Plant docket before the California Public Utilities Commission Proceeding R.23-01-007.
https://mothersforpeace.org/wp-content/uploads/2023/07/Rao-Konidena-Testimony_Final.1.pdf

- Voltus, an aggregator, engaged Rakon Energy to provide expert testimony before the Minnesota Public Utilities Commission – Docket No. E999/CI-22-600 (Aggregator of Retail Customers), and Kansas Corporation Commission – Docket No. 23-EKCE-588-TAR (Demand Response Aggregator).
https://www.edockets.state mn.us/edockets/searchDocuments.do?method=showPoup&documentId={509C6C87-0000-C610-A629-18F8958B5C38}&documentTitle=20234-194648-01

  https://estar.kcc ks.gov/estar/ViewFile.aspx/S202307071819321214.pdf?Id=01c14579-4f44-42e7-887a-14381b43b514

- The Commonwealth of Pennsylvania's Office of Consumer Advocate engaged Rakon Energy LLC to provide expert testimony before the Pennsylvania Public Utilities Commission on a transmission line rebuild project. Docket No. A-2022-3037374. Starting on Page 198, https://www.puc.pa.gov/pcdocs/1797979.pdf

- The Commonwealth of Pennsylvania's Office of Consumer Advocate engaged Rakon Energy LLC to support OCA's response to the questions posed by the Pennsylvania Public Utility Commission's Secretary in the policy proceeding - Utilization of Storage Resources as Electric Distribution Assets. Docket No. M-2020-3022877. Starting on Page 18, https://www.puc.pa.gov/pcdocs/1726077.pdf

- A prominent solar advocacy group – Vote Solar, engaged Rao for expert testimony work in Nevada and Minnesota IOUs IRP filing. The docket # for Minnesota PUC is Docket No. E002/RP-19-368 and the docket #s for Public Utilities Commission of Nevada PUC are Docket Nos. 21-06001 and 21-06002.

  For Nevada testimony,
https://ecms.nv.gov/puc/api/Document/ATczlezYGwl0gYI%C3%81kEPTWEapPcfzukJf8jLWbk0n4gatA%C3%81WwN8OhaGK%C3%81Y%C3%89J4njfgfyQKShz62MTaictAWaf3PsA%3D/?OverlayMode=View

  For Minnesota PUC testimony - Starting Page 110, https://votesolar.org/wp-content/uploads/2021/02/XcelMNIRP2021.pdf

- He has provided expert testimony support for Environmental Law and Policy Center (ELPC) at the Public Service Commission of Wisconsin (PSCW) on the MISO Multi-Value Project (MVP) line in Wisconsin. Docket No. 5-CE-146. https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=365126

- He provided affidavit support for the Office of the People's Counsel of the District of Columbia (OPC-DC) at the Federal Energy Regulatory Commission (FERC) on PJM's Reserves Pricing Proposal and municipal utilities in Wisconsin and Missouri at FERC on MISO's Resource Adequacy construct. Starting Page 177,
https://edocket.dcpsc.org/apis/api/filing/download?attachId=100991&guidFileName=ae06faca-5aa9-43f2-aea4-dc5457ab7adb.pdf

- Rao also submitted an affidavit before FERC on behalf of Missouri Joint Municipal Electric Utilities Commission, Missouri River Energy Services, and WPPI Energy regarding the Midcontinent Independent System Operator's (MISO) External Resource Zone proposal. Docket No. ER18-1173-001.
https://elibrary ferc.gov/eLibrary/filelist?accession_number=20180626-5242&optimized=false

Providing consulting services related to Federal and state energy policies, focusing on energy storage and distributed energy resources.

- Rakon Energy, as part of the Center for Renewables Integration team, is supporting a renewable energy developer to look at the MISO and PJM generator interconnection queue for solar/storage site evaluation.
- Rakon Energy is supporting a solar developer to evaluate distributed energy and battery energy storage system (BESS) development opportunities in MISO.
- Rakon Energy supported a Community Solar Garden developer with MISO's DER Affected Systems Study process.
- Rakon Energy is engaged as a Battery Energy Storage System consultant to the Georgia Public Service Commission.
- An Independent Power Producer engaged Rakon's services to understand MISO's seasonal resource adequacy construct and its impact on Power Purchase Agreement negotiations with a MISO utility.
- A renewable energy developer engaged Rakon Energy to provide MISO expertise for their renewable energy project portfolio in various stages and study cycles of the Generator Interconnection Queue and the capacity credit impact from MISO's seasonal capacity construct.
- An aggregator engaged Rakon Energy as part of the team to represent their interests at RTO stakeholder committees on FERC Order 2222.
- Advanced Energy Economy and the Natural Resources Defense Council's Sustainable FERC Project engaged Rakon to monitor MISO's FERC Order 2222 implementation process.
- Rakon Energy was part of the team engaged by a technology company to represent their interests at the PJM RTO. Another similar company hired Rao to navigate MISO's market rules for data center interconnection.
- Rakon Energy provides generic electrical engineering expertise for the Commonwealth of Pennsylvania's Office of Consumer Advocate in the transmission, distribution services and miscellaneous electric issues.
- He provided training as part of the Tuatara team on DERs to Colombia's grid operator XM and the ESTA International team on energy storage benefits to Mexican regulator CRE.
- He provided advocacy support for Energy Storage Association (ESA) at MISO on FERC Order 841 Compliance.

Advisor, Volunteer, Pro-Bono assignments

- Rao presented on US Energy Markets, Capacity Markets and Retail Energy Markets to Independent Electricity Market Operator Philippines (IEMOP) and other stakeholders, as part of a workshop organized by the United States Energy Agency (USEA).
- Rao presented on Distributed Energy Resources (DER) and peer-reviewed Demand Side Management and DER plans for Central American regulators, as part of NARUC International Peer Review.
- Rao presented and shared best practices around the impact of provisioning ancillary services. At an Eastern Africa regional workshop organized by the United States Energy Agency (USEA), the United States Agency for International Development (USAID) and the Power Africa initiative.

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR (MISO), Eagan, MN
Principal Advisor, Policy Studies Aug 2015 – May 2018

- Recognized as an expert on all thing's energy storage and distributed energy resources from an economic transmission planning perspective
- Project manager for long term independent load forecast and demand response/energy efficiency/distributed generation potential study.
- MISO representative on Department of Energy (DOE) US DRIVE Grid Interaction Technical Team

Senior Manager, Transmission Asset Management Operations Feb 2013 – July 2015

- He engaged the division lead in the development of strategic initiatives and operating plans.
- Rao chaired the Economic Modeling Framework Working Group of international Grid operators GO-15.

Manager, Resource Forecasting (started at Engineer II) Sep 2003 – Jan 2013

- ***Main Accomplishments***
  - In this role, I directed the Demand Response & Energy Efficiency potential study for MISO, with the support of Global Energy Partners consultants.
  - Directed the MISO Energy Storage Study identifying the economic potential for grid-scale energy storage in MISO footprint, providing strategic consulting services to investor-owned utilities, public power utilities, asset owners, and investors.
- ***Regulatory Experience***
  - Responsible for analytical assessments that meet MISO's Federal Energy regulatory compliance obligations as well

as our Transmission Owners (e.g., FERC Market-based rates).
- Responsible for supporting state regulators and MISO Board of Directors with technical analysis related to policy drivers.

PWRSOLUTIONS, Inc., Dallas, TX (Consulting) May 2001 – August 2003
Student Intern and Electrical Engineer
- Rao executed generator interconnection studies for Independent Power Producers (IPPs) clients.
- Analyzed future generator and transmission needs in the Eastern Interconnection.

EDUCATION

THE UNIVERSITY OF MINNESOTA, Minneapolis, Minnesota
Carlson School of Management
Master of Business Administration, Global Executive Program May 2011
Emphases: Strategic Management, International Business

- Responsible for all financial aspects of marketing mobile charging services for Electric vehicles in the Singapore market.

UNIVERSITY OF TEXAS AT ARLINGTON, Arlington, Texas
Energy Systems Research Center (ESRC)
Master of Science in **Electrical Engineering** May 2002

- Master's Thesis in Economic Analysis of Distributed Generation (Photovoltaics (P.V.) and Fuel Cells)

BLOG POSTING, PUBLICATIONS & PRESENTATIONS

1. Co-Author for a graduate level textbook titled "Modern Electricity Systems: Engineering, Operations, and Policy to address Human and Environmental Needs". Release date - August 2022 with Wiley.
2. **He has authored multiple publications in Electricity Journal, Renewable Energy World (blog), and other peer-reviewed industry journals.**

BOARD & VOLUNTEER ACTIVITIES

- Board of Directors, Ever Green Energy. Sep 2019 – present
- President, Board of Directors, Center for Renewables Integration. Dec 2023 - present.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 71

Public Interest Organizations' June Rehearing Request

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-3

Motion to Intervene and Request for Rehearing and Stay of 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 (collectively, "Public Interest Organizations")

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INTRODUCTION

On May 23, 2025, the Secretary of Energy, on behalf of the Department of Energy (collectively the "Department" or "DOE"), issued an order pursuant to Section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c) ("Section 202(c)") instructing the Midcontinent Independent System Operator ("MISO") and Consumers Energy Company ("Consumers" or "Consumers Energy") to "take all measures necessary to ensure that" the J.H. Campbell coal-fired power plant, in West Olive, Michigan (the "Campbell Plant," or "Campbell") "is available to operate" and directing MISO "to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers," until August 21, 2025. Ex. 1 at 2 (DOE Campbell Order) (the "Order"). Prior to the issuance of the Order, Consumers Energy was preparing to retire the Campbell Plant on May 31, 2025, with the approval of the Michigan Public Service Commission ("Michigan Commission") and MISO.

The Department should grant rehearing and rescind this costly, harmful, unnecessary, and unlawful order. The Order was not requested by Consumers, MISO, or the Michigan Commission. On the contrary, all of those entities—who collectively bear primary responsibility over Michigan's electric system—have confirmed that retiring the Campbell Plant is economically and environmentally beneficial, and poses no significant risk to the reliability of the electric system in Michigan or elsewhere. The Order is based on a profoundly incorrect understanding of the handful of sources it selectively quotes. Those sources, and the Order itself, do not support the Order's claim of a resource adequacy emergency in any of the various locations at which the Order ambiguously gestures. In fact, each of those areas have more resources than are projected as needed to meet demand.

The Order also fails to grapple with the Campbell Plant's inability to reliably operate even in normal circumstances, let alone an emergency. Because the Campbell Plant is at the end of its useful life and Consumers has substantially reduced capital and major maintenance investments over the past few years in anticipation of retirement, the plant would require tremendous maintenance and investment to function consistently. The Department has no authority to compel Consumers to rehabilitate (and effectively reconstruct) the increasingly unreliable plant, nor to override the state's and utility's decision to replace the plant with less expensive and cleaner sources. The Order is thus beyond the Department's authority.

On top of all these failures, the Order makes no effort to limit the significant environmental and public health harms caused by burning coal at the plant, despite explicit instruction from Congress to do so. Campbell harms its neighbors—the same Michiganders that decided to close the plant. The Department has, moreover, thus far done all this behind closed doors, without making public the information

demanded of MISO and Consumers, despite Departmental procedure requiring transparency.

At its heart, the Order represents an effort to replace the market- and state-led planning process provided by statute with an ill-advised and misinformed exercise in federal command-and-control. That effort disserves the public and violates the law. The Order must be rescinded.

I. Statement of Issues and Specification of Error

The undersigned Public Interest Organizations move to intervene and request rehearing and a stay pursuant to section 313(a) of the Federal Power Act, 16 U.S.C. § 825*l*(a), and the applicable rules of practice and procedure, U.S. Dep't of Energy, *DOE 202(c) Order Rehearing Procedures* (last visited June 18, 2025), https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures (attached as Ex. 30) [hereinafter "DOE Rehearing Procedures"]; 18 C.F.R. §§ 385.214, 385.713,[1] based upon the following errors and issues:

A. The Department has not demonstrated that an emergency exists that authorizes it to issue the Order. 16 U.S.C. §§ 824a(a)–(c), 824o; 10 C.F.R. § 205.371–.375; *Emergency Interconnection of Elec. Facilities and the Transfer of Elec. to Alleviate an Emergency Shortage of Elec. Power,* 46 Fed. Reg. 39,984 (Aug. 6, 1981); *Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150 (2016); *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120 (2000); *Jarecki v. G.D. Searle & Co.*, 367 U.S. 303 (1961); *Citizens Action Coal. v. FERC*, 125 F.4th 229 (D.C. Cir. 2025); *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477 (D.C. Cir. 2009); *Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009); *Cal. Indep. Sys. Op. Corp. v. FERC*, 372 F.3d 395 (D.C. Cir. 2004); *Richmond Power and Light v. FERC*, 574 F.2d 610 (D.C. Cir. 1978); *Otter Tail Power Co. v. Fed. Power Comm'n*, 429 F.2d 232 (8th Cir. 1970).

B. (1) Even if the emergency described by the Order did exist—it does not—the Department has not demonstrated a reasoned basis for its determination that additional dispatch of Campbell is necessary to "best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c); 10 C.F.R. § 205.373; *Dep't of Homeland Sec. v. Regents of the Univ. of Calif.*, 591 U.S. 1 (2020); *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208 (2009); *Allentown Mack Sales & Service, Inc. v. NLRB*, 522 U.S. 359 (1998); *Motor Vehicle Mfrs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S.

[1] *See* Ex. 8 (Email from Cooke to Alle-Murphy) (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.").

29 (1983); *NAACP v. Fed. Power Comm'n*, 425 U.S. 662 (1976); *Gulf States Utils. Co. v. Fed. Power Comm'n*, 411 U.S. 747 (1973); *Otter Tail Power Co. v. United States*, 410 U.S. 366 (1973); *California v. Fed. Power Comm'n*, 369 U.S. 482 (1962); *Pa. Water & Power Co. v. Fed. Power Comm'n*, 343 U.S. 414 (1952); *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); *Sierra Club v. Env't. Prot. Agency*, 353 F.3d 976, 980 (D.C. Cir. 2004); *Wabash Valley Power Ass'n, Inc. v. FERC*, 268 F.3d 1105 (D.C. Cir. 2001). And (2) the Order is unlawfully ambiguous, impermissibly vague, and does not provide fair notice of what MISO, Consumers Energy, and others are required to do. 16 U.S.C. § 824a(c); *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); *Allentown Mack Sales & Service, Inc. v. NLRB*, 522 U.S. 359 (1998).

C. The Order's availability requirements exceed the Department's authority. 16 U.S.C. §§ 824(a)–(b), 824a(b)–(c); *Gallardo v. Marstiller*, 596 U.S. 420 (2022); *Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150 (2016); *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260 (2016); *Gomez-Perez v. Potter*, 553 U.S. 474 (2008); *Fed. Power Comm'n v. Fla. Power & Light Co.*, 404 U.S. 453 (1972); *Conn. Light & Power v. Fed. Power Comm'n*, 324 U.S. 515 (1945); *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477 (D.C. Cir. 2009).

D. The Department has unlawfully failed to ensure that the Order compels generation only during hours necessary to meet the emergency and serve the public interest, that operations are consistent with any applicable environmental laws to the maximum extent practicable, and that any adverse environmental impacts are minimized. 16 U.S.C. § 824a(c)(2); *Fla. Power & Light Co. v. FERC*, 88 F.3d 1239 (D.C. Cir. 1996); *City of New Orleans v. FERC*, 67 F.3d 947 (D.C. Cir. 1995).

E. 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); DOE Rehearing Procedures.

II. 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. § 385.215.

Each of the Public Interest Organizations also demonstrates a concrete injury arising from the Order that is redressable by a favorable outcome. Each organization is therefore aggrieved by the Department's Order and may properly apply for rehearing. *See* Federal Power Act, § 313(a), 16 U.S.C. § 825*l*(a); *Wabash Valley Power Ass'n, Inc. v. FERC*, 268 F.3d 1105, 1112 (D.C. Cir. 2001); *NextEra Energy Res. v. ISO New Eng., Inc.*, 157 FERC ¶ 61,059, at P 5 (2016).

A. Sierra Club

Sierra Club and its members are aggrieved by the Order. Over 17,500 Sierra Club members reside in Michigan; over two dozen of those members reside within just three miles of the Campbell Plant and thousands more live in nearby townships and further downwind. Sierra Club members are harmed by pollution produced by operating the Campbell Plant. The Order to operate the plant beyond its planned retirement date will subject Sierra Club members to additional air and water pollution in the areas where they live and recreate. Sierra Club members also hear the plant operating and hear and see open coal trains delivering coal to the plant. 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 (discussed in section IV.D below). In addition, Sierra Club members are ratepayers who may be subject to higher electric bills as a result of the Department's Order.

Sierra Club has a demonstrated organizational commitment to the above-described interests. Sierra Club's Beyond Coal Campaign seeks to reduce the pollution currently being produced by coal-fired power plants such as Campbell, and to reduce energy bills by ensuring that ratepayers do not fund the cost of continuing to operate uneconomic coal plants like Campbell. To those ends, Sierra Club has participated in multiple regulatory proceedings relating to the Campbell Plant. *See, e.g.*, Michigan Comm'n Case No. U-21224 (Consumers application for an increase in its electricity rates); Michigan Comm'n Case No. U-21090 (Consumers 2021 Integrated Resource Plan ("IRP")); Sierra Club Comments to Michigan Dep't of Env't, Great Lakes, and Energy on Nat'l Pollution Discharge Elimination System ("NPDES") Permit No. MI10001422 (May 21, 2021); Michigan Comm'n Case No. U-20165 (Consumers 2018 IRP); Sierra Club, Earthjustice, and Great Lakes Environmental Law Center Comments to Michigan Dep't of Env't, Great Lakes, and Energy on NPDES Permit No. MI10001422 (Apr. 22, 2018).

If the Order stands, Sierra Club will sustain an independent organizational injury in addition to those sustained through its members. As described in detail below, Campbell's planned retirement date of May 31, 2025 was the result of a settlement reached in Consumers' 2021 Integrated Resource Plan proceeding before the Michigan Commission. Sierra Club was heavily involved in the Integrated Resource Plan proceeding from its earliest stages and is a signatory to the

settlement. Sierra Club invested in participating (through staff, volunteers, and members) in multiple stakeholder meetings held by Consumers in 2020 to inform its Integrated Resource Plan filing, galvanized hundreds of its members to submit comments to Consumers, formally intervened once Consumers filed its Integrated Resource Plan, and sponsored extensive expert testimony in that proceeding to demonstrate that the Campbell Plant's existing and likely future costs fully justified its closure by 2025. The Order's attempt to override the settlement undermines Sierra Club's investments in the Integrated Resource Plan proceeding and its reliance on the results of the settlement, inflicting procedural and organizational harm on Sierra Club.

B. 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 and its members are aggrieved by the Order, which threatens those fundamental rights. Over 15,781 NRDC members reside in Michigan and approximately 162 of those members reside within ten miles of the Campbell plant. These NRDC members are harmed by the order to operate the Campbell plant beyond its planned retirement date because continued operations 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, including the delivery of coal via open coal trains. 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 IV.D below). In addition, NRDC members are ratepayers in the MISO region who will be subject to higher electric bills as a result of the Order.

NRDC has a longstanding organizational commitment to protect the interests of its members and to reducing pollution caused by coal-fired power plants such as Campbell. To that end, NRDC has participated in multiple regulatory proceedings relating to the Campbell Plant. *See, e.g.*, Michigan Comm'n Case No. U-21224 (Consumers Energy Co. application for an increase in its electricity rates); Michigan Comm'n Case No. U-21090 (Consumers 2021 IRP); Michigan Comm'n Case No. U-20165 (Consumers 2018 IRP); Michigan Comm'n Case No. U-21585 (Consumers Electric Rate Case); Michigan Comm'n Case No. U-21816 (Consumers Renewable Energy Plan). NRDC also was a party to the 2022 settlement agreement with Consumers Energy for the closure of the Campbell Plant and the end of Consumers' use of coal by May 31, 2025.

C. Michigan Environmental Council

Michigan Environmental Council ("MEC") is a statewide environmental nonprofit organization founded in 1980 and based in Lansing, Michigan. MEC has over 100 member groups and a collective membership of over 300,000 people who live, recreate, and consume energy in Michigan. On behalf of its members, MEC advocates at the local, state, and federal level for lasting protections of its members' health and economic well-being, as well as protections for Michigan's air, water, and land. This includes promoting policies that protect Michigan residential utility ratepayers, increase adoption of clean energy sources, reduce harmful pollution, and address the causes of climate change.

Since 1999, MEC's advocacy on these issues has included participation as an intervening party in hundreds of Michigan Commission cases to represent the interests of its members in lower-cost, cleaner energy generated from renewable sources. In 2022, MEC was a party to the settlement agreement with Consumers Energy that would result in the closure of the Campbell Plant and end Consumers' use of coal by May 31, 2025. This settlement was designed to provide reliable energy at significantly lower cost, while also improving public health and reducing harmful environmental impacts.

D. Environmental Defense Fund

The Environmental Defense Fund ("EDF") is a nonprofit membership organization with hundreds of thousands of members nationwide, including more than nine thousand members in Michigan, 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 MISO region.

E. Environmental Law and Policy Center

Environmental Law and Policy Center ("ELPC") is a not-for-profit environmental organization with members, contributors, and offices throughout the Midwest, including in Michigan. Among other things, ELPC advocates before the Michigan Commission and the Federal Energy Regulatory Commission for clean,

reliable energy generation in order to reduce ratepayer costs and improve environmental outcomes. ELPC has a long history of participating in regulatory proceedings involving Consumers. *See, e.g.*, Michigan Comm'n Case No. U-21224 (Consumers Energy Co. application for an increase in its electricity rates); Michigan Comm'n Case No. U-21090 (Consumers 2021 IRP); Michigan Comm'n Case No. U-20165 (Consumers 2018 IRP); Michigan Comm'n Case No. U-20984 (Consumers Renewable Energy Plan); Michigan Comm'n Case No. U-21585 (Consumers Electric Rate Case); Michigan Comm'n Case No. U-21816 (Consumers Renewable Energy Plan). With respect to Campbell, ELPC played a key role in the 2021 Integrated Resource Plan proceeding from its earliest stages and is a signatory to the settlement agreement in which Consumers committed to retiring the Plant by May 31, 2025.

Since the settlement, ELPC has played a role in upholding the public's interest and refining the details as to the future of the Campbell site. In partnership with other stakeholders, ELPC has engaged and will continue to engage in negotiations with Consumers and other community members in pursuit of conservation, recreation, and clean energy goals at the site. ELPC members in Michigan will be harmed by the Order, as it delays the plant's retirement and may subject members to higher electric bills. Further, the Order's attempt to override the settlement undermines ELPC's investment in the Integrated Resource Plan proceeding and its reliance on the results of the settlement, inflicting procedural and organizational harm on ELPC.

F. Vote Solar

Vote Solar is an independent 501(c)(3) nonprofit working to re-power the U.S. with clean energy by making solar power more accessible and affordable through effective policy advocacy. In over half of the country, Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale plants. Vote Solar has over 90,000 members nationally, including over 2,700 members in Michigan. Vote Solar is not a trade organization, nor does it have corporate members. Vote Solar has provided testimony and comments in many regulatory dockets in front of the Michigan Commission, including the 2021 Integrated Resource Plan proceeding. Vote Solar is committed to promoting clean, renewable energy and transitioning away from coal generation.

G. 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 country, including those who pay electric utility bills in Michigan and in MISO. Public Citizen is active before the Federal Energy Regulatory Commission promoting just and reasonable rates, and supporting efforts for utilities to be

accountable to the public interest. Its interests in this proceeding are unique and cannot be represented by any other party. Financial details about the organization are on its website. Public Citizen, "Annual Reports," www.citizen.org/about/annual-report/.

H. Union of Concerned Scientists

The Union of Concerned Scientists ("UCS") is a national non-profit organization headquartered in Cambridge, Massachusetts, with additional offices in Washington, D.C.; Berkeley, California; and Chicago, Illinois. UCS is a public interest organization with more than 55 years of experience advocating for science-based policies, including responsible energy policy and utility oversight at the state and federal levels, and with over a decade working in Michigan on these issues. UCS has approximately 5,800 supporters, 1,800 members, and 500 Science Network members that live, use electricity, and pay electric bills in Michigan, including in Consumers Energy's service territory. UCS intervened and participated fully as a party in Consumers' 2021 Integrated Resource Plan proceeding, including authoring expert testimony and supporting resolution of that case through the settlement agreement that included retirement of Campbell.

I. The Ecology Center

The Ecology Center is a Michigan-based nonprofit organization headquartered in Ann Arbor, Michigan, with additional offices in Detroit, Michigan. Ecology Center is a public interest organization with more than 50 years of experience advocating for clean production, healthy communities, environmental justice, and a sustainable future. Ecology Center works at the local, state, and federal level. Its programs address systemic sources of poor health and environmental degradation through unique partnerships with environmental health and environmental advocates. Ecology Center has over 6000 members and supporters, that live, use electricity, and pay electric bills in Michigan, including in Consumers Energy's service territory. Ecology Center intervened and participated fully as a party in Consumers' 2021 Integrated Resource Plan proceeding, and supported resolution of that case through the settlement agreement that included retirement of Campbell.

J. Urban Core Collective

The Urban Core Collective ("UCC") is a member-based organization in Grand Rapids, Michigan. As well as advocacy in strengthening democracy, leadership development and education reform, much of UCC's work has been in climate and environmental justice, specifically in policy which moves toward a transition to renewable sources of energy, energy that is affordable and reliable and which does not contribute to climate change. Our constituents are in the front lines, being affected first and most severely by its impacts. The UCC has intervened in Michigan Public Service Commission cases such as the Consumers Energy Electric

Rate Case (U-21585), the DTE Gas Rate Case (U-21291), and will be filing to intervene in Consumers Energy's electric rate case (Case No. U-21870) recently filed.

The UCC was heavily involved in engaging community members and collaborating with other stakeholders during the last Consumers Energy Integrated Resource Plan. The UCC advocated for the closing of the Campbell Coal Plan.

The UCC contests the reopening of the Campbell coal plant. Firstly, continuing to rely on coal-fired power contradicts efforts towards environmental justice. Communities near the plant, especially in Grand Rapids and surrounding areas, face heightened exposure to health risks like respiratory issues and heart disease due to pollution. Coal plants emit significant amounts of pollutants like sulfur dioxide, nitrogen oxides, and particulate matter, which can exacerbate health problems for vulnerable populations. The decision to keep the plant operational undermines the transition to cleaner energy sources, affecting air quality and contributing to climate change.

Lastly, there are other options to provide Michigan residents and the business community with clean, reliable and affordable energy which does not come from coal such as the Campbell coal plant.

III. BACKGROUND

A. The Campbell Plant Does Not Benefit Consumers Energy's Customers.

1. Campbell Is Old, Unreliable, Dirty, and Expensive.

Located in West Olive, Michigan, 30 miles west of Grand Rapids, Campbell is a power plant that relies on burning coal to generate electricity. The plant has three generating units, which are between 45 and 63 years old. Ex. 11 at 7 (Blumenstock 2024 Direct Testimony). Units 1 and 2 are beyond the typical operational life of coal units, Ex. 3 at 15 (Powers Decl.) (*citing* Exs. 63 (Palgrave Handbook) and 64 (IEA Report)), and all three units have experienced long and recurrent outages in recent years that reflect aged, worn components that are expensive and may be difficult to repair or replace. *Id.* at 4, 15. In the tables below, and with further context in his declaration, Public Interest Organizations' expert engineer identifies the duration and reasons for the units' longest outages in the past two years based on Consumers' filings with the Michigan Commission. *Id.* at 5.

Longest 2024 Outages by Type

Unit	Outage Description	Total Duration (hours)
1	• Degraded governing valve (3 outages) • Worn leaking superheater tube (1 outage)	911 491
2	• Obsolete boiler feedwater pump failure (1 outage) • Degraded valve(s) malfunction (3 outages) • Worn equipment leaks, various (4 outages)	1,417 1,723 854
3	• Worn/failed turbine turning gear (1 outage) • Worn tube leak (1 outage)	1,104 356

The numbers above are rounded to the nearest hour.

Longest 2023 Outages by Type

Unit	Outage Description	Total Duration (hours)
1	• Worn leaking valve and superheater tube (2 outages)	661
2	• Obsolete boiler feedwater pump failure (4 outages) • Worn equipment leaks (3 outages)	3,445 571
3	• Worn leaking boiler/superheater tubes (3 outages) • Worn/vibrating turbine bearings (1 outage)	1,857 426

The numbers above are rounded to the nearest hour.

The outages demonstrate Campbell's increasing inability to consistently perform even under normal conditions, let alone to meet an emergency. All three Campbell units have been unexpectedly unable to produce power during significant portions of recent years (known as the units' "forced outage rate"[2]). *Id.* at 4 (*citing* Consumers' filings with the Michigan Commission). In 2023, the units' forced outage rates were 18.66% (Unit 1), 57.32% (Unit 2), and 22.41% (Unit 3). *Id.* In 2024, the rates were 14.84% (Unit 1), 48.07% (Unit 2), and 19.25% (Unit 3). *Id.* By contrast, the national average forced outage rate for coal-burning units is approximately 12%. *Id.*

Campbell has been a significant source of pollution. Each year when operating, the plant emitted around one hundred thousand pounds of air toxics, hundreds of thousands of pounds of particulate matter, many millions of pounds of nitrogen oxides and sulfur dioxide, and over ten billion pounds of carbon dioxide. *See* U.S. Environmental Protection Agency ("EPA"), ECHO, https://echo.epa.gov/air-pollutant-report-new?fid=110000411108 (last visited June 18, 2025); *see also* EPA, eGRID, https://www.epa.gov/egrid/egrid-pm25 (Jan. 15, 2025). In fact, the plant

[2] Consumers Energy typically uses the phrase "random outage rate" in place of "forced outage rate."

emitted more sulfur dioxide and particulate matter than any other plant in Consumers' generation fleet. Ex. 23 at 10–12 (Bilsback Direct Testimony). Campbell also used approximately *one billion gallons* of water per day from Lake Michigan while discharging significant amounts of contaminated wastewater back into the lake. *See* Ex. 3 at 21 (Powers Decl.) (*citing* Ex. 48 (2021 CWA Permit)). In 2023, for example, the plant discharged approximately 96,000 pounds of pollution, including 10,000 pounds of toxic metals, into Lake Michigan. EPA, ECHO, https://echo.epa.gov/detailed-facility-report?fid=110000411108 (last visited June 18, 2025). Additionally, burning coal at the plant creates toxic coal ash. The plant already holds roughly 6.2 million cubic yards of coal ash in an on-site landfill. Ex. 47 at 4 (2024 Campbell Coal Ash Inspection Report).

Campbell's pollution harms its neighbors. Prior expert analysis of the Campbell units' pollution found that retiring the plant would eliminate annual emissions into the air of 538 tons of particulate matter, 13 tons of volatile organic compounds, 2,918 tons of nitrogen oxides, 5,244 tons of sulfur dioxide, and 8.2 million tons of carbon dioxide emissions based on 2019 operational levels. Ex. 23 at 11 (Bilsback Direct Testimony). Each year, those emissions led to modeled mortality impacts of 36–81 premature deaths and $389–$879 million in health impact costs, including non-fatal respiratory and cardiovascular harms affecting people. *Id.* at 15. According to the Michigan Department of Environment, Great Lakes, and Energy, the census tract in which Campbell is located has far more "adverse environmental factors"—like water pollution and proximity to toxic waste dumps—than the rest of the state, and also has a high socioeconomically vulnerable population compared to the rest of the state. Mich. Dep't of Env't, Great Lakes, and Energy, MiEJScreen, https://www.michigan.gov/egle/maps-data/miejscreen (last visited June 18, 2025). Nearby Grand Rapids has communities that are significantly overburdened by environmental pollution and populations that are uniquely sensitive to pollution due to socioeconomic factors, high rates of disease, and other factors. *Id.*

Campbell is also an expensive plant to run. In 2021, Consumers projected that retiring Campbell in 2025 would avoid $365,008,000 in capital expenditures and major maintenance costs. Ex. 13 at 3–4 (Kapala Direct Testimony) (summing "avoided capital expenditures" and "avoided major maintenance expenses" for Units 1–3). At that time, the cost of power generated by Campbell—including capital, operation, maintenance, and fuel costs—was $33.64 per megawatt hour ("MWh"). Ex. 49 (2025 Energy Innovation Dataset) (compiling data from the U.S. Energy Information Administration). Campbell has gotten even more expensive to run since then. In 2024, the cost of Campbell's power rose to $40.65 per MWh, a 21% increase over the 2021 cost. *Id.* This means the cost of Campbell's power grew significantly faster than inflation (roughly 16%) over the same period. Ex. 50 at 3 (2025 Energy Innovation Coal Cost Report); *see also* Ex. 51 at 12 (2023 Energy Innovation Coal Cost Report) (describing the same methodology used in the 2025 report).

All of these harms could be avoided by retiring Campbell. As further discussed below, Consumers Energy wanted to retire the plant on May 31, 2025. The Michigan Commission and the regional grid operator MISO approved the retirement.

2. Consumers Energy Is a Utility in MISO.

Consumers Energy is the second largest electric utility in Michigan. The utility serves 1.9 million customers across a broad swath of the state's Lower Peninsula.

To meet its customers' energy needs, Consumers owns and operates, or contracts for, a wide array of resources, including gas, oil, hydroelectric, renewables, and hydro-pumped storage. *See* Ex. 27 (2028/2029 Consumers Capacity Demonstration); Ex. 11 at 7 (Blumenstock 2024 Direct Testimony). Consumers also deploys load-modifying resources that significantly reduce energy needs during periods of peak demand. Ex. 27 at PDF 50 (2028/2029 Consumers Capacity Demonstration).

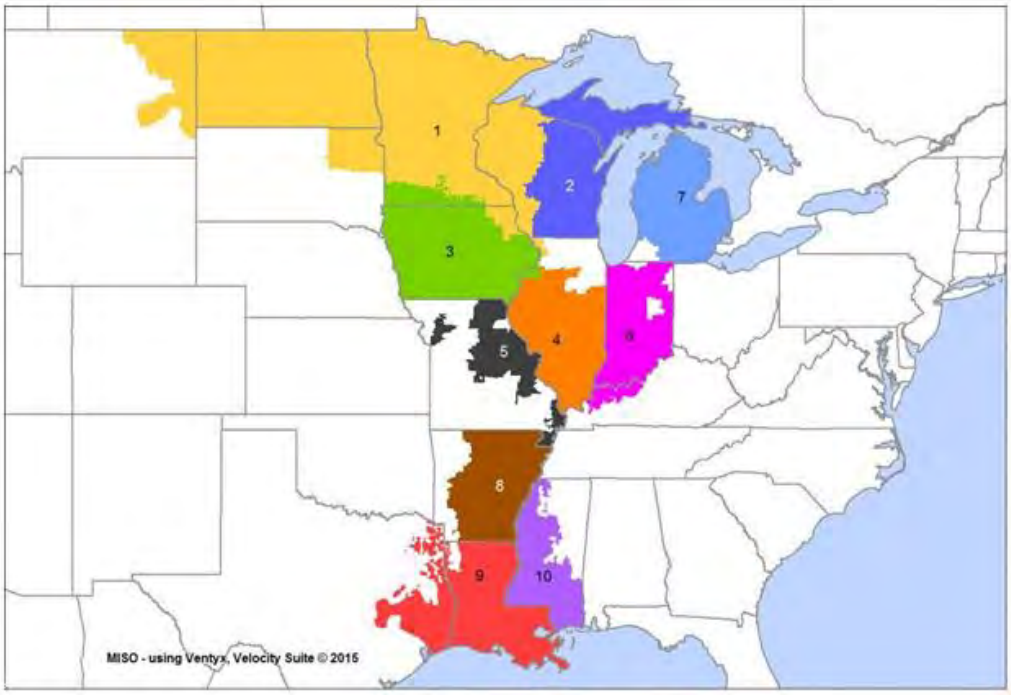
Consumers is also a MISO member, meaning among other things that it participates in MISO-run wholesale interstate markets including energy, ancillary service, and capacity markets, and that it allows MISO to operate its transmission grid. Like most other electric utilities in Michigan, Consumers elected to join MISO (then known as the Midwest Independent Transmission System Operator, Inc.) in the years that followed FERC's issuance of Order No. 888 in 1996 (creating a framework for the creation of Regional Transmission Organizations), MISO's founding in 1998, and FERC's issuance of Order No. 2000 in 1999 (encouraging transmission-owning electric utilities to join Regional Transmission Organizations). *See generally Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996); *Regional Transmission Organizations*, Order No. 2000, 89 FERC ¶ 61,285 (1999).

B. Multiple Authorities Already Protect Resource Adequacy.

As discussed below, Consumers has consistently maintained resource adequacy within its own service territory. Additionally, the resources procured by Consumers and other electric utilities in Michigan have collectively done the same throughout the Lower Peninsula of Michigan. Meanwhile, Consumers is within a larger system also overseeing and safeguarding resource adequacy.

1. MISO Protects Resource Adequacy Through Reserve Margin Requirements and a Residual Capacity Auction.

MISO is the grid operator for territory stretching roughly from North Dakota to Michigan and down to Louisiana. This territory is organized into zones numbered 1 through 10, as shown in MISO's FERC-approved tariff and reproduced below.



MISO implements resource adequacy standards across its territory to ensure it achieves a level of grid reliability meeting both industry standards and those of the North American Electric Reliability Corporation ("NERC"). To meet its resource adequacy requirements, MISO utilizes a series of interconnected mechanisms that both measure current and future system needs and help the utilities in its region secure the resources that best meet those needs at least cost. *See generally* Ex. 46 at 66–75, 87–90 (FERC Energy Primer).

i. Reserve Margin Requirements.

The foundation of MISO's resource adequacy implementation process is its Loss of Load Expectation ("LOLE") study, which measures whether available generation capacity is capable of meeting load demand under various conditions, including low probability but high impact events (such as extreme weather). *See generally* Ex. 38 (MISO LOLE Presentation). MISO runs its LOLE study every year. It utilizes a systemic model, taking inputs from the past thirty years of weather data as well as resource performance characteristics from a broad range of operating conditions. Using this wealth of information, MISO then runs thousands of simulations looking to future years. Each of the simulations examines the system at every individual hour of each year being studied. These simulations thereby identify circumstances that could most stress the system, while also predicting how the system's fleet of resources will perform. Ex. 58 (MISO Tariff Module E-1 – Resource Adequacy). MISO runs this model annually, based on the latest available data.

MISO uses its LOLE study results in conjunction with its system-wide peak demand forecast, which it develops from projections provided by each of the load-

serving entities within its territory. It combines these inputs to determine how much generating capacity is required to meet MISO's industry-standard goal of experiencing no more than one loss-of-load event every ten years. *See* Ex. 2 at 2–5 (Grid Strategies Report). The result of this calculation is a reasonable buffer of extra capacity to account for potential emergencies and other conditions, which is known as the regional Planning Reserve Margin ("Reserve Margin"). The Reserve Margin, stated as a percentage, reflects the amount of generating capacity that must be procured in each season to meet resource adequacy standards across the region. MISO develops a separate Reserve Margin for each season of the year. An illustrative calculation of a Reserve Margin is below.

Illustrative Reserve Margin Calculation

Expected Peak Demand	100,000 MW
Extra Buffer	7,000 MW
Reserve Margin	**7%**

After developing the system-wide Reserve Margin, MISO uses it to convert the peak demand projection for each zone into a capacity requirement (in accredited megawatts, or "MW") that each zone must meet for each season. The requirement for each zone is known as that zone's Planning Reserve Margin Requirement ("Reserve Margin Requirement"), which is the amount of megawatts of capacity that must be procured for each zone. These megawatts can come from inside or outside the zone, so long as they are deliverable to the zone.

As with the zonal calculation, MISO also converts each individual load-serving entity's projected peak demand into a capacity requirement using the system-wide Reserve Margin. A load-serving entity is, like Consumers, an entity that "has undertaken an obligation to serve [l]oad for end-use customers by statute, franchise, regulatory requirement or contract." *See* MISO's FERC-Approved Tariff at Module A, *available at* https://etariff.ferc.gov/TariffBrowser.aspx?tid=1162. And the Reserve Margin Requirement for each zone is, roughly speaking, the sum of all load-serving entities' obligations in that zone.

MISO assigns to each individual resource a capacity value based on its conservative estimate of how likely that generator is to be able to provide energy during peak net demand conditions. The purpose of this estimate is to determine a percentage of resources' maximum capacity (their "accredited capacity") that can be used by load-serving entities to achieve their Reserve Margin Requirements, and it reflects that resources cannot always ensure that they will operate at their maximum possible capacity. Generally speaking, MISO's approach combines probabilistic modeling with historic and unit-specific performance. Through the capacity accreditation process, MISO fully accounts for the limitations of each resource's ability to contribute to MISO's resource adequacy during peak demand conditions or during times of overall system stress (e.g. when extreme weather affects unit performance). And MISO's capacity accreditation rules are regulated

and overseen by FERC. *See, e.g.*, *Midcontinent Indep. Sys. Op., Inc.*, 180 FERC ¶ 61,141, at P 1 (2022) (approving MISO's seasonal resource adequacy construct); *see also Midcontinent Indep. Sys. Op., Inc.*, 189 FERC ¶ 61,065, at P 1 (2024) (approving new methodology applicable to 2028/2029 delivery year).

ii. MISO's Residual Capacity Market.

Finally, once MISO has (1) established the regional Reserve Margin, (2) converted it to a Reserve Margin Requirement for each zone using peak demand projections, (3) apportioned each zone's Reserve Margin Requirement among load-serving entities, and (4) determined all eligible resources' accredited capacity, the load-serving entities must meet their capacity obligations. Load-serving entities have a few options for procuring capacity. First, they can use generating capacity they already own. Second, they can contract with another entity that owns generating capacity to promise to sell energy in the future when called upon by MISO to do so. Third, as a final fallback option they can obtain capacity through a residual capacity market run by MISO known as the Planning Resource Auction ("Planning Auction").

MISO conducts the Planning Auction every year. The Planning Auction is actually four separate simultaneous seasonal auctions. In each auction, MISO solicits operational commitments for the season from a suite of generation resources that will ensure resource adequacy. Many resources provide an "offer" identifying what price they would need to be paid to keep operational (*i.e.*, remain capable of delivering power upon command) all or part of the resource's accredited capacity for each of the four seasons. Other resources, including those already committed to operate via outside contracts, are self-scheduled into the auction process, meaning that MISO treats them as price takers or $0 offers. MISO then stacks each of these resources in ascending cost order, forming a supply curve.

The supply curve crosses a preset sloped demand curve, known as the Reliability Based Demand Curve. The sloped demand curve is designed by MISO to procure a certain amount of capacity at each price point; although it is tethered around MISO's goal of experiencing no more than one loss of load event per decade, it will obtain more capacity if it is cheaper and less if it is more expensive. This is consistent with the general principle that grid operators must always balance the tradeoff between resource adequacy and cost. *See* Ex. 2 at 2–3 (Grid Strategies Report).

The point where the supply and demand curves intersect is called the capacity market clearing price. All resources on the supply curve with offers at or below that amount are then committed to remain operational and be available for the respective season(s) in which they cleared, with the owners of those resources' capacity rights receiving the clearing price. Ex. 58 (MISO Tariff Module E-1).

2. Michigan Protects Resource Adequacy Through Integrated Resource Planning and Annual Capacity Demonstration Requirements.

MISO is not the only entity monitoring resource adequacy. Michigan, like other states in MISO, closely watches this too.

Michigan state law requires that electric utilities file an Integrated Resource Plan with the Michigan Public Service Commission at least every five years. MCL § 460.6t. Those Integrated Resource Plans serve both to ensure resource adequacy and to ensure implementation of the state's and each utility's preferred mix of generation. *See generally Pac. Gas & Elec. Co. v. State Energy Res. Conserv. & Dev. Comm'n*, 461 U.S. 190, 205 (1983) (explaining that states have characteristically governed the need for new power facilities and their economic feasibility); *Citizens Action Coal. v. FERC*, 125 F.4th 229, 239 (D.C. Cir. 2025) ("[T]he States retain authority to choose their preferred mix of energy generation resources."). Pursuant to state law, the Integrated Resource Plan is required to:

> Provide . . . a 5-year, 10-year, and 15-year projection of the utility's load obligations and a plan to meet those obligations, to meet the utility's requirements to provide generation reliability, including meeting planning reserve margin and local clearing requirements determined by the commission or the appropriate independent system operator, and to meet all applicable state and federal reliability and environmental regulations over the ensuing term of the plan.

MCL § 460.6t(3). Each Integrated Resource Plan must include a broad range of information and analysis regarding forecasted energy and capacity needs, supply-side generating resources (*i.e.*, electric generating facilities), and demand-side resources such as energy waste reduction and demand response measures. *Id.* § 460.6t(5).

The Integrated Resource Plan statute requires the Michigan Commission to establish modeling scenarios and assumptions to be used in each Integrated Resource Plan filing. *Id.* §§ 460.6t(1) (modeling scenarios and assumptions), 460.6t(3) (filing requirements). Once an Integrated Resource Plan is filed, the Michigan Commission reviews the plan through a year-long contested case process under the Michigan Administrative Procedures Act, *see id.* §§ 460.6t(7), 24.271–.288, pursuant to which interested parties may intervene, conduct discovery, submit expert testimony, and present and cross-examine witnesses at an evidentiary hearing. The Michigan Commission is statutorily required to approve an Integrated Resource Plan if it determines that "[t]he proposed integrated resource plan represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs." *Id.* § 460.6t(8)(a). In deciding whether the Integrated Resource Plan satisfies that standard, the statute directs the Michigan Commission to consider several factors, including resource adequacy and capacity to serve

anticipated peak electric load, applicable planning reserve margin, and local clearing requirement; reliability; commodity price risks; and diversity of generation supply. *Id.*

Under Michigan law, electric utilities are also required to make annual capacity demonstration filings that project the utility's capacity position over a four-year planning period. *Id.* § 460.6w. After auditing each year's submissions, the Michigan Commission Staff prepares an annual report that discusses resource adequacy throughout the state. *See, e.g.*, Ex. 28 at 16 (2028/2029 Michigan Commission Staff Capacity Demonstration Results) (finding that Michigan meets resource adequacy requirements).

3. NERC Protects Resource Adequacy Through Standards and Regular Assessments.

The North American Electric Reliability Corporation ("NERC") is the Electric Reliability Organization responsible for developing mandatory reliability standards, subject to FERC's review and approval. Ex. 2 at 7 (Grid Strategies Report). NERC also annually assesses seasonal and long-term reliability of the bulk power system and monitors system performance. *Id.* at 7–8. NERC's assessments and activities are further discussed *infra* in section IV.A.2.iii.

C. Campbell's May 31, 2025 Retirement and Resource Adequacy in Summer 2025 Have Been Carefully Planned.

1. Campbell's May 31, 2025 Retirement Was the Product of Careful Planning from Diverse Stakeholders Under a Settlement that Improves Resource Adequacy.

In 2021, Consumers Energy filed an Integrated Resource Plan that proposed retiring the Campbell Plant in 2025, acquiring the 1,176 MW New Covert gas plant in 2023, and making substantial investments in new generation and storage resources. Following a lengthy contested case process—with thousands of pages of testimony, multiple rounds of briefing, and an evidentiary hearing—the Michigan Commission approved in 2022 a comprehensive settlement agreement ("2022 Settlement") that established Consumers' long-term resource plan and provided for Campbell's May 31, 2025 retirement. Ex. 9 at PDF 95, 100–02 (Order Approving Campbell Settlement Agreement and Settlement Agreement). The 2022 Settlement was negotiated and signed by a wide array of parties in the Integrated Resource Plan case, including:

- Michigan Commission Staff;
- Michigan's Attorney General;
- Consumers Energy;
- residential ratepayer advocates;
- commercial and industrial customers;
- businesses in the energy sector;
- advocacy groups such as Sierra Club, Natural Resources Defense Council, Michigan Environmental Council, Environmental Law and Policy Center, Vote Solar, and Urban Core Collective;
- a transmission company; and
- third-party energy developers.

Id. at PDF 116–130; Ex. 18 at 5–6 (Proudfoot Rebuttal Testimony); *see also* Ex. 53 (Consumers News Release) ("A key regulatory decision today cleared the way for Consumers Energy to stop burning coal to generate electricity by 2025 — 15 years faster than previously planned — and provide reliable electricity for Michigan . . . A broad coalition of supporters for the plan includes customer groups, environmental organizations, MPSC staff, energy industry representatives and the Michigan Attorney General.").

While the 2022 Settlement included some elements of Consumers' original Integrated Resource Plan, such as acquiring the New Covert gas plant, it also made several changes that further bolstered the plan's ability to ensure resource adequacy both within the state and across MISO. In particular, as part of the 2022 Settlement, Consumers agreed to extend to 2031 the operation of two oil- and gas-fired peaker units at the utility's Karn plant from their originally proposed retirement date of 2023. Ex. 9 at PDF 101–02 (Order Approving Campbell Settlement Agreement and Settlement Agreement). Doing so added approximately 784 MW of generating capacity compared to the original plan. Ex. 56 at 21 (Blumenstock 2021 Second Rebuttal Testimony); Ex. 19 at PDF 94 (Walz Direct Testimony). Under the 2022 Settlement, Consumers would also solicit power purchase agreements to provide capacity beginning in the 2025/2026 planning year. Ex. 9 at PDF 103–04 (Order Approving Campbell Settlement Agreement and Settlement Agreement). Such solicitation would be for up to 500 MW of thermal generation, and up to 200 MW of clean energy resources. *Id.* Under the settlement, Consumers would also add new battery storage assets (a dispatchable resource) in the 2024–2027 timeframe. *Id.* at PDF 101; Ex. 57 at 18 (Jester 2021 Direct Testimony).

In approving the 2022 Settlement, the Michigan Commission specifically addressed the importance of maintaining resource adequacy. Ex. 9 at PDF 93–95 (Order Approving Campbell Settlement Agreement and Settlement Agreement). The Commission imposed requirements to consider resource adequacy for a utility's own customers, MISO zones, and other regions. *Id.* at PDF 93. It found that the plan embodied in the settlement was supported by substantial evidence and "is the

most reasonable and prudent means of meeting Consumers' energy and capacity needs and otherwise meets the requirements of" Michigan's Integrated Resource Plan statute. *Id.* at PDF 95.

A few parties challenged the 2022 Settlement on various grounds. Of note, Wolverine Power Supply Cooperative ("Wolverine"), a minority owner of Campbell Unit 3 with a stake less than 2%,[3] raised concerns about resource adequacy.

The Michigan Commission explained why objections to the settlement based on resource adequacy were unpersuasive. The Michigan Commission discussed the record evidence regarding acquisition of the 1,176 MW New Covert gas-fired power plant, extended operation of Karn units 3 and 4, new battery storage, and ongoing investments in solar, energy waste reduction, and demand response. *Id.* at PDF 90–93. The Michigan Commission then found that "the approval of the settlement agreement enhances zonal resource adequacy in the short, medium, and long term(s)." *Id.* at PDF 92. As such, the Michigan Commission found that the 2022 Settlement "provides a reasonable and prudent plan for meeting resource adequacy requirements." *Id.* at PDF 91.

Wolverine in turn appealed the Michigan Commission's decision to the Michigan Court of Appeals. The court rejected the challenge, noting in part that Wolverine "mischaracterize[d]" the Michigan Commission's handling of the resource adequacy issue, and "fail[ed] to address the substantive basis for the [Michigan Commission's] conclusion" that the 2022 Settlement properly addressed resource adequacy. *Wolverine Power Supply Coop., Inc. v. Mich. Pub. Serv. Comm'n*, No. 362294, 2023 WL 2620437, at *5 (Mich. Ct. App. Mar. 23, 2023).

2. MISO Approved Campbell's May 31, 2025 Retirement Upon Finding No Reliability Violations.

Pursuant to MISO's FERC-approved tariff, a utility within MISO seeking to suspend the operation of a generating unit must provide an "Attachment Y" notice to MISO. Ex. 60 at 1 (MISO Tariff Section 38.2.7); Ex. 61 (MISO Tariff Attachment Y); *see also* MISO's FERC-Approved Tariff at Attachment Y, *available at* https://etariff.ferc.gov/TariffBrowser.aspx?tid=1162 (containing prior versions of the

[3] Consumers owns about 93% of Unit 3, the Michigan Public Power Agency owns 4.8%, and Wolverine owns less than 2%. Ex. 24 at 2 ¶ 4 (Mich. Pub. Power Agency Petition to Intervene); Ex. 13 at 6 (Kapala Direct Testimony); Ex. 20 at PDF 28 (King Direct Testimony). The Michigan Public Power Agency did not oppose Consumers' decision to retire Unit 3. Under the ownership agreements that govern Unit 3, Consumers has the sole authority to decide when to retire it. Ex. 20 at 95 (King Direct Testimony).

tariff). The purpose of the notice is to enable MISO to evaluate the potential local grid reliability impacts of such suspension. *See* Ex. 60 at 1.

Consumers submitted the required notice to MISO in December 2021. Ex. 29 at PDF 6 (2024 Consumers ELG Annual Report). Consumers stated its intent to suspend operation of Campbell Units 1–3 effective June 1, 2025. *Id.*

In March 2022, MISO notified Consumers that it had reviewed the Campbell retirement for "power system reliability impacts," and concluded that retirement "would not result in violations of applicable reliability criteria." *Id.* at PDF 9. As such, MISO concluded that the retirement could proceed "without the need for the generators to be designated as a System Support Resource ('SSR') units [*sic*]," a designation that allows MISO to retain generators needed for reliability reasons. *See id.* MISO has not acted to revise its conclusion that Campbell could retire without implicating local reliability issues in the area around the facility.

3. Consumers Has Been Winding Down Campbell and Ramping Up Replacement Resources.

Following its filing of the Integrated Resource Plan and the Michigan Commission's approval of the 2022 Settlement, Consumers changed its approach to Campbell. Rather than invest in and maintain the plant to provide an adequate level of reliability, Consumers transitioned to a reactive, "fix it if breaks" approach to Units 1–3. Ex. 3 at 15–16 (Powers Decl.). Public Interest Organizations' expert engineer provides the following summary of the significant decline in investment and maintenance of the units. *Id.* at 6 (developed based on testimony from Consumers witnesses Kapala and Blumenstock, Exs. 10–13).

Reductions in Capital and Major Maintenance Spending at Campbell for 2022–2025

	Pre-IRP Projected Spend	Post-IRP Actual/Projected Spend	Reduction
Capital Spending			
Units 1&2	$60.6 Million	$4.1 Million	93%
Unit 3	$85.5 Million	$8.4 Million	90%
Major Maintenance Spending			
Units 1&2	$14.4 Million	$5.5 Million	62%
Unit 3	$23.5 Million	$5.1 Million	78%

The figures above are rounded to the nearest decimal shown. "IRP" refers to Consumers' 2021 Integrated Resource Plan proceeding, which concluded with the Michigan Commission's approval of the 2022 Settlement.

The expert engineer further details Consumers' canceled projects and explains the cancellations' likely impact on the units' reliability. *Id.* at 5–16. As just one example among the dozens that he identifies, Consumers canceled a $7.9 million

turbine overhaul project to maintain Unit 3 scheduled to take place in 2024. *Id.* at 13, 16. In April 2024, the turbine failed, resulting in a 46-day outage. *Id.* The turbine was eventually repaired, but *only for the limited objective of allowing Unit 3 to continue to operate until the planned retirement in May 2025*. *Id.* at 5 n.9, 13, 16.

As a result of the canceled projects and forgone maintenance and investment, it is unlikely that Campbell can reliably dispatch without significant further expense. *Id.* at 5–6, 13, 15–17. The Chair of the Michigan Commission reportedly believes the costs to render Campbell operational range from a minimum of tens of millions of dollars to close to $100,000,000. Ella Nilsen, CNN, *The Trump Admin Ordered a Coal Power Plant to Stay on Past Retirement. Customers in 15 States Will Foot the Bill* (June 6, 2025), https://www.cnn.com/2025/06/06/climate/michigan-coal-plant-energy-cost-wright.

The evidence bears out the plant's unreliability. As explained above in section III.A.1, the Campbell units have demonstrated their inability to consistently perform in recent years. This unreliability reflects the impact of worn and difficult-to-repair or replace components, causing outages that tended to be long and recurrent. Ex. 3 at 4 (Powers Decl.).

At the same time that Consumers has prepared to retire the aging and increasingly unreliable units at Campbell, Consumers has taken multiple steps over the last several years to bring substantial new generating capacity online that bolsters resource adequacy and reliability in Michigan, MISO Zone 7, and the region. In the years since the Michigan Commission approved Consumers' 2021 Integrated Resource Plan, and since MISO's considered determination that retiring Campbell did not present reliability concerns, Consumers proceeded with acquiring or constructing many of the generating assets called for under the 2022 Settlement. In 2023, Consumers completed its acquisition of the Covert plant, a three-unit combined cycle gas plant. Ex. 12 at 8 (Blumenstock 2025 Direct Testimony). By acquiring Covert and transferring the plant to MISO, Consumers added 1,090 MW of net generating capacity to MISO Zone 7. Ex. 21 at 7–9 (Bleckman Direct Testimony); *see also* Ex. 22 at 8 (Hahn Direct Testimony). Consumers has continued developing renewable assets, including a 198 MW wind facility that went into service in 2024, and several solar projects, totaling 1,421 MW, with commercial operation dates in 2026–28. Ex. 21 at 7–9 (Bleckman Direct Testimony). Ultimately, Consumers intends to develop 6.6 gigawatts ("GW") of solar and wind generation resources. *Id.* at 8. Consumers has also entered into long-term contracts for three large battery storage projects, a power purchase agreement that will provide 175 accredited MW of gas-fired generation capacity in the 2025 and 2026 MISO planning years, and another power purchase agreement providing a further 100 MW of capacity in the 2025–27 planning years. Ex. 12 at 8–9 (Blumenstock 2025 Direct Testimony).

4. Consumers Has Continued to Demonstrate Resource Adequacy.

Apart from the Integrated Resource Plan proceeding—which, as noted above, resulted in a plan that bolsters resource adequacy in MISO—Consumers has also consistently met Michigan's resource adequacy requirements to demonstrate capacity each year under MCL section 460.6w. Consumers' filings have consistently shown that the company is maintaining and procuring sufficient capacity to serve its customers, while meeting the necessary reserve margin. Ex. 25 (2026 Consumers Energy Capacity Demonstration); Ex. 26 (2027/2028 Consumers Energy Capacity Demonstration); Ex. 27 (2028/2029 Consumers Capacity Demonstration). For the Summer 2025 season—the timeframe that is the subject of DOE's Order—Consumers has surplus resources. Ex. 27 at PDF 14 (Consumers 2028/2029 Capacity Demonstration). And as discussed in its most recent annual report, issued on May 12, 2025, the Michigan Commission Staff found that Consumers meets resource adequacy requirements for both the 2025/26 year, and through the 2028/29 year. Ex. 28 at 16. As a result of the most recent MISO Planning Resource Auction, the Michigan Commission Staff noted that MISO Zone 7 "cleared above seasonal reliability targets, representing additional reliability value at cost competitive prices." *Id.*

5. MISO Has More Resources than It Needs to Ensure Resource Adequacy in Summer 2025.

MISO published the results of its LOLE study for Summer 2025—the timeframe that is the subject of DOE's Order—in mid-March. *See* Ex. 31 at 2 (MISO 2025–26 Auction Results). In that study, MISO concluded that an overall Reserve Margin of 7.9% above peak load projections would be adequate to maintain the overall resource adequacy of the MISO region. *Id.* Here is MISO's calculation.

MISO's Summer 2025 Reserve Margin Calculation

Expected Peak Demand[4]	125,313.3 MW
Extra Buffer	9,900.1 MW
Reserve Margin	**7.9%**

MISO published the results of its Planning Auction process for Summer 2025 at the end of April 2025. Those results demonstrate that MISO secured more than sufficient resources to achieve resource adequacy for Summer 2025. In fact, consistent with the design of its Reliability Based Demand Curve, MISO secured an overall 9.8% Reserve Margin—almost two percentage points more than the 7.9%

[4] The figure shown here adds approximately 2,700 MW to actual expected peak demand to account for electric energy losses as the power moves through the transmission system, consistent with MISO's approach. *See* Ex. 59 (MISO 2025–2026 Prelim. PRA Report with Final Results).

target that MISO determined was needed to meet resource adequacy requirements. Ex. 31 at 5 (MISO 2025–26 Auction Results).

MISO's Planning Auction also secured adequate local offers to maintain resource adequacy in MISO Zone 7, which covers almost the entirety of Michigan's Lower Peninsula. Specifically, Zone 7's accredited offers from local resources were over 98% of the Zone's required Reserve Margin in Summer 2025, which in combination with transmission availability from neighboring Zones was more than enough to maintain the Zone's resource adequacy. *Id.* at 18 (demonstrating that Zone 7 had sufficient local offers to easily exceed, by 1.2 GW, its Local Clearing Requirement, which is the minimum amount of local resource offers that must be located within each Zone); *see* Ex. 2 at 10. This means Zone 7 also has plenty of leftover headroom on its transmission connections with neighboring regions to meet unexpected circumstances.

Additionally, in real-time and near-term operations, MISO will be able to employ the flexibility provided by its markets, including the energy and ancillary services markets. *Id.* at 5–6. Through the ancillary services market, for instance, MISO can procure services like operating reserves from flexible resources that help balance fast variability in supply and demand. *Id.* And MISO has numerous additional tools it can employ in stepwise fashion should it encounter a risk of a generation shortage in real-time operations. *Id.* at 6–7.

6. FERC's Recent Technical Conference Confirms that MISO Has Adequate Resources for Summer 2025.

Recently, FERC held a technical conference to address, among other things, resource adequacy in MISO. Ex. 62 at 13 (FERC Technical Conference Notice). The technical conference focused on long-term planning issues, not any purported short-term emergency. *See id.* at 13–17.

To the extent short-term conditions were addressed, witnesses dispelled the notion that MISO is experiencing a resource adequacy emergency. MISO's representative testified that no capacity deficits have materialized in 2025. Ex. 34 (Ramey MISO Comments). Similarly, the Independent Market Monitor for MISO, whose job is to scrutinize the performance of MISO's markets and related procedures for efficiency and efficacy, emphasized that "MISO is *more than* adequate moving into the Summer of 2025, and [he does] not have substantial concerns about the MISO region in the near term." Ex. 35 at 2 (Patton MISO Comments) (emphasis added). The technical conference further demonstrates that normal processes are unfolding to address long-term issues.

IV. REQUEST FOR REHEARING

A. The Order Exceeds the Department's Authority Because the Department Has Not Demonstrated, and Cannot Demonstrate, an Emergency Necessitating Continued Operation of the Campbell Plant.

The Order exceeds the Department's authority because there is no emergency within the meaning of Section 202(c). Both MISO and Michigan have confirmed the absence of any immediate resource shortfall, and the sources cited by the Order only confirm that absence.

1. Section 202(c) Only Authorizes the Department to Respond to Specific, Imminent, and Temporary Events Necessitating Immediate Response.

Section 202(c) of the Federal Power Act allows the Department to order "the generation . . . of electric energy" only "[d]uring the continuance of any war in which the United States is engaged," or if "the [Department] determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy or of fuel or water for generating facilities, or other causes." 16 U.S.C. § 824a(c)(1). That provision's fundamental textual requirement—an "emergency"—limits the Department's authority to immediate, unexpected circumstances that cannot be otherwise avoided. An emergency is "an unforeseen combination of circumstances or the resulting state that calls for *immediate* action." Merriam Webster's Dictionary 407 (11th ed. 2009) (emphasis added).[5] And the statute's use of the present tense—"exists"—demands, at a minimum, that the emergency be imminent and certain rather than distant and contingent. *See also* 16 U.S.C. § 824a(c) (empowering Department only "during" an existing emergency).

The remainder of Section 202(c) underscores the exigency inherent in the governing term "emergency": the authority granted by Section 202(c) is, in the first instance, a war-time power. 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*

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[5] 3 Oxford English Dictionary 119 (1st ed. 1913) (defining emergency similarly as "a state of things *unexpectedly* arising, and urgently demanding *immediate* action" (emphasis added)); *see also* 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").

Power and Light 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 202(c) provides "temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose").[6]

Section 202(c) is further limited to actions addressing temporary shortfalls in supply—it provides no power to implement long-term policy preferences, including preferences for particular sources or fuels. The statute "is aimed at situations in which demand for electricity exceeds supply and not at those in which supply is adequate but a means of fueling its production is in disfavor." *Richmond Power and Light*, 574 F.2d at 615. Nor, more fundamentally, does Section 202(c) allow the Department to override a state's choice of the appropriate mix of in-state generation. *Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power,* 46 Fed. Reg. 39,984, 39,985 (Aug. 6, 1981) (recognizing that the Department cannot, via Section 202(c), "replace prudent utility planning and system expansion"); *see also Hughes v. Talen Energy Mktg., LLC,* 578 U.S. 150, 154 (2016) (noting the "States' reserved authority . . . over in-state 'facilities used for the generation of electric energy'" (quoting 16 U.S.C. 824(b)(1)); *Citizens Action*, 125 F.4th at 238–39 ("[T]he States retain authority to choose their preferred mix of energy generation resources"); *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009) (upholding FERC's approval of capacity requirements because they do not interfere with the right of "[s]tate and municipal authorities . . . to require retirement of existing generators," to prefer "environmentally friendly units," or "to take any other action in their role as regulators of generation facilities without direct interference from the Commission").

The wider statutory context reinforces Section 202(c)'s tightly limited scope. First, the preceding subsections 202(a) and (b) provide cabined authority (exercised by FERC, rather than the Department) to "direct a public utility . . . to establish physical connection[,] . . . sell energy to or exchange energy" with other persons, under normal, non-emergency conditions. 16 U.S.C. § 824a(a)–(b). Those subsections establish specific standards and procedural requirements for such non-emergency orders. *Id.* Section 202(c) removes many of those requirements—but does so only during wartime or similarly extreme circumstances. *Id.* § 824a(c); *see Otter Tail Power Co. v. Fed. Power Comm'n*, 429 F.2d 232, 234 (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

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[6] While Congress amended Section 202(c) in 2015, it did not alter the Department's basic grant of emergency authority; it only addressed occasions on which a Department order might produce a conflict with other laws. *See* H.R. Rep. No. 114-357 (2015).

future"). That structure establishes a clear divide between quotidian energy-system management (even where necessary to avert a non-imminent shortage) governed by Section 202(b), and unusual, unforeseeable emergencies governed by Section 202(c).

Second, Section 215 of the Federal Power Act, added in 2005, separately addresses non-imminent reliability planning: It provides for federal reliability standards subject to discrete procedures and timeframes, and with specified enforcement mechanisms. *See generally* 16 U.S.C. § 824o. As the D.C. Circuit has recognized, the portion of the Federal Power Act that predates that section—which includes Section 202(c)—did not provide the federal government with the power to enforce requirements designed to ensure broad, long-term reliability. *Alcoa Inc. v. FERC,* 564 F.3d 1342, 1344 (D.C. Cir. 2009) (noting that prior to the Energy Policy Act of 2005, "the reliability of the nation's bulk-power system depended on participants' voluntary compliance with industry standards"). Congress added a comprehensive scheme, in Section 215, including separate and tightly cabined procedures to address non-imminent reliability concerns; that scheme precludes expanding Section 202(c)'s "emergency" authority to encompass those same concerns. S*ee FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 132–33 (2000) (noting that when interpreting broad statutory terms, courts should be particularly attentive to whether "Congress has spoken subsequently and more specifically to the topic at hand"). Reading Section 202(c) to provide such authority would bypass the limits and procedures that Congress enacted in Section 215; upset the careful balance that section strikes between federal, state, and private power; and override Congress' calibrated choice of enforcement mechanisms. *See Cal. Indep. Sys. Op. 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 [separate section] confers no such authority on [agency].").

The Department's longstanding regulations to implement Section 202(c) confirm those textual and contextual limitations. They define an "emergency" as "an unexpected inadequate supply of electric energy" resulting from "the unexpected outage or breakdown of facilities," which may result from "weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent." 10 C.F.R. § 205.371. Anticipated customer demand can be an emergency only upon "a *sudden* increase" in such demand. *Id.* (emphasis added); 46 Fed. Reg. at 39,985–86 (stating that the regulation defines "emergency" such that the Department may provide "assistance [to a utility] during a period of unexpected inadequate supply of electricity," but cannot "solve long-term problems"). Those examples reflect the limited nature of the emergencies encompassed by Section 202(c): unusual, unforeseen, and unexpected events, with immediate and substantial consequences. The Department's implementing regulations further confirm that Section 202(c) does not permit the Department to use "emergency" orders to commandeer long-term planning: That "a shortage of electric energy is projected" to result from economic factors, or utility decision-making, is not an

emergency absent an "*imminent*" "inability to supply electric service." 10 C.F.R. § 205.371 (emphasis added). They confirm that Section 202(c) authorizes orders "meeting a *specific* inadequate power supply situation"—it does not allow the Department to act merely because it believes that other parties have undertaken "inadequate planning." *Id.* (emphasis added). And the regulations recognize that inadequate energy supply can form the basis of an emergency only where existing resources are "unable to meet . . . *normal* peak load requirements"—not where they merely fall short of extreme or abnormal projections—and only where those requirements cannot be met through "use of all . . . otherwise available resources." 10 C.F.R. § 205.375 (emphasis added).

2. There Is No Factual Basis Supporting the Department's Order.

The Department's determination that an emergency exists "is based on" a purported "insufficiency of dispatchable capacity" to meet "anticipated demand during the summer months." Ex. 1 at 2 (DOE Campbell Order). But none of the facts or materials it relies on indicate that a present or imminent emergency exists. Indeed, the Department's own justification does not assert that there is a present or imminent emergency, only "potential tight reserve margins" or an "elevated risk of operating reserve shortfalls." *Id.* at 1. The Order expresses concern about plant closures in Michigan and the potential temporary unavailability of the Palisades nuclear power plant, and cites to MISO's discussion of its Planning Auction results for Planning Year 2025–2026 and a NERC 2025 Summer Assessment that identifies MISO as facing an "elevated risk"—but none of these references describe factual circumstances that come close to meeting the narrow definition of "emergency" that permits Departmental action under Section 202(c). 16 U.S.C. § 824a(c)(1). As a result, the Department fails to justify its emergency determination.

As the following sections explain, the Department has misrepresented the reports on which it relies, for a few reasons: i) Both Consumers and Michigan have prepared diligently for the retirement of Campbell such that its long-planned retirement is not remotely likely to impact the state's resource adequacy; ii) MISO has already determined that its grid will be secure this summer presupposing Campbell's planned retirement; and iii) NERC's 2025 Summer Assessment does not undermine any of those determinations. To the extent the Department's vague references were intended to refer to longer-term planning issues, those would be well outside both the stated justification for this Order, and Section 202(c)'s ambit more broadly. Thus, there is no factual or legal basis for the Department's emergency declaration.

i. Michigan's Stewardship of Grid Security has Already Ensured that the Campbell Retirement Will Not Disrupt Michigan's Grid.

As explained above, nothing about the process Consumers and Michigan followed to evaluate, plan for, approve, and ultimately implement the retirement of

Campbell and its replacement with sufficient resources to maintain resource adequacy provides any factual support for the Department's emergency declaration here. Consumers and Michigan regulators have been planning for the retirement of Campbell, as well as other recent retirements cited in the Order, for years. *See supra* sections III.B.2, III.C.1, III.C.3–.4. These plans reflect the 2022 Settlement, approved by the Michigan Commission, to which many of the Public Interest Organizations are a party and which set the May 31, 2025, retirement date for the plant. *See supra* section III.C.1. Michigan has been running annual assessments of its resource adequacy to ensure that no part of its system is threatened by recent and planned retirements. *See supra* sections III.B.2, III.C.4. And MISO conducted a local reliability assessment to ensure Campbell's retirement does not even destabilize a smaller load pocket on the system. *See supra* section III.C.2. Nothing about Campbell's planned retirement was unexpected, and nobody was unprepared.

More broadly speaking, individual generator retirements simply cannot, of themselves, demonstrate a resource shortfall: they must be paired with some demonstration that those responsible for maintaining resource adequacy failed to anticipate and, if necessary, compensate for such retirements. Indeed, generators shut down on a regular basis, just as new generators open on a regular basis. As long as those responsible for the system account for those retirements (as occurred here) and ensure that system resources remain adequate, there is no basis to cite the retirement of any particular facility as evidence of an emergency on the grid. Consumers and Michigan have both provided extensive assurances of resource adequacy here; the Order fails to provide any basis to conclude that there have been any "unforeseen occurrences," or any "inadequate planning" that is expected to produce an emergency from the cited retirements. 10 C.F.R. § 205.371.

ii. MISO's Stewardship of Grid Security Across its Region has Already Ensured that It Will Not Experience an "Electricity Supply Shortfall" in Summer 2025.

MISO's multilayered resource adequacy protections have also ensured that no emergency exists within the meaning of Section 202(c). As described above, MISO followed exactly the same resource adequacy protocol for Summer 2025 as it has for over a decade, beginning with the operation of a comprehensive LOLE model analysis to identify a target Reserve Margin of 7.9%. *See supra* section III.B.1.i After developing the regional Reserve Margin for the summer, MISO then converted it to Reserve Margin Requirements based on the Zones' individual load projections, and conducted the 2025–26 Planning Auction to secure the resources necessary to meet those Reserve Margin Requirements. *See supra* section III.B.1.ii. And the results of MISO's Planning Auction for Summer 2025, published this past April, show that MISO did not just meet its 7.9% Reserve Margin, which would have meant procuring 135.2 GW of capacity across its system. Through operation of its new sloped demand curve, MISO secured an additional 2.3 GW of capacity *beyond* what it initially targeted, thereby achieving a 9.8% Reserve Margin, almost 2%

more than the 7.9% it concluded was needed to keep the grid stable. *See supra* section III.C.5. This Planning Auction was the first to procure more capacity than was needed, so MISO has actually taken *more* steps to ensure the stability of its grid for Summer 2025 than in any previous year. Ex. 31 at 5 (MISO 2025–26 Auction Results).

To the extent the Order's emergency declaration relies on an alleged shortfall in Michigan specifically, the Planning Auction results in Zone 7, which encompasses the lower peninsula of Michigan, belie any such shortfall. As explained above, Zone 7 cleared well in excess of its Local Clearing Requirement, which is the level of resources located within Zone 7 that are necessary, in conjunction with existing transmission ties to the rest of MISO, to ensure resource adequacy. In other words, Zone 7 had more than adequate resources to meet its needs through a combination of locally sourced generation and readily available out-of-Zone assets.

Further confirming those determinations of resource adequacy, just this month, in testimony before FERC during the Commissioner-led Technical Conference Regarding the Challenge of Resource Adequacy in RTO and ISO Regions, MISO's representative testified that no capacity deficits have materialized in 2025. *See generally* Ex. 34 (Ramey MISO Comments). Similar testimony came from David Patton, the Independent Market Monitor for MISO, whose job it is to scrutinize the performance of MISO's markets and related procedures for efficiency and efficacy. In his testimony, Dr. Patton emphasized that "MISO is *more than* adequate moving into the Summer of 2025, and [he does] not have substantial concerns about the MISO region in the near term." Ex. 35 at 2 (Patton MISO Comments). This testimony provides further evidence disproving the existence of a resource adequacy emergency within the meaning of Section 202(c).

To reach a contrary result, the Order includes two citations to MISO's 2025–26 Planning Auction results, apparently as evidence of a resource adequacy "emergency" in the MISO region. Ex. 1 at 2 (DOE Campbell Order). But both of these citations rest on a fundamental mischaracterization of the nature and purpose of the Planning Auction and MISO's discussion of its results. First, the Order quotes MISO for the proposition that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources," *id.*—but in making this observation, MISO was in no way suggesting that there were insufficient resources to achieve resource adequacy in Summer 2025. MISO was simply explaining why the total accredited volume of resources that bid into the Planning Auction went down slightly from 2024 to 2025. Ex. 31 at 13 (MISO 2025–26 Auction Results). Indeed, the charts directly below this quotation and on the next page show that 137.8 GW of accredited capacity were available; and the chart on page 18 shows that only 135.2 MW were needed to achieve MISO's resource adequacy goals (although, as highlighted above, more were actually procured by operation of MISO's sloped demand curve). *Id.* at 13–14, 18. In

other words, the MISO system will be even more secure in Summer 2025 than the industry standard.

Meanwhile, the Order's quotation of MISO for the proposition that the summer season's "highest risk and . . . tighter supply–demand balance" "reinforce the need to increase capacity" is truncated: MISO was referring to a need to increase capacity "as demand is expected to grow with new large load additions." *Id.* at 2. This need can only realistically arise after Summer 2025; any large load additions coming online by this summer were included in the Zones' load projections for the Planning Auction. This is a crucial distinction because the entire basis for the Department's declaration of an emergency is, and only ever could be, near-term resource adequacy shortfalls. It is therefore clear that the Department's citations to MISO's Planning Auction do not indicate that an emergency exists within the meaning of the Federal Power Act Section 202(c).

The Department cannot arbitrarily invent an emergency. Yet, its reliance on MISO Planning Auction results and other statements is inapposite: MISO has made clear time and again that the vast region over which it has balancing authority is resource adequate for Summer 2025. This means that MISO is not facing any imminent shortage that might justify an emergency declaration within the meaning of Section 202(c).

iii. NERC's Identification of an "Elevated Risk" for MISO Does Not Support a Finding of an Emergency under Section 202(c).

The final citation the Department relies on to support its assertion that an emergency supposedly exists in the MISO region comes from the North American Electric Reliability Corporation's ("NERC") 2025 Summer Reliability Assessment. Specifically, the Department emphasizes NERC's conclusion that "MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output." Ex. 1 at 1 (DOE Campbell Order) (*citing* Ex. 41 at 16 (NERC 2025 Summer Reliability Assessment)). Once again, the Department's reliance on this Assessment is based on a foundational mischaracterization of its nature, purpose, and conclusions.

First, the NERC Assessment does not serve the purpose the Department seems to believe. The purpose of the NERC Assessment is to identify and point out to grid operators such as MISO constraints that might arise and implicate grid reliability if not mitigated appropriately. Ex. 41 at 4 (stating that the report "is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure [bulk power system] reliability."). This means the events flagged by NERC are not necessarily grid emergencies; they are periods of time in which MISO might need to take certain mitigation measures to maintain grid security. Crucially, the types of mitigation measures NERC endorses are readily available to MISO; they do not come close to

the extreme measures the Order demands. The Assessment's recommendations include "[r]eview[ing] seasonal operating plans and protocols for communicating and resolving potential supply shortfalls," including the "potential for higher-than-anticipated forced generator outage rates" in operating plants; entering into "conservative operations" earlier and better coordinating generator outages; and "prepar[ing] for efficient implementation of demand-side management mechanisms." *Id.* at 8. This list of interventions focuses on operational preparedness rather than resource manipulation as the most viable pathway to ensuring grid stability even in extreme scenarios; notably absent from this list of recommendations is a suggestion to interfere with previously established resource management decisions.

Second, and consistent with its foundational purpose, NERC's Assessment designates "load-modifying resources" (*i.e.*, demand response reserve resources) and "energy transfers from neighboring systems" as "operating mitigations" available to MISO rather than as "anticipated" (available) resources. *Id.* at 16; *see also* 10 C.F.R. § 205.375 ("A system may be considered to have an inadequate . . . energy supply capability when" "it is unable to meet normal peak load requirements based upon use of *all of its otherwise available resources* . . . .") (emphasis added).[7] This is consistent with the NERC Assessment—using both resource types requires advanced planning and preparedness by MISO—but it underscores the Department's misunderstanding when it cites to NERC's classification scheme without acknowledging that "risks" identified by NERC can easily be "mitigated" by these two crucial categories of resources. In other words, the "elevated risk" identified in NERC's assessment is *not* one of a grid emergency; it is instead a risk of an event that MISO could mitigate by accessing a suite of demand response resources and imports of power from neighboring regions to keep the grid operating smoothly.

The possibility that MISO might ask backup demand response resources to activate is not an "emergency" within the meaning of Section 202(c) because that is the point of such resources: they offer to curtail their use of power on demand in exchange for hefty payments. Instead, it is indicative of routine analysis and planning. Similarly, MISO's operational planning metrics already presume that most grid-straining events can be reduced or eliminated by importing large quantities of power from neighboring regions, even without firm import

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[7] The Department must incorporate demand response and other alternatives in determining whether an emergency exists, and as a condition precedent to circumstances calling for generation by a polluting resource like Campbell, a requirement consistent with Departmental practice. *See* 16 U.S.C. § 824a(c)(1)–(2); 10 C.F.R. § 205.375; *e.g.*, Ex. 39 at 4–5 (DOE Order No. 202-22-2); Ex. 45 at 2–3 (DOE Order No. 202-21-1); Ex. 17 at 3 (DOE Order No. 202-20-2).

commitments (*i.e.*, from resources that have committed in MISO's Planning Auction to principally serve MISO's load). Any "event" identified by NERC can already be addressed by the large number of transmission interconnections between MISO and its neighboring regions.

Indeed, MISO's ability to import power, both into Michigan and into its broader footprint, is one of the key resources it relies on to alleviate grid constraints. For the entire period of the Order, Zone 7 can import around 3,600 MW. Ex. 37 at 13 (MISO 2025–2026 CIL/CEL Final Results). And the MISO territory's transmission connectivity with its neighbors gives MISO approximately 24 GW of import capability[8] from other regions that, according to the NERC Assessment, are not even facing "elevated risk" this summer, including PJM, TVA, SERC, Ontario, and Manitoba. Ex. 41 at 6, fig.1 (NERC 2025 Summer Reliability Assessment); Ex. 66 at 22–35 (NERC 2024 Interregional Transfer Capability Study, Part 1). MISO has an additional almost 5 GW of import capability from SPP. *Id.* And that capability is very relevant: regions import and export power from and to neighbors on a regular basis to alleviate grid constraints—as anticipated and encouraged by Section 202(a). *See, e.g.*, Ex. 43 at § III.A.3.b (Winter Storm Elliott System Operations Inquiry) ("Despite tightening conditions on the MISO system . . . MISO maintained steadily increasing exports to TVA throughout the day."); Ex. 44 at 43 (PJM Elliott Report) (describing PJM exports of between 8 and 11 GW to TVA and other neighboring regions), 83–84 (describing PJM power exports to MISO and graphically depicting those exports over time); Ex. 36 at 6 (MISO Elliott Max. Gen. Event Overview) ("MISO consistently exported power to southern neighbors with a maximum value of nearly 5 GW."). These examples underscore that the "elevated risk" identified in the NERC assessment describes the possibility of events that MISO already has the tools to address.

Finally, even within the terminology of the Assessment, an "elevated risk" designation does not constitute an emergency because it does not indicate the possibility of imminent shortfalls; indeed, it is only the second of three risk levels offered by NERC. Since it began providing standardized "risk" assessments by region in the summer of 2021, NERC has adhered to a three-tiered assessment of risk: areas facing the least risk are "low" or "normal" risk regions, areas facing the most risk are "high" risk regions, and areas in between are "elevated" risk regions. *See id.* at 6; Ex. 42 at 74, 124, 170, 218 (2019–24 NERC Summer Reliability Assessments); *cf. id.* at 1–32. NERC's determination of "elevated" risk indicates only that there is a "[p]otential for insufficient operating reserves in above-normal conditions." Ex. 41 at 6 (NERC 2025 Summer Reliability Assessment). In other

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[8] This figure is subject to downward revisions due to the dynamics of maintaining voltage, frequency, thermal stability, and other operational issues associated with the transmission grid.

words, the only circumstances in which NERC even identifies the *possibility* of shortfalls are scenarios in which conditions that NERC itself identifies as "extreme" due to historically high outage rates among the generation fleet or demand levels that are well above utilities' maximum projections. *Id.* at 16; *see* Ex. 2 at 7–8, 10–11 (Grid Strategies Report). The Department's decision to declare a Section 202(c) emergency based on an eminently remediable shortfall that could only transpire in the first instance during historically extreme weather exceeds its lawful authority, as does its use of Section 202(c) to force a favored generation resource to stay open. *See* 10 C.F.R. § 205.375 ("A system may be considered to have an inadequate . . . energy supply capability when" "it is unable to meet *normal* peak load requirements" (emphasis added)).

The routine nature of NERC's "elevated risk" determinations further undermines the Department's framing of such determinations as "emergencies." In four of the past five years, NERC has assessed MISO as an "elevated" risk region; and in 2022, it identified MISO as a "high" risk region. *Id.* These "elevated" risk determinations are not unique to MISO: Texas's ERCOT region has been identified as an "elevated" risk region each of the past five years, and three other regions[9] have been classified as elevated or high risk in four of the past five years. *Id.* Crucially, in none of these summers, including the summer of 2022, was MISO forced to actually shed load as a result of a resource adequacy shortfall.[10] *See* Ex. 32 (MISO Emergency Declarations) (demonstrating that MISO has not faced a Market Footprint Maximum Generation Emergency Event Step of 3 or higher from 2009 to 2024); Ex. 33 at 9–26 (MISO Market Capacity Emergency) (describing Max Gen Emergency Event procedures, which only include shedding of unwilling load at Event Step 5). Thus, the NERC 2025 Summer Assessment does not provide the Department with a statutory basis for a Summer 2025 MISO emergency determination.

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The statute only permits the Department to act in the face of an imminent, exigent, short-term supply shortfall. The Order is not based on any such shortfall

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[9] These three regions roughly correspond to California (WECC-CA/MX), Arizona and New Mexico (WECC-Southwest), and New England (NPCC-New England).

[10] As Ex. 33 reveals, MISO establishes a ten-step process for addressing what it describes as a "Max Gen Emergency": for the first nine steps of this process ("1a" through "4b"), an increasing list of mitigation measures is deployed, including requesting power transfers from neighboring regions, turning on backup generators, utilizing contracted demand response resources, and asking the public for voluntary reductions. Only on the final step ("5") does any involuntary load shedding occur. *See also* Ex. 2 at 6–7 (discussing tools MISO can employ in stepwise fashion).

that is, or could be, supported by substantial evidence. Both Michigan and MISO have confirmed that the retirement of the plant creates no reliability concerns, in the near-term or otherwise. The materials cited by the Order do not provide any meaningful basis to contradict those well-supported conclusions. As a result, the Order violates the law.

B. Even if There Were a Short-Term Need—Which 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.

Section 202(c)(1) demands 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 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 emergency and serves the public interest, including deficiencies associated with the alternative.

And as part of exercising reasoned decision-making, the Department must consider alternatives. 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); *Motor Vehicle Manufs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 51 (1983); *Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200, 215 (D.C. Cir. 2013). 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) (evaluating agency failure to consider alternative raised by dissenting Commissioners and introduced by commenters); *cf.* 10 C.F.R. § 205.370 (stating ability 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, permits a more abbreviated consideration than an emergency for which the Department has days to decide.

The Department's regulations and practice identify 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," and "available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions." 10 C.F.R. § 205.373(g)–(h); Ex. 5 at 5 (DOE Order No. 202-22-4).

The Department may then only choose the best alternative. The best alternative is the one which is most advantageous for meeting the stated emergency and serving the public interest.

The statutory command to take only measures that serve the public interest, including with respect to environmental considerations, 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); *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 Fails to Impose Requirements that Best Meet the Claimed Emergency and Serve the Public Interest.

The Order determines that additional dispatch of Campbell is necessary to best meet the emergency and serve the public interest. But the Order provides no rational basis for that determination. The Order does not address the Campbell Plant's limitations or explain how, in light of those limitations, it could even meet the claimed emergency. In fact, Campbell is unlikely to be able to do so. The Order does not examine the expense of running Campbell or its environmental damage,

relevant factors which cause additional dispatch of the plant to harm, rather than serve, the public interest. And the Order does not address readily available and obvious alternatives which, in point of fact, would better compensate for the "insufficiency of dispatchable capacity" asserted (inaccurately) by the Order. Ex. 1 at 2 (DOE Campbell Order). Consequently, the Order is without support in the record and unlawful. *Allentown Mack Sales & Service, Inc. v. NLRB*, 522 U.S. 359, 374 (1998); *State Farm*, 463 U.S. at 42–43, 51.

Campbell's age, exacerbated by the last several years spent planning for its retirement, raises significant doubt that Campbell is capable of reliable operation such that it could meet the claimed emergency. Even before the planned retirement in May 2025, the Campbell plant suffered from poor reliability. Ex. 3 at 4 (Powers Decl.). In 2024, the forced outage rate for the units was approximately 15 percent (Unit 1), 48 percent (Unit 2), and 19 percent (Unit 3); in 2023, it was approximately 19 percent (Unit 1), 57 percent (Unit 2), and 22 percent (Unit 3). *Id.* (*citing* exhibits to Consumers' witness Hoffman's 2024 and 2025 testimonies). Across all units, these rates are substantially worse than the national average for coal-fired units of 12 percent. *Id.* (*citing* Ex. 40 (NERC 2024 Reliability Report)).

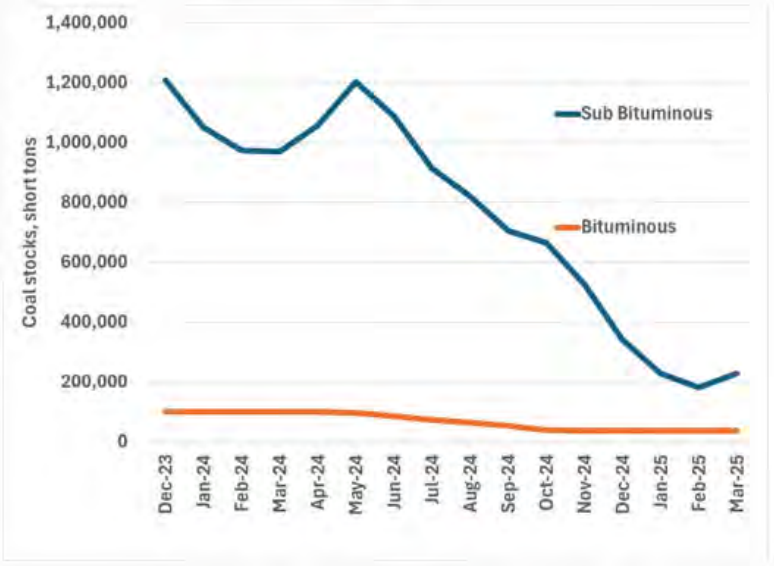
The nature of the units' outages in 2023 and 2024 "reflects the impact of worn and difficult-to-repair or replace coal unit components on operational reliability." *Id.* at 4. Outages were long and recurrent. For example, in 2023, Unit 2 experienced four outages totaling 3,445 hours—nearly 40 percent of the year—due to a pump failure, and in 2024, Unit 3 experienced an outage totaling 1,104 hours due to a failure in one of the turbine's gears. *Id.* at 5 (citing exhibits to Consumers' witness Hoffman's 2024 and 2025 testimonies). Across the units, thousands of hours of outages occurred in 2023 and 2024 due to failed and degraded parts, which "are the predictable result of old equipment, no capital investment, and minimal maintenance." *Id.* at 4–5.

The precipitous drop-off in investment at Campbell in recent years likely makes the plant even less reliable. In 2024, Consumers' witness Blumenstock testified that "[p]rojects that are targeted to improve reliability will not be considered" for Units 1 and 2 and, for Unit 3, "[c]apital projects that are targeted to improve reliability will not be considered." Ex. 11 at 19, 21 (Blumenstock 2024 Direct Testimony). Consumers' filings with the Michigan Commission show that for 2022 through 2025, the company's capital spending at Campbell Units 1 and 2 and Campbell Unit 3 is 93% and 90% lower, respectively, than what the company projected it would need to spend if it had planned to keep the plant online longer. Ex. 3 at 6 (Powers Decl.). Likewise, the company's major maintenance spending at Campbell Units 1 and 2 and at Campbell Unit 3 is 62% and 78% lower, respectively. *Id.*

Consumers' strategic decision to decrease investment in Campbell means Consumers did not undertake projects that it likely believed were necessary for reliable operation past the planned retirement date, *id.*, consistent with witness

Blumenstock's 2024 testimony that Consumers was not considering projects targeted to improve reliability, Ex. 11 at 19, 21 (Blumenstock 2024 Direct Testimony). For example, one of the projects Consumers cancelled was a $7.9 million Unit 3 turbine overhaul project originally scheduled for 2024. Ex. 3 at 16 (Powers Decl.). If that project had been undertaken before April 2024, it likely could have prevented the 1,104-hour outage at Unit 3 that occurred in late April 2024 due to a turbine gear failure. *Id.*

In addition, information from the Department and Consumers indicate that Campbell's coal supplies were already dwindling, Ex. 2 at 13–14 (Grid Strategies Report), and its employees were already relocating prior to the Order. At a minimum, Campbell's last-second pivot to continued operations, forced by the Order, is inconsistent with the long-term and orderly planning processes that utilities undertake to shore up reliable operations; at worst, it sets the plant up to scramble with inadequate resources if and when the plant is forced to run. As Public Interest Organizations' expert demonstrates with Department data in the chart reproduced below, Consumers depleted its coal stocks as it prepared for retirement. *Id.* at 14; *see also* Ex. 52 (MI State Energy Profile) (stating that "[m]ost of the coal consumed in Michigan comes by rail from the West").



Separately, the Order provides no reasoned basis to conclude that Campbell, even if fully maintained and operational, could meet the claimed emergency. Campbell is not designed to turn on quickly in response to times of extreme demand. In general, coal-fired power plants like Campbell typically take approximately 12 hours to become fully operational. Ex. 3 at 17 (Powers Decl.) (*citing* Ex. 55 (IEA Flexibility Report)). By comparison, "utility-scale battery storage can dispatch from a cold start to full power in a matter of seconds." *Id.* Campbell's long lead time makes it especially unsuitable for any Section 202(c) order: the type of grid emergency contemplated by Section 202(c)'s text and requirement of

imminence would need to be addressed on a timescale that the Campbell plant simply would not be able to start up fast enough to meet—thereby either defeating the purported purpose of keeping the plant operational past its retirement date, or forcing the plant to run constantly in anticipation of such emergencies, which would contravene the limitations set forth in Section 202(c)(2), discussed below. Thus, Campbell is plainly not the best means of meeting the range of energy emergencies MISO might plausibly face, even were there a resource adequacy problem.

The power outage in Louisiana on May 25, 2025, powerfully demonstrates this point, as well as more broadly the need for solutions tailored to particular circumstances. Inadequate transmission connectivity between southeastern Louisiana and neighboring regions prevented the copious availability of generating capability in those other regions from filling the gap that was created when a major nuclear plant had an unplanned outage. Amanda D. Cook, *MISO: New Orleans Area Outages Owed to Scant Gen, Congestion, Heat* (June 9, 2025), https://www.rtoinsider.com/106609-miso-new-orleans-outages-owed-to-scant-gen-congestion-heat. As a result, energy prices in Louisiana exceeded $2000/MWh even as prices in the neighboring Mississippi Delta dropped into the negatives, down to -$400/MWh. *Id.*

Campbell could not address events like the Louisiana outage for two key reasons. First, no additional generation (from Campbell or elsewhere) can supply power to a region that is transmission constrained. Thus, the Louisiana outage demonstrates the futility of solutions not tailored to the problem they are supposedly addressing. Second, by the time Campbell might have initiated operations, electric service had long been restored to the Louisiana customers who experienced blackouts.

Further, the expense of operating Campbell renders it unable to serve the public interest, a topic the Order does not address. As discussed in section III.A.1, Campbell has been, and continues to be, an expensive plant to run. In 2021, Consumers projected that retiring Campbell in 2025 would avoid $365,008,000 in capital expenditures and major maintenance costs. Ex. 13 at 3–4 (Kapala Direct Testimony). Campbell has gotten more expensive to run since then: the cost of Campbell's power was 21% higher in 2021 than in 2024, rising faster than inflation. Ex. 49 (2025 Energy Innovation Dataset); Ex. 50 at 3 (2025 Energy Innovation Coal Cost Report); *see also* Ex. 51 at 12 (2023 Energy Innovation Coal Cost Report).

Bringing Campbell from a cold start condition to full output to meet any claimed emergency would also be extremely expensive. The estimated cost to "cold start" a coal-fired power plant is $417 per MW of capacity. Ex. 3 at 18–19 (Powers Decl.) (*citing* Ex. 54 (NARUC Coal Report)). The total nameplate capacity of Campbell Units 1–3 is 1,561 MW. *Id.* at 18. Therefore, the estimated cost to cold start Campbell at its nameplate capacity is approximately $650,000. *Id.* at 19.

Moreover, as discussed above, Consumers has significantly decreased investment in Campbell since the Integrated Resource Plan proceeding that established the plant's May 2025 retirement date, forgoing a long list of capital and maintenance projects totaling approximately $161 million. Ex. 3 at 5–6 (Powers Decl.). As Public Interest Organizations' expert engineer states, "[i]t is reasonable to assume that much of this investment was necessary to ensure continued, nominally reliable operation of Campbell." *Id.* at 16. Consumers itself explains that, "given the ages and designs of the systems, replacement parts are not always readily available. In some instances, replacement parts do not exist at all." *Id.* at 15 (*quoting* Consumers' witness Hoffman's testimony). And as discussed *supra* in section III.A.1, operation of the Campbell plant results in significant environmental pollution. Thus, even accepting *arguendo* that an emergency exists and Campbell could address it, the Department still has not met its burden to provide a reasoned basis that the directive best meets the emergency and serves the public interest.

Other alternatives are available to the Department that better meet the claimed emergency and serve the public interest. For instance, Public Interest Organizations have highlighted above the robust transmission connectivity between MISO and neighboring regions, which MISO has accessed on a regular basis to support the stability of its grid. *See supra* section IV.A.2.iii. 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. However, the Department's citation of the NERC 2025 Summer Assessment, which considers interregional connectivity only as a mitigation option, suggests that the Department does not have full confidence in the availability of this resource. As explained above, 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).

Neither the Order nor its supporting memorandum includes any consideration of other alternatives. *See* Ex. 4 (DOE Campbell Memorandum). And the Order contains no reasoning demonstrating why Campbell is the best alternative, or a better alternative than other options, or is even capable of meeting the claimed emergency. As such, the Order is unlawful.

3. The Order Is Unlawfully Ambiguous, Impermissibly Vague, and Does Not Provide Fair Notice of What MISO, Consumers Energy, and Others Are Required to Do.

The Order requires MISO and Consumers Energy to "take all measures necessary to ensure that the Campbell Plant is available to operate." Ex. 1 at 2 (DOE Campbell Order). The Order further requires MISO to "take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers." *Id.* Those requirements are unlawfully susceptible of multiple meanings and lack necessary precision.

The availability requirement is impermissibly ambiguous and vague. The Order does not explain, for instance, whether it requires (a) only that MISO and Consumers Energy 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 MISO and Consumers Energy take additional measures that enlarge their capabilities to operate (like capital investments). The Order also does not define the Campbell Plant, *see* Order at *passim*, so it is unclear whether MISO and Consumers Energy are required to take measures to ensure that each of the three units at the plant are equally "available to operate." *Id.* at 2.

The economic dispatch requirement is also impermissibly ambiguous and vague (in addition to being unlawful as discussed *infra* in section IV.D). The MISO Tariff contains provisions governing economic dispatch, *see generally* MISO's FERC-Approved Tariff at Module C & Schedules 29, 29A, *available at* https://etariff.ferc.gov/TariffBrowser.aspx?tid=1162, but those provisions generally depend on offer submissions from market participants containing a variety of parameters, *see, e.g.*, MISO, *Business Practices Manual: Energy and Operating Reserve Markets* § 4.2 (effective Sept. 30, 2024) (discussing resource offer requirements). The Order does not specify whether Consumers Energy is required to submit offers and, if so, the extent to which the utility has discretion either in the price and parameters of those offers or in the markets to which the offers are submitted. If Consumers is not required to submit offers, the Order does not specify whether MISO is required to adjudge when economic dispatch calls for dispatch of the plant, and if so on what basis.

Additionally, the Order's reference to "ratepayers" is impermissibly ambiguous and vague. For instance, does the Order refer to ratepayers in the MISO wholesale energy markets, the MISO 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 MISO is directed to minimize cost to ratepayers in Michigan, across MISO, or some other area. It further contains no temporal limit, such that it is unclear whether MISO is directed to minimize cost to current ratepayers, future ratepayers, or both. Moreover, the

Order contains no standards or guidance on how MISO is to reconcile or balance countervailing tensions, like minimization of costs to current and future ratepayers.

The above defects are fatal to the Order's validity. A reasonably prudent person—regardless of whether such person is familiar with the electric industry—cannot ascertain the Order's meaning. MISO and Consumers are left in the dark as to what they are required to do. 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. As such, the Order does not give fair notice of conduct that is forbidden or required, and it is therefore unlawful. *Fed. Commc'ns Comm'n v. Fox Telev. Stations, Inc.*, 567 U.S. 239, 253 (2012); *Grayned v. City of Rockford*, 408 U.S. 104, 108–09 (1972).

In addition, the ambiguities and vagaries leave open such a wide variety of actions and interpretations by MISO and Consumers that the Department fails to state in the Order its judgment as to the requirement that will best meet the emergency and serve the public interest. 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*, 522 U.S. at 375.

Also, the Department orders "relevant governmental authorities" to take action and make accommodations. Ex. 1 at 3 (DOE Campbell Order). This is vague, ambiguous, arbitrary, and beyond the Department's authority under Section 202(c). The Order does not identify which governmental entities, if any, are covered by the directive. Moreover, the Department does not have authority under Section 202(c) to issue directives to governmental authorities. 16 U.S.C. § 824a(c)(1).

C. The Order's Availability Requirements Exceed the Department's Statutory Authority.

In directing MISO and Consumers Energy to take "all measures" to ensure that the Campbell Plant is "available to operate," Ex. 1 at 2 (DOE Campbell Order), the Department exceeded its authority under Section 202(c) of the Federal Power Act and impermissibly intruded on the authority over generating facilities that Section 201(b) of the statute reserves to the states, 16 U.S.C. §§ 824(b)(1), 824a(c)(1). The sweeping language in the Department's Order would encompass physical and all other changes necessary to revive a generating plant that is being closed pursuant to a state-approved closure process. The Federal Power Act's language, structure, legislative history, and interpretation by the courts all confirm that the Department's Order is unlawful.

The structure and language of the Federal Power Act reflect Congress's deliberate choices to preserve the states' traditional authority over generating

facilities and to circumscribe the Department's emergency authority in light of the states' role. The first sentence of the Federal Power Act declares that federal regulation extends "only to those matters which are not subject to regulation by the States." *Id.* § 824(a). Section 201(b)(1) states that, except as otherwise "specifically" provided, federal jurisdiction does not attach to "facilities used for the generation of electric energy." *Id.* § 824(b)(1). The courts have held that Section 201(b)(1) reserves to the states authority over electric generating facilities, *see, e.g., Hughes*, 578 U.S. at 155, including the authority to order their closure, *Conn. Dep't of Pub. Util. Control*, 569 F.3d at 481 (under Section 201(b), states retain the right "to require the retirement of existing generators" or to take any other action in their "role as regulators of generation facilities."). Congress also recognized the states' exclusive authority over generating facilities in Section 202(b), which provides that FERC's interconnection authority does not include the power to "compel the enlargement of generating facilities for such purposes." 16 U.S.C. § 824a(b).

There is a clear distinction between authority to regulate generation facilities and the Department's authority under Section 202(c) to require generation of electric energy. Electric energy is an electromagnetic wave, and its "generation, delivery, interchange, and transmission" is the creation and propagation of that wave. *See* Brief *Amicus Curiae* of Electrical Engineers, Energy Economists and Physicists in Support of Respondents at 2, *New York v. FERC*, 535 U.S. 1 (2002); *see also* Edison Electric Institute Glossary of Electric Utility Terms (1991 ed.) (defining electric generation as "the act or process of transforming other forms of energy into electric energy"). Section 202(c)(1), like the rest of the Federal Power Act, is written "in the technical language of the electric art" and federal jurisdiction generally "follow[s] the flow of electric energy, an engineering and scientific, rather than a legalistic or governmental test." *Conn. Light & Power v. Fed. Power Comm'n*, 324 U.S. 515, 529 (1945); *see also Fed. Power Comm'n v. Fla. Power & Light Co.*, 404 U.S. 453, 454, 467 (1972).

The scope of the Department's emergency power under Section 202(c) is bounded both by the provision's specific language and Congress's clear intention and repeated direction in the Federal Power Act to respect the states' authority over generating facilities. When an actual emergency exists, Section 202(c)(1) authorizes the Department to require just two specific things: (1) "temporary connections of facilities" and (2) "generation, delivery, interchange, or transmission of electric energy." *Id.* § 824a(c)(1). The only reference to "facilities" in the authorizing provision of Section 202(c)(1) appears in the clause relating to temporary connections, not in the clause pertaining to "generation" of electric energy. And that clause only authorizes connections "of" facilities; it does not provide authority to regulate the facilities. The differences in Congress's word choice in these clauses—referencing "facilities" in one authorizing provision but not the other–must be given effect. *See, e.g.*, *Gallardo v. Marstiller*, 596 U.S. 420, 430 (2022); *Gomez-Perez v. Potter*, 553 U.S. 474, 486 (2008).

Given Congress's use of the term "generating facilities" elsewhere in the statute, if it had intended to give the Department authority over generating facilities in Section 202(c)(1), it would have done so explicitly. Instead, the provision conspicuously excludes authority to manage the physical characteristics of power plants. Congress purposely limited and particularized the Department's emergency powers, carefully avoiding intrusion on the states' authority over generating facilities recognized in Section 201(b)(1). *See* S. Rep. No. 74-621, at 19 (explaining that the emergency powers in Section 202(c)(1) "which were indefinite in the original bill have been spelled out with particularity"); *compare* S. 1725, Cong. Tit. II § 203(a) (providing in original, unenacted bill that control of the production and transmission of electric energy "except in time of war or other emergency declared to exist by proclamation of the President, shall, as far as practicable, be by voluntary coordination"), *with* 16 U.S.C. § 824a(c)(1) (providing particularized, specific authorities and circumstances in which the authorities may be exercised).

The Department may require generation of electric power, and a utility may properly take steps at the facility to produce the power. It is commonplace in the electric sector for the federal regulator properly acting within its authority to cause effects in a state regulator's jurisdictional sphere, and vice versa. *See FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 281 (2016). But the federal regulator may neither directly regulate generation facilities nor impose requirements aimed at the facilities, even if nominally regulating within its sphere. *See id.* at 281–82; see also *Hughes*, 578 U.S. at 164–65. Such encroachment is impermissible, even in a real emergency or in a wrongly claimed one. *See Conn. Light & Power*, 324 U.S. at 530 ("Congress is acutely aware of the existence and vitality of these state governments. It sometimes is moved to respect state rights and local institutions even when some degree of efficiency of a federal plan is thereby sacrificed."). Thus, the Department may not require generation which necessitates the utility taking steps reserved to state authority, such as building a new generating unit or refurbishing a broken one.

Congress did not give the Department sweeping authority to order "all measures" needed to make a generation facility "available to operate." *See* Ex. 1 at 2 (DOE Campbell Order). Nowhere does the statute empower the Department to order "all" steps that may be needed to resuscitate the Campbell Plant, which could include repairs or modifications to physical facilities and other measures going far beyond electric power generation. Because the plant is at the end of its useful life, with years of forgone maintenance and investment, rendering it capable of meeting a short-term supply shortfall could essentially require rebuilding significant parts of the plant. On its face, the Department's Order is *ultra vires*. The Order also contravenes Congress's repeated direction in the Federal Power Act to respect the states' authority over generating facilities, which includes the authority that

Michigan exercised to approve the Campbell Plant's closure. The Order therefore is unlawful and should be withdrawn.[11]

D. The 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 (DOE Campbell Order). 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 laws;" 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 Campbell Plant.

1. The Order Lacks the Conditions Required by Section 202(c)(2).

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, MISO is directed to take every step to employ *economic dispatch* of the Campbell Plant to *minimize cost* to ratepayers." Ex. 1 at 2 (DOE Campbell Order) (emphasis added). 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 or outages," during the upcoming summer. *Id.* Even if the Department had substantiated that emergency (which it has not) the Act would allow the Department to compel generation only when such losses would occur absent operation of the Campbell Plant. 16 U.S.C. 824a(c)(2); *see, e.g.*, Ex. 6 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

[11] A utility that takes steps subject to state authority cannot point to a Section 202(c) order as the basis for a right to recover associated costs. *See* 16 U.S.C. § 824a(c)(1) (providing for compensation or reimbursement to be paid based on just and reasonable terms for carrying out an authorized order).

economic dispatch and reserve capacity rules). By directing MISO to dispatch the plant along those cost-based principles, rather than "only during the hours necessary to meet the emergency" forming the basis for its Order, the Department has violated Section 202(c)(2). 16 U.S.C. § 824a(c)(2).[12]

Second, the Order fails to ensure that the Campbell Plant operates, "to the maximum extent practicable," in conformity with applicable environmental rules. *Id.* The Order paraphrases the statutory text—that "operation of the Campbell Plant 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 (DOE Campbell Order). It imposes no further conditions beyond requiring Consumers Energy to "pay fees or purchase offsets or allowances for emissions." *Id.* The direction to "comply . . . to the maximum extent feasible" is, as a result, wholly 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. 5 at 5–6 (DOE Order No. 202-22-4) (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 requirement to comply with environmental requirements to 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 that would mitigate impacts when compliance with environmental standards proves impracticable—measures that have been routinely included in past orders. *See, e.g.*, Ex. 6 at 4 (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. 5 at 7 (DOE Order No. 202-22-4) (requiring "reasonable measures to inform affected communities" of non-compliant operations); Ex. 6 (DOE Order No. 202-17-4 Summary of Findings). 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.*, U.S. Dep't

[12] That direction further fails to conform to the statute's command to compel only the generation that will "best meet the emergency." 16 U.S.C. § 824(c)(1).

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, in the future, 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).

2. The Campbell Plant's Pollution and Lack of Maintenance Mean that the Absence of Effective Environmental Conditions Will Have Especially Severe Effects.

The absence of enforceable conditions—coupled with the inadequate limits on when Campbell can operate—is especially concerning here for two reasons: the significant environmental impacts of coal-fired power generation; and the apparent disrepair of the plant's pollution controls.

Coal-fired power plants like Campbell are a significant source of air and water pollution and waste. *See, e.g.*, *National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review*, 88 Fed. Reg. 24,854, 24,857 (Apr. 23, 2023) ("[C]oal- and oil-fired [power plants] remain the largest domestic emitter of [mercury] and many other [hazardous air pollutants]."). Air emissions from coal plants can cause serious human health and environmental impacts. *See, e.g.*, *id.*; EPA, *Health and Environmental Effects of Particulate Matter* (PM);[13] EPA, *Effects of NO_2*.[14] Wastewater discharges from coal plants "contain toxic metals such as mercury, arsenic, lead, and selenium, which bioaccumulate in fish, accumulate in lake and reservoir sediment, and pollute drinking water supplies. People who eat the tainted fish or drink the tainted water can suffer negative health consequences such as cancer, cardiovascular disease, neurological disorders, kidney and liver damage, and lowered IQs (in children)." *Sw. Elec. Power Co. v. EPA*, 920 F.3d 999, 1007 (5th Cir. 2019). Likewise, coal ash—the waste product that results from burning coal—"contain[s] myriad carcinogens and neurotoxins that contribute to increased rates of 'cancer in the skin, liver, bladder, and lungs,' 'neurological and psychiatric effects,' 'damage to blood vessels,' and 'anemia' in people exposed to them" while also "pos[ing] risks to plant and animal wildlife, including '[e]levated selenium levels in migratory birds, wetland vegetative damage, fish kills, amphibian deformities, . . . [and] plant toxicity.'" *Elec. Energy, Inc. v. Env't Prot.*

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[13] Available at https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm (last visited June 18, 2025).

[14] Available at https://www.epa.gov/no2-pollution/basic-information-about-no2#Effects (last visited June 18, 2025).

Agency, 106 F.4th 31, 35 (D.C. Cir. 2024) (alterations in original) (quoting EPA rulemakings on coal ash). Campbell will produce this environmentally damaging and health-harming pollution if it continues to operate. Ex. 3 at 21 (Powers Decl.).

Moreover, Consumers' filings at the Michigan Commission indicate that the plant may no longer be able to meet certain legal limits on its pollution due to deferred investment and maintenance. The company planned to conduct multiple capital and maintenance projects related to Campbell's air pollution control equipment *if* the plant operated past 2025. *Id.* at 19–20. However, after committing to retire Campbell in May 2025, the company did not undertake many of these projects. *Id.* The following table from Public Interest Organizations' expert engineer shows these cancelled projects. *Id.* at 20.

Cancelled Capital Projects at Campbell from 2022–2025 for Air Quality Control

Year	Unit	Project	Budget ($)
2022	2	• (SCR) catalyst management	1,120,000
	3	• Fabric filter bag(s) & cleaning air manifold replacement	3,994,601
2023	1	• Fabric filter bag replacement	1,514,100
	2	• SCR reactor catalyst replacement	2,000,000
	3	• Fabric filter bag(s) & cleaning air manifold replacement	3,263,331
2025	3	• SCR reactor catalyst management	3,000,000
		• Air quality control sys. (AQCS) equip. repair/replacement	1,000,000

The dollar figures shown above are as presented in Ex. 13 at 14–18 (Kapala Direct Testimony).

Without that critical upkeep, Campbell's air pollution controls may no longer work effectively and the plant may no longer be able to meet its air permit limits. *Id.* at 19–20.

Ordering a heavily polluting coal-fired power plant to operate when its pollution controls have fallen into disrepair plainly would not be consistent with the requirement that Section 202(c) orders are, "to the maximum extent practicable," consistent with environmental requirements and that the Department minimize any adverse environmental impact. 16 U.S.C. § 824a(c)(2). Robust reporting requirements and tight limits on Campbell's operations are therefore especially necessary to effectuate the Department's statutory duty. The Department's Order will be responsible for the plant's additional pollution: If Campbell retired on May 31, 2025 as planned, its air emissions, coal ash production, and much of its wastewater discharges would have ceased. But for the Order, that new air and water pollution and waste creation—and the associated environmental impacts—would not occur. This makes it all the more important for the Department to closely track and aggressively mitigate Campbell's adverse environmental impacts. As such, the Department should require verification from Consumers that its air

pollution control systems are functioning properly before authorizing Campbell to operate under emergency demand conditions. Ex. 3 at 20 (Powers Decl.). Further, if the units' continuous air pollution monitors detect any exceedance of permit limits during operation, DOE should require the offending unit(s) to shut down. *Id.*

E. 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. DOE Rehearing Procedures (linking to U.S. Dep't of Energy, *DOE's Use of Federal Power Act Emergency Authority* (last visited June 18, 2025), https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority [hereinafter "DOE 202(c) Website"]).

The Department has received, and is supposed to receive, materials related to this proceeding that it has not posted. On June 10, 2025, the Department "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 May 23, 2025 Order. Ex. 16 (DOE Letter to FERC). Additionally, in the May 23 Order, the Department ordered MISO to "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." Ex. 1 at 3 (DOE Campbell Order). The Department further ordered MISO to provide, by June 15, 2025, "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." *Id.* Additionally, the Department ordered that "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." *Id.*

None of those materials are posted on the DOE 202(c) Website. The Department's letter to FERC indicates that it has reviewed the letter it received from Consumers; the letter nevertheless does not appear on the website, and the Department has not indicated there the docket or other locations in which to find Consumers' letter and similar materials.

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).

V. 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.[15] 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 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. *Nken v. Holder*, 556 U.S. 418, 434, 436 (2010); *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 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 61,887 (2000); *City of Tacoma*, 89 FERC ¶ 61,273, at 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 980, 991 (D.C. Cir. 2022). 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).

Under those standards, a stay of the Order is appropriate.

A. Intervenors Are Irreparably Harmed by the Order.

A stay is necessary to ensure that Consumers 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 Department's Order. *See Consumers Energy v. Midwestern Independent Sys. Operator, Inc.*, Complaint Requesting Fast Track Processing, FERC Docket No. EL25-90, 2 (June 6, 2025), Accession No. 20250606-5231 ("[T]he Campbell Plant is currently being offered into the MISO

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[15] Pursuant to FPA Section 313 and Rule 713(e) of the applicable rules, the filing of a request for rehearing does not automatically stay a Department Order. 16 U.S.C. § 825*l*, 18 C.F.R. § 385.713(e).

market and is producing energy when dispatched."). As noted extensively above in Section III.A.1, during its time of operation, Michiganders' health and environment have been profoundly and irreparably harmed by pollution from the Campbell Plant. Along with the highest emissions of sulfur dioxide, carbon dioxide, and volatile organic compounds of any plant in Consumers' generation fleet, it was also a major source of water pollution in its area. Ex. 23 at 11 (Bilsback Direct Testimony); EPA, ECHO, https://echo.epa.gov/detailed-facility-report?fid=110000411108 (last visited June 18, 2025). Campbell's closure is set to eliminate 538 tons of particulate matter, 13 tons of volatile organic compounds, 2,918 tons of nitrogen oxides, 5,244 tons of sulfur dioxide, and 8.2 megatons of carbon dioxide emissions per year based on 2019 operational levels. Ex. 23 at 11. This translates to ending 36–81 premature deaths and $389–$879 million in health impact costs *every year*. *Id.* at 15. These harms, which flow directly from the Department's Order, are actual, specific, imminent, and deadly. They will affect the lives and well-being of Public Interest Organizations and their members. The stark public health stakes of Public Interest Organizations' request for stay require the Department to pause implementation of its Order until a Court reviews its validity.

Moreover, the economic impacts of complying with this Order will be steep. This planned retirement represented major cost savings for ratepayers stemming directly from the closure of the unreliable and highly expensive Campbell plant. *See, e.g.*, Ex. 53 (Consumers News Release). Without a stay, the Department will needlessly force Consumers to divert attention and investment dollars away from compliance with the 2022 Settlement, thereby exceeding its jurisdiction and denying Public Interest Organizations' members the benefits of Michigan energy policies they and the public are designed to benefit from. 16 U.S.C. § 824; *see also Hughes*, 578 U.S. at 154 ("Under the FPA, FERC has exclusive authority to regulate 'the sale of electric energy at wholesale in interstate commerce' . . . 'But the law places beyond FERC's power, and leaves to the States alone, the regulation of "any other sale"—most notably, any retail sale—of electricity.'") (*quoting* 16 U.S.C. § 824(b)(1) *and Elec. Power Supply Ass'n*, 577 U.S. at 265). The states' reserved authority includes control over in-state "facilities used for the generation of electric energy." 16 U.S.C. §824(b)(1); *see Pac. Gas & Elec.*, 461 U. S. at 205 ("Need for new power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the States."). In forcing ratepayers to reopen and operate an uneconomic, unreliable, and obsolete resource that the state, stakeholders, and owner want to close, *see supra* sections III.A.1, III.C.1, the Department's Order jeopardizes the diversification of generating resources the Department itself has said increases grid reliability and will inherently and unjustifiably add to ratepayer costs. DOE, *Energy Reliability and Resilience,* https://www.energy.gov/eere/energy-reliability-and-resilience (last visited June 18, 2025). 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 costs increases—especially at a time when energy prices are already on the rise. *See, e.g.,*

Stan Huxley, *Average Cost of Utilities in Michigan* (June 1, 2025), https://realestates.network/data-research/average-cost-of-utilities-in-michigan; Kyle Davidson, Michigan Advance, *Detroit Households Face High Energy Costs, Study Says* (Sept. 16, 2024), https://michiganadvance.com/2024/09/16/detroit-households-face-high-energy-costs-study-says.

Estimates of cost savings from the plant closure are substantial. *See, e.g.*, *supra* section III.A.1; Ex. 53 (Consumers News Release) (describing total cost savings from 2022 updates to Consumers Clean Energy Plan, including Campbell's closure). These are savings that are already being reinvested in newer, more reliable facilities. Because of the age of the Campbell Plant and the unreasonably short notice and lack of warning around the Order's issuance, the facility has had to scramble not just to try and procure coal, but to hire new operators and perform highly expensive maintenance necessary to operate the units. *See, e.g., supra* section IV.B.2. Consumers reports to FERC that it is taking steps in response to the Order, and it has also filed for cost recovery with FERC. *Consumers Energy v. Midwestern Indep. Sys. Operator, Inc.*, Complaint Requesting Fast Track Processing, FERC Docket No. EL25-90, (June 6, 2025), Accession No. 20250606-5231. If Consumers' filing is granted, costs will be borne by Michigan and MISO ratepayers, and the Department does not identify any clear recourse for a refund in the event the Order is declared unlawful.

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* sections III.B–C, IV.A. Furthermore, because Consumers and MISO have both already planned for the closure of the Campbell Plant, a stay would only have the effect of relieving them of the administrative, compliance, and planning burdens imposed by the Order. *See, e.g.*, Ex. 1 at 2–3 (DOE Campbell Order). 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 Given the Significant Evidence Demonstrating There is No Factual or Legal Support for This Order, and the Harm it Produces to the Broader Public.

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 Campbell's continued operation. *See League of Women Voters v. Newby*, 838 F.3d 1, 12 (D.C. Cir. 2016) (noting "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, the Order overrides Michigan's exercise of its "authority to choose [its] preferred mix of energy generation resources." *Citizens Action*, 125 F.4th at 239. And third, it would protect the broader public—beyond Public Interest Organizations and their members—from the onerous costs, and dangerous pollution, produced by unnecessary operation of the Campbell Plant.

VI. 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.

Filed on June 18, 2025

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Attachment: Index of Exhibits

Index of Exhibits

Exhibit No.	Exhibit Name	Document Name	URL
1	DOE Campbell Order	DOE 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
2	Grid Strategies Report	Michael Goggin, *A Review of DOE's 202(c) Order for the Campbell Coal Plant* (June 18, 2025)	
3	Powers Decl.	Declaration of Bill Powers, P.E. (June 15, 2025) (including attachments)	
4	DOE Campbell Memorandum	DOE, Decision Order Pursuant to Section 202(c) of the Federal Power Act for J.H. Campbell Power Plant (May 23, 2025)	https://www.documentcloud.org/documents/25956475-cuiprivileged-department-of-energy-memorandum-re-jh-campbell-coal-plant-in-michigan-section-202c-federal-power-act-order-may-2025/
5	DOE Order No. 202-22-4	DOE, Order No. 202-22-4 (Dec. 24, 2022)	https://www.energy.gov/sites/default/files/2022-12/PJM%20202%28c%29%20Order.pdf
6	DOE Order No. 202-17-4 Summary of Findings	Summary of Findings DOE Order No. 202-17-4 (Sep. 14, 2017)	https://www.energy.gov/sites/default/files/2017/09/f36/Order%20202-17-4%20Summary%20of%20Findings.pdf
7	DOE Order No. 202-02-1	DOE, Order No. 202-02-1 (Aug. 16, 2002)	https://www.energy.gov/sites/default/files/202%28c%29%20order%20202-02-1%20August%2016%2C%202002%20-%20CSC.pdf
8	Cooke Email to Alle-Murphy	Email from Lot Cooke, DOE to Linda Alle-Murphy Re: Rehearing procedures for DOE Order No. 202-05-3	https://www.energy.gov/oe/articles/question-and-answer-procedural-questions-application-rehearing-order-no-202-05-02?nrg_redirect=397676

Exhibit No.	Exhibit Name	Document Name	URL
9	Order Approving Campbell Settlement Agreement and Settlement Agreement	MPSC Case No. U-21090, Order Approving Settlement Agreement (June 23, 2022)	https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000003KjSDAA0
10	Blumenstock 2023 Direct Testimony	MPSC Case No. U-21389, Direct Testimony & Exhibits of Richard T. Blumenstock on Behalf of Consumers Energy Company (May 2023) (excerpted from larger transcript)	**Testimony**: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000ACpRQAA1 **Exhibits**: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000ACV7bAAH
11	Blumenstock 2024 Direct Testimony	MPSC Case No. U-21585, Direct Testimony & Exhibits of Richard T. Blumenstock on Behalf of Consumers Energy Company (May 2024) (excerpted from larger transcript)	**Testimony**: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000KfWrgAAF **Exhibits**: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000KLJlzAAH
12	Blumenstock 2025 Direct Testimony	MPSC Case No. U-21870, Direct Testimony & Exhibits of Richard T. Blumenstock on Behalf of Consumers Energy Company (June 2025) (excerpted from larger filing)	**Testimony**: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000s6UQyAAM **Exhibits**: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000s7CdKAAU

Exhibit No.	Exhibit Name	Document Name	URL
13	Kapala Direct Testimony	MPSC Case No. U-21090, Revised Direct Testimony of Norman J. Kapala on Behalf of Consumers Energy Company (Oct. 2021) (excerpted from larger transcript)	**Testimony**: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000001QqldAAC **Exhibits**: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000001OZHpAAO
14	Hoffman 2024 Direct Testimony	MPSC Case No. U-21258, Direct Testimony and Exhibits of Nathan J. Hoffman on Behalf of Consumers Energy Company (Mar. 2024) (excerpted from larger transcript)	**Testimony**: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000ljeStAAI **Exhibits**: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000g8QemAAE
15	Hoffman 2025 Direct Testimony	MPSC Case No. U-21424, Direct Testimony & Exhibits of Nathan J. Hoffman on Behalf of Consumers Energy Company (Mar. 2025) (excerpted from larger filing)	**Testimony and exhibits**: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000hjHqNAAU
16	DOE Letter to FERC	Holly Rachel Smith, Deputy Gen. Counsel, U.S. Dep't of Energy to Debbie-Anne A. Reese, Secretary, FERC (dated June 13, 2025, filed June 16, 2025)	https://elibrary.ferc.gov/eLibrary/filelist?accession_num=20250616-4000

Exhibit No.	Exhibit Name	Document Name	URL
17	DOE Order No. 202-20-2	Department of Energy Order No. 202-20-2 (Sept. 6. 2020)	https://www.energy.gov/oe/articles/federal-power-act-section-202c-caiso-september-2020?nrg_redirect=454296
18	Proudfoot Rebuttal Testimony	MPSC Case No. U-21090, Rebuttal Testimony of Paul Proudfoot in Support of the Settlement Agreement on behalf of MPSC Staff (May 13, 2022) (excerpted from larger transcript)	https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000002z5EqAAI
19	Walz Direct Testimony	MPSC Case No. U-21090, Revised Direct Testimony & Exhibits of Sara T. Walz on Behalf of Consumers Energy Company (June 2021) (excerpted from larger transcript)	**Testimony**: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000001OEXnAAO **Exhibits**: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t000000NibWaAAJ
20	King Direct Testimony	MPSC Case No. U-21090, Direct Testimony & Exhibits of Thomas King Jr. on Behalf of Wolverine Power Supply Cooperative, Inc. (2021) (excerpted from larger transcript)	**Testimony**: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000002paWpAAI **Exhibits**: https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t000000Vibb0AAB

Exhibit No.	Exhibit Name	Document Name	URL
21	Bleckman Direct Testimony	MPSC Case No. U-21816, Direct Testimony of Marc R. Bleckman on Behalf of Consumers Energy Company (Nov. 2024) (excerpted from larger transcript)	https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000nPekYAAS
22	Hahn Direct Testimony	MPSC Case No. U-21592, Direct Testimony of Joshua W. Hahn on Behalf of Consumers Energy Company (Sept. 2024) (excerpted from larger transcript)	https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000CFqsPAAT
23	Bilsback Direct Testimony	MPSC Case No. U-21090, Direct Testimony of Kelsey Bilsback on Behalf of ELPC, Ecology Center, UCS, and Vote Solar (Oct. 2021) (excerpted from larger transcript)	https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000002paWpAAI
24	Mic. Pub. Power Agency Petition to Intervene	MPSC Case No. U-21090, Michigan Public Power Agency's Petition to Intervene (July 19, 2021)	https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t000000Qf5I7AAJ

Exhibit No.	Exhibit Name	Document Name	URL
25	2026 Consumers Energy Capacity Demonstration	MPSC Case No. U-21225, Consumers Energy Company's Capacity Demonstration for Planning Year 2026 (Dec. 21, 2022)	https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000005iOnPAAU
26	2027/2028 Consumers Energy Capacity Demonstration	MPSC Case No. U-21393, Consumers Energy Company's Capacity Demonstration for Planning Year 2027/2028 (Feb. 22, 2022)	https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y00000C8NDHAA3
27	2028/2029 Consumers Capacity Demonstration	MPSC Case No. U-21775, Consumers Energy Company's Capacity Demonstration for Planning Year 2028/2029 (Feb. 24, 2025)	https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000bz8crAAA
28	2028/2029 MPSC Staff Capacity Demonstration Results	MPSC Case No. U-21775, Michigan Public Service Commission Staff, Capacity Demonstration Results: Planning Year 2028/29 (May 12, 2025)	https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000ocKc4AAE

Exhibit No.	Exhibit Name	Document Name	URL
29	2024 Consumers ELG Annual Report	Consumers Energy, Notice of Planned Participation; Annual Progress Report Pursuant to 40 C.F.R. 423.19(g)(3); Consumers Energy Company, JH Campbell Complex NPDES Permit No. MI0001422, Steam Electric Effluent Limitations Guidelines (Dec. 16, 2024)	https://www.consumersenergy.com/-/media/CE/Documents/sustainability/coal-combustion-residuals/jhc/2024/2024-seeg-jhc-nopp-annual-progress%20Report_FINAL.pdf
30	DOE Rehearing Procedures	U.S. Dep't of Energy, DOE 202(c) Order Rehearing Procedures (last visited June 17, 2025)	https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures
31	MISO 2025–26 Auction Results	MISO, Planning Resource Auction, Results for Planning Year 2025-2026 (Apr. 2025)	https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf
32	MISO Emergency Declarations	MISO, Maximum Generation Emergency Declarations through June 2024 (Aug. 30, 2024)	https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/Capacity_Emergency_Historical_Information.pdf
33	MISO Market Capacity Emergency	MISO, Market Capacity Emergency, SO-P-EOP-11-002 Rev: 21 (Mar. 3, 2025)	https://cdn.misoenergy.org/SO-P-EOP-11-002%20Rev%2021%20MISO%20Market%20Capacity%20Emergency683501.pdf

Exhibit No.	Exhibit Name	Document Name	URL
34	Ramey MISO Comments	Comments of Todd Ramey on Behalf of Midcontinent ISO, Inc. (May 28, 2025), Docket No. AD24-11-000, Accession No. 20250528-4032	https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250528-4032&optimized=false&sid=4f4f3475-8309-4416-8289-2aee6d84c1a8
35	Patton MISO Comments	Technical Conference Comments of David B. Patton, Ph.D., MISO Independent Market Monitor (May 28, 2025), Docket No. AD25-7-000, Accession No. 20250528-4006	https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250528-4006&optimized=false&sid=2c5ac909-a7f0-47eb-9bb3-c35f89976250
36	MISO Elliott Max. Gen. Event Overview	MISO, Overview of Winter Storm Elliott December 23, Maximum Generation Event (Jan. 17, 2023)	https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf
37	MISO 2025-2026 CIL/CEL Final Results	MISO, 2025-2026 PY Seasonal CIL/CEL Final Results (Oct. 24, 2024)	https://cdn.misoenergy.org/20241024%20LOLEWG%20Item%2004%20PY%202025-2026%20Final%20CIL_CEL%20Results654989.pdf
38	MISO LOLE Presentation	MISO, *LOLE 101: Probabilistic Analyses*	https://cdn.misoenergy.org/LOLE%20101%20Training624875.pdf
39	DOE Order No. 202-22-2	Department of Energy Order No. 202-22-2 (Sept. 4, 2022)	https://www.energy.gov/ceser/federal-power-act-section-202c-banc-september-2022
40	NERC 2024 Reliability Report	NERC, 2024 State of Reliability (June 2024) (excerpt)	https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2024_Technical_Assessment.pdf
41	NERC 2025 Summer Reliability Assessment	NERC, 2025 Summer Reliability Assessment (May 2025)	https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf

Exhibit No.	Exhibit Name	Document Name	URL
42	2019–24 NERC Summer Reliability Assessments	NERC, Summer Reliability Assessments for 2019-2024 (Compiled)	2019 Reliability Assessment: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2019.pdf 2020 Reliability Assessment: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2020.pdf 2021 Reliability Assessment: https://nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20SRA%202021.pdf 2022 Reliability Assessment: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf 2023 Reliability Assessment: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf 2024 Reliability Assessment: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf
43	Winter Storm Elliott System Operations Inquiry	FERC, NERC, and Regional Entity Staff Report, *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott* (Oct. 2023)	https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022#

Exhibit No.	Exhibit Name	Document Name	URL
44	PJM Elliott Report	PJM, *Winter Storm Elliott: Event Analysis and Recommendation Report* (July 17, 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
45	DOE Order No. 202-21-1	Department of Energy Order No. 202-21-1 (Feb. 14, 2021)	https://www.energy.gov/oe/articles/federal-power-act-section-202c-ercot-february-2021?nrg_redirect=364318
46	FERC Energy Primer	FERC, Energy Primer: A Handbook of Energy Market Basics (Dec. 2023) (excerpt)	https://www.ferc.gov/media/energy-primer-handbook-energy-market-basics
47	2024 Coal Ash Inspection Report	J.H. Campbell Generating Facility 2024 Facility Inspection Report (Oct. 2024)	https://www.consumersenergy.com/-/media/CE/Documents/sustainability/coal-combustion-residuals/jhc/2024/2024_JH-Campbell_Dry-Ash-Landfill_Inspection-Report_10-06-24.pdf
48	2021 CWA Permit	J.H. Campbell National Pollutant Discharge Elimination System Permit No. MI000142 (Oct. 2021)	https://mienviro.michigan.gov/nsite/map/results/detail/6241586858212305105/documents (type "Notice of NPDES permit issuance" within the "file" field, which should automatically filter results to one file dated 10/21/2021 and titled "CECO-J H Campbell Power Plt -- Notice NPDES permit issuance -- Major modification.pdf"; click the file name to download)
49	2025 Energy Innovation Dataset	Energy Innovation, dataset for Coal Power 28 Percent More Expensive In 2024 Than In 2021 (June 5, 2025)	https://energyinnovation.org/report/coal-power-28-percent-more-expensive-in-2024-than-in-2021/

Exhibit No.	Exhibit Name	Document Name	URL
50	2025 Energy Innovation Coal Cost Report	Energy Innovation, Coal Power 28 Percent More Expensive In 2024 Than In 2021 (June 5, 2025)	https://energyinnovation.org/wp-content/uploads/Coal-Cost-Update.pdf
51	2023 Energy Innovation Coal Cost Report	Energy Innovation, Coal Cost Crossover 3.0 (Jan. 2023)	https://energyinnovation.org/wp-content/uploads/Coal-Cost-Crossover-3.0-2.pdf
52	MI State Energy Profile	U.S. EIA, Michigan State Energy Profile (Oct. 17, 2024)	https://www.eia.gov/state/print.php?sid=mi
53	Consumers News Release	Consumers Energy, *Landmark Plan to Accelerate End of Coal Era, Provide Reliability and Protect Environment Earns Approval* (June 23, 2022)	https://www.consumersenergy.com/news-releases/news-release-details/2022/06/23/20/43/plan-to-accelerate-end-of-coal-era-provide-reliability-and-protect-environment-earns-approval
54	NARUC Coal Report	National Association of Regulatory Utility Commissioners, Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices (Jan. 2020) (excerpt)	https://www.osti.gov/servlets/purl/1869928
55	IEA Flexibility Report	C. Henderson, International Energy Agency, Increasing the flexibility of coal-fired power plants (Sept. 2014) (excerpt)	https://usea.org/sites/default/files/092014_Increasing%20the%20flexibility%20of%20coal-fired%20power%20plants_ccc242.pdf

Exhibit No.	Exhibit Name	Document Name	URL
56	Blumenstock 2021 Second Rebuttal Testimony	MPSC Filing No. U-21090, Second Rebuttal Testimony of Richard T. Blumenstock on Behalf of Consumers Energy Company (May 9, 2022) (excerpted from larger transcript)	https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000002z5EqAAI
57	Jester 2021 Direct Testimony	MPSC Filing No. U-21090, Testimony of Douglas B. Jester in Support of Settlement Agreement on Behalf of the Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan (May 9, 2022) (excerpted from larger transcript)	https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000002z5EqAAI
58	MISO Tariff Module E-1	MISO Tariff Module E-1 – Resource Adequacy	https://docs.misoenergy.org/miso12-legalcontent/Module_E-1_-_Resource_Adequacy.pdf
59	MISO 2025–2026 Prelim. PRA Report with Final Results	MISO PY 2025-2026 Seasonal Preliminary PRA Report with Final Results (June 16, 2025)	https://cdn.misoenergy.org/PY 2025_2026 Seasonal Preliminary PRA Report 03_18_25686471.xlsxhttps://cdn.misoenergy.org/PY%202025_2026%20Seasonal%20Preliminary%20PRA%20Report%20with%20Final%20Results%2006_15_25703532.xlsx

Exhibit No.	Exhibit Name	Document Name	URL
60	MISO Tariff Section 38.2.7	MISO Tariff Section 38.2.7	https://docs.misoenergy.org/miso12-legalcontent/TariffAsFiledVersion.pdf
61	MISO Tariff Attachment Y	MISO Tariff Attachment Y	https://docs.misoenergy.org/miso12-legalcontent/Attachment_Y_-_Notification_of_Potential_Resource_-_SCU_Change_of_Status.pdf
62	FERC Technical Conference Notice	FERC, *Meeting the Challenge of Resource Adequacy in Regional Transmission Organization and Independent System Operator Regions* (June 2, 2025)	https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250602-3068&optimized=false&sid=457eb824-f5ed-41fa-a043-a0cd8c55cb4b
63	Palgrave Handbook	M. Hafner & G. Luciana, Palgrave Handbook of International Economics (2022) (excerpt)	https://link.springer.com/book/10.1007/978-3-030-86884-0
64	IEA Report	International Energy Agency, The role of CCUS in low-carbon power systems (2020) (excerpt)	https://www.iea.org/reports/the-role-of-ccus-in-low-carbon-power-systems
65	DOE Transmission Planning Study	DOE, Nat'l Transmission Planning Study, Ch. 2: Long-Term U.S. Transmission Planning Scenarios (2024)	https://www.energy.gov/sites/default/files/2024-10/NationalTransmissionPlanningStudy-Chapter2.pdf

Exhibit No.	Exhibit Name	Document Name	URL
66	NERC 2024 Interregional Transfer Capability Study, Part 1	NERC, Interregional Transfer Capability Study: (ITCS) Strengthening Reliability Through the Energy Transformation, Transfer Capability Analysis (Part 1) (Aug. 2024)	https://www.nerc.com/pa/RAPA/Documents/ITCS_Part_1_Results.pdf

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 72

Department's July Notice

UNITED STATES OF AMERICA
Department of Energy
Washington, DC 20585

Midcontinent Independent System Operator, Inc. and Consumers Energy Company Regarding the J.H. Campbell Generation Facility

Order No. 202-25-3A

NOTICE OF DENIAL OF REHEARING BY OPERATION OF LAW AND PROVIDING FOR FURTHER CONSIDERATION

(July 28, 2025)

Rehearing has been timely requested of the Department of Energy's order issued on May 23, 2025, in the above-captioned matter.[1] Thirty (30) days having passed from the date on which rehearing requests were filed, the requests for rehearing are deemed denied by operation of law.[2]

As provided in 16 U.S.C. § 825*l*(a) and 16 U.S.C. § 824a(c), the requests for rehearing of the above-cited order may be addressed in a future order.[3]

Chris Wright
Secretary of Energy

[1] *Midcontinent Indep. Sys. Operator, Inc., and Consumers Energy Company*, Order No. 202-25-3 (2025) (regarding the J.H. Campbell generation facility).
[2] 16 U.S.C. § 825*l*(a).
[3] 16 U.S.C. § 825*l*(a) (DOE may modify or set aside its above-cited order, in whole or in part, in such manner as it shall deem proper); 16 U.S.C. § 824a(c) (DOE may issue a supplemental order).

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 73

Consumers' July 2025 10-Q

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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
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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

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

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

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

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

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

NOx

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

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

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

- 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

- 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

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:

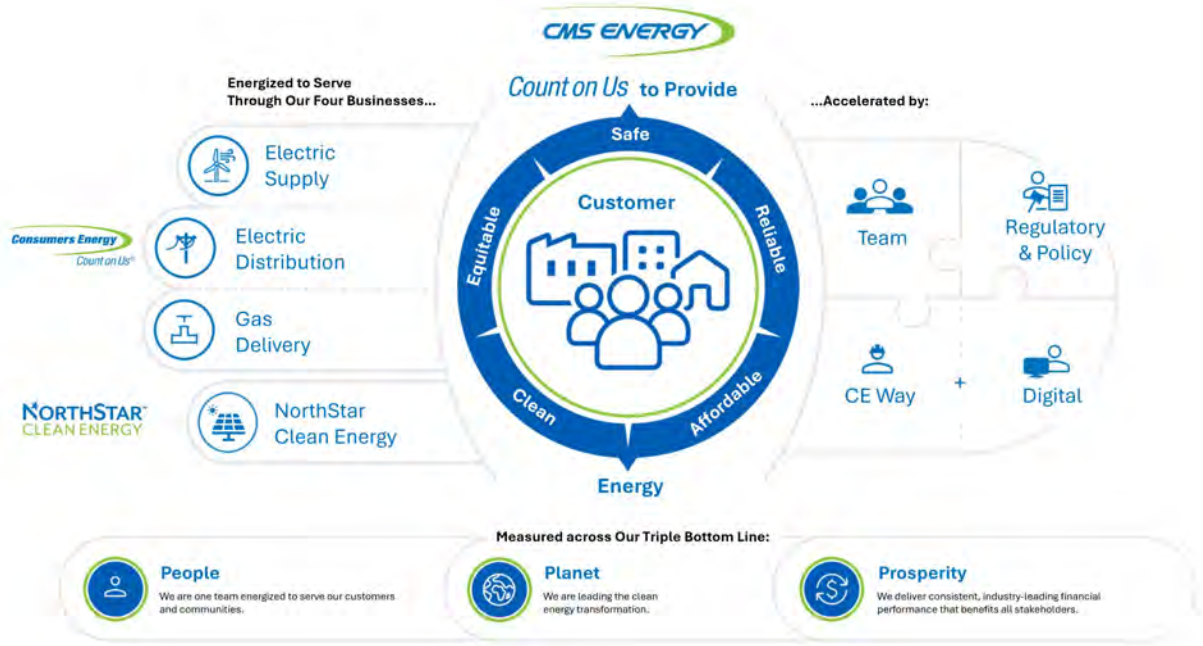
- regulation and regulatory matters
- state and federal legislation
- economic conditions
- weather
- energy commodity prices
- interest rates
- their securities' credit ratings

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,

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

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

- 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

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

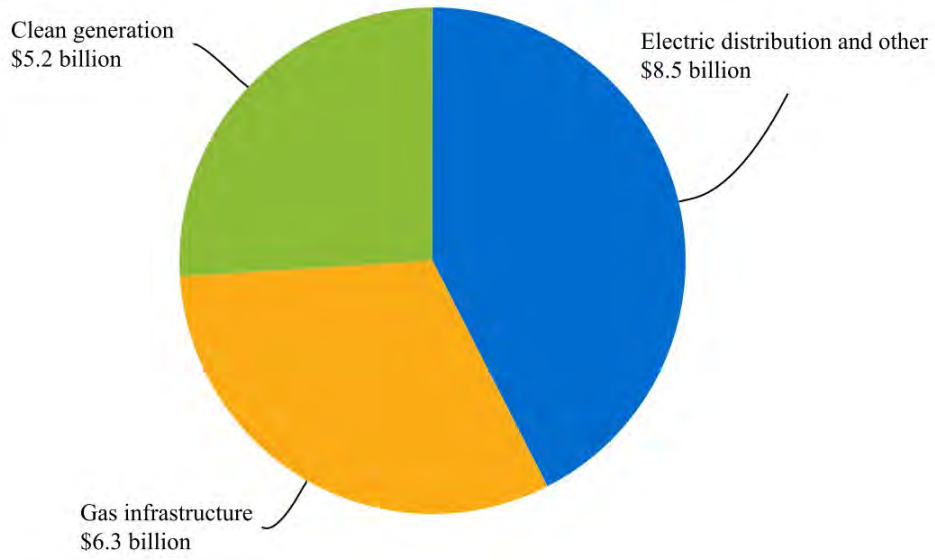
- announced deployment of eight state-of-the-art vehicles that will survey the company's nearly 30,000-mile gas distribution system to find methane emissions, enhancing safety and reliability for Consumers' natural gas customers

- 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

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.

Results of Operations

CMS Energy Consolidated Results of Operations

In Millions, Except Per Share Amounts

	Three Months Ended			Six Months Ended		
June 30	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

	Three Months Ended			Six Months Ended		
June 30	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

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:

In Millions

	Three Months Ended		Six Months Ended	
June 30, 2024		$ 195		$ 480
Reasons for the change				
Consumers electric utility and gas utility				
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.

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:

In Millions

	Three Months Ended		Six Months Ended	
June 30, 2024		$ 170		$ 267
Reasons for the change				
Electric deliveries[1] and rate increases				
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
Maintenance and other operating expenses				
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)
Depreciation and amortization				
Increased plant in service, reflecting higher capital spending		(13)		(21)
General taxes				
Higher property taxes, reflecting higher capital spending		(5)		(7)
Other income, net of expenses		—		(7)
Interest charges		(10)		(11)
Income taxes				
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.

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:

In Millions

	Three Months Ended		Six Months Ended	
June 30, 2024		$ 15		$ 184
Reasons for the change				
Gas deliveries[1] and rate increases				
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
Maintenance and other operating expenses				
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
Depreciation and amortization				
Increased plant in service, reflecting higher capital spending		(3)		(14)
General taxes				
Higher property taxes, reflecting higher capital spending		(2)		(7)
Other income, net of expenses		—		(3)
Interest charges		(5)		(5)
Income taxes				
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.

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:

In Millions

	Three Months Ended		Six Months Ended	
June 30, 2024	$	16	$	47
Reason for the change				
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:

In Millions

	Three Months Ended		Six Months Ended	
June 30, 2024	$	(6)	$	(18)
Reasons for the change				
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:

		In Millions
CMS Energy, including Consumers		
Six Months Ended June 30, 2024	$	1,663
Reasons for the change		
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
Reasons for the change		
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.

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:

		In Millions
CMS Energy, including Consumers		
Six Months Ended June 30, 2024	$	(1,246)
Reasons for the change		
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)
Reasons for the change		
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)

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:

		In Millions
CMS Energy, including Consumers		
Six Months Ended June 30, 2024	$	124
Reasons for the change		
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
Reasons for the change		
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.

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.

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.

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

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.

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:

In Millions

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.

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

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

(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

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:

		In Millions
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.

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

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.

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.

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.

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.

CMS Energy Corporation

Consolidated Statements of Comprehensive Income (Unaudited)

In Millions

	Three Months Ended		Six Months Ended	
June 30	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)

In Millions

Six Months Ended June 30	2025	2024
Cash Flows from Operating Activities		
Net income	$ 488	$ 445
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	676	641
Deferred income taxes and investment tax credits	124	79
Other non-cash operating activities and reconciling adjustments	(144)	(107)
Changes in assets and liabilities		
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		
Non-cash transactions		
Capital expenditures not paid	$ 537	$ 259

The accompanying notes are an integral part of these statements.

CMS Energy Corporation
Consolidated Balance Sheets (Unaudited)

ASSETS

In Millions

	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
Inventories at average cost		
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

LIABILITIES AND EQUITY

In Millions

	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		
Common stockholders' equity		
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.

CMS Energy Corporation

Consolidated Statements of Changes in Equity (Unaudited)

In Millions, Except Per Share Amounts

	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				
Retirement benefits liability				
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.

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.

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.

Consumers Energy Company
Consolidated Statements of Cash Flows (Unaudited)

In Millions

Six Months Ended June 30	2025	2024
Cash Flows from Operating Activities		
Net income	$ 534	$ 453
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	651	617
Deferred income taxes and investment tax credits	66	76
Other non-cash operating activities and reconciling adjustments	(80)	(38)
Changes in assets and liabilities		
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		
Non-cash transactions		
Capital expenditures not paid	$ 425	$ 255

The accompanying notes are an integral part of these statements.

Consumers Energy Company
Consolidated Balance Sheets (Unaudited)

ASSETS

In Millions

	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
Inventories at average cost		
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

LIABILITIES AND EQUITY

In Millions

	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		
Common stockholder's equity		
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.

Consumers Energy Company
Consolidated Statements of Changes in Equity (Unaudited)

In Millions

	Three Months Ended		Six Months Ended	
June 30	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. Intervenors 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.

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

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:

In Millions

	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.

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.

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:

In Millions

	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:

In Millions

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.

[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.

[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.

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

In Millions

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
Consumers[5]				
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.

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:

			Forward Price Per Share	
Contract Date	Maturity Date	Number of Shares	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:

In Millions

	CMS Energy, including Consumers		Consumers	
	June 30 2025	December 31 2024	June 30 2025	December 31 2024
Assets[1]				
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
Liabilities[1]				
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.

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.

In Millions

	June 30, 2025					December 31, 2024				
		Fair Value					Fair Value			
			Level					Level		
	Carrying Amount	Total	1	2	3	Carrying Amount	Total	1	2	3
CMS Energy, including Consumers										
Assets										
Long-term receivables[1]	$ 7	$ 7	$ —	$ —	$ 7	$ 9	$ 8	$ —	$ —	$ 8
Liabilities										
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										
Assets										
Long-term receivables[1]	$ 7	$ 7	$ —	$ —	$ 7	$ 9	$ 8	$ —	$ —	$ 8
Notes receivable – related party[4]	92	92	—	—	92	94	94	—	—	94
Liabilities										
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.

[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:

In Millions

	DB Pension Plans				OPEB Plan			
	Three Months Ended		Six Months Ended		Three Months Ended		Six Months Ended	
June 30	2025	2024	2025	2024	2025	2024	2025	2024
CMS Energy, including Consumers								
Net periodic credit								
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)
Amortization of:								
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								
Net periodic credit								
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)
Amortization of:								
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

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 %
Increase (decrease) in income taxes from:		
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 %
Increase (decrease) in income taxes from:		
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

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:

In Millions, Except Per Share Amounts

	Three Months Ended		Six Months Ended	
June 30	2025	2024	2025	2024
Income available to common stockholders				
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
Average common shares outstanding				
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
Income from continuing operations per average common share available to common stockholders				
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.

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:

In Millions

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				
Consumers utility revenue				
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.

In Millions

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				
Consumers utility revenue				
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.

In Millions

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				
Consumers utility revenue				
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.

In Millions

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				
Consumers utility revenue				
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

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.

In Millions

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
Operating expenses						
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.

In Millions

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
Operating expenses					
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.

In Millions

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
Operating expenses						
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.

In Millions

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
Operating expenses					
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.

Presented in the following tables is financial information by segment:

In Millions

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
Operating expenses						
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.

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
Operating expenses					
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.

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
Operating expenses						
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.

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
Operating expenses					
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

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

[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.

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

In Millions

	June 30, 2025	December 31, 2024
Current		
Cash and cash equivalents	$ 16	$ 18
Accounts receivable	7	4
Prepayments and other current assets	4	3
Non-current		
Plant, property, and equipment, net	993	1,024
Other non-current assets	6	3
Total assets[1]	$ 1,026	$ 1,052
Current		
Accounts payable	$ 10	$ 8
Accrued taxes	1	—
Non-current		
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.

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:

In Millions

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.

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.

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.

Exhibits		Description
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.

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

ANNUAL NORTHSTAR CLEAN ENERGY EMPLOYEE INCENTIVE COMPENSATION PLAN

ANNUAL NORTHSTAR CLEAN ENERGY EMPLOYEE INCENTIVE COMPENSATION PLAN

I. GENERAL PROVISIONS

1.1 Purpose. The purpose of the Annual NorthStar Clean Energy Employee Incentive Compensation Plan ("Plan") is to provide an equitable and competitive level of compensation that will permit NorthStar Clean Energy and its subsidiaries to attract, retain and motivate their employees.

1.2 Effective Date. The Plan as described herein is effective as of January 1, 2014, as amended and revised January 1, 2016; August 4, 2017; December 1, 2018; December 1, 2019; February 1, 2020; May 16, 2021; December 1, 2021; January 27, 2022; August 22, 2022,July 1, 2023, February 1, 2024, January 1, 2025 *and* May 1, 2025.

1.3 Eligibility. Except as otherwise provided in this Section 1.3, regular non-union U.S. employees and NorthStar Clean Energy Officers who do not participate in a broad-based incentive plan contingent upon objectives and performance unique to the employees' or NorthStar Clean Energy Officers' Subsidiary, affiliate, site and/or business unit, are eligible for participation in the Plan. In addition, the following positions at NorthStar Clean Energy Subsidiaries are eligible for participation in this plan based on the annual award formula provided in Section 3.1 and are not eligible to participant in the Subsidiaries' incentive plan:

Company Code	Position Number
4177	70037175
4177	70040785
4177	70041126
4177	70028412
4177	70043264
4160	70037384
4160	70042024
4710	70043401
4030	70012520

An individual listed on the Company payroll records as a contract employee is not eligible for this Plan. Eligible regular non-union U.S. employees and NorthStar Clean Energy Officers who have received a performance rating of at least 'Needs Improvement' for the Performance Year as documented on their annual performance, evaluation, feedback and development appraisal are eligible for participation in the Plan. Any regular non-union employee or NorthStar Clean Energy Officer who has received a performance rating of less than 'Needs

Improvement'(as defined above), such as 'Under Performing', 'under-contributing" or ('U') for the Performance Year as documented on their annual performance, evaluation, feedback and development appraisal is not eligible for participation in the Plan.

1.4 Definitions. As used in this Plan, the following terms have the meaning described below:

(a) "Annual Award" means an annual incentive award granted under the Plan.

(b) "Base Salary" means regular straight-time salary or wages paid to the employee or NorthStar Clean Energy Officer.

(c) "CMS Energy" means CMS Energy Corporation, the parent of Consumers Energy Company and NorthStar Clean Energy.

(d) "Code" means the Internal Revenue Code of 1986, as amended.

(e) "Company" means NorthStar Clean Energy.

(f) "Deferred Annual Award" means the amount deferred pursuant to Section 4.2.

(g) "Disability" means that a participant has terminated employment with the Company or a Subsidiary and is disabled, as that term is defined under Code Section 409A and any applicable regulations.

(h) "NorthStar Clean Energy" means NorthStar Clean Energy Company, a wholly owned subsidiary of CMS Energy.

(i) "NorthStar Clean Energy Officer" for purposes of this Plan means an elected officer of NorthStar Clean Energy.

(j) "Leave of Absence" for purposes of this Plan means a leave of absence that has been approved by the Company.

(k) "Payment Event" means the time at which a Deferred Annual Award may be paid pursuant to Section 4.2.

(l) "Payment Term" means the length of time for payment of a Deferred Annual Award under Section 4.2.

(m) "Pension Plan" means the Pension Plan for Employees of Consumers Energy and Other CMS Energy Companies.

(n) "Performance Year" means the calendar year prior to the year in which an Annual Award is made under this Plan.

(o) "Plan Administrator" is the Benefits Administration Committee appointed by the CMS Energy Chief Executive Officer and the CMS Energy Chief Financial Officer.

(p) "Record Keeper" means the person(s) or entity named as such by the Plan Administrator.

(q) "Retirement" means that a Plan participant is no longer an active employee or NorthStar Clean Energy Officer and qualifies for a retirement benefit other than a deferred vested retirement benefit under the Pension Plan. For a participant ineligible for coverage under the Pension Plan and covered instead under the Defined Company Contribution Plan, retirement occurs when there is a Separation from Service on or after age 55 with 5 or more years of service.

(r) "Separation from Service" means an employee or NorthStar Clean Energy Officer retires or otherwise has a separation from service from the Company as defined under Code Section 409A and any applicable regulations. The Plan Administrator will determine, consistent with the requirements of Code Section 409A and any applicable regulations, to what extent a person on a leave of absence, including on paid sick leave pursuant to Company policy, has incurred a Separation from Service. Notwithstanding the above, a Separation from Service will occur consistent with Treasury Regulation Section 1.409A-1(h) when it is reasonably anticipated that the level of service provided by the employee or NorthStar Clean Energy Officer will be no more than 45% of the average level of bona fide service performed by the employee or NorthStar Clean Energy Officer over the immediately preceding 36-month period.

(s) "Standard Award Percentage" means the target award amount as a percentage of Base Salary as set forth in Section 3.1 of this Plan.

(t) "Subsidiary" means any direct or indirect subsidiary of the Company.

II. CORPORATE PERFORMANCE GOALS

2.1 In General. Each year the President of NorthStar Clean Energy will establish the Performance Goals ("Goals") for the Plan. The Goals will consist of between three and ten company specific performance criteria relating to such items as net income;CMS Energy adjusted earnings per share; customer origination; environmental, safety and cultural metrics. When establishing the Goals for a

Performance Year, the President of NorthStar Clean Energy will include the total number of criteria to be used for the year as well as the award percent for achievement of a specified number of the established criteria. The specific Goals will be communicated to employees and NorthStar Clean Energy Officers no later than March 31st of the Performance Year. The Award Formula may include additional adjustments based on financial performance goals relating to CMS Energy Corporation as determined NorthStar Clean Energy Board of Directors.

2.2 **Plan Performance.** The adjustments, if applicable, based on financial performance goals relating to CMS Energy used to calculate an Annual Award is capped at two times the applicable Standard Award Percentage. The Goals for a Performance Year are established in a table relating specific performance results to specific performance goals. This table shall be created by the President of NorthStar Clean Energy for each Performance Year.

III. ANNUAL AWARD FORMULA

3.1 **Annual Awards**. Annual Awards for each eligible Plan participant shall be equal the target percentages by career stream and job level as indicated in the chart below. The Standard Award Percentages stated in this Section 3.1 are subject to adjustment by the President of NorthStar Clean Energy as indicated by market practices.

Career Stream Award Tables

Career Stream	NS Broad Band 1	NS Broad Band 2	NS Broad Band 3	NS Broad Band 4	NS Broad Band 5	NS Broad Band 6
Management	N/A	Supervisor	Manager	Senior Manager	Director	Executive Director
Professional	Career	Senior	Principal	Senior Principal	N/A	N/A
Technical	Career	Senior	Principal	Senior Principal	Fellow	N/A
Legal	N/A	Career	Senior	Principal	Senior Principal	N/A
EICP %	**10%**	**12%**	**15%**	**20%**	**25%**	**30%**

Career Stream	NS Broad Band 1				
Support	Entry	Career	Senior	Lead	Senior Lead
EICP %	**5%**	**5%**	**5%**	**5%**	**5%**

Note: Reduced Schedule (Includes part-time employees) employees will receive the Standard Award Percentage multiplied by their work week schedule percentage. For example if a part-time employee works 30 hours per week (75% of a standard 40 hour per week schedule), then Standard Award Percentage would be multipled by 75%.

3.2 **NorthStar Clean Energy Officer Annual Awards**. Annual Awards for each eligible Plan NorthStar Clean Energy Officer participant will be based upon a standard award percentage as set forth in the table below:

Officer	Standard Award Percentage of Base Salary
President of CMS NorthStar Clean Energy	45%
Chief Operating Officer of CMS NorthStar Clean Energy	35%
Vice President of CMS NorthStar Clean Energy Development	30%
Chief Commercial Officer NorthStar (70% based on Individual goal and 30% based on Corporate Plan)	60%

IV. ADMINISTRATION OF THE PLAN

(a) The Plan is administered by the President of CMS NorthStar Clean Energy under the general direction of the CMS Energy Chief Executive Officer and NorthStar Clean Energy Board of Directors.,

(b) Each year, normally in January, but no later than March 30th of the Performance Year, the CMS Energy Chief Executive Officer and NorthStar Clean Energy Board of Directors will approve the established Performance Goals for the Performance Year.

(c) The CMS Energy Chief Executive Officer and NorthStar Clean Energy Board of Directors no later than March 31st of the calendar year following the Performance Year, will review for approval proposed Annual Awards as recommended by the President of CMS NorthStar Clean Energy.

(d) The CMS Energy Chief Executive Officer reserves the right to modify the established Performance Goals with respect to unforeseeable circumstances or otherwise exercise discretion with respect to proposed Annual Awards as he or she deems necessary to maintain the spirit and intent of the Plan, provided that if such discretion increases the Annual Award it does not exceed the computed performance factor by more than 20%. The CMS Energy Chief Executive Officer also reserves the right in his or her discretion to not pay Annual Awards or to reduce the amount of Annual Awards for a Performance Year. All decisions of the CMS Energy Chief Executive Officer are final.

V. PAYMENT OF ANNUAL AWARDS

5.1 Cash Annual Award. All Annual Awards for a Performance Year will be paid in cash no later than March 15th of the calendar year following the Performance Year provided that the Annual Award for a particular Performance Year has not been

deferred voluntarily pursuant to Section 4.2. The amounts required by law to be withheld for income and employment taxes will be deducted from the Annual Award payments. All Annual Awards become the obligation of the company on whose payroll the employee or NorthStar Clean Energy Officer is enrolled at the time CMS NorthStar Clean Energy makes the Annual Award.

5.2 Deferred Annual Awards.

(a) The payment of all or any portion (rounded to an even multiple of 10%) of a cash Annual Award may be deferred voluntarily at the election of individual participants in salary grades 19-25 or Career Stream Management. Any such deferral will be net of any applicable FICA or FUTA taxes. A separate irrevocable election must be made prior to the Performance Year. Any Annual Award made by CMS NorthStar Clean Energy after termination of employment of a participant or retirement of a participant will be paid in accordance with any deferral election made within the enrollment period.

(b) At the time the participant makes a deferral election he or she must select the payment options (including the Payment Event as set forth at (c) below and the Payment Term as set forth at (d) below) applicable to the Deferred Annual Award for the Performance Year, as well as any earnings or income attributable to such amounts. The payment options elected will apply only to that year's Deferred Annual Award and will not apply to any previous Deferred Annual Award or to any subsequent Deferred Annual Award. Any participant who elects to defer all or a portion of an Annual Award and who fails to select a Payment Event or a Payment Term will be presumed to have elected a Payment Event of Separation from Service in accordance with paragraph (c)(i) below and/or a Payment Term of a single sum.

(c) The Payment Event elected can be either:

(i) Separation from Service for any reason other than death. Payment will be made, or begin, in the later of: (1) January of the year following the year of the Separation from Service; or (2) the seventh month after the month of the Separation from Service. Later installments, if any, will be paid in January of the succeeding years. Effective for amounts deferred in 2019 and succeeding years, payment will be made, or begin, in the seventh month after the month of Separation from Service. Later installments, if any, will be paid in the same month of the succeeding years;

(ii) Payment upon attainment of a date certain that is more than 1 year after the last day of the applicable Performance Year. Later installments, if any, will be paid in the same month of the succeeding years; or

(iii) The later to occur of (i) or (ii) above.

(d) Payment Term. At the time of electing to defer an Annual Award, the participant must also elect how he or she wishes to receive any such payment from among the following options (the participant may elect a separate Payment Term for each Payment Event elected):

(i) Payment in a single sum upon occurrence of the Payment Event.

(ii) Payment of a series of annual installment payments over a period from two (2) years to fifteen (15) years following the Payment Event. Each installment payment shall be equal to a fractional amount of the balance in the account the numerator of which is one and the denominator of which is the number of installment payments remaining. Although initially such installment payments will be identical, actual payments may vary based upon investment performance. For example, a series of 5 installment payments will result in a payout of 1/5 of the account balance in the first installment, ¼ of the account balance (including investment gains or losses since the first installment date) in the second installment, etc.

(e) Changes to Payment Options. Once a payment option has been elected, subsequent changes which would accelerate the receipt of benefits from the Plan are not permitted, except that the Plan Administrator, which is the Benefit Administration Committee as defined in the Savings Plan for Employees of Consumers Energy and other CMS Energy Companies (the "Savings Plan"), may at its discretion accelerate payments to the extent permitted by Code Section 409A and applicable regulations. A subsequent election to change the payment options related to a Payment Event, in order to delay a payment or to change the form of a payment, can only be made when all of the following conditions are satisfied:

(i) such election may not take effect until at least 12 months after the date on which the election is made;

(ii) the payment(s) with respect to which such election is made is deferred for a period of not less than 5 years from the date such payment would otherwise have been made (or, in the case of installment payments under Section 4.2(d)(ii) with regard to amounts deferred

(and the related earnings) prior to January 1, 2016, 5 years from the date the first installment was scheduled to be paid); and

(iii) such election must be made not less than 12 months before the date the payment was previously scheduled to be made (or, in the case of installment payments under Section 4.2(d)(ii) with regard to amounts deferred (and the related earnings) prior to January 1, 2016, 12 months before the first installment was scheduled to be paid), if the participant's previous commencement date was a specified date.

Effective January 1, 2016, the right to a series of installment payments is to be treated as a right to a series of separate payments to the extent permissible under Code Section 409A and any applicable regulations. When making a subsequent election with respect to the payment of any post-December 31, 2015 deferral, the participant may make a separate election with respect to each separate payment, provided that such election must result in all of the applicable Performance Year's deferral with related earnings being paid in a single sum or in a series of annual payments over a period from two (2) to fifteen (15) consecutive years.

(f) Investments. At the time of electing to voluntarily defer payment, the participant must elect how the Deferred Annual Award will be treated by CMS NorthStar Clean Energy. To the extent that any amounts deferred are placed in a rabbi trust with an independent Record Keeper, a participant who has previously deferred amounts under this Plan will automatically have his or her existing investment profile apply to this deferral also. All determinations of the available investment options by the Plan Administrator are final and binding upon participants. A participant may change the investment elections at any time prior to the payment of the benefit, subject to any restrictions imposed by the Plan Administrator, the plan Record Keeper or by any applicable laws and regulations. A participant not making an election will have amounts deferred treated as if in a Lifestyle Fund as defined in the Savings Plan applicable to the participant's age 65, rounded up, or such other investment as determined by the Plan Administrator. All gains and losses will be based upon the performance of the investments selected by the participant from the date the deferral is first credited to the nominal account. If the Company elects to fund its obligation as discussed below, then investment performance will be based on the balance as determined by the Record Keeper.

(g) The amount of any Deferred Annual Award is to be satisfied from the general corporate funds of the company on whose payroll the Plan participant was enrolled prior to the payout beginning and are subject to the claims of general creditors of the Company. This is an unfunded

nonqualified deferred compensation plan. To the extent the Company elects to place funds with a trustee to pay its future obligations under this Plan, such amounts are placed for the convenience of CMS NorthStar Clean Energy, remain the property of CMS NorthStar Clean Energy and the participant shall have no right to such funds until properly paid in accordance with the provisions of this Plan. For administrative ease and convenience, such amounts may be referred to as participant accounts, but as such are a notional account only and are not the property of the participant. Such amounts remain subject to the claims of the creditors of CMS NorthStar Clean Energy.

(h) Payment in the Event of an Unforeseeable Emergency. The participant may request that payments commence immediately upon the occurrence of an Unforeseeable Emergency as that term is defined in Code Section 409A and any applicable regulations. Generally, an unforeseeable emergency is a severe financial hardship resulting from an illness or accident of the participant or the participant's spouse or dependent, loss of the participant's property due to casualty, or other similar extraordinary and unforeseeable circumstances arising as a result of events beyond the control of the participant. A distribution on account of unforeseeable emergency may not be made to the extent that such emergency is or may be relieved through reimbursement or compensation from insurance or otherwise, by liquidation of the participant's assets (without causing severe financial hardship), or by cessation of deferrals under this arrangement, the Savings Plan or other arrangements. Distributions because of an unforeseeable emergency shall not exceed the amount permitted under Section 409A and accordingly are limited to the amount reasonably necessary to satisfy the emergency need (after use of insurance proceeds, liquidation of assets, etc.) plus an amount to pay taxes reasonably anticipated as a result of the distribution. In the event any payment is made due to an unforeseeable emergency, all deferral elections for the current Performance Year will cease and the participant will not be eligible to make any deferral elections under this Plan for the following Performance Year. For any participant receiving a hardship withdrawal under the Savings Plan, all deferral elections under this Plan for the current Performance Year will cease and the participant will not be eligible to make any deferral elections under this Plan for the following Performance Year.

5.3 Payment in the Event of Death.

(a) A participant may name the beneficiary of his or her choice on a beneficiary form provided by the Company or record keeper, and the beneficiary shall receive, within 90 days of the participant's death, in a single sum, all payments credited to the participant in the event that the

participant dies prior to receipt of Deferred Annual Awards. If there is no beneficiary named at the time of participant's death or if the beneficiary does not survive the participant, the payment will be made to the participant's estate. In no event may any recipient designate a year of payment for an amount payable upon the death of the participant.

(b) A participant may change beneficiaries at any time, and the change will be effective as of the date the plan record keeper or the Company accepts the form as complete. The Company will not be liable for any payments made before receipt and acceptance of a written beneficiary request.

VI. CHANGE OF STATUS

Payments in the event of a change in status will not be made if no Annual Awards are made for the Performance Year.

6.1 Pro-Rata Annual Awards. A new Plan participant, whether hired or promoted to the position, or an Plan participant promoted to a higher broad band or to an NorthStar Clean Energy Officer position during the Performance Year will receive a pro rata Annual Award based on the percentage of the Performance Year in which the employee is in a particular broad band or NorthStar Clean Energy Officer position. A Plan participant whose broad band has been lowered or who is no longer an NorthStar Clean Energy Officer, but whose employment is not terminated during the Performance Year, will receive a pro rata Annual Award based on the percentage of the Performance Year in which the employee is in a particular broad band or NorthStar Clean Energy Officer position. Awards will also be prorated for any change in full time or part time work status.

6.2 Termination. A Plan participant whose employment is terminated pursuant to a violation of the Company code of conduct or other corporate policies will not be considered for or receive an Annual Award**.**

6.3 Resignation A Plan participant who resigns during a Performance Year will not be eligible for an Annual Award. If the Plan Participant resigns after the Performance Year, but prior payment, the Plan Participant will be eligible for an Annual Award.

6.4 Death, Disability, Retirement A Plan participant whose status as an active employee or NorthStar Clean Energy Officer is changed during the Performance Year due to Death, Disability, or Retirement, (as determined by the Plan Administrator) will receive a pro rata Annual Award. An Plan participant whose employment is terminated following the Performance Year, but prior to payment due to Death, Disability or Retirement will continue to be eligible for an Annual Award for the Performance Year. Any such payment or Annual Award payable due to the death of the Plan participant will be made to the named beneficiary, or if no beneficiary is named or if the beneficiary doesn't survive the Plan participant, then

to the Plan participant's estate no later than March 15 following the applicable Performance Year. Notwithstanding the above, an Plan participant who retires, is on Disability and who becomes employed by a competitor of CMS Energy or its subsidiaries or affiliates prior to award payout will forfeit all rights to an Annual Award, unless prior approval of such employment has been granted by the Chief Financial Officer of CMS Energy. A "competitor" shall mean an entity engaged in the business of (1) selling (a) electric power or natural gas at retail or wholesale within the State of Michigan or (b) electric power at wholesale within the market area in which an electric generating plant owned by a subsidiary or affiliate of CMS Energy is located or (2) developing an electric generating plant within the State of Michigan or a market area in which an electric generating plant owned by a subsidiary or affiliate of CMS Energy is located.

6.5 **Payment Following Leave of Absence.** Payment of an award for an Plan participant who is on leave of absence or Family Medical Leave Act leave at the time of payment shall be paid in the same payroll period as active participants. Payment of an award for an Plan participant who is laid-off at the time of payment shall be paid in the payroll period that is within an administratively reasonable time after returning to work, but no later than March 15 of the year following the year the participant has returned to work.

VII. MISCELLANEOUS

7.1 **Impact on Benefit Plans.** Payments for eligible participants made under the Plan will be considered as earnings for the Supplemental Executive Retirement Plans but not for purposes of the Employees' Savings Plan, Pension Plan, or other employee benefit programs.

7.2 **Impact on Employment**. Neither the adoption of the Plan nor the granting of any Annual Award under the Plan will be deemed to create any right in any individual to be retained or continued in the employment of the Company or any corporation within the Company's control group.

7.3 **Termination or Amendment of the Plan.** The Company may amend or terminate the Plan at any time. Upon termination, any Deferred Annual Award accrued under the Plan and vested will remain in the Plan and be paid out in accordance with the payment elections previously selected. The Plan Administrator is authorized to make any amendments that are deemed necessary or desirable to comply with any applicable laws, regulations or orders or as may be advised by counsel or to clarify the terms and operation of the Plan. The Company may terminate the Plan and accelerate any benefits under the Plan, at its discretion, if it acts consistent in all manners with the requirements of Code Section 409A and any applicable regulations with respect to when a terminated plan may accelerate payment to a participant.

7.4 **Governing Law**. The Plan will be governed and construed in accordance with the laws of the State of Michigan.

7.5 **Dispute Resolution**. Any disputes related to the Plan must be brought to the Plan Administrator. The Plan Administrator is granted full discretionary authority to apply the terms of the Plan, make administrative rulings, interpret the Plan and make any other determinations with respect to the Plan. If the Plan Administrator makes a determination and the participant disagrees with or wishes to appeal the determination, the participant must appeal the decision to the Plan Administrator, in writing and not later than 60 days from when the determination was mailed to the participant. If the participant does not timely appeal the original determination, the participant has no further rights under the Plan with respect to the matter presented in the claim. If the participant appeals the original determination and that appeal does not result in a mutually agreeable resolution, then the dispute shall be subject to final and binding arbitration before a single arbitrator selected by the parties to be conducted in Jackson, Michigan, provided the participant makes such request for arbitration in writing within 30 days of the final decision by the Plan Administrator. The arbitration will be conducted and finished within 90 days of the selection of the arbitrator. The parties shall share equally the cost of the arbitrator and of conducting the arbitration proceeding, but each party shall bear the cost of its own legal counsel and experts and other out-of-pocket expenditures. The arbitrator must use an arbitrary and capricious standard of review when considering any determinations and findings by the Plan Administrator.

VIII. AMENDMENT TO REFLECT CODE SECTION 409A

8.1 **Code Section 409A.** To the extent counsel determines amendments may be reasonable or desirable in order to comply with Code Section 409A, and any other applicable rules, laws and regulations, such changes shall be authorized with the approval of the Plan Administrator.

Certification of Garrick J. Rochow

I, Garrick J. Rochow, certify that:

1. I have reviewed this quarterly report on Form 10-Q of CMS Energy Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: July 31, 2025

By: /s/ Garrick J. Rochow

Garrick J. Rochow
President and Chief Executive Officer

Certification of Rejji P. Hayes

I, Rejji P. Hayes, certify that:

1. I have reviewed this quarterly report on Form 10-Q of CMS Energy Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: July 31, 2025

By: /s/ Rejji P. Hayes

Rejji P. Hayes
Executive Vice President and Chief Financial Officer

Certification of Garrick J. Rochow

I, Garrick J. Rochow, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Consumers Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: July 31, 2025

By: /s/ Garrick J. Rochow

Garrick J. Rochow
President and Chief Executive Officer

Certification of Rejji P. Hayes

I, Rejji P. Hayes, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Consumers Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: July 31, 2025

By: /s/ Rejji P. Hayes

Rejji P. Hayes

Executive Vice President and Chief Financial Officer

Certification of CEO and CFO Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Quarterly Report on Form 10-Q of CMS Energy Corporation (the "Company") for the quarterly period ended June 30, 2025 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Garrick J. Rochow, as President and Chief Executive Officer of the Company, and Rejji P. Hayes, as Executive Vice President and Chief Financial Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Garrick J. Rochow

Name: Garrick J. Rochow
Title: President and Chief Executive Officer
Date: July 31, 2025

/s/ Rejji P. Hayes

Name: Rejji P. Hayes
Title: Executive Vice President and Chief Financial Officer
Date: July 31, 2025

Certification of CEO and CFO Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Quarterly Report on Form 10-Q of Consumers Energy Company (the "Company") for the quarterly period ended June 30, 2025 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Garrick J. Rochow, as President and Chief Executive Officer of the Company, and Rejji P. Hayes, as Executive Vice President and Chief Financial Officer of the Company, each hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his knowledge:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Garrick J. Rochow

Name: Garrick J. Rochow
Title: President and Chief Executive Officer
Date: July 31, 2025

/s/ Rejji P. Hayes

Name: Rejji P. Hayes
Title: Executive Vice President and Chief Financial Officer
Date: July 31, 2025

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 74

DOE 202(c) Webpage as of Aug. 30, 2025

An official website of the United States government Here's how you know

DOE's Use of Federal Power Act Emergency Authority

Under Federal Power Act (FPA) section 202(c), during the continuance of a war in which the United States is engaged or when 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 the fuel or water for generating facilities, or other causes, the Secretary of Energy may require by order temporary connections of facilities, and generation, delivery, interchange, or transmission of electricity as the Secretary determines will best meet the emergency and serve the public interest. 16 U.S.C. § 824a(c).

All public comments and requests related to FPA section 202(c) should be sent via email to AskCR@hq.doe.gov. Information that the sender deems sensitive and not eligible for public release should be marked accordingly, and both a public (redacted) and non-public version of such materials should be submitted. Additional information about 202(c) procedures, if necessary, will be announced on this page.

The provision of this process for submission of correspondence or comments on any pending application is for purposes of ensuring the receipt by the

appropriate office and personnel within the Department. Establishment of this email address does not establish a "docket," and those submitting correspondence do not constitute parties or intervenors to any proceeding. Further, submission of correspondence to the Department does not in any way limit or prevent the ability of the Secretary to act on any application, or pursuant to section 202(c) without application, in any way and at any time as he or she deems appropriate.

Beginning in 2022, the Department modified the numbering scheme associated with its section 202(c) emergency orders. Prior to 2022, emergency orders followed a fiscal year timeline, whereas since the beginning of 2022, emergency orders have aligned with the calendar year. For example, a 202(c) emergency order issued in November 2017 is identified as Order No. 202-18-1 and an order issued in December 2022 is identified as Order No. 202-22-3.

DOE 202(c) Emergency Orders 2020-present:

- On August 28, 2025, the Department of Energy (DOE) issued an emergency order, pursuant to section 202(c) of the Federal Power Act, to PJM Interconnection (PJM). The order directs PJM, in coordination with Constellation Energy, to ensure Units 3 and 4 of the Eddystone Generating Station in Pennsylvania remain available for operation. This order is in effect beginning on August 28, 2025, and continues until November 26, 2025.
- On August 20, 2025, the Department of Energy (DOE) issued an emergency order, pursuant to section 202(c) of the Federal Power Act, to Midcontinent Independent System Operator (MISO). The emergency order directs MISO, in coordination with Consumers Energy, to ensure that the J.H. Campbell Power Plant in West Olive, Michigan remains available for operation, minimizing any potential generation shortfall that could lead to unnecessary power outages. This order is in effect beginning on August 21, 2025, and continuing until November 19, 2025.
- On August 14, 2025, the Department of Energy (DOE) issued two emergency orders extensions, pursuant to section 202(c) of the Federal

Power Act, to the Puerto Rico Electric Power Authority (PREPA). The first emergency order extension directs PREPA to continue dispatching generation units necessary to maintain grid reliability and closing the gap in generation shortfall. The second order extension directs PREPA to continue performing vegetation management activities. These extension orders are in effect beginning on August 15, 2025, and continuing through November 12, 2025.

- On July 28, 2025, the Department of Energy (DOE) issued an emergency order, pursuant to section 202(c) of the Federal Power Act, to PJM Interconnection (PJM). PJM shall, in coordination with Talen Energy Corporation, operate Unit 4 at the Wagner Generating Station as PJM deems necessary beyond its environmental run-hour limitations through October 26, 2025.
- On June 24, 2025, the Department of Energy (DOE) issued an emergency order, pursuant to section 202(c) of the Federal Power Act, to Duke Energy Carolinas authorizing specific electric generating units (specified resources) located within the Duke Energy Carolinas area to operate at their maximum generation output levels due to ongoing extreme weather conditions and to preserve the reliability of bulk electric power system. The order is in effect until 10:00 PM ET on June 25, 2025.
- On May 30, 2025, the Department of Energy (DOE) issued an emergency order, pursuant to section 202(c) of the Federal Power Act, to PJM Interconnection. The emergency order directs PJM, in coordination with Constellation Energy, to ensure specified generation units at the Eddystone Generation Station in Pennsylvania remain available for operation, minimizing the risk of generation shortfall that could lead to unnecessary power outages.
- On May 23, 2025, Department of Energy (DOE) issued an emergency order, pursuant to section 202(c) of the Federal Power Act, to Midcontinent Independent System Operator (MISO). The emergency order directs MISO, in coordination with Consumers Energy, to ensure that the J.H. Campbell Power Plant in West Olive, Michigan remains available for operation, minimizing any potential generation shortfall that could lead to unnecessary power outages.

- On May 16, 2025, Department of Energy (DOE) issued two emergency orders, pursuant to section 202(c) of the Federal Power Act, to the Puerto Rico Electric Power Authority (PREPA). The first emergency order directs the PREPA to dispatch generation units necessary to expand baseload generation for the island and maintain grid reliability, closing the gap in generation shortfall. The second order directs PREPA to perform vegetation management activities –that mitigate risk of shortages and fire – to help ensure operational availability of the Specified Transmission Facilities.
- On October 9, 2024, Department of Energy (DOE) issued an emergency order, pursuant to section 202(c) of the Federal Power Act, to Duke Energy Florida, authorizing certain electric generating units located within the Duke Energy service territory to operate at low load as needed under the limited circumstances related to Hurricane Milton effective through 12 AM Eastern Standard Time (EST) on October 13, 2024.
- On September 7, 2023, the Department of Energy (DOE) issued an emergency order, pursuant to section 202(c) of the Federal Power Act, to the Electric Reliability Council of Texas (ERCOT), authorizing specific electric generating units (specified resources) located within the ERCOT area to operate at their maximum generation output levels due to ongoing extreme weather conditions and to preserve the reliability of bulk electric power system. The order is in effect until 21:00 CDT on September 8, 2023.
- On December 24, 2022, the Department of Energy (DOE) issued an emergency order, pursuant to section 202(c) of the Federal Power Act, to the PJM Interconnection, L.L.C. (PJM) authorizing specific electric generating units (specified resources) located within the PJM area to operate at their maximum generation output levels due to ongoing extreme weather conditions and to preserve the reliability of bulk electric power system. The order is in effect until Monday, December 26, 2022, at 12 p.m. EST.
- On December 23, 2022, the Department of Energy (DOE) issued an emergency order, pursuant to section 202(c) of the Federal Power Act, to the Electric Reliability Council of Texas (ERCOT), authorizing specific

electric generating units (resource list) located within the ERCOT area to operate at their maximum generation output levels due to ongoing extreme weather conditions and to preserve the reliability of bulk electric power system. The order is in effect until December 25, 2022, at 10 a.m. CST.

- On September 8, 2022, the Department of Energy (DOE) issued an extension, with modification, of an emergency order pursuant to section 202(c) of the Federal Power Act granted to the Balancing Authority of Northern California (BANC), originally issued on September 4, 2022. The order is in effect until September 11, 2022.
- On September 8, 2022, the Department of Energy (DOE) issued an extension of an emergency order pursuant to section 202(c) of the Federal Power Act granted to the California Independent System Operator Corporation (CAISO), originally issued September 2, 2022. The order is in effect until September 12, 2022.
- On September 7, 2022, the Department of Energy (DOE) issued a modification of an emergency order pursuant to section 202(c) of the Federal Power Act granted to the California Independent System Operator Corporation (CAISO) on September 4, 2022. The modification added as Covered Resources two units at Calpine's Greenleaf Unit 1 site at Yuba City, California (the Greenleaf Units), both aero-derivative gas turbine generators with a nameplate capacity of approximately 30 MW, and allows the Greenleaf Units to run through September 11, 2022.
- On September 4, 2022, the Department of Energy (DOE) issued an emergency order, pursuant to section 202(c) of the Federal Power Act, to the Balancing Authority of Northern California (BANC), authorizing specific electric generating resources to operate when directed, under specified conditions, to prevent or mitigate potential power disruptions and provide relief to the bulk power system during stressed grid conditions caused by extreme heat. The order is in effect until September 8, 2022.
- On September 2, 2022, the Department of Energy issued a 202(c) emergency order pursuant to the Federal Power Act to California Independent System Operator Corporation (CAISO) authorizing specific

electric generating units located within its service territory to operate at their maximum generation output levels in order to preserve the reliability of the bulk electric power system due to extreme heat causing a diminished ability to generate enough power to meet higher than usual electricity demand. The order is in effect until September 8, 2022.

- On September 10, 2021, the DOE issued a 202(c) emergency order pursuant to the Federal Power Act to the California Independent System Operator Corporation (CAISO) authorizing specific electric generating units located within its service territory to operate at their maximum generation output levels in order to preserve the reliability of the bulk electric power system due to ongoing wildfires, extreme heat, and droughts causing a diminished ability to generate hydropower resulting in higher than usual electricity demand.
- On February 14, 2021, a 202(c) emergency order was issued to the Electric Reliability Council of Texas (ERCOT) authorizing specific electric generating units (resource list) located within the ERCOT area to operate at their maximum generation output levels due to ongoing extreme weather conditions and to preserve the reliability of bulk electric power system
- On September 6, 2020, a 202(c) emergency order was issued to the California Independent System Operator (CAISO) authorizing specific electric generating units located within the CAISO balancing authority area to operate at their maximum generation output levels due to an ongoing “Extreme Heat Event” and to preserve the reliability of bulk electric power system.
- On August 27, 2020, a 202(c) emergency order was issued authorizing and directing CenterPoint Energy Houston Electric (CEHE) to operate an existing, permanent tie-line to assist in electricity restoration of power to Entergy Texas, Inc. and electric cooperatives and municipal customers within the State of Texas as a result of Hurricane Laura making landfall near the Texas-Louisiana border.

View DOE 202(c) emergency orders issued prior to 2020.

U.S. DEPARTMENT of ENERGY

Committed to Restoring America's Energy Dominance.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

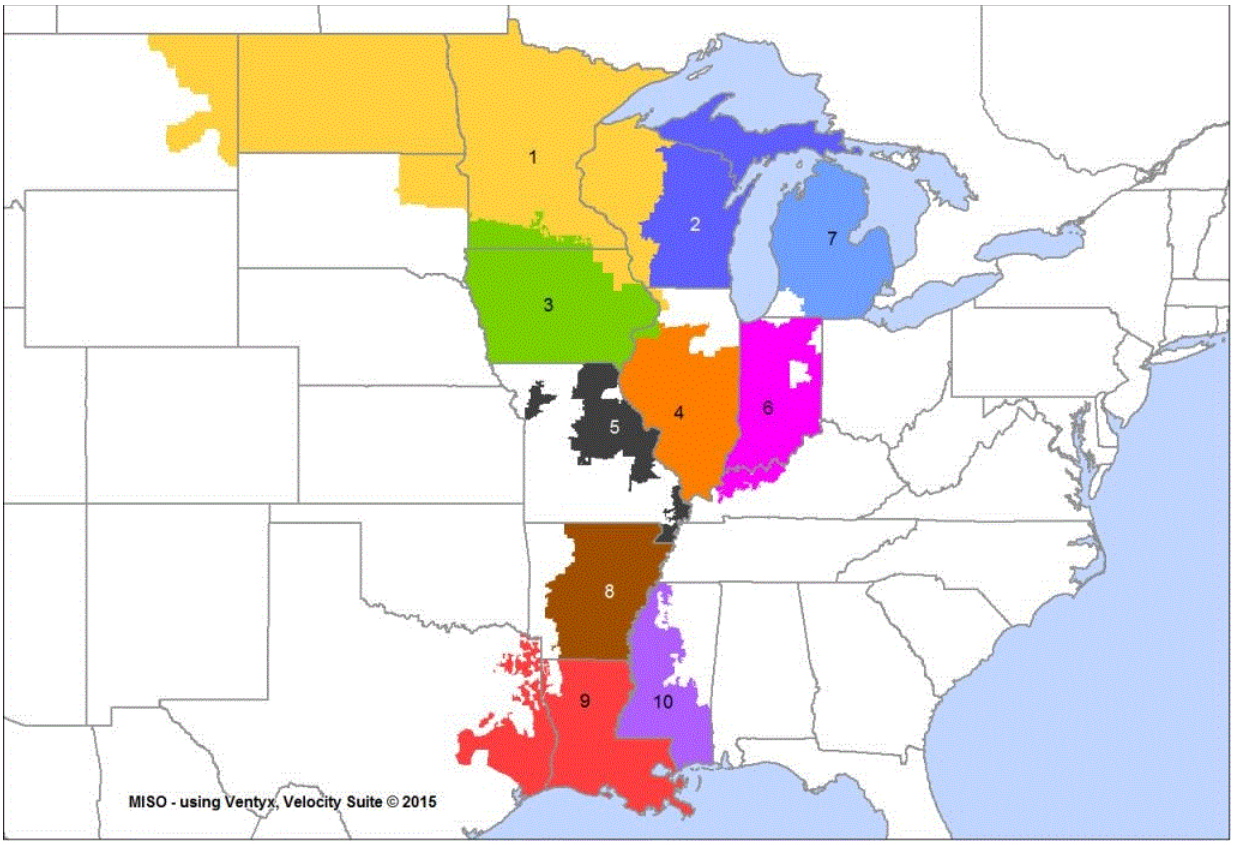
Exhibit 75

MISO Tariff Zonal Map

Midcontinent Independent System Operator, Inc.,FERC Electric Tariff

Filing Category:	Normal	Filing Date:	02/28/2020
FERC Docket:	ER20-01119-000	FERC Action:	Accept
FERC Order:	Delegated Letter Order	Order Date:	04/27/2020
Effective Date:	03/01/2020	Status:	Effective

ATTACHMENT VV, MAP of Local Resource Zone Boundaries (39.0.0)



Local Resource Zone	Local Balancing Authority
1	DPC, GRE MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWPLP, GLH, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, HMPL, IPL, NIPS, SIGE
7	CONS, DECO

8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EES, SME

Local Balancing Authorities:

ALTE - Alliant East

ALTW - Alliant West

AMIL - Ameren Illinois

AMMO - Ameren Missouri

BREC - Big Rivers Electric Corporation

CIN - Cinergy

CLEC - Central Louisiana Electric Company

CONS - Consumers

CWLD - Columbia Water and Light Department

CWLP - City Water Light and Power

DECO - Detroit Edison

DPC - Dairyland Power Cooperative

EAI - Entergy Arkansas

EES - Entergy Electric System

GLH - GridLiance Heartland, LLC

GRE - Great River Energy

HE - Hoosier Energy

HMPL – City of Henderson, Kentucky (d/b/a Henderson Municipal Power & Light)

IPL - Indianapolis Power and Light

LAFA - Lafayette Utilities

LAGN - Louisiana Generating Company

LEPA - Louisiana Energy and Power Authority

MDU - Montana Dakota Utilities

MEC - MidAmerican Energy Company

MGE - Madison Gas and Electric

MIUP – Michigan Upper Peninsula

MP - Minnesota Power

MPW - Muscatine Power and Water

NIPS - Northern Indiana Public Service Company LLC

NSP - Northern States Power

OTP - Otter Tail Power

SIGE - Southern Indiana Gas and Electric

SIPC - Southern Illinois Power Cooperative

SME - South Mississippi Electric Power Association

SMP - Southern Minnesota Municipal Power Agency

UPPC - Upper Peninsula Power Company

WEC - Wisconsin Electric Power Company

WPS - Wisconsin Public Service Company

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 76

Secretary Wright's West Virginia Remarks

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

TOP STORY

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

by Charles Young SENIOR STAFF WRITER
Jul 5, 2025

1 of 2



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

Staff photo by Charles Young

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



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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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



Hamilton

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

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

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



Capito



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

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

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

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

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

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

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

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 77

MISO 2021 Transmittal Letter

Michael Kessler
Assistant General Counsel
Direct Dial: 317-249-5290
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November 30, 2021

VIA ELECTRONIC FILING

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Midcontinent Independent System Operator, Inc.'s Filing to Include Seasonal and Accreditation Requirements for the MISO Resource Adequacy Construct Docket No. ER22-____-000

Dear Secretary Bose:

The Midcontinent Independent System Operator, Inc. ("MISO"), through this filing, proposes revisions to its Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff")[1] to establish Resource Adequacy Requirements on a seasonal basis for each of the Summer, Fall, Winter and Spring Seasons, and to implement an availability-based Seasonal Accredited Capacity ("SAC") methodology for resources participating in MISO's annual Planning Resource Auction ("PRA"). As discussed in detail below, Commission action is needed at this time in order to ensure that MISO has in place the proposed enhancements to its Resource Adequacy construct necessary to address the growing risks to reliability in the MISO Region resulting from a changing resource mix and shrinking excess reserve margins. Moreover, the recommendations from the Federal Energy Regulatory Commission ("FERC") and the North American Electric Reliability Corporation ("NERC") Final Report,[2] as well as MISO's internal report,[3] following the February 2021 Winter event reinforces the need for and urgency of the proposed reforms to the Resource Adequacy construct. Ultimately, MISO's proposal will help ensure Planning Resources are available to convert capacity procured in the PRA to energy when and where they are most needed.

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1 MISO submits these amendments pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and section 35.12 of the Federal Energy Commission's ("FERC" or "Commission") regulations, 18 C.F.R. § 35.12 (2018). All capitalized terms in this filing not otherwise defined have the same meaning as they have under the current MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff").

2 *See* FERC, Final Report on February 2021 Freeze Underscores Winterization Recommendations November 16, 2021 (November 2021) ("FERC Final Report"), available at: https://www.ferc.gov/news-events/news/final-report-february-2021-freeze-underscores-winterization-recommendations.

3 *See* https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf ("MISO Arctic Report").

In order to accommodate the implementation of this proposal in advance of the 2023 / 2024 Planning Year, MISO requests the Commission issue an order on this proposal within 120-days of this filing granting an effective date of September 1, 2022 for the proposed revisions. The requested timeline for acceptance and implementation of the instant proposal will accommodate all necessary stakeholder and MISO actions well in advance of the initial PRA in the Spring of 2023. Commission action within the requested 120-day period also is needed to help ensure MISO has adequate time to implement the changes to its software and systems prior to the 2023 / 2024 PRA, and to help guide decisions and investments that resource owners should be making to improve their accreditation under the proposed construct. Importantly, the software and system changes necessary to implement this proposal are not dependent upon MISO's ongoing Market System Enhancement initiative.

I. EXECUTIVE SUMMARY

The MISO Region is experiencing significant shifts in generation resource retirement, increased reliance on intermittent resources, significant weather events with correlated generator outages, and declining excess reserve margins. To highlight the priority and urgency of this transformation, the North American Electric Reliability Corporation ("NERC") in its Long-Term Reliability Assessment report recently stated:

> The addition of variable energy resources, primarily wind and solar, and the retirement of conventional generation is fundamentally changing how the [Bulk Power System] is planned and operated. Resource planners must consider greater uncertainty across the resource fleet as well as uncertainty in electricity demand that is increasingly being effected [*sic*] by demand-side resources. As a result, reserve margins and capacity-based estimates can give a false sense of comfort and need to be supplemented with energy adequacy assessments.[4]

In the Reliability Assessment, NERC also stated, "To ensure reliability during the transition to greater reliance on wind and solar resources, emerging resource and energy adequacy issues must be addressed. Planning for long-term Resource Adequacy is becoming increasingly complex with a resource mix that is more unpredictable and less energy-assured."[5] To address these issues, NERC recommended that: "Regulators and policy makers should consider revising their resource adequacy requirements to consider new risks that emerge during non-peak hours, limitations from neighboring systems during system-wide events, and the reduced resource diversity and/or increased reliance on a single fuel source or delivery mode."[6] Pointedly, FERC and NERC have also recently made recommendations in light of the extensive resource outages of the February 2021 Winter event. These recommendations support both improved seasonal risk

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4 NERC, 2020 Long Term Reliability Assessment (LTRA), at 6 (Dec. 2020), ("NERC Reliability Assessment") available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf (NERC 2020 LTRA).

5 *Id.* at 7.

6 *Id.*

assessments and the stronger alignment between accreditation and expectations of availability during times of highest need.[7]

MISO agrees with these statements and as discussed in the testimony of Mr. Wright, MISO's Executive Director of Market Development and Design, these shifts, coupled with lower excess reserve margins, increases in extreme weather events, correlated generator outages, and emergency operations, will have a profound impact on the reliability of the grid in the coming years.[8] Ultimately, all industry participants have a shared responsibility to plan for these impacts and implement new policies and practices to ensure the continued reliability of the grid. MISO refers to this shared responsibility as the "Reliability Imperative." As part of its response to the Reliability Imperative, MISO must make substantive changes to its Resource Adequacy construct to address these emerging issues as the transition accelerates in the coming years.

MISO's response to the Reliability Imperative is being accomplished through a number of initiatives that work in concert to mitigate the challenges facing the MISO Region. MISO organizes this work into four major categories: (1) Market Redefinition; (2) Long Range Transmission Planning; (3) Operations of the Future; and, (4) Market Systems Enhancements.

Through Market Redefinition, MISO aims to ensure that sufficient resources with the capabilities and attributes the MISO Region needs will be available during the highest risk periods across the year. MISO's current Resource Adequacy construct, which focuses on the procurement of capacity for an entire Planning Year to meet demand during one peak day of the Summer Season was not designed to address the trends currently facing the MISO Region.

Reliability risks associated with Resource Adequacy have shifted from "Summer only" to a year-round concern. Since 2016 MISO has experienced 40 Maximum Generation declarations (including alerts, warnings and events) ("MaxGens") with more than 60% occurring outside of the Summer months, as evidenced in the graph below.



7 *See* FERC Final Report at 6.

8 Wright at 11.

MaxGens are governed by MISO's emergency operations procedures and include a number of emergency actions, up to and including shedding firm load. Consistent with NERC's Reliability Assessment, the significant increase in MaxGens is being driven by the confluence of: the retirement of traditional, baseload generation resources; planned and forced generator outages in non-Summer months; an increased reliance on intermittent generation such as wind and solar, which has reached nearly 30 percent of the generation resource mix in certain portions of the MISO Region and is projected to continue to grow; and, extreme weather events resulting in numerous forced generator outages, including multiple polar vortex and arctic storms reaching south to the Gulf of Mexico.

The causes of the increase in MaxGens cannot be addressed through one-off, quick fixes; rather, they require a robust solution that incentivizes capacity resources to be available when and where they are needed. Ultimately, the existence of resources, even if ample in quantity and well-located, is meaningless if those resources do not provide energy or reserves when needed. MISO cannot reliably operate the system if the resources it depends on do not or cannot perform — that is, do not provide energy or reserves as offered during periods of highest risk. A well-designed market construct is inclusive of both the planning horizon and the operating horizon. The planning horizon includes the identification and incorporation of risks across the year in Resource Adequacy Requirements. The operating horizon ensures that those resources are appropriately incentivized to provide the energy and reserves when and where needed. More closely aligning the planning horizon with the operating horizon is a central goal of the proposed reforms in the instant filing.[9]

To address these critical issues, MISO's Resource Adequacy reform proposals focus on related areas including: the establishment of a seasonal Resource Adequacy construct coupled with availability-based accreditation for certain Planning Resources; and, a Minimum Capacity Obligation that promotes securing capacity well in advance of the Planning Resource Auction. The instant filing presents MISO's Seasonal and Accreditation proposal.

A. Seasonal Resource Adequacy Construct

MISO intends to transition from the current Summer-based, annual construct to four distinct Seasons: June to August for Summer, September to November for Fall, December to February for Winter, and March to May for Spring. Under the proposed construct MISO will establish Planning Reserve Margin Requirements ("PRMR") for all Market Participants ("MPs") representing Load Serving Entities ("LSEs") on a seasonal basis. MISO will then conduct the PRA and establish an Auction Clearing Price for each Local Resource Zone ("LRZ") for each Season. The PRA will still be conducted one time per year, in the Spring before the applicable Planning Year, but will clear the requirements for each Season.

Overall, the shift to a seasonal construct is expected to further mitigate Resource Adequacy risks across the year, not just in the peak Summer Season, by establishing more granular, seasonal Resource Adequacy Requirements to help ensure sufficient resources are committed and obligated to be available when needed. Expected outcomes from this transition are to: (1) identify reliability

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9 Wright at 14.

needs unique to each Season; (2) align resource availability with seasonal needs; and (3) facilitate and better account for seasonal outages or partial year operations.

B. Availability-Based Resource Accreditation

MISO's Resource accreditation reforms seek to assure that Resources are available when needed the most by aligning Resource accreditation with availability during the highest risk periods in each Season. To accomplish this in a seasonal construct, MISO proposes to determine the Seasonal Accredited Capacity ("SAC") for certain classes of Resources. MISO also proposes a tiered weighting structure, with a transition period, to determine individual resource accreditation by Season based on each resource's real-time offered availability, accounting for coordinated planned outages.

The expected outcomes of MISO's efforts are to: (1) increase confidence in the capacity MISO can count upon when needed by shrinking the gap between cleared capacity within the PRA and realized capacity during tight conditions; (2) provide improved signals for availability and coordination; and (3) improve outage coordination processes. Measuring and accrediting Planning Resources based on availability and performance during Resource Adequacy Hours (or "RA Hours"), as described in the testimony of Mr. Wright, will better align expectations during times of highest need. Actual historic Resource availability and performance during times of highest need is a useful and reasonable indicator of what to expect in the future. Relying on installed capacity, adjusted for forced outages and reflecting average availability throughout the year, no longer provides an accurate expectation of availability, as proven by recent emergency events, especially those driven by extreme weather.

II. BACKGROUND

This filing is a component of the next phase of MISO's ongoing Resource Availability and Need ("RAN") initiative. The factors giving rise to the need for MISO to explore various short- and longer-term RAN initiatives, and related Tariff enhancements, have by now been well-documented, including a series of MISO-published White Papers dating back to March 2018,[10] as well as MISO's prior RAN filings and related Commission Orders. As described in those documents, MISO established its RAN initiative to identify strategies to better convert committed Planning Resources into energy during times of need.[11] MISO submits this filing to establish the design for additional Resource Adequacy reforms, including a Seasonal Resource Adequacy Construct, Availability-Based Accreditation, and Seasonal Planning Resource Auctions. MISO is

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[10] *See* Resource Availability and Need, *Issues Statement Whitepaper*, March 30, 2018; Load Modifying Resources, *Capacity Instruments affecting Resource Availability and Need*, May 25, 2018; Resource Availability and Need, *Evaluation Whitepaper*, September 10, 2018; Aligning Resource Availability and Need, December 2019, MISO Forward, March 2019, and MISO Forward 2020, *Utilities of the Future: What do they need from a grid operator?*, March 2020. *See generally* Resource Availability and Need (RAN) (IR025). Available at https://www.misoenergy.org/stakeholder-engagement/issue-tracking/resource-availability-and-need-ran/

[11] *See* Aligning Resource Availability and Need, December 2019, MISO, pp. 2-3. Available at https://cdn.misoenergy.org/Aligning%20Resource%20Availability%20and%20Need%20(RAN)410587.pdf

making a concurrent filing related to the establishment of a new Minimum Capacity Obligation. The details of this additional reform will be addressed in the concurrent filing.

MISO is facing a Reliability Imperative during this period of unprecedented change. While MISO and its stakeholders have successfully managed reliability there has been a significant increase in the number of MaxGens occurring outside of the traditional Summer peak months. These changes have prompted MISO to evaluate the alignment of resource availability and need to determine how today's processes can be improved to ensure the reliable and efficient conversion of procured capacity to energy throughout the year.[12] This process has become increasingly uncertain as a result of a dramatically changing landscape and factors such as retiring and aging generation units, lower overall capacity levels and higher outage rates, growth in demand-side and other emergency-only capacity as a percent of the portfolio, growing reliance on unscheduled resources (notably non-firm imports), and the growth of intermittent energy resources as a percentage of the fleet.[13]

MISO has proactively engaged with stakeholders and developed its RAN initiative to mitigate these and other challenges. The RAN program initially identified four goals: (1) Improve outage scheduling and expectations; (2) Link Resource accreditation and requirements with initial focus on Load Modifying Resources ("LMRs"); (3) Align the PRA resource commitments with energy needs all year; and (4) Ensure flexible Resource availability to address changing fleet characteristics. Each goal corresponds to a group of potential solutions discussed with stakeholders that address related gaps, such as a lack of transparency in outage scheduling or limited access to LMRs.

To achieve these goals, MISO proposed and implemented several incremental changes, each of which was intended to improve reliability within the MISO Region. These changes are known as MISO's RAN Phase I initiative, and are outlined below:

- MISO's first RAN Phase I filing was submitted on December 21, 2018. There, MISO filed proposed revisions to its Tariff to more effectively assess the capabilities of LMRs.[14] MISO proposed to require an LMR to (1) offer its capability based on its actual availability in all Seasons, including maintaining the current requirement that LMRs be available for the entire Summer Season, and (2) deploy based on the shortest notification requirement that it can consistently meet, while maintaining that LMRs must be available in less than 12 hours.[15] MISO also proposed Tariff revisions that would allow it to issue Scheduling Instructions to LMRs in advance of anticipated Emergency

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12 *See* Resource Availability and Need, *Issues Statement Whitepaper*, March 30, 2018, at pp. 2-3. Available at https://cdn.misoenergy.org/20180405%20RSC%20Item%2007%20RAN%20Issues%20Statement%20White%20Paper164746.pdf

13 *Id.*

14 *Midcontinent Indep. System Operator, Inc.*, 166 FERC ¶ 61,116 (Feb. 19, 2019).

15 *Id.*

conditions.[16] The Commission accepted those revisions subject to certain revisions in an order dated February 19, 2019.[17]

- MISO's second RAN Phase I filing was also submitted on December 21, 2018. There, MISO filed proposed revisions to its Tariff to enhance the testing requirements for Demand Resources that participate in MISO's markets as LMRs.[18] Additionally, MISO proposed to revise its Tariff to require all Demand Resources to conduct a real power test annually, starting with qualification for the 2020/21 Planning Year.[19] MISO also set forth certain proposed waiver and opt-out provisions.[20] The Commission accepted those revisions subject to certain revisions in an order dated March 29, 2019.[21]

- On January 30, 2019, MISO filed proposed revisions to its Tariff to enhance Generator Planned Outage scheduling.[22] These proposed incremental changes were intended to supplement MISO's then-existing Generator Planned Outage process by improving transparency through forward signals and incentives.[23] The Commission accepted those revisions subject to certain revisions in an order dated March 29, 2019.[24]

- On March 18, 2019—in compliance with the Commission's prior February 19, 2019 Order—MISO filed a request to revise its Tariff provisions regarding MISO's advanced access of the capabilities of LMRs, as previously directed by the Commission.[25] The Commission accepted MISO's submittal, as requested, in an entry dated April 29, 2019.[26]

As recognized by FERC and NERC, MISO's first RAN Phase I filing constituted "a broad analysis and plan to confront the increase in Maximum Generation emergencies even though sufficient capacity appeared to be available through the Planning Reserve Auction."[27] "Some of

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16 *Id*.

17 *Id*.

18 *Midcontinent Indep. System Operator, Inc*., 166 FERC ¶ 61,235 (Mar. 29, 2019).

19 *Id*.

20 *Id*.

21 *Id*.

22 *Midcontinent Indep. System Operator, Inc*., 166 FERC ¶ 61,236 (Mar. 29, 2019).

23 *Id*.

24 *Id*.

25 April 29, 2019 Letter to J. Krouse, Docket No. ER-19-650-001 (Apr. 29, 2019).

26 *Id*.

27 *See* The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018, 2019 FERC and NERC Staff Report, at p. 75, fn 101.

the early fruits of the initiative [have been] tariff changes to better insure capacity availability[.]"[28] "MISO's revisions, which included a penalty for planned outages and derates that occur during Max Generation events, were intended to: (1) provide additional incentives for Generator Owners to schedule Generator Planned Outages and derates well in advance of the scheduled start time and (2) identify times with increased system risk due to correlation of outages and derates."[29] "The Commission agreed with MISO's efforts, believing that MISO's proposal [would] 'promote advanced scheduling of Generator Planned Outages, improve Generator Planned Outage coordination, and help MISO address the recent increase in the number of declared Emergency events during non-summer seasons.'"[30]

Following the initial RAN Phase I filings, MISO made a number of additional RAN-related filings with the Commission, including the following:

- On May 18, 2020 MISO filed to enhance the LMR accreditation provisions of the Tariff to ensure LMRs are appropriately accredited for their participation in the PRA based on the LMRs actual availability and notification times. The Commission accepted this proposal on August 14, 2020 and the enhanced LMR accreditation were implemented on August 16, 2020.[31]

- On December 21, 2020 MISO submitted a filing to clarify the LMRs that are chosen to be deployed by Market Participants in response to MISO's Scheduling Instructions will be evaluated on an individual resource basis, rather than in aggregate across a Market Participant's portfolio of LMRs. The Commission accepted this clarification by letter order on February 3, 2021.[32]

- On January 30, 2019, MISO filed with the Commission a proposal to enhance Generator Planned Outage scheduling. MISO explained in this filing that the proposed revisions were necessary due in part to base load generation retirements that were contributing to the MISO Region operating with actual capacity margins that were approaching its minimum Planning Reserve Margin Requirements. MISO explained in that filing that operating at or near its minimum Planning Reserve Market Requirements exposed the MISO Region to greater impacts from correlated risks, such as extreme weather events and natural gas availability. The Commission accepted this filing on March 29, 2019.[33]

- On October 16, 2019, MISO submitted a filing to limit the ability of resources to participate in the PRA if the resource is expected to be on full or partial outage for any ninety (90) or

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28 *Id*. at p. 77.

29 *Id*.

30 *Id*., citing *Midcontinent Indep. System Operator, Inc*., 166 FERC ¶ 61,236 (Mar. 29, 2019) at P. 60.

31 *See Midcontinent Independent System Operator, Inc.,* 172 FERC ¶ 61,138 (August 14, 2020).

32 February 3, 2021 Letter to J. Krouse, Docket No. ER21-693-000 (February 3, 2021).

33 *See Midcontinent Independent System Operator, Inc.*, 166 FERC ¶ 61,236 (March 29, 2019).

more of the first one hundred twenty (120) Calendar Days in the Planning Year. The Commission accepted this filing on January 30, 2020.[34]

- MISO has also submitted reforms related to the deliverability of both conventional and intermittent resources. On October 27, 2020 the Commission accepted MISO's proposal to require conventional (*i.e.,* non-intermittent) Capacity Resources to demonstrate deliverability through Energy Resource Interconnection Service ("ERIS") coupled with firm Transmission Service up to the Capacity Resource's Installed Capacity level in order to be eligible to convert the entire Unforced Capacity of the Resource to ZRCs.[35] In addition, on November 13, 2020 the Commission accepted MISO's proposal to implement a long-term deliverability requirement for Intermittent Capacity Resources, including a methodology to determine the level of firm Transmission Service needed to convert Unforced Capacity into ZRCs.[36]

The proposed Resource Adequacy construct reforms also align with MISO IMM recommendations dating back to 2014. The IMM first recommended a transition to seasonal capacity procurement in its 2014 State of the Market Report.[37] In recommendation 2014-5 the IMM noted that the system and available system supply change substantially from one season to the next, which could be recognized by clearing the PRA on a seasonal basis rather than an annual basis.[38] The IMM also suggested that the shift to a seasonal PRA construct would produce benefits including: better alignment of revenues with the value of capacity; opportunities for high-cost resources to achieve savings by taking seasonal outages during shoulder seasons; and, more flexible mid-year retirements for resources without having to procure significant capacity to satisfy post-retirement capacity obligations.[39]

In the 2018 State of the Market Report, MISO's IMM noted that MISO's January 2019 filing to reduce the accreditation of resources taking short-notice outages during emergency conditions was a slight improvement but recommended that MISO file with FERC a more complete accreditation solution that would: a) expand the Generator Planned Outage scheduling enhancements filed in January 2019 to include all unforced and unreported outages and debates; and b) calculate the accreditation based on outages and derates that occur during the tightest supply conditions.[40] The IMM suggested that these changes would result in sizable accreditation

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34 *See Midcontinent Independent System Operator, Inc.* (Docket No. ER20-129-000)*; Wolverine Power Supply Cooperative, Inc. v. Midcontinent Independent System Operator, Inc.* (Docket No. ER19-102-000) (Not Consolidated), 170 FERC ¶ 61,066 (January 20, 2020).

35 *See Midcontinent Independent System Operator, Inc.* 173 FERC ¶ 61,095 (October 27, 2020).

36 *See Midcontinent Independent System Operator, Inc.* 173 FERC ¶ 61,139 (November 13, 2020).

37 2014 State of the Market Report for the MISO Electricity Markets Prepared by Potomac Economics (June 2015) at 99-100.

38 *Id.*

39 *Id.*

40 2018 State of the Market Report for the MISO Electricity Markets Prepared by Potomac Economics (June 2019) at 110-111.

improvements and eliminate the current incentive for suppliers to not report their outages and derates. Ultimately, the IMM argues that adopting the proposed accreditation reform would better represent the reliability value that resources provide to MISO (in periods when the resources are needed) and can be easily adapted to a seasonal capacity accreditation construct.[41]

While the changes implemented through MISO's RAN Phase I initiative and subsequent RAN-related filings have been helpful, MISO continues to face a Reliability Imperative and correspondingly needs to implement further reforms to its Resource Adequacy construct. MISO was clear that the RAN Phase I filings were the initial step in addressing specific issues in the Resource Adequacy construct and that more comprehensive solutions were being developed to address Resource Adequacy in the MISO Region. As such, the proposed Resource Adequacy reforms, submitted in this filing, better align accreditation with observed Resource availability during the periods of highest risk.

While true across all Seasons of the year, MISO has experienced notable reliability challenges during the Winter Season.[42] Consistent with Key Recommendation 2 in NERC's recent "Cold Weather Report," MISO's proposal would give Generator Owners accreditation values that align with the reliability benefits of winterization and Winter preparedness. These measures will enable Resources to operate in the temperature and weather conditions that have occurred during times of need during recent Winters.

In line with the guiding principles of the RAN initiative and the response to the Reliability Imperative, MISO's proposal will create better availability, flexibility, and visibility of resources to meet MISO's changing system needs including the need to address generator reliability for extreme cold weather. Seasonal requirements, including seasonal auctions, will ensure MISO's Resource Adequacy Requirements reflect reliability needs and required capabilities across the year. Accreditation reforms will ensure resources committed during the seasonal Planning Resource Auction receive accreditation based on their reliability contribution during the times of highest need. The proposed availability based seasonal construct will award more relative accreditation to resources that have properly mitigated risks during all Seasons.

III. SEASONAL RESOURCE ADEQUACY CONSTRUCT

A. Establishment of Seasonal Resource Adequacy Requirements

MISO proposes continuing its Resource Adequacy reform efforts – in part – by establishing seasonal Resource Adequacy Requirements. MISO intends to transition from its current annual construct, which focuses on the historic Summer peak period, to a seasonal construct with four distinct Seasons: (1) Summer (June to August); (2) Fall (September to November); (3) Winter (December to February); and (4) Spring (March to May).[43] Under the proposed seasonal Resource

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41 *Id.*

42 MISO Arctic Event at 5, 7.

43 Wright at 26.

Adequacy construct, MISO will perform an LOLE evaluation to establish PRMRs for all Market Participants representing LSEs[44] and Local Clearing Requirements ("LCR") for all LRZs on a seasonal basis.[45] MISO will then conduct the Planning Resource Auction and establish an Auction Clearing Price for each LRZ for each Season.[46] The Planning Resource Auction will continue to be conducted once per year, in the Spring preceding the applicable Planning Year, but the PRA will clear the requirements separately for each Season.[47]

As explained by Mr. Wright, this shift to a seasonal Resource Adequacy construct is designed to ensure that resources with needed capabilities and attributes will be available during the highest risk periods across the year.[48] Under the current construct, the requirements of the annual PRA are based on Summer Coincident Peak Demand forecasts, and transmission capability and most Resource accreditation is also based on Summer conditions.[49] As a result, actual needs outside the Summer Season are not explicitly determined and defined, leaving potential risks unmitigated.[50] Such risks are intensifying as indicated by the increased incidence of MaxGens occurring in the Seasons outside of the traditional Summer peak.[51] Moreover, sizeable segments of dispatchable thermal generation are aging with correlated increased outage rates, and MISO's resource portfolio is shifting to increasing amounts of intermittent and highly weather-dependent wind and solar resources, all against a backdrop of lower excess reserve margins.[52] In his testimony, Mr. Smith notes that the trends and generation resource fleet transition driving the challenges to reliable market operations are only expected to accelerate, leading to further reduced operating margins.[53] Moving to a seasonal Resource Adequacy construct will align seasonal resource accreditation with seasonal resource availability to meet this changing risk.[54]

MISO proposes several changes to implement the seasonal Resource Adequacy construct, including accrediting resources by Season based on their availability during times of need and developing seasonal values for several construct parameters such as: (1) LOLE sub-annual modeling; (2) PRMRs; (3) Local Reliability Requirements ("LRR") and LCRs; and (4) Capacity

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44 As used throughout this transmittal letter, references to LSE is intended to also include Market Participants representing LSEs.

45 Wright at 26.

46 *Id*.

47 *Id*.

48 Wright at 13.

49 Smith at 18.

50 *Id*. at 18-19.

51 McFarlane at 4.

52 Wright at 16.

53 Smith at 22-23.

54 McFarlane at 6.

Import Limits ("CIL") and Capacity Export Limits ("CEL").[55] Each of these changes is discussed more fully below.

MISO proposes changes to the modeling and methodology of the LOLE study to more accurately model seasonally-sensitive variables and calculate the construct parameters through: (1) seasonal LOLE risk allocation; and (2) improving seasonal LOLE modeling, including the modeling of planned outages, modeling of non-firm external support (*i.e.,* imports), and hourly modeling of intermittent resources.[56] As explained by Mr. McFarlane, this new LOLE model needs to have a defined LOLE threshold for each Season to calculate seasonal Resource Adequacy reserve requirements.[57] Seasonal requirements will be determined under a two-step LOLE analysis.[58] For the first step, the LOLE model will be solved to an annual LOLE value of 0.1 day per year to determine the natural LOLE distribution.[59] If after the first step there is a minimum of 0.01 day per year LOLE in all four Seasons, then the seasonal requirements will be determined directly from this step and there will be no need for additional analysis.[60] If a Season has an LOLE of less than 0.01 day per year from step 1, then an additional step will be performed to solve that Season to an LOLE of 0.01 day per year.[61] In the second step, if required, MISO proposes to round LOLE targets up to a minimum of 0.01 day per year for any Season with LOLE less than 0.01 day per year, and to maintain LOLE targets for Seasons with LOLE greater than 0.01 day per year.[62]

In order to determine a Planning Reserve Margin ("PRM") for the four Seasons, MISO proposes performing an additional two-step LOLE analysis with seasonal input assumptions.[63] The LOLE model will be used to meet the seasonal LOLE targets by adjusting the capacity within the model up or down as needed.[64] If the LOLE is less than the target for a Season, then a "perfect unit" with a negative capacity value and zero forced outage rate will be added to the model.[65] If the LOLE is greater than the target for a Season, then proxy combustion turbine generators of typical size (160 MW) and class average Equivalent Forced Outage Rate Demand ("$XEFOR_d$") will be added to the model until the seasonal LOLE target is achieved.[66] Once the seasonal LOLE targets are met, the seasonal PRM values in terms of Unforced Capacity ("UCAP") will be

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55 *Id*. at 7.

56 *Id*. at 8.

57 *Id*. at 11.

58 *Id*.

59 *Id*. at 12.

60 *Id*.

61 *Id*.

62 *Id*.

63 *Id*.

64 *Id*. at 11.

65 *Id*. at 11-12.

66 *Id*.

calculated and expressed as a percentage of seasonal coincident peak demand.[67] The PRM for each Season is multiplied by the 50/50 forecast of coincident peak load to determine the PRMR (in MWs) for that Season.[68]

To determine zonal Local Reliability Requirements, MISO proposes using the same two-step process as the PRM analysis with each zone treated as an isolated system consistent with the existing LRR analysis methodology under the current annual PRA construct.[69] Seasonal LRR values will be calculated in terms of UCAP and expressed as a percentage of seasonal zonal coincident peak demand once the model has been solved to the appropriate LOLE targets.[70] The seasonal LRR values will be used to determine the seasonal LCR values by subtracting the seasonal CIL from the seasonal LRR.[71]

MISO proposes performing seasonal transfer analyses to determine seasonal CILs and CELs, capturing the seasonal variation of transfer limits for each LRZ.[72] Planning Year seasonal peak powerflow models and input files developed from MISO Transmission Expansion Plan studies will be used to perform transfer analysis for each Season including Summer Peak, Fall Peak, Winter Peak, and Spring Peak study models.[73] The resulting seasonal Zonal Import Ability ("ZIA"), in conjunction with controllable exports, will be used to determine the seasonal LCR for each LRZ.[74]

The proposed Resource Adequacy construct more accurately represents Resource capabilities at different times during the year, improves certainty of Resource availability outside the Summer Season, better incentivizes Resources to be available when needed, establishes seasonal reserve requirements that better align with risks, and delivers additional visibility into the risks throughout the year – which are not currently captured in the annual construct.[75] When discussing the expected impact of the seasonal approach on MISO's operations, Mr. Smith explains that the proposed reforms measure and mitigate non-Summer reliability risk. This is accomplished by calculating seasonal requirements using seasonal inputs based on demonstrated seasonal resource availability to ensure that seasonal risks are known and mitigated. In general, resource owners and LSEs benefit from lower non-Summer peak loads, resulting in lower non-Summer PRMRs that reduce the required cleared capacity and allow for seasonal operation and

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67 *Id*. at 13.

68 *Id*.

69 *Id*. at 13.

70 *Id*.

71 *Id*.

72 *Id*. at 13-14.

73 *Id*. at 14.

74 *Id*.

75 *Id*. at 7.

related cost savings.[76] Overall, this proposed seasonal shift is expected to identify and mitigate reliability risks across the year during the periods of highest reliability risk.

B. Revisions to the Planning Resource Auction

As discussed above, the annual PRA will continue to be administered in the Spring of each year in advance of the upcoming Planning Year beginning in June. In most instances, MISO's PRA processes will remain the same but will be applied on a seasonal basis rather than an annual basis. The PRA offer window will continue to be the last four business days in March. In addition, the "must offer" requirement for resources that clear the PRA will only apply in the Season or Seasons in which the Resource clears.[77] Moreover, MISO will increase the amount of time it has available to clear the PRA from 10 to 20 business days in order to clear the four Seasons. The following graphic shows the Seasonal PRA timeline:



C. Planning Resource Replacement and Capacity Replacement Non-Compliance Charge

MISO's current capacity replacement requirements are limited to suspensions and retirements of resources and carry no specific financial non-compliance provisions. As Mr. McFarlane explains, these limited requirements are no longer sufficient as the performance and availability of committed capacity to meet seasonal requirements will be critical.[78] As such, MISO proposes to require replacement for any Planning Resource that will be on planned outage or planned derate for more than 31 days in a Season in which they clear. Consistent with current Tariff requirements, replacement can only be made from uncleared ZRCs.[79] The capacity replacement requirement will also apply to resources that have received exemptions through the updated outage coordination process discussed below. MISO is also adding provisions allowing the replacement of resources that have experienced catastrophic outages, enabling such resources to maintain class average accreditation upon return to service, with further details to be established in the Business Practices Manual for Resource Adequacy. It is important to note that existing rules regarding deliverability and zonal transfer limits will still apply.

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76 Smith at 19

77 *Id*. at 37.

78 *Id*. at 38.

79 *Id*. at 40.

Given the critical impacts non-replacement of resources could have on reliability, MISO proposes a Capacity Replacement Non-Compliance Charge for Resource owners that do not replace Planning Resources that retire or suspend during the Season, or are on planned outage or planned derate for more than 31 days in a Season. Mr. McFarlane explains that the Capacity Replacement Non-Compliance Charge will be a be a daily charge, equal to the amount of ZRCs that failed to be replaced multiplied by sum of the Auction Clearing Price and the daily CONE value.[80] Capacity Replacement Non-Compliance Charges will be distributed to Market Participants representing LSEs on a *pro rata* basis, based upon the LSE's share of total PRMR for the MISO Region. Mr. McFarlane notes that the billing, invoicing, default, and uplift provisions will be similar to the existing Installed Capacity ("ICAP") Deferral Non-Compliance Charge.[81]

IV. AVAILABILITY-BASED ACCREDITATION

The shift to seasonal Resource Adequacy Requirements will impact all resources in the MISO Region; however, the availability-based accreditation provisions only apply to Capacity Resources that are Demand Response Resources or Generation Resources (collectively referred to as "Schedule 53 Resources"), but not Dispatchable Intermittent Resources, Intermittent Generation, Electric Storage Resources, External Resources or Use Limited Resources. MISO refers to these resources as "Schedule 53 Resources" because it submits herewith a new Schedule 53 to the MISO Tariff entitle Seasonal Accredited Capacity Calculation.

Mr. McFarlane explains that the proposed changes align resource accreditation for Schedule 53 Resources with historic availability and performance during the highest risk periods while also accounting for general availability of resources across the year.[82] To accomplish this, MISO proposes a two-tiered calculation to determine individual Resource accreditation by Season, as described below.[83]

A. Determination of RA Hours

Pursuant to MISO's proposal, resource accreditation for Schedule 53 Resources will no longer be based on forced outage rates from Generator Availability Data System (or "GADS"). Instead, accreditation for Schedule 53 Resources will primarily be based on the average real-time offered availability from MISO's Day-Ahead and Real-Time market system during times of highest need, which are referred to as "RA Hours" in MISO's proposal. Other factors such as the type and volume of interconnection service and a seasonally corrected Generation Verification Test Capacity ("GVTC") will be utilized as well. Mr. McFarlane explains that the proposed construct will continue to base accreditation on the three prior years starting September 1 through August 31 of the year prior to the Planning Year, which reflects the cumulative availability of a

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80 *Id*. at 39.

81 *Id*.

82 *Id*. at 16.

83 *Id*.

resource.[84] MISO proposes a tiered weighting structure to determine individual resource accreditation by Season based on each Resource's real-time offered availability during Tier I hours (*i.e.,* all hours not including RA Hours) and Tier 2 hours (*i.e.,* RA Hours) while incentivizing the coordination of Generator Planned Outages by providing exemptions when certain conditions are met, as discussed in further detail below.[85]

As indicated, MISO's Seasonal Accredited Capacity approach will shift to the application of RA Hours, which Mr. McFarlane explains represent the periods of highest risk and greatest need during a Season and throughout the year.[86] These periods include declared MaxGens and the hours when the operating margin is at its lowest. MISO proposes to determine RA Hours for each Season based on MaxGens and the 65 hours with the tightest operating margin, subject to a maximum operating margin threshold established at 25 percent.[87] Mr. McFarlane explains that RA Hours will be defined within the First Planning Area and Second Planning Area separately to reflect the growing frequency of MaxGens and emergencies that occur on either side of the Sub-Regional Power Balance Constraint, which have been driven by: trapped capacity in one sub-region due to the contractual transfer limits, increasing sub-regional challenges driven by portfolio differences, and the impacts of extreme weather including hurricanes, cold weather events, and renewable penetration.[88]

Pursuant to MISO's proposal, each Season will have a target of 65 RA Hours based on three (3) percent of the hours in a Season. Mr. McFarlane explains that the number of RA Hours in a Season can exceed the target when declared MaxGens during that Season have a cumulative duration greater than 65 hours.[89] The number of RA Hours in a Season can be less than the target because of the 25 percent maximum operating margin threshold, which will ultimately lead to a deficiency equal to the difference between the target RA Hours and the actual number of RA Hours.

B. Resource Specific Accreditation

1. Schedule 53 Resources

MISO's resource accreditation proposal is intended to reflect the anticipated capability and availability of Planning Resources during times when they are most needed. Mr. McFarlane explains that utilizing offered availability, including actual performance data during RA Hours provides an improved measure of expected availability.[90] Ultimately, MISO proposes a two-tiered

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84 *Id*. at 19.

85 *Id*. at 19-20.

86 *Id*. at 20.

87 *Id*. at 20.

88 *Id*. at 22.

89 *Id*. at 20.

90 *Id*. at 15.

weighting structure to calculate resource accreditation for Schedule 53 Resources that will reflect general availability while emphasizing availability during times of greatest need based on a tiered weighting structure.

Pursuant to the proposed Schedule 53, a Resource will have its Intermediate Seasonal Accredited Capacity ("ISAC") determined based on its real-time offered availability (Emergency Maximum Limit, or Targeted Demand Reduction Level for Demand Response Resources Type I) during seasonal RA Hours (Tier 2) and Non-RA Hours (Tier 1). The number of Tier 2 RA Hours may vary during individual Seasons when the 25% maximum margin threshold is applied or individual resources receive outage exemptions, impacting sample sizes of RA Hours and corresponding accreditation calculations. If Tier 2 RA Hours for a Season or a specific resource fall below the 3% target of 65 hours, a Resource's Annual Average Offered Capacity ("AAOC") will be used to supplement the deficient number of hours as part of the Tier 2 portion of the accreditation calculation. Seasonal Tier 1 Non-RA Hours on the other hand include all hours in a Season of a Planning Year, excluding except Tier 2 RA Hours and any hours where a Resource had an exemption or was not designated for Resource Adequacy Requirements ("RAR"). Mr. McFarlane's testimony provides a detailed description of this process, along with hypothetical examples.[91]

As described by Mr. McFarlane, MISO will determine ISAC values for each Resource for each Season in the upcoming Planning Year while the final SAC calculation is "in process."[92] The final ISAC value will be the weighted average over its values from the two tiers as described in Mr. McFarlane's testimony.[93] MISO proposes an 80% Tier 2 and 20% Tier 1 weighting as assigning the heavier weighting to Tier 2 tight conditions ensures the alignment between a resource's SAC value and its availability and performance during times of highest risk and greatest need. The basis for the 80% Tier 2 and 20% Tier 1 weighting is discussed further in section VII below.

In response to stakeholder feedback on the SAC proposal, MISO has implemented a transition to the full 80% Tier 2 weighting in the third Planning Year to account for the fact that the historical real-time offers, outages, and notification times used in the Schedule 53 calculations were submitted for resources without knowledge of the final accreditation methodology proposed in the instant filing. Under the proposal, Tier 2 weighting would start at 60% in PY 2023 / 24, rise to 70% in PY 2024 / 25 and then reach the full 80% in PY 2024 / 25.

In addition, MISO has adopted a UCAP to ISAC ratio proposed by its Independent Market Monitor to avoid undesirable impacts to PRA requirements and non-Schedule 53 resources. Application of this ratio addresses stakeholder concerns on deliverability and auction revenue reduction. The IMM presented its new ratio recommendation at the October 6, 2021 Resource Adequacy Subcommittee ("RASC") meeting, and formal feedback was solicited. Feedback

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91 *Id.* at 25-30.

92 *Id.* at 27.

93 *Id.* at 27-28.

received from stakeholders generally supported the revised conversion method and MISO adopted the revised method and shared related Tariff redlines at the November 3, 2021 meeting of the RASC.

2. Non-Schedule 53 Resources

As indicated, the majority of MISO's proposed resource accreditation revisions address Schedule 53 Resources. While MISO intends to address potential accreditation enhancements to non-Schedule 53 Resource accreditation in a future filing after development and stakeholder discussions, non-Schedule 53 Resources will receive a SAC value based on Resource type consistent with their current accreditation rules adjusted for seasonality. As explained by Mr. McFarlane, wind resources will receive accreditation for each Season based on seasonal Effective Load Carrying Capability studies with capacity credit allocated based on eight peak hours for each Season.[94] In addition, non-wind intermittent resources such as run-of-river hydro, solar, Behind the Meter Generation ("BTMG") and biomass will be based on historic output during hours ending 15, 16 and 17 Eastern Standard Time ("EST") for the relevant Spring, Summer, and Fall months. Winter accreditation will be based on hours 8, 9, 19 and 20 EST for the Winter months. Mr. McFarlane explains in his testimony that the selected hours represent the typical seasonal peak demand hours for the specified Seasons.[95] Finally, Demand Resources registered as LMRs will be accredited based on lead-time and number of calls per year consistent with current LMR rules, with adjustments to establish a minimum number of calls for each Season – five for Summer, five for Winter, three for Spring and three for Fall.[96]

C. Generator Outage Coordination

MISO's current Resource Adequacy construct provides for exemptions for generator planned outages if certain criteria are met.[97] MISO has since worked collaboratively with stakeholders to develop an exemption process that integrates with the tiered accreditation calculations in Schedule 53.[98] The three levels are: (1) full exemption for Generator Planned Outages from Tier 1 and Tier 2 SAC calculations in Schedule 53; (2) partial exemption (only exempt in Tier 1 SAC calculations); and (3) no exemption.[99] The table below detailing the proposed exemption requirements is also in Schedule 53 of the Tariff:

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94 *Id.* at 31.

95 *Id.* at 32.

96 *Id.*

97 *Id.* at 46.

98 *Id.* at 47.

99 *Id.*

Generator Outage Submission Criteria	**Maintenance Margin >=0 for duration of outage**	**Maintenance Margin <0 for any day in the duration of outage**
>120 days prior to outage start date, and >120 days from end of previous outage for unit	Exempt Tier 1 & 2	Exempt Tier 1 Only
>120 days Prior to Outage Start date and <120 days from end of Previous outage for unit or Outage submitted between 31-119 days Prior to outage start date	Exempt Tier 1 Only	No Exemption
14-30 days prior to outage start date and passes No Harm Test	Exempt Tier 1 Only	No Exemption
Outage moved per MISO request	Exempt Tier 1 & 2 (Weather, forced outages, other conditions in BPM-008)	Exempt Tier 1 & 2 (Weather, forced outages, other conditions in BPM-008) at Transmission Provider's discretion

MISO's outage exemption analysis will apply no harm tests that include, but will not be limited to, outage approval, compliance with all applicable operation guides, review of possible conflicting outages or system conditions, and forecasts of system capacity.[100] The tests will also include criteria outlined in the Business Practices Manual for Outage Coordination and will apply only to specific categories of outages.[101]

For those planned outages submitted before MISO's proposal goes into effect, MISO proposes a transition with a bright-line distinction based on whether the outage is scheduled to start before September 1, 2022.[102] Planned outages submitted since Spring 2019 are coded as exempt or not in the Control Room Operations Window ("CROW") under RAN Phase 1.[103] Exempt resources will be treated as fully exempt for Tier 1 and 2 even though they may not have met both of the primary requirements of: (1) being submitted 120 days or greater in advance; and, (2) leaving positive Maintenance Margin in the subregion for the duration of the outage.[104] As explained by Mr. McFarlane, MISO believes this approach is appropriate given the risks to

100 *Id.* at 48.

101 *Id.*

102 *Id.*

103 *Id.*

104 *Id.*

capacity sufficiency from correlated planned outages and its ongoing efforts to encourage sufficient outage coordination.[105]

In light of the strong correlation between high outage levels and MaxGen events, MISO proposes to implement processes and procedures to enhance SAC determinations for Schedule 53 resources.[106] Under MISO's proposed framework, outage exemptions will usually be given at the time of outage submittal review or in response to a CROW ticket change request.[107] Partial and full exemptions ensure that a Resource's accreditation is appropriately impacted based on adherence to the outage coordination criteria.[108] The criteria for exemptions are outage lead time and adequate Maintenance Margin.[109] Mr. McFarlane notes that outage approvals and outage exemptions have separate purposes and criteria but bridge the gap between the planning and operational horizons.[110] As is the case today, approvals will be based on reliability analysis in the Outage Coordination process.[111]

MISO is also developing enhancements to Maintenance Margin to improve the information available to Resource owners scheduling outages. Maintenance Margin is the maximum megawatt of additional generation that can be taken out of service for planned maintenance for a given time-period without undue risk to supply adequacy for MISO's Balancing Authority Area, including MISO sub-regions.

Full outage-related exemptions (exempt Tier 1 and Tier 2) will be provided if: (1) the generator owner or operator schedules its first planned outage 120 days or more in advance of the outage start date and 120 days or more beyond the end date of any previously scheduled outages for the unit, and certain projected Maintenance Margin levels are met; and (2) the generator owner or operator reschedules its planned outage at MISO's request due to certain enumerated conditions.[112] These criteria are set forth in additional detail in Schedule 53 and the Testimony of Mr. McFarlane.

Partial outage-related exemptions (exempt Tier 1 only) will be provided if one of the following conditions are met: (1) the generator owner or operator schedules its first generator planned outages 120 days or more in advance of the outage start date and 120 days or more beyond the end date of any previously scheduled outages for the unit; (2) a subsequent generator unit outage requests 120 days or more in advance and/or generator owner or operator's planned outage is less than 120 days in advance but at least 31 days in advance of outage start date; (3) the planned

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105 *Id.* at 48-49.

106 *Id.* at 49.

107 *Id.*

108 *Id.*

109 *Id.* at 49-50.

110 *Id.* at 50.

111 *Id.*

112 *Id.* at 47.

outage is less than 31 days in advance but at least 14 days in advance of outage start date; or (4) the generator owner or operator reschedules its planned outage at the Transmission Provider's request. These criteria are set forth in additional detail in Schedule 53 and the Testimony of Mr. McFarlane.

V. OTHER RELATED ENHANCEMENTS

A. Market Monitoring and Mitigation Revisions

MISO also intends to modify its market monitoring and mitigation provisions in Module D of the Tariff. More specifically, the revisions to Module D of the Tariff focus, in part, on substantive enhancements regarding physical and economic withholding.[113] With regard to physical withholding, the shift to a seasonal construct requires minor modifications to ensure existing protections continue to work in the future.[114] MISO proposes to remove the preclusion from participation for resources that expect to be on outage for greater than 90 of the first 120 days of the Planning Year and replace that with a provision that states that a Market Participant with a Resource that has submitted an outage for greater than 31 days of a Season can ask the IMM for a determination ahead of the auction allowing it to forego offering excess Zonal Resource Credits from the Resource into the PRA, without being deemed to have engaged in physical withholding.[115]

The shift to a seasonal construct could mean that a Resource may only be able to recover capacity revenues in a single Season, which need to cover its relevant costs of being designated for Resource Adequacy Requirements.[116] The threshold for economic withholding remains at 10% of daily CONE but it is expected that more Resources will request facility-specific Reference Levels or use Default Technology Specific Avoidable Costs to help ensure they can cover their costs when they might only clear for one Season in contrast to the full Planning Year under the current construct.[117] The threshold for economic withholding remains at $0 when a Resource has a facility-specific Reference Level at which it can offer.[118]

B. Make-Whole Payment / Revenue Sufficiency Guarantee

When evaluating the shift to the seasonal PRA construct, MISO identified rare circumstances that result in the potential for over or underpayment. As explained by Mr. McFarlane, historical PRA results suggest that these situation will not occur frequently but,

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113 *Id.* at 50.

114 *Id.* at 51.

115 *Id.*

116 *Id.*

117 *Id.*

118 *Id.*

nonetheless, it is reasonable to ensure mitigation for such potential instances.[119] To address this potential risk, MISO proposes enhancements to its offer caps and will add the ZRC Offer Revenue Sufficiency Guarantee Credit to ensure Resources clearing the PRA recover their costs reflected in their offer while also ensuring the LSEs are not exposed to Auction Clearing Prices that result in charges that amount to multiples of the annual CONE value as a result of participation in the PRA. Mr. McFarlane's testimony contains specific descriptions of the proposed Auction Clearing Price adjustments and make whole payment provisions.[120]

Charges to fund the ZRC Offer Revenue Sufficiency Guarantee will be allocated to Market Participants representing LSEs in the LRZ(s) experiencing shortage or near shortage conditions *pro rata,* based on their respective LSEs' share of the PRMR within the LRZs during the Season or Seasons where the Auction Clearing Prices were reduced.[121] Mr. McFarlane notes in his testimony that this allocation of ZRC Offer Revenue Sufficiency Guarantee charges is similar to the allocation of the Zonal Deliverability Benefit, which occurs when an LRZs' Auction Clearing Price separates from the Region-wide Auction Clearing Price due to limited import or expert capability.[122]

VI. STAKEHOLDER ENGAGEMENT

MISO has been engaged in dedicated, detailed discussions with stakeholders at the RASC and RAN workshops about these proposed reforms since March 2020. As previously referenced, however, issues identified prior to and throughout the RAN initiative were discussed with stakeholders as early as 2015. As described above, MISO has already taken action with FERC filings related to outage coordination and LMRs in 2018, 2019 and 2020. Regarding the current proposals, MISO has discussed a variety of alternatives since 2017 through the stakeholder issues process and the publication of various "white-papers." Attached to Mr. Wright's testimony as Exhibit A is a table outlining the numerous meetings and topics covered with stakeholders during the development to this proposal. As indicated by the table, stakeholder involvement in the development and evaluation of this proposal has been extensive.

Stakeholders have passed three motions requesting that MISO delay its filing, specifically citing the need for additional time to understand MISO's proposal. The details of these motions and related vote tallies are described in detail in the testimony of Mr. Wright. MISO responded to a stakeholder motion passed at the September 2021 RASC requesting that MISO delay the instant filing beyond the planned September 30, 2021 filing date and provided stakeholders with an additional two months to continue discussions. While the filing was not delayed into 2022 as requested by the motion, MISO held three additional RASC meetings and three additional stakeholder workshops to further discuss stakeholder questions and concerns. In addition, MISO established a formal question and answer process with written and verbal responses. This included

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119 *Id.* at 40.

120 *Id.* at 39-46.

121 *Id.* at 45.

122 *Id.*

the cataloging and responding to over 120 questions through the formal stakeholder feedback process.[123] In parallel to the RASC and RAN workshops mentioned above focusing on MISO's proposal, MISO held one implementation workshop to solicit stakeholder inputs on MECT tool enhancements in support of transitioning to proposed Resource Adequacy reforms.

During these additional stakeholder discussions, MISO made several refinements and improvements to the proposal. These modifications include the following: implementation of the UCAP/ISAC ratio; provisions for catastrophic outage replacements; resource capacity increases during the Planning Year; transitional Tier 1 and Tier 2 weightings of 20% and 80%, respectively; Auction Clearing Price adjustment during scarce and near-scarce conditions; and, provisions to address revenue sufficiency under rare circumstances. Many of these changes were proposed by stakeholders through written and verbal feedback. MISO evaluated each proposal to determine consistency with the objectives of current proposal and potential reliability or efficiency impacts. Based on that evaluation and upon discussions with the IMM, MISO believes these changes to be reasonable and has included them in its final proposal. The specific Tariff changes described below reflect these changes and their merits are discussed in the testimony submitted with this filing.

MISO appreciates the willingness of all its stakeholders and state regulators to review and comment on this final proposal, which MISO believes reasonably accommodates concerns raised by stakeholders.

VI. TARIFF REVISIONS

MISO proposes the following revisions to its Tariff to implement its proposed Resource Adequacy reforms including Seasonal Resource Adequacy Construct and Availability-Based Accreditation.

A. Module A - Common Tariff Provisions – Definitions

1. Allowable ZRC Offer Costs

MISO proposes adding the definition of Allowable ZRC Costs to specify that Allowable ZRC Offer Costs means "[c]osts associated with a Planning Resource reflected in its ZRC offer, or the CONE, or facility-specific Reference Level costs, considered in determining ZRC Offer Revenue Sufficiency Credits for a Planning Year."

2. Auction Clearing Price (ACP)

MISO proposes modifying the definition of Auction Clearing Price by inserting the phrase "for a Season" into the definition to clarify that Auction Clearing Price means the price associated with the MW quantity that clears in the Planning Resource Auction for a given LRZ or ERZ for a Season for the applicable Planning Year.

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123 *See* https://cdn.misoenergy.org/20211118%20RA%20Construct%20Workshop%20Item%2002c%20Review%20Q%20and%20A605111.pdf

3. Border External Resource

MISO proposes modifying the definition of Border External Resource by replacing "Unforced Capacity" with "Capacity" in the definition to clarify that a Border External Resource means an External Resource that: (i) has direct interconnection facilities to a substation that contains the terminal of a transmission line under the Transmission Provider's functional control; (ii) will schedule in response to notification by the Transmission Provider during a declared Energy Emergency solely from unit(s) connected to each substation; and, (iii) whose Capacity offered into MISO may be accommodated on those transmission line(s) under the Transmission Provider's functional control.

4. Capacity Deficiency Charge

MISO proposes modifying the definition of Capacity Deficiency Charge by inserting language into the definition to clarify that Capacity Deficiency Charge means a charge that is assessed to an LSE that has provided notification prior to the Planning Resource Auction that it will meet its PRMR in part or in whole by paying the Capacity Deficiency Charge so that the Transmission Provider does not clear associated Zonal Resource Credits ("ZRC") for the associated PRMR through the PRA.

5. Capacity Export Limit (CEL)

MISO proposes modifying the definition of Capacity Export Limit by inserting the phrase "for each Season" into the definition to clarify that Capacity Export Limit means the amount of Planning Resources in MWs for an LRZ or ERZ determined by the Transmission Provider that can be reliably exported from that LRZ or ERZ for each Season.

6. Capacity Import Limit (CIL)

MISO proposes modifying the definition of Capacity Import Limit by inserting the phrase "for each Season" into the definition to clarify that Capacity Import Limit means the amount of Planning Resources in MWs for an LRZ determined by the Transmission Provider that can be reliably imported into that LRZ for each Season.

7. Capacity Replacement Non-Compliance Charge

MISO proposes adding the definition of Capacity Replacement Non-Compliance Charge to specify that Capacity Replacement Non-Compliance Charge means "[t]he charge assessed to a Market Participant for failing to replace ZRCs that were designated for RAR and did not fulfill their performance obligations as set forth in Module E-1."

8. Catastrophic Generator Outage

MISO proposes adding the definition of Catastrophic Generator Outage to specify that Catastrophic Generator Outage means a forced outage that results in a unit being, or reasonably expected to be unavailable for a minimum of six (6) continuous months, which is not the result of a planned maintenance outage.

9. Coincident Peak Demand

MISO proposes modifying the definition of Coincident Peak Demand by inserting the phrase "for each Season" into the definition to clarify that Coincident Peak Demand means the

demand in MWs, for an LSE and/or EDC, that occurs coincident to the peak Demand for each Season, where all Demand has been augmented to include any known reductions in Demand related to LMRs and/or Energy Efficiency Resources.

10. Deliverability Benefit Zone

MISO proposes modifying the definition of Deliverability Benefit Zone by inserting the phrase "for a Season" into the definition to clarify that Deliverability Benefit Zone means a group of Local Resource Zones that have equal Auction Clearing Prices for a Season in a Planning Resource Auction resulting from the same auction constraint.

11. Diversity Contract

MISO proposes modifying the definition of Diversity Contract by removing the phrases "for the period between June 1st and September 30th" and "for any period during October 1st to May 31st" to clarify that Diversity Contract means a type of power purchase agreement between an LSE in the Transmission Provider Region and an LSE with demand external to the Transmission Provider Region that includes a one for one MW exchange of capacity which is committed to the Transmission Provider Region in exchange for capacity committed outside of the Transmission Provider Region.

12. Fixed Resource Adequacy (FRAP)

MISO proposes modifying the definition of Fixed Resource Adequacy Plan by inserting the phrase "in a Season" into the definition to clarify that Fixed Resource Adequacy Plan means a plan submitted by an LSE through the MECT to the Transmission Provider that is approved by the Transmission Provider which demonstrates that the LSE has sufficient ZRCs to meet all or part of its PRMR for one or more LRZs in a Season.

13. ICAP Deferral Non-Compliance Charges

MISO proposes modifying the definition of ICAP Deferral Non-Compliance Charges by inserting the phrase "start of any Season for which a Market Participant has an ICAP deferral" into the definition to clarify that ICAP Deferral Non-Compliance Charges means a charge that is assessed by a Market Participant that fails to submit GVTC results, demonstrate deliverability, demonstrate commercial operation, and/or replace ZRCs by the last Business Day prior to the start of any Season for which a Market Participant has an ICAP deferral associated with Planning Resources that participate in the Resource Adequacy Requirements provisions, including the Planning Resource Auction and the Fixed Resource Adequacy Plan.

14. Local Clearing Requirement (LCR)

MISO proposes modifying the definition of Local Clearing Requirement by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" and inserting the phrase "for each Season" into the definition to clarify that Local Clearing Requirement means the minimum amount of Seasonal Accredited Capacity for an LRZ that is required to meet its LOLE for each Season while fully using the Zonal Import Ability for such LRZ and accounting for controllable exports.

15. Local Clearing Requirement Charge

MISO proposes modifying the definition of Local Clearing Requirement Charge by inserting the phrase "for a Season" into the definition to clarify that Local Clearing Requirement

Charge means a charge that is assessed to Load Serving Entities whenever an LRZ's Auction Clearing Price for a Season is increased due to its LCR being greater than the sum of individual PRMR of the LSEs.

16. Local Reliability Requirement (LRR)

MISO proposes modifying the definition of Local Reliability Requirement by inserting the phrase "for each Season" into the definition to clarify that Local Reliability Requirement means the minimum of amount of Unforced Capacity for an LRZ to meet its LOLE for each Season, without considering transmission ties to systems outside of the LRZ.

17. Local Resource Zone Peak Demand

MISO proposes modifying the definition of Local Resource Zone Peak Demand by removing the word "annual" and inserting the phrase "for each Season" into the definition to clarify that Local Resource Zone Peak Demand means the Demand in MWs, for an LSE and/or EDC, in a Local Resource Zone that occurs coincident to the peak Demand for each Season in the Local Resource Zone, where all Demand has been augmented to include any known reductions in Demand related to LMRs and/or Energy Efficiency Resources.

18. Loss of Load Expectations (LOLE)

MISO proposes modifying the definition of Loss of Load Expectation by removing the phrase "[t]he requirement is set such that the loss of Load is no greater than 0.1 day in one (1) year" from the definition to clarify that Loss of Load Expectation means the sum of the loss of Load probability for the integrated daily peak Hour for each Day of the year.

19. Planning Reserve Margin Requirement (PRMR)

MISO proposes modifying the definition of Planning Reserve Margin Requirement by inserting the phrase "in each Season" into the definition to clarify that Planning Reserve Margin Requirement means the amount of ZRCs required of each LSE with Coincident Peak Demand in an LRZ to meet the LSE's Resource Adequacy Requirements in each Season.

20. Planning Resource Auction (PRA)

MISO proposes modifying the definition of Planning Resource Auction by replacing the phrase "annual" with the phrase "each Season in" in the definition to clarify that Planning Resource Auction means auctions conducted by the Transmission Provider to determine the ACP and the cleared ZRC Offers for each LRZ and ERZ for each Season in the applicable Planning Year.

21. Seasonal Accredited Capacity (SAC)

MISO proposes adding the definition of Seasonal Accredited Capacity to specify that Seasonal Accredited Capacity means the amount of Capacity, for a given Season, in MW, assigned to a Planning Resource after accounting for its historic availability.

22. Sub-Regional Export Constraint (SREC)

MISO proposes modifying the definition of Sub-Regional Export Constraint by inserting the phrase "for each Season" into the definition to clarify that Sub-Regional Export Constraint means the amount of Planning Resources in megawatts modeled in the PRA for each Season within an applicable Sub-Regional Resource Zone ("SRRZ") that can be cleared in excess of the total

individual LRZ's PRMR comprising the SRRZ in accordance with applicable seams agreements, coordination agreements, or transmission service agreements.

23. Sub-Regional Import Constraint (SRIC)

MISO proposes modifying the definition of Sub-Regional Import Constraint by inserting the phrase "for each Season" into the definition to clarify that Sub-Regional Import Constraint means the amount of Planning Resources in megawatts modeled in the PRA for each Season, not within an applicable Sub-Regional Resource Zone ("SSRZ"), that can be cleared to meet the total PRMR of the individual LRZs comprising the SRRZ in accordance with applicable seams agreements, coordination agreements, or transmission service agreements.

24. Sub-Regional Resource Zone (SRRZ)

MISO proposes modifying the definition of Sub-Regional Resource Zone by removing the reference to Module E-2 and inserting the phrase "for each Season" into the definition to clarify that Sub-Regional Resource Zone means a zone, comprised of a LRZ or combination of two or more LRZs, established by the Transmission Provider for each Season for Resource Adequacy Requirements under Module E-1 to administer constraints in accordance with applicable seams agreements, coordination agreements, or transmission service agreements.

25. System Auction Clearing Price (System ACP)

MISO proposes modifying the definition of System Auction Clearing Price by inserting the phrase "for a Season" into the definition to clarify that System Auction Clearing Price means the marginal value ("shadow price") associated with the system-wide Demand constraint for a Season. This Demand constraint ensures that the amount cleared, in all LRZs, is at least equal to the total PRMR in all LRZs. The marginal value of this constraint provides a quantitative result of the value of obtaining the marginal MW from the non-export constrained LRZ(s).

26. Zonal Resource Credit (ZRC)

MISO proposes modifying the definition of Zonal Resource Credit by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" in the definition to clarify that Zonal Resource Credit means a MW unit of Planning Resource which has been converted from a MW of Seasonal Accredited Capacity to a credit in the MECT, which is eligible to be offered by a Market Participant into the PRA, to be sold bilaterally, and/or to be submitted through a FRAP.

27. ZRC Near-Shortage Conditions

MISO proposes adding the definition of ZRC Near-Shortage Conditions to specify that ZRC Near-Shortage Conditions means any Season in a Planning Resource Auction in which there is sufficient volume of ZRC Offers in the LRZ, group of LRZs, or SRRZ to cover PRMR and locational requirements minus the PRMR associated with the Capacity Deficiency Charge for the LRZ, group of LRZs, or SRRZ, but the Season's ACP is greater than the daily CONE value (i.e. 1/365 times CONE).

28. ZRC Offer Revenue Sufficiency Credit

MISO proposes adding the definition of ZRC Offer Revenue Sufficiency Credit to specify that ZRC Offer Revenue Sufficiency Credit means a Resource credit guaranteed by the Transmission Provider ensuring the minimum recovery of the actual costs a Planning Resource

that has been cleared for one or more Seasons in the Planning Resource Auction needed to be incurred by the Planning Resource to be available for the cleared Season(s).

29. ZRC Shortage Conditions

MISO proposes adding the definition of ZRC Shortage Conditions to specify that ZRC Shortage Conditions means any Season in a Planning Resource Auction in which there is an insufficient volume of ZRC Offers to cover LCR or the total PRMR for the LRZ, group of LRZs, or SRRZ minus the amount of PRMR associated with the Capacity Deficiency Charge for an LRZ, group of LRZs, or SRRZ, or the total PRMR for the SRRZ minus the SRIC minus the amount of PRMR associated with the Capacity Deficiency Charge for a SRRZ.

30. Transitional Planning Resource Auction (TPRA) and Module E-2 References

MISO proposes deleting the definition of Transitional Planning Resource Auction ("TPRA") as well as all references to the TPRA and to Module E-2 (which establishes the TPRA) throughout the Tariff. Such references are no longer needed because new transitional auction provisions will need to be developed in order to accommodate the proposed seasonal Resource Adequacy construct. For example, any new Market Participant proposing to integrate Schedule 53 type Resources into MISO mid-Planning Year will not have available data necessary for MISO to establish appropriate accreditation. In this regard, MISO notes that, upon acceptance of this filing by the Commission, MISO proposes to submit a separate Section 205 filing to cancel Module E-2 and remove it from the Tariff. In addition, MISO expects to establish and file with the Commission new transitional seasonal PRA provisions, as may be necessary.

B. Module A - Section 7.11 - Billing Procedure for Capacity Deficiency Charge and Capacity Replacement Non-Compliance Charge

MISO proposes adding Tariff language to Section 7.11 of the Tariff to clarify that the billing procedure for Capacity Deficiency Charges set forth in Section 7.11 of the Tariff will also apply to Capacity Replacement Non-Compliance Charges. Specifically, the language will require that five business days after the assessment of the Capacity Deficiency Charge or Capacity Replacement Non-Compliance Charge; or as soon as practical thereafter the Transmission Provider shall submit an invoice to Market Participants for charges owed that are associated with capacity deficiencies or the Capacity Replacement Non-Compliance Charge pursuant to the Tariff.

C. Module A - Section 7.13 - Default and Past Due Capacity Deficiency Charge, Capacity Replacement Non-Compliance Charge and ICAP Deferral Non-Compliance Charges

MISO proposes adding Tariff language to Section 7.13 of the Tariff to clarify that the rights and remedies for default and past due Capacity Deficiency Charges set forth in Section 7.13 of the Tariff will also apply to Capacity Replacement Non-Compliance Charges.

D. Attachment L – Credit Policy

MISO proposes modifying Attachment L of the Tariff by inserting language to clarify that Capacity Replacement Non-Compliance Charges will also be excluded from the Resource Adequacy Requirements Estimated Exposure calculation as they are settled all at once rather than daily.

E. Attachment UU – Energy Efficiency Resources Measurement & Verification Procedures

MISO proposes modifying Attachment UU of the Tariff by replacing coincident peak load with "Coincident Peak Demand" throughout the attachment and adding language related to "Season(s) in the" Planning Year, "Season", "in any Season", "applicable Season(s)", and "each Season in the Planning Year which the EE Resource expects to qualify" throughout the attachment.

MISO proposes inserting language into Attachment UU specifying that the hours in the Season for which the coincident peak is likely to occur "currently include the hours 15:00, 16:00, and 17:00 Eastern Prevailing Time (EPT) for the Spring, Summer, and Fall Seasons and hours 08:00, 09:00, 19:00, and 20:00 EPT for the Winter Season."

F. Module C - Energy and Operating Reserve Markets

1. Section 38.2.5 - Market Participant Obligations

MISO proposes modifying Sections 38.2.5 of the Tariff by adding language to Section 38.2.5.g.vii of the Tariff to clarify that if a Market Participant refuses to reschedule a Proposed Generator Planned Outage as requested by the Transmission Provider, then during the next Planning Year, the Transmission Provider shall determine the Seasonal Accredited Capacity value for such Generation Resource under RAR by treating the outage as a Forced Outage. MISO proposes inserting Section 38.2.5.g.viii specifying that "[a] Resource may be eligible for accreditation adjustments for purposes of RAR pursuant to Schedule 53 based on the advance notification requirements set forth in Sections 38.2.5.g.ix and 38.2.5.g.x." MISO proposes removing language from Section 38.2.5.g.ix-xi regarding the forced outage rate adjustment.

2. Section 39.2.5A - Demand Response Resource-Type 1 Offer Rules

MISO proposes modifying Section 39.2.5A.b.ix of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity".

3. Section 40.2.5 - Generation Offer, DRR-II Offer, or SER-II Offer

MISO proposes modifying Section 40.2.5.b.xv of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity".

G. Module D - Market Monitoring and Mitigation Measures

1. Section 53.1 – Conditions, Functions or Actions Monitored

MISO proposes modifying Section 53.1 of the Tariff by removing the phrase "other than ZRCs" from Section 53.1.b regarding the IMM's analysis of conditions, functions, or actions.

2. Section 53.1A – Auditing Physical Withholding

MISO proposes modifying Section 53.1A of the Tariff by inserting the phrase "Stored Energy Resources," "Electric Storage Resources," and "Generator Planned Outages" to clarify that "[i]n order to prevent and/or discern the exercise of market power by Stored Energy Resources, Electric Storage Resources, and certain Generation Resources, including Stored Energy Resources – Type II through Physical Withholding, the IMM shall audit Generator Forced Outages, Generator Planned Outages, and Generator deratings" and other changes.

3. Section 64.1.1 - Thresholds for Identifying Physical Withholding

MISO proposes modifying Section 64.1.1 of the Tariff by removing Section 64.1.1.g.ix regarding the 2015-2016 Planning Year, inserting the phrase "Season of the applicable" Planning Year into Sections 64.1.1.g.i-iii, and modifying renumbered Section 64.1.1.g.xi to clarify that "Market Participants with capacity expected to be on outage for greater than thirty-one (31) Days in a Season of the Planning Year may submit documentation of such circumstances to the IMM, and the IMM shall provide a written explanation upon request of its determination to the Market Participant regarding whether that capacity can forego participation without being deemed to have engaged in Physical Withholding. The portion of a Resource that the IMM has determined can forego participation based on full or partial outage expected to exceed thirty-one (31) Days in a Season of the Planning Year can still offer the excluded portion of the Resource in the relevant Season, if it so chooses, up to the annual CONE value divided by the number of days in the Season without needing to request a facility-specific Reference Level and will not be investigated for economic withholding in that Season."

4. Section 64.1.2 - Thresholds for Identifying Economic Withholding

MISO proposes modifying Section 64.1.1 of the Tariff by inserting the phrase "a threshold equal to the sum of 10% of the applicable CONE value divided by the number of days in the Planning Year for the Local Resource Zone where the Zonal Resource Credit is located and the applicable Reference Level for the Zonal Resource Credit" into section 64.1.2.d and by clarifying that "[i]f the Zonal Resource Credit Offer is associated with a Planning Resource that has a facility-specific Reference Level pursuant to Section 64.1.4.f, for which the IMM shall instead use a threshold of $0/MW-day above the facility-specific Reference Level."

5. Section 64.1.4 - Reference Levels

MISO proposes modifying Section 64.1.4 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" in Section 64.1.4.f.ii and by inserting language throughout Section 64.1.4 clarifying that Reference Levels shall be calculated based on Seasons and seasonal costs and inserting language regarding seasonal operations and seasonal shutdowns.

MISO proposes modifying Section 61.1.4.f.iii.c.2.ii-iii specifying with respect to forecasts for the Planning Resource to be in service that "[a]fter the applicable Season, the remainder of the 24 months should reflect the anticipated operations of the Planning Resource in the absence of capacity revenues. Typically, the Operating Forecast would show the costs of proceeding with retiring or suspending the Resource as applicable at the conclusion of the Season but it may show suspensions for just select Seasons of the year" and with respect to a forecast of the cost to retire, suspend, or keep a Planning Resource in suspension that "[a]fter the applicable Season, the remainder of the 24 months should reflect the anticipated operations of the Planning Resource in the absence of capacity revenues. Typically, the Operating Forecast would show the costs of proceeding with retiring or suspending the Resource as applicable at the conclusion of the Season but it may show suspensions for just select Seasons of the year."

6. Section 64.2.1 - Market Impact Thresholds

MISO proposes modifying Section 64.2.1 of the Tariff by inserting the phrase "divided by the number of days in the Planning Year" into Section 64.2.1.e to clarify that "[t]he threshold to determine a substantial effect on Auction Clearing Prices for Planning Resources shall be an

increase in the Auction Clearing Price equal to ten (10) percent of the CONE value divided by the number of days in the Planning Year."

7. Section 65.3.2 - Base Penalty Amount

MISO proposes modifying Section 65.3.2 of the Tariff by inserting language regarding the "Season of the" Planning Year into Section 65.3.2.c to clarify that the Penalty Period will be based on the Season of the Planning Year in which capacity was deemed to be withheld by a Market Participant from the auction and the phrase "applicable Season of the" Planning Year into Section 65.3.2.d to clarify that the Penalty Price for conduct affecting the outcomes of a PRA will be based on the Auction Clearing Price for the applicable Season of the Planning Year.

H. Module E-1 – Resource Adequacy

1. 68A – Introduction

MISO proposes modifying the Introduction to Module E-1 to clarify that "Module E-1 includes provisions for establishing Local Resource Zones and associated limits (*i.e.*, Capacity Import Limits (CIL) and Capacity Export Limits (CEL)); establishing Local Reliability Requirements (LRR); establishing Local Clearing Requirements (LCR); establishing External Resource Zones and associated limits (i.e. Capacity Export Limits (CEL)); determining the Planning Reserve Margin, Coincident Peak Demand forecasting; Local Resource Zone Peak Demand forecasting; qualifying and quantifying Planning Resources; participation of Demand and Planning Resources in the Planning Resource Auction process; settlement provisions; and Planning Resource performance requirements for each Season."

2. Section 68A.1 – Establishment of Planning Reserve Margins

MISO proposes modifying Section 68A.1 of the Tariff by inserting the phrases "in terms of Unforced Capacity for each Season" and "regulatory authority" into the Establishment of Planning Reserves Margins section to clarify that the PRM will be determined for each Season and that if a state regulatory authority establishes a PRM that is higher or lower than the PRM determined by the Transmission Provider, then the state regulatory authority-established PRM will apply to the Coincident Peak Demand of LSEs under that state's jurisdiction.

3. Section 68A.2 – Planning Reserve Margin Analysis

MISO proposes modifying Section 68A.2 of the Tariff by inserting the phrase "for each Season" to clarify that the Transmission Provider shall perform a technical analysis on an annual basis to establish the PRM for each Season for the Transmission Provider Region and by removing the word "resource" from the phrase specific Planning Resource reserve requirements.

4. Section 68A.2.1 – Loss of Loss Expectation Analysis

MISO proposes modifying Section 68A.2.1 of the Tariff by inserting the phrase "Season in the" Planning Year to clarify that the Transmission Provider shall coordinate with Market Participants to determine the appropriate PRM for the applicable Season in the Planning Year based upon the probabilistic analysis of being able to reliably serve the Transmission Provider Region's Demand for the applicable Season in the Planning Year.

MISO proposes modifying Section 68A.2.1 of the Tariff by inserting language into Section 68A.2.1 to clarify that "[t]he following process will be utilized to determine the minimum PRM

requirement for each Season in the Planning Year using the LOLE analysis. First, an LOLE analysis for the Planning Year will be conducted such that the LOLE for the Planning Year is one (1) day in ten (10) years, or 0.1 day per year, by either adding or removing capacity."

MISO proposes inserting additional language into Section 68A.2.1 to clarify that "[i]f the LOLE for the Planning Year is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE for the Planning Year is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year."

MISO proposes inserting additional language into Section 68A.2.1 to clarify that "[i]f the LOLE for a Season is equal to or greater than 0.01 day per year, the minimum PRM requirement for that Season will be calculated based on this LOLE analysis. If the LOLE for any Season is less than 0.01 day per year, an additional LOLE analysis will be performed to determine a minimum PRM requirement for that Season by adding a perfect negative unit with zero forced outage rate to that Season until the LOLE in that Season reaches 0.01."

MISO proposes inserting additional language into Section 68A.2.1 clarifying that the PRM will first be established as an Unforced Capacity requirement based upon the weighted average forced outage rate of all Planning Resources in the Transmission Provider Region.

5. Section 68A.3.1 – Establishment of SRRZs, SRECs, and SRICs

MISO proposes modifying Section 68A.3.1 of the Tariff by inserting language to clarify that the provisions regarding establishing SRRZs, SRECs, and SRICs apply to each "Season" and that the Transmission Provider's feasibility analysis is to review operation events from "each Coincident Peak Demand hour during the previous Planning Year."

6. Section 68A.4 – Establishment of CIL and CEL Limits

MISO proposes modifying Section 68A.4 of the Tariff by inserting language to clarify that the provisions regarding establishing CIL and CEL Limits apply to each "Season."

7. Section 68A.5 – Establishment of Local Reliability Requirements

MISO proposes modifying Section 68A.5 of the Tariff by inserting language to clarify that the LRR metric for each LRZ relates to "each Season", the forecasted Local Resource Zone Peak Demand relates to "each Season", and that "[f]irst, the LOLE analysis for the Planning Year will be conducted," that "[i]f the LOLE for the Planning Year is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE for the Planning Year is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year," and that "[i]f the LOLE for a Season is equal or greater than 0.01 day per year for the LRZ, the LRR for that Season will be calculated based on this LOLE analysis. If the LOLE for any Season is less than 0.01 day per year for the LRZ, an additional LOLE analysis will be performed to determine the LRR for that Season by adding a perfect negative unit with zero forced outage rate to that Season until the LOLE in that Season reaches 0.01 day per year for the LRZ."

8. Section 68A.6 – Establishment of Local Clearing Requirements

MISO proposes modifying Section 68A.6 of the Tariff by inserting language to clarify that "[t]he Local Clearing Requirement for each LRZ for each Season will be determined by subtracting Zonal Import Ability and controllable exports from the LRR, as set forth in the Resource Adequacy Business Practices Manual. Controllable exports are exports from MISO resources that have firm capacity commitments to non-MISO load and that may be committed and dispatched by the Transmission Provider during a declared Energy Emergency."

9. Section 68A.7 – Establishing Planning Reserve Margin Requirements

MISO proposes modifying Section 68A.7.a of the Tariff by inserting language to clarify that the PRMR relates to "each Season" and to insert the language that the PRMR "will be determined by multiplying the LSE's forecasted Coincident Peak Demand for each Season, including transmission losses, by (1 + Transmission Provider Region PRM)."

MISO proposes modifying Section 68A.7.b of the Tariff by inserting language to clarify that when an alternative PRM is established by a state "regulatory authority" the Transmission Provider will use the alternate PRM that a state regulatory "authority" has created for the geographic area in which the state has jurisdiction, and the Transmission Provider will convert any state "regulatory authority" provided PRM for a comparable Unforced Capacity basis.

10. Section 68A.8 – Calculation of Transmission Losses

MISO proposes modifying Section 68A.8.a of the Tariff by inserting the phrases "Coincident Peak Demand" and "for each Season" to clarify that the Transmission Provider shall calculate the LBA transmission loss percentages for each Season and that the total transmission loss value (MW) for each LBA will based on Coincident Peak Demand instead of system peak.

11. Section 69A – RAR Process

MISO proposes modifying Section 69A of the Tariff by inserting language to clarify that LSEs and EDCs shall provide forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data "for the Planning Year", the Transmission Provider will calculate each LSE's PRMR "for each Season", and an ACP will be determined through the PRA process for each LRZ and ERZ "for each Season" and the ACP will be used to credit ZRCs and debit LSEs.

12. Section 69A.1 – Load Serving Entities Responsibilities

MISO proposes modifying Section 69A.1 of the Tariff by inserting language into Section 69A.1.b to clarify that the Transmission Provider will use Coincident Peak Demand, Local Resource Zone Peak Demand, and Energy forecasts "for each Season", by removing Section 69A.1.c regarding what happens when the EDC does not provide a procedure for assigning LSE obligations as described in Section 69A.1.b, and by inserting language into the renumbered Section 69A.1.c to clarify that all LSEs shall report to the Transmission Provider whether such LSE will meet their PRMR for each LRZ "for each Season" in which the LSE serves Load.

13. Section 69A.1.1 – Forecasted Demand Identification

MISO proposes modifying Section 69A.1.1 of the Tariff by removing the phrase "annual" throughout and inserting the word a/any/each "Season" throughout.

MISO proposes modifying Section 69A.1.1.b of the Tariff by inserting the phrase "including Demand from any retail demand side management programs" into that section to clarify that "[t]he supplied Coincident Peak Demand and Local Resource Zone Peak Demand forecasts shall include the Demand expected for the forecast time period (*e.g.* the Coincident Peak Demand hour) augmented to include the normal Demand from forecasted demand resources, whether registered or not registered with the Transmission Provider, including Demand from any retail demand side management programs."

MISO proposes modifying Section 69A.1.1.d of the Tariff by removing the phrase "(e.g., annually for Coincident Peak Demand and Local Resource Zone Peak Demand, and monthly for non-coincident peak Demand" from that section to clarify that "[a]ll Coincident Peak Demand and Local Resource Zone Peak Demand forecasts shall reflect a 50% probability that the Demand will not exceed the forecasted Demand for the relevant period.

MISO proposes modifying Section 69A.1.1.e of the Tariff by inserting the clarifying language that "[c]onsistent" with Section 69A.1.2.1, the EDC must provide both the Transmission Provider and the respective LSEs with each retail customer's peak load contribution (PLC) "in each Season", including transmission losses and PRM as determined by the Transmission Provider, in the EDC's service territory by December 15th and by removing the phrase "[i]f an EDC uses the daily peak load default methodology in Section 69A.1.2.1, then the EDC must provide both the Transmission Provider and each of the respective LSEs with the LSE's historic share of the EDC's Coincident Peak Demand, by December 15th."

14. Section 69A.1.1.1 – Accounting for total Demand Forecasts Given Wholesale and Retail Load Switching

MISO proposes modifying Section 69A.1.1.1 of the Tariff by replacing the phrase "June 1 of the next Planning Year" with "the 1st day of each Season in the next Planning Year" in Section 69A.1.1.1.a, replacing the phrase "June 1 of the next Planning Year" with "the 1st day of any Season in the next Planning Year" in Section 69A.1.1.1.b, adding the phrase "for such Season" in Section 69A.1.1.1.b, and adding the phrase "each Season in the" in Section 69A.1.1.1.b.

15. Section 69A.1.2 – Daily Assignment of Coincident Peak Demand Obligations

MISO proposes modifying Section 69A.1.2 of the Tariff by removing Section 69A.1.2.c regarding states that permit retail load switching and satisfy other criteria, removing language from Section 69.A.1.2.b stating "and where the EDC has adopted the preferred default method in Section 69A.1.2.1", and inserting language into Section 69A.1.2.b specifying that that in a state that permits retail load switching the Transmission Provider shall allocate Resource capacity on a daily basis to LSEs through an outlined formula "consistent with Section 69A.1.2.1."

16. Section 69A.1.2.1 – Default Methods

MISO proposes modifying Section 69A.1.2.1 of the Tariff by inserting clarifying language into Section 69A.1.2.1.b that "EDC will assign a Peak Load Contribution ("PLC") value to each retail customer, based on the most recent PLC values derived for each Season from each retail customer's Demand at the time of the Transmission Provider's peak Demand (*i.e.*, the Prior Seasonal Retail Customer Coincident Peak ("PSRCCP"))" and by inserting the phrase "for each Season" to clarify that the PLCs determined by the EDC must equal the PRMR that is calculated

from the forecast Coincident Peak Demand provided by the EDC "for each Season" and that this equality is achieved by multiplying each retail customer's demand at the time of the Transmission Provider's peak Demand during "each Season" prior to the Planning Year by the same adjustment factor. MISO proposes further modifying Section 69A.1.2.1 by replacing "Prior Summer Retail Customer Coincident Peak" with "PRSCCP" throughout the section, by deleting the phrase "[t]he specific methods used by the EDC to compute each retail customer's PLC must be submitted to the Transmission Provider by December 1, and requires approval by, the Transmission Provider" from Section 69A.1.2.1.b, and by deleting Section 69A.1.2.1.c in its entirety because this method is no longer supported by MISO.

17. Section 69A.1.3 – Load Switching

MISO proposes modifying Section 69A.1.3 of the Tariff by removing Section 69A.1.3.b and replacing the phrase "[b]eginning June 1 of each Planning Year" in Section 69A.1.3.a with the phrase "[b]eginning the first Calendar Day of each Season in the Planning Year." and by deleting Section 69A.1.3.b in its entirety because this method is no longer supported by MISO.

18. Section 69A.3 – Planning Resource Requirements

MISO proposes modifying Section 69A.3 of the Tariff by removing language regarding resources with full or partial outages expected to last for ninety days or more of the first one-hundred and twenty days in the Planning Year being precluded from a FRAP or the PRA.

19. Section 69A.3.1 – Capacity Resources

MISO proposes modifying Section 69A.3.1 of the Tariff by inserting the phrase "any applicable Season in the" upcoming Planning Year into the sentence in Section 69A.3.1 "[t]he Transmission Provider will qualify a Capacity Resource for any applicable Season in the upcoming Planning Year, in accordance with processes specified in the BPM for Resource Adequacy" and by replacing the phrase "Capacity Resources cannot be Stored Energy Resources" with the phrase "Stored Energy Resources cannot be Capacity Resources."

20. Section 69A.3.1.a – Generation Resources that are not Dispatchable Intermittent Resources

MISO proposes modifying Section 69A.3.1.a of the Tariff by inserting the phrase "Season in the" into Section 69A.3.1.a.1.b to clarify that it relates to each Season in the Planning Year.

21. Section 69A.3.1.b – Demand Response Resources

MISO proposes modifying Section 69A.3.1.b of the Tariff by inserting language into Sections 69A.3.1.b.1 and 69A.3.1.b.3 to clarify that those sections relate to the applicable "Season" in the Planning Year rather than the Planning Year as a whole.

22. Section 69A.3.1.c – External Resources

MISO proposes modifying Section 69A.3.1.c.1 of the Tariff by inserting the phrases each "Season that the resource will be registered in" and "for each Season that the resource is to be registered in" into Section 69A.3.1.c to clarify that demonstrating GVTC capability relates to each Season and not the Planning Year on an annual basis.

MISO proposes modifying Section 69A.3.1.c.3 of the Tariff by inserting the phrase "applicable Season in the" upcoming Planning Year into Section 69A.3.1.c.3 to clarify that the section relates to the applicable Season and not the upcoming Planning Year.

MISO proposes adding Section 69A.3.1.c.6 of the Tariff stating "Existing Resources that modify their registration, scheduling and market participation in the Energy and Operating Reserves Markets and become pseudo-tied External Resources after September 1, 2022 will be accredited at the lesser of class average SAC in Schedule 53 or the accreditation provisions governing External Resources in section 69A.4.1.b."

23. Section 69A.3.1.d – Use Limited Resources

MISO proposes modifying Section 69A.3.1.d of the Tariff by inserting the phrase "each applicable Season" to clarify that the request that "[a] Use Limited Resource must be able to operate for a minimum set of four (4) consecutive operating Hours across the Transmission Provider's coincident peak for each day in each applicable Season in order to qualify as a Capacity Resource" relates to each Season and not to the Planning Year as a whole.

24. Section 69A.3.1.h – Retirement, Suspension and Replacement of Planning Resources

MISO proposes modifying Section 69A.3.1.h by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" throughout, by removing "or TPRA" throughout, and by inserting language throughout regarding the relevant "Season" of or during the Planning Year. MISO proposes inserting language into Section 69A.3.1.h.a clarifying that "[i]f a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is Retired or Suspended prior to the end of the Season during the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs." MISO proposes inserting language into Section 69A.3.1.h.a clarifying that "[i]f a Market Participant does not replace such ZRCs associated with a Retired or Suspended Planning Resource, a Capacity Replacement Non-Compliance Charge will be assessed as determined below in this Section."

MISO proposes modifying Section 69A.3.1.h by inserting language into Section 69A.3.1.h.a clarifying that "[i]f a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Section 69A.5 for greater than thirty-one (31) Days in total due to full or partial Generator Planned Outage during the Season of the Planning Year in which the ZRCs cleared, or for Capacity Resources that are the subject to Diversity Contracts for greater than one (1) Month during any Season of the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs to transfer the performance requirements applicable to the Planning Resource."

MISO further proposes inserting language into Section 69A.3.1.h.a clarifying that "[a]ny combination of cleared or replaced ZRCs that are on full or partial Generator Planned Outage for greater than thirty-one (31) Days in total during a Season, or for any other reason including full or partial Generation Outages that were not planned but were known or could have been reasonably anticipated at the time of the PRA, as set forth in the Market Monitoring and Mitigation Business Practices Manual, or unavailable because subject to a Diversity Contract that is not available for greater than one (1) Month during a Season, will be assessed a Capacity Replacement Non-

Compliance Charge. If a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Sections 69A.3.3.1 and 69A.5 due to a Catastrophic Generator Outage any time during the Season of the Planning Year in which the ZRCs cleared such Market Participant may replace the cleared ZRCs with uncleared ZRCs to transfer the performance requirements applicable to the Planning Resource. A Planning Resource may not transfer its performance requirements by replacing the cleared ZRCs with uncleared ZRCs other than in the case of suspension, retirement, Catastrophic Generator Outage or full or partial Generator Planned Outages that may exceed thirty-one (31) Days in the Season as discussed immediately above."

MISO proposes modifying Section 69A.3.1.h by inserting language into Section 69A.3.1.h.a clarifying that "ZRC replacement shall have no impact on settlements from the PRA and FRAPs, including any assessed Capacity Replacement Non-Compliance Charges." MISO proposes further modifying Section 69A.3.1.h by creating Section 69A.3.1.h.b with language specifying that Capacity Replacement Non-Compliance Charges will be assessed for the number of days the Market Participant had an obligation to replace and failed to do so and calculated based on the amount of ZRCs that failed to be replaced multiplied by the sum of the ACP and the daily CONE Value which will be based on the LRZ where the Planning Resource cleared those ZRCs and that revenues from such charges received by the Transmission Provider will be distributed to LSEs that have met their PRMR during the applicable Season of the Planning Year on a *pro rata* basis based upon the LSEs share of total PRMR for the Transmission Provider Region.

25. Section 69A.3.2 – Energy Efficiency Resources (EE Resource)

MISO proposes modifying Section 69A.3.2 of the Tariff by replacing "annually" with "for each Season" to clarify that "[a]n EE Resource can qualify as a Planning Resource for ZRCs for each Season for up to four (4) Planning Years immediately following the EE Resource's initial qualification provided that the energy efficiency measures are fully implemented prior to each Planning Year."

26. Section 69A.3.3 – Load Modifying Resource

MISO proposes modifying Section 69A.3.3 of the Tariff by removing "TPRA", inserting the phrase "for a Season" to describe that all LMRs that are cleared in the PRA or were submitted in a FRAP for a Season needing to be available for use in the event of an Emergency as declared by the Transmission Provider, inserting the phrase "the applicable Season in" in the sentence "[i]n accordance with the BPM for Resource Adequacy, the Transmission Provider will qualify an LMR for the applicable Season in the upcoming Planning Year", and replacing the phrase coincident peak with "Coincident Peak Demand."

27. Section 69A.3.3.1 – Deployment Procedures for LMR

MISO proposes modifying Section 69A.3.3.1 of the Tariff by inserting the language "minimum" and "for the applicable Season" into the sentence "[a] Market Participant that acknowledge Scheduling Instructions for its LMR(s) as required by the BPM for Resource Adequacy will receive credit for one (1) of the minimum deployments or interruptions required for the LMR for the applicable Season whether or not an emergency is declared" and by inserting the language that an LMR which does not perform consistent with the Market Participant's

response to its Scheduling Instructions will not receive credit "as one (1) of the minimum deployments or interruptions required for such resource for the applicable Season."

28. Section 69A.3.4 – Demand Resources (DR)

MISO proposes modifying Section 69A.3.4 of the Tariff by inserting the word "authority" into the phrase "applicable state regulatory authority" and by inserting the phrase "each Season in" into the sentence "[i]n accordance with the BPM for Resource Adequacy, the Transmission Provider will qualify a DR for each Season in the upcoming Planning Year."

29. Section 69A.3.5 – Demand Resource Eligibility

MISO proposes modifying Section 69A.3.5 by inserting language into Section 69A.3.5.a clarifying that a grouping of smaller resources aggregated together than can reduce an LSE's Coincident Peak Demand "for the applicable Season" may qualify in meeting the requirement that a Demand Resource must be equal to or greater than 100 kW.

MISO proposes modifying Section 69A.3.5 by inserting language into Section 69A.3.5.b clarifying that beginning in the 2023/2024 Planning Year, a Demand Resource must have a notification time requirement "less than or equal to six (6) hours to receive credit as a Planning Resource in the applicable Seasons."

MISO proposes modifying Section 69A.3.5 by inserting language into Section 69A.3.5.e clarifying that the prior requirements of that section will apply to the 2022/2023 Planning Year but that for the 2023/2024 Planning Year a Demand Resource must have a notification time equal to or less than "six (6) hours and be capable of being interrupted for: (i) at least the first five (5) times requested in the Summer Season; and, at least the first five (5) times in the Winter Season; and, (iii) for at least the first three (3) times requested in the Spring Season; and (iv) for at least the first three (3) times in the Fall Season, based on their physical availability when called upon by the Transmission Provider for an Emergency during any applicable Season in the Planning Year for which the Demand Resource receives credit as a Planning Resource." MISO proposes modifying Section 69A.3.5.e by removing the provisions related to limitations due to contractual obligations and the requirement that the Demand Resource's availability must include the entire Summer Season.

MISO proposes modifying Section 69A.3.5 by inserting language into Section 69A.3.5.j that a Demand Resource for which a real power test is conducted will receive credit as one (1) of the "minimum" deployments or interruptions required for such Resource for the "applicable Season of the" Planning Year in which such a test occurs.

30. Section 69A.3.6 – Behind the Meter Generation Eligibility

MISO proposes modifying Section 69A.3.6 by inserting language into Section 69A.3.6.1 clarifying that the Transmission Provider will qualify as BTMG for the "applicable Season in the" upcoming Planning Year.

MISO proposes modifying Section 69A.3.6 by inserting language into Section 69A.3.6.1.b clarifying that a BTMG can request accreditation for such BTMG - in part - by demonstrating GVTC capability for "applicable Season in" each Planning Year on an annual basis.

MISO proposes modifying Section 69A.3.6 by removing language in Section 69A.3.6.1.d regarding limitations due to contractual obligations that are more restrictive than the physical limitations of the BTMG in place as of December 21, 2018.

MISO proposes modifying Section 69A.3.6 by inserting language into Section 69A.3.6.1.f clarifying that a BTMG can request accreditation for such BTMG - in part – by demonstrating that the BTMG is capable of being deployed at the accredited MW level for: (i) at least the first five (5) times requested in the Summer Season; and, (ii) at least the first five times requested in the Winter Season; and (iii) at least the first three (3) times requested in the Spring Season; and (iv) at least the first three (3) times requested in the Fall Season", by removing language in Section 69A.3.6.1.f that "[t]his availability must include at least the entire Summer Season", and by removing language in Section 69A.3.6.1.f regarding limitations due to contractual obligations that are more restrictive than the physical limitations of the BTMG in place as of December 21, 2018.

31. Section 69A.4 – Planning Resource Capacity Values

MISO proposes modifying Section 69A.4 of the Tariff by inserting language clarifying that Capacity Resources will be given "a capacity value for each applicable Season based on the Seasonal Accredited Capacity calculation applicable to its Resource type."

32. Section 69A.4.1 – Seasonal Accredited Capacity of Capacity Resources

MISO proposes modifying Section 69A.4.1 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" throughout the section.

MISO proposes modifying Section 69A.4.1.a of the Tariff by inserting clarifying language that "[t]he Seasonal Accredited Capacity for a Capacity Resource that is a Generation Resource, but not a Dispatchable Intermittent Resource, Intermittent Generation, Electric Storage Resource, External Resource or Use Limited Resource, is based on an evaluation of the type and volume of the interconnection service, GVTC value, and Real-Time offered availability of such Generation Resource for each Season as set forth in Schedule 53" and by removing language regarding resources that are not required to report generator availability.

MISO proposes modifying Section 69A.4.1.b of the Tariff by inserting clarifying language that "[t]he Seasonal Accredited Capacity for a Capacity Resource that is an External Resource, but not a Dispatchable Intermittent Resource, Intermittent Generation or Use Limited Resource, is based on the GVTC value and $XEFOR_d$ values of such External Resource for each Season."

MISO proposes modifying Section 69A.4.1.c of the Tariff by inserting clarifying language that "[t]he Transmission Provider will determine the appropriate capacity value for DRR that qualifies as a Capacity Resource and that interrupts or controls Load, based upon historical performance and availability, for each Season, as set forth in Schedule 53" and by removing language regarding resources that are not required to report generator availability.

MISO proposes modifying Section 69A.4.1.d of the Tariff by inserting clarifying language that "[t]he Transmission Provider will determine the Seasonal Accredited Capacity for each DRR that qualifies as a Capacity Resource and that is a behind the meter generation facility based on an evaluation of the GVTC value and Real-Time offered availability for such behind the meter generation facility for each Season as set forth in Schedule 53."

MISO proposes modifying Section 69A.1.e of the Tariff by inserting the phrase "or Use Limited Resource" into that section.

MISO proposes adding Section 69A.1.h of the Tariff stating that "[t]he Seasonal Accredited Capacity for a Capacity Resource that is a Use Limited Resource will be determined by the Transmission Provider based on the type and volume of interconnection service, the GVTC and $XEFOR_d$ values of such Use Limited Resource in accordance with the BPM for Resource Adequacy."

33. Section 69A.4.2 – Seasonal Accredited Capacity of Demand Resources

MISO proposes modifying Section 69A.4.2 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity."

34. Section 69A.4.3 – Seasonal Accredited Capacity of Behind the Meter Generation

MISO proposes modifying Section 69A.4.3 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" when stating that "[t]he Transmission Provider will determine the Seasonal Accredited Capacity for each BTMG that qualifies as an LMR as set forth in the Resource Adequacy Business Practices Manual" and when stating that "[i]f such BTMG is interconnected to the Transmission System, the Transmission Provider will consider the type and volume of interconnection service when determining Seasonal Accredited Capacity." MISO proposes modifying Section 69A.4.3 of the Tariff by removing the phrase that the Transmission Provider will determine capacity for each BTMG that qualifies as an LMR "based on an evaluation of the GVTC value and $XEFOR_d$ values of such BTMG."

35. Section 69A.4.4 – EE Resources

MISO proposes modifying Section 69A.4.4 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" when describing how capacity will be determined for a qualified EE Resource by the Transmission Provider.

36. Section 69A.4.5 – Attributes of ZRCs

MISO proposes modifying Section 69A.4.5 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" throughout that section and by removing language related to the calculation of the convertible Unforced Capacity. MISO proposes further modifying Section 69A.4.5 of the Tariff to include language in Section 69A.4.5.A regarding the allocation of Seasonal Accredited Capacity and the calculation of Seasonal Accredited Capacity value.

37. Section 69A.5 – Capacity Resource Must Offer and Performance Requirements

MISO proposes modifying Section 69A.5 of the Tariff by replacing the phrase "Unforced Capacity" with "Seasonal Accredited Capacity" throughout the section, removing the word "TPRA" from the section, inserting language regarding a/any/each "Season" into the section to clarify that the Capacity Resource Must Offer and Performance Requirements relate to each Season in the Planning Year and not to the Planning Year as a whole.

MISO proposes further modifying Section 69A.5 of the Tariff by inserting language into Section 69A.5.a clarifying that Market Participants that convert Seasonal Accredited Capacity

from Capacity Resources into ZRCs that clear in a Season in the PRA or are used in a FRAP (and that do not replace such ZRCs in accordance with Section 69A.3.1.h), "including Capacity Resources that are the subject of Diversity Contracts," must submit Self-Schedules or Offers for Energy, and Contingency Reserve if qualified, and offers for Short-Term Reserve if qualify, for the Installed Capacity value of the Capacity Resources converted to ZRCS "and clear in a Season in the PRA or used in a FRAP" for each Hour of each Day during the applicable Season in the Planning Year, in the Day-Ahead Energy Market and all pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment process."

MISO proposes modifying Section 69A.5.a by adding the sentence "[a]ny such Capacity Resource with full or partial Generator Planned Outages that exceeds thirty-one (31) Days during any Season will be deemed not to have met its performance requirement for any days greater than thirty-one (31) days and must replace ZRCs in accordance with Section 69A.3.1.h, provided that Capacity Resources subject to Diversity Contracts that are unavailable for greater than one Month during any Season will be deemed not to have met its performance requirement and will be subject to the ZRC replacement provisions set forth in Section 69A.3.1.h."

MISO proposes modifying Section 69A.5.b by inserting language clarifying that "[i]f a Capacity Resource that has ZRCs cleared in the PRA during any Season or is used in a FRAP during any Season is capable of performing but fails to perform when called upon by the Transmission Provider for an Emergency, the Transmission Provider shall assess the owner of such Capacity Resource the costs that were otherwise incurred to replace the energy from the deficient Capacity Resource at the time that the Capacity Resource is called upon by the Transmission Provider and does not respond in full or in part, for each day of non-performance of such Capacity Resource, provided that the planned or forced outage of the Capacity Resource is not properly reported in the Transmission Provider's Outage Scheduler, as set forth in the Business Practices Manual for Outage Operations."

38. Section 69A.6.3 – Facilitation of a Bilateral Capacity Bulletin Board

MISO proposes modifying Section 69A.6.3 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" with respect to the Transmission Provider's electronic bulletin board platform that may be used by Market Participants.

39. Section 69A.7 – Planning Resource Auction

MISO proposes modifying Section 69A.7 of the Tariff by replacing "ten (10)" with "twenty (20)" with respect to the number of Business Days after the last Business Day in March when the Transmission Provider will conduct a RA to determine the ACP in each LRZ and ERZ.

40. Section 69A.7.1 – PRA Procedures

MISO proposes modifying Section 69A.7.1 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" throughout the section, removing "TPRA", clarifying that "[t]he price associated with these ZRC Offers cannot exceed the annual CONE value divided by the number of days in the Season for the LRZ where the ZRC is represented", inserting the sentence in Section 69A.7.1.x that "[t]he maximum Auction Clearing Price will be based on the annual CONE and the number of Seasons deficient in the Planning Resource Auction", replacing "tenth" Business Day in Section 69A.7.1.xi with "twentieth" Business Day, specifying in Section 69A.7.1.c.i that "[a]fter a maximum of two (2) successive iterations per Season to address network

violations, the auction clearing iteration with the fewest megawatts of network violations will be deemed as the final auction result", and adding language regarding "each Season" throughout.

MISO proposes modifying Section 69A.7.1.c.x by inserting language clarifying that "[t]he final Auction Clearing Price (ACP) for a LRZ, group of LRZs, or SRRZ with Seasons in ZRC Shortage Conditions will be set as the amount obtained by dividing the applicable LRZ's annual CONE value by the number of days in Seasons which the LRZ, group of LRZs, or a SRRZ were in ZRC Shortage Conditions and Near ZRC Shortage Conditions in the Planning Resource Auction. The final Auction Clearing Price (ACP) for a LRZ, group of LRZs, or SRRZ with Seasons in Near ZRC Shortage Conditions will be set as the minimum of: (a) the original ACP as determined in section 69A.7.1.c.(v) or section 69A.7.1.c.(vi) as applicable; or (b) the amount obtained by dividing the applicable LRZ's annual CONE value by the number of days in Seasons which the LRZ, group of LRZs, or SRRZ were in ZRC Shortage Conditions and Near ZRC Shortage Conditions in the Planning Resource Auction."

41. Section 69A.7.3 – Uncleared ZRCs

MISO proposes modifying Section 69A.7.3 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" and removing "TPRA."

42. Section 69A.7.6 – PRA Settlement

MISO proposes modifying Section 69A.7.6 of the Tariff by inserting language into Section 69A.7.6.a to clarify that "[t]he reduced compensation will be based on the total number of days the capacity from the Diversity Contract is dedicated to demand in the Transmission Provider Region in each Season divided by the total number of days in the Season."

MISO proposes adding Section 69A.7.6.d specifying that "[f]or instances where a LRZ, group of LRZs, or SRRZ clears under ZRC Shortage Conditions or ZRC Near-Shortage Conditions in more than one Season in a Planning Resource Auction and final ACPs are adjusted per Section 69A.7.1.c.(x), certain cleared ZRC Offers may exceed the final ACPS" and clarifying the circumstances under which certain ZRCs may be eligible for a ZRC Offer Revenue Sufficiency Credit and how that credit would be calculated and allocated.

MISO proposes adding Section 69A.7.6.e specifying that ZRC Offer Revenue Sufficiency Charges "will be assessed as the sum of all ZRC Offer Revenue Sufficiency Credits for a Season distributed to Market Participants representing LSEs in an LRZ, group of LRZs, or SRRZ clearing under ZRC Shortage Conditions or Near ZRC Shortage Conditions on a *pro rata* basis, based upon their respective LSE's share of total PRMR in the appropriate LRZ, group of LRZs, or SRRZ."

43. Section 69A.7.9 – Installed Capacity (ICAP) Deferral Requirements and Charges

MISO proposes modifying Section 69A.7.9 by inserting language to clarify that the ICAP Deferral Notice, ICAP Deferral Non-Compliance Charges, and Distribution of ICAP Deferral Non-Compliance Charges are based on the "Season" and not the "Planning Year."

44. Section 69A.9 – Opting out of the Planning Resource Auction

MISO proposes modifying Sections 69A.9.a of the Tariff by inserting language clarifying that an LSE electing to opt out of the PRA "for any Season" can continue to use its existing

resource planning processes to meet their PRMR by providing the Transmission Provider with a FRAP for each LRZ which must include the forecasted Coincident Peak Demand for "each Season" and must also identify its load ratio share for "each Season." MISO proposes modifying Sections 69A.9.b of the Tariff by inserting language clarifying and that an LSE that submits a FRAP for a LRZ will be able to opt out of the PRA for such "Season" for such LRZ to the extent that the LSE's ZRC's satisfy the LSE's PRMR "for the applicable Season(s)." MISO proposes to clarify the provisions relating to the Capacity Deficiency Charge by modifying Section 69A.9.c of the Tariff by removing the phrase "[a]n LSE that is capacity deficient will be assessed a Capacity Deficiency Charge in accordance with Section 69A.10."

45. Section 69A.10 – Capacity Deficiency Charge

MISO proposes modifying Section 69A.10 of the Tariff by inserting language clarifying that the Transmission Provider will impose a Capacity Deficiency Charge on an LSE that has "provided notification prior to the Planning Resource Auction that they will meet their PRMR in part or in whole for the Planning Year by paying the Capacity Deficiency Charge." MISO proposes modifying further language clarifying that "[t]he CONE value for the LRZ(s) where the LSE has provided notice it will be meeting its PRMR by paying the Capacity Deficiency Charge for the Planning Year will be multiplied by 2.748 times the PRMR volume indicated by the LSE for Planning Year."

MISO proposes modifying Section 69A.10.b to clarify that the distribution of Capacity Deficiency Charge revenues will not be distributed to any Market Participant representing an LSE that has provided notice it will be meeting its PRMR by paying the Capacity Deficiency Charge, and specifying details of the distribution calculation.

I. Schedule 53 – Seasonal Accredited Capacity Calculation

1. Section I – General

MISO proposes creating Schedule 53 Section I of the Tariff by inserting language specifying that "Seasonal Accredited Capacity (SAC) for a Capacity Resource that is a DRR or Generation Resource but not a Dispatchable Intermittent Resource, Intermittent Generation Electric Storage Resource, or Use Limited Resource will be determined pursuant to this Schedule 53." MISO proposes inserting language into Section I clarifying that "[a] two-tiered weighting structure is used to calculate Seasonal Accredited Capacity for such Resource".

2. Section II – Tier 1 and Tier 2 Planned Outage Exemptions Requirements

MISO proposes creating Schedule 53 Section II of the Tariff by adding Section II.A-B to specify the requirements for Tier I and Tier 2 outage exemptions for Generator Planned Outages after September 1, 2022. The language in Section II.A specifies the Tier 2 Planned Outage exemption requirements. The language in Section II.B specifies the Tier 1 Planned Outage exemption requirements. MISO further proposes that "Generator Planned Outages scheduled to begin before September 1, 2022 will be granted a Tier 2 exemption based on Section 38.2.5.g.ix., and as set forth in the Business Practices Manual for Resource Adequacy."

Section II.C will contain language specifying that under the No Harm Test "[o]utages submitted between 14 to 30 days of start date will be evaluated for final approval and exemption status together. The No Harm Test includes, but is not limited to, outage approval, compliance

with all applicable operation guides, review of possible conflicting outages or system conditions, and system capacity (Maintenance Margin, Multiday Operational Margin, 30-day margin). It also includes the criteria outlined in the Business Practices Manual for Generator Outage."

3. Section III – Resource Adequacy Hours

MISO proposes creating Schedule 53 Section III of the Tariff by inserting language specifying that "Resource Adequacy (RA) Hours represent the periods of highest risk and greatest need during a Season and throughout the year. They include hours during Maximum Generation Emergency declarations and the hours when the operating margin, a measure of available supply capacity above demand and reserve requirements, is at its lowest." "Resource Adequacy Hours will be identified based on an evaluation of the three (3) most recent completed years using the period September 1st and ending August 31st which will be used to determine Resource Adequacy Hours for each Season (Seasonal RA Hours) and for each annual period (Annual RA Hours)."

MISO proposes inserting language into Section III.A describing how Seasonal RA Hours will be determined, inserting language into Section III.B describing how Annual RA Hours will be determined, and inserting language into Section III.C describing how Seasonal Non-RA Hours will be determined. MISO proposes inserting language into Section III.D specifying that Tier 1 exemptions apply only to Non-RA Hours whereas Tier 2 exemptions apply to any Hours referenced in Schedule 53 and that Tier 1 and Tier 2 outage exemption requirements are set forth in Section II of Schedule 53.

4. Section IV – Operating Margin Calculation

MISO proposes creating Schedule 53 Section IV of the Tariff by inserting language specifying that "[t]he Operating Margin is determined using historical information to identify Seasonal RA Hours and Annual RA Hours within the three (3) most recent periods beginning September 1st and ending August 31st." MISO proposes inserting language into Section IV defining the equation used to calculate Operating Margin.

5. Section V –Seasonal Accredited Capacity Calculation

MISO proposes creating Schedule 53 Section V of the Tariff by inserting language into Section V.A-C specifying that Annual Average Offered Capacity, Tier 1 Intermediate SAC (ISAC), and Tier 2 ISAC will all be calculated in part utilizing either the Hourly Emergency Maximum Limit or the Targeted Demand Reduction Level for DRR-1. The proposed language specifies that for any Annual RA Hour or Seasonal RA Hour where a Resource is offline and the sum of the Start-Up Time and Start-Up Notification Time Offers exceeds 24 hours, the Resource "will have its Hourly Emergency Maximum Limit, or Targeted Demand Reduction Level for DRR-1, set to zero (0)."

MISO proposes inserting language into Section V.D specifying that "the Hourly Emergency Maximum Limit, or Targeted Demand Reduction Level for DDR-1, will be capped at the currently effective GVTC value of the Resource and whether or not a Resource was only committed for a portion of its ICAP due to partial clearing will not impact the offers considered in the accreditation calculations.

MISO proposes inserting language into Section V.E specifying that "the historical values for Hourly Emergency Maximum Limit, or Targeted Demand Reduction Level for DDR-1, will

be increased for those hours prior to the upgrade going into effect to account for the upgrade as set forth in the Business Practices Manual for Resource Adequacy."

MISO proposes inserting language into Section V.F specifying that "RA Hours will receive a greater weight than non-RA hours", inserting language into Section V.G defining the equation used to calculate ISAC, inserting language into Section V.H defining the equation used to calculate "[a] system-wide conversion ratio", and inserting language into Section V.I defining the equation used to calculate SAC.

6. Section VI – New Resources or Resources with Insufficient Performance Data

MISO proposes creating Schedule 53 Section VI of the Tariff by inserting language into specifying that "New Resources or existing Resources that do not have at least 60 days of Real-Time offered availability when designated for RAR over the last three (3) years for each Season (Summer, Fall, Winter, Spring) will have a SAC based on the Class Average SAC to ICAP Ratio for its Resource type." MISO proposes inserting language specifying that "Resources on a Catastrophic Generator Outage during a Season they are designated for RAR may elect to use a SAC based on the Class Average SAC or ICAP Ratio for its Resource type the next time it is accredited for that Season provided all of its committed ZRCs were replaced with uncleared ZRCs and that it has successfully returned from the Catastrophic Generator Outage."

VII. RESPONSE TO KEY STAKEHOLDER ISSUES

As described above, MISO has engaged in substantial stakeholder discussions relating to the development of the Resource Adequacy enhancements proposed in this filing. As part of those discussions, stakeholders have raised various issues that have been documented, vetted and, as appropriate, incorporated in this filing. MISO also has determined that a number of stakeholder suggested modifications are either outside the scope of this filing and/or should be addressed through alternative means. Following is a list of key issues raised by stakeholders and MISO's responses. It should be noted that this list is not exhaustive, but MISO believes represents the major issues presented.

- *Implementation of seasonal reforms only* – Stakeholders have requested that MISO implement only the proposed PRA seasonal reforms separate from the proposed accreditation reforms. Moreover, stakeholders have requested that MISO delay filing and implementation of any accreditation changes to allow the opportunity for additional discussions.

As discussed with stakeholders during the RASC presentation on June 9, 2020, in order to meet future reliability risks, there needs to be an alignment between Resource Adequacy Requirements and Resource accreditation. To adjust requirements on a seasonal basis without making corresponding adjustments to a resource's seasonal accreditation could potentially create more risk for the MISO system. As further described in the Testimony of Mr. Wright, by transitioning to a seasonal construct only, requirements may decrease and true availability of resources may be overstated and adversely impact system reliability.[124] Since 2016, over 60% of

[124] Wright at 2-3.

MaxGen events have occurred outside of the Summer. Creating a scenario where requirements are lower when considered on a seasonal basis and resource accreditation continues to be based on the current method with only muted and weak linkages to actual resource availability during times of highest need could exacerbate the risk of capacity shortfalls. Further, the proposed seasonal construct facilitates stakeholder preferences for increased seasonal outages, possibly lowering excess reserve margins. In light of this, MISO must have higher confidence in the availability of the resources that do clear for any given Season, as accomplished through the proposed improvements to accreditation and outage coordination processes.

Furthermore, as detailed in the Testimonies of Messrs. Wright, McFarlane, and Smith, the proposed seasonal and accreditation changes are urgently required at this time in response the Reliability Imperative. MISO cannot afford to wait any longer to implement this integrated package of changes needed to enhance its Resource Adequacy construct and to help ensure reliability in the MISO Region.

- *Determination of Resource Adequacy Hours* – Stakeholders have argued that MISO has not adequately justified the proposed use of 65 RA Hours per Season (which, as described above, is based upon 3% of the hours during each Season). In addition, stakeholders have objected to the manner in which MISO proposes to "backfill" seasonal RA Hours with AAOC hours.

As described above, RA Hours represent the periods of highest risk and greatest need during a Season and throughout the year. They include emergency declaration periods and the hours when the operating margin, a measure of available supply capacity above demand and reserve requirements, is at its lowest. MISO's analysis indicates that the tightest 3 percent of hours align with emergency event occurrence is reasonable. Further, MISO examined the operating margins during the times of highest risk, which also informed the selection of 3 percent.

As proposed, RA Hours will be determined seasonally, based on emergency events, the tightest 3 percent of operating margin hours, and a maximum operating margin threshold established at 25 percent. RA Hours will be used to determine each resource availability for calculating its seasonal accreditation. To ensure that MISO includes all appropriate RA Hours, the total number of RA Hours in a Season can exceed the minimum target (*i.e.,* 65 hours) when a higher number of hours during declared system or sub-regional emergencies occurs. Moreover, in some Seasons (or for resources with Tier 2 planned outage exemptions for seasonal RA Hours) there may not be 65 hours during the Season to use for the Schedule 53 calculations. The proposal strikes a balance between identifying RA Hours that represent the times of high risk and having sufficient RA Hour sample sizes to avoid undue volatility. MISO's proposal supplements the seasonal RA Hours for a resource with the average offers over the tightest operating conditions during the same Planning Year where it was not on an exempt outage.

For any Season that a resource lacks sufficient hours, set at 65 hours minimum, the accreditation will augment the deficient number of hours less than 65 for that Resource with its AAOC, which is determined over the tightest 3 percent of hours during the year, or 263 hours. Certain stakeholders have expressed concern that the availability of a resource in one Season may not accurately represent the availability of that resource during a different Season. MISO believes

that the use of RA Hour availability during the other tight margin hours in the Planning Year is a reasonable substitute in the determination of accreditation as it reflects actual resource availability during tight conditions throughout the year. Some stakeholders suggested using all-hours availability during the Season to "backfill" RA Hours would be more appropriate. However, MISO believes this approach would inappropriately dilute assessments of a Resource's availability during tight conditions because it effectively substitutes the resource's availability during non-tight conditions.

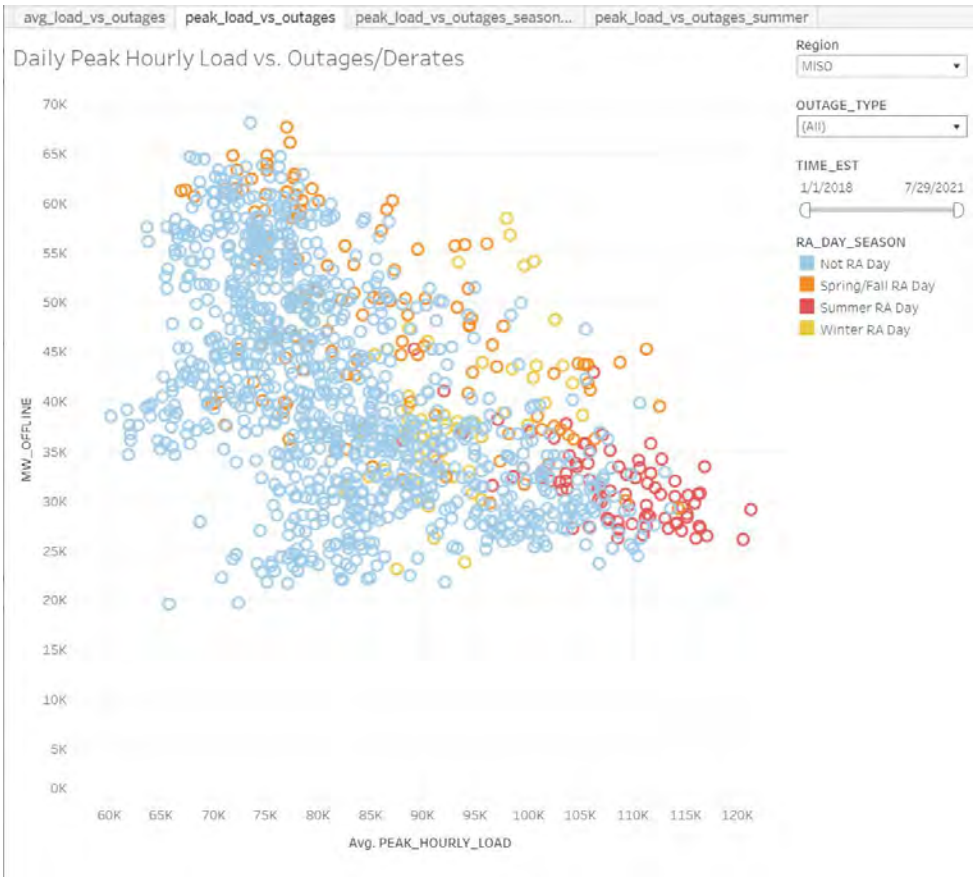
- *Schedule 53 Tier weighting and volatility of requirements* – Stakeholders have asked for further support regarding the basis for the proposed 20/80 weighting of Tier 1 vs. Tier 2 hours in Schedule 53. Stakeholders also requested that MISO phase in the proposed Tier 1 vs. Tier 2 weighting over a period of time in order to provide stakeholders the opportunity to adjust their planning and operations. In addition, stakeholders have raised concerns about the potential volatility of the proposed changes as they may impact Resource accreditation year over year.

The initial Resource accreditation proposal shared with Stakeholders in January of 2021 essentially weighted RA Hours (*i.e.,* Tier 2 hours) at 100% towards a Resource's offered availability. This solely emphasized the importance of resource availability during the tightest operating conditions. In a recent State of the Market Report, MISO's IMM recommended a similar approach to align a resource's auction value with its true contribution to reliability.[125] Seasonal requirements also necessitate accreditation align with actual expectations during times of highest risk during each Season. In response to the initial proposal, stakeholders requested a method that also recognized a resource's reliability contribution during non-RA Hours, basing some portion of accreditation on general availability.

MISO recognizes the value of general availability, however, as the IMM's analysis of the current UCAP method illustrates, it does not adequately reflect availability during times of highest risk and the true reliability value. As a result, MISO responded by developing the two-tier accreditation proposal, which sets the Tier 1 (*i.e,* non-RA Hours) weighting to 20%, acknowledging a Resource's general availability and its contribution to avoiding capacity emergency events. Importantly, however, MISO sets the Tier 2 (RA Hour) weighting at 80% to emphasize Resource reliability contribution during times of greatest reliability needs. The data plot below illustrates how RA Hours occur on days with high peak load, high outage rates or a combination of both, and supports the rationale for the heavier weighting of Tier 2 hours in resource accreditation.

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125 *See* fn. 40 *supra*.



To address stakeholder requests to phase in the proposed Schedule 53-tiered weighting, MISO has adopted a three-year phased in approach proposed by stakeholders. Beginning in PY 2023/2024, the Tier 1/Tier 2 weighting will be 40/60, increasing to 30/70 in PY 2024/2025, and ending up with the full adoption of the 20/80 weighting in PY 2025/2026. Adopting this transition will generally lessen the impact of these accreditation changes in the near-term while providing more time for stakeholders to adjust planning and operations before the entire weighting takes effect.

With respect to stakeholder concerns regarding volatility, analysis of Market Participant level, zonal and MISO-wide results indicate reasonably low levels of volatility and appropriate relative accreditation based on resource performance during times of need.[126] The key principle of the proposed accreditation is to determine the relative accredited values among different resources to align with their actual performance during times of needs while maintaining the overall supply and demand balance at the footprint level. By design, more resource level volatility with the proposed accreditation methodology would be expected, but in aggregate the proposal leads to very little volatility at the MISO Region-wide level from year to year, especially over time. As

126 *See* Resource Adequacy Reforms, MISO RASC (September 2021) at 6.

presented at the September RASC meeting, the proposal leads to, less than 2% volatility at MISO Region-wide level, in part as a result of the application of the UCAP to SAC ratio.[127]

- *Generator Planned Outage exemptions* – Stakeholders have argued that MISO's proposal does not offer sufficient flexibility to permit Generator Planned Outages without exposing them to potential accreditation impacts.

In its initial proposal, MISO was outage agnostic, choosing to base availability solely on availability during RA Hours with no exemption for effective coordination regarding Generator Planned Outages. This also aligned with IMM State of the Market recommendations regarding availability-based accreditation, discussed above. Stakeholders requested that MISO consider enhancements to the RAN Phase 1 outage exemption process for incorporation in the proposal, as those processes involved significant stakeholder engagement in the past and have provided reliability benefits. MISO agreed with the stakeholder suggestion, noting improved outage coordination was one of the goals of these reforms. However, MISO also cautioned that any exemptions must be strongly aligned with effective coordination processes to ensure reliable outcomes and incent coordination. If all planned outages receive exemptions, resources will not be deterred from scheduling outages during the tightest operating conditions.

Ultimately, in response to stakeholder feedback, MISO built upon the RAN Phase 1 outage process when developing its proposal to exempt certain outages under the revised accreditation proposal. As set forth in Schedule 53, the exemption rules specifically consider whether an outage is submitted 120 days or more in advance, whether there is a positive Maintenance Margin for the duration of the outage, and whether the outage is scheduled to start less than 120 days from the end of a previous outage. MISO believes the proposed exemption rules reasonably accommodate the needs of stakeholders to take appropriate planned outages with the need for MISO to ensure that resources will be available during times of greatest risk. Moreover, the proposed rules appropriately reflect a resource's unavailability in its accredited value, whether such unavailability is a result of planned, forced or maintenance outages that put the system at increased risk.

- *Capacity replacement requirement* – Stakeholders have suggested that the capacity replacement requirement, and associated Capacity Replacement Non-Compliance Charge, impose unfair obligations. Some stakeholders specifically object to the requirement that they replace resources that are unavailable for more than 31 days, and that MISO is imposing a charge for failure to replace.

MISO believes the proposed replacement requirements are reasonable to ensure that resources that clear for a Season will be available to contribute to reliability when committed. As MISO shifts from an annual to a seasonal construct, it is reasonable to require replacement of resources that are unavailable more than 31 days out of an approximately 91-day Season as a result of Generator Planned Outages. The proposed replacement requirement also is consistent with the existing Tariff requirement that resources that are not available for 90 out of the 120 days preceding the PRA are not eligible to participate in the PRA for that Planning Year.

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127 *Id.*

Moreover, a resource contemplating a Generator Planned Outage in excess of 31 days can request approval from the IMM prior to the PRA for exclusion from physical withholding market mitigation measures, and if approved, not offer the resource into the PRA. If such a request is approved, the IMM has indicated a resource could still offer at its discretion and would be able to offer the excluded portion of the resource at any price up to the offer cap without the need to obtain a facility specific Reference Level. MISO has added the IMM's recommended provisions in section 64.1.1.g.xi of Module D.

The Capacity Replacement Non-Compliance Charge ensures that Market Participants whose resources clear the PRA for a Season are sufficiently available for a majority of the Season to contribute to reliability. Currently, there is no specified financial non-compliance provisions for failure to replace a resource that clears the PRA and subsequently retires or suspends. Increased flexibility for Market Participants to choose whether to participate in a Season requires financial consequences for the failure to replace unavailable units. The proposed Capacity Replacement Non-Compliance Charge reasonably addresses this need. In addition, the proposal generally indicates lower requirements for non-Summer Seasons compared to today's construct. Accordingly, it is reasonable to impose a financial non-compliance charge to incent availability of sufficient resources to meet the lower requirements. As noted above, MISO is also adding provisions allowing the replacement of resources that have experienced catastrophic outages, enabling such resources to maintain class average accreditation upon return to service.

- *Need for additional analysis* – Stakeholders have argued that MISO has not provided sufficiently detailed analysis for them to determine the impact of the proposed changes on their specific resources.

Contrary to some stakeholder assertions, MISO has provided stakeholders many elements of required analysis, including: seasonal SAC values and requirements at the portfolio level (highlighting the changes relative to their current requirements); unit-level SAC values on a seasonal basis; and, extensive and detailed data for at least one individual resource, for each stakeholder requesting such data, including all the inputs and calculations necessary to allow stakeholders to independently validate how MISO derived the SAC values for that resource. This information was provided more than once for those stakeholders requesting this data over the course of the conceptual design.

MISO also provided preliminary and revised impact analysis results at the system-wide and zonal levels at multiple RASC stakeholder meetings over the course of the RA construct conceptual design. In addition, MISO:

- Provided preliminary and revised historical RA Hours including MaxGen hours, and hourly operating margins for the past four Planning Years at multiple RASC stakeholder meetings; and

- Posted and walked through a step-by-step resource accreditation calculation example worksheet at a RAN workshop and provided a revised example calculation worksheet to reflect the refined proposal; and

- Provided preliminary and revised Resource accreditation SAC values for all resources within each Market Participant portfolio, Market Participant level surplus/shortfall, and at least one CP node with detailed raw information for SAC calculation to illustrate how SAC is calculated; and

- Engaged in one-on-one meetings with Market Participants, upon request, to walk through detailed SAC calculations of their fleet and address any discrepancies or questions.

MISO appreciates that replicating MISO's calculation is important to stakeholders to gain a better understanding of the potential impacts of the proposed changes. To this end, MISO will continue engaging with stakeholders prior to implementation of the proposed changes to provide additional transparency on new accreditation values. For example, MISO has already provided a workshop for stakeholders to solicit their ideas for Module E Capacity Tracking Tool improvements. MISO will have additional workshops in 2022 to further help prepare stakeholders.

- *Transition periods and deferral of reforms* – Stakeholders have requested that MISO phase in various aspects of its proposal to allow more time to adjust to the changes. In addition, stakeholders have requested that MISO delay implementation of the proposal overall for at least another year, and in some cases, significantly longer.

As MISO responds to the Reliability Imperative, the need to transition to a new Resource Adequacy construct requires adoption sooner rather than later. This need has been detailed extensively in the Testimonies of Messrs. Wright, McFarlane, and Smith.

With respect to a transition period, MISO has proposed a number of changes in response to stakeholder requests. First, MISO has adopted the Schedule 53 tiered weighting transition described above. In addition, MISO has proposed a transition period with respect to the implementation of the planned outage provisions established in Schedule 53. Specifically, this transition recognizes planned outages coordinated through the existing processes, with the new proposal being phased over three years.

- *Number of changes* – A number of stakeholders have expressed concern about the number of changes MISO has made to its proposal since extending stakeholders discussions over the last few months.

MISO acknowledges that it has made refinements to its proposal during this period of time. These changes have largely been in response to stakeholder feedback, IMM collaboration, and other improvements identified by MISO to ensure the completeness of the proposal.

VIII. DOCUMENTS SUBMITTED WITH THIS FILING

In addition to this Transmittal Letter, this submission includes:

- Tab A – Redline Tariff[128]
- Tab B – Clean Tariff
- Tab C – Testimony of Shawn McFarlane
- Tab D – Testimony of Jameson Smith
- Tab E – Testimony of Scott Wright

IX. PROPOSED EFFECTIVE DATE

MISO requests an effective date of September 1, 2022 for the Tariff revisions submitted herein. MISO recognizes that this date is beyond 120-days from the date of this filing and therefore requests waiver of Section 35.3(a) of the Commission's regulations to permit this effective date.

As discussed above, MISO also requests that FERC issue an order accepting the proposed Tariff revisions within 120 days from the date of this filing. MISO's request for Commission action on this filing within 120 days from the date of filing is intended to provide regulatory certainty to both stakeholders and MISO with respect to the Tariff provisions applicable to the 2023 / 2024 Planning Year well in advance of the Planning Resource Auction that will be held in the Spring of 2023. Prior to the 2023 / 2024 Planning Year auction, MISO will be working to both enhance the software used in administering the Resource Adequacy Requirements and PRA as well as training stakeholders on how they will demonstrate and monitor their compliance through the tool enhancements.

MISO commits to making a subsequent Section 205 filing with the Commission to update the Tariff sheets to reflect the most up-to-date versions of the then-current Tariff provisions. The update filing will be submitted at least 60 days prior to the proposed effective date of the Tariff provisions as discussed above.

In addition, MISO requests waiver of any requirements of 18 C.F.R. Part 35 the Commission deems applicable to this filing to the extent that the specific requirement is not addressed herein.

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[128] MISO has revised metadata of several sections to change the Tariff Record Titles. MISO's eTariff software does not redline changes to the metadata associated with its Tariff Records, thus no redlines will be shown in the Tariff Record Title.

X. COMMUNICATIONS

MISO respectfully requests waiver of Rule 203(b)(3) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.203(b)(3) (2019), to the extent necessary to permit the designation of more than two persons for service on behalf of MISO in this proceeding and requests all communications related to this filing be directed to:

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XI. NOTICE AND SERVICE

MISO has served a copy of this filing electronically, including attachments, upon all Tariff Customers, MISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, as well as all state commissions within the region. The filing has been posted electronically on MISO's website currently at https://www.misoenergy.org/legal/ferc-filings/ for other parties interested in this matter.

XII. CONCLUSION

For all of the foregoing reasons, MISO respectfully requests that the Commission accept these proposed revisions for filing, grant the proposed effective date, and grant waiver of any Commission regulation the Commission deems applicable to this filing in order for the Commission to accept it as proposed.

Respectfully submitted,

/s/ Michael Kessler

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Attachments

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 78

McFarlane Testimony

Tab C

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PREPARED DIRECT TESTIMONY OF SHAWN MCFARLANE

I. PROFESSIONAL BACKGROUND AND QUALIFICATIONS

Q. Please state your name, business address, and position with your employer.

A. My name is Shawn F. McFarlane. I am employed by the Midcontinent Independent System Operator, Inc. ("MISO"), which is located at 720 City Center Drive, Carmel, Indiana, 46032. My current position is Executive Director of Market Operations, which I have held since October 2015. During that time, I have had executive oversight of various functions under MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff"), including Resource Adequacy, Day-Ahead Energy and Operating Reserve Market, Auction Revenue Rights and Financial Transmission Rights markets, as well as the Forward Reliability Assessment Commitment, and Market and Transmission Settlements. I joined MISO in April of 2014 and served as Executive Director of Strategy through September 2015.

Q. Please briefly describe your educational and professional background before you joined MISO.

A. I hold a Bachelor of Science Degree in Petroleum Engineering at Pennsylvania State University and an MBA in Finance from Rutgers University. Prior to joining MISO, I was employed at Reliant Energy and successor companies from 1998-2013 as a Director and then as Vice President in various roles in Business Development, Commercial Analytics, and Wholesale Strategy in the merchant generation, energy trading, and retail energy marketing businesses. Prior to joining Reliant Energy, I was an Engagement Manager at a management consulting firm, McKinsey & Company, in their energy consultancy group from 1996-1998; in various finance

roles at Texaco, Inc. from 1990-1996; and, as a petroleum engineer in Southern California Gas Company's natural gas storage unit from 1985-1988.

Q. Please describe your job responsibilities as they relate to this filing.

A. As MISO's Executive Director of Market Operations, I have executive oversight of Resource Adequacy, including administration of MISO's Planning Resource Auction, within which accreditation of resources is a key parameter to better ensure that the Planning Reserve Margin Requirement and Planning Resource volumes are appropriately accurate to better ensure that resources are available to satisfy needs in real time. Additionally, accurate accreditation enables that cleared resources in the Planning Resource Auction are priced appropriately, based on their expected availability.

II. PURPOSE OF TESTIMONY AND RAN PROGRAM OVERVIEW

Q. What is the purpose of your testimony?

A. My testimony supports MISO's filing in this docket and provides operational and implementation detail associated with MISO's proposal.

III. SEASONAL RESOURCE ADEQUACY CONSTRUCT

Q. How does MISO propose to meet the challenges of the Reliability Imperative in this filing?

A. As discussed in Mr. Wright's Testimony, the Reliability Imperative is the term MISO uses to describe the shared responsibility of MISO, Load Serving Entities, and Relevant Electric Retail Regulatory Authorities to address the challenges that rapid fleet change, increased frequency and severity of extreme weather events, and other factors are posing to the reliability of the MISO Region. As part of

MISO's Market Redefinition efforts in response to the Reliability Imperative, MISO proposes Resource Adequacy enhancements in two primary areas: (1) establishing seasonal Resource Adequacy Requirements ("RAR); and (2) improving availability-based accreditation. These enhancements are designed to verify sufficient generation adequacy within each Season of the year and to provide the right incentives for resources to maintain system reliability. MISO will be submitting a separate, but related, Minimum Capacity Obligation proposal in another filing concurrent with this filing.

Q. Please describe MISO's current Resource Adequacy (RA) Construct.

A. In accordance with MISO's Resource Adequacy Tariff provisions contained in Module E-1, Market Participants representing Load Serving Entities ("LSEs") are expected to procure sufficient resources to meet their forecast coincident peak load, plus a reserve margin, for the upcoming Planning Year. A detailed description of the provisions of MISO's existing RAR, including the specific requirements established in Module E-1 of the Tariff, is included in the Testimony of Mr. Scott Wright.

Q. Why is MISO proposing to move to a seasonal RA construct with accreditation based on availability during times of need?

A. MISO is proposing to move to a seasonal RA construct so that it can better manage reliability risks brought about by the key trends impacting resource availability identified in 2018 as part of MISO's Resource Availability and Need

("RAN") initiative.[1] As described in the Testimony of Mr. Scott Wright, MISO now faces a Reliability Imperative. As part of its response with respect to Resource Adequacy, MISO is focused on addressing the following: (1) Improving outage scheduling and expectations; (2) Linking resource accreditation and requirements with initial focus on Load Modifying Resources ("LMRs"); (3) Aligning Planning Resource Auction ("PRA") commitments with energy needs all year; and (4) Ensuring flexible resource availability to address changing fleet characteristics. The proposed Tariff enhancements presented in this filing are necessary to further address the Reliability Imperative. Moreover, the urgency of implementing the proposed Tariff enhancements is evidenced by the increased incidence of capacity emergency maximum generation alerts, warnings, and events (collectively referred to as "MaxGens"),[2] particularly in the Seasons outside of Summer as demonstrated in the chart below. The reasons for and impacts of these changes are described in more detail in the Testimonies of Mr.

[1] *See* https://cdn.misoenergy.org/20180405%20RSC%20Item%2007%20RAN%20Issues%20Statement%20White%20Paper164746.pdf

[2] *See* https://cdn.misoenergy.org/SO-P-EOP-00-002%20Rev%2012%20MISO%20Market%20Capacity%20Emergency554411.pdf

Scott Wright and Mr. Jameson Smith supporting this filing.

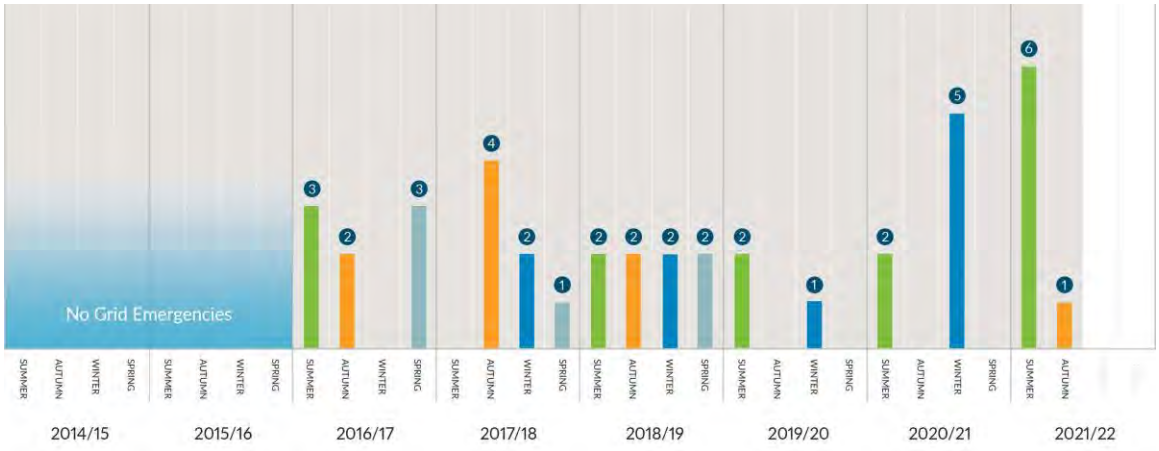


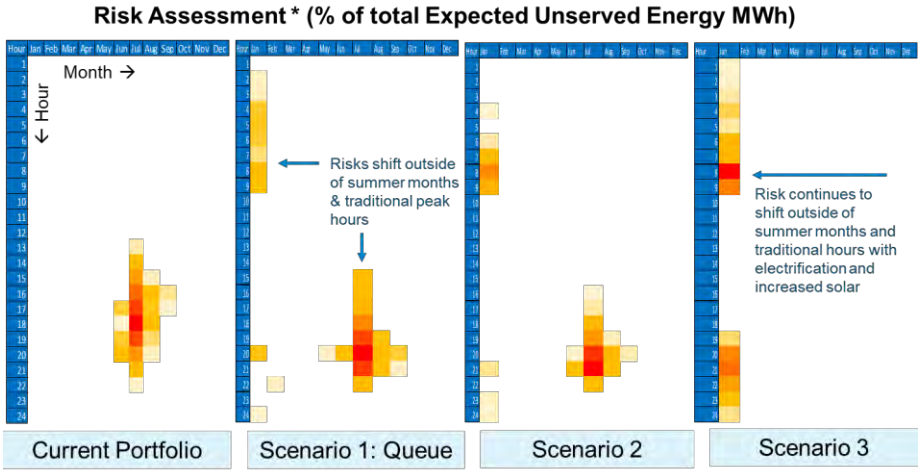
Chart indicates the number of days under a max gen alert, warning or event.

Q. How will reliability risks change as MISO's resource portfolio continues to evolve?

A. In addition to the increasing number of non-Summer MaxGens that MISO has experienced in the past several years, Loss of Load risks are projected to continue shifting outside of Summer and traditional peak hours. This is expected to be the case under a broad range of plausible future resource portfolio scenarios that MISO has developed and analyzed, as illustrated in the Figure below. Scenario 1 represents a 2025 resource mix outlook based on current MISO Generator Interconnection Queue and OMS-MISO survey projected retirements. Scenario 2 models a continuation of current trends and largely represents MISO member resource plans and provides a 2030 resource mix as defined in MISO Future 1.[3] Scenario 3 represents a 2035 resource mix outlook with accelerated existing fleet

[3] *See* https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf

retirements and adoption of renewables and electrification as defined in MISO Future 3.[4]



Q. How will a seasonal RA construct address the concerns identified by MISO?

A. Moving to a seasonal RA construct will align seasonal resource accreditation with seasonal resource availability to meet the changing risk profile that is emerging and is expected to increase dramatically in the near future. The proposed change to a seasonal Resource Adequacy construct is expected to mitigate risks to reliability within the MISO footprint by promoting Availability, Visibility, and Flexibility, which are "Key Needs" MISO outlined in the 2019 and 2020 MISO Forward Reports.[5] For Availability, a seasonal RA construct enables a more accurate representation of resource capability at different times during the year, improves certainty of resource availability outside the Summer Season, and better incentivizes resources to be available when needed. For Visibility, a seasonal RA

[4] *Id.*

[5] https://www.misoenergy.org/about/miso-strategy-and-value-proposition/MISO_Strategy/strategy-papers/#nt=%2Fstrategypapertype%3AMISO%20FORWARD&t=10&p=0&s=strategypaperpublisheddate&sd=desc

construct establishes seasonal reserve requirements, both system-wide and in LRZs, that better align with risks and deliver additional visibility into the risks throughout the year, which are not currently captured in the annual RA construct. There are also indirect improvements to the flexibility of resources that operators may not have had previously. These resources may improve their characteristics to be able to take shorter outages or need less time to respond. Additionally, consideration of unit lead time for offline units for the purposes of accreditation is a part of the proposal. At implementation, the flexibility required for accreditation purposes is a lead time that does not exceed 24 hours allowing the resource to be committed the day ahead in MISO's existing commitment processes. Finally, these reforms considered together provide the ability for resource owners to commit resources only when they are needed and expands opportunities for resources to participate in the PRA, suspend, or retire.

Q. What changes are necessary to implement the proposed RA construct?

A. Changes include developing seasonal values for a number of construct parameters: MISO's Loss of Load Expectation ("LOLE"); Planning Reserve Margin Requirements ("PRMR"); Local Reliability Requirements ("LRR"); Local Clearing Requirements ("LCR"); Capacity Import Limits ("CIL"); and Capacity Export Limits ("CEL"). In addition, the changes will require accrediting resources by Season based on their availability during times of need.

Q. How does MISO define the various Seasons for its proposed seasonal RA construct?

A. The seasonal RA construct will follow the definition of Season as defined in Module A of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff"): Winter (December, January, February); Spring (March, April, May); Summer (June, July, August); and Fall (September, October, November). This definition of Season is used in various MISO processes, including Financial Transmission Rights and seasonal resource assessments.

Q. Why does MISO need to update its LOLE modeling and methodology to implement a Seasonal RA construct?

A. The modeling and methodology of the LOLE study needs to change to model seasonally sensitive variables and calculate the construct parameters outlined above more accurately. This can be achieved through: (1) improving sub-annual LOLE modeling, including the modeling of planned outages, modeling of non-firm external support, and hourly modeling of intermittent resources; and (2) seasonal LOLE risk targets and requirement calculations.

Q. What does seasonal forced and planned outage modeling entail?

A. Seasonal forced outage rates based on historic North American Electric Reliability Corporation's ("NERC") Generator Availability Data System ("GADS") data will be used in the LOLE analysis for all thermal units. Additionally, an adjustment will be applied within the model to account for increased forced outages during extreme cold weather events. When the temperature drops below a certain threshold in the model, the outage rates for

thermal resources will be increased to reflect the correlation between extreme weather and temperatures and forced outages that are observed in real-time, especially during the Winter Season. This correlation was developed based on five years of historical outage and weather data. Five-year average planned outage rates from GADS by Season, including the observed increases during extreme cold in the Winter Season, will be included in the seasonal modeling for all thermal resources. SERVM (the software used to conduct the LOLE study) will schedule planned outages using a flexible outage method. This outage modeling method requires a portion of the planned outages to be fixed and then optimally schedules the remaining outages to reflect the actual operational flexibility to do so and maintain reliability.

Q. What does the improvement of non-firm external support in the LOLE model entail?

A. Non-firm external support (*i.e.,* imports) will be modeled as a probabilistic distribution input in SERVM, an enhancement from current modeling practice that uses an annual fixed value. One of the benefits of being part of the Eastern Interconnection is the ability to import energy from neighboring regions as needed, subject to availability. Hourly historical non-firm imports during emergency pricing hours, for the period 2016 to 2019, calculated by subtracting firm import MWs from total import MWs, will be used to determine the probabilistic distribution of non-firm imports into the MISO Region as an input to the LOLE model. During the LOLE simulations, SERVM randomly draws from this distribution of non-firm imports, which is used to serve the hourly load. This

methodology is a better representation of non-firm imports when compared to the current annual approach (which assumes a static value) as it captures the variability observed in operations.

Q. Please describe the enhancements to the treatment of intermittent resources in the LOLE model.

A. Instead of modeling wind and solar resources as monthly fixed capacity values under current practice, wind and solar resources will be modeled as hourly profiles that correspond to each of the 30 load shapes within SERVM to better reflect the availability and variability of these resources across the year. Hourly wind profiles are developed for 30 historical weather years by normalizing historical hourly wind outputs for recent weather years from 2011 to 2019 and constructing synthetic hourly wind shapes for weather years from 1990 to 2010 based on temperature correlation.[6] Figures 4 to 13 in the MISO published sub-annual LOLE Modeling Methodology Document illustrate the close correlation between historical wind output and temperature/load.[7] MISO believes it is appropriate to use the correlation between wind and temperature to develop wind profiles to reasonably model the relationship of load to wind outputs and have a similar distribution of wind outputs as a function of the 1990-2010 load shapes as seen in the 2011-2019 shapes where actual historical wind outputs are available. Hourly solar profiles for 42 selected sites across the MISO Region are developed using the NREL National Solar Radiation Database Data Viewer from 1998 to

[6] *See* https://cdn.misoenergy.org/20201104 RASC Item 04a Astrape MISO Sub-annual LOLE Modelling Methodology Document489436.pdf

[7] *Id.* at 5 – 10.

2019 and processed through the System Advisor Model to generate fixed and tracking solar profiles. The hourly solar profiles for 1990 to 1997 weather years are then selected by using daily solar profiles from the day that most closely matched the peak temp out of all days (+/- 2 days) of the source day from 1998 to 2019.[8] Similar to wind profiles, using the correlation between solar outputs and temperature reasonably models the relationship between load and solar outputs and creates a similar distribution of solar output as a function of load for 1990 to 1997 as is seen in the 1998 to 2019 time frame.

Q. How will seasonal LOLE targets be determined and Resource Adequacy Requirements be calculated?

A. To determine seasonal Resource Adequacy reserve requirements, the LOLE model needs to have a defined LOLE target for each Season. MISO proposes to round LOLE targets up to a minimum of 0.01 day per year for any Season(s) with LOLE less than 0.01 day per year and maintain LOLE targets for the Seasons with LOLE greater than 0.01 day per year. MISO believes this approach is reasonable considering the practicality of solving the model to a reasonably small LOLE target to determine reserve requirements, as described further below. The following process will be utilized to determine the seasonal requirements via the LOLE analysis. First, an LOLE analysis for the Planning Year will be conducted to solve the model to an annual LOLE of 0.1day per year to determine the natural LOLE distribution, by either adding proxy combustion turbine units with typical size (160 MW) and class average Forced Outage Rate Demand

[8] *See* https://cdn.misoenergy.org/20201104 RASC Item 04a Astrape MISO Sub-annual LOLE Modelling Methodology Document489436.pdf

("EFORd") if the LOLE for the Planning Year is greater than 0.1 day per year or a perfect negative unit with zero forced outage rate if the LOLE for the Planning Year is less than 0.1 day per year, consistent with the approach under the current annual construct.[9] If the LOLE for a Season is equal or greater than 0.01 day per year, the reserve requirement for that Season will be calculated based on this LOLE analysis. If the LOLE for any Season is less than 0.01 day per year, an additional LOLE analysis will be performed to determine the reserve requirement for that Season by adding a perfect negative unit with zero forced outage rate to that Season until the LOLE in that Season reaches 0.01 day per year. In collaboration with stakeholders, the 0.01 day per year LOLE minimum target is chosen for each Season because it is a large enough target to allow the LOLE model to accurately solve to determine seasonal reserve requirements while keeping an annual LOLE largely close to 0.1 day per year. This method also ensures that requirements in Seasons where the LOLE is naturally greater than 0.01 day per year are not artificially inflated, which would result in increased cost to Market Participants.

Q. Please describe the seasonal Planning Reserve Margin and Planning Reserve Margin Requirements.

A. A Planning Reserve Margin ("PRM") (expressed as a percentage) will be determined for each of the four Seasons by performing an LOLE analysis with seasonal input assumptions. The LOLE model will be used to meet the seasonal LOLE targets by adjusting the capacity within the model up or down as needed,

[9] https://cdn.misoenergy.org/PY%202021%2022%20LOLE%20Study%20Report489442.pdf

as described above. The seasonal PRM values in terms of Unforced Capacity ("UCAP") will be calculated and expressed as a percentage of seasonal coincident peak demand. The PRM for each Season is multiplied by the 50/50 forecast of coincident peak load to determine the PRMR (in MWs) for that Season.

Q. Please describe the seasonal zonal Local Reliability Requirements and Local Clearing Requirements.

A. The zonal Local Reliability Requirements ("LRR") will be determined using the same two-step process as the PRM analysis. Each Zone will be treated as an isolated system, consistent with the existing LRR analysis methodology under the current annual PRA construct.[10] The seasonal LRR values will be calculated in terms of UCAP and expressed as a percentage of seasonal zonal Coincident Peak Demand once the model has been solved to the appropriate LOLE targets. The seasonal LRR values will be used to determine the seasonal LCR values by subtracting the seasonal Capacity Import Limits ("CIL") from the seasonal LRR.

Q. Please describe seasonal Capacity Import/Export Limits.

A. Consistent with the existing transfer limit analysis methodology defined in MISO's Resource Adequacy Business Practices Manual ("BPM"), BPM-011, seasonal transfer analyses will be performed to determine seasonal CILs and Capacity Export Limits ("CELs"), capturing the seasonal variation of transfer limits for each LRZ. Planning Year seasonal peak powerflow models and input files developed from MISO Transmission Expansion Plan ("MTEP") studies built for timeframes matching the effective periods of transfer limit analysis will be

[10] *See* https://cdn.misoenergy.org/PY%202021%2022%20LOLE%20Study%20Report489442.pdf

used to perform transfer analyses for each Season, including Summer Peak, Fall Peak, Winter Peak, and Spring Peak study models. Seasonal MTEP powerflow models will include both approved and planned transmission projects through the MTEP planning process with effective dates on or before the effective date of the study models. Single-element contingencies in MISO and its seams areas will be evaluated and all facilities under MISO functional control and all seams facilities of 100kV and higher will be monitored. First Contingency Incremental Transfer Capacity ("FCITC") analysis will be performed for each of the seasonal powerflow models to identify limiting constraints with a generation-to-generation transfer model. Additional Generation Limited Transfer and voltage limited transfer analyses may be performed on an as needed basis if certain scenarios occur as described in the BPM for Resource Adequacy. The resulting seasonal Zonal Import Ability ("ZIA"), in conjunction with controllable exports, will be used to subtract from the LRR to determine the seasonal LCR for each LRZ.

IV. RESOURCE ACCREDITATION OVERVIEW

Q. What is MISO's current approach to Resource Accreditation?

A. The current resource accreditation process, which for thermal resources is based on Unforced Capacity ("UCAP"), is determined using resource performance between September 1 and August 31 of the three years prior to the Planning Year. Market Participants submit GADS data to MISO on a quarterly basis. This data is utilized to determine Equivalent Forced Outage Rate Demand ("XEFORd"), excluding events outside of management control, which is then used as a component in the calculation of Unforced Capacity. The UCAP is calculated by

taking Installed Capacity ("ICAP"), which is the lesser of Generator Verification Test Capacity ("GVTC") and Total Interconnection Service, multiplied by one minus the XEFORd. UCAP values are communicated to Market Participants on December 15 prior to the Planning Resource Auction. The proposed rules will continue to utilize the same period to evaluate availability for determining Seasonal Accredited Capacity ("SAC").

Q. How does MISO propose to calculate Resource Accreditation going forward?

A. Resource accreditation should primarily reflect the anticipated capability and availability of Planning Resources during times when they are most needed. Utilizing offered availability and actual performance provides an improved measure of expected availability for each Season.

Q. Which resources will the Resource accreditation proposal affect?

A. All resource types will be generally affected by moving to a seasonal Resource Adequacy construct. However, accreditation for certain resources will be determined based on their availability during times of need, as described in detail below. Specifically, Demand Response Resources and Capacity Resources that are Generation Resources (collectively "Schedule 53 Resources"), but not Dispatchable Intermittent Resources, Intermittent Generation, Electric Storage Resources, External Resources or Use Limited Resources, will be subject to these new availability-based accreditation requirements. The resources designated as Schedule 53 Resources will be subject to the proposed availability-based accreditation methodology established in new Schedule 53 of the Tariff. Resources that are not subject to Schedule 53 will continue to have their

accreditation determined generally as it is done today, with appropriate adjustments made to convert their accreditation to a seasonal basis. I note that MISO plans to further evaluate the accreditation methodologies of non-Schedule 53 Resources commencing with stakeholder discussions in 2022.

Q. What changes does MISO propose with respect to Resource Accreditation for Schedule 53 Resources?

A. The proposed changes align Resource accreditation for Schedule 53 Resources with historic availability and performance during the highest risk periods while also accounting for general availability of resources across the year. More specifically, MISO proposes a two-tiered calculation to determine individual resource accreditation by Season. The first tier will determine each resource's real time offered availability during non-tight operating condition hours, and the second tier will determine each resource's real-time offered availability during hours with the tightest operating conditions, including declared MaxGens. The second tier will be more heavily weighted so that the majority of a resource's accreditation will be based on its availability during times of need. Additional details about the weighting and the proposed transition period to phase in the full 80% weighting for Tier 2, are described in detail below.

MISO supported its Independent Market Monitor's ("IMM") recommendation to base 100% of accreditation on availability during times of need but introduced a revised two-tier proposal in May 2021 with 20% weighting based on availability during hours that aren't tight to accommodate stakeholder requests that these hours should still be relevant to resource accreditation. The proposal was

modified to recognize that general resource availability supports reliability by allowing resources to take needed maintenance outages. Moreover, general resource availability reduces the time the system is operating within the margin of error for capacity sufficiency.

Each tier calculation also will account for exemptions obtained by sufficiently coordinating planned outages when determining availability, as described in detail below.

Q. Why are MISO's proposed changes necessary?

A. Historically, most if not all LOLE occurred at or near the annual Coincident Peak Demand for the system, which occurred in the Summer. However, MISO has experienced an increasing number of days with tight operating margins in all four Seasons of the year despite clearing the targeted level of reserves in the PRA each year. This is attributable, in part, to a wave of retirements that began before the start of the 2016/17 Planning Year. Given this and recent operational experiences, including involuntary load shed outside of Summer, MISO has worked with stakeholders to provide tools and incentives to improve the availability, flexibility, and visibility of our resource fleet to mitigate the risks of capacity insufficiency.

Resource accreditation should reflect the anticipated capability and availability of Planning Resources during times when they are most needed. Historically, accreditation for conventional generation has been based only on forced outage rates defined in GADS. Recent experience shows this approach does not effectively reflect the actual availability and capability of resources during times

when capacity needs are highest – during periods of peak demand, high generation outages, low levels of renewable generation output, or a combination of these which can occur in any Season. Additionally, the current approach to accreditation for conventional thermal resources does not provide the proper incentives to improve availability, especially during critical periods, as described more fully in the Testimony of Mr. Smith.

Q. What benefits does MISO expect to receive from these proposed changes to Resource Accreditation?

A. MISO expects the proposed Tariff changes to achieve several important and necessary benefits, including: (1) increased confidence in the accredited capacity MISO can count upon during times of need; (2) improved signals for resource availability during times of need; (3) improved outage coordination processes; and (4) lower non-Summer Season requirements, which will enable seasonal operation of resources, as requested by many resource owners.

Q. How does the proposal mitigate reliability risks during extreme weather events?

A. The proposal incentivizes resource availability during times of need and does so specific to each Season. For example, Winter RA Hours have been observed to occur during extreme cold events and decisions and investments which impact resource availability in such conditions (*e.g.*, winterization and firming up of fuel procurement) are expected to have a significant impact on resource availability.

Q. How will MISO's Resource accreditation proposal apply to Schedule 53 Resources?

A. Resource accreditation for Schedule 53 Resources will no longer be based on forced outage rates from GADS as MISO intends on using energy market offers and related parameters to determine these resources' accreditation. Specifically, their accreditation will be based on Real Time Hourly Emergency Maximum Limits (or Targeted Demand Reduction Level ("TDRL") for Demand Response Resources) information in MISO's Day-Ahead and Real-Time system. If a unit is offline, then its lead time and outage status are also relevant to determine if it could be reasonably committed today to be used tomorrow during a time of need. Other factors such as the type and volume of interconnection service and seasonally corrected GVTC values will be utilized as well to account for changes to deliverability or unit capability not reflected in past offers. The proposed construct will continue to base accreditation on the three prior years starting September 1 through August 31 of the year prior to the Planning Year, which reflects the cumulative availability of a Resource. As noted above, MISO proposes a tiered weighting structure with more emphasis on low operating margin RA Hours to determine individual resource accreditation by Season. Accreditation will be based on each resource's real-time offered availability during all hours with heavier weighting for hours with the tightest operating conditions (*i.e.,* RA Hours) while incentivizing the coordination of planned outages by offering exemptions that remove hours when offers were zero when certain conditions are met.

Q. What are Resource Adequacy hours?

A. Resource Adequacy Hours ("RA Hours") represent the periods of highest risk and greatest need both during a Season and throughout the Planning Year. They include declared MaxGens and the hours when the operating margin, a measure of available economic supply capacity above demand and reserve requirements, is at its lowest. RA Hours will be determined seasonally, based on declared MaxGens and the tightest operating margin hours subject to a maximum operating margin threshold established at 25 percent. Each Season will have a target of 65 RA Hours (which represents approximately three (3) percent of the hours in a Season). The number of RA Hours in a Season can exceed the target when declared MaxGens during that Season have a duration greater than 65 hours. The number of RA Hours in a Season can be less than the target because of the 25 percent maximum operating margin threshold. In this latter case, these Seasons will have an RA Hour deficiency equal to the difference between the target of 65 RA Hours and the actual number of RA Hours.

Q. How does MISO ensure resources have a minimum target number of Resource Adequacy Hours?

A. MISO proposes to ensure resources have a minimum of 65 RA Hours for any Season for which they were designated for RAR by multiplying the number of deficient hours for a Season with the Annual Average Offered Capacity ("AAOC") over all RA hours for that resource during the same annual period (*i.e.,* September to August). It is necessary to have a minimum number of RA Hours to support stability of accreditation values and avoid situations where a Resource loses most of its capacity value for the Season because it happened not to be

available on the one or two days when operating margins were at their lowest for the Season. The RA Hours used for determining the AAOC for a resource are the tightest 3 percent of operating margin hours and declared MaxGen hours whenever they occur over the same annual period provided a resource was designated for RAR and had not secured an exemption. The target number of hours for AAOC is 260 for the annual period (*i.e.*, 65 hours per Season multiplied by four Seasons) with the distribution based on tightness and MaxGens rather than a specified target in any Season. Historical analysis shows many of these hours have occurred in the Summer during recent Planning Years. MISO believes it is prudent to supplement deficient seasonal RA Hours with a proxy-based on AAOC as it reflects the next best available information about a resource's availability during times of need, which is a core focus of MISO's proposed enhancements to resource accreditation.

It is important to note that, despite the general discussion above about how RA Hours are identified for a Season, ultimately the set of RA Hours are specific to each resource being accredited because of outage exemptions, capacity replacement requirements (each as described later in my testimony), and differences in resource commitment over the three-year look back period. No resource can have more RA Hours than the amount that has been identified for a Season or year, but many resources will have fewer RA Hours requiring more of a resource's accreditation to be based on availability during times of need during the annual period and not just the specific Season to ensure sufficient sample sizes for RA Hours to support stability of resource accreditation.

Q. How will the location of a resource impact its RA Hours?

A. To reflect the varying risk of capacity insufficiency across the MISO Region, Resource Adequacy hours are defined within the First Planning Area (*i.e.*, MISO North/Central) and the Second Planning Area (*i.e.,* MISO South) separately. RA Hours will be determined on this sub-regional basis to reflect the growing frequency of MaxGens that occur on either side of the Sub-Regional Power Balance Constraint, as demonstrated in the below chart:

Region of highest severity	# of MaxGens
Central	3
North/Central	9
South	21
Footprint	7
Total	40

MaxGen Events are often the result of issues that disproportionately impact one Planning Area or the other but are usually not felt uniformly across the entire MISO region. Typically, these issues include: trapped capacity in one sub-region due to the contractual transfer limits; increasing sub-regional challenges driven by portfolio differences; and, the varying locational impacts of extreme weather, including hurricanes, cold weather events, and renewable penetration.

Q. How is the hourly Operating Margin percentage calculated?

A. As described in Schedule 53, the Operating Margin is determined using historical information to identify Seasonal RA Hours and Annual RA Hours within the three

(3) most recent periods beginning September 1st and ending August 31st. The Operating Margin Equation is as follows:

$$Operating\ Margin\ (\%)_j = \frac{Online\ margin\ (MW)_j + \ offline\ margin\ (12 - hour\ lead\ time)(MW)_j}{Real\ Time\ (RT)\ Load\ (MW)_j}$$

Where:

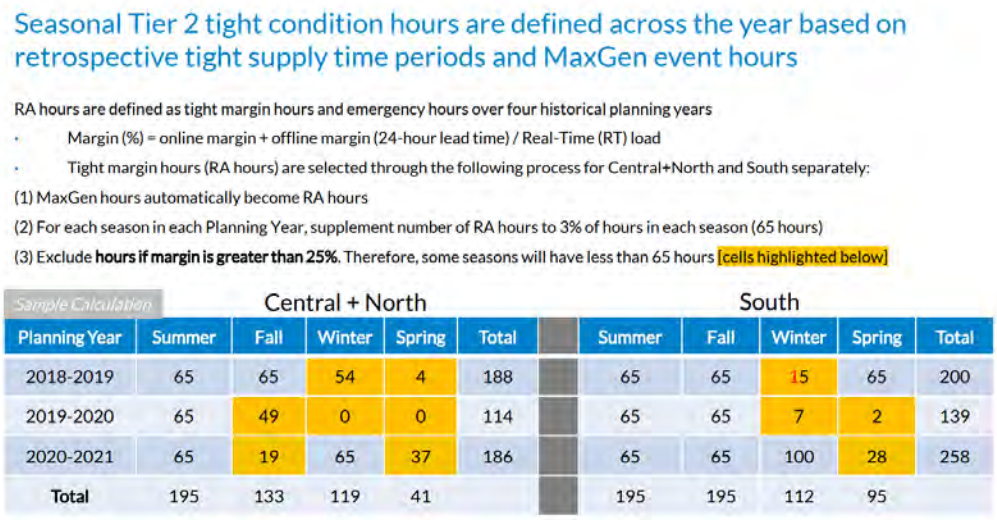
$Online\ margin\ (MW)_j = \sum_{unit\ i\ in\ region\ j}(EmergencyMax_i - Energy\ MW_i - cleared\ operating\ reserve_i)$ For all Resources online and under normal dispatch control.

$Offline\ margin\ (MW)_j = \sum_{unit\ i\ in\ region\ j} Emergency\ Max_i - cleared\ offline\ supplemental\ reserve(MW)_j$ For Resources where all of the following is true: (i) Resource is Offline; (ii) it's cold-start lead-time is less than or equal to 12 hours; and (iii) it's not on outage.

Q. Why does MISO propose to use a 12-hour lead time for offline resources in the Operating Margin calculations?

A. Previously MISO proposed a 24-hour lead time but the IMM suggested that use of a shorter lead time would better reflect the actual operating margins MISO is seeing in real-time operations, which may be impacted by uncertainty that occurs after the deadline to commit longer lead resources has passed. MISO agrees that the use of a shorter threshold better reflects historical margins in the recent past, as evidenced by the chart below. It also leads to the identification of more RA Hours below the 25% operating margin threshold used to identify RA Hours. Moreover, twelve hours leads to more RA Hours being identified in each Season,

allowing resource accreditation to be based on availability during a specific Season with less need to fill in deficient hours through the use of the AAOC, as explained above.



Seasonal Tier 2 tight condition hours are defined across the year based on retrospective tight supply time periods and MaxGen event hours

RA hours are defined as tight margin hours and emergency hours over four historical planning years

- Margin (%) = online margin + offline margin (24-hour lead time) / Real-Time (RT) load
- Tight margin hours (RA hours) are selected through the following process for Central+North and South separately:

(1) MaxGen hours automatically become RA hours

(2) For each season in each Planning Year, supplement number of RA hours to 3% of hours in each season (65 hours)

(3) Exclude **hours if margin is greater than 25%**. Therefore, some seasons will have less than 65 hours [cells highlighted below]

Sample Calculation

	Central + North						South				
Planning Year	Summer	Fall	Winter	Spring	Total		Summer	Fall	Winter	Spring	Total
2018-2019	65	65	54	4	188		65	65	15	65	200
2019-2020	65	49	0	0	114		65	65	7	2	139
2020-2021	65	19	65	37	186		65	65	100	28	258
Total	195	133	119	41			195	195	112	95	

Q. Why is MISO using a 12-hour lead time to identify RA Hours but a 24-hour lead time for accreditation in Schedule 53?

A. As described above, due to the operational uncertainties that MISO faces, tight conditions are more likely to be identified 12 hours before a projected capacity shortfall than 24 hours. Use of a 12-hour threshold better identifies RA Hours that represent "times of need." On the other hand, the use of a 24-hour threshold for accreditation with respect to offline resources better reflects whether MISO could have reasonably committed a resource in its Day-Ahead Market or Forward Reliability Assessment Commitment processes. This is consistent with the goal of MISO's RAN initiative to close the gap between planning and operational outcomes. MISO's proposal bases most of a resource's accreditation on its offers during times of need but the process of identifying RA Hours that reflect times of

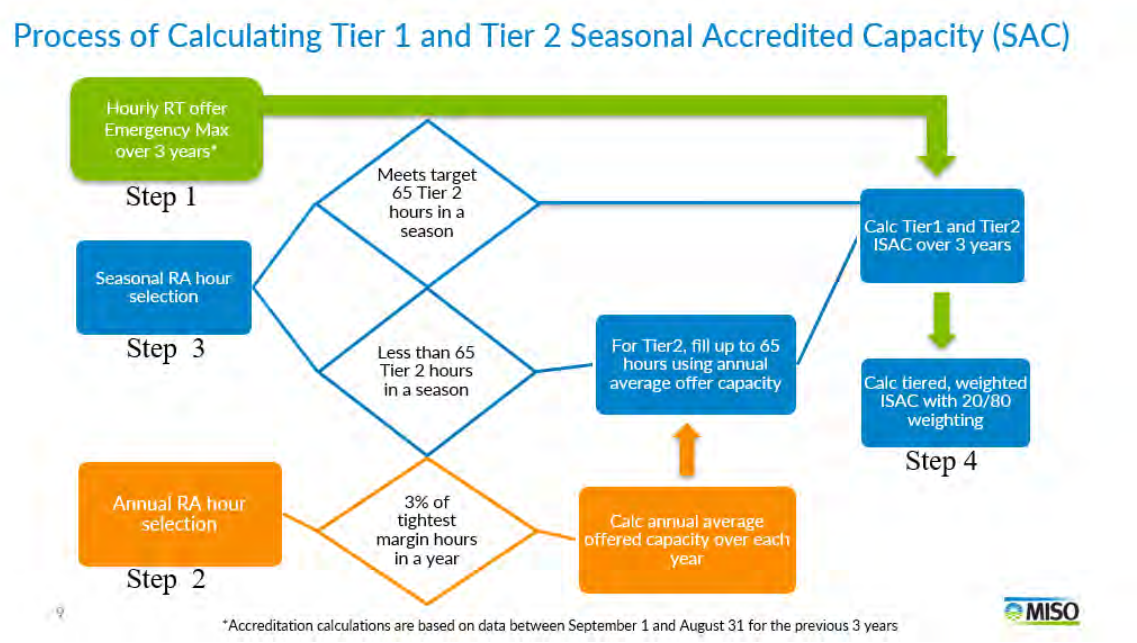
need must also account for resources that could not be accessed due to long start-up and notification times.

Q. Why is a 25% margin threshold applied in identifying Resource Adequacy hours?

A. MISO has examined the distribution of Operating Margin and Operating Margin levels for historical MaxGen events. The evaluation indicates that a 25% margin threshold captures the vast majority of declared MaxGens events. Also, by examining the cumulative count of hours at different levels of Operating Margin in each Season, MISO found that the 25% threshold provides a reasonable balance between having an adequate number of RA Hours for each Season and selecting the set of RA Hours that are truly tight.

Q. Please provide a step-by-step description of the Intermediate SAC calculations in Schedule 53.

A. First, a Resource will have its Intermediate Seasonal Accredited Capacity ("ISAC") determined based on offers of its Real-Time Hourly Emergency Maximum Limit, or TDRL for Demand Response Resources, during both seasonal RA Hours (Tier 2) and Non-RA Hours (Tier 1), as set forth in Schedule 53. References to "RT offers" in the steps below refer to Hourly Emergency Maximum Limit or TDRL as applicable. The following graphic illustrates the process of calculating Tier 1 and Tier 2 ISAC for a Resource.



Step 1: Cap Real-Time offers for the three-year look back period by the relevant seasonally corrected GVTC value to account for a resource's most recently demonstrated capability. For resource's that have increased their capacity, MISO will increase the RT offers based on a class average SAC percentage for hours prior to such increased capacity to reflect the additional capacity. Ensure RT offers equal zero when a Resource is on outage or is offline and has a combined Start-Up Time and Start-Up Notification Time greater than 24 hours to reflect that the resource was not available in the Day-Ahead commitment processes.

Step 2: For each year in the three-year look back period (September 1 – August 31) identify declared MaxGen hours and then the tightest non-MaxGen hours needed to reach 260 hours (3%) for the relevant Planning Area in which the resource is located and then remove any hours during which the Resource had a Tier 2 Planned Outage Exemption. The remaining hours are the Annual RA Hours for the resource. Sum the RT offers and divide by the number of Annual

RA Hours for the Resource to calculate its Average Annual Offer Capacity ("AAOC") for each year in the three-year look back period.

Step 3: For each Season, identify declared MaxGen hours and then the tightest non-MaxGen hours with operating margin less than 25% for the Planning Area that needed to reach the target of 65 hours (3%). Then remove any hours during which the Resource had a Tier 2 Planned Outage Exemption. If the Resource has less than 65 hours in any Season MISO will add hours with RT offers equal to the relevant AAOC for any deficient hours. MISO will sum up the RT offers during RA Hours for the Season over the 3-year look back period and divide by the total number of hours (195 or greater) to determine the Tier 2 ISAC value for each Season. Calculate the Resource's Tier 1 ISAC value for each Season by summing the RT offers for any non-RA hours over the 3-year look back period (after first removing any hours for which the Resource had a Tier 1 Planned Outage Exemption) and then dividing by the total number of hours.

Step 4: Multiply the Resource's Tier 1 and Tier 2 ISAC values for each Season by their weightings (20% for Tier 1 and 80% for Tier 2 after the proposed transition) to calculate its final ISAC value.

Q. What does "Intermediate SAC (ISAC)" mean in Schedule 53?

A. Schedule 53 describes various steps in the calculation of SAC and until the very end the "in process" value is referred to as "intermediate" SAC or "ISAC." Each Resource will have four ISAC values (one for each Season of the upcoming Planning Year) while the SAC calculation is in process.

Q. How does the ISAC value become SAC?

A. Once the final ISAC for each Resource has been determined for each Season of the upcoming Planning Year, then a system-wide conversion ratio is determined for each Season and applied to each Resource's ISAC to determine a Resource's final SAC value for each Season.

$$RATIO\frac{UCAP}{ISAC} = \frac{Sum(UCAP_{Schedule\ 53\ Resources})}{Sum(ISAC_{Schedule\ 53\ Resources})}$$

Q. Why is a conversion ratio necessary and why is it applied as the final step to calculate SAC in Schedule 53?

A. MISO's IMM originally suggested, and MISO adopted, a proposal that would scale seasonal requirements by the change in accreditation under Schedule 53 to ensure alignment with how requirements were determined during the LOLE study conducted under a UCAP approach. However, this approach required changes to how PRMR and LCRs are determined and appeared likely to have several unintended consequences, including the relative share of accreditation between Schedule 53 (generally thermal resources) and non-Schedule 53 Resources. Subsequently, the IMM proposed a simpler methodology that avoided the issues noted by having the required scaling occur at the end of the calculations proposed in Schedule 53, thereby removing the unneeded and unintended impacts to auction requirements and non-Schedule 53 resources. Additionally, the revised proposal addressed stakeholder concerns on deliverability and revenue reduction. The IMM presented its new recommendation at the October 6, 2021 meeting of the RASC, and formal feedback was solicited. Feedback received from

stakeholders was generally in support of the revised conversion method and MISO adopted the revised method and shared related Tariff redlines at the November 11, 2021, meeting of the RASC.

Q. How will the tiers be weighted?

A. The ISAC value is the weighted average over its values from the two tiers as calculated in the steps above. Ultimately assigning heavier weighting for Tier 2 tight condition hours ensures the alignment between a resource's Seasonal Accredited Capacity value and its availability and performance during times of highest risk and greatest need in MISO's Planning Areas. The corresponding tier weightings, which will be effective following a two Planning Year transition (described below), are:

$$ISAC_{Tier1_weighting} = 20\%$$

$$ISAC_{Tier2_weighting} = 80\%$$

$$ISAC = ISAC_{Tier1_value} \times ISAC_{Tier1_weighting} + ISAC_{Tier2_value} \times ISAC_{Tier2_weighting}$$

Q. Is there a transition to the 80% weighting for Tier 2?

A. Yes. Stakeholders requested a transition and MISO felt it would be appropriate to phase in the full 80% weighting until the third Planning Year ("PY") following initial implementation (*i.e.,* the 2025/2026 Planning Year). Doing so will account for the fact that the historical RT offers, outages, and notification times used in the Schedule 53 calculations were submitted for resources without knowledge of the final accreditation methodology proposed in the instant filing. Under the proposal, Tier 2 would start at 60% in PY 2023/24, rise to 70% in PY 2024/25 and then reach the full 80% in PY 2025/26.

Q. What is the ultimate product of this process?

A. The ultimate product of Schedule 53 is four SAC values for each Resource, one to be used for each Season commencing with the upcoming Planning Year 2023/24.

Q. How will MISO account for resources with insufficient performance data, such as new resources?

A. Units with insufficient performance data will utilize a class average proxy for accreditation as done today, but this class average will be based on SAC rather than UCAP. Class averages will be determined for each resource type as they are today. However, the class average will be a ratio of SAC to ICAP for a particular class. A new resource will apply this ratio to its ICAP to determine its SAC. A resource will only use a class average for a Season when there is less than 60 days of real-time offered availability for that Season during a time when the resource was designated for RAR. However, for Planning Year 2023/24 MISO accommodated a stakeholder request by adding Tariff language giving a resource that hadn't been designated for RAR in a recent annual PRA the option to have its accreditation based on its real-time offers rather than a class average.

Q. Does MISO's proposal account for seasonal resource deliverability?

A. Yes, it does. For seasonal deliverability, similar to the current process, if a Resource does not have full Network Resource Interconnection Service ("NRIS") granted for its seasonal GVTC, to the extent the output is within the total granted Energy Resource Interconnection Service ("ERIS") and does not violate the generator's Generator Interconnection Agreement ("GIA"), it can: (1) request

additional NRIS through the established process in Attachment X; or (2) procure firm Transmission Service Requests to align with seasonal deliverability needs.

Q. How will MISO's proposal address deliverability requirements?

A. The recently accepted ICAP deliverability Tariff changes remain in effect without modification as these requirements are appropriately applied to each Season under the proposal. However, based on stakeholder feedback, MISO will continue to evaluate whether additional modifications to these requirements are needed in the future.

Q. How will MISO's accreditation proposal apply to wind resources?

A. Wind resources are currently accredited through an annual Effective Load Carrying Capability ("ELCC") methodology with capacity credits allocated based on each individual wind resource's performance over eight peak demand hours for the year, historically occurring in the Summer. Similarly, under a seasonal construct, accreditation for each Season will be based on seasonal ELCC studies with capacity credit allocated based on eight peak hours for each Season.

Q. How will MISO's accreditation proposal apply to non-wind intermittent and Energy Efficiency Resources?

A. Seasonal accreditation for non-wind intermittent resources (such as run-of-river hydro, solar, and biomass) and for Energy Efficiency Resources will be based on historic output during hours ending 15, 16 and 17 EST for the relevant Spring, Summer, and Fall months. Winter accreditation will be based on hours 8, 9, 19 and 20 EST for the Winter months. The selected hours represent the typical seasonal peak demand hours for the specified Seasons.

Q. How will MISO's accreditation proposal apply to Demand Resources?

A. MISO's May 2020 Tariff filing that was accepted by FERC will also be implemented with the 2022-2023 Planning Year. That filing accredits Demand Resources registering as Load Modifying Resources ("LMRs") based on lead time and number of calls per year.[11] The lead time requirements will remain unchanged, but the number of calls will be modified to transition to a seasonal construct. LMRs must be available for a minimum number of calls for each Season as follows: five for Summer, five for Winter, three for Spring, and three for Fall to be eligible to offer into the PRA for each respective Season. Establishing a minimum number of calls per Season rather than per Planning Year is consistent with procuring seasonal capability to meet seasonal needs and incurs a minimum obligation to inform offers into each Season. Demand Response Resources that are not registering as LMRs will be accredited pursuant to Schedule 53 since they submit offers in the day-ahead markets and can be appropriately accredited based on their availability during times of need.

Q. How will MISO's accreditation proposal apply to behind-the-meter generation?

A. Intermittent Behind the Meter Generation ("BTMG") will be accredited like all other non-wind intermittent resources (such as run-of-river hydro and solar), under a seasonal construct. As described above, accreditation will be based on historic output during hours ending 15, 16 and 17 EST for the relevant Spring, Summer, and Fall months. Winter accreditation will be based on hours 8, 9, 19

[11] *See Midcontinent Independent System Operator, Inc.,* 127 FERC ¶ 61,138 (August 14, 2020).

and 20 EST for the Winter months. Thermal BTMG with historic GADS data (*i.e.,* with capacity greater than or equal to 10 MW) will be accredited based on their seasonal forced outage rates as it is today. Thermal BTMG with no GADS history will be accredited based on the class average seasonal forced outage rates. FERC approved notification times for LMRs and call limits for DR in MISO's May 2020 filing described in the answer to the prior question. In transitioning to the proposed seasonal capacity construct, all LMRs, including, BTMG, will be subject to those same call limits on a seasonal basis: five for Summer, five for Winter, three for Spring, and three for Fall.

Q. How Will Generation Verification Test Capacity ("GVTC") requirements change under MISO's proposal?

A. The current GVTC process has three steps: (1) Generator Operators ("GO") conduct a real power test or base GVTC on operational data between September 1 and August 31 prior to the Planning Year; or (2) Correct to historical MISO Summer coincident peak conditions, and (3) Submit in PowerGADS through the MISO Market Portal by October 31 prior to the Planning Year. A GADS integration is run to bring the GVTC from PowerGADS to the Module E Capacity Tracking ("MECT") tool. Under a seasonal construct, the GO would still conduct a real power test or base GVTC on operational data between September 1 and August 31. MISO would publish four historical MISO coincident seasonal peak dates and times for the last five years. The GO will correct the single test to each of the seasonal peak conditions for temperature and submit four seasonally corrected GVTC values by October 31.

Q. Will MISO still permit Installed Capacity deferral?

A. Installed Capacity ("ICAP") deferral, formerly known as GVTC Deferral, requires a Market Participant to submit notice by February 15, post credit no later than March 1, and test and submit test results before the last business day of May prior to the start of the Planning Year. The February 15 notice and March 1 credit posting timeline still apply, and the credit requirement will continue to be calculated as the deferred ICAP megawatts multiplied by 90 days of the annual Cost of New Entry ("CONE"). However, the deferral notice will be modified to indicate to which Season the deferral applied and the credit would be held until the resource tested. The testing would need to be performed and submitted prior to the last business day prior to the start of the applicable Season, otherwise the existing ICAP Deferral Non-Compliance Charges would apply. No changes are proposed to the ICAP Deferral Non-Compliance Charges.

V. PLANNING RESOURCE AUCTION

Q. What changes to the PRA will be needed to implement the Seasonal construct?

A. The seasonal construct will require a number of important changes relative to the annual construct, including: how MISO conducts the Simultaneous Feasibility Test ("SFT"); time needed to run the PRA; need for non-Summer seasonal forecasts; calculation of non-Summer transmission losses; seasonal must offer requirements, capacity replacement requirements, and non-compliance charges; calculation of the Auction Clearing Price ("ACP") during shortage or near-

shortage conditions; calculation of offer cap impacts; and, establishing a new make whole payment mechanism. Each of these changes is discussed below.

Q. How will MISO conduct the SFT as part of the seasonal PRA?

A. Participants in the PRA may offer resources for each Season in the upcoming Planning Year during the PRA offer window period, which occurs over the last four business days in March. During the first 20 business days in April, MISO will build four SFT models to meet seasonal requirements. Results for each upcoming Season of the Planning Year that pass the SFT auction run will be posted and valid by the 20th business day in April. Results for Seasons where unacceptable constraints are found will have their SFT model rebuilt and re-run for one additional iteration. MISO will accept the result with fewest MWs of network violations of the two iterations for that Season and post the result by the 20th business day of April.

Q. How will the proposed seasonal construct affect auction timing?

A. Under a seasonal construct, all four seasonal auctions will occur at approximately the same time as the current annual PRA. The PRA offer window will remain as the last four business days of March. The auction period will be expanded from 10 business days to occur within the first 20 business days of April, allowing a maximum of two SFT auction run iterations per Season. PRA Results for each Season will be posted on the 20th business day in April. The following graphic summarizes the timeline leading up to the start of the 2023/2024 Planning Year on June 1:



Q. Will LSEs be required to submit seasonal load forecasts?

A. Yes, the current annual load forecast submittal process will be repeated for each Season. LSEs will supply Coincident Peak Demand and LRZ Peak Demand forecasts for each Season including the estimated demand from forecasted demand resources, whether registered as LMRs or not registered with MISO. The forecasts will also include demand that would have occurred but for the existence of energy efficiency resources that have been in operation less than 4 years. All submissions for such forecast values will include distribution losses but not transmission losses. All demand forecasts will reflect a 50 percent probability that the demand will not exceed the forecasted demand for the relevant time period.

Q. How will the proposal impact the treatment of transmission losses?

A. Under the current annual PRA construct, MISO calculates annual transmission losses for each Local Balancing Authority Area and LRZ based on the MISO coincident peak hour. Under the seasonal PRA construct, transmission losses will be calculated at each of the four published MISO seasonal peak hours and will be made available on both the market portal and its public website.

Q. How will must offer obligations for cleared Capacity Resources be impacted by MISO's seasonal proposal?

A. Currently resources are committed for an entire Planning Year and their must-offer obligation is the same throughout the year despite lower load expectations

outside of Summer. Under a seasonal approach, resource capabilities and capacity requirements will be tailored to each Season and resources may be committed for one Season but not committed in other Seasons. The must-offer obligation only applies for those Seasons when a Resource is committed. The must offer obligation will be ICAP multiplied by the percentage of total ZRCs a resource clears (*e.g.,* a unit eligible for 10 ZRCs that clears 5 will have a must offer of 50% of its ICAP).

Q. Will MISO require replacement of ZRCs if a resource has a planned outage or derate?

A. Yes, but only if the Generator Planned Outage or derate exceeds 31 days during a Season when the resource is committed. The proposal establishes a maximum threshold number of 31 days of full or partial Generator Planned Outages per Season that will require replacement when exceeded. A threshold of 31 days is reasonable as it retains much of the latitude resources need to schedule Generator Planned Outages while putting an upper limit on the amount of a Season that a committed resource can choose to miss without consequence under MISO's Resource Adequacy construct. Additionally, resources with unplanned outages that were known or could have been reasonably anticipated at the time of the PRA will also have a capacity replacement requirement where the full or partial outages exceeds 31 days since the outage was expected despite not being a Planned Generation Outage. An after-the-fact determination will be made following each Season to determine if resources were on planned outages or planned derates that exceeded the threshold and if such resources met the

replacement requirements. Future non-Summer seasonal PRMRs are expected to be lower than today's annual Summer-peak target, representing an efficiency in the amount of required capacity for the MISO Region. Currently, capacity replacement requirements are only in place for capacity suspensions and retirements. Under a seasonal construct with lower PRMRs, the performance and availability of committed capacity to meet seasonal requirements will be critical. Relying on resources that have submitted planned outages for a large portion of a Season is not consistent with availability-based accreditation and seasonal requirements.

A non-compliance charge will be assessed for days exceeding the threshold (as described further below) since some resource owners may not be willing or able to replace their capacity with uncleared ZRCs deliverable to the needed LRZ in the relevant Season. It should be noted that exemptions granted through the outage coordination process are not relevant to capacity replacement and will not relieve a resource owner of the ZRC replacement obligation. MISO systems and processes will continue to accommodate ZRC replacement transactions. Current replacement rules regarding deliverability and zonal transfer limits will still apply.

Q. Why is MISO imposing a charge for failure to replace ZRCs associated with a retired or suspended resource or a resource that exceeds its maximum outage or derate threshold in a season?

A. Currently, resources that convert UCAP to ZRCs and retire or suspend prior to the end of the Planning Year and fail to replace do not face any explicit non-compliance charges under the Tariff. This creates uncertainty and fails to

quantify the consequences of failure to replace. In the past, this has led Market Participants to seek waivers from FERC as opposed to complying with the Tariff requirements. The proposal is to implement a financial charge that incentivizes replacement of ZRCs that are retired, suspended, or have outages that exceed 31 days in a Season. This non-compliance charge is reasonable because, despite the owner of the resource benefitting from its committed ZRCs each day of the Season, the resource owner has decided to make itself unavailable for more than one month of the three-month Season, thus possibly failing to be available when needed to support reliability in line with our one day in ten-year standard. The proposed Capacity Replacement Non-Compliance Charge will be based on the number of days where a Market Participant had a replacement requirement but failed to do so multiplied by the amount of ZRCs that failed to be replaced multiplied by the sum of the Auction Clearing Price and the daily CONE value. Effectively the resource will stop receiving the Auction Clearing Price for clearing and start paying a daily CONE payment that reflects the missing capacity in the applicable LRZ. Distribution of Capacity Replacement Non-Compliance Charges will be distributed to Market Participants representing LSEs that have met their PRMR during the Planning Year on a pro rata basis, based upon the Market Participant's share of total PRMR for the MISO Region. Billing, invoicing, default, and uplift provisions will be similar to the ICAP Deferral Non-Compliance Charge.

Q. What are the eligibility criteria for ZRCs to be used for capacity replacement?

A. As is the case today, only uncleared ZRCs can be used for capacity replacement. ZRCs must be registered and converted in advance as part of the PRA process.

Q. With the proposed move to seasonal auctions how is MISO mitigating the risk of capacity revenue insufficiency for resources or payment above annual CONE for LSEs?

A. The move to seasonal auctions could lead to concerns about over or underpayment in certain circumstances. Based on historical PRA results, MISO does not expect such circumstances to occur frequently but considers it prudent to ensure reasonable mitigation in the unlikely event of such outcomes. MISO's proposal incorporates enhancements to offer caps and make whole provisions that ensure appropriate resources recover their costs when committed for the PRA while also ensuring that LSEs are not exposed to ACPs that result in charges that amount to multiples of annual CONE value as result of auction participation. Additional details about these enhancements are provided below.

Q. Will the PRA continue to include offer caps?

A. Yes. An LRZ may fail to clear its target PRMR in fewer than all four Seasons. Seasonal offer caps and facility-specific reference levels need to take this into account to enable some resources to economically participate in the seasonal auctions. Offers higher than the daily allocation of the annual CONE value (*i.e.*, "daily CONE" or CONE/365) could be cleared and/or set prices when needed to enable resources to cover their avoidable costs. Therefore, ZRC Offers will be enabled to recover a resource's costs if they only clear in one Season by enabling the Auction Clearing Price to be set at a level up to annual CONE divided by the

number of days in each Season, (*e.g.,* CONE/91 days, up to approximately $1,000 per megawatt day). As a result, the Auction Clearing Prices for individual LRZs and Seasons may clear above the current daily value of Annual CONE (CONE/365 or ~$250/MW-day), which is the highest price at which the current annual Planning Resource Auction can clear when there are insufficient ZRC Offers to meet auction requirements. Consequently, if no further action is taken, the auction could provide revenues up to four (4) times Annual CONE if all Seasons cleared in shortage conditions.

Q. Will the proposal mitigate the potential for recovering above the annual CONE?

A. Yes. The proposal includes provisions to mitigate, but not completely eliminate, the potential for annual auction revenue charges to exceed CONE on a per Megawatt-Year basis. An ex-post adjustment will set reduced Auction Clearing Prices when more than one Season clears in ZRC Shortage Conditions or ZRC Near-Shortage Conditions. The final Auction Clearing Price will be set based on annual CONE and the number days in all applicable Seasons when an LRZ, group of LRZs, or the MISO footprint clear with less than the required number of ZRCs or the Season's initial Auction Clearing Price clears above daily CONE in a Planning Resource Auction.

Q. Given the mitigation described above, could annual auction revenue charges exceed CONE on a per Megawatt-Year basis?

A. Yes, whenever the Planning Resource Auction clears at least one Season, but fewer than all Seasons with Auction Clearing Prices above the daily value of

CONE, it is possible that the Planning Resource Auction charges for all four Seasons could exceed annual CONE on a per Megawatt-Year basis. For example, when one Season clears at CONE due to shortage and the other three Seasons clear less than the daily CONE value. In this situation, MISO will not adjust any of the Auction Clearing Prices and any revenues collected in the non-shortage Seasons would increase the annual auction charge amounts beyond annual CONE which is being fully collected in the one Season which has a shortage. For example, if Summer clears in shortage conditions at CONE divided by 92 days ($1,001 MW-day) and then Fall at $20/MW-day, Winter at $25/MW-day, and Spring at $15/MW-day the total annual auction revenue charges would equal $97,575 per MW for the Planning Year, 6% above the CONE value for the Local Resource Zone of $92,100/MW-year.

Q. Are the mitigation provisions sufficient to minimize annual charges above CONE?

A. Yes. While the proposed offer caps and Auction Clearing Price adjustments could result in annual charges exceeding CONE, the likelihood should be infrequent and minimized. Historically, the Planning Resource Auction, has only cleared above the default economic withholding threshold two times: the first was during the 2016-2017 PRA where Zones 2-7 cleared at $72/MW-day (the economic threshold was approximately $26/MW-day); the second was during the 2020-2021 PRA when Zone 7 cleared in shortage at CONE. Even during the 2015-2016 Planning Resource Auction, when the ACP in LRZ 4 cleared at $150/MW-day, the economic withholding threshold was $180/MW-day. MISO is

not proposing further mitigation so as to prevent shortage price suppression which could exacerbate potential revenue sufficiency issues. Existing ZRC Offer mitigation measures will be retained, including the threshold for economic withholding which remains set at 10% of CONE (approximately $25/MW-day) above a default reference level of $0. Market Participants desiring to offer above the economic withholding threshold will need to request and obtain facility or technology specific reference levels in consultation with the IMM that consider relevant costs per section 64.1.4 of Module D. Such Reference Levels have historically accounted for a small fraction of ZRC Offers in the annual Planning Resource Auctions.

Q. How could the Auction Clearing Price adjustments result in revenue sufficiency issues for Market Participants that clear ZRCs in Seasons where adjustments occur?

A. Market Participants that obtain facility-specific Reference Levels or are otherwise not subject to the economic withholding provisions of Module D, for example Demand Response, may submit ZRC Offers for individual Seasons up to a cap which will be set at annual CONE divided by the number of days in the Season, approximately $1,000/MW-day. When an LRZ clears with two or more Seasons in shortage or near shortage conditions, the final ACPs for those Seasons are reduced below the marginal offer (or CONE when short) that was used to clear the auction. As a result, cleared ZRC Offers would exceed the final ACPs. Assuming the cleared ZRC Offers reflect the actual costs associated with the Planning Resource, Market Participants may not recover their costs. This would

necessitate a payment or credit to ensure the Resource recovers its costs, but no more, to incentivize it to meet its capacity commitment in all Seasons in which it cleared.

Q. How is MISO proposing to formulate make-whole provisions?

A. In concept, make-whole payments compare market revenues to costs and provide credits to the extent costs exceed revenues. In energy markets, costs are computed based upon resource offers, assuming they reflect the costs of producing energy. ZRC Offers may not reflect the actual costs of providing capacity if a Planning Resource clears in multiple Seasons but its annual costs are compressed into each season's ZRC Offer to ensure recovery if the Resource only clears in a single Season. To account for this, MISO proposes a make-whole provision, defined as the ZRC Offer Revenue Sufficiency Credit, that considers a Resource's revenues from all cleared Seasons and credits a Resource if needed to meet the minimum of the following amounts: (i) the sum of cleared ZRC Offer price segments multiplied by the cleared ZRC Offer Volumes multiplied by the number of days in the Season; (ii) annual CONE; or (iii) the applicable reference level costs for resources that obtained technology or facility-specific Reference Levels for cleared Seasons. This formulation will prevent the ZRC Offer Revenue Sufficiency Credit from contributing to over-recovery of costs.

Q. Who will pay for ZRC Offer Revenue Sufficiency Guarantee Credits and how will they be distributed?

A. Charges to fund ZRC Offer Revenue Sufficiency Guarantee Credits will be distributed to Market Participants representing LSEs in the LRZs experiencing

shortage or near shortage conditions *pro rata*, based on their respective LSEs' share of PRMR minus the PRMR associated with the Capacity Deficiency Charge within the LRZs during the Seasons where ACPs were reduced. The allocation is similar to the allocation of the Zonal Deliverability Benefit which occurs when an LRZs ACP separates from the systemwide ACP due to limited import or export capability, which will occur whenever LRZs experience shortage or near shortage conditions.

Q. Should ZRC Offer Revenue Sufficiency Guarantee Credits occur frequently?

A. MISO expects that payment of ZRC Offer Revenue Sufficiency Guarantee Credits will be infrequent due to the conditions necessitating the payments that include: (i) LRZs, a group of LRZs, or a Sub-Regional Resource Zone must clear in shortage or near shortage conditions in more than one Season; (ii) ZRC Offers must exceed the final ACP for the applicable LRZs and Seasons; (iii) in order for ZRC Offers to exceed the economic withholding threshold, they must obtain facility-specific reference levels or be excluded from the economic withholding provisions of Module D; and (iv) the Planning Resource's actual costs associated with its ZRC Offer must exceed auction revenue credits for the Seasons cleared. As noted above, in past PRAs very low volumes of ZRCs have offered above the economic withholding threshold and the PRA has only cleared above the economic withholding threshold twice since the PRA began in 2013.

VI. <u>OUTAGE COORDINATION</u>

Q. What are the current RAN Phase 1 exemption rules for Generator Planned Outages?

A. Under the current RAN Phase 1 generator outage exemption rules, exemptions will be provided if one of the following conditions are met:

(1) The Generator Owner or Generator Operator schedules its first Generator Planned Outage 120 days or more in advance of the outage start date and 120 days or more beyond the end date of any previously scheduled outages for the unit; (2) Subsequent generator unit outage requests 120 days or more in advance and Generator Owners or Generator Operators Generator Planned Outage less than 120 days in advance and at least 14 days in advance of outage start date. Proposed Generator Planned Outage to occur entirely during a period that the subregion containing the generator unit has an adequate projected margin, at the time the outage is provided to the Transmission Provider. There is adequate margin when the Maintenance Margin is greater than or equal to zero megawatts after subtracting the megawatts of the requested Proposed Generator Planned Outage. The request shall be determined based on highest queued request; or (3) Generator Owner or Generator Operator reschedules its Generator Planned Outage at the Transmission Provider's request, including outages submitted less than 14 days in advance of the start date.

Q. What is MISO's proposal for exemption of Generator Planned Outages?

A. MISO worked with stakeholders to develop an exemption process that integrates with the tiered accreditation calculations in Schedule 53. The three levels are: Full exemption for Generator Planned Outages (from Tier 1 and Tier 2 SAC calculations in Schedule 53), partial exemption (only exempt in Tier 1 SAC calculations), and no exemption. The following chart illustrates the proposed

exemption requirements, please note that Maintenance Margin is currently calculated and posted for MISO's north, central, and south sub-regions separately:

Generator Outage Submission Criteria	**Maintenance Margin >=0 for duration of outage**	**Maintenance Margin <0 for any day in the duration of outage**
>120 days prior to outage start date, and >120 days from end of previous outage for unit	Exempt Tier 1 & 2	Exempt Tier 1 Only
>120 days Prior to Outage Start date and <120 days from end of Previous outage for unit or Outage submitted between 31-119 days Prior to outage start date	Exempt Tier 1 Only	No Exemption
14-30 days prior to outage start date and passes No Harm Test	Exempt Tier 1 Only	No Exemption
Outage moved per MISO request	Exempt Tier 1 & 2 (Weather, forced outages, other conditions in BPM-008)	Exempt Tier 1 & 2 (Weather, forced outages, other conditions in BPM-008) at Transmission Provider's discretion

A more detailed description of how to procure Generator Planned Outage Exemptions are provided in proposed Schedule 53.

Q. What is the No Harm Test?

A. No harm tests will include, but will not be limited to outage approval, compliance with all applicable operation guides, review of possible conflicting outages or system conditions, and forecasts of system capacity (Maintenance Margin, Multiday Operational Margin, 30-day margin). It will also include criteria outlined in the Business Practices Manual for Outage Coordination, specifically: the ability to maintain voltage required by nuclear generation resources, or to

meet any other nuclear plant interface requirements; the ability to maintain the Transmission System within system operating limits using normal (non-emergency) operating procedures or restore the Transmission System to normal operating conditions following a single contingency with the use of normal (non-emergency) operating procedures; or does not have the potential for credible contingencies to significantly affect Transmission System reliability of metropolitan areas.

Q. How will MISO treat planned outages that were submitted before this proposal goes into effect?

A. MISO proposes a transition with a bright line distinction based on whether a planned outage is scheduled to start prior to September 1, 2022. Planned outages submitted since spring 2019 are coded as exempt or not in the Control Room Operations Window ("CROW") under RAN Phase 1. Where coded exempt, those resources will be treated as fully exempt for Tier 1 & 2 in the calculations proscribed in Schedule 53 even though they may not have met both of the primary requirements of (1) being submitted 120 days or greater in advance and (2) leaving positive Maintenance Margin in the subregion for the duration of the outage. MISO believes this approach is appropriate as it has been highlighting the risks to capacity sufficiency from correlated planned outages since September 2017 and ongoing efforts to encourage sufficient outage coordination and improve tools and processes have greatly reduced the frequency of MaxGens declared in Spring and Fall since RAN Phase 1 went into effect.

Q. Describe MISO's authority related to coordination of generator outages.

A. Under the Tariff (section 38.1.1.e titled "Scope of Services") MISO is required to "Coordinate maintenance schedules for Generation Resources and approve, coordinate, and reschedule as necessary Planned Transmission Outages operated within the Transmission Provider Region." MISO does not have the authority to deny generation outages, but the existing tariff does allow MISO's accreditation of Planning Resources to be reduced based on insufficient coordination of Generator Planned Outages.

Q. What changes are being proposed to MISO's generation outage exemption rules under the proposal?

A. Given the strong correlation between high outage levels and MaxGens, modifications to MISO's outage coordination processes and procedures will be implemented to enhance the determination of SAC for Resources subject to Schedule 53.

Q. What changes are being proposed to the rules governing the exemption of Generator Planned Outages for accreditation purposes?

A. Outage exemptions will usually be given at the time of outage submittal review or in response to a CROW ticket change request. The purpose of the exemption is to ensure that a Resource's accreditation is not negatively impacted by unavailability associated with a sufficiently coordinated outage. Exemptions are granted based outage lead time criteria and adequate Maintenance Margin as outlined above. A generation outage ticket submitted into CROW will be reviewed to determine if such outage is exempt from accreditation impacts under Schedule 53. Outage approvals and exemptions have separate purposes and criteria but bridge the gap

between the planning and operational horizons. As is the case today, approvals will be based on reliability analysis in the Outage Coordination process. The outage will receive exemption from the SAC calculation if it meets the criteria outlined above. It should be noted that the exemption status of an outage does not impact whether it is "approved" in the Outage Coordination processes. Outage exemptions will usually be given at the time of outage submittal review or in response to a CROW ticket change request. The purpose of the exemption is to ensure that resources are not penalized for unavailability for a sufficiently coordinated outage. The criteria for exemptions are outage lead time and adequate Maintenance Margin.

VII. MARKET MONITORING AND MITIGATION

Q. Will MISO's current market monitoring and mitigation provisions be modified to address market power concerns in the new seasonal construct?

A. Yes, current market monitoring and mitigation provisions have been modified in the submitted tariff redlines and substantive enhancements regarding physical and economic withholding are discussed below.

Q. Please describe how physical withholding of Zonal Resource Credit offers into the PRA will be affected.

A. The move to seasonal auctions calls for minor modifications that ensure these same protections continue to work going forward. Primarily, it is the exclusions from auction participation in Section 64.1.1.g of Module D that need to be adapted for a seasonal approach. In one more substantive change in that section, MISO proposes removing the preclusion from participation for a resource that

expects to be on outage for greater than 90 of the first 120 days of the Planning Year and replacing that with a provision that says an Market Participant with a resource that has submitted an outage for greater than 31 days of a Season can ask the IMM for a determination ahead of the auction allowing it to forego offering excess ZRCs from the resource without being deemed to have engaged in Physical Withholding.

Q. Please explain about how Economic Withholding will be affected.

A. MISO is not proposing to change the initial reference level, economic withholding threshold. The initial reference level remains at $0 and the economic withholding threshold is 10% of CONE above $0, which currently would make ~$25/MW-day the effective offer cap unless an MP gets a facility-specific Reference Level or uses Default Technology Specific Avoidable Costs at which point it becomes the economic withholding threshold for the resource. It is expected that more resources will request facility-specific Reference Levels or use Default Technology Specific Avoidable Costs to help ensure they can cover their costs when they might only clear for one Season instead of the full Planning Year under the current construct.

Q. Do you believe the proposed enhancements are just and reasonable changes to the MISO Tariff?

A. Yes. For the reasons set forth above and in the supporting testimonies of Messrs. Wright and Smith, the proposal set forth in this filing is both just and reasonable and is needed now to help ensure the continued reliability of the MISO Region through enhancements to MISO's Resource Adequacy construct. For this reason,

MISO urges the Commission to accept the proposed Tariff enhancements to be effective for the 2023 – 2024 PRA.

Q. Does this conclude your testimony?

A. Yes.

Affidavit of Shawn McFarlane

COUNTY OF HAMILTON)
)
STATE OF INDIANA)

Shawn McFarlane, being duly sworn, deposes and states that he prepared the Prepared Direct Testimony of Shawn McFarlane, and the statements contained therein are true and correct to the best of his knowledge and belief.

/s/ Shawn McFarlane

Shawn McFarlane

SUBSCRIBED AND SWORN BEFORE ME, this 30th day of November, 2021.

My Commission Expires:

My County of Residence:

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 79

MISO 2022 Accreditation Order

180 FERC ¶ 61,141
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Richard Glick, Chairman;
James P. Danly, Allison Clements,
Mark C. Christie, and Willie L. Phillips.

Midcontinent Independent System Operator, Inc. Docket Nos. ER22-495-000
ER22-495-001

ORDER ACCEPTING PROPOSED TARIFF REVISIONS SUBJECT TO CONDITION

(Issued August 31, 2022)

1. On November 30, 2021, as amended on April 8, 2022,[1] pursuant to section 205 of the Federal Power Act (FPA),[2] Midcontinent Independent System Operator, Inc. (MISO) submitted proposed revisions to MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff) to establish a seasonal resource adequacy construct. As discussed below, we accept MISO's proposed Tariff revisions, effective September 1, 2022, subject to condition.

I. Background

2. MISO's currently effective resource adequacy construct, primarily located in Module E-1 of its Tariff, requires that MISO establish annually a system-wide Planning Reserve Margin, which the Tariff defines as the percentage of Planning Resources[3] above the system's forecasted Coincident Peak Demand required to meet the Loss of Load Expectation (LOLE).[4] The Tariff requires that the Planning Reserve Margin be based on

[1] MISO's April 8, 2022 amendment was a response to a Commission staff deficiency letter.

[2] 16 U.S.C. § 824d.

[3] A Planning Resource is a Capacity Resource, Energy Efficiency Resource, or Load Modifying Resource that can be used to satisfy resource adequacy requirements. MISO, FERC Electric Tariff, Module A, § 1.P (65.0.0).

[4] MISO, FERC Electric Tariff, Module A, § 1.P (65.0.0). MISO's Planning Year begins on June 1 and ends on May 31 of the following year. *Id.*

an LOLE study, which assumes an LOLE of one day in 10 years (0.1 day per year).[5] MISO then calculates the Planning Reserve Margin Requirement (Reserve Requirement) for each Load Serving Entity (LSE) based on the LSE's Coincident Peak Demand and MISO's system-wide Planning Reserve Margin.[6]

3. LSEs must demonstrate that they satisfy their respective Reserve Requirements for each Planning Year. An LSE can satisfy its Reserve Requirement in any of the following four ways: (1) purchase Zonal Resource Credits (ZRC) through the Planning Reserve Auction (Auction) process; (2) submit a Fixed Resource Adequacy Plan (FRAP) to demonstrate that it has designated ZRCs to meet all or a portion of its Reserve Requirement; (3) self-schedule ZRCs and bid them into the Auction at a price of zero; and/or (4) pay the Capacity Deficiency Charge.[7]

4. MISO conducts the Auction annually in the first 10 business days of April and posts the results approximately six weeks prior to the Planning Year, which begins on June 1 and ends on May 31 of the following year.[8] The Auction uses a fixed reliability target, represented by a vertical demand curve, to indicate the total amount of ZRCs each Local Resource Zone (Zone) needs to satisfy the Reserve Requirements for each LSE located in that Zone. The Auction selects the least-cost set of Planning Resources needed to meet each Zone's total required Reserve Requirement, while respecting local and sub-regional constraints, and establishes the Auction Clearing Price for each Zone for the upcoming Planning Year.[9]

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[5] *Id.*, Module E-1, § 68A.2.1 (32.0.0). The LOLE study also assumes that there are no internal transmission limitations within MISO. *Id.*

[6] MISO, FERC Electric Tariff, Module E-1, § 68A.7 (32.0.0). If a state regulatory authority establishes an alternate Planning Reserve Margin, MISO will use the alternate Planning Reserve Margin for the geographic area under that state's jurisdiction. *Id.*

[7] *Id.* § 69A (35.0.0). The Capacity Deficiency Charge is equal to the Cost of New Entry (CONE) in the Zone where the LSE is deficient ZRCs, multiplied by 2.478, for each ZRC. *Id.*, Module E-1, § 69A.10 (31.0.0).

[8] *Id.*, Module A, § 1.P (65.0.0); Module E-1, § 69A.7 (35.0.0).

[9] *Id.*, Module E-1, § 69A.7.1 (46.0.0).

5. Planning Resources are eligible to convert Unforced Capacity (UCAP)[10] to ZRCs, which indicate the units of capacity (in MW) a given market participant can offer into the Auction, sell bilaterally, or submit through a FRAP.[11] MISO currently determines the UCAP value of Planning Resources based on resource type. For example, MISO will determine the UCAP for a Generation Resource based on an evaluation of the type and volume of interconnection service, Generator Verification Test Capacity (GVTC)[12] value, and forced outage rating of such Generation Resource.[13] MISO determines the UCAP for a Dispatchable Intermittent Resource or Intermittent Generation based on historical performance, availability, and type and volume of interconnection service, in accordance with MISO's Business Practices Manual (BPM) for Resource Adequacy.[14]

II. Filing

6. MISO states that generation resource retirements, increased reliance on intermittent resources, significant weather events with correlated generator outages, and declining excess reserve margins will profoundly impact future grid reliability, and that all industry participants have a shared responsibility to plan for these impacts and implement new policies and practices to ensure the continued reliability of the grid. MISO states that, as part of this responsibility, MISO must make substantive changes to its resource adequacy construct to address these emerging issues.[15]

7. MISO states that its current resource adequacy construct, which focuses on the procurement of capacity for an entire 12-month Planning Year to meet demand during one peak day of the Summer Season, was not designed to address the trends currently facing the MISO Region.[16] MISO explains that reliability risks associated with resource

[10] UCAP is the amount of Capacity in megawatt (MW) assigned to a Planning Resource after accounting for its forced outage rate or historical availability. *Id.*, Module A, § 1.U (36.0.0).

[11] *Id.* § 1.Z (38.0.0).

[12] GVTC is the maximum output, in MW, that a Generation Resource, External Resource, or Behind-the-Meter-Generation (BTMG) can sustain over the specified period of time. *Id.* § 1.G (41.0.0).

[13] *Id.*, Module E-1, § 69A.4.1 (36.0.0).

[14] *Id.*

[15] Transmittal at 2-3.

[16] *Id.* at 3. The months included in the Summer Season are June, July, and August.

adequacy have shifted from "Summer only" to a year-round concern, noting that, since 2016, MISO has declared 40 Maximum Generation Emergencies[17] (MaxGen Events), with more than 60% occurring outside of the Summer months. MISO states that the significant increase in MaxGen Events is being driven by the confluence of: the retirement of traditional, baseload generation resources; planned and forced generator outages in non-Summer months; an increased reliance on intermittent generation such as wind and solar; and extreme weather events resulting in numerous forced generator outages, including multiple polar vortex and Arctic storms.[18]

8. MISO argues that the causes of the increase in MaxGen Events cannot be addressed through "one-off, quick fixes" but rather require a robust solution that creates incentives for Capacity Resources[19] to be available when and where they are needed, as the existence of Capacity Resources is meaningless if those resources do not provide energy or reserves when needed.[20] MISO contends that a well-designed market construct includes both the planning horizon, which entails the identification and incorporation of risks across the planning year in developing resource adequacy requirements, and the operating horizon, which ensures that those resources have the incentive to provide energy and reserves when and where needed. MISO states that aligning the planning horizon with the operating horizon is a central goal of the proposed reforms in the instant filing.[21]

9. MISO states that its resource adequacy reform proposals focus on two related proposals: (1) the establishment of a seasonal resource adequacy construct coupled with availability-based accreditation for certain Planning Resources, and (2) a Minimum Capacity Obligation (MCO) that promotes securing capacity well in advance of the

[17] MISO, FERC Electric Tariff, Module A § 1.M (71.0.0).

[18] Transmittal at 3-4.

[19] Capacity Resources are the Generation Resources, Demand Response Resource-Type I, Demand Response Resource-Type II, Dispatchable Intermittent Resources, External Resources, Intermittent Generation, Stored Energy Resources – Type II, or Electric Storage Resources that are available to meet Demand. MISO, FERC Electric Tariff, Module A § 1.C (67.0.0).

[20] Transmittal at 4.

[21] *Id.*

Auction.[22] MISO states that the instant filing presents MISO's seasonal and accreditation proposal.

10. MISO states that it expects the shift to a seasonal construct will further mitigate resource adequacy risks throughout the year, not just in the peak Summer Season, by establishing more granular, seasonal resource adequacy requirements to help ensure sufficient Planning Resources are committed and obligated to be available when needed. MISO expects this transition to: (1) identify reliability needs unique to each Season; (2) align Planning Resource availability with seasonal needs; and (3) facilitate and better account for seasonal outages or partial year operations.[23]

11. MISO states that its accreditation reforms seek to ensure that resources are available when needed the most by aligning resource accreditation with availability during the highest risk period in each Season. MISO proposes a new Seasonal Accredited Capacity (SAC) methodology to determine the capacity accreditation of certain classes of resources. MISO states that it also proposes a tiered weighting structure, with a transition period, to determine individual resource accreditation by Season based on each resource's Real-Time offered availability, accounting for coordinated planned outages. MISO explains that expected outcomes of MISO's accreditation reforms are to: (1) increase confidence in the capacity MISO can count upon when needed by shrinking the gap between cleared capacity within the Auction and realized capacity during tight system conditions; (2) provide improved signals for availability and coordination; and (3) improve resource outage coordination processes. MISO states that measuring and accrediting Planning Resources based on their availability and performance during Resource Adequacy Hours (RA Hours) will better align expectations during times of highest need. MISO argues that the current practice of relying on installed capacity, adjusted for forced outages and reflecting average availability throughout the Planning Year, no longer provides an accurate expectation of availability, as proven by recent emergency events, especially those driven by extreme weather.[24]

12. To address these trends, MISO proposes to: (1) replace its single annual resource adequacy requirement with four seasonal resource adequacy requirements; (2) implement seasonal, availability-based accreditation called SAC for thermal resources and modify

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[22] *Id.* Concurrently with this filing, MISO submitted, in Docket No. ER22-496-000, a proposal to establish an MCO on LSEs. Concurrently with this order, the Commission rejects MISO's MCO Filing. *Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,142 (2022).

[23] Transmittal at 4-5.

[24] *Id.* at 5.

non-thermal resource accreditation to align with MISO's proposed seasonal resource adequacy construct; and (3) modify MISO's outage procedures and establish new requirements for resources to replace capacity during outages under certain conditions. MISO requests an effective date of September 1, 2022 for its proposed Tariff revisions.[25]

III. Notice of Filing and Responsive Pleadings

13. Notice of the filing was published in the *Federal Register*, 86 Fed. Reg. 69,024 (Dec. 6, 2021), with interventions and protests due on or before December 21, 2021. On December 3, 2021, Entergy Services, LLC (Entergy), acting on behalf of the Entergy Operating Companies[26] and the Supporting Parties,[27] filed a motion for an extension of the comment date, from December 21, 2021, to January 14, 2022. On December 9, 2021, the Commission granted Entergy's motion for an extension of the comment date to January 14, 2022.

14. Notices of intervention were filed by: the Mississippi Public Service Commission and Mississippi Public Utilities Staff (Mississippi Commission); the Missouri Public Service Commission; the Illinois Commerce Commission (Illinois Commission); the Michigan Public Service Commission (Michigan Commission); the City Council of the City of New Orleans; the Public Service Commission of Wisconsin; the Organization of MISO States (OMS); the Arkansas Public Service Commission; the Louisiana Public Service Commission (Louisiana Commission); the Public Utility Commission of Texas;

[25] *Id.* at 52.

[26] The Entergy Operating Companies are: Entergy Arkansas, LLC; Entergy Louisiana, LLC; Entergy Mississippi, LLC (Entergy Mississippi); Entergy New Orleans, LLC; and Entergy Texas, Inc.

[27] The Supporting Parties are: Alliant Energy Corporate Services, Inc.; Ameren Services Company (Ameren), as agent for Union Electric Company, Ameren Illinois Company (Ameren Illinois) and Ameren Transmission Company of Illinois (Ameren Transmission); American Municipal Power, Inc. (AMP); Cleco Power LLC (Cleco Power); Consumers Energy Company (Consumers Energy); Dairyland Power Cooperative; DTE Electric Company (DTE Electric); Duke Energy Business Services, LLC for Duke Energy Indiana, LLC; EDF Renewables; Hoosier Energy Rural Electric Cooperative, Inc. (Hoosier); Illinois Municipal Electric Agency (IMEA); Indiana Municipal Power Agency; Indianapolis Power & Light Company (IPL); Madison Gas & Electric Company; Midland Cogeneration Venture; Minnesota Power; Northern Indiana Public Service Company; Otter Tail Power Company; Prairie Power Inc.; Rockland Capital; Southern Illinois Power Cooperative; Vistra; Wabash Valley Power Alliance; and WEC Energy Group.

the Indiana Utility Regulatory Commission (Indiana Commission); and the Kentucky Public Service Commission.

15. Timely motions to intervene were filed by: Cooperative Energy; NRG Power Marketing LLC; AMP; Energy Michigan, Inc. (Energy Michigan); Alliant Energy Corporate Services (Alliant); Wabash Valley Power Association, Inc.; Indiana Municipal Power Agency; Hoosier; Exelon Generation Company, LLC (Exelon); Solar Energy Industries Association (SEIA); American Clean Power Association (ACP) and Clean Grid Alliance (CGA); Fresh Energy; the Sustainable FERC Project and Natural Resources Defense Council (Sustainable FERC Project and NRDC); Duke Energy Corporation (Duke Energy); IPL; Calpine Corporation; Ameren; NextEra Energy Resources, LLC; Entergy; MidAmerican Energy Company (MidAmerican); Great River Energy; IMEA; Xcel Energy Services Inc.; Indiana Office of Consumer Counselor; Illinois Industrial Energy Consumers (IIEC); Association of Businesses Advocating Tariff Equity (ABATE); Indiana Industrial Group (IIG); the Louisiana Energy Users Group (LEUG); Texas Industrial Energy Consumers (TIEC); the Coalition of MISO Transmission Customers (CMTC); Southwest Louisiana Electric Membership Corporation and Concordia Electric Cooperative, Inc.; Arkansas Electric Cooperative Corporation (AECC); EDF Trading North America, LLC and EDF Energy Services, LLC; and East Texas Electric Cooperative (East Texas).

16. Additional timely motions to intervene were filed by: the MISO Transmission Owners;[28] Wisconsin Electric Power Company, Wisconsin Public Service Corporation and Upper Michigan Energy Resources Corporation (collectively, WEC Utilities); DTE Electric; Coalition of Midwest Power Producers, Inc. (COMPP); Sierra Club; Consumers

[28] The MISO Transmission Owners for this filing consist of: Ameren, Ameren Illinois, and Ameren Transmission; Big Rivers Electric Corporation (Big Rivers); Central Minnesota Municipal Power Agency; City Water, Light & Power (Springfield, IL); Cleco Power; Cooperative Energy; Dairyland Power Cooperative; Duke Energy Business Services, LLC for Duke Energy Indiana, LLC; East Texas; Entergy Arkansas, LLC; Entergy Louisiana, LLC; Entergy Mississippi; Entergy New Orleans, LLC; Entergy Texas, Inc.; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company; Lafayette Utilities System; Minnesota Power (and its subsidiary Superior Water, L&P) (Minnesota Power); Missouri River Energy Services; Montana Dakota Utilities Co.; Northern Indiana Public Service Company LLC; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Prairie Power, Inc.; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company; Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.

Energy; Great Lakes Utilities, Madison Gas and Electric Company, Midwest Municipal Transmission Group, Missouri Joint Municipal Electric Utility Commission, Missouri River Energy Services, Southern Minnesota Municipal Power Agency, Southwest Louisiana Electric Membership Corporation, and WPPI Energy (collectively, Midwest TDU); American Electric Power Service Corporation; Retail Energy Supply Association (RESA); Southern Illinois Power Cooperative (SIPC); Cleco Corporate Holdings LLC; Cleco Cajun LLC; COMPP; Big Rivers; Steel Producers; GridLab; International Transmission Company, Michigan Electric Transmission Company, LLC, and ITC Midwest LLC (collectively, ITC); and Manitoba Hydro.

17. On January 18, 2022, Potomac Economics, Ltd. (Potomac Economics), which is the MISO Independent Market Monitor (Market Monitor), filed a motion to intervene out-of-time.

18. Protests were filed by: the Louisiana Commission; the Mississippi Commission; Alliant; Consumers Energy; Entergy, AECC, and Cleco Power (collectively, Entergy Coalition); Steel Producers; Midwest TDUs; DTE Electric; Ameren; IIEC, ABATE, IIG, LEUG, TIEC, and CMTC (collectively, Industrial Customers); ITC; COMPP; IPL; and East Texas. Comments were filed by: MidAmerican; the Indiana Commission; the Michigan Commission; OMS; Duke Energy; Manitoba Hydro; Entergy; Great River Energy; WEC Utilities; the MISO Transmission Owners; Big Rivers, Hoosier, and SIPC (collectively, Joint Commenters); CGA, Sierra Club, Sustainable FERC Project, and NRDC, Fresh Energy, GridLab, ACP, and SEIA (collectively, Clean Energy Coalition); Minnesota Power; and Potomac Economics.

19. On February 10, 2022, MISO filed a motion for leave to answer and answer to comments and protests (MISO February 10 Answer). Motions for leave to answer and answers to the MISO February 10 Answer were filed by: Alliant; the Mississippi Commission; Midwest TDUs (Midwest TDUs February 25 Answer); WEC Utilities; Entergy; and Industrial Customers.

IV. Deficiency Letter and Deficiency Letter Response

20. On March 9, 2022, Commission staff issued a deficiency letter and requested additional information. On April 8, 2022, MISO filed a response to the deficiency letter (Deficiency Letter Response).

V. Notice of Deficiency Letter Response and Responsive Pleadings

21. Notice of MISO's Deficiency Letter Response was published in the *Federal Register*, 87 Fed. Reg. 22,529 (Apr. 15, 2022), with interventions and protests due on or before April 29, 2022. Timely comments were filed by: Alliant; Consumers Energy; Minnesota Power; Entergy; Clean Energy Coalition; Duke Energy; and Potomac

Economics. Timely protests were filed by: DTE Electric; Industrial Customers; and Midwest TDUs. On May 4, 2022, the Mississippi Commission filed a late protest.

22. On May 20, 2022, MISO filed a motion for leave to answer and answer to the comments and protests of its Deficiency Response (MISO May 20 Answer). On June 6, 2022, Midwest TDUs filed a motion for leave to respond and response to the MISO May 20 Answer (Midwest TDUs June 6 Answer).

VI. Discussion

A. Procedural Matters

23. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2021), the notices of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

24. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d), we grant Potomac Economics' late-filed motion to intervene, given its interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay. In addition, we will accept the late-filed protest of the Mississippi Commission, as this will not unduly delay the proceeding or cause undue prejudice to any party.

25. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2021), prohibits an answer to a protest or answer unless otherwise ordered by the decisional authority. We accept the answers because they have provided information that assisted us in our decision-making process.

B. Substantive Matters

26. As discussed below, we find MISO's proposal to be just, reasonable, and not unduly discriminatory or preferential. Accordingly, we accept MISO's proposed Tariff revisions, effective September 1, 2022, as requested, subject to condition.[29] Below, we address MISO's proposal to: (1) implement a seasonal resource adequacy construct; (2) accredit certain resources using the SAC methodology; and (3) require replacement of any Planning Resource that will be on planned outage or planned derate for more than 31 days in a Season which they are designated for Resource Adequacy Requirements. We

[29] The United States Court of Appeals for the District of Columbia Circuit has held that, in certain circumstances, the Commission has "authority to propose modifications to a utility's [FPA section 205] proposal *if the utility consents to the modifications*." *NRG Power Mktg., LLC v. FERC*, 862 F.3d 108, 114-15 (D.C. Cir. 2017).

also address concerns regarding MISO's stakeholder process, as well as other comments raised in the pleadings.

1. Seasonal Resource Adequacy Construct

a. MISO Filing

27. MISO states that, under the proposed seasonal resource adequacy construct, MISO will perform an LOLE evaluation to establish Reserve Requirements for all Market Participants representing LSEs and Local Clearing Requirements for all Zones on a seasonal basis for four Seasons: Summer; Fall; Winter; and Spring. MISO further states that it will then conduct the Auction and establish an Auction Clearing Price for each Zone for each Season. MISO explains that it will continue to conduct the Auction annually, in the Spring preceding the applicable Planning Year, but the Auction will clear the requirements separately for each Season.[30]

28. MISO states that shifting to a seasonal resource adequacy construct is designed to ensure that resources with needed capabilities and attributes will be available during the highest risk periods across the Planning Year. MISO explains that the current resource adequacy construct is based on the Summer Coincident Peak Demand forecasts, and, as a result, actual needs outside the Summer Season are not explicitly determined and defined, leaving potential risks unmitigated.[31] MISO contends that moving to a seasonal resource adequacy construct will align seasonal resource accreditation with seasonal resource availability to meet MISO's changing risk.[32]

29. MISO proposes to develop seasonal values for several construct parameters, including: (1) LOLE sub-annual modeling; (2) Planning Reserve Margin and Reserve Requirements; (3) Local Reliability Requirements and Local Clearing Requirements; and (4) Capacity Import Limits and Capacity Export Limits.[33]

30. MISO proposes changes to the modeling and methodology of the LOLE study to more accurately model seasonally sensitive variables and calculate resource adequacy construct parameters through: (1) seasonal LOLE risk allocation; and (2) improving seasonal LOLE modeling, including the modeling of planned outages, modeling of non-firm external imports, and hourly modeling of intermittent resources. MISO submits that

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[30] Transmittal at 10-11.

[31] *Id.* at 11 (citing Tab E (Testimony of Scott Wright), at 13 (Wright Test.)).

[32] *Id.* (citing Tab D (Testimony of Jameson Smith, at 18 (Smith Test.)).

[33] *Id.* at 11-12.

this new LOLE model needs to have a defined LOLE threshold for each Season to calculate seasonal resource adequacy Reserve Requirements, which will be determined under a two-step LOLE analysis. MISO states that, in the first step, the LOLE model will be solved to an annual LOLE value of 0.1 day per year to determine the natural LOLE distribution. MISO explains that, if after the first step there is a minimum of 0.01 day per year LOLE in all four Seasons, then the seasonal requirements will be determined directly from this step and there will be no need for additional analysis. MISO states that, if the first step determines that a Season has an LOLE of less than 0.01 day per year, then an additional step will be performed to solve that Season to an LOLE of 0.01 day per year. MISO states that in the second step, MISO will round LOLE targets up to a minimum of 0.01 day per year for any Season with an LOLE less than 0.01 day per year, and to maintain LOLE targets for Seasons with an LOLE greater than 0.01 day per year.[34]

31. MISO states that, to determine a Planning Reserve Margin for the four Seasons, MISO proposes performing an additional two-step LOLE analysis with seasonal input assumptions. MISO explains that the LOLE model will be used to meet the seasonal LOLE targets, which can differ from the annual LOLE target, by adjusting the capacity within the seasonal model up or down as needed.[35] MISO explains that, once the seasonal LOLE targets are met, the seasonal Planning Reserve Margin values in terms of UCAP will be calculated and expressed as a percentage of seasonal coincident peak demand. MISO states that the Planning Reserve Margin for each Season is multiplied by the 50/50 forecast of coincident peak load to determine the Reserve Requirements (in MW) for that Season.[36]

32. MISO asserts that, to determine zonal Local Reliability Requirements, MISO proposes using the same two-step process as the Planning Reserve Margin analysis with each Zone treated as an isolated system consistent with the existing Local Reliability Requirements analysis methodology under the current annual resource adequacy construct. MISO explains that seasonal Local Reliability Requirements values will be calculated in terms of UCAP and expressed as a percentage of seasonal zonal coincident peak demand once the model has been solved to the appropriate LOLE targets. MISO

[34] *Id.* at 12.

[35] MISO states that if the LOLE is less than the target for a Season, then a "perfect unit" with a negative capacity value and zero forced outage rate will be added to the model. If the LOLE is greater than the target for a Season, then proxy combustion turbine generators of typical size (160 MW) and class average Equivalent Forced Outage Rate Demand (XEFORd) will be added to the model until the seasonal LOLE target is achieved. *See* Transmittal at 12-13; McFarlane Testimony at 11-12.

[36] Transmittal at 12-13.

states that the seasonal Local Reliability Requirements values will be used to determine the seasonal Local Clearing Requirement values by subtracting the seasonal Capacity Import Limited from the seasonal Local Reliability Requirement.[37]

33. MISO proposes to modify its existing determination of Capacity Import Limits and Capacity Export Limits capturing the seasonal variation of transfer limits for each Zone to account for four seasons. MISO explains that Planning Year seasonal peak power flow models and input files developed from MISO Transmission Expansion Plan studies will be used to perform transfer analyses for each Season including Summer Peak, Fall Peak, Winter Peak, and Spring Peak study models. MISO states that the resulting seasonal Zonal Import Ability,[38] in conjunction with controllable exports, will be used to determine the seasonal Local Clearing Requirements for each Zone.[39]

34. MISO contends that the proposed resource adequacy construct more accurately represents resource capabilities at different times during the year, improves certainty of resource availability outside the Summer Season, provides better incentives for resources to be available when needed, establishes seasonal reserve requirements that better align with risks, and delivers additional visibility into risks throughout the Planning Year. According to MISO, these advantages are not currently captured in the annual construct. MISO adds that, in general, resource owners and LSEs benefit from lower non-Summer peak loads, resulting in lower non-Summer Reserve Requirements that reduce the required cleared capacity and allow for seasonal resource operation and related cost savings to loads.[40]

35. MISO states that the Auction will continue to be administered in the spring of each year, and that, in most cases, the process will remain the same but will be applied on a seasonal basis rather than on an annual basis. MISO explains that the Auction offer window will continue to be the last four business days in March. MISO states that the "must offer" requirement for resources that clear the Auction will only apply in the Season or Seasons in which the resource clears. Finally, MISO notes that it will increase

[37] *Id.* at 13.

[38] MISO defines Zonal Import Ability as "[t]he ability of a[] [Zone] to import capacity from areas outside of that [Zone]. MISO, FERC Electric Tariff, Module A § 1.Z (38.0.0).

[39] Transmittal at 13.

[40] *Id.* at 13-14.

the time available to clear the Auction from 10 to 20 business days in order to clear the four Seasonal auctions.[41]

36. MISO proposes to modify its market monitoring and mitigation provisions in Module D of the Tariff. With regard to physical withholding provisions, MISO proposes to remove provisions that prohibit resources that expect to be on outage for more than 90 of the first 120 days of the Planning Year to participate in the Auction and replace that with a provision that states that a Market Participant with a resource that has submitted an outage for more than 31 days of a given Season can ask the Market Monitor for a determination ahead of the Auction allowing it to forego offering excess ZRCs from the resource into the Auction, without being deemed to have engaged in physical withholding. MISO states that the threshold for economic withholding remains at 10% of daily Cost of New Entry (CONE),[42] but MISO expects that more resources will request facility-specific Reference Levels or use Default Technology Specific Avoidable Costs to help ensure they can cover the costs when they might only clear for one Season, rather than the full Planning Year under the current construct.[43] MISO notes that the threshold for economic withholding remains at $0/MW-day when a resource offers at a facility-specific Reference Level.[44]

37. MISO states that, under the proposed seasonal construct, there are rare circumstances that could result in over or underpayment to Planning Resources. MISO's proposal includes an ex-post adjustment to reduce the Auction Clearing Price when more than one Season clears in ZRC Shortage Conditions or ZRC Near-Shortage Conditions.[45] If this occurs, the final Auction Clearing Price will be set based on annual CONE and the

[41] *Id.* at 14.

[42] Cost of New Entry (CONE) is the "capital, operating, financial and other costs of acquiring a new Generation Resource within the Transmission Provider Region for any designated [Zone]." MISO, FERC Electric Tariff, Module A § 1.C (67.0.0).

[43] In MISO, facility-specific Reference Levels may be established for certain Planning Resources if a market participant provides documentation of going-forward costs of keeping a Planning Resource in operation or going-forward costs of returning a Planning Resource from suspension. *See* MISO, FERC Electric Tariff, Module D § 64.1.4(f) (65.0.0).

[44] Transmittal at 21.

[45] ZRC Near-Shortage Conditions occur in a Zone in any Season that has sufficient volume of ZRC Offers to cover that Zone's Reserve Requirements, but the Season's Auction Clearing Price is greater than the daily CONE value. *See* MISO, FERC Electric Tariff, Module A, § 1.Z (40.0.0) (proposed).

number of days in all applicable Seasons when a Zone clears below the required number of ZRCs or the Season's initial Auction Clearing Price clears above daily CONE. MISO explains that, to address this potential risk, MISO proposes enhancements to the offer caps in the seasonal Auctions and will add the ZRC Offer Revenue Sufficiency Guarantee Credit, a make-whole payment provision, to ensure that resources that clear the Auction recover the costs reflected in their seasonal offer, while also ensuring that the LSEs are not exposed to Auction Clearing Prices and capacity charges that amount to multiples of the annual CONE value as a result the proposed seasonal construct.[46] MISO states that charges to fund the ZRC Offer Revenue Sufficiency Guarantee Credit will be allocated to Market Participants representing LSEs in the Zone(s) experiencing shortage or near shortage conditions *pro rata*, based on their respective LSEs' share of the Reserve Requirement within the Zones during the Season or Seasons where the Auction Clearing Prices were reduced.[47]

b. Comments and Protests

38. Some commenters note that MISO's proposal supports resource adequacy throughout the 12-month Planning Year by recognizing that MaxGen Events are occurring more frequently outside of the Summer Season, and by providing for a more granular assessment of risk across the year.[48] OMS states that MISO's proposal builds on previously accepted Tariff provisions and modifies them to fit the proposed seasonal construct.[49] The Indiana Commission states that a more granular assessment of risks across the year will allow MISO to plan and provide for each Season's own unique reliability needs.[50] ITC states that the use of a four-Season construct will allow MISO to anticipate the supply needs of its members and ensure reserves to meet demand during all hours of the year.[51] Manitoba Hydro argues that the proposal will continue to allow and encourage bilateral trade, diversity exchange agreements, and external participation in

[46] Transmittal at 21-22.

[47] *Id.* at 22.

[48] Michigan Commission Comments at 3; OMS Comments at 3-4; Manitoba Hydro Comments at 2; Indiana Commission Comments at 3-5; ITC Comments at 3.

[49] OMS Comments at 4.

[50] Indiana Commission Comments at 4-5.

[51] ITC Comments at 3.

MISO, which it argues reduce overall costs to consumers and enhances overall grid security.[52]

39. Potomac Economics supports MISO's proposal to transition to a seasonal capacity market, and believes it is an improvement over MISO's current market design and rules.[53] Potomac Economics states that moving to a seasonal resource adequacy construct will provide suppliers better incentives to satisfy the unique needs of each Season while also allowing MISO the flexibility to establish market requirements on a seasonal basis and is better aligned with reliability needs.[54]

40. Potomac Economics explains that, compared to an annual construct, resources retiring mid-year would have more flexibility to select a retirement or suspension date without having to procure significant replacement capacity to satisfy post-retirement capacity obligations. Potomac Economics states that, over time, as new resources enter the market with distinct seasonal output patterns, such as intermittent wind and solar, the value of procuring capacity seasonality will rise.[55]

41. While Potomac Economics supports the transition to a seasonal construct, it suggests that conducting four simultaneous auctions unnecessarily increases uncertainty regarding the supply and demand for capacity in any given Season. Potomac Economics contends that sequential, rather than simultaneous, auctions would allow the decisions and offers in the remaining Seasons to be informed by results of the initial Seasons. Potomac Economics submits that this can be highly beneficial for suppliers that are making retirement and/or suspension decisions based on the seasonal capacity auctions they clear. As an example, Potomac Economics states that a resource that clears in the Summer Auction and covers its going-forward costs is likely to be willing to offer at a lower price in the remaining Seasons than in a simultaneous auction where the supplier is uncertain in which Season(s) the resource will clear, if any. Potomac Economics states that likewise, a supplier considering a suspension or seasonal shutdown may make a different decision or offer at the different level in one Season depending on whether the resource cleared in the prior Season.[56]

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[52] *Id.*

[53] Potomac Economics Comments at 2.

[54] *Id.*

[55] *Id.* at 3-4.

[56] *Id.* at 5.

42. East Texas states that it has repeatedly asked MISO to substantiate how the shift from an annual to a seasonal construct, with discrete Reserve Requirements for all LSEs, would enhance resource availability and forestall unnecessary capacity market shortfalls within MISO, and that MISO has failed to provide adequate data to justify its proposal. East Texas alleges that MISO instead attempts to justify its proposal with generalized and nebulous assertions concerning the supposed advantages of a more granular construct in mitigating reliability risks in non-Summer months. East Texas states that, for example, it requested MISO to provide a simulation showing how MISO's seasonal construct proposal would have strengthened MISO's response to Winter Storm Uri in February 2021 or any other non-Summer event in recent years. East Texas further states that it asked MISO to provide cost-benefit analyses illustrating how the seasonal construct's supposed advantages in mitigating reliability risks within the MISO footprint compared to the costs that this new capacity procurement paradigm would inflict on market participants representing LSEs, which MISO failed to do.[57]

43. East Texas alleges that MISO repeatedly invokes the specter of an impending reliability crisis, while asserting that its seasonal construct would address this crisis by mitigating MISO's reliability risks during the non-Summer months. East Texas argues that MISO fails to show why it could not employ more targeted reforms, nor does MISO specify what benefits this policy would garner for MISO market participants and other stakeholders. East Texas asserts that MISO should not be allowed to effect a broad overhaul of its capacity market without marshaling greater evidence of the ostensible benefits and impacts such a critical reform would yield, and, given the claimed benefits of MISO's seasonal construct as speculative and lacking in factual support, that the Commission should reject MISO's filing and instruct MISO to return to the stakeholder process to revise a better substantiated solution to its claimed resource adequacy challenges.[58]

44. Clean Energy Coalition argues that MISO has not explored whether the increased complexity of the proposal is manageable as part of utility planning processes. Clean Energy Coalition argues that, if LSEs cannot effectively plan to meet seasonal capacity requirements along the timeline contemplated, the proposal will result in building higher amounts of capacity than needed.[59]

45. Alliant states that generation investments are long-term decisions that require years of planning and implementation to bring a new resource online, and MISO's proposal does not provide market participants with timely actionable information to allow

[57] East Texas Protest at 4-5.

[58] *Id.* at 5.

[59] Clean Energy Coalition Protest at 17.

generation owners to make informed investment decisions. Alliant asserts that it is now put in the untenable position of potentially making inefficient resource planning decisions in the near-term in order to fall in line with MISO's unsubstantiated and overly conservative Planning Reserve Margins. Alliant submits that delaying the implementation date to no sooner than the 2024/2025 Planning Year will allow capacity resource owners time to reconfigure their resource plans and portfolios and for MISO to provide a reasonable path to obtain seasonal interconnection rights.[60]

46. Several protestors contend that MISO's proposed market structure lacks mitigation to ensure just and reasonable Auction revenues. Clean Energy Coalition and Midwest TDUs contend that there are multiple scenarios in which annual capacity revenues could be expected to exceed the current maximum Auction price of CONE, potentially due to one tight Season, thereby potentially resulting in a resource setting a Season's Auction Clearing Price at four times the current annual Auction's maximum price, and generating greater auction revenue from all four Seasons than is permitted under the current annual Auction.[61] Clean Energy Coalition argues that, even though MISO takes steps to mitigate the likelihood of price spikes in certain Zones for certain Seasons, MISO's proposal goes out of its way to establish the ZRC Offer Revenue Sufficiency Guarantee Credit to protect generation owners from any risk from Auction Clearing Price reductions.[62] Clean Energy Coalition states that, while it makes sense in theory to insulate capacity owners that may be forced to provide capacity while being paid less than they bid into the market, these make-whole payments will come from LSEs and their ratepayers and are defined in part by facility-specific Reference Levels that are calculated independently through a process involving the Market Monitor. Clean Energy Coalition argues that MISO has not provided enough information to justify the make-whole payment process and argues that ongoing tracking and evaluation of the market adjustment make-whole payment system is necessary.[63] Midwest TDUs add that MISO's ex post adjustment to Auction Clearing Prices proposal produces higher auction revenues when there are fewer Seasons in shortage conditions.[64]

47. Midwest TDUs contend that, because MISO has not demonstrated that allowing annual Auction revenues above annual CONE, and potentially more than double annual

[60] Alliant Protest at 7-8.

[61] Clean Energy Coalition Protest at 14; Midwest TDUs Protest at 38-40.

[62] Clean Energy Coalition Protest at 14.

[63] *Id.* at 15.

[64] Midwest TDUs Protest at 41.

CONE, is just and reasonable, the Commission should reject MISO's filing.[65] Midwest TDUs state that the current, Commission-approved cap for annual capacity supply offers in the Auction and the price for shortage conditions all treat annual CONE as the appropriate capacity price signal. Midwest TDUs submit, however, that, under MISO's proposal, if a resource that clears in just one Season sets the price for that Season at MISO's offer cap, other resources that clear in multiple Seasons could recover well above annual CONE. Midwest TDUs add that, if revenues above annual CONE produce over-recovery for individual resources, total Auction revenues above annual CONE would produce over-recovery on a much greater scale.[66]

48. Midwest TDUs suggest that MISO is attempting to minimize the potential for over-recovery by relying on the unlikelihood of such an event occurring, and contend that this is contrary to MISO's stated basis for the present filing, which is to address, among other things, shrinking excess margins. Midwest TDUs argue that, if a shift to a seasonal reliability construct is necessary to ensure adequate capacity, MISO cannot ignore the risk of inadequate capacity in the mitigation component of its proposal.[67]

49. Midwest TDUs argue that MISO claims that existing Tariff provisions to determine facility-specific Reference Levels are sufficient because "[s]uch Reference Levels have historically accounted for a small fraction of ZRC Offers in the annual [Auctions]."[68] Midwest TDUs suggest that this is contradicted by a different MISO statement that MISO "expect[s] that more resources will request facility-specific Reference Levels."[69] Midwest TDUs submit that this means that MISO expects that offers above the economic withholding thresholds will comprise a larger fraction of offers in the seasonal auction, weakening the protection of the initial economic withholding threshold and potentially driving up prices. Midwest TDUs further argue that the availability of make-whole payments that ensure cost-recovery for resources clearing in a single Season may also create incentives for resources to clear in just one Season and be relieved of the must-offer obligation in other Seasons, again potentially driving up prices.[70]

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[65] *Id.* at 44.

[66] *Id.* at 41-42.

[67] *Id.* at 42.

[68] *Id.* at 42-43 (citing McFarlane Test. at 42).

[69] *Id.* at 43 (citing McFarlane Test. at 51).

[70] *Id.* at 42-43.

50. Midwest TDUs claim that the proposed Tariff language does not appear to mitigate auction prices in the way described in the McFarlane Testimony. Midwest TDUs state that, according to the McFarlane Testimony, MISO would adjust auction prices "when more than one Season clears in ZRC Shortage Conditions or ZRC Near-Shortage Conditions."[71] However, Midwest TDUs note that revisions to Tariff section 69.A.7.1.c.x. state that MISO will adjust prices in two situations: (1) in Zones "with Seasons in ZRC Shortage Conditions," and (2) in Zones "with Seasons in ZRC Near-Shortage Conditions."[72] Midwest TDUs contend that this language does not appear to cover Zones with one Season in shortage conditions and one Season in Near-Shortage conditions and thus creates a gap in mitigation that could allow for two Seasons that each have prices producing revenues equal to annual CONE, allowing for total auction revenues that are more than double annual CONE.[73]

51. Alliant, East Texas, and Entergy Coalition raise concerns with MISO's proposed implementation schedule. East Texas points out that, should the Commission accept MISO's proposal within MISO's requested time frame, LSEs would have approximately 15 months before the proposal takes effect in June 2023. East Texas submits that generation owners would not have time to assess the impacts to their generation fleets, adjust their operations and planning functions to accommodate this new accreditation paradigm, and negotiate any necessary amendments to existing power supply agreements.[74] Alliant argues that MISO's request to implement the new construct in less than a year between filing the proposal and MISO's proposed September 1, 2022 effective date does not reflect the realities of the conditions under which MISO stakeholders and generation owners must operate, given the length of time required to get capacity projects through MISO's interconnection process.[75] East Texas and Entergy Coalition contend that LSEs will not have sufficient time to effectuate any significant generation or transmission investments to enhance their capacity positions, which could result with customers facing elevated prices in the Auction for several years.[76]

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[71] *Id.* at 43-44 (citing Tab C (Testimony of Shawn McFarlane), at 41 (McFarlane Test.)).

[72] *Id.* at 44 (citing MISO, FERC Electric Tariff, Module E-1, § 69A.7.1.c.x (45.0.0) (proposed)).

[73] *Id.*

[74] East Texas Protest at 7.

[75] Alliant Protest at 5-6.

[76] East Texas Protest at 7; Entergy Coalition Protest at 21-22.

52. Some commenters protest MISO's proposed methodology to determine seasonal Planning Reserve Margins and Reserve Requirements. Entergy Coalition submits that, while MISO states that one of the benefits MISO expects to achieve with the proposal is lowering non-Summer resource adequacy requirements, MISO's proposal fails to accomplish this goal. Entergy Coalition states that data provided by MISO during the stakeholder process indicates that under MISO's proposal many of the LSEs in MISO South would have Spring Reserve Requirements that are higher than their Summer requirements. Entergy Coalition states that, given that the Spring Season is traditionally considered an off-peak Season in MISO South during which significant maintenance outages are taken, this outcome is counterintuitive and would create significant planned maintenance scheduling challenges for these LSEs.[77]

53. Similarly, the Mississippi Commission argues that the proposal would decrease Zone 10's surplus generation by between 721 MW and 1,621 MW, depending on the Season, and cause economic hardship for Mississippi retail customers.[78] The Mississippi Commission states that, if Zone 10 does not have enough capacity to meet its Local Clearing Requirement, Entergy Mississippi's retail customers would be subjected to seasonal penalties of tens of millions of dollars; an amount that, according to the Mississippi Commission, negates the estimated net positive benefit of Entergy Mississippi's participation in MISO.[79]

54. Alliant argues that MISO's Planning Reserve Margin for non-Summer results is unnecessarily high. Alliant explains that MISO proposed to stakeholders the use of a 7.1% Planning Reserve Margin for the Summer Season, while Planning Reserve Margins for the non-Summer Seasons were between 14% and 22%. Alliant states that it is concerned that the non-Summer Planning Reserve Margins are driven by arbitrary inputs without a supporting sensitivity analysis. Alliant requests that the Commission delay implementation of MISO's filing until MISO can provide robust analysis for why Planning Reserve Margins in non-Summer months need to be excessively conservative for purposes of reliability.[80]

55. Alliant notes that MISO proposes to use a non-Summer LOLE as conservative as 0.1 day in 10 years, even though MISO currently uses a LOLE target of 1 day in 10 years. Alliant contends that using such a conservative assumption drives non-Summer capacity obligations to near-Summer requirements, despite lower load levels. Alliant

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[77] Entergy Coalition Protest at 19.

[78] Mississippi Commission Protest at 30-31.

[79] *Id*. at 30.

[80] Alliant Protest at 9-10.

states that, while the evolution of the generation portfolio may increase risk for Winter and other non-Summer Seasons, MISO's overly conservative assumptions and constrained implementation deadline will needlessly drive inefficient resource plans. Alliant states that Winter peak load in MISO is approximately 85% of Summer peak load, but Winter capacity requirements are approximately 93% of the Summer Reserve Requirements. Alliant contends that, as a result, MISO's approach to non-Summer Seasons does not accommodate efficiency gains for seasonal conditions in the generation portfolio.[81]

56. The Mississippi Commission argues that MISO's proposed CONE penalty does not promote resource adequacy because, according to the Mississippi Commission, MISO proposes to apply a total penalty of 100% CONE on a deficient LSE regardless of whether it is deficient for one Season or multiple.[82] The Mississippi Commission states that, if an LSE is deficient in multiple Seasons, MISO would impose fractions of the CONE penalty so that at the end of the year, the penalty would be the same amount. The Mississippi Commission states that this sends the message that, if an LSE is deficient for one Season, there is no need to cure that deficiency for subsequent Seasons. Further, the Mississippi Commission asserts that, if an LSE is informed that it will be deficient, there is not enough time to construct a new generating facility before MISO's proposed effective date, and the utility's retail customers will be subject to unreasonable penalty charges.[83]

57. Clean Energy Coalition argues that MISO's showing that risk occurs throughout the year does not necessarily demonstrate that the proposed seasonal construct would provide better reliability than the current annual construct.[84] Clean Energy Coalition argues that the proposed solution is not sufficient for addressing resource adequacy for a system with greater penetrations of energy limited resources and that MISO has not evaluated its proposed design under a renewable heavy scenario.[85]

58. Clean Energy Coalition asserts that MISO has not provided any data to demonstrate that its metrics to identify risk hours align with realized loss of load risk. Clean Energy Coalition states that MISO has not conducted a system-level loss of load

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[81] *Id.* at 10.

[82] Mississippi Commission Protest at 7.

[83] *Id*. at 7-8.

[84] Clean Energy Coalition Protest at 18.

[85] *Id.* at 18-19.

modeling analysis of a technically high quality to assess the periods or hours in which there is greatest risk of not serving load.[86]

59. Clean Energy Coalition argues that MISO's LOLE modeling lacks an accurate assessment of weather-related risks, which, according to Clean Energy Coalition, is necessary to understand whether MISO's proposal ensures reliability under a potentially radically different resource mix.[87] Clean Energy Coalition contends that MISO's flawed method to extrapolate wind and solar datasets to periods of synthetic load results in non-time synchronized data, and does not correctly identify periods where the combination of high loads and low wind and solar output create system risk.

60. Clean Energy Coalition argues that the assumption that solar or wind profile shape on a given day is a function of MISO-wide temperature data for nearby calendar days from other days is physically invalid. Clean Energy Coalition contends that correlating wind profiles to MISO-wide minimum temperature for November through March and MISO-wide maximum temperature for April through October is not substantiated, has no physical basis, and cannot possibly predict local wind speeds.[88] Clean Energy Coalition also argues that cloud cover is a much greater determinant of solar output than temperature and notes that there is a weak correlation between the two.[89] Clean Energy Coalition states that the validation provided by MISO indicated a poor match between actual and synthesized shapes even after smoothing for averaging. Clean Energy Coalition argues that the tails of the distribution in figures presented to validate the appropriateness of this method indicate a poor match between actual and simulated data during high load periods.[90] Clean Energy Coalition further argues that data presented for wind generation does not match regional attributes, as the average generation is low relative to current technology expectations and the diurnal shape is inconsistent with reality.[91] Finally, Clean Energy Coalition argues that methods used to develop future wind and solar generation profiles for the 2025 interconnection queue receive only

[86] *Id.* at 12.

[87] *Id.*

[88] *Id.*

[89] *Id.*

[90] *Id.*

[91] *Id.* at 13.

cursory mention and the information provided indicates that these methods do not capture physical processes or expected diversity increases in a meaningful way.[92]

c. MISO February 10 Answer

61. In response to comments about seasonal capacity prices, MISO argues that its proposal adequately mitigates against excessive prices in the seasonal Auctions. MISO explains that annual Auction revenue can only approach 1.75x CONE when one Season clears at CONE and the others clear just below 10% of CONE (approximately $250/MW-day), in which case the Auction Clearing Price is adjusted per the proposal.[93]

62. In response to the Mississippi Commission's assertion that MISO's proposal would convert Entergy Mississippi's capacity surplus into a shortage, MISO submits that the Mississippi Commission fails to recognize inherent differences in Seasonal Local Clearing Requirement positions that are driven by a number of factors, including resource performance and availability, load profiles, and Capacity Import Limits for each Season. MISO states that the current annual zonal Local Clearing Requirement positions are derived from Summer-focused assumptions and do not accurately reflect the seasonality of resource capabilities, load, and transfer capabilities under seasonal system conditions.[94] MISO argues that, compared to the overall average resource performance at the footprint level, Zone 10 resources have lower availability and are expected to see a reduction in their accredited values under the proposal to better reflect their reliability contribution during times of need. MISO states that, although varying levels of reduction in Zone 10 resource accredited values are projected for each Season, the projected seasonal zonal positions remain to be surpluses, not shortages, under the set of analysis parameters presented in the November 3, 2021 Resource Adequacy Subcommittee (RASC) meeting.[95]

63. In response to Alliant's argument that MISO's approach to set LOLE targets for non-Summer Seasons is overly conservative and drives non-Summer requirements to "near-Summer" requirements, MISO contends that Alliant fundamentally mischaracterizes MISO's proposal of defining seasonal LOLE targets in determining seasonal reserve requirements. MISO submits that its approach aims to set seasonal requirements reasonably while keeping the annual LOLE for the Planning Year largely close to 0.1 day per year. MISO states that this is accomplished by rounding LOLE

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[92] *Id.*

[93] MISO February 10 Answer at 44.

[94] *Id.* at 41-42.

[95] *Id.* at 42.

targets up to a minimum of 0.01 day per year for any Season(s) with an LOLE less than 0.01 day per year and maintaining LOLE targets for the Seasons with an LOLE greater than 0.01 day per year. MISO further states that Alliant fails to recognize that seasonal Planning Reserve Margins are in terms of percentage and seasonal peak demand forecasts will be applied to determine the MW requirements for each Season. MISO states that Reserve Requirements for non-Summer Seasons tend to be significantly lower than the Summer MW reserve requirement.[96]

64. In response to Clean Energy Coalition's assertion that MISO has not performed a system wide LOLE analysis of a technically high quality to assess loss of load risks, MISO states that it has enhanced its LOLE modeling to better reflect the seasonality of various types of resource capabilities, including seasonal forced outage rates with cold weather adjustments, a probabilistic representation of non-firm external support, and multi-year hourly wind and solar profiles. MISO explains that it has also spent many months conducting a suite of high-fidelity LOLE risk analysis under both current resource portfolio and a broad range of future resource portfolio scenarios to gain a good understanding of changing reliability risk profiles with the evolving resource portfolio. MISO further explains that it used historical hourly wind outputs for recent weather years from 2011 to 2019 to develop correlations between historical wind output and temperature/load to ensure the variation of wind output as a function of load is well represented. MISO argues that its approach to developing synthetic wind profiles for 1990-2010 reasonably captures the historical variability and volatility around the synthetic load shapes by developing a similar distribution of wind outputs as a function of the 1990-2010 load shapes as seen in the 2011-2019 load and wind shapes where actual historical wind outputs are available. MISO explains that, similarly, hourly solar profiles from 1998 to 2019 generated using the NREL National Solar Radiation Databased Data Viewer were used to develop synthetic solar profiles for 1990 to 1997 weather years to maintain a similar relationship between load and solar outputs as seen in the 1998 to 2019 time frame.[97]

d. Answers to MISO February 10 Answer

65. Midwest TDUs argue that MISO did not explain how its proposed departure from using annual CONE as the capacity price signal and the resulting excessive seasonal Auction prices and revenues allowed under its proposal are just and reasonable.[98] Midwest TDUs state that MISO concedes that its proposal could result in annual auction

[96] *Id.*at 44-45.

[97] *Id.* at 45-46.

[98] Midwest TDUs Answer at 26-27.

revenues that approach 1.75x CONE.[99] Regarding the calculation of Auction prices, Midwest TDUs assert that, if MISO intends to adjust Auction prices when there is more than one Season in or near shortage conditions, then the Tariff should make that clear.[100] According to Midwest TDUs, MISO fails to adequately mitigate unreasonable and unjust capacity prices, and its proposal actually produces less annual Auction revenue when more Seasons are in or near shortage conditions.[101]

66. Alliant states that MISO's February 10 Answer shows that non-Summer Reserve Requirements will be nearly as high as Summer Reserve Requirements, which Alliant contends could lead to inefficient resource planning based on overly conservative assumptions.[102] Alliant requests that the Commission delay implementation of the MISO proposal until MISO provides analysis to support the Planning Reserve Margins proposed in non-Summer months.[103]

e. Deficiency Letter Response and Responsive Pleadings

67. As noted above, on March 9, 2022, Commission staff issued a deficiency letter and requested additional information, and MISO submitted its Deficiency Letter Response on April 8, 2022. In response to a question requesting additional support for the proposal to allow Auction revenue to potentially exceed annual CONE, MISO states that it recognized the need to raise the $/MW-day offer cap so that resources only available or only needed in a single Season are still eligible to receive payments up to annual CONE. MISO states that, while this continues to ensure revenue adequacy, it could lead to scenarios where load pays capacity charges in excess of annual CONE. MISO asserts that its proposal mitigates this result by reducing Auction Clearing Prices for shortage and near-shortage Seasons so that, in the aggregate, such Seasons collect revenue up to annual CONE but no more. MISO states that the potential for charges above annual CONE comes from revenues based on the Auction Clearing Price in Seasons that were not in shortage or near-shortage conditions. MISO states that, by

[99] *Id.* at 26 (citing MISO February 10 Answer at 44).

[100] *Id.* at 28.

[101] *Id.*

[102] Alliant Answer at 3.

[103] *Id.*

definition, those prices will always be below the mitigated prices in the shortage or near-shortage conditions, which MISO contends is a reasonable result.[104]

68. In response to a question requesting additional information about the relationship between MISO's LOLE target of 0.01 day per year for each Season and the annual LOLE target of 0.1 day per year, MISO states that the annual 0.1 day per year target is cumulative across all Seasons. MISO states that, after performing the two-step LOLE analysis, it is possible for the summation of the LOLE across all Seasons to equal 0.1 days per year, with some Seasons having LOLE less than 0.01 days per year. MISO explains that, to determine a seasonal requirement for Seasons with LOLE less than 0.01 days per year, a minimum of 0.01 days per year LOLE target for the Season is used because a defined non-zero LOLE target is needed to solve the model. MISO states that the 0.01 days per year target allows the model to converge accurately and without significant computational burden while holding the Season to near 0 LOLE and staying as close as possible to an annual LOLE of 0.1 days per year. MISO submits that a target smaller than 0.01 makes it difficult for the model to converge while a target above 0.01 causes the total LOLE to increase too far beyond the annual 0.1 days per year.[105]

69. MISO states that it provided analysis to market participants indicating that between 14%-27% of approximately 110 market participants would experience higher non-Summer Reserve Requirements than their Summer Reserve Requirements, and that these results are driven by market participants with flatter seasonal load profiles and higher non-Summer MISO-system Planning Reserve Margins. MISO notes that it has yet to collect seasonal coincident peak load forecasts, so that the impact analysis was performed using proxy seasonal coincident peak load forecasts estimated based on seasonal load forecast factors and Summer coincident peak forecasts. MISO states that, as a result, the Reserve Requirement values are subject to change once market participants submit actual seasonal coincident peak load forecasts.[106]

70. Midwest TDUs, Clean Energy Coalition, Entergy, and Alliant submitted comments on MISO Deficiency Letter Response. Midwest TDUs argue that MISO has not justified its proposal to allow Auction revenues in excess of annual CONE. Midwest TDUs contend that the potential for Auction revenues tens of thousands of dollars per MW-year above CONE does not, as MISO claims, protect load from paying capacity charges that are well in excess of annual CONE. Midwest TDUs further argue that MISO

[104] MISO Deficiency Letter Response at 26.

[105] *Id.* at 21.

[106] *Id.* at 22.

does not respond to the fact that MISO's proposal allows for higher Auction revenues as fewer Seasons are in shortage or near-shortage conditions.[107]

71. Clean Energy Coalition states that artificially setting the LOLE seasonal target to 0.01 per year in a Season that has no risk ignores the results from annual LOLE modeling. Clean Energy Coalition argues that, while it agrees with MISO's statement that setting a seasonal LOLE target to 0.01 is the only way to get the model to solve, the model cannot find the Effective Load Carrying Capability (ELCC) of any resource if there is no risk in that Season. Clean Energy Coalition submits that artificially adding risk to a Season that has none, and then accrediting resources for mitigating this artificial risk, is not a just and reasonable approach to maintaining reliability. Clean Energy Coalition adds that, if MISO's modeling approach cannot quantify the risk that demonstrably occurs in all Seasons, then MISO is missing a key improvement necessary to identify reliability risks.[108]

72. Entergy states that MISO's response to a question requesting additional data on how often LSEs will experience higher non-Summer Reserve Requirements demonstrates that up to a quarter of LSEs will not realize one of the primary intended benefits of the seasonal construct as stated by MISO, which is that the seasonal construct will result in lower non-Summer Reserve Requirements, enabling seasonal operation of resources. Entergy argues that MISO's overly broad seasonal risk allocation of the 0.1 LOLE target is flawed and does not obtain the desired outcome of lower non-Summer Reserve Requirements for all LSEs.[109]

73. Alliant contends that MISO's Deficiency Letter Response demonstrates Alliant's initial argument that there are still important details that need to be resolved before implementation of the proposal can occur. Alliant contends that MISO still has not addressed concerns that non-Summer Planning Reserve Margins, which will be potentially two to three times higher than Summer Planning Reserve Margins, are a rational outcome. Alliant states that the higher Planning Reserve Margins for non-Summer Seasons results in Reserve Requirements for non-Summer Seasons that are nearly as high as the Reserve Requirements for the Summer Season, despite significant load differences. Alliant states that MISO has explained the modeling process and challenges with modeling limitations but has not addressed concerns that the proposed

[107] Midwest TDUs Response to MISO Deficiency Letter Response at 27-29.

[108] Clean Energy Coalition Response to MISO Deficiency Letter Response at 8.

[109] Entergy Response to MISO Deficiency Letter Response at 6-7.

obligation determination processes lead to an unreasonable outcome for the Planning Reserve Margin and Reserve Requirements.[110]

74. Alliant asserts that MISO continues to ignore the dramatic impact the seasonal construct will have on short-term portfolio plans. Alliant states that MISO has the data and tools available to assess this impact and could take its conceptual seasonal reserve margin obligations and apply those to the MISO/OMS survey data to illustrate indicative changes in projected capacity positions by year and Season for the footprint and each Zone. Alliant contends that this information is critical for the Commission, MISO, market participants, and state regulators to understand the true forecasted impact of the seasonal construct.[111]

f. MISO May 20 Answer

75. With regard to concerns about Auction revenues exceeding annual CONE, MISO states that its Deficiency Letter Response explained that the proposal mitigates, but cannot fully eliminate, the possibility. MISO states that its proposal strikes a balance between ensuring that resources designated for resource adequacy are revenue adequate even if they are only designated for a single Season, and protecting load from excessive capacity prices above the annual CONE value (expressed in a daily $/MW-day value) across multiple Seasons. MISO states that, under the proposal, a Zone that is short on capacity in all Seasons would pay revenues equal to annual CONE and a resource receiving the Auction Clearing Price in a Zone that is short would receive capacity payments equal to annual CONE. MISO states that, in some cases, where at least one but not all four Seasons are short, CONE would be charged in the short Seasons and additional charges paid in Seasons that were neither short nor near-shortage, driving total capacity charges for the year above CONE. MISO states that, however, in the most extreme case, where one Season is short and the others are close but not quite "near-shortage," then 25% of CONE could be collected in each of the other three Seasons, which would drive the total Auction revenues across the four Seasons to 175% CONE. MISO asserts that this would be highly unlikely but still a reasonable outcome as the Auction would be signaling a shortage in one Season and fairly tight conditions in the rest of the seasons.[112]

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[110] Alliant Response to MISO Deficiency Letter Response at 5.

[111] *Id.*

[112] MISO May 20 Answer at 12-13.

g. Midwest TDUs June 6 Answer

76. Midwest TDUs argue that the MISO May 20 Answer repeats the assertion that it would be a reasonable outcome for total Auction revenues across the four Seasons to be as high as 175% of CONE without explaining why it is appropriate to charge consumers significantly more than CONE, which is the current Commission-approved cap on annual Auction revenues. Midwest TDUs further argue that MISO has not provided any explanation for why Auction revenues well above CONE are an appropriate signal for short or tight capacity conditions. Midwest TDUs state that recent Auction results for the 2023/2023 Planning Year confirm the importance of this aspect of MISO's proposal and the need for the Commission to ensure that consumers do not pay excessive prices.[113]

h. Commission Determination

77. We find MISO's proposal to implement a seasonal resource adequacy construct is just, reasonable, and not unduly discriminatory or preferential. We find that MISO has demonstrated that its proposal would better align resource adequacy requirements with periods of increased risks on the MISO system, which, as MISO demonstrates, increasingly occur outside of the peak Summer Season.[114] Further, by providing a more granular assessment of seasonal resource adequacy needs, MISO's proposal will ensure that LSEs are not required to procure capacity beyond what is necessary to ensure resource adequacy in a given Season. This, combined with MISO's proposal to accredit resources based on their seasonal performance (discussed further in Section IV.B.2 below), will offer further assurance that MISO's resource adequacy provisions are sufficient to mitigate the system's resource adequacy risk throughout the Planning Year. As the Wright testimony explains, MISO's proposal will "incorporate changing risk drivers, including seasonal aspects, into a more precise determination of reliability requirements."[115]

78. In response to East Texas's request that MISO provide evidence that MISO's proposal would have strengthened MISO's response to Winter Storm Uri, we do not believe it is incumbent upon MISO to provide such a counterfactual to demonstrate that its proposal is just and reasonable. Similarly, a cost-benefit analysis is not necessary to evaluate MISO's proposal, but as noted above, we find that MISO has demonstrated that the proposal is likely to benefit MISO customers by enhancing reliability in the region

[113] Midwest TDUs June 6 Answer at 8-9.

[114] *See* Transmittal at 3 ("Since 2016 MISO has experienced 40 [MaxGen Events] with more than 60% occurring outside of the Summer months.").

[115] Wright Test. at 27.

with a more granular determination of resource adequacy risks that MISO has demonstrated vary throughout the Planning Year.

79. Some protestors prefer that MISO propose alternative, or more targeted, revisions to its resource adequacy construct. However, under FPA section 205, MISO bears the burden to show that its filing is *a* just and reasonable proposal, but need not show that it is the best or most just and reasonable option.[116] Further, we do not find MISO's proposal to be overly complex such that LSEs and other market participants will be unable to understand the new seasonal resource adequacy requirements or unable to plan for the upcoming Planning Year.

80. We disagree with claims that, because it is possible that the annual Auction revenues across all four Seasons can exceed the annual CONE value, MISO's proposal lacks sufficient mitigation to ensure just and reasonable annual Auction revenues. As an initial matter, we do not believe that an Auction construct that allows annual revenues to exceed CONE necessarily renders that construct to be unjust and unreasonable. We note that the Commission has accepted capacity market designs that allow annual auction revenues to exceed Net CONE.[117] As MISO explains, such outcomes will incent new entry in the event the MISO system is short capacity.

81. Further, MISO has proposed to mitigate customer cost impacts to reduce the Auction Clearing Prices in Seasons that clear in ZRC Shortage Conditions or ZRC Near-Shortage Conditions to ensure that, in aggregate, resources that clear the Auction in such Seasons collect revenue up to, but not above, annual CONE. Specifically, MISO's proposal includes an ex-post adjustment to reduce the Auction Clearing Price when more than one Season clears in ZRC Shortage Conditions or ZRC Near-Shortage Conditions. If this occurs, the final Auction Clearing Price will be set based on annual CONE and the

[116] *City of Winnfield, La v. FERC.*, 744 F.2d 871 at 874-76 (D.C. Cir. 1984); *PJM Interconnection, L.L.C.*, 170 FERC ¶ 61,243, at P 57 (2020) (citing *Petal Gas Storage, L.L.C. v. FERC*, 496 F.3d 695, 703 (D.C. Cir. 2007); *Cities of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984); *Cal. Indep. Sys. Operator Corp.*, 128 FERC ¶ 61,282, at P 31 (2009)). *See also Neb. Pub. Power Dist. v. FERC*, 957 F.3d 932, 943 (8th Cir. 2020) (recognizing that "courts have made it clear that FERC 'restricts itself to evaluating the confined proposal'" and "[t]herefore, FERC 'need only find the *proposed* rates to be just and reasonable.'") (citations omitted).

[117] ISO New England Inc. (ISO-NE) sets the starting price of the Forward Capacity Auction as the higher of CONE or 1.6 times Net CONE. *See* ISO-NE Tariff, § III. 13.2 § 13.2.4 (66.0.0). PJM Interconnection, L.L.C. (PJM) sets the starting price of the Variable Resource Requirement Curve at the greater of CONE or 1.5 times Net CONE. *See* PJM, Tariff, OATT VI, attach. DD § 5.10 (1.0.1).

number of days in all applicable Seasons when a Zone clears below the required number of ZRCs or the Season's initial Auction Clearing Price clears above daily CONE. We find that the potential for outcomes resulting in annual Auction revenues at or exceeding CONE result from MISO attempting to enable sufficient compensation for resources that clear in few Seasons while protecting ratepayers from substantially increased aggregate capacity costs across the Planning Year. Finally, some protestors suggest that, because MISO's proposed ex post adjustments to Auction Clearing Prices may produce higher annual Auction revenues when there are fewer Seasons in shortage conditions, this suggests a fundamental price signaling flaw, inconsistent with supply and demand fundamentals. We disagree. In both scenarios, the total annual revenues demonstrate that MISO is in need of additional capacity and to provide a signal to attract additional resource adequacy investments.

82. We disagree with Midwest TDUs' characterization that MISO justified its facility-specific Reference Levels on the basis that they were rarely used. Rather, MISO was providing context that facility-specific Reference Levels are rarely used in MISO's current construct and that they expect more resource owners to use them, should the Commission accept MISO's proposal. We also disagree that this suggests that MISO expects increased use of facility-specific Reference Levels means that offers above the economic withholding conduct threshold will comprise a larger fraction of offers in the seasonal Auction. We find that nothing in the record indicates that increased use of facility-specific Reference Levels would weaken the protections of MISO's economic withholding conduct thresholds. Further, under MISO's market power mitigation provisions, capacity offers above a resource's economic withholding threshold are not subject to mitigation unless they also cause the Auction Clearing Price to exceed the impact threshold equal to 10% of the Zone's CONE value (or $0/MW-day in Zones where import constraints bind).[118] Therefore, we find MISO's mitigation provisions to be sufficient under MISO's proposed seasonal Auction construct. Similarly, we are also unpersuaded by Midwest TDUs' argument that make-whole payments to resources that only clear one Season may create incentives for resources to clear in only one Season so that they are relieved of the must-offer requirement in other Seasons, as Midwest TDUs does not explain why MISO's mitigation provisions are insufficient to protect against such potential gaming. Specifically, make-whole payments are only provided to resources that do not clear in certain Seasons, and offers in those Seasons are subject to the economic withholding thresholds noted above, including being limited to the facility-specific reference level.

83. We are not persuaded that additional information is required to justify MISO's proposed market adjustment make-whole payment system. Under the seasonal construct, Planning Resources will bid into each Season's Auction the cost of providing capacity in

[118] MISO, FERC Electric Tariff, Module D, § 64.2.1 (45.0.0) (proposed).

that Season. The ZRC Offer Revenue Sufficiency Guarantee Credit make-whole payments provide two important benefits: (1) they ensure that capacity sellers are not required to provide capacity at a loss; and (2) they shield consumers from excessive prices.

84. However, we agree with Midwest TDUs' claim that MISO's proposed Tariff language is inconsistent with MISO's statements and the McFarlane Testimony. Proposed Tariff section 69A.7.1.c.x states:

> The final Auction Clearing Price [] for a [Zone]. . .with Seasons in ZRC Shortage Conditions will be set as the amount obtained by dividing the applicable [Zone's] annual CONE value by the number of days in Seasons which the [Zone was] . . .in ZRC Shortage Conditions and ZRC Near-Shortage Conditions in the [] Auction. The final Auction Clearing Price [] for a [Zone]. . . with Seasons in ZRC Near-Shortage Conditions will be set as the minimum of: (a) the original [Auction Clearing Price] as determined in section 69A.7.1.c.(v) or section 69A.7.1.c.(vi) as applicable; or (b) the amount obtained by dividing the applicable [Zone's] annual CONE value by the number of days in Seasons which the [Zone was]. . . in ZRC Shortage Conditions and ZRC Near-Shortage Conditions in the [] Auction[119]

In contrast, the McFarlane Testimony states that "[a]n ex-post adjustment will set reduced Auction Clearing Prices when more than one Season clears in ZRC Shortage or ZRC Near-Shortage Conditions."[120] Further, MISO's Deficiency Letter Response indicates that the provisions of section 69A.7.1.c.x are only intended to apply "in situations where more than one Season is in Shortage or Near-Shortage Condition."[121]

85. The proposed Tariff language is unclear because the use of the singular "final Auction Clearing Price for a Zone" without reference to a *Season's* Auction Clearing Price implies that each Zone only has one Auction Clearing Price, rather than four (one for each Season). Thus, it is reasonable to interpret this provision as applying only in situations where a Zone has "Seasons in ZRC Shortage Conditions" *or* "Seasons in ZRC-Near-Shortage Conditions," and not, as Midwest TDUs explain, situations where a Zone has one Season in ZRC Shortage Conditions and a second Season in ZRC Near-Shortage Conditions. Therefore, we direct MISO to, within 30 days of the date of this order, to file

[119] *Id.*, Module E-1, § 69A.7.1.c.x (45.0.0) (proposed).

[120] McFarlane Test. at 41.

[121] MISO Deficiency Letter Response at 26.

revised tariff sheets that clarify section 69A.7.1.c.x, consistent with the McFarlane Testimony, the Deficiency Letter Response, and the MISO February 10 Answer.[122]

86. Clean Energy Coalition criticizes various aspects of MISO's LOLE modeling, including its use of weather data. We find that such concerns are beyond the scope of this filing insofar as they pertain to calculations that already occur independently of the addition of seasonality to the LOLE analysis.

87. In response to protestors' concerns regarding MISO's proposed LOLE target of 0.01 days per year for each Season, we find that MISO has demonstrated that a minimum seasonal LOLE target of 0.01 days per year is just and reasonable because without such a minimum LOLE target, the model will not produce accurate results. We find that MISO has sufficiently demonstrated that the model requires a non-zero LOLE target and that an LOLE target of 0.01 days per year allows MISO to maintain the annual LOLE target of 0.1 days per year, cumulative across all Seasons. We disagree with Clean Energy Parties' that Seasons with an LOLE less than 0.01 days per year indicates that such a Season has "no risk." In Seasons with a lower LOLE risk than other Seasons, it is reasonable for MISO to adjust the LOLE target to a value that allows its model to converge. Absent this adjustment, the accuracy of MISO's LOLE modeling could be impacted, which could have negative consequences for reliability. We also find that MISO's proposal to maintain LOLE targets for Seasons where the LOLE is greater than 0.01 days per year, without adjustment, is just and reasonable because those values are already sufficiently large for the model to solve accurately and that MISO has demonstrated that such an outcome would be consistent with an annual LOLE target of 0.1 days per year. As such, we do not agree with Alliant that the resulting Planning Reserve Margins are unnecessarily high.

88. MISO has demonstrated that its proposal will result in lower Reserve Requirements for non-Summer Seasons, at the MISO-wide level, which should in and of itself reduce costs to customers.[123] Although it may be the case that some LSEs may experience higher non-Summer Reserve Requirements as compared to their Summer Reserve Requirements, we do not find that to be an unjust and unreasonable result, so long as MISO's methodology to determine seasonal Reserve Requirements provides a reasonable assessment of seasonal risk, including the availability of imports and historical resource availability. MISO has demonstrated that its methodology does so. For example, MISO explains that the expected reduction in Zone 10's Local Clearing Requirement surplus in the Winter Season is primarily driven by a significant reduction in its Winter Capacity Import Limit value.

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[122] *See* MISO February 10 Answer at 43-44.

[123] MISO Deficiency Letter Response at 22.

89. To the extent that the Mississippi Commission's statement regarding MISO's "proposed CONE penalty" is referring to the Capacity Deficiency Charge, we note that MISO's revised Tariff states that the annual Capacity Deficiency Charge will be "the CONE value for the [Zone] . . . multiplied by 2.748 times the [Reserve Requirement] volume indicated by the LSE for the Planning Year."[124] We find that MISO's proposed Tariff revisions are unclear with regard to the seasonality of the Capacity Deficiency Charge and could be interpreted as being applied separately to each Season that an LSE is deficient ZRCs. Under such an interpretation, a Planning Resource that was deficient 10 ZRCs in all four Seasons would be assessed a charge of CONE multiplied by 2.748 times 40 ZRCs, whereas under the current annual construct, an LSE that is 10 ZRC deficient for the Planning Year would be assessed a charge of CONE multiplied by 2.748 times 10 ZRCs. Because MISO's proposed Tariff revisions are unclear on how the Capacity Deficiency Charge will be assessed to each Season, we direct MISO to, within 30 days of the date of this order, file revised tariff sheets that clarify the seasonality of the Capacity Deficiency Charge.

90. In response to protestors' concerns regarding MISO's proposal to implement the new construct for the next Planning Year, we note that the instant filing was made 16 months in advance of the 2023/24 Auction, after several years of stakeholder discussion. We disagree that LSEs will not have sufficient time to enhance their capacity positions, as LSEs have several options beyond "generation or transmission investments" to meet their Reserve Requirements, including bilateral contracting and Auction participation. Finally, we note that Zone 10 (Mississippi) and the MISO South subregion overall are expected to have a capacity surplus overall, suggesting that LSEs in MISO South will be able to purchase capacity to meet their Reserve Requirements for the Winter Season.[125]

2. Accreditation

a. MISO Filing

91. MISO proposes to implement a SAC proposal, which is an availability-based accreditation methodology for a newly defined set of resources called Schedule 53 Resources. MISO states that Schedule 53 Resources are Capacity Resources that are Demand Response Resources or Generation Resources, but not Dispatchable Intermittent

[124] MISO, FERC Electric Tariff, Module E-1, § 69A.10 (32.0.0) (proposed).

[125] *See* MISO February 10 Answer at 42 ("Although varying levels of reduction in [Zone] 10 resource accredited values is projected for each season, the projected Zone 10 seasonal zonal positions remain to be a surplus not a shortage."). *See* also RASC presentation at 8 (Nov. 3, 2021), https://cdn.misoenergy.org/20211103%20RASC%20Item%2004a%20Resource%20Adequacy%20Reforms%20Presentation%20(RASC010,%20011,%20012)600791.pdf.

Resources, Intermittent Generation, Electric Storage Resources, External Resources, or Use Limited Resources. MISO explains that resource accreditation for Schedule 53 Resources will no longer be based on installed capacity adjusted for forced outage rates from the Generation Availability Data System (GADS) but instead will primarily be based on the average capacity available in times of highest need given resource offers in MISO's Day-Ahead and Real-Time markets, i.e., RA Hours. MISO states that it proposes a tiered weighting structure to determine individual accreditation for Schedule 53 Resources by Season based on each Resource's Real-Time offered availability during Tier 1 hours, defined as all hours other than RA Hours; and Tier 2 hours, defined as RA Hours.

92. MISO proposes to define RA Hours for each Season as a 65-hour target that include all hours with declared MaxGen Events and the remaining hours with the tightest operating margin, subject to a maximum operating margin threshold of 25%.[126] MISO would determine RA Hours separately for MISO North and MISO South. MISO explains that the 65-hour target represents the tightest 3% of hours in a Season. MISO states that the number of RA Hours in a Season can exceed the target when declared MaxGen Events during that Season have a cumulative duration of greater than 65 hours. MISO explains that the number of RA Hours in a Season can be less than the 65-hour target because of the 25% maximum operating margin threshold, which will ultimately lead to a deficiency equal to the difference between the target RA Hours and the actual number of RA Hours.[127]

93. MISO proposes to accredit the capacity of a Schedule 53 Resource based on its Intermediate Seasonal Accredited Capacity (ISAC) determined based on its Real-Time offered availability (capped at the resource's GVTC value) during seasonal RA Hours and Non-RA Hours. MISO recognizes that the number of Tier 2 RA Hours may vary during individual Seasons when the 25% maximum margin threshold is applied or individual resources receive outage exemptions, impacting sample sizes of RA Hours and corresponding ISAC accreditation calculations. Therefore, MISO proposes that, if the number of Tier 2 RA Hours for a Season or a specific resource fall below the 3% target of 65 hours, a resource's Annual Average Offered Capacity (AAOC) will be used to

[126] MISO proposes to include offline resources with a 12-hour-or-less lead time in the operating margin calculations, arguing that a 12-hour-or-less lead time better reflects actual operating margins MISO sees in real-time operations, which may be impacted by uncertainty that occurs after the deadline to commit longer lead resources has passed. MISO adds that a 12-hour-or-less lead time leads to more RA Hours being identified in each Season, allowing resource accreditation to be based on availability during a specific Season, with less need to fill in deficient RA Hours. McFarlane Test. at 23-24.

[127] Transmittal at 16.

supplement the deficient number of hours as part of the Tier 2 portion of the accreditation calculation.[128] MISO states that Seasonal Tier 1 Non-RA Hours, in contrast, include all hours in a Season of a Planning Year, excluding Tier 2 RA Hours and any hours where a resource had an exemption or was not designated for Resource Adequacy Requirements.[129]

94. MISO states that the final ISAC value will be the weighted average over its values from the two tiers. MISO explains that it proposes an 80% Tier 2 and 20% Tier 1 weighting, arguing that assigning the heavier weighting to Tier 2 tight conditions ensures the alignment between a resource's SAC value and its availability and performance during times of highest risk and greatest need. MISO proposes a three-year transition period, such that Tier 2 weighting would start at 60% for Planning Year 2023/2024, rise to 70% in Planning Year 2024/2025, and reach the full 80% in Planning Year 2025/2026.[130]

95. To convert a Schedule 53 Resource's ISAC to its final SAC value, MISO proposes to apply a system-wide UCAP/ISAC ratio, which is the sum of MISO's fleet-wide UCAP accreditation of Schedule 53 Resources divided by the sum of MISO's fleet-wide ISAC accreditation of Schedule 53 Resources. MISO states that the UCAP/ISAC ratio is proposed to avoid undesirable impacts to Auction requirements and non-Schedule 53 resources.[131]

96. MISO explains that, while MISO intends to address potential accreditation enhancements to non-Schedule 53 Resources in a future filing after development and stakeholder discussions, non-Schedule 53 Resources will receive SAC values based on a resource type consistent with their current accreditation rules, adjusted for seasonality. MISO states that wind resources will receive accreditation for each Season based on seasonal ELCC studies with capacity accreditation allocated based on eight peak hours for each Season. MISO further states that non-wind intermittent resources such as run-

[128] A resource's AAOC is determined by calculating a resource's average offered availability during Annual RA Hours for each 12-month period within the three most recent periods beginning September 1st and ending August 31st. Annual RA Hours for each year are a 260-hour target that include all hours with declared MaxGen Events and the remaining hours with the tightest operating margin, subject to a maximum operating margin threshold of 25%. *See* MISO, FERC Electric Tariff, Module E-1 § Schedule 53 III.B (32.0.0) (proposed)).

[129] Transmittal at 17.

[130] *Id.*

[131] *Id.*

of-river hydro, solar, intermittent BTMG, and biomass SAC will be based on historical output during hours ending 15:00, 16:00, and 17:00 Eastern Standard Time (EST) for the relevant Spring, Summer, and Fall Seasons, and that Winter accreditation will be based on historical output in hours ending 8:00, 9:00, 19:00, and 20:00 EST in the Winter Season. MISO asserts that Load Modifying Resources (LMRs), which include both Demand Resources registered as LMRs (LMR DR) and BTMG registered as LMRs, will be accredited based on lead time and number of calls per year consistent with current LMR rules, with adjustments to establish a minimum number of calls for each Season—five for each Summer and Winter, and three for each Spring and Fall.[132]

97. MISO also argues that the SAC proposal will incent better coordination of Generator Planned Outages by limiting—through exemptions—the extent to which planned outages impact a resource's SAC, provided certain conditions are met.[133] MISO explains that its current resource adequacy construct provides for exemptions for generator planned outages if certain criteria are met. MISO states it worked collaboratively with stakeholders to develop the proposed exemption process that integrates with the SAC accreditation process in Schedule 53 to provide for three levels of exemptions: (1) full exemption for Generator Planned Outages from Tier 1 and Tier 2 SAC calculations; (2) exemption from Tier 1 SAC calculations only; and (3) no exemption. MISO states that Tier 1 and Tier 2 exemptions will be provided if: (1) the generator owner or operator schedules its first planned outage 120 days or more in advance of the outage date and 120 days or more beyond the end date of any previously scheduled outages for the unit, and the Maintenance Margin[134] for the time period of the outage is equal to or greater than 0; or (2) the generator owner or operator reschedules its planned outage at MISO's request. MISO further states that Tier 1 only exemptions will be provided if the following conditions are met: (1) the generator owner or operator schedules its first generator planned outages 120 days or more in advance of the outage start date and 120 days or more beyond the end date of any previously scheduled outages for the unit, and the Maintenance Margin is less than 0 for the time period of the outage; (2) a subsequent generator unit outage requests 120 days or more in advance and/or generator owner or operator's planned outage is less than 120 days in advance but at least 31 days in advance of the outage start date; (3) the planned outage is less than 31 days in advance but at least 14 days in advance of the outage start date and passes the No Harm

[132] *Id.* at 18.

[133] *Id.* at 15-16.

[134] Maintenance Margin is the maximum MW of additional generation that can be taken out of service for planned maintenance for a given time-period without undue risk to supply adequacy for MISO's Balancing Authority Area, including MISO sub-regions. Transmittal at 20.

Test;[135] or (4) the generator owner or operator reschedules its planned outage at MISO's request.[136] MISO explains that, for planned outages submitted before MISO's proposal goes into effect, outages that are scheduled to start prior September 1, 2022 will be treated as fully exempt for Tier 1 and 2.

b. Comments and Protests

98. OMS states that the seasonal component of this proposal will allow resources to take extended seasonal outages for both maintenance and economic reasons, and it will relieve those resources from any must-offer requirement, allowing for better maintenance and economic decisions.[137] The Indiana Commission considers MISO's SAC proposal a just and reasonable approach to determining what can be reasonably expected of a resource and reflecting that expectation in that resource's accreditation.[138] The Indiana Commission states that accrediting resources based on their Real-Time offered availability during tight system hours is both prudent and equitable. The Indiana Commission contends that a resource's accreditation should reflect "a realistic expectation of its performance, and resources should be rewarded for delivering when they are most needed."[139] The Indiana Commission submits that MISO's proposal achieves this standard.

99. Potomac Economics supports MISO's SAC proposal, stating that resources whose availability or capability varies significantly by Season would receive revenues that reflect those seasonal differences. Potomac Economics argues that relatively high-cost resources would have an opportunity to achieve savings by taking seasonal outages during shoulder Seasons.[140] Potomac Economics states that the MISO accreditation proposal will provide substantial benefits over the current construct where generating

[135] MISO proposes that the No Harm Test includes, but is not limited to, "outage approval, compliance with all applicable operation guides, review of possible conflicting outages or system conditions, and system capacity (Maintenance Margin, Multiday Operational Margin, 30-day margin)." It also includes the criteria outlined in the Generator Outage BPM. *See* MISO, FERC Electric Tariff, Schedule 53 § II.C (32.0.0) (proposed).

[136] Transmittal at 20-21.

[137] OMS Comments at 4-5.

[138] Indiana Commission Comments at 6-7.

[139] *Id.* at 7.

[140] Potomac Economics Comments at 3.

resources are accredited to sell capacity based on their self-reported forced outage performance, which is used to calculate their UCAP levels. Potomac Economics, though generally supportive of the filing, argues the accreditation portion of MISO's proposal is suboptimal for a number of reasons: (1) other types of outages and derates reduce MISO's access to Capacity Resources; (2) resources do not completely report their outages and derates; (3) less reliable resources that are rarely needed are credited as fully available when not asked to run, inflating their UCAP levels; and (4) long-lead time resources that are frequently offline provide far less capacity value than their UCAP value because, when tight conditions arise unexpectedly, they cannot be used.[141]

100. Potomac Economics states that the application of MISO's proposed UCAP/ISAC ratio is an important dimension of MISO's accreditation proposal because it maintains the relative supply and demand balance in the Auction. Potomac Economics acknowledges that, although MISO's proposed availability-based accreditation will generally be lower than the UCAP accreditation, the application of the UCAP/ISAC ratio is reasonable because it recognizes that each MW of ISAC provides more reliability than each MW of UCAP; therefore, less-available resources will receive less capacity accreditation while more-available resources will receive higher accreditation amounts. Potomac Economics contends that, by shifting capacity accreditation from less-available resources to more-available resources, the capacity market procurements will be better aligned with the reliability value provided by MISO's resources.[142]

101. Potomac Economics highlights some aspects of the proposed SAC methodology that are not consistent with its recommendations. First, Potomac Economics notes that an important aspect of MISO's proposal is how to calculate the operating margin MISO uses to determine whether an hour should be classified as an RA Hour or a non-RA Hour. Potomac Economic states that MISO's proposal includes resources with a lead time of 12 hours or less to calculate this operating margin. Potomac Economics suggests that, by including such resources in the operating margin calculation, MISO may calculate an artificially high margin and not designate an hour as an RA Hour even though the hour is among the tightest of the year. Therefore, Potomac Economics recommends that MISO only include resources with a lead time of less than 6 hours, which is the timeframe in which MISO often recognizes that emergency conditions are developing.[143]

102. Second, Potomac Economics states that it prefers a sliding scale to reduce an offline resource's deemed availability as its offered lead time increases, ranging from 100% at 2 hours to 0% at 12 hours. Potomac Economics contends that it is rare for any

[141] *Id.* at 6.

[142] *Id.* at 7.

[143] *Id.* at 8-9.

offline resource with lead times longer than 12 hours to provide any reliability contribution when reliability events occur. Potomac Economics contends that MISO's proposal to treat offline resources with lead times less than 24 hours as available up to their offered output intentionally overvalues less flexible, long-lead time units.[144] Potomac Economics suggests that, regardless of whether a resource could have reasonably been committed in MISO's day-ahead process, if most of the threats to reliability emerge during the operating day, only offline resources that can start once the threat is recognized can contribute to reliability. Potomac Economics adds that offline resources that theoretically could have been committed the prior day, but whose lead time is too long for them to start to mitigate the reliability threat provide no value in such events.[145]

103. Third, Potomac Economics argues that the 80%/20% weighting on availability in Tier 1 and Tier 2 hours MISO proposes for accreditation is not ideal because, according to Potomac Economics, resources provide very little marginal reliability value in non-RA Hours as virtually all resource marginal reliability value is captured in RA Hours. Potomac Economics suggests that the tiered approach is inferior to a simpler accreditation approach that would be based entirely on tight-margin RA Hours. Potomac Economic notes, however, that it does not deem MISO's approach to be a major shortcoming and certainly not a basis to find the proposal unreasonable.[146]

104. Finally, Potomac Economics contends that MISO's proposed outage exemptions are inconsistent with the principles underlying the availability-based accreditation. Potomac Economics states that resources that schedule more frequent or longer-duration outages are less likely to be available during reliability events, and, because reliability events are increasingly likely to occur when they are not expected, there is no reason to grant exemptions from the availability-based accreditation. Potomac Economics states that maintenance margins are deterministically calculated based on expected conditions at the time that the outages, therefore the proposed maintenance margin criteria ignore unexpected factors and conditions that may arise that trigger reliability events. Potomac Economics submits that since resources that take frequent or long-duration planned outages are less available to respond to these types of reliability events, planned outages should not exempted from the availability-based accreditation, and including such exemptions reduces the benefits of MISO's proposal.[147]

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[144] *Id.* at 9-10.

[145] *Id.* at 10.

[146] *Id.* at 11.

[147] *Id.* at 11-12.

105. The Michigan Commission argues that, while it has concerns about the ability to develop new resources in the MISO North region under the new seasonal construct in time to meet MISO's proposed implementation date of the proposals, set for the 2023/2024 Planning Year, these are issues that can be addressed by MISO to make any adjustments necessary in order to allow resources to be available by the proposed implementation date. In particular, the Michigan Commission notes that MISO filed its proposed Tariff revisions for reducing the generator interconnection queue from 505 to 365 days with the Commission in Docket No. ER22-661-000.[148] The Michigan Commission believes that ensuring that MISO meets this generator interconnection queue target will be critically important in meeting MISO's implementation timeline for MISO's instant proposal, particularly given the fact that the MISO generator interconnection queue currently has been experiencing more delays in the East Region due to PJM's Affected System Studies. The Michigan Commission states that, if MISO and its reliance on affected system studies from its neighbors cannot keep the interconnection queue to its proposed 365-day timeline to bring on necessary generation to meet the new Tariff requirements, then MISO may need to file to delay implementation by a year.[149]

106. ITC contends that the SAC provisions will ensure that committed generation capacity is accurately assessed for its ability to meet the needs of the MISO system at all times, and that generators have the incentive to ensure the delivery of all energy for which they are committed.[150]

107. Several protestors argue that MISO has not fully supported its proposed SAC methodology. DTE Electric contends that MISO has not demonstrated that its accreditation proposal will lead to an increase in the availability or mix of resources.[151] COMPP argues that SAC is unproven and, much like UCAP accreditation, inflates capacity by maintaining too many exemptions.[152] Clean Energy Coalition argues that the calculation process for Schedule 53 resources is data-intensive, time consuming, and susceptible to errors, and it is difficult to obtain intuition around how a change in the

[148] Michigan Commission Comments at 3. On March 14, 2022, the Commission accepted MISO's propose revisions to its Generator Interconnection Procedures (GIP). *See Midcontinent Indep. Sys. Operator, Inc.*, 178 FERC ¶ 61,141 (2022).

[149] Michigan Commission Comments at 3-4.

[150] ITC Comments at 3.

[151] DTE Electric Protest at 13.

[152] COMPP Protest at 13.

inputs will affect outputs.[153] While Ameren agrees with MISO that MISO's accreditation requirements need to be updated and strengthened, Ameren argues that the SAC proposal has not been shown to be just and reasonable.[154] The Mississippi Commission states that the SAC proposal is untested, has never been adequately modeled, offers no assurance that it will effect the intended changes, has not been linked to an actual problem, and has not been used by any other Regional Transmission Organization (RTO) or Independent System Operator (ISO).[155] The Mississippi Commission argues that the SAC proposal attempts to create a price signal to promote investment in certain types of generation, instead of focusing on better outage coordination to ensure generation is available to serve load.[156] The Mississippi Commission notes that, according to MISO's first proposed tranche of MISO's Long-Range Transmission Planning projects, the areas in immediate need of reliability upgrades are Minnesota and Iowa, which coincidently have extensive renewable generation penetration. The Mississippi Commission states that MISO has no plans to evaluate whether Long-Range Transmission Planning projects are needed in MISO South for two years, a strong indication that MISO South is not facing the same reliability concerns as the rest of MISO.[157]

108. East Texas argues that MISO's proposed accreditation process creates an unnecessary, unwarranted, and in many cases, unfair burden on generation owners. East Texas suggests that MISO's justifications for the proposed accreditation methodology are blanket assertions not tied to any basis for immediate change.[158] East Texas submits that MISO has not provided a more thorough analysis of MISO's accreditation proposal that would allow East Texas and other parties to develop a thorough understanding of what these new standards will mean to their operations. East Texas contends that, if the parties who know their resources the best are unable to ascertain the impacts of this complicated accreditation process, it is unreasonable for the Commission to assume that MISO has a full grasp of the potential consequences.[159]

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[153] Clean Energy Coalition Protest at 17.

[154] Ameren Protest at 4.

[155] The Mississippi Commission Protest at 2, 5.

[156] *Id*. at 36.

[157] *Id*. at 6-7.

[158] East Texas Protest at 7.

[159] *Id*.

109. Some protestors contend that the SAC methodology will be unable to predict future availability during times of highest need. Minnesota Power states that the proposal has no defined means to improve on MISO's objective of "converting the capacity procured in the [Auction] to energy when and where they are most needed," given that the SAC values are not reflected into any parameters used in the MISO Security Constrained Economic Dispatch.[160] Clean Energy Coalition argues that the methodology may not provide the intended incentive to utilities and market participants to improve performance of their generators.[161] DTE Electric argues that past performance in tight hours can provide little prediction of future performance.[162] East Texas states that MISO has not explained how concentrating on limited operational time periods would accurately portray the likelihood of a generating unit's availability in a future Season.[163]

110. Entergy Coalition asserts that MISO has not demonstrated that its SAC proposal aligns with MISO's Resource Availability and Need (RAN) initiative goal to close the gap between planning and operational outcomes.[164] Entergy Coalition emphasizes that MISO's SAC proposal is not a good predictor of a resource's future availability and moreover is subject to a high degree of randomness. Entergy Coalition contends that, as a consequence of this randomness, if LSEs base their supply planning decisions on data and information communicated via their SAC accreditation values, many of those decisions will be sub-optimal and will not help achieve MISO's desired operational goals.[165] Entergy Coalition argues that such uncertainty arising from MISO's proposal unnecessarily and unhelpfully complicates the already complex task of assessing the expected future accreditation for a given resource.[166]

111. Alliant is concerned that MISO's proposal is overly aggressive and can have unintended, long-term impacts that could thwart MISO's best intentions. Alliant requests that the Commission require MISO to further engage stakeholders before implementing the changes in the proposal and to postpone the implementation date by at least one

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[160] Minnesota Power Comments at 1 (quoting Transmittal at 1).

[161] Clean Energy Coalition Protest at 17-18.

[162] DTE Electric Protest at 14.

[163] East Texas Protest at 8.

[164] Entergy Coalition Protest at 10 (citing McFarlane Test. at 24).

[165] *Id.* at 11.

[166] *Id.*

year.[167] Entergy Coalition argues that MISO's proposed implementation period is inappropriate for such a significant change in market design. Entergy Coalition notes that the Commission has accepted transition periods both for the establishment of new capacity markets and for significant changes in capacity markets, such as the Settlement Agreement that established PJM's capacity market, where the Commission accepted a four-year transition period for locational pricing.[168] Entergy Coalition further notes that the Commission accepted a five-year transition period for PJM's proposed Capacity Performance Resource,[169] as well as required PJM to apply its new rules to Fixed Resource Requirement[170] entities only after the conclusion of the Fixed Resource Requirement plans to which those entities were currently obligated as of the date of the order.[171] WEC Utilities state that MISO's proposed implementation leaves insufficient time for utilities to adjust preexisting business operations and decision processes, specifically insufficient time for LSEs to modify their resource planning or operational strategies to account for seasonal accreditation requirements and performance-based capacity accreditation. WEC Utilities explain that planned outages, which will directly affect seasonal availability, are often scheduled years in advance. WEC Utilities add that some resource owners will likely need to adjust their fuel supply provisions or to improve winterization to ensure availability and accreditation within the new seasonal construct. WEC Utilities argue that MISO's proposal provides "deceptively" little time for market participants to adjust commercial and operation plans to reflect the proposed seasonal requirements.[172] East Texas and Entergy Coalition add that using historic data for the 2023/2024 Planning Year means that resource owners will have little opportunity to take actions to improve their accreditation.[173]

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[167] Alliant Protest at 1.

[168] Entergy Coalition Protest at 20-21 (citing *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 68 (2006) (PJM Reliability Pricing Model Order)).

[169] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208, at P 253 (2015) (PJM Capacity Performance Resource Order).

[170] Entergy Coalition states that PJM's Fixed Resource Requirement option is a self-supply option for LSEs to avoid the capacity market auction in PJM. Entergy Coalition Protest at 21.

[171] PJM Capacity Performance Resource Order, 151 FERC ¶ 61,208 at P 218.

[172] WEC Utilities Comments at 4-5.

[173] East Texas Protest 8-9; Entergy Coalition Protest at 22.

112. Some protestors argue that it is inappropriate to accredit resources based on their prior availability under an entirely different capacity accreditation construct. Consumers Energy and MISO TOs argue that the proposed transition framework may punish generators based on operational choices that were prudently made under the existing accreditation framework, because the proposed accreditation methodology will be applied to historical real-time energy offers, outages, and notification times on which those operational choices were based.[174] Consumers Energy asserts that it is inappropriate to impose a "different and controversial" accreditation framework over those choices based on the existing market construct, conditions, and accreditation framework.[175] DTE Electric objects to MISO's proposed implementation timeline, noting that it will require using historical data from before the proposal was approved to calculate accreditation and that it does not allow market participants time to adjust, especially if they will need to add capacity through the interconnection process.[176] East Texas states that, for the initial 2023/2024 Planning Year, two-thirds of the operational performance data would be based on how units operated and took outages in a completely different accreditation construct. East Texas argues that MISO's proposed use of historical data also undercuts one of its assertions for why a new accreditation methodology is needed—that the new methodology will improve incentives to improve availability. East Texas asserts that, because MISO will accredit based on operational data from the prior three years, a generator owner that makes improvements to its facility would not receive full credit for those enhancements until the third year after their completion. East Texas maintains that this delay of credit for an investment would discourage owners from improving current generating units.[177]

113. Entergy Coalition suggests that MISO's implementation plan could open accreditation values and Auction results to allegations of retroactive ratemaking because market participants were not given proper notice. Entergy Coalition states that, while it is common for various rates on file at the Commission to rely on historical information, at the time such rates were filed, ratepayers were prospectively put on notice about the use of their historical activity. In contrast, if a new or newly changed rate relies on historical information where ratepayers had no notice in the past as to how their past behavior would be used in the new rate, that is retroactive ratemaking.[178] Entergy Coalition states that MISO's implementation plan also violates the Commission's policy that changes in

[174] Consumers Energy Limited Protest at 1-2; MISO TOs Comments at 5-6.

[175] Consumers Energy Limited Protest at 6.

[176] DTE Electric Protest at 15.

[177] East Texas Protest at 9.

[178] Entergy Coalition Protest at 22-23.

rate design are appropriate only on a prospective basis. Entergy Coalition states that, at this point, it is too late for generation owners to alter previous accreditation and outage decisions they had made. Entergy Coalition argues that all aspects of MISO's proposal should be implemented on a prospective basis once the rate design is accepted by the Commission.[179]

114. On the other hand, COMPP avers that MISO's proposed three-year transition mechanism delays urgent reforms which are needed sooner. COMPP argues that under the current proposal MISO will only become aware of deficiencies in the SAC construct in Planning Year 2025/2026. COMPP adds that, if the Commission approves the SAC proposal, it should go into effect as soon as practicable.[180]

115. Some protestors express concerns about the specifics of MISO's SAC calculation. DTE Electric argues that MISO's proposal bases capacity accreditation on chance and that basing it on retroactively determined RA Hours will not improve system reliability or efficiency.[181] DTE Electric states that the MISO proposal will "handicap prudent planning" during periods of significant change in the resource mix.[182] DTE Electric argues that MISO's proposal "inappropriately" requires resource owners to predict tight system conditions in advance although MISO itself is not able to because some of these events are unpredictable and emergency scenarios are increasingly common.[183] DTE Electric states that MISO should have based resource accreditation on all hours in a Season if MISO expected generators to always be available as they are expected to be during RA Hours.[184] DTE Electric contends that basing accreditation on select RA Hours rather than on all hours in a Season decreases the impact of the proposal and will not achieve MISO's goal of increasing confidence that capacity is available when needed.[185] Similarly, the Mississippi Commission asserts that an 80%/20% weighting is biased towards periods with emergencies in tight hours because it over-values those hours when infrequent emergencies are forecasted to occur and when the system is tight, and ignores

[179] *Id.* at 23 (citing *Arkla Energy Res.*, 48 FERC ¶ 61,305, at 61,980 (1989); *Nat'l Fuel Gas Supply Corp.*, 140 FERC ¶ 61,114 (2012)).

[180] COMPP Protest at 16-17.

[181] DTE Electric Protest at 2.

[182] *Id.*

[183] *Id.* at 6.

[184] *Id.* at 7.

[185] *Id.*

the majority of hours when reliable resources ensure resource adequacy.[186] The Louisiana Commission and Ameren argue that the 80% weighting factor on RA hours (Tier 1) can be especially punitive to an otherwise reliable and well-performing generator that was unavailable during the often-times randomly occurring RA Hours.[187]

116. Other protestors dispute that RA Hours accurately capture the hours of highest risk. Midwest TDUs argue that MISO has not demonstrated that hours with reserve margins as high as 25% are truly tight and warrant the same heavy weighting as MaxGen hours. Midwest TDUs dispute MISO's suggestion that the 25% threshold "provides a reasonable balance between having an adequate number of RA Hours for each Season and selecting the set of RA Hours that are truly tight," suggesting that MISO's reasoning does not explain why MISO does not base accreditation on hours that are truly tight or represent true emergency conditions.[188] Clean Energy Coalition argues that MISO's attempt to separate high-risk hours from other hours is flawed because it arbitrarily uses a fixed 65 hours per Season and is not consistent with MISO's assertion that risk periods are changing with the adoption of more renewable resources. Clean Energy Coalition further argues that this may artificially create perceived times of risk when there is no risk and may result in periods that are overlooked if there are more than 65 hours of high risk in a Season.[189]

117. Midwest TDUs add that resources do not have the same advanced notice about RA Hours that are not MaxGen hours, as it is impossible to determine whether a particular hour is one with the lowest operating margins in a Season until the end of the Season.[190]

118. Clean Energy Coalition is concerned that the times of tight reserve margins, as defined by MISO, may or may not be the same as those with high Loss of Load Probability (LOLP) risk. Clean Energy Coalition argues that MISO's approach of allowing resources with a 12-hour lead time to count as available for purposes of determining the system's reserve margin fails to consider how unexpectedly tight hours typically arise in the range of 2-8 hours.[191]

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[186] Mississippi Commission Protest at 8.

[187] Ameren Comments at 5; Louisiana Commission Protest at 6.

[188] Midwest TDUs Protest at 7-8 (citing McFarlane Test. at 25).

[189] Clean Energy Coalition Protest at 10.

[190] Midwest TDUs Protest at 8.

[191] Clean Energy Coalition Protest at 11.

119. Several protestors contend that MISO's proposal to use AAOC to supplement deficit RA Hours in a particular Season highlights several flaws in MISO's proposal.[192] Midwest TDUs argue that MISO has not demonstrated that there is any connection between capacity needs in a given Season and a resource's availability during hours in other Seasons, or hours within MISO's 25% operating reserve margin threshold; therefore, it is unjust and unreasonable for MISO to include those hours as part of the 80% weighting in calculating SAC when those hours do not represent the "periods of highest risk and greatest need" during each Season.[193] Midwest TDUs state that this approach means that an in-Season RA Hour could be double-counted, both as part of a resource's Seasonal RA Hours and as part of its AAOC used to backfill Tier 2. Midwest TDUs contend that this use of AAOC means that a resource's accreditation value for a specific Season is based at least in part—and sometimes primarily—on its performance in other Seasons.[194] Clean Energy Coalition argues that AAOC use creates an artificial profile for these resources and assumes risk in a Season when there is none.[195] Similarly, DTE Electric, MISO TOs, and Minnesota Power argue that using AAOC when fewer than 65 RA Hours are available for a Season undermines the seasonality of the construct and does not accurately represent a unit's performance during a specific Season.[196] WEC argues that poor performance in one Season is not necessarily indicative of poor performance in another Season that contains fewer than 65 RA Hours. WEC Utilities suggests backfilling RA Hour deficiencies with the seasonal UCAP of a resource would be more indicative of each resource's seasonal availability.[197]

120. Midwest TDUs state that the use of AAOC to determine Tier 2 accreditation will not be an infrequent or insignificant part of the Tier 2 calculation. Midwest TDUs contend that MISO's Conceptual Design document for the proposal shows that, in MISO North, each of the past three Planning Years had at least one Season with fewer than 65 Seasonal RA Hours, and that, in some cases, a resource's RA Hours for a Season could be determined primarily based on out-of-Season hours. As an example, Midwest TDUs

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[192] Midwest TDUs Protest at 7-14; Clean Energy Coalition Protest at 10; DTE Electric Comments at 14; MISO TOs Comments at 9-10; Minnesota Power Protest at 2; WEC Utilities Comments at 10-12; East Texas Protest at 8.

[193] Midwest TDUs Protest at 14 (citing Transmittal at 16).

[194] *Id.* at 9.

[195] Clean Energy Coalition Protest at 10.

[196] DTE Electric Protest at 14; MISO TOs Comments at 9; Minnesota Power Comments at 2.

[197] WEC Utilities Comments at 10-12.

explain that the Conceptual Design document shows that the Winter of the 2019/2020 Planning Year had just one RA Hour, meaning that over 98% of the Tier 2 hours for that Season would be backfilled based on AAOC during Annual RA Hours. Midwest TDUs argue that, despite MISO's claim that its "proposed reforms measure and mitigate non-Summer reliability risk," MISO's proposal could accredit non-Summer Seasons based primarily on Summer performance, as most Annual RA Hours occur in the Summer.[198] Midwest TDUs argue that this fails to implement MISO's stated goal of "transition[ing] from the current Summer-based, annual construct to four distinct seasons."[199] Midwest TDUs further contend that, if a resource is unavailable during a Winter RA Hour because of extreme cold weather, there is no reason that hour should factor into its accreditation for Seasons that do not have extreme cold weather conditions. Midwest TDUs therefore argue that MISO's proposal to use AAOC to determine SAC fails to ensure seasonal accreditations that reasonably reflect availability in a particular Season.[200] Midwest TDUs contend that, rather than using a resource's availability during RA Hours in other Seasons to backfill RA Hours in one particular Season, it would be more appropriate to fill in deficient RA Hours based on average availability in all hours of that Season. Midwest TDUs argue that, in Seasons with very few MaxGen hours, average availability throughout the rest of that Season is a reasonable approximation of a resource's availability to meet capacity needs in that Season.[201]

121. Midwest TDUs suggest that MISO is inconsistent in describing how MISO will replace Seasonal RA Hours that are exempt from a resource's Tier 2 calculation. Midwest TDUs note that MISO's testimony states that MISO will identify RA Hours, then remove any hours where a resource received a Tier 2 Planned Outage exemption, and finally backfill any deficiency to reach the 65-hour target. Midwest TDUs argue that this implies that MISO will not attempt to identify additional hours with operating margins under the 25% threshold to reach the 65-hour Seasonal RA Hour target after it removes exempt hours, but instead backfill those exempt hours based on Annual RA Hours. Midwest TDUs submit that, in contrast, the proposed Tariff language excludes Planned Outage exemptions from the initial identification of Seasonal RA Hours, meaning that exempt hours are removed *before* MISO attempts to identify sufficient Seasonal RA Hours to reach the 65-hour target. Midwest TDUs state that, under this approach, MISO would first look to replace exempt hours with other non-MaxGen hours within the 25% operating margin threshold before backfilling based on Annual RA

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[198] Midwest TDUs at 9-10 (citing Smith Test. at 19).

[199] *Id.* at 10 (citing Transmittal at 4).

[200] *Id.* at 10-11.

[201] *Id.* at 13-14.

Hours, reducing the extent to which MISO would rely on problematic Annual RA Hours. Midwest TDUs submit that MISO should be required to clarify the inconsistency in its testimony and proposed Tariff language.[202]

122. Some entities argue that MISO's SAC methodology will create an unacceptable level of annual accreditation volatility. DTE Electric states that the current year-to-year accreditation volatility for its capacity resources is 0.8% and that MISO's own analysis indicates that under MISO's proposal, half of market participants will see volatility around 3% and a quarter will see volatility of 6%-12%.[203] DTE Electric argues that the increase in accreditation volatility will send a signal for market participants to overbuild, which will be an additional expense for consumers and is counter to the reserve-sharing purpose foundational to MISO.[204] Entergy Coalition contends that increased volatility is due, in large part, to MISO's placing an 80% weight on historic unit performance during a small subset of tight margin hours, which means randomness—rather than past or expected future unit performance—becomes a primary factor in determining a resource's seasonal accreditation year. Entergy Coalition claims that this, on its face, is unreasonable.[205]

123. Entergy Coalition explains that, if a generally high performing generator is unavailable for one or two days where RA Hours occur, then that resource will see a significant *reduction* in accredited capacity as the outage event is included in the three-year look back period, followed by a significant *increase* in accredited capacity as the forced outage event is excluded from (or rolls off of) the three-year look back period. Entergy Coalition contends that including planned maintenance outages in determining unit accreditation will also lead to higher levels of accreditation volatility.[206]

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[202] *Id.* at 11-12 (citing McFarlane Test. at 26-27).

[203] DTE Electric Protest at 8, 12 (citing RASC presentation, at 6 (Sep. 1, 2021), https://cdn.misoenergy.org/20210901%20RASC%20Item%2003%20RAN%20Resource%20Adequacy%20Contruct%20Presentation%20(RASC%20010,%20011,%20012)584259.pdf).

[204] *Id.* at 8-9.

[205] Entergy Coalition Protest at 4 (citing RASC presentation, at 6 (Sep. 1, 2021), https://cdn.misoenergy.org/20210901%20RASC%20Item%2003%20RAN%20Resource%20Adequacy%20Contruct%20Presentation%20(RASC%20010,%20011,%20012)584259.pdf).

[206] *Id.* at 5.

124. Entergy Coalition notes that MISO's analysis provided in the stakeholder process produced standard deviations of SAC values and found that 25% of market participants will experience a standard deviation between 7.6% and 15.5% from one Planning Year to the next. Entergy Coalition states that its calculations show that a 15.5% standard deviation corresponds with a 20% chance that a market participant's total accredited capacity will undergo a year-to-year change of 20%. Entergy Coalition contends that large year-to-year swings in any availability-based accreditation proposal are evidence that the proposal is a poor predictor of future unit availability, particularly given the small number of RA Hours. Entergy states that, as a result, it is not reasonable to believe that MISO's SAC proposal will be a good measure of a resource's anticipated capability and availability during times of need.[207]

125. Several comments raised the issue of how MISO will incorporate planned generator outages into the SAC accreditation proposal. OMS contends that MISO's proposed outage exemption framework affords generator owners the flexibility to schedule short-notice outages while incentivizing prudent outage planning done well in advance and provides grid operators greater levels of certainty. OMS states it is important to note that, from a utility operations perspective, as the operating day approaches, generator owners have the benefit of more accurate information on expected load and resource conditions to manage the risk associated with taking a short-lead time outage. OMS contends that it would be counterproductive to exempt resources from potential accreditation impacts if system conditions are expected to be tight. OMS argues that this proposal reduces the risk that resources will experience unfair accreditation impacts because resources can schedule outages as short as 14 days out if system conditions are favorable and the outage passes a no-harm test.[208] OMS contends that MISO's current outage classification framework fails to recognize many types of outages and assumes minimal planning outages during different seasonal peak periods, which does not align with observed history. OMS notes that this lack of accounting of correlated outages and past performance history is precisely why the North American Electric Reliability Corporation (NERC) has pointed out the shortcomings of the traditional Reserve Requirements approach.[209] Duke Energy supports MISO's proposed

[207] *Id.* at 6-7.

[208] OMS Comments at 6-7.

[209] *Id.* at 7 (citing NERC, 2020 Long Term Reliability Assessment at 6 (Dec. 2020), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf)

exemption process for full generator planned outages because it appropriately reduces the denominator to accurately reflect the capability of a generator.[210]

126. Consumers Energy agrees that increasing the impact of forced outages during tight hours on resource accreditation will create incentives for generators to appropriately invest in maintenance and supply; but argues that reducing the flexibility to prudently schedule planned outages is arbitrary and does not address MISO's identified issues.[211] Consumers Energy asserts that it is more important for market participants to have flexibility to schedule and plan outages when baseload generation is becoming less common and more consolidated.

127. Consumers Energy states that, if MISO's Maintenance Margin is increasingly insufficient, then MISO should reconsider how it determines the Maintenance Margin or increase how forced outages impact accreditation, as opposed to punishing generators that appropriately coordinate and schedule outages.[212] Consumers Energy asserts that MISO does not explain how modifying the exemption rules for prudently planned outages will improve operating or Maintenance Margins.[213] Consumers Energy also states that eliminating the ability for generators to schedule planned outages less than 120 days in advance without risking accreditation does not address the correlation between forced outages and insufficient investments in winterization or fuel supply.[214] Regarding the shift in resource types, Consumers Energy asserts that MISO also does not tie that concern to the timing of scheduling planned outages, and argues that the proposal will not improve the "confidence in the availability of remaining resources."[215] Furthermore, Consumers Energy argues that MISO's explanation that coordinating outages well in advance will provide more visibility into the resources available under tight conditions does not sufficiently explain how its proposal will improve reliability.[216]

128. Entergy Coalition disputes MISO's statements that resource owners currently have little to no incentive to minimize the length of planned outages. Entergy Coalition argues

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[210] Duke Energy Comments at 4.

[211] Consumers Energy Limited Protest at 7.

[212] *Id.* at 8-9.

[213] *Id.* at 8.

[214] *Id.* at 8-9 (citing Smith Test. at 18).

[215] *Id.* at 9 (citing Wright Test. at 23).

[216] *Id.* at 9-10 (citing Smith Test. at 20).

that resource owners have obvious economic and system reliability incentives to minimize the length of planned outages in order to ensure high availability of their resources, as each day a resource is offline is a day that resource does not collect revenue from energy and ancillary services markets.[217]

129. Several entities protest the requirement to schedule an outage at least 120 days in advance in order to receive a Tier 2 exemption for that outage. East Texas and DTE Electric contend that MISO has not adequately explained why outages must be scheduled 120 days ahead of time to be eligible for a full exemption, nor has MISO explained how such a cutoff would increase resource availability during RA Hours. Consumers Energy argues that increasing the advance notice period required to secure a full outage exemption from 14 days to 120 days is arbitrary, unsupported, and fails to address the issues identified by MISO.[218] East Texas further argues that MISO has not described why all MISO-approved, planned outages cannot receive a full exemption when the Maintenance Margin is greater than zero.[219] Entergy Coalition and Consumers Energy are concerned that the 120-day advance notice criterion could have the perverse effect of discouraging generation owners from performing some maintenance activities, resulting in worse unit performance.[220] Consumers Energy asserts that increasing the advance notice period creates incentives for risky, suboptimal plant operation by discouraging prudent, planned outages in the short to medium term.[221] Entergy Coalition argues that MISO's Tier 2 exemption requirements are unreasonable because, as long as there is a positive Maintenance Margin at the time of submission for the entire duration of a planned outage (with at least 14 days' notice, as currently required under RAN Phase I exemption criteria), it is unreasonable to conclude that the planned outage will materially increase system risk and therefore should lower the resource's accreditation value.[222] Ameren suggests that MISO should be directed to revise the tariff language to require that either the 120-day criterion *or* the Maintenance Margin is met, but not both.[223]

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[217] Entergy Coalition Protest at 13-14 (citing Smith Test. at 20-21).

[218] Consumers Energy Limited Protest at 2.

[219] East Texas Protest at 9; DTE Electric Protest at 10-11.

[220] Entergy Coalition Protest at 14; Consumers Energy Limited Protest at 3-5.

[221] Consumers Energy Limited Protest at 1.

[222] Entergy Coalition Protest at 14.

[223] Ameren Protest at 5-6.

130. Midwest TDUs argue that MISO has not explained why it requires 120 days between planned outages to receive a Tier 2 exemption. Midwest TDUs state that MISO's current Tariff specifically provides for an exemption from the forced outage rate adjustment in resource accreditation in this exact scenario, noting that, currently, a resource will be given an exemption if the market participant provides 120 days' notice and if there is adequate projected Maintenance Margin at the time the request is submitted. Midwest TDUs contend that MISO's proposal may make outage coordination harder, rather than easier, by effectively eliminating the option of scheduling planned outages during the 120-day windows if there is adequate Maintenance Margin during that time.[224] Midwest TDUs submits that, in a situation where a resource requires 30 days of non-consecutive outage, if one day in that 30 day period did not have a positive Maintenance Margin, a resource would be discouraged from splitting its planned outage in two parts to schedule around that one day because the second outage would not receive a Tier 2 Planned Outage exemption. Midwest TDUs argue that MISO's proposal to treat a resource as unavailable during that second outage bears no rational relationship to that resource's expected availability during times of need.[225] DTE Electric states that, compared to the current process, the proposal would limit the ability of market participants to plan outages and receive exemptions for accreditation impacts such that even prudently planned outages may not qualify for an exemption.[226]

131. The Mississippi Commission asserts that outage planning and coordination is an operational issue, not a marketplace issue, and that close coordination, rather than ambiguous price signals and penalties, will lead to better outage planning to avoid periods of shortage.[227] Clean Energy Coalition argues that planning solutions cannot address the underlying problem of scheduled maintenance events and that MISO should propose an operational solution to manage scheduling of outages that may include changes to outage protocols and Maintenance Margins.[228] Clean Energy Coalition contends that MISO has not conducted sufficient analysis to understand the implications of scheduled resource maintenance on grid reliability.[229] Clean Energy Coalition argues that MISO's main concern is the implications of scheduled resource maintenance on grid reliability and that MISO does not use LOLE modeling in a straightforward manner to

[224] Midwest TDUs Protest at 16-17.

[225] *Id.* at 15-16.

[226] DTE Electric Protest at 9-10.

[227] Mississippi Commission Protest at 37.

[228] Clean Energy Coalition Protest at 4.

[229] *Id.*

assess the maximum level of capacity that can be out of service without affecting reliability.[230] Clean Energy Coalition asserts that MISO's proposal resorts to inappropriate modeling that develops seasonal planning reserve margins based on inconsistent resource metrics and flawed inputs. Clean Energy Coalition argues that changing risk profiles throughout the year will make it increasingly difficult for MISO to ensure LOLE targets are met when scheduled resource maintenance may result in insufficient availability of capacity during periods that historically had little risk.[231]

132. Clean Energy Coalition argues that MISO's outage proposal provides a blanket exemption from availability-based accreditation that allows units to avoid an "unavailable" evaluation for an historical RA Hour as long as it gives four months' notice of a planned outage, up to three times a year. Clean Energy Coalition contends that MISO's proposed exemptions severely limit the reliability value of MISO's proposal and gives resource owners little motivation to think twice before scheduling an outage, even at peak times.[232]

133. WEC Utilities state that MISO's proposed filing fails to address potential hoarding of planned maintenance outage margin. WEC Utilities note that the proposed tariff revisions do not include any language to ensure that a resource owner does not hoard Maintenance Margin thereby precluding any other resource owners from scheduling their own outages. WEC Utilities state that nothing in the Tariff or proposed Tariff prohibits a resource owner from scheduling a planned outage every year when it might only need a planned outage every other year; as proposed, the unneeded outage can be simply withdrawn with no penalty and, if the withdrawal of the planned outage occurs within the 120-day window, the resulting increase in Maintenance Margin created by the withdrawal would not be available for other resource owners.[233]

134. Midwest TDUs state that MISO's exemption approach results in different resources having different RA Hours, which, according to Midwest TDUs, further increases the disconnect between MISO's SAC accreditation proposal and an accurate measure of the hours of highest need in a given Season. Midwest TDUs contends that, to avoid this, MISO should truly exempt a resource that qualifies for a Tier 2 Planned

[230] *Id.*

[231] *Id.*

[232] *Id.* at 16.

[233] WEC Utilities Comments at 8-9.

Outage exemption by treating it as if it were available during these hours for purposes of the accreditation determination.[234]

135. Midwest TDUs note that certain Tier 1 exemptions are given if a planned outage passes the No Harm Test. Midwest TDUs state that the No Harm Test includes, but is not limited to, outage approval compliance with all applicable operation guides, review of possible conflicting outages or system conditions, system capacity, and the criteria outlined in the BPM for Generator Outage. Midwest TDUs oppose deference of MISO's Tier 1 exemption criteria to the BPM, as well as the fact that MISO will consider additional unidentified factors beyond those in the BPM. Midwest TDUs add that, similarly, MISO's proposal allows MISO to, at its discretion, grant a Tier 1 Planned Outage exemption if a resource reschedules its Generator Planned Outage at MISO's request. Midwest TDUs argue that the language of these exemptions does not allow the Commission, or resource owners, to understand when MISO will grant Tier 1 exemptions, and, ultimately, how MISO will determine a resource's SAC. Midwest TDUs contend that MISO should be directed to provide greater detail in the Tariff describing the criteria for Planned Outage exemptions.[235]

136. Duke Energy and MISO TOs argue that MISO needs to provide more support for excluding prudently planned derates from accreditation exemptions.[236] Duke Energy states that, during the stakeholder process, it explained its concerns that to treat planned partial outages differently than full generator planned outages by not excluding hours with planned derates from the SAC calculation but doing so for full generator outages would result in an unjust, unreasonable, and unduly discriminatory accreditation calculation.[237] Midwest TDUs state that excluding partial outages from planned outage exemptions would unreasonably reduce a resource's accreditation because of properly coordinated partial outages, and it would create a problematic incentive to schedule full outages rather than partial ones.[238] Great River Energy requests clarification that planned outages scheduled to begin before September 1, 2022 will be granted both a Tier 1 and Tier 2 exemption.[239]

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[234] Midwest TDUs Protest at 12-13.

[235] *Id.* at 47-48.

[236] Duke Energy Comments at 3; MISO TOs Comments at 8.

[237] Duke Energy Comments at 4.

[238] Midwest TDUs Protest at 17-18.

[239] Great River Energy Comments at 2.

137. DTE Electric, Midwest TDUs, and Duke Energy protest MISO's proposal to cap a Schedule 53 Resource's maximum offer at its GVTC, arguing that the cap ignores a Schedule 53 Resource's available capacity.[240] Midwest TDUs assert that using GVTC values as a cap in the SAC methodology, even if those values are seasonally adjusted, is inconsistent with MISO's stated goal of "[u]tilizing offered availability and actual performance [to] provide[] an improved measure of expected availability for each Season."[241] Midwest TDUs state that a resource's capability may vary at different times due to temperature, humidity, and other conditions, and that operating conditions in late May can be much different than those in early March, even though both are within the Spring Season. Midwest TDUs assert that, just as it would be unreasonable to impose a cap on a resource's SAC based on an annual GVTC value that does not reflect capability within a particular Season, it is unreasonable to use a uniform GVTC throughout an entire Season.[242] Duke Energy asserts that MISO's proposed hourly GVTC cap creates a disincentive for reliable service at the top end of generator output and fails to give full accreditation value for the service actually provided to the grid in instances where a generator can and does operate above its GVTC limit.[243]

138. Duke Energy states that a unit's offered availability may be zero in a particular hour when the unit did generate power that was used and available to the market, potentially during times when that generation is needed most. Duke Energy explains that offered availability is commonly at zero during startup and shutdown when, per MISO's rules, generators are not permitted to enter offers. Duke Energy states that, in addition, there may be no offered availability when the generating unit is off-Automatic Generation Control returning from an outage, or entering an outage, but the unit may nevertheless be generating and producing energy. Duke Energy states it is common for a generator to be in-service, physically supporting the grid with its generation output, but have its offer show no availability, which will result in an understated value for accredited capacity. According to Duke, MISO's proposed availability metric would not provide any accredited availability to the generator in those circumstances, despite the fact that the generator actually injects net positive generation into the grid. Duke Energy contends that this will result in an understated value for accredited capacity, potentially

[240] DTE Electric Protest at 14; Midwest TDUs Protest at 18-19; Duke Energy Comments at 14.

[241] Midwest TDUS Protest at 18-19 (citing McFarlane Test. at 15).

[242] *Id.* at 19.

[243] Duke Energy Comments at 14.

increasing cost for customers, and also create a problematic misalignment of incentives.[244]

139. WEC Utilities, DTE Electric, Alliant, and MISO TOs raise concerns that MISO's proposal lacks a mechanism to transition Generator Interconnection Agreements (GIA) to higher Winter capacity values, explaining that some thermal generation resources, such as combustion turbine and combined-cycle generators, have Winter output capabilities that are higher than their Summer capabilities because of lower ambient air temperatures.[245] DTE Electric states that, while MISO recognizes that GVTC values are necessary to appropriately reflect non-Summer capabilities, MISO's proposal fails to recognize that Interconnection Service limitations will also be affected by a more granular construct.[246] WEC Utilities state that some GIAs, especially those that were executed several years ago, may reflect only Summer operating conditions and that the proposed seasonal approach to resource adequacy noted in the deliverability limits of these outstanding GIAs may limit the Winter capacity of some resources.[247] Alliant states that, as a result, as resources make their way through the multi-year interconnection process, significant amounts of existing capacity will be left unaccounted, but available. Alliant argues that MISO's rush to implement its proposal in one year could create artificial resource shortfalls, which could, in turn, force unreasonable costs on customers that would not occur if a complete and orderly transition to a seasonal construct was required.[248] In addition, MISO TOs contend that the SAC proposal may allow for SAC values to be higher than a resource's Network Resource Interconnection Service (NRIS) rights.[249]

140. Some commenters dispute MISO's proposed use of a 24-hour resource lead time in the SAC proposal. For example, Midwest TDUs state that, for an offline resource where "the sum of the Start-Up Time and Start-Up Notification Time Offers exceeds 24 hours," MISO proposes to treat its Hourly Emergency Maximum Limit or Targeted Demand Reduction Level as zero. Midwest TDUs note that this means that longer-lead time resources will be treated as if they were completely unavailable during these critical

[244] *Id.* at 13-14.

[245] WEC Utilities Comments at 9; DTE Electric Protest at 14; Alliant Protest at 6; MISO TOs Comments at 5.

[246] DTE Electric Protest at 14.

[247] WEC Utilities Comments at 9.

[248] Alliant Protest at 6-7.

[249] MISO TOs Comments at 5.

RA Hours. Midwest TDUs argue that MISO has not demonstrated why it proposes to treat an offline, but available, resource with a 26-hour lead time the same as a resource that is unexpectedly unavailable due to a non-exempt outage, as, according to Midwest TDUs, this fails to reflect the value of longer-lead time resources. Midwest TDUs contend that, if these resources have submitted offers but are offline due to MISO's decision not to commit them, that should not negatively impact their accreditation. Midwest TDUs add that many of the situations MISO seeks to address, such as extreme weather events, can be anticipated more than 24 hours in advance.[250]

141. Midwest TDUs contend that MISO should be required to take steps to facilitate the ability of these longer-lead time resources to avoid this extreme, negative impact on accreditation. Midwest TDUs explain that, unless these resources have been committed through the Reliability Assessment Commitment process, which is conducted seven days ahead of the operating day, or the Day-Ahead Reliability Assessment Commitment process, these resources must act proactively to self-commit in order to avoid a hit to their accreditation. Midwest TDUs argue that, if MISO is going to impose a harsh, bright-line threshold of 24 hours, it should provide resource owners with timely information about potential upcoming RA Hours so that they can make informed decisions about whether to self-commit.[251]

142. Entergy Coalition states that MISO's 24-hour lead time proposal would be impractical for many otherwise valuable resources due to either physical limitations or, more often, constraints and costs of contracting firm natural gas supply and delivery to those resources. Entergy Coalition argues that, as a result, the SAC proposal would likely result in substantial increased self-commitment of comparatively inefficient resources to avoid loss of accreditation and potentially significant increased fixed contractual costs for fuel, resulting in less efficient overall use of resources within the MISO region, contrary to MISO's broader goals to provide economic benefits to market participants.[252]

143. While supporting the filing overall as just and reasonable, Potomac Economics argues that treating offline resources with up to a 24-hour lead time as available up to their offered output overvalues less flexible, long lead time units. Potomac Economics asserts that tight conditions typically emerge due to load forecast errors, wind forecast errors, large unit forced outages, or other factors that are not known far in advance.[253]

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[250] Midwest TDUs Protest at 20-21.

[251] *Id.* at 21.

[252] Entergy Coalition Protest at 8.

[253] Potomac Economics Comments at 8.

According to Potomac Economics, most emergencies are recognized and declared between 30 minutes and 6 hours in advance.[254] Therefore, Potomac Economics contends that, despite MISO's assertion that MISO could have reasonably committed a resource in the Day-Ahead Market or Forward Reliability Commitment Process, if most reliability threats emerge during the operating day, then offline resources whose lead times are too long to mitigate the reliability threat provide no value in such events.[255]

144. Some commenters express concerns about MISO's proposal to use a UCAP/ISAC ratio to calculate the SAC accreditation for Schedule 53 Resources. COMPP contends that MISO's use of the UCAP/ISAC ratio highlights inconsistencies between capacity accreditation and MISO's LOLE studies. COMPP explains that, while MISO's Seasonal LOLE Study will determine the amount of UCAP MISO needs to procure to maintain resource adequacy, MISO's Capacity Resources will now be accredited ZRCs based on their SAC. COMPP avers that UCAP does not equal SAC, and the failure to align LOLE metrics with accreditation metrics amounts to MISO's proposal being unjust, unreasonable, and unlawful.[256] COMPP submits that, while MISO recognizes this disconnect, and proposes a conversion ratio between SAC value and the UCAP amount, MISO should instead be directed to conduct a LOLE study that determines needed capacity volumes using the same definition used in the Auction.[257] COMPP notes that no other organized market has approved separating the way capacity is defined in underlying reliability studies from the way capacity is procured.[258] Clean Energy Coalition argues that this ratio adjustment has not undergone independent analysis and its impact on overall system reliability is unclear.[259]

145. Clean Energy Coalition and Midwest TDUs submit that MISO's use of the UCAP/ISAC ratio is discriminatory against non-Schedule 53 Resources. Midwest TDUs assert that non-Schedule 53 Resources are similarly situated to Schedule 53 Resources in terms of accreditation, as well as the relationship between that accreditation and the methodology for determining Reserve Requirements. Midwest TDUs argue that MISO has not supported its proposal to apply a conversion ratio to some resources with accreditation based on historical performance but not others and that, as a result, MISO's

[254] *Id.* at 9.

[255] *Id.* at 10-11.

[256] COMPP Protest at 12.

[257] *Id.*

[258] *Id.*

[259] Clean Energy Coalition Protest at 8.

proposal is unduly discriminatory and may distort the relative share of accreditation between similarly situated resources.

146. Clean Energy Coalition contends that, after ISAC values are calculated, MISO is proposing to use the UCAP/ISAC ratio to shift the supply curve of Schedule 53 resources to the right, benefitting thermal resources relative to renewable resources.[260] Clean Energy Coalition argues that Schedule 53 resources with better historical availability than their peers will be rewarded, whereas Schedule 53 resources that have worse historical availability will be penalized, while an average Schedule 53 resource will receive a capacity credit equal to its UCAP value, which takes into account forced outages only. Clean Energy Coalition asserts that MISO has not clarified whether widening the accreditation gap between the best performing and worst performing Schedule 53 resources will require the best performing resources to contribute to reliability at levels that exceed their nameplate, and whether the contribution would help or hurt reliability.[261] Clean Energy Coalition further argues that, while the total amount of Schedule 53 Resources accredited under this proposal would be unchanged, it is counterintuitive that high performing resources could be accredited at a level that exceeds their physical ability to perform in an effort to "make up" for the poorer performing units.[262] Similarly, Entergy Coalition contends that the use of the UCAP/ISAC ratio means that under the proposal a resource can have a final accreditation rating exceeding its GVTC. Entergy Coalition suggests that this is another indication that MISO's SAC proposal is a poor indicator of resource capability.[263]

147. COMPP argues that, under MISO's proposal, internal generation resources are accredited using the SAC methodology, while external resources are accredited using a seasonal GVTC methodology. COMPP submits that it is unclear why internal and external resources are subjected to different treatment, as external resources that commit capacity to MISO but fail to make themselves available during RA Hours will not be penalized.[264]

148. Several entities argue that intermittent resources should be accredited using MISO's proposed SAC methodology. Ameren and DTE Electric contend that the proposal to apply the SAC provisions to only Schedule 53 Resources and to except other

[260] *Id.*

[261] *Id.*

[262] *Id.*

[263] Entergy Coalition Protest at 7-8.

[264] COMPP Protest at 15.

resources until a future filing is made does not result in comparable treatment of all resource types and undermines the purpose of requiring accreditation.[265] Minnesota Power supports updating the wind and solar accreditation method to align with the SAC methodology to avoid discriminatory resource planning criteria.[266] COMPP states that, while MISO attempts to ease concerns by committing to a future ELCC effort, MISO has not started work on that effort and it could take years before an improved ELCC construct is adopted.[267] DTE Electric notes that the resources MISO excludes from the proposal are the same resources that MISO cites as in need of change.[268] MISO TOs state that, although MISO indicated that it would address accreditation enhancements to non-Schedule 53 Resources in the future, the Commission should require MISO to start stakeholder discussions prior to the effective date.[269] WEC Utilities argue that MISO has proposed an innovative SAC accreditation methodology for Capacity Resources that will be based on availability during times of need, which should be applied to all resources, not just Schedule 53 Resources.[270]

149. Clean Energy Coalition argues that MISO does not apply consistent risk metrics across different types of resources to evaluate a resource's contribution to risk mitigation.[271] Clean Energy Coalition further argues that MISO's use of average offered MW during times of system risk to measure thermal resource availability is an *ex post* approach based on actual historical performance to assess tight margin hours and measure LOLP or LOLE risk.[272] Clean Energy Coalition then argues that MISO will continue to use ELCC to calculate seasonal accreditation of wind resources (and potentially solar in the future).[273] Clean Energy Coalition contends that ELCC is a probabilistic metric that

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[265] Ameren Protest at 4; DTE Electric Protest at 15-16.

[266] Minnesota Power Comments at 2.

[267] COMPP Protest at 15.

[268] DTE Electric Protest at 2-3, 16.

[269] MISO TOs Comments at 10.

[270] WEC Utilities Comments at 6-7

[271] Clean Energy Coalition Protest at 5.

[272] *Id.*

[273] *Id.* (citing MISO, MISO's Responses to Stakeholder Questions, at 8 (Oct. 5, 2021) ("Further enhancements on solar accreditation will continue at the RASC after the RAN RA construct reform filing to evaluate ELCC or similar availability-based accreditation approaches."),

is based on a statistical expected value and represents an *ex ante* or forecasted capacity. Clean Energy Coalition further argues that MISO's proposal is deficient since it does not address seasonal accreditation for energy storage resources.[274]

150. Clean Energy Coalition further argues that this discrepancy persists even if a wind and thermal resource's performance were identical. Clean Energy Coalition argues that MISO's proposal to use alternative accreditation proposals for different resource types is not consistent with good market design, does not provide consistent signals for resources to respond to periods of reliability risk, and may not provide the level of reliability that MISO seeks.[275] Clean Energy Coalition further argues that MISO's proposal is unjust, unreasonable, and unduly discriminatory since it will compensate thermal generators more than other resources for providing the same amount of capacity.[276]

151. Clean Energy Coalition argues that MISO does not use the same input data to assess periods of risk to calculate thermal and wind resource accreditation. Clean Energy Coalition argues that under MISO's proposal, thermal resources would get credit based upon actual offers during tight margin hours, while wind resources would get credit based upon an expected value of generation during different hours.[277] Clean Energy Coalition argues that the use of ELCC for wind means that risk periods that wind can potentially mitigate are hours when there is a LOLP, measured *ex ante*, whereas tight margin hours for thermal resources, measured *ex post*, are not necessarily the same time periods.[278] Clean Energy Coalition argues that the proposal is therefore not comparing a resource's available capacity on the same basis.[279] Clean Energy Coalition explains that thermal resources are credited based on their performance during tight margin hours that may correspond with LOLP hours. Clean Energy Coalition then argues that MISO's own analysis shows that tight margin hours do not always occur during LOLP hours.[280] Clean

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https://cdn.misoenergy.org/20211006%20RASC%20Supplemental%20Q%20and%20A%20Document595123.pdf).

[274] *Id.* (citing McFarlane Test. at 31-33).

[275] *Id.*

[276] *Id.* at 6.

[277] *Id.* at 7.

[278] *Id.* at 6.

[279] *Id.*

[280] *Id.* at 6-7.

Energy Coalition argues that MISO has not examined whether it is better to pool tight margin hours and LOLE hours and use those periods to assess all resources, or adopt either the LOLP approach or the tight margin approach and apply it to all resources.[281]

152. Clean Energy Coalition argues that the Commission previously accepted MISO's ELCC construct for wind resource accreditation on an annual basis and that the approach would be inappropriate for calculating a seasonal construct as currently proposed by MISO.[282] Clean Energy Coalition argues that current flaws in MISO's ELCC methodology may credit wind resources during hours of no risk while not crediting wind resources for contributions during periods of high risk.[283] Clean Energy Coalition then argues that MISO's SAC proposal arbitrarily re-allocates annual LOLP risk to each Season by assuming that 25% of the annual risk occurs in each of the four Seasons, in direct contrast to the results of MISO's own LOLP modeling and the need for a seasonal construct.[284] Clean Energy Coalition then states that MISO's own analysis shows that risk is not equally spread into each of the four Seasons, creating periods of artificial risk.[285] Clean Energy Coalition finally argues that this arbitrary allocation method removes times of risk that were identified by the annual LOLE calculations used in the status quo approach.[286]

153. Clean Energy Coalition argues that MISO's proposal is unjust, unreasonable, and unduly discriminatory because it does not expressly consider fuel supply risk for coal and natural gas resources but does consider fuel supply risk for wind and solar resources. Clean Energy Coalition argues that MISO's proposal does not explain whether, or to what extent, the availability-based method for determining thermal resource capacity accreditation captures past limitations on fuel availability and whether historic fuel availability is representative of future periods given changes in the resource mix, extreme weather patterns, and other factors.[287] Clean Energy Coalition argues that, in contrast, the ELCC methodology applied to wind resources and the availability-based accreditation for solar resources does take into account fuel supply risks since the assessment of their

[281] *Id.* at 7.

[282] *Id.* at 13.

[283] *Id.*

[284] *Id.*

[285] *Id.*

[286] *Id.* at 14.

[287] *Id.* at 7.

ability to deliver power is directly tied to whether they have fuel (sun or wind) to generate power.[288]

154. Midwest TDUs state that MISO will determine the SAC of wind and non-wind resources, based on particular hours in each Season. Midwest TDUs contend, however, that MISO's proposed Tariff language merely states that SAC accreditation for Dispatchable Intermittent Resources and Intermittent Generation "will be determined by the Transmission Provider based on historical performance, availability, and type and volume of interconnection service, for each Season in accordance with the BPM for Resource Adequacy."[289] Midwest TDUs assert that, given the detailed methodology MISO is proposing to include in the Tariff for Schedule 53 Resources, it is not appropriate for MISO to propose vague changes to the accreditation process for intermittent resources that it will implement through its BPM. Midwest TDUs contend that resources should be on a level-playing field in terms of the level of detail the Tariff provides in terms of the accreditation methodology MISO applies, and the extent to which the Commission has reviewed and accepted those accreditation methodologies. Midwest TDUs state that including these critical details regarding accreditation provides certainty and ensures that the Commission has determined they are just, reasonable, and unduly discriminatory.[290]

155. Industrial Customers argue that MISO has not demonstrated that its proposal to increase the number of calls on LMR DRs who participate as an LMR are required to allow during the Planning Year from 10 to 16 to receive 100% capacity accreditation for the full Planning Year is just and reasonable.[291] Industrial Customers assert that MISO's transmittal letter and prepared testimony provide no information or analysis with respect to how MISO determined the need for 16 LMR calls per Planning Year for LMRs that are accredited for a full Planning Year. Industrial Customers contend that MISO completely ignores the fact that for an LMR that participates in all four Seasons of a Planning Year, the sum of the required allowed seasonal calls amounts to 16 calls per Planning Year, versus the currently required 10 calls per Planning Year.[292]

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[288] *Id.*

[289] Midwest TDUs Protest at 49 (citing MISO, FERC Electric Tariff, Module E-1, § 69A.4 (33.0.0) (proposed)).

[290] *Id.*

[291] Industrial Customers Protest at 4-5.

[292] *Id.* at 6.

156. Industrial Customers state that MISO identified the basis for the proposal in its initial August 4, 2021 presentation to the MISO RASC. According to Industrial Customers, MISO identified that the basis of its proposed requirement for five calls in Summer, three calls in Fall, five calls in Winter, and three calls in Spring is the result of MISO's 2020 LOLE analysis that it performed to support its proposal in Docket No. ER20-1846-000, which the Commission accepted in August 2020, to require LMR DRs receiving a 100% capacity accreditation for a full Planning Year to allow MISO 10 interruption calls per Planning Year.[293] Industrial Customers argue that MISO is essentially proposing to reinterpret its conclusion from the results of MISO's 2020 LOLE analysis to support further increasing the required number of allowed MISO interruption calls on LMR DRs that receive a 100% capacity accreditation for a full Planning Year to 16 calls per Planning Year. Industrial Customers argue that the results of MISO's 2020 LOLE analysis do not support requiring 16 interruption calls per Planning Year given MISO's very recent past interpretation of these results and given the saturation in the above capacity credit curve results beyond 10 calls per Planning Year.[294]

157. Industrial Customers contend that no more than 10 interruption calls in total, in any given Planning Year, should be required of any LMR DR that is receiving 100% capacity accreditation for an entire Planning Year. Further, Industrial Customers assert that MISO has historically never called any LMR more than three times in a given Planning Year. Industrial Customers argue that MISO's proposal would result in an unnecessary chilling of LMR DR participation merely because the risk of 16 interruptions would exist, even though MISO has not demonstrated any operational basis for calling more than four or five interruptions in any given Planning Year.[295]

158. Industrial Customers emphasize that the interruption of electric service when called upon by MISO results in significant costs and operational disruptions to these end-use customers. Industrial Customers state that such costs include, but are not necessarily limited to, lost production, process restart costs, and the cost for consumables, where necessary, to allow the interruptions. With respect to operational disruptions, Industrial Customers assert that, while the minimum MISO Tariff requirement for an LMR DR to remain curtailed is only at least four consecutive hours, many industrial facilities are

[293] *Id.* at 6-7 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 172 FERC ¶ 61,138 (2020) (LMR DR Accreditation Order)).

[294] *Id.* at 7-8.

[295] *Id.* at 8-9.

incapable of ramping up their processes after only four hours of being down such that once they are shut down, they may have to stay at that level for 12 hours or longer.[296]

159. Steel Producers explain that the Tariff requires Demand Resources maintain interruptions for at least four continuous hours, meaning that MISO would effectively increase the amount of hours of interruption from a minimum of 40 to 64. Steel Producers argues that this increase is not supported by any new analysis.[297]

160. The Mississippi Commission argues that the SAC proposal, which it asserts favors quick start-flexible generation units over base-loaded gas and nuclear generation, will marginalize the value of existing generation and drive state utility investment toward MISO's preferred resources. The Mississippi Commission asserts that MISO's proposal would create an artificial shortage of generation that must be filled by flexible ramping generation that is needed in MISO North to address reliability concerns caused by overreliance on wind resources. However, the Mississippi Commission argues, MISO has no authority to marginalize generation that state regulatory authorities have sited, authorized for construction and cost recovery, and that are used to serve state load, based on operating characteristics.[298] The Mississippi Commission asserts that neither the Commission nor RTOs/ISOs may direct a utility to construct a specific type of generation resource, and that the SAC proposal indirectly does what MISO lacks the authority to do.[299]

161. Entergy Coalition contends that MISO's proposal will disrupt LSE resource planning activities and frustrate the state regulatory authority oversight and planning objectives and notes that the Commission has emphasized that the design of MISO's Auction is complementary to LSE integrated resource planning that takes place subject to the rules and procedures of state regulatory authorities.[300] Entergy Coalition argues that the unpredictability embedded in MISO's proposal will make it extremely difficult for: (1) state regulatory authorities and LSEs to replicate and predict future outcomes of

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[296] *Id.* at 9.

[297] Steel Producers Limited Protest at 4.

[298] Mississippi Commission Protest at 31.

[299] *Id.* at 32 (citing 16 U.S.C. § 824(b)(1); *Hughes v. Talen Energy Mktg, LLC.*, 136 S. Ct. 1288, 1292; *see also Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205 (1983)).

[300] Entergy Coalition Protest at 9 & n.19 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 162 FERC ¶ 61,176 (2018), *order on reh'g*, 170 FERC ¶ 61,215 (2020)).

MISO's proposal; and (2) for LSEs to conduct long term planning consistent with the objectives of the state regulatory authorities that regulate them.[301]

162. Duke Energy argues that MISO has not shown how the proposed SAC accreditation calculation will accurately account for jointly owned units.[302] Duke Energy submits that, in data MISO provided during the stakeholder process, it is not clear that MISO will accurately calculate the capacity accreditation of Capacity Resources that are jointly owned.[303]

c. MISO February 10 Answer

163. MISO reiterates that its proposal will result in demonstrable and effective increases in reliability, stating that protestors fail to recognize the improvements to reliability described in MISO's filing. MISO states that its SAC accreditation proposal will increase system reliability in multiple ways and is a substantial improvement over the current UCAP approach. MISO states that first, establishing seasonal SAC values will provide improved incentives for resources to be available outside of the traditional Summer peak months, in contrast to MISO's current UCAP approach which allows for resources to get capacity credit year-round without having to be available year-round outside of the Summer months. MISO adds that the three-year expected forced outage rating used for a resource's UCAP is highly diluted as it considers all hours over a three-year period and does not give MISO operators a true sense of what capacity can be relied upon when system conditions get tight. MISO contends this is especially critical outside the Summer months where MISO has seen an increase in MaxGen Events.[304] MISO states that establishing seasonal requirements and seasonal SAC values provides increased visibility to MISO operators of resource availability throughout the Planning Year, which will give operators more confidence in what Planning Resources they can expect and count upon when system conditions tighten. MISO adds that its SAC accreditation proposal will provide resources with incentives to be available during times of need because of the 80% weighting of Tier 2 RA Hours. MISO states that aligning accreditation incentives with real-time system needs will enhance operators' confidence in the availability of resources, further improving reliability. MISO states that under its

[301] *Id.* at 10.

[302] Duke Energy Comments at 17.

[303] *Id.*

[304] MISO February 10 Answer at 21-22.

proposal, as time goes on, average resource availability will improve, giving operators more resources to manage tight system conditions, improving reliability even further.[305]

164. MISO explains that its current UCAP approach only accounts for forced outages and derates not determined to be Outside Management Control and, as such, does not fully reflect real-time resource availability—especially during times of need. MISO asserts that using the Hourly Emergency Maximum Limit that resources submit in the Real-Time Market, which MISO proposes to use, among other things, for accreditation more accurately represents a resource's expected availability during tight system conditions than the current UCAP methodology.[306] MISO states that its proposal better aligns planning and operations efforts to ensure capacity sufficiency, closing a gap which has contributed to an overestimate of resource availability. MISO states that, ideally, MISO would be able to know exactly a resource's availability ahead of time, but, without a crystal ball, historical data is the best indicator of future performance.[307]

165. In response to arguments suggesting that MISO's proposed implementation timeline is unreasonable, MISO asserts that its proposed timeline balances the urgent need to address growing reliability risks with the countervailing stakeholder need for time to adjust to the new requirements. MISO submits that, the PJM capacity market precedent regarding a transition mechanism is inappropriate because MISO's proposal is fundamentally different from the changes PJM made to its Reliability Pricing Model for Capacity Performance Resources. First, MISO states that application of the UCAP/ISAC ratio will maintain the overall supply and demand balance at the footprint level, while aligning relative accredited values among different resources. Second, MISO states that Capacity Resources have a must offer obligation under the current resource adequacy requirements, therefore their offered capacity should already generally align with their availability and should already be driven by existing incentives provided by MISO's energy and ancillary services market. Third, MISO states that the proposed transition plan retains the RAN Phase 1 exemptions for generator outages in the initial years of SAC calculations, which MISO asserts are comparable to, if not more lenient than, the proposed Tier 1 and Tier 2 exemptions contained in the proposal.[308] Further, MISO explains that the three-year lookback period, which will begin in the 2023/2024 Planning Year, will only include outage behavior and resource availability that occurred after RAN Phase 1 was accepted and implemented. MISO states that, by that time, the evolving risks to reliability and focus on resource availability during times of need throughout the

[305] *Id.* at 22.

[306] *Id.* at 24-25.

[307] *Id.* at 25.

[308] *Id.* at 7-8.

year were well established and it is reasonable to consider resource performance from this period.[309]

166. In response to arguments that it is inappropriate for MISO to use historical offer and outage data from before SAC implementation because generation owners' operational decisions were based on the market construct and accreditation framework in place at the time, MISO submits that system operators need to know what is truly available to meet real time system conditions, and waiting or prolonging the use of data until after the implementation date of the SAC proposal will continue to provide MISO operators with a false sense of what is truly available. MISO adds that it has also provided a transition period to the 80% weighting of availability in prior Tier 2 RA Hours, which is intended to mitigate some of this concern.[310]

167. MISO states that it has provided detailed data to stakeholders, including seasonal SAC value and requirements at the portfolio level, unit-level SAC values on a seasonal basis, and extensive and detailed data for at least one individual resource for each stakeholder, including all the inputs and calculations necessary to allow stakeholders to independently validate how MISO derived the SAC values for that resource. MISO states that this information was provided more than once to stakeholders that requested the data over the course of the conceptual design.[311]

168. MISO disputes arguments suggesting that the proposal's approach to risk hour identification and compensation of resources for reducing loss of load risk is flawed by arguing that MISO has worked deliberately in recent years to explain and lay out evidence that changes to the generation portfolio, load patterns, and weather are driving uncertainty and variability that necessitate accreditation approaches that account for these changes' risks and their timing. MISO states that in the past it was considered sufficient to have enough capacity to cover a system's expected peak load, with a reasonable Reserve Requirement. MISO adds that it was also reasonable to assume that the same amount of capacity would also be sufficient during non-peak times of the year. MISO contends that, because MISO has experienced 41 MaxGen Events since June 2016 with more than 60% of those MaxGen Events occurring outside of the Summer Season, this is no longer a safe assumption. MISO states that it worked with stakeholders and the Market Monitor to craft a proposal that accounts for LOLE risk and carefully considers resource performance in each Season and the incentives needed to improve availability during times of need. MISO states that instead of being rigid, the proposal dynamically

[309] *Id.* at 29.

[310] *Id.*

[311] *Id.* at 31.

accounts for changing risks by basing most of a resource's accreditation on its availability during RA Hours that reflect the times of greatest need.[312]

169. MISO submits that its original proposal weighted Tier 2 hours at 100% toward a resource's offered availability, but stakeholders requested a method that also recognized a resource's reliability contribution during non-RA Hours. MISO states that it recognizes the value of general availability, especially as it supports needed generator planned outages; however, as the Market Monitor's analysis of the current UCAP method illustrates, general availability at all times does not adequately reflect availability during times of highest risk and availability during times of highest risk better represents a resource's true reliability value. MISO states that, as a result, MISO responded by developing the two-tier accreditation proposal, weighting offered availability in Tier 2 RA Hours at 80% to emphasize each resource's reliability contribution during times of greatest reliability needs.[313]

170. In response to comments regarding the potential impacts of missing an RA Hour due to Market Participants' self-commitments decision, MISO states that it is worth noting that the impacts to future accreditation and capacity revenues can be estimated by considering the probability of missing RA Hours and an expectation of Auction Clearing Prices and the reduction in accreditation over the upcoming three planning years. MISO adds that the quantified impacts of a resource missing an RA Hour and the potential impact to future capacity revenues can be compared to other relevant costs and energy market revenues to help inform decisions that impact resource operation and availability.[314]

171. MISO disputes arguments that MISO's proposal introduces unreasonable volatility into accreditation. MISO asserts that, by design, more resource level volatility with the proposed SAC accreditation methodology would be expected, but in aggregate the proposal leads to very little volatility at the MISO Region-wide level from year to year, especially over time. MISO states that its proposal leads to less than 2% volatility at the MISO Region-wide level, in part because of the application of the UCAP to SAC conversion ratio. MISO states that its proposal reduces the potential for individual resource volatility by retaining the three-year lookback period, which helps ensure that a resource's accreditation is not dramatically reduced as a result of a couple of bad days during a Season. MISO states that a key consideration for market participants is the stability of the accreditation of their resource portfolio in a Zone or subregion rather than

[312] *Id.* at 36-37.

[313] *Id.* at 25-26.

[314] *Id.* at 35-36.

the higher volatility expected from individual resources, which may move up or down due to specific conditions that impacted a particular resource's availability.[315]

172. MISO argues that its proposal will allow regulatory authorities and LSEs to continue to be able to replicate and predict future outcomes from the proposed SAC accreditation methodology and LSEs will still be able to conduct long term planning consistent with the objectives of the state regulatory authorities that regulate them. MISO states that resources may experience some volatility from one year to the next in the amount of accreditation they receive, but, on an aggregate basis, MISO does not expect large swings, especially as outage behavior changes and resources avoid unavailability during times of need.[316]

173. With regard to arguments that MISO's use of the AAOC may not accurately represent a resource's availability in a particular Season, MISO states that it believes that the use of RA Hour availability during out-of-Season RA Hours in a Planning Year is a reasonable substitute in the determination of accreditation as AAOC reflects actual resource availability during tight conditions throughout the year. MISO states that, while some stakeholders suggested using all-hours availability during the Season to "backfill" RA Hours, MISO believes that approach would inappropriately dilute the assessment of a resource's availability during tight conditions because it substitutes the resource's availability during non-tight conditions. In addition, MISO states that it does not support WEC Utilities' suggestion to use a Seasonal UCAP when there is a deficiency in RA Hours in a particular Season because, according to MISO, UCAP does not fully reflect a resource's actual availability, which is why MISO has proposed its accreditation reforms.[317]

174. MISO states that it is necessary to have a minimum number of RA Hours to support stability of accreditation values and avoid situations where a resource loses most of its capacity value for the Season because it happened to not be available on the one or two days during that Season's RA Hours. MISO asserts that the use of AAOC to backfill RA Hours is therefore appropriate when a Season has deficient RA Hours.[318]

175. MISO disputes arguments that in-Season RA Hours could be double counted in determining a resource's accreditation. MISO states that for any Season that lacks sufficient RA Hours, set at 65 hours minimum, the SAC accreditation will augment the

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[315] *Id.* at 20.

[316] *Id.*

[317] *Id.* at 27-28.

[318] *Id.* at 28.

deficient number of hours less than 65 for that resource with its AAOC over the tightest 3% of hours during the year, or 260 hours. MISO submits that, while referencing availability outside the Season is not the ideal metric, it is a reasonable proxy with which to supplement needed resource performance data. MISO adds that to the extent any of the Seasonal RA Hours are also in the set of Annual RA Hours, this would not statistically constitute double counting because the individual hours would be 1/65th (1.538%) of the resource performance for any seasonal RA Hour but would only be 1/260th of the AAOC, which itself would account for 1/65th (0.006% combined) of the resource performance in Tier 2. MISO adds that, even in the unlikely event that there were only 1 seasonal RA Hour, that hour would only account for 1.913% of the resource performance, which is less impactful than counting that same RA Hour twice. MISO states that, regardless, it is reasonable and appropriate to include these RA Hours in both cases as they successfully represent seasonal and annual availability during high-risk hours.[319]

176. With regard to transparency for planned outages, MISO states that it has been publishing information for years about submitted planned outages in its Maintenance Margin tool with results posted on the MISO Open Access Same-Time Information System (OASIS) every weekday. MISO states that in particular, the transparency report MISO provides on OASIS shows the total amount of submitted planned outages for future days and an after-the-fact accounting of the actual realized amount of planned outages for historical days, which is provided separately for each sub-region.[320]

177. MISO states that, as part of the RAN Phase 1 Tariff changes, a planned outage currently receives an exemption from being included in a resource's future accreditation by: (1) submitting the outage 120 days or more in advance; or (2) if there is positive Maintenance Margin for the duration of the outage. MISO argues that, rather than continuing this either-or approach, MISO proposes that both conditions from RAN Phase 1 should be met in order to completely disregard a unit's unavailability when it is on a planned outage during the times of greatest need.[321]

178. MISO disagrees with arguments that its proposal creates incentives for resources to delay full or partial outages. MISO states that, currently, the vast majority of forced outages count against accreditation without consideration of their timing and impact, and, as a result, the precipitating event for many MaxGen Events is higher than expected forced outages, especially during extreme weather or capacity scarcity. MISO asserts that under the proposal, forced outages during an RA Hour are much more impactful than

[319] *Id.* at 29-30.

[320] *Id.* at 11.

[321] *Id.* at 16.

under the current accreditation rules, which will create incentives for decisions such as preventive maintenance, winterization, and fuel assurance that will ultimately help avoid unavailability during RA Hours.[322] MISO submits that currently, a unit on a forced outage for one day would see an impact of .1% of potential UCAP accreditation, whereas under the proposal a unit missing 8 RA Hours out of the target 195 hours of a Season (accounting for the three-year averaging) amounts to 4.1% of the Tier 2 accreditation, which comprises 80% of the Seasonal SAC accreditation. MISO argues that the higher impact on accreditation from forced outages aligns with the intent of MISO's proposal to base accreditation on resource availability during times of needed.[323]

179. MISO suggests that it may not be prudent for generators to push needed outages out 120 days to secure a full exemption, and that, if delaying an outage is expected to risk grave harm, then the resource can and should do what it deems necessary. MISO states that, if instead the outage is not urgent and a resource is confident that there is little risk of capacity scarcity due to sufficient Maintenance Margin or other considerations, then taking an outage with a Tier 1 exemption or no exemption at all poses little if any risk to its accreditation. MISO contends, however, that should an RA Hour occur despite expectations of sufficient capacity, it is proper for accreditation to consider that the Resource Adequacy Requirements resource was not available when it was needed and had not sufficiently coordinated to obtain a Tier 2 exemption.[324]

180. MISO disagrees that its proposal will discourage generation owners from performing prudent maintenance activities. MISO states that its proposal provides exemptions for outages planned well in advance (i.e., 120 days), and, even if an outage is not planned well in advance, that does not mean a resource will automatically see a huge effect on accreditation due to MISO's proposed tiered accreditation and because a resource can choose not to participate in that Season's Auction. MISO states that it disagrees that resource owners will push planned outages off because the SAC proposal provides incentives for those resource owners to be available and minimize outages. MISO states that delaying outages could lead to future forced outages that may be catastrophic in nature and result in little or no future credit for that resource.[325]

181. MISO argues that its proposal does not fail to address the potential that a resource will hoard the Planned Outage Maintenance Margin because the proposal builds on its current generator outage provisions, which include protections against a generator

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[322] *Id.* at 17-18.

[323] *Id.* at 18.

[324] *Id.* at 18-19.

[325] *Id.* at 21.

submitting frequent or long planned outages that did not reflect their actual outage needs. MISO states that, under its proposal, outages will not be considered timely and will not secure the related exemption if they occur less than 120 days from the end of the previous outage. MISO states that, while it is true that room for planned outages can be scarce due to capacity scarcity, MISO carefully coordinates outages and the proposal provides incentives for scheduling the duration of an outage during times of sufficient margin.[326]

182. MISO contends that its proposal does not unduly discriminate against certain resource types. MISO explains that under the current proposal non-Schedule 53 Resources will receive a SAC value based on resource type consistent with their current accreditation rules adjusted for each specific Season. MISO states that non-Schedule 53 Resources already receive credit based on their availability; therefore, MISO's proposed changes to the accreditation for Schedule 53 Resources would better align the accreditation for all resource types than the current UCAP approach that has been approved by the Commission as just and reasonable. MISO states that it recognizes that there are improvements that can be made to the accreditation of non-Schedule 53 Resources and has already commenced renewable accreditation discussions with stakeholders.[327]

183. In response to Clean Energy Coalition's claim that MISO arbitrarily allocates 25% of the annual LOLE risk to each Season to calculate seasonal wind ELCC, MISO explains that the purpose of LOLE risk target used in the wind ELCC accreditation calculation is fundamentally different from the risk target used in determining seasonal Reserve Requirements. MISO states that the ELCC calculation involves modeling and solving two cases, one with wind and one without wind, to the same reliability LOLE target in order to have an accurate comparison between the two cases to determine the reliability contribution of wind. MISO states that the LOLE target for the ELCC analysis needs to be large enough to produce a sufficient sample size of LOLE risk days to accurately calculate wind ELCC value. MISO states that it has performed a range of sensitivity analysis on various LOLE risk targets for the ELCC calculations and found that using a LOLE target of 0.025 day per year produces sufficient data samples for each Season and stabilizes seasonal ELCC values for wind resources.[328]

184. MISO explains that it proposes capping the Real-Time Emergency Maximum Limit offers used for SAC accreditation at the resource's GVTC value for two reasons: (1) to ensure a resource does not receive more capacity credit within a Season than it has demonstrated through seasonal correction of a GVTC test; and (2) to align the LOLE

[326] *Id.* at 39-40.

[327] *Id.* at 24.

[328] *Id.* at 46.

modeled capacity with the SAC values for purposes of the MISO-system wide UCAP/ISAC ratio. MISO states that, because GVTC is a basis for UCAP, if the SAC values were not capped the ratio would be skewed, further misaligning the capacity LOLE model and the Hourly Emergency Maximum Limits.[329]

185. In response to arguments that MISO's proposal unnecessarily restricts Winter capacity and that MISO should modify its interconnection provisions to reflect non-Summer Seasons, MISO notes that its existing GIP allows interconnection customers to request their desired interconnection service amount (in MW) within the Installed Generating Facility Capacity, which is the facility's maximum gross output. MISO states that as of today, higher Winter capacity amounts have already been requested by multiple interconnection customers. MISO argues that capacity restrictions may exist today under existing GIP and that it is appropriate and necessary for resource owners to initiate separate interconnection requests for additional interconnection service amounts. MISO contends that the proposal maintains the existing interconnection service amounts granted as is, and that the proposal provides additional incentives to encourage Interconnection Customers to request at higher seasonal capabilities with transitioning to the seasonal construct.[330]

186. MISO contends that it has supported the proposed provision to consider a resource unavailable for accreditation purposes when it is offline with a lead time that exceeds 24 hours. MISO states that a majority of capacity is either cleared or committed in the Day-Ahead Market and the first post Day-Ahead Reliability Assessment Commitment, and the 24-hour threshold assumes the resource could reasonably be economically committed if needed. MISO states that most MaxGen Events have been driven by events occurring after the Day-Ahead Market clears. MISO adds it intends to review the impact and appropriateness of this provision after sufficient time has passed after implementation to inform continued refinements should they be needed.[331]

187. MISO acknowledges that there is a "disconnect" between the LOLE model, which produces the seasonal requirements, and SAC accreditation. MISO states that it proposes a system-wide UCAP/ISAC ratio to address this "disconnect." MISO states that it will strive to produce SAC requirements directly from the LOLE model as it further develops

[329] *Id.* at 34.

[330] *Id.* at 38-39.

[331] *Id.* at 42-43 (citing Potomac Economics Comments at 10).

the LOLE model capabilities; however, MISO believes the proposed ratio is an appropriate solution that aligns the LOLE model requirements with accreditation.[332]

188. MISO states that its Tariff currently includes detail on how wind and non-intermittent resources are accredited, and that MISO is not proposing to make changes to those provisions. MISO contends that arguments raised by Midwest TDUs and others related to wind and non-intermittent resource accreditation should be addressed in any future filing involving those resources.[333]

189. MISO disagrees with arguments that it has failed to demonstrate the proposal to increase the minimum number of required allowed interruption calls for LMR DRs from 10 per Planning Year to 16 in order to receive 100% capacity accreditation is just and reasonable. MISO states it performed an analysis in early 2020 (2020 LOLE Analysis)—prior to the Commission-approved LMR filing in Docket No. ER20-1846-000—that showed on an annual basis that LMR DRs needed 15 calls to get 100% capacity accreditation.[334] MISO asserts that it used this analysis along with MaxGen Events in particular Seasons to distribute the number of annual calls across the four Seasons. MISO states that its proposal requires one additional call per Planning Year than the 2020 analysis indicated. MISO explains that under the proposed seasonal construct, all LMR DR resources have the option to participate in a respective Season's auction with no more than the five calls historically required for LMR qualification. MISO contends that, if an LMR DR cannot respond 16 times to qualify for all four Seasons in a Planning Year, it can offer in just those Seasons that correspond with its capabilities to participate.[335]

d. Answers to the MISO February 10 Answer

190. Alliant states that MISO's proposed seasonal accreditation methodology will inappropriately rely on limited data that includes anomalous values and/or fails to represent future resource performance.[336] Alliant expresses doubt that MISO's proposed SAC methodology will improve reliability in a cost-effective way or accurately reflect

[332] *Id.* at 34-35.

[333] *Id.* at 48.

[334] *Id.* at 33 (citing RASC presentation (Feb. 5, 2020), https://cdn.misoenergy.org/20200205%20RASC%20Item%2005b%20RAN%20LMR%20Accreditation%20and%20LOLE%20modeling423730.pdf).

[335] *Id.*

[336] Alliant Answer at 5.

resource availability.[337] The Mississippi Commission argues that MISO fails to demonstrate or offer evidence that the SAC proposal will improve reliability.[338] The Mississippi Commission notes that MISO acknowledges that Zone 10 resource accreditation is expected to decrease under the proposal and contends that MISO has not provided analysis to demonstrate that these resources are less reliable than other resources, and that MISO is overlooking the contribution of these resources during February 2021 cold weather event.[339]

191. WEC Utilities support the seasonal resource adequacy construct but seeks additional transition time to adjust resource planning and operational strategies.[340] WEC Utilities note that the MISO proposed transition timeframe will not mitigate the impact on decisions that require a long lead time or have already been made, such as the decision to add new generation resources.[341] WEC Utilities note that it can take 18 months to obtain a GIA and additional years are needed to complete construction of new resources.[342] WEC Utilities state that there is no exemption for accreditation impacts on resources with inadequate weatherization or non-firm fuel supplies, the way there is an exemption for planned outages.[343] WEC Utilities assert that activities such as capacity resource planning, fuel procurement, backup fuel readiness, winterization, and staffing levels require additional time but will enhance resource availability during times of highest risk.[344] WEC Utilities state that additional stakeholder discussions and time for preparation are necessary before MISO's proposed SAC can be implemented.[345]

192. Alliant states that MISO's proposed timeline is not realistic from a cost or scheduling perspective, especially if it relies on the GIP process to address some

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[337] *Id.*

[338] Mississippi Commission Answer at 4.

[339] *Id.* at 5.

[340] WEC Utilities Answer at 4.

[341] *Id.*

[342] *Id.*

[343] *Id.*

[344] *Id.* at 4-5.

[345] *Id.* at 5.

stakeholder concerns.[346] Alliant states that it is illogical for MISO to express concern with reliability in the footprint while capacity that is currently available is waiting to interconnect and access MISO markets.[347] Alliant argues that MISO's commitment to ignoring the practical realities of using existing processes to achieve overly aggressive short-term goals will result in resource owners purchasing high-cost, unnecessary capacity to meet overly conservative capacity need estimates.[348] Alliant requests that the Commission require MISO to delay the proposed implementation schedule.[349]

193. Entergy states that the MISO February 10 Answer does not alleviate concerns regarding MISO's implementation timeline. Entergy states that, while MISO may be correct that supply/demand balances will be maintained at the footprint level, the supply/demand balance at the Zonal level will change, and MISO does not provide an opportunity for LSEs to take actions to improve their supply/demand balance prior to the 2023/2024 Planning Year. Further, Entergy states that it agrees with MISO that the existing must-offer requirement for Capacity Resources means "their offered capacity should already generally align with their availability," but argues that these rules actually lend added support for rejecting MISO's availability-based SAC proposal because existing MISO rules already create such general alignment.[350]

194. Midwest TDUs argue that the MISO February 10 Answer fails to demonstrate that it is just and reasonable to determine seasonal accreditations by backfilling Tier 2 hours with Annual RA Hours (or AAOC) comprised of: (1) hours already included in Tier 2 for that Season; and (2) out-of-Season RA Hours.[351] Midwest TDUs state that in-Season RA Hours would factor into SAC twice and be weighted more heavily than other hours.[352] Midwest TDUs assert that MISO provides no evidence that availability during

[346] Alliant Answer at 7.

[347] *Id.*

[348] *Id.*

[349] *Id.*

[350] Entergy Answer at 7 (citing MISO February 10 Answer at 7-8).

[351] Midwest TDUs Answer at 6-7.

[352] *Id.* at 6.

out-of-Season tight hours is a better measure of seasonal availability than other in-Season hours, and that such an assumption is inapposite to a shift to a seasonal construct.[353]

195. Entergy states that the MISO February 10 Answer confirms the underlying uncertainty and volatility of its SAC proposal and argues that the proposal will make prudent resource planning extremely difficult.[354] Entergy argues that the aggregate effects of the volatility in MISO's SAC proposal will be evident in LSE Reserve Requirement surplus and deficit positions and Local Clearing Requirement surplus and deficit positions, but ignore and overlook the effects on individual LSEs and resource owners.[355] Entergy argues that a planning paradigm that cannot reasonably be predicted defies any reasonable effort to conduct long-term planning consistent with such an objective.[356]

196. Entergy argues that MISO's statement that "[i]deally, MISO would be able to know exactly a resource's availability ahead of time but, without a crystal ball, historical data is the best indicator of future performance" highlights the underlying uncertainty or randomness of the SAC proposal.[357] Entergy further states that, like MISO, resource owners do not have a "crystal ball" or know when events requiring the greatest need will occur and Entergy argues that it is not reasonable for MISO to claim it is incentivizing resources to be available during times of greatest need when those times are unpredictable.[358] Entergy argues that the minimum number of RA Hours in MISO's proposal (i.e., 65 hours) does not address concerns about the volatility of resources accreditation or inherent unpredictability of events that lead to times of greatest need.[359]

197. Alliant states that MISO's proposal would allow for significant volatility in accredited capacity at a local level, even if there is not excessive accredited capacity

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[353] *Id.*

[354] Entergy Answer at 3.

[355] *Id.* at 3-4.

[356] *Id.* at 5.

[357] *Id.* at 5 (citing MISO February 10 Answer at 25).

[358] *Id.* at 4.

[359] *Id.* at 5.

volatility across the MISO footprint.[360] Alliant asserts that local capacity resource accredited capacity volatility will not enhance reliability.[361]

198. Midwest TDUs argue that MISO offers no defense of its proposed requirement that outages must be scheduled at least 120 days from the last planned outage to qualify for a Tier 2 Planned Outage Exemption.[362] Midwest TDUs argue that MISO provides no explanation for its proposal to ignore historical performance and cap accreditation based on a seasonally corrected GVTC test.[363] Midwest TDUs assert that MISO fails to explain the relationship between its LOLE model, proposed GVTC adjustment, and proposed UCAP/ISAC ratio.[364] Midwest TDUs state that MISO's proposal does not resolve the disconnects between the various components of its resource adequacy construct, but rather includes a "patchwork of ad hoc adjustments."[365] Midwest TDUs also argue that MISO has not shown that it is just and reasonable to provide zero accreditation for offline resources with lead times longer than 24 hours.[366] Midwest TDUs assert that MISO does not explain why it is appropriate for such longer lead time resources to bear the entire risk of anticipating RA Hours more than 24 hours in advance, as opposed to MISO, or why these longer lead time resources are in a better position than MISO to anticipate RA Hours.[367] Midwest TDUs claim that self-commitments based on limited information would likely lead to less efficient dispatch, resulting in higher costs for consumers without providing meaningful reliability benefits.[368] Midwest TDUs assert that MISO provides no justification for applying a UCAP/ISAC conversion ratio to Schedule 53

[360] Alliant Answer at 4.

[361] *Id.*

[362] Midwest TDUs Answer at 7-8.

[363] *Id.* at 8-9.

[364] *Id.* at 9.

[365] *Id.* at 10.

[366] *Id.* at 10-11.

[367] *Id.* at 11.

[368] *Id.*

Resources but not to other similarly situated resources, such as intermittent resources that are also accredited based on actual availability.[369]

199. Regarding MISO's proposal to increase the number of required allowed calls for LMR DRs from 10 per Planning Year to 16 per Planning Year to receive 100% capacity accreditation, Industrial Customers argue that the MISO February 10 Answer does not clarify or correct any misstatements identified in their protest and does not address their concerns including the problematic nature of MISO's reliance on its early 2020 analysis.[370] Industrial Customers argue that, in Docket No. ER20-1846-000, MISO used the 2020 LOLE Analysis to support increasing the minimum number of required interruption calls for LMR DRs from 5 to 10 per Planning Year to receive 100% capacity accreditation for a full Planning Year, and that MISO concluded that only 10 required calls per Planning Year were needed. Industrial Customers argue that MISO has not produced a new analysis that shows different results and has not justified its reinterpretation of the 2020 LOLE Analysis to now support requiring LMR DRs to provide up to 16 interruption calls per Planning Year for 100% capacity accreditation for a full Planning Year rather than up to 10 calls per Planning Year.[371]

200. Industrial Customers contend that MISO has not demonstrated that past MaxGen Events support its proposal to require up to 16 interruption calls per Planning Year from LMR DRs in order for them to receive a 100% capacity accreditation for a full Planning Year.[372] Regarding MISO's assertion that that LMRs who cannot meet its proposed 16 interruption calls per Planning Year can still participate and receive 100% capacity accreditation for a single Season, Industrial Customers reiterate that unnecessarily decreasing the ability of end-use customers to participate as an LMR DRs for a full Planning Year and increasing their cost of such participation would unnecessarily harm the end-use customers that are participating as LMRs and unnecessarily decrease the total supply of capacity in the MISO footprint (through a reduction in full Planning Year LMR participation). Industrial Customers claim these impacts would unnecessarily increase the capacity costs of all end-use customers in the MISO footprint.[373]

201. Midwest TDUs argue that MISO inappropriately defers matters to the Market Monitor and BPMs that should otherwise be included in MISO's Tariff because they

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[369] *Id.* at 11-12.

[370] Industrial Customers Answer at 3-4.

[371] *Id.* at 4-5.

[372] *Id.* at 5.

[373] *Id.*

significantly affect rates, terms, and conditions of service.[374] Midwest TDUs assert that the following matters should be included in MISO's Tariff: (1) determination of whether an outage could have been reasonably anticipated; (2) Tier 1 Planned Outage Exemptions; (3) accreditation of non-Schedule 53 Resources.[375]

e. Deficiency Letter Response

202. As noted above, on March 9, 2022, Commission staff issued a deficiency letter and requested additional information, and MISO submitted its Deficiency Letter Response on April 8, 2022. In response to a question requesting quantitative evidence demonstrating the extent to which historical resource performance as reflected in the proposed SAC accreditation is more indicative of future resource performance than the current UCAP method, MISO reiterates that the current UCAP method only accounts for forced outages and derates deemed not outside management control. MISO explains that, by design, UCAP ignores many factors that impact resource availability resulting in significant overstatement of resource availability. MISO adds that the UCAP method does not differentiate between periods of high risk and low risk, resulting in overstating resource availability during emergency periods, especially when those risks occur outside of Summer. MISO submits that, by contrast, the SAC methodology emphasizes resource availability during times in need and accounts for factors described above that UCAP ignores.[376]

203. MISO argues its analysis demonstrates that the proposed SAC methodology is more indicative of future resource performance during emergency periods than the current UCAP methodology. MISO provides a table comparing actual resource offers to how that resource is accredited using UCAP, ISAC, and AAOC in two scenarios: (1) MISO North, Summer; and (2) MISO South, Winter. The table indicates that in MISO North, Summer, resources offered 73,280 MW during MaxGen Events. MISO's UCAP accreditation for that same period was 79,062 MW (a 7.8% deviation), and its ISAC accreditation was 73,885 (a 0.8% deviation). In MISO South, Winter, resources offered 30,588 MW during MaxGen Events. MISO's UCAP accreditation for that same period was 37,322 (a 22% deviation), and its ISAC accreditation was 30,223 MW (a -1.2% deviation).[377] MISO explains that MISO and the Market Monitor believe that ISAC is the most relevant basis for comparison to UCAP because ISAC is directly calculated

[374] Midwest TDUs February 25 Answer at 28-29.

[375] *Id.* at 29-30.

[376] MISO Deficiency Letter Response at 7.

[377] *Id.* at 5.

based on Real-Time offers and is highly correlated with historical and future resource performance during emergency periods.[378]

204. MISO states that its analysis indicates most Seasons reach 65 RA Hours based on the four years of historical data MISO examined, with only 2 of the 32 Seasons MISO evaluated falling significantly short of the 65-hour target. MISO state that, as a result, a resource's Schedule 53 SAC calculation for any specific Season was based primarily on the performance of a resource during the relevant Season.[379]

205. MISO states that it is theoretically possible for a resource's SAC to be calculated primarily based on its performance in other Seasons, but this would only happen if there were a large amount of RA Hour exemptions applicable to a specific resource. MISO states that, for example, a resource could miss the vast majority of RA Hours for a Season year after year due to lengthy planned outage exemptions. MISO states that, for the majority of SAC to be based on performance outside the Season a resource would have to average more than 40 exempt RA Hours in each Season. MISO states that simply missing 50% of RA Hours in a Season is not enough to make other Seasons more important to a resource's SAC accreditation because Tier 1 is weighted at only 20%.[380]

206. MISO submits that, when the full 65 RA Hours per Season does not exist for a resource, the AAOC is a reasonable proxy because it reflects the typical availability for the resource during times of need. MISO provides a table demonstrating that in MISO North, Summer, accrediting the MISO fleet with AAOC resulted in a -4.7% deviation from offers during MaxGen Events, while in MISO South Winter, AAOC accreditation resulted in a 0.5% deviation from actual offers.[381]

207. MISO contends that the AAOC was specifically developed to address small sample sizes of RA Hours in a given Season so that Tier 2 accreditation would not be based on a limited set of hours, which could under or overstate a resource's capacity value. MISO states that without AAOC to use as an indicative measure of a resource's availability during high-risk periods, a resource might have a limited sample of non-

[378] *Id.* at 7-8.

[379] *Id.* at 4.

[380] *Id.* at 5.

[381] *Id.*

exempt RA Hours over a three-year lookback period making its accreditation highly volatile.[382]

208. In response to a question regarding the UCAP/ISAC ratio, MISO states that the ratio has two primary benefits. First, MISO states that use of the UCAP/ISAC ratio prevents the need to convert Reserve Requirements and Local Clearing Requirements into SAC terms. Second, MISO states that the ratio eliminates the possibility that the Auction Clearing Price would need to be increased in order to offset the lower volume and to maintain the overall supply and demand balance. In addition, MISO asserts that the UCAP accreditation method overstates resource availability because it only considers forced outages when accounting for availability. Further, MISO submits that it is exploring whether the LOLE study can use SAC instead of UCAP, but explains that industry tools and modeling practices would have to be modified and then tested to ensure they accurately measure LOLE risk.[383]

209. With regard to proposed outage exemptions for the SAC, MISO states that the requirement that an exempt outage be 120 days or more since the end of a previous planned outage is designed to disincentivize frequent outages, which could reduce the Maintenance Margin available to other resources.[384] MISO clarifies that it does not intend for planned outage exemption provisions to apply to planned and unplanned partial generator outages, also known as derates. MISO states that exemptions for derates could be considered in a future enhancement as the current outage coordination processes do not evaluate derates, which are typically submitted with no or little advanced warning.[385]

210. In response to a question about why MISO is not proposing to accredit certain resources that are currently accredited based on availability as Schedule 53 Resources, MISO states that MISO has a long-standing history of different accreditation methods for different resource types, which the Commission has accepted as just and reasonable. MISO states that its ultimate goal is to align accreditation for all resources with the resource's availability during times of need. MISO states that, while accreditation methods are different across resource types, they are comparable and relevant to the characteristics of those resource types. MISO states that, as an example, wind resources will continue to be accredited based on seasonal ELCC with capacity credits allocated based on each wind resource's performance over eight peak demand hours per Season,

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[382] *Id.*

[383] *Id.* at 9.

[384] *Id.* at 13.

[385] *Id.* at 10.

and solar resources will be accredited based on historical availability during specific hours representing typical seasonal peak demand hours.[386]

211. MISO states that it recognizes the need to further align the proposed accreditation methodology for Schedule 53 Resources and the existing accreditation for non-Schedule 53 Resources, but submits that its proposal closes the gap that currently exists as it better aligns the resource accreditation for all resource types than under the current UCAP approach. MISO adds that wind and solar have different offer requirements and are not as easily incentivized to be available during times of need as compared to Schedule 53 Resources.[387]

212. In response to a question regarding the proposed increase of required calls for LMR DRs from 10 in a year to 16, MISO reiterates that its 2020 LOLE analysis demonstrates that LMR DRs needed 15 calls on an annual basis to receive 100% accreditation for the Planning Year. MISO explains that, with the proposed changes to a seasonal construct, MISO used this analysis, together with an analysis of past MaxGen Events, to distribute the number of annual calls across the four Seasons. MISO states that continuing to only require 10 interruption calls in a Planning Year would be over-stating LMR DR availability at times of system need.[388]

f. Responses to Deficiency Letter Response

213. Some commenters addressed the evidence MISO provided to support the proposed SAC accreditation method. Potomac Economic states that it finds MISO's data regarding SAC accreditation and expected performance to be compelling, and adds that SAC will be more accurate because it comprehensively addresses all reasons for resource availability compared to MISO's current UCAP accreditation, which only reflects forced outage rates. Potomac Economics states that, because UCAP accreditation only considers outages reported in GADS, it is not possible for UCAP accreditation to predict availability during emergencies.[389]

214. Alliant raises concerns that MISO's Deficiency Letter Response indicates that the piecemeal approach MISO proposes has the potential for costly and option-limiting consequences. Alliant reiterates its request for the Commission to require further

[386] *Id.* at 15-16.

[387] *Id.* at 16.

[388] *Id.* at 17-19.

[389] Potomac Economics Response to MISO Deficiency Letter Response at 4-5.

stakeholder process before implementing a seasonal resource adequacy construct.[390] Clean Energy Coalition argues that MISO's response to the Deficiency Letter's request to provide further quantitative evidence that SAC is a better indicator of expected future resource availability than UCAP is insufficient because MISO provides only aggregated data for two Seasons.[391] Minnesota Power argues that MISO did not provide quantitative evidence of SAC accreditation being more indicative of future performance in emergency periods than UCAP.[392]

215. The Mississippi Commission argues that MISO's Deficiency Letter Response fails to provide quantitative evidence demonstrating the extent to which historical performance as reflected in SAC accreditation is more indicative of future performance in emergency periods than the UCAP methodology. The Mississippi Commission suggests that MISO's rationale presupposes that a resource owner can predict when an emergency will occur, and that the occurrence of historical emergencies accurately reflects the occurrence of future emergencies. The Mississippi Commission argues that neither of these assumptions are true.[393] Further, the Mississippi Commission argues that the table MISO provided, which is based on 6 days in the Summer and 5 days in the Winter of 2021, is not sufficient evidence to support MISO's conclusion.

216. Midwest TDUs argue that MISO fails to provide quantitative evidence supporting final SAC values because MISO instead compares its existing UCAP methodology to ISAC, rather than final SAC values. Midwest TDUs also argue that MISO provides only data from a single Season in MISO North and MISO South, which, according to Midwest TDUs, is too small of a sample size to evaluate MISO's proposed methodology.[394]

217. Entergy states that MISO's response as to whether historical performance using the SAC accreditation methodology is more indicative of future performance than the existing UCAP accreditation is flawed. First, Entergy states that MISO's answer is not responsive to the Deficiency Letter because MISO provides ISAC values rather than SAC values. Second, Entergy states that MISO only provides analysis on one emergency period for MISO North and South, which, according to Entergy, is too small of a sample size to draw meaningful conclusions from. Third, Entergy contends that examining region-wide aggregated accreditation values does not provide insight into the ability of an

[390] Alliant Response to MISO Deficiency Letter Response at 6.

[391] Clean Energy Coalition Response to MISO Deficiency Letter Response at 5-6.

[392] Minnesota Power Response to MISO Deficiency Letter Response at 2.

[393] Mississippi Commission Response to MISO Deficiency Letter Response at 4.

[394] Midwest TDUs Response to MISO Deficiency Letter Response at 3-4.

accreditation methodology to predict the availability of individual units, and it would be much more insightful to investigate the correlation between the accreditation ratings of individual resources and those resources' availability during emergency periods. Entergy submits that this analysis would demonstrate whether units with higher SAC accreditation relative to their GVTC are more likely to be available during emergency periods than units with lower SAC ratings. Entergy contends that MISO's analysis provides no evidence as to whether SAC is a better predictor of a unit's availability during MaxGen hours than UCAP or any other alternative accreditation methodology. Entergy states that, for example, it is possible that a significant number of units with high SAC ratings were unavailable during the 2021 MaxGen emergency hours studied by MISO, which would undermine the predictive performance of SAC. Entergy states that MISO's analysis did not look at individual unit performance during the 2021 MaxGen hours so there is not enough information to properly judge SAC's or UCAP's ability to predict future performance during emergency periods.[395]

218. Several commenters discussed MISO's proposed use of AAOC in SAC accreditation. Potomac Economics agrees with MISO that AAOC is a reasonable approach in cases where RA Hours are deficient in a given Season. Potomac Economics submits that using data from other Seasons' RA Hours is preferable to using performance data during the same Seasons from non-RA Hours because RA Hours are not known in advance so resources that perform well must either be running in most hours or have the flexibility to be available on short notice. Potomac Economics argues that, because historical data from Non-RA Hours do not capture resource responsiveness to short-notice RA Hour events, it would be inferior to MISO's proposal.[396]

219. Minnesota Power argues that MISO failed to address the question raised in the Deficiency Letter regarding the inclusion of RA Hours from another Season being used to meet the 65-hour RA Hour target.[397] Similarly, the Mississippi Commission contends that MISO's Deficiency Letter Response fails to justify using data from other Seasons to supplement deficient RA Hours in a particular Season. The Mississippi Commission submits that, instead, MISO states it is unlikely that there will be fewer than 65 RA Hours in any given Season.[398]

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[395] Entergy Response to MISO Deficiency Letter Response at 3-4.

[396] Potomac Economics Response to MISO Deficiency Letter Response at 5.

[397] Minnesota Power Response to MISO Deficiency Letter Response at 2.

[398] The Mississippi Commission Response to MISO Deficiency Letter Response at 3.

220. Midwest TDUs argue MISO has not demonstrated that the AAOC method is just and reasonable because MISO's support for use of AAOC relies on too small of a sample size and MISO does not evaluate all Seasons.[399] Midwest TDUs argue that MISO compares AAOC to offers during emergency hours during Summer 2021, but because Summer 2021 would have met the 65 RA Hour target, there would have been no need to use AAOC in that situation. Midwest TDUs argue that, in contrast, the AAOC is most relevant in non-Summer Seasons, but MISO has not provided evidence demonstrating how well AAOC approximates performance during times of need during non-Summer Seasons.[400]

221. Clean Energy Coalition contends that using performance data from other Seasons for accreditation of a thermal resource in a given Season does not fulfill the objectives of the filing, which is to identify times of risk and credit resources to the extent they mitigate that risk. Clean Energy Coalition states that a resource's typical availability during times of need in other Seasons does not always correlate with availability during the Season for which it is being accredited.[401] Clean Energy Coalition states that, while on a system-wide basis, using performance hours from other Seasons may give similar results, this may not be true on an individual resource basis, violating the principle that generators must be compensated based on their actual contribution to resource adequacy and thus to reliability during the specific Season they are accredited.[402] Clean Energy Coalition argues that for the Winter Season, many generators would see higher accreditation using the AAOC methodology than they would if only RA hours from prior Winter Seasons were used. Clean Energy Coalition states that, conversely, wind generation tends to be higher in the Winter, and if a similar accreditation approach for wind generation is used in the future, wind accreditation for the Winter would likely be lower than wind's actual Winter capacity availability.[403]

222. Many commenters discussed MISO's proposed use of the UCAP/ISAC ratio to calculate final SAC accreditation values. Potomac Economics states that the foundation of MISO's availability-based accreditation is that it should not fundamentally alter the supply and demand balance in the capacity market. Potomac Economics explains that since the planning model calculates Planning Resource needs in UCAP terms and resources are accredited in SAC terms, a ratio must be used to adjust the demand for

[399] Midwest TDUs Response to MISO Deficiency Letter at 5.

[400] *Id.* at 6.

[401] Clean Energy Coalition Response to MISO Deficiency Letter Response at 3.

[402] *Id.* at 4.

[403] *Id.*

planning resources into SAC terms or the capacity supply values back into UCAP terms. Potomac Economics states that the proposed UCAP/ISAC ratio is superior to alternative approaches because of its relative effects on Schedule 53 and non-Schedule 53 Resources. Potomac Economics states that, if MISO were to adjust the UCAP demand downward into SAC terms, this would effectively increase the quantity of demand that can be served by every accredited MW of capacity. Potomac Economics contends that this would not be appropriate for non-Schedule 53 Resources because the proposal does not modify the accreditation of these resources. Potomac Economics states that this would result in a relative increase in accredited capacity for non-Schedule 53 Resources and provide for an "unjustified windfall" benefit at the expense of Schedule 53 Resources.[404]

223. Potomac Economics adds that the UCAP/ISAC ratio is needed to maintain the available accredited capacity consistent with MISO's LOLE planning process. Potomac Economics states that, although the planning study produces resource adequacy requirements in UCAP terms, it considers most of the factors that affect unit availability, not just forced outages. Potomac Economics states that, for example, if planned outages were to increase substantially over historic levels, the resource adequacy requirements (expressed in UCAP) would rise correspondingly. Potomac Economic submits that it is therefore necessary to resolve the difference between the UCAP-based demand for Planning Resource capacity and availability-based accreditation under SAC in order for the capacity market to achieve its objectives.[405]

224. Potomac Economics states that, with some changes, the LOLE planning models could produce requirements in SAC terms. Potomac Economics cautions, however, that it is important to recognize the model would not be assuming the SAC values for each resource in its modeling because many of the factors that affect the availability of resources are random factors that must be modeled in the planning model through a Monte Carlo process that produces thousands of random draws. Potomac Economic states that the result of this process indicates the amount of capacity that is needed (or demanded), which can be denominated in ICAP, UCAP or SAC. Potomac Economics concludes that, while transitioning the LOLE model to produce requirements in SAC terms could have some value, it is not essential to implement MISO's proposal.[406]

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[404] Potomac Economics Response to MISO Deficiency Letter Response at 2-3.

[405] *Id.* at 3.

[406] *Id.* at 4.

225. Minnesota Power argues that MISO did not provide any technical basis for the proposed UCAP/ISAC ratio.[407] Midwest TDUs argue that MISO continues to provide a reasonable explanation for its proposal to scale up Schedule 53 Resource accreditation but not non-Schedule 53 Resources. Midwest TDUs contend that MISO's explanation that accrediting non-Schedule 53 Resources based on UCAP overstates a resource's availability because it only considers forced outages does not describe the accreditation of all non-Schedule 53 Resources. Midwest TDUs explain that certain resources, such as wind and solar, are currently accredited based on their historical availability during times of need. Midwest TDUs argue that MISO has failed to explain why it is just and reasonable to apply a UCAP/ISAC conversion ratio to some resources, but not others.[408]

226. Entergy states that MISO's Deficiency Letter Response fails to explain how Local Clearing Requirements are impacted by the two options provided by the Market Monitor. Entergy states that in the first option, the MISO-wide Reserve Requirement was scaled by the UCAP/ISAC ratio and zonal Local Clearing Requirements were scaled by the zonal UCAP/ISAC ratio. Entergy states that as a result, MISO-wide supply/demand balance was maintained and each Zone's Summer Local Clearing Requirement supply/demand balance was also maintained. Entergy states that the Market Monitor's second proposal scales up SAC accreditation of thermal resources such that only the MISO-wide supply/demand balance is maintained and the zonal Local Clearing Requirement supply/demand balance is altered. Entergy states that MISO has not explained why it took the inconsistent approach of designing a proposal that maintains the MISO-wide supply/demand balance but does not maintain the zonal Local clearing Requirement supply/demand balance. Entergy states that the result of this decision means that some zones' Local Clearing Requirement supply/demand balance will be improved and other zones' Local Clearing Requirement supply/demand balance will be worsened. Entergy argues that given the importance of Local Clearing Requirement in determining zonal Auction Clearing Prices, it is unjust and unreasonable for MISO to drastically change the Local Clearing Requirement supply/demand balance of a zone due to a change in accreditation methodology without providing adequate time for market participants in the zone to procure additional capacity to restore the prior Local Clearing Requirement supply/demand balance.[409]

227. Commenters also raised concerns about MISO's proposed exclusion process for planned outages. Duke Energy asserts that MISO's Deficiency Letter Response demonstrates that more clarification is necessary and submits that MISO's justification

[407] Minnesota Power Response to MISO Deficiency Letter Response at 3.

[408] Midwest TDUs Response to MISO Deficiency Letter Response at 13-14.

[409] Entergy Response to MISO Deficiency Letter Response at 1-2.

for the exclusion of planned derates from outage exemptions fails to acknowledge other sources of reliable information on planned derates that could be used until MISO develops further system enhancements. Duke Energy suggests that MISO could use planned derate information submitted in GADS. Duke Energy states that the Commission should require MISO to commit to a timeline to file changes that would apply the Schedule 53 Resource planned outage exemptions to derates, as well.[410]

228. Midwest TDUs argue that MISO has not justified its proposal to disqualify derates from planned outage exemptions outside of the fact that its current outage provisions do not evaluate for derates. Midwest TDUs argue that MISO should be required to explain why it is just and reasonable to disqualify all planned outage derates from Schedule 53 planned outage exemptions.[411]

229. The Mississippi Commission argues that MISO fails to explain why a 120-day gap between planned outages to receive Tier 2 exemptions is an appropriate duration. The Mississippi Commission argues that MISO provides no evidence of prior excessive outages.[412]

230. Consumers Energy argues that planned derates should be eligible for the same exemptions as full scheduled outages. Consumers Energy contends that penalizing planned derates but not planned outages creates incentives for generator operators to fully shut down resources that could be partially operating and producing needed energy to ensure they receive a full Tier 2 exemption. Consumers Energy contends that this is a suboptimal outcome for all parties, hurting grid reliability, raising energy prices, and weakening generator economics.[413]

231. Midwest TDUs argue that MISO's attempt to justify its Tier 2 Planned Outage exemption requirements are largely unresponsive, as MISO does not explain why a requirement for 120 days between outages would increase Maintenance Margin availability for other resources. Midwest TDUs suggest that this requirement creates incentives for resources to schedule longer outages, thereby decreasing Maintenance Margin for others, because one 30-day outage could qualify for a Tier 2 exemption but

[410] Duke Energy Response to MISO Deficiency Letter Response at 2-3.

[411] Midwest TDUs Response to MISO Deficiency Letter Response at 12-13.

[412] The Mississippi Commission Response to MISO Deficiency Letter Response at 6-7.

[413] Consumers Energy Response to MISO Deficiency Letter Response at 2-3.

two 10-day outages could not.[414] Consumers Energy argues that MISO does not provide enough support for the required 120-day notice requirement for planned outages to receive a Tier 2 exemption. Consumers Energy asserts that MISO does not explain why this amount of lead time is necessary, how or why this amount of notice will be superior to the existing two-week requirement, or what risk assessments will be available that currently are not.[415]

232. Entergy argues MISO failed to answer why Tier 2 exemptions are not granted in the event that the Maintenance Margin is above zero. Entergy states that MISO's response fails to recognize that the use of Maintenance Margin already assists generation owners in coordinating planned outages, making MISO's proposed 120-day coordination period excessive and unnecessary. Entergy states that, when an outage is scheduled during a time with a positive Maintenance Margin, MISO should not need to conduct extensive coordination processes or risk assessments.[416]

233. Industrial Customers argues that MISO's Deficiency Letter Response does not provide any additional support to increase the minimum amount of allowed calls for LMR DRs to receive 100% capacity accreditation in a Planning Year. Industrial Customers states that, in particular, MISO does not address the problematic nature of relying on the 2020 LOLE analysis as the basis for requiring 16 interruptions per Planning Year.[417] Industrial Customers state that MISO's 2020 LOLE Analysis showed that 10 calls per Planning Year would provide 97.4% capacity accreditation, while requiring an additional call would only increase capacity accreditation by an additional 2.6%. Industrial Customers reiterate that MaxGen Events have never exceeded eight total in any given Planning Year, and MISO has historically never called any LMR more than three times in a Planning Year.[418] Industrial Customers argue that MISO's response demonstrates that its proposal does not provide prorated capacity credit for LMR DRs, even though MISO's analysis indicates support for 97.4% accreditation for LMR DRs that make themselves available for 10 calls in a Planning Year.[419]

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[414] Midwest TDUs Response to MISO Deficiency Letter Response at 11.

[415] Consumers Energy Response to MISO Deficiency Letter Response at 2-3.

[416] Entergy Response to MISO Deficiency Letter Response at 5.

[417] Industrial Customers Response to MISO Deficiency Letter Response at 7.

[418] *Id.* at 8-9.

[419] *Id.* at 9-10.

234. Clean Energy Coalition argues that MISO fails to adequately explain why it is inappropriate to include other resources that are currently accredited based on availability as Schedule 53 Resources. Clean Energy Coalition argues that MISO must "demonstrate that the two accreditation methodologies work together and assess capacity availability during the same risk hours in order for the construct to hold together both theoretically and practically to ensure a reliable system that can meet load during these high-risk hours."[420]

235. Clean Energy Coalition argues that accreditation should be consistent across all resource types, so as to not discriminate between different technologies. Clean Energy Coalition submits that several principles should be applied to avoid discrimination: (1) capacity accreditation for all resource types should be performed using the same methodology, including assessment during the same set of high-risk hours; (2) accreditation approach should be consistent so that a resource that mitigates more risk should receive a higher accreditation, and two resources that mitigate the same level of risk should receive the same accreditation; and (3) accreditation of each resource should be the same, regardless of the order in which resources' accreditation is calculated and accounted for. Clean Energy Coalition argues that MISO's proposal fails to meet these principles.[421]

236. Clean Energy Coalition states that it recognizes that the Commission recently approved PJM's capacity accreditation approach, which uses different accreditation methodologies for thermal and intermittent resources. Clean Energy Coalition states, however, that PJM recognizes in its filing that it would need to revisit its approach when its energy mix transition includes more intermittent resources. Clean Energy Coalition states that MISO's energy mix includes approximately 22% wind resources, with approximately 153 gigawatts of mostly solar and wind in its interconnection queue. Clean Energy Coalition believes that MISO should use a comparable accreditation approach for all resources now, rather than later.[422]

237. The Mississippi Commission argues that MISO's response does not justify treating External Resources differently from MISO internal resources, nor does MISO's response justify the exclusion of Stored Energy Resources – Type II from Schedule 53 Resource

[420] Clean Energy Coalition Response to MISO Deficiency Letter Response at 6.

[421] *Id.* at 7.

[422] *Id.* (citing *PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,056, at P 67 (2021) (*PJM Interconnection*)).

accreditation.[423] The Mississippi Commission further argues that MISO does not explain why it proposes a 24-hour-or-less lead time requirement for Tier 2 accreditation. The Mississippi Commission asserts that MISO has not tied the requirement to modeling results, a contingency analysis, or operating parameters.[424]

g. MISO May 20 Answer

238. MISO states that its Deficiency Letter Response addresses the substance of the Commission's questions regarding the proposed 120-day requirement and application to Tier 2 exemptions. MISO states that the 120-day language in regard to granting a Generator Planned Outage exemption is included in MISO's Commission-approved Tariff. MISO states that the filed proposal resulted from a collaborative stakeholder process that sought to balance accurate capacity accreditation with proper incentives for prudent outage planning. MISO contends that, contrary to protestors' assertions, MISO provided support to establish that the proposal is just, reasonable, and non-discriminatory. MISO notes, for example, its Deficiency Letter Response explains that the proposal to require 120 days' notice of a planned outage in order to receive a Tier 2 exemption is designed to provide MISO the information needed prior to the start of a Season in order to identify and mitigate potential reliability issues.[425]

239. MISO states that it sufficiently explained the rationale for not including derates in the Schedule 53 Tier 2 exemption process by noting that its current outage processes do not evaluate planned derates, which are typically submitted with little to no advance notice.[426] MISO notes that over the last two years only 2.2% of derates were submitted with advanced notice of at least 14 days, which is the minimum amount of time needed to secure an exemption under MISO's proposal.[427]

240. MISO states that its Deficiency Letter Response provided a table showing that SAC is a better predictor of future offers than UCAP, which Potomac Economics found compelling. MISO states that it has demonstrated that its SAC methodology for Schedule 53 Resources would reasonably measure future availability during times of need in each

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[423] The Mississippi Commission Response to MISO Deficiency Letter Response at 2.

[424] *Id.* at 2-3.

[425] MISO May 20 Answer at 6 (citing Deficiency Letter Response at 13).

[426] *Id.* at 8 (citing Deficiency Letter Response at 12).

[427] *Id.* at 8-9.

Season and create powerful new incentives to offer as much availability as possible when MISO declares a MaxGen or when operating margin forecasts suggest tight conditions.[428]

h. Midwest TDUs June 6 Answer

241. Midwest TDUs dispute MISO's claim in its May 20 Answer that MISO has adequately responded to the Commission's request for quantitative evidence. Midwest TDUs argue that MISO does not, and cannot, explain how providing data from only a single Season in MISO North and a single Season in MISO South demonstrates how its SAC proposal is indicative of availability in all Seasons. Midwest TDUs assert that MISO's own emphasis on recent emergency events in other Seasons highlights the inability of this limited data to provide any basis for a Commission determination that MISO's proposed accreditation methodology is indicative of future performance during emergency periods in all seasons.[429]

242. Midwest further TDUs argue that the MISO May 20 Answer glosses over protestors' concerns regarding MISO's treatment of planned outage exemptions under Schedule 53. Midwest TDUs contends that MISO has not justified why planned derates that meet MISO's advanced notice requirements should be foreclosed from qualifying for exemptions.[430]

i. Commission Determination

243. We find MISO's proposed SAC accreditation is a just, reasonable, and not unduly discriminatory or preferential method for accrediting the capacity of Schedule 53 Resources because it will assign resources a capacity value based on their historical performance during high-risk hours in each Season. We find this approach is a reasonable basis to estimate a resource's expected availability during future times of need in a Season, which, in turn, is a reasonable basis to accredit the capacity of Schedule 53 Resources. MISO's SAC proposal provides resource owners with strong incentives to maximize resource availability during high-risk hours, which in turn will increase MISO operator confidence that those resources will perform when they are most needed.

244. We disagree that MISO's accreditation proposal is overly burdensome or complicated for resource owners. MISO's proposed SAC accreditation provides market participants with the specific calculations to determine how their resources will be valued under the new proposal. We also disagree that the SAC calculation process is overly

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[428] *Id.* at 10-11.

[429] Midwest TDUs June 6 Answer at 3.

[430] *Id.* at 3-4.

data-intensive or time-consuming. If MISO can calculate SAC values for all Schedule 53 Resources in its footprint and provide those values to resource owners within the timeframe provided for in MISO's Tariff, we believe that replicating and estimating or confirming those calculations will not be overly burdensome for individual resource owners.

245. We disagree with the Mississippi Commission that MISO has not supported the application of the SAC proposal to MISO South. We find that MISO has sufficiently demonstrated that its SAC proposal is just and reasonable and will result in several improvements to capacity accreditation in MISO, such as increased confidence in generator availability during high-risk hours, better coordination of resource outages, and stronger incentives for resources to be available in times of need. Collectively, these outcomes should provide benefits to MISO's entire system, not just a particular MISO region.[431] Further, as illustrated by 2021 Winter Storm Uri, MISO South can face capacity challenges for which additional accuracy in resource accreditation and incentives for resources throughout MISO to maximize their availability during peak periods would be beneficial.

246. We disagree with protestors' arguments that the SAC methodology will not predict the availability of Planning Resources during times of MISO's highest need. As an initial matter, the SAC methodology aligns a Schedule 53 Resource's reliability value with its historical availability at times of system needs throughout the Planning Year. While no capacity accreditation methodology can perfectly predict a resource's future availability or performance during all intervals, we find that MISO has demonstrated that the SAC methodology resource offers will reasonably predict resource availability in future Seasons.[432] We also disagree with claims that the SAC accreditation unduly increases volatility or otherwise is based on random data. We find that, by considering additional factors, including derates and planned outages that are not scheduled well in advance, the SAC methodology improves the accuracy of capacity accreditation by considering unit performance in times where the unit is most needed. We find that the resulting improved accuracy and alignment of performance incentives of the SAC value outweigh increased volatility.

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[431] *See., e.g.*, MISO February 10 Answer at 22 ("The more available resources become during these [high-risk] periods, the more future capacity credit they will receive. Aligning accreditation incentives with real time system needs will enhance operators' confidence in the availability of resources, further improving reliability.").

[432] *See* MISO Deficiency Letter Response at 7-8 (demonstrating that the ISAC accreditation was significantly more accurate in predicting MISO's fleet-wide offers during MaxGen hours in the Summer in North/Central and the Winter in MISO South).

247. While we find that MISO has supported its proposed SAC accreditation method, additional information regarding SAC's accuracy after the MISO's proposal is fully implemented would benefit the Commission and the public. Accordingly, we direct MISO to submit an informational report covering the first three Planning Years SAC accreditation is implemented. Specifically, we require MISO to, within 90 days of the conclusion of the 2025/2026 Planning Year, submit an informational report that compares the results of SAC accreditation to actual resource availability. The report should include data providing the SAC accreditation, resource availability, and UCAP accreditation (as a point of reference) for all RA Hours in all Seasons for the 2023/2024, 2024/2025, and 2025/2026 Planning Years. The data report should include the requested data (1) by Season, both in aggregate and for each sub-region; (2) by Season and by resource type (e.g., combined cycle, combustion turbine, coal units, and LMRs); and (3) for individual resources (specifically the weighted average percent variance for individual resources across the Planning Year).[433]

248. We disagree that MISO's proposed implementation timeline is unjust and unreasonable. MISO filed its proposal 16 months ahead of the 2023/2024 Auction, after several years of stakeholder discussion. Further, MISO's proposal includes a three-year transition process that gradually increases the accreditation weight of RA Hours each Planning Year. Further, the three-year rolling average used to calculate ISAC values reduces the extent to which resource availability in any one Season will impact a resource's capacity value, and over time the SAC will update to reflect resource performance under the new capacity accreditation methodology. Finally, MISO's proposal to treat resources that are scheduled to go on outage prior to September 1, 2022, the effective date of this proposal, as fully exempt from both Tier 1 and Tier 2 Hours will assist in the transition to a new accreditation framework, as the largest operational decision that resource owners will likely face as a result of this proposal is whether, and how, to adjust their planned outage schedules going forward. In response to arguments suggesting that MISO has not provided resource owners with sufficient time to account for a performance-based capacity accreditation, we agree with MISO that Capacity Resources are currently subject to a must-offer obligation under the current resource adequacy requirements and, therefore, resources should already have an expectation that they should be available and offering into MISO's energy markets. The transition period appropriately balances the need to implement the SAC methodology with the recognition that resource owners and LSEs may need to adjust their operations—including outage timing—and their contractual arrangements to maximize their potential SAC values. Accordingly, we disagree with COMPP that the transition period unduly delays needed reforms. For the same reasons, we are unpersuaded by arguments that MISO's

[433] This informational filing will not be noticed for comment or require Commission action.

accreditation will unduly harm resource owners because of their past operational decisions.

249. We disagree that the Commission's acceptance of longer transition mechanisms in PJM binds the Commission to reject a shorter timeframe in the instant filing. In the order accepting PJM's proposed Reliability Pricing Model, the Commission accepted PJM's proposed transition timeline because it "allows the participants in the market a period of time to understand and get used to the dynamics of the new capacity market prior to its full implementation."[434] We are not persuaded that market participants require the same transition period for MISO's proposal to *modify* its existing capacity market as PJM's proposal to *create* a capacity market.[435] In the PJM Capacity Performance Order, the Commission noted that the proposed five year transition period would: (1) allow resources to make gradual improvements and reduce the burden such improvements may impose; and (2) mitigate the potential for short-term shortage that might result from an immediate requirement of 100% Capacity Performance Resources.[436] We agree with MISO that, because the three-year lookback period will be based on operational experience from after MISO's RAN Phase 1's implementation, resources already have an expectation of needing to be available and therefore, it is reasonable for resources to have a shorter transition period.

250. However, with respect to Great River Energy's request for clarification that planned outages scheduled to begin before September 1, 2022 will be granted both a Tier 1 and Tier 2 exemption, we agree that additional clarification is required. The McFarlane Testimony states that such planned outages will be treated as fully exempt for Tier 1 and Tier 2 for accreditation purposes. However, MISO's proposed Tariff language states that "Generator Planned Outages scheduled to begin before September 1, 2022, will be granted a Tier 2 exemption."[437] While section II.B of proposed Schedule 53 notes that resource owners receiving a Tier 2 exemption will receive a Tier 1 exemption as well, it appears that this only applies if a resource owner receives a Tier 2 exemption under the normal Tier 2 exemption provisions of section II.A. Therefore, we require MISO to,

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[434] PJM Reliability Pricing Model Order, 117 FERC ¶ 61,331 at P 68.

[435] We also note that, in the order establishing MISO's Planning Reserve Auction construct, MISO proposed, and the Commission accepted, a two-year (from the filing date) transition period for the full implementation of MISO's capacity market. *Midwest Indep. Sys. Operator, Inc.*, 139 FERC ¶ 61,199 (2012). Protestors have not demonstrated why a longer transition period is necessary for MISO's proposed modifications to its existing capacity market construct.

[436] PJM Capacity Performance Resource Order, 151 FERC ¶ 61,208 at P 253.

[437] MISO, FERC Electric Tariff, Schedule 53 § II (32.0.0) (proposed).

within 30 days of the date of this order, file revised tariff sheets that clarify that generator planned outages scheduled to begin before September 1, 2022, will receive both a Tier 2 and Tier 1 exemption, consistent with the McFarlane Testimony.

251. Some protestors contend that resource owners will not have sufficient time to ensure preparedness through fuel supply planning and weatherization. We disagree. Resource owners should already make investments in their units to ensure future availability; to the extent that they have not done so, or have been insufficiently incented to do so under MISO's current capacity accreditation rules, we find that this lends further support to MISO's argument that its current construct does not appropriately incent resource owners to ensure their units remain available. Furthermore, the proposal includes a three-year transition period that will gradually increase the weight of RA Hours for purposes of SAC accreditation.

252. We disagree with Entergy Coalition's arguments that acceptance of MISO's proposal constitutes retroactive ratemaking. As noted above, MISO filed the instant proposal 16 months in advance of its proposed implementation; and it will become effective prospectively only. Moreover, although rates must take effect prospectively, there is no prohibition against the use of historical inputs, which MISO proposes to do so here.[438] This is commonly the case for formula rates that use past inputs. MISO's proposal does not alter its rate retroactively. Thus, MISO's proposal does not constitute retroactive ratemaking.

253. We find that MISO has demonstrated that the proposed weighting of RA Hours in determining a resource's SAC accreditation is just and reasonable. Specifically, MISO proposes a tiered weighting structure to determine individual resource accreditation by Season based on each Resource's Real-Time energy offers during Tier 1 hours (*i.e.*, all hours not including RA Hours) and Tier 2 hours (*i.e.*, RA Hours). We are not persuaded by protestors' arguments that MISO's proposed weighting over- or underemphasizes certain hours or by arguments that a resource's entire accreditation should be based on Tier 2 Hours. We find that MISO's proposed weighting of 80% Tier 2 Hours and 20% Tier 1 Hours, which will occur after a three-year transition, is an acceptable approach that reasonably recognizes the importance of a resource's contributions during times of greatest need, recognizes a resource's reliability contributions during all other times, and appropriately accounts for and allows for generator planned outages. In contrast to those who suggest that using a small number of hours to determine the majority of a Schedule

[438] *See, e.g.*, *PJM Interconnection, L.L.C.*, 172 FERC ¶ 61,054, at P 58 (2020) ("Longstanding practice, Commission and court precedent allow the use of reasonably representative historic test period data to craft rates, terms and conditions of service."). *See also id.* P 54 ("the use of past data to determine prospective costs is not retroactive ratemaking") (citing *Old Dominion Elec. Coop.*, 162 FERC ¶ 61,262, at P 50 (2018)).

53 Resource's accreditation, we find that MISO's 65-hour Tier 2 RA Hour target strikes a reasonable balance between being small enough to ensure that a resource's availability during the most needed hours is captured, while being large enough such to reduce volatility, as we discuss further below.[439]

254. We find that MISO has demonstrated that it is reasonable to supplement MaxGen hours with hours that have operating reserve margins as high as 25% in order to meet the 65-hour RA Hour target. While another cutoff may also be just and reasonable, on balance we find it just and reasonable that MISO consider hours other than just MaxGen hours and MISO has supported the proposed 25% cutoff. Performance during hours surrounding MaxGen hours also appear indicative of future performance during times of greatest system need, and reliance only on MaxGen hours, of which there are few, could dramatically increase the need to use AAOC hours.[440] We also note that the 65-hour target intends to include the tightest 3% of hours, which may exceed the number of MaxGen hours. Using a smaller target number of hours could increase accreditation volatility. Relatedly, while resource owners may not know whether an hour with less than 25% operating margin will be considered an "RA Hour" until after the conclusion of a Season, resource owners are on notice that any hour with less than 25% operating margin could potentially be an RA Hour and are thus able to adjust their operations accordingly. Additionally, resource owners can gain some visibility into high-risk hours through MISO's notices of Conservative Operations, which MISO declares based on system conditions including severe weather, hot/cold weather, or geomagnetic disturbance warnings, and Capacity Advisories that indicate the potential for limited operating margins.[441]

255. We find MISO's proposal to use resources with a 12-hour lead time for purposes of calculating the operating margin needed to determine RA Hours and non-RA Hours to be just and reasonable. We recognize that Potomac Economics and Clean Energy Coalition argue that a shorter lead time could also be reasonable given that emergency

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[439] Clean Energy Protest argues that MISO's proposal may overlook periods of increased risk because, according to Clean Energy Protests, MISO's proposal limits RA Hours to 65 hours in a Season. We note that the 65 hours is a minimum target, not a cap, and MISO's proposal designates all MaxGen hours as RA Hours.

[440] *See* MISO Deficiency Letter Response at 4-5 (table demonstrating that the number of MaxGen hours in most seasons is less than or equal to 65).

[441] *See* MISO Operating Procedures at 1, https://cdn.misoenergy.org/Three%20Pager%20-%20MISO%20Operating%20Procedures%2009202018318965.pdf.

conditions may develop with a less-than-12-hour notice.[442] MISO explains that, although it initially considered proposing a 24-hour lead time, it determined that, due to the operational concerns it faces, tight conditions are more likely to be identified 12 hours before a projected capacity shortfall than 24 hours ahead of time.[443] Therefore, we find the 12-hour requirement is a reasonable timeframe to ensure that such resources' contributions are accounted for in the determination of RA Hours.

256. We find MISO has demonstrated that AAOC is a just and reasonable proxy to reflect expected resource availability in Seasons that have not met their 65-hour RA Hour target. Some protestors suggest that, because MISO has proposed a seasonal construct, using non-RA Hours from a particular Season would be a better predictor of resource availability in that Season. However, we are persuaded by MISO and Potomac Economics that using AAOC (which reflects a unit's availability during high-risk hours throughout the year) is a reasonable approach to estimate availability during high risk hours because MISO's proposal intentionally weights RA Hours more heavily than non-RA Hours and including non-RA Hours in a resource's Tier 2 accreditation calculation could overestimate their expected availability in tight conditions. We disagree with protestors that it is unreasonable for certain hours to be used for both a Seasonal RA Hour and as part of a unit's AAOC. MISO explains that such hours "would not statistically constitute double counting because the individual hours would be 1/65th (1.538%) of the resource performance for any RA Hour but would only be 1/260th of the AAOC".[444] We agree with MISO that using a particular hour for both a Seasonal RA Hour and as part of a unit's AAOC has a *de minimis* effect on a resource's overall accreditation and find that MISO's use of AAOC is a reasonable proxy when a season is deficient RA Hours.

257. In response to Midwest TDUs' concern that there is an inconsistency between MISO's testimony and its proposed Tariff language regarding how MISO will replace Seasonal RA Hours that are exempt from a resource's Tier 2 calculation, we note that section III.A.ii of MISO's proposed Schedule 53 states that:

> If there are fewer than 65 hours identified for the Season in Section III.A.i above, additional hours will be identified up to a total of 65 starting with those hours with the lowest Operating Margin that is below a threshold of 25 percent excluding any operating hour where a Resource has a Tier 2

[442] We note that Potomac Economics states that it finds MISO's filing reasonable as proposed. Potomac Economics Comments at 5.

[443] *See* McFarlane Test. at 23-24.

[444] MISO February 10 Answer at 30.

> Planned Outage exemption or has periods where the Resource was not designated for RAR under Module E-1 of the Tariff.[445]

Regardless of any inconsistency with the testimony, we find that the Tariff is clear with respect to the replacement Seasonal RA Hours.

258. We are not persuaded by arguments that MISO's proposal introduces an unreasonable level volatility in capacity accreditation for a given resource. We find that any seasonal or year-over-year volatility in a resource's SAC accreditation will reasonably reflect supply fundamentals, principally the resource's seasonal availability, and demand fundamentals, through the identification and weighting of RA Hours and non-RA Hours.

259. Regarding arguments that any increased volatility in SAC accreditation is due to MISO's proposed weighting of historical unit performance (as measured by offer behavior) in RA Hours, MISO indicates that volatility, in aggregate, is expected to be very low (less than 2%).[446] As noted above, we find MISO's RA proposal strikes a reasonable balance between identifying RA Hours that represent the times of high risk and having sufficient RA Hour sample sizes, and avoids an undue level of volatility into MISO's resource accreditation. Additionally, we note that MISO's proposal mitigates volatility by using a three-year rolling average. Further, MISO's proposal contains a transition mechanism that mitigates the potential for volatility in the first three years of SAC implementation by gradually scaling up the percentage of a resource's accredited capacity that is based on offers in Tier 2 RA Hours.

260. We are not persuaded by arguments that MISO's proposal will lead to levels of volatility in resource accreditation that disrupt resource planning or inappropriately interfere with state regulatory resource planning. We find that regulatory authorities, LSEs, and resource owners will continue to be able to plan in accordance with MISO's resource adequacy requirements and the objectives of state regulatory authorities. While we acknowledge that individual resource accreditation volatility is possible as a result of MISO's SAC proposal, we expect that any additional volatility to be low and that LSEs will be able to look to historical performance to reasonably estimate future accreditation of their individual resources and resource fleet as a whole to meet their Reserve Requirements. Additionally, MISO's seasonal accreditation construct is premised on the need to better account for resource availability in each Season and matching expected resource availability with the needs in that Season. Accordingly, to the extent a

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[445] MISO, FERC Electric Tariff, Schedule 53 § III.A.ii (32.0.0) (proposed).

[446] *See* MISO February 10 Answer at 19-20 (citing RASC presentation at 6 (Sept. 1, 2021)).

resource's availability to meet MISO system needs varies across Seasons or year-over-year, volatility in that resource's accreditation is warranted and is appropriately captured in MISO's SAC accreditation proposal. Further, we are not persuaded by protestors' concerns that an LSE's entire portfolio will undergo drastic changes. Many LSEs have diverse resource fleets, which mitigates the planning implications of accreditation volatility for individual resources. LSEs that fulfill their resource adequacy obligations with a small number of resources can engage in bilateral arrangements or other hedging vehicles, or procure capacity from the Auction to manage any new accreditation volatility from this proposal.

261. We disagree with Consumers Energy's contention that MISO's proposal arbitrarily reduces the flexibility of resource owners to prudently schedule planned outages and does not address MISO's identified issues. MISO has demonstrated that current system conditions of reduced reserve margins necessitate greater outage coordination to maintain resource adequacy. We find MISO's proposed exemption requirements with respect to the notice and time between outages provide resources with economic incentives to give MISO more advance notice of outages, which should help MISO improve coordinated outage scheduling and maximize availability of resources in all hours, including hours with tight reserve margin conditions.

262. Consumers Energy asserts that MISO does not explain how modifying the exemption rules for prudently planned outages will improve operating or Maintenance Margins. As MISO explains, an "[a]fter the fact review of MaxGen Events often show the significant contribution of planned and maintenance outage to unit unavailability during times of realized LOLE risk."[447] By having additional tools to coordinate planned generator outages and to incent resource owners to submit planned outages with sufficient notice (120 days) through its accreditation rules, MISO and resource owners will have more accurate expectations regarding whether resources will be available when they are needed.

263. We disagree with Consumers Energy's claim that eliminating the ability for generators to schedule planned outages less than 120 days in advance without risking accreditation does not address the correlation between forced outages and insufficient investments in winterization or fuel supply. MISO explains the purpose of this provision is to encourage resource owners to plan outages well in advance to improve outage coordination—not to specifically encourage sufficient investment in winterization of fuel supply. We find that MISO's overall proposal, however, will create incentives for winterization investments when a market conditions warrant, such as higher capacity prices in the Winter Season, which should incent more resources to be available during the Winter Season through either winterization, revised planned outage scheduling, or

[447] MISO May 20 Answer at 9.

other means. The seasonality, combined with the accreditation methodology, dramatically increases the economic incentives for resource owners to take steps including maintenance and weatherization to maximize resource availability, including in non-Summer Seasons.

264. We agree with Entergy Coalition that resource owners may already have economic and system reliability incentives to minimize the length of planned outages. Nevertheless, as discussed above, MISO's planned outage exemption proposals are intended to do more than to solely minimize planned outage length. They are intended to maximize coordination of outages by timing them for when the Maintenance Margin is sufficient. Further, even if such incentives exist in MISO's current provisions, Entergy Coalition does not dispute that MISO's proposal will introduce additional incentives to minimize and coordinate planned outages, which should enhance resource adequacy.

265. We disagree with East Texas and DTE Electric's arguments that MISO has not adequately explained why outages must be scheduled 120 days in advance to be eligible for a Tier 2 exemption. MISO's outage exemption criteria with respect to the 120-day lead time encourages resource owners to give MISO more visibility and advance notice of available resources, which is needed in order to ensure resource adequacy in future periods. We find that the 120-day lead time appropriately balances the need for resources to have flexibility to schedule planned outages and the need for MISO have such visibility. We also disagree with Entergy Coalition and Consumers Energy's contentions that MISO's proposed 120-day lead time criteria could have the perverse effect of discouraging resources from performing maintenance activities, and thereby resulting in worse unit performance. Given the functional relationship between resource accreditation and resource availability, we believe that resources will not risk delaying necessary maintenance, because such delays could result in resource underperformance, unavailability, or forced outages, which would negatively impact that resource's future accreditation. We believe that together, the incentives will encourage resource owners to appropriately balance maximizing short-term availability when it is most needed and to perform maintenance, which requires scheduling planned outages, to ensure long-term resource performance.

266. We find that MISO has sufficiently explained and supported the proposed requirement to have a planned outage no sooner than 120 days after the previous planned outage to receive full exemptions. As MISO explains, this requirement serves to disincentivize frequent planned outages.[448] We find that MISO's proposal limiting outages reasonably balances resource owner flexibility with the need to coordinate outages. While there may be efficiencies and advantages to allowing additional flexibility (for example, being able to "split" a planned outage around days where the

[448] MISO Deficiency Letter Response at 13.

Maintenance Margin is negative, rather than having to submit two outages 120 days apart), we do not find that the lack of such flexibility renders the proposal unjust and unreasonable. We further find that this provision largely addresses concerns, articulated by WEC Utilities, about the potential to "hoard" outage dates.

267. We disagree with Entergy Coalition and East Texas arguments that outage exemptions should be granted whenever the Maintenance Margin is greater than zero. MISO's Maintenance Margin calculation is a forward-looking calculation based on Planning Year inputs from resource adequacy and the annual LOLE study. Maintenance Margin results subtract current planned generator outages in the Control Room Operations Window from the Maintenance Limit provided by resource adequacy and provides the number of MW that are available for scheduling generator outages while still allowing MISO to meet all its obligations.[449] Since the Maintenance Margin is a function of planned generator outages it does not take into account resources that may be on unplanned or forced outage. To this end, the Maintenance Margin does not give a complete picture of system reliability, but rather projects a snapshot which is intended to be used to identify time periods where there is available margin for a generator to take a planned outage.[450] Furthermore, as described above, there is a value in MISO having more advance notice and improved visibility into planned outages. Granting exemptions whenever the Maintenance Margin is above zero, as suggested by Entergy Coalition and East Texas, would reduce the incentive for resource owners to schedule outages well in advance and would reduce information available to MISO operators about resource outages, thereby decreasing operator confidence in future projections of future resource availability.

268. We disagree with the Mississippi Commission and Clean Energy Coalition arguments that outage planning and coordination is an operational issue and not a "marketplace issue." As an initial matter, no Commission policy precludes Tariff proposals pertaining to "operational issues" if the primary substance of the filing pertains to markets. Market and operational issues are inextricably linked as these markets are

[449] MISO, FERC Electric Tariff, Module A, § 1.M (71.0.0) ("Projected megawatts of additional generation that can be taken out of service for planned maintenance within MISO during a given time period without impacting adequacy of generation supply. The projection will be based on a forward looking [LOLE] analysis with known Proposed Generator Planed Outages of entire units.").

[450] We note that, to the extent that system conditions change as a planned outage start date near, MISO's proposal allows MISO to grant exemptions if a generator owner reschedules its planned outage at MISO's request due to "weather, forced outages, or other conditions listed in the [BPM] for Outage Operations. . ." *See* MISO, FERC Electric Tariff, Module E-1, § Schedule 53.II.A.iii (32.0.0)

designed to price, schedule, and dispatch energy and ancillary services over the operational timeframe (i.e., the 24-hour operating day). Furthermore, MISO's filing recognizes the interaction between operational and marketplace issues. Operational decisions can affect market outcomes, and market prices and incentives can affect operational decisions. Additionally, precedent exists for the Commission accepting proposals regarding Tariff revisions for how resource outages affect their participation in capacity constructs. Specifically, the Commission accepted MISO's 2019 proposed Tariff revisions limiting the ability of resources to participate in the Auction if that resource has full or partial outages that last for any 90 or more of the first 120 Calendar Days in the Planning Year.[451]

269. We disagree with Duke Energy and MISO TOs' contention that MISO needs to provide more support for excluding prudently planned derates from accreditation exemptions. As MISO explains, such derates have tended to be short-term in nature and would require further modifications to MISO's current outage coordination process which does not consider derates. However, we encourage MISO to continue to evaluate whether its current outage coordination process could be improved in light of MISO's instant proposal, including how derates impact SAC accreditation as MISO gains experience with the SAC exemptions over time.

270. We accept as just and reasonable MISO's proposal to outline in the BPM for Generator Outage additional criteria that MISO would use to determine whether a planned outage passes the No Harm Test.[452] We find that MISO's proposed Tariff language provides sufficient detail regarding what circumstances MISO will grant Tier 1 exemptions: (1) when resource owners submit a planned outage less than 31 days in advance and at least 14 days in advance of the outage start date; (2) when the planned outage occurs entirely during a period with adequate Maintenance Margin; and (3) when the planned outage does not cause harm, with the Tariff detailing the possible ways that the planned outage could cause harm. We do not believe that it is necessary to require that the Tariff contain further detail.[453]

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[451] *Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,066 (2020) (2020 Summer Outage Order).

[452] Section II.C of proposed Schedule 53 states that "[t]he No Harm Tests include, but are not limited to, outage approval, compliance with all applicable operation guides, review of possible conflicting outages or system conditions, and system capacity (Maintenance Margin, Multiday Operational Margin, 30-day margin). It also includes the criteria outlined in the [BPM] for Generator Outage." MISO, FERC Electric Tariff, Schedule 53 § II.C (32.0.0) (proposed).

[453] *Energy Storage Ass'n v. PJM Interconnection, L.L.C.*, 162 FERC ¶ 61,296, at

271. Similarly, we disagree that MISO's Tariff should be revised to contain additional detail on accreditation for Dispatchable Intermittent Resources and Intermittent Generation. MISO's effective Tariff provides the same level of detail in this regard as MISO's proposed Tariff. As MISO is merely proposing to use its current accreditation process for Dispatchable Intermittent Resources and Intermittent Generation and apply it seasonally, rather than annually, further detail is unnecessary.

272. We find that it is just and reasonable to cap a resource's offer at its GVTC for purposes of SAC accreditation, as MISO proposes. First, as protestors acknowledge, MISO will use seasonally corrected GVTC values, which are calculated by conducting a single real power test or using operational data that is adjusted for each Season using that Season's peak conditions. We agree with MISO that capping SAC accreditation at GVTC, which is the basis for UCAP, prevents the UCAP/ISAC ratio from being skewed, which could misalign accreditation values with the LOLE model. Although it is possible that in some specific circumstances resources can produce energy above their GVTC, such performance may be less certain in future circumstances than amounts at the GVTC. Further, nothing in the record indicates that resource output frequently exceeds their GTVC such that allowing ISAC accreditations to exceed GVTC would materially impact the final SAC accreditation values of resources.

273. With respect to Duke Energy's arguments, as discussed above, we find it just and reasonable for MISO to accredit Schedule 53 Resources based on their prior offered availability, which MISO's determines through a resource's Hourly Emergency Maximum Limit (or Targeted Demand Reduction Level). To the extent that a resource is unable to submit an Hourly Emergency Maximum Limit (or Targeted Demand Reduction Level) because there is no expectation of that resource being able to inject into the grid at that level, we find it reasonable for MISO to not consider a resource as having offered availability in those hours. We further note that nothing in the record indicates that a Schedule 53 Resource's accreditation will be materially impacted by not including intervals where the resource is being committed or decommitted.

274. We are not persuaded that a mechanism to transition GIAs to higher Winter capacity values is necessary. We disagree that the lack of a mechanism unduly harms units that have Winter output capabilities that exceed the level of interconnection service that they receive under their GIA. Under MISO's proposal, Schedule 53 Resources will

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P 103 (2018); *see also City of Cleveland v. FERC*, 773 F.2d 1368, 1376-77 (D.C. Cir. 1985) (*City of Cleveland*) (affirming the Commission's decision not to require that certain terms be included in the tariff, explaining that "only those practices that affect rates and service *significantly*, that are reasonably *susceptible* of specification, and that are not so generally understood in any contractual arrangement as to render recitation superfluous" must be included in a tariff) (emphasis in original).

be accredited based on their availability and output, which may be limited not only by the resource's operating characteristics but on the level and amount of interconnection service that it receives under its GIA. Under MISO's GIP, MISO studies resources in the interconnection queue based on the level of requested interconnection service requested by the customer in order to preserve system reliability, and allowing resources to go above that level could compromise system reliability.[454] As MISO notes, its existing GIP allows interconnection customers to request incremental interconnection service, and all resource owners are free to do so should they wish to take advantage of potentially higher Winter output capabilities.[455] We find that the seasonal provisions contemplated in this proposal are just and reasonable without further revisions to MISO's GIP. With regard to the fact that some SAC values may be higher than a resource's existing interconnection service, we note that, under MISO's current resource adequacy construct, a resource's UCAP value can exceed its existing interconnection service.

275. We find that MISO's proposal to treat offline resources with lead times in excess of 24 hours as unavailable during RA hours, such that they receive zero credit for purposes of SAC accreditation, is just and reasonable because they provide little reliability value to MISO. As MISO explains, MISO's proposed 24-hour lead time threshold for SAC accreditation appropriately reflects whether MISO could have reasonably committed the resource in its Day-Ahead Market or Forward Reliability Assessment Commitment process.[456] Resources that can be committed through the Day-Ahead or Forward Reliability Assessment Commitment process contribute to MISO's resource adequacy needs and thus we find MISO's proposal to accredit these resources to be just and reasonable.

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[454] *See, e.g., Ariz. Pub. Serv. Co.*, 170 FERC ¶ 61,111, at P 39 (2020) (noting that in Order No. 845, the Commission required, in *pro forma* LGIP revised section 3.1, that transmission providers have a process in place to consider requests for interconnection service below the generating facility capacity and that the Commission stipulated that such requests should be studied at the level of interconnection service requested for purposes of determining interconnection facilities, network upgrades, and associated costs, but that such requests may be subject to other studies at the full generating facility capacity to ensure safety and reliability of the system.) (citing *Reform of Generator Interconnection Procs. & Agreements*, Order No. 845, 163 FERC ¶61,043, at PP 383-384 (2018)); *see also Midcontinent Indep. Sys. Operator, Inc.*, 108 FERC ¶ 61,027, at P 26 (2004) (generators operating above the output limits, which the generators themselves provide, can compromise system reliability).

[455] *See* MISO February 10 Answer at 38-39.

[456] *See* McFarlane Test. at 24.

276. We are not persuaded by arguments that MISO should use a shorter lead time than 24 hours (e.g., 12 hours) in SAC accreditation because a lead time less than 24 hours could inappropriately ignore the role that resources with lead times of up to 24 hours play in meeting MISO's resource adequacy needs. Although MISO notes that tight conditions are "more likely" to be identified 12 hours beforehand than 24 hours beforehand, this suggests that some resource adequacy needs are identified 24 hours beforehand.[457] The Day-Ahead Market or Forward Reliability Assessment Commitment process can be used to address MISO's resource adequacy needs and we disagree with arguments or suggestions that resources that can be committed through either of these processes (i.e., resources with startup times up to 24 hours) should not be accredited at a level commensurate with their ability to meet those needs. For example, MISO could identify certain capacity needs over a longer time horizon than 12 hours, such as resources being out on an extended planned or forced outage, transmission maintenance that creates a capacity need, or certain meteorological events forecast 24 or more hours in advance. To the extent that MISO uses either the Day-Ahead Market or Forward Reliability Assessment Commitment processes to meet these or other needs, we find it appropriate to accredit resources commensurate with their ability to meet those needs. Further, we believe that a resource being unavailable within 12 (or fewer) hours because MISO did not select it through a day-ahead or FRAC commitment process is not a reasonable basis to penalize that resource by assigning it a zero SAC accreditation value for those hours.

277. We find MISO's proposed UCAP/ISAC conversion ratio to determine a Schedule 53 Resource's final SAC value to be just and reasonable. Acknowledging MISO's own admission of the disconnect between the UCAP-based resource valuation in the LOLE model and the availability-based SAC accreditation, we accept the use of a UCAP/ISAC ratio as just and reasonable because it is necessary to address the misalignment between MISO's current LOLE planning model that produces UCAP-based Reserve Requirements and the proposed SAC accreditation method. The UCAP/ISAC ratio also prevents the need to modify its LOLE model and convert Reserve Requirements and Local Clearing Requirements into SAC terms, and maintains an appropriate supply and demand balance in the Auction. We agree with MISO and Potomac Economics that the proposed ratio is reasonable and that applying the ratio to the ISAC (supply) side prevents some of the unintended consequences that would occur by applying a similar ratio to Reserve Requirements, such as the possibility that the Auction Clearing Price would increase. In addition, as discussed further below, the proposed UCAP/ISAC ratio prevents inappropriate impacts on the accreditation of non-Schedule 53 resources. Further, noting MISO has already pledged to do so, we encourage MISO to continue exploring whether its LOLE study can use SAC instead of UCAP.

[457] *See* McFarlane Test. at 24.

278. While Entergy Coalition notes that the application of the UCAP/ISAC ratio means that some Schedule 53 Resources may have final SAC ratings that exceed their GVTC rating, Entergy Coalition does not explain why this this is unreasonable, or why SAC, rather than ISAC, is appropriate to compare to GVTC. We find that this potential outcome, which Entergy Coalition has not demonstrated will have a material impact on the reliability or the Auction, or occur frequently, is a byproduct of the UCAP/ISAC conversion ratio, which as noted above, we find to be just and reasonable.

279. We find, contrary to Clean Energy Coalition's argument, that the UCAP/ISAC ratio does not lead to unduly discriminatory treatment between Schedule 53 and non-Schedule 53 Resources. While Clean Energy Coalition is correct that Schedule 53 Resources and certain non-schedule Resources will be both accredited based on availability, that alone does not necessitate application of the UCAP/ISAC ratio to non-Schedule 53 Resources. As MISO explains, the purpose of the UCAP/ISAC ratio is to ensure continued alignment between MISO's UCAP-based Reserve Requirements and its SAC proposal, such that the overall supply/demand balance of MISO's capacity market generally remains unchanged. In addition, the UCAP/ISAC ratio recognizes that, although Schedule 53 Resources are likely to be accredited less ZRCs using the SAC method (as compared to the current UCAP-based method), one ZRC of SAC accreditation provides more reliability value than one ZRC of UCAP accreditation. In contrast, non-Schedule 53 Resources will continue to be accredited using their existing accreditation framework, with modifications to account for a seasonal construct. As such, they will not experience the same level of accreditation reduction as Schedule 53 Resources. Clean Energy Coalition has provided no evidence that the existing accreditation methodologies for non-Schedule 53 Resources such as wind undervalue their resource adequacy contributions. Applying the UCAP/ISAC ratio to non-Schedule Resources will result in overvaluing those resources, potentially harming resource adequacy due to insufficient resources being used to meet the Reserve Margin while maintaining the 0.1 LOLE target.

280. We find that MISO has sufficiently justified excluding External Resources from the Schedule 53 Resource definition and SAC accreditation. MISO explains that External Resources do not submit Generation Offers into MISO's real-time market, meaning that MISO does not have the data to accredit those resources using the SAC method.

281. We disagree with protestors that contend that the SAC methodology should be applied to both Schedule 53 Resources and intermittent resources. As an initial matter, we note that these two resource groups are already accredited using different methodologies. Having different accreditation methodologies for different types of resources does not necessarily present undue discrimination; in fact, it is often the case that the operating characteristics of different resource classes require various different

accreditation frameworks.[458] Further, we agree with MISO that it is appropriate that the LOLE risk target used in the wind ELCC accreditation calculation be distinct from the risk target used in determining seasonal Reserve Requirements. Clean Energy Coalition's concern with MISO's use of ELCC for purposes of wind accreditation under a seasonal construct rests on the assumption that MISO must "demonstrate that the two accreditation methodologies do work together and assess capacity availability during the same risk hours in order for the construct to hold together both theoretically and practically to ensure a reliable system that can meet load during these high-risk hours."[459] MISO has, in this instant filing, proposed: (1) an availability-based accreditation methodology for Schedule 53 Resources, to be applied to MISO's new seasonal resource adequacy construct; and (2) revisions to its existing methodologies for non-Schedule 53 Resources to allow those resources to be accredited on a seasonal basis. We find these revisions to be just and reasonable, and we do not believe that further revisions to non-Schedule 53 Resource accreditation is required at this time.

282. We also disagree with Clean Energy Coalition's argument that MISO's proposal is unjust and reasonable because it does not expressly consider fuel supply risk for coal and gas resources but does consider fuel supply risk for wind and solar resources. While it is true that the SAC methodology is indifferent as to *why* a resource is available or unavailable during emergency periods, the SAC accreditation implicitly accounts for fuel availability because it is specifically designed to ensure that, if a resource is unavailable and has not received a Tier 1 or Tier 2 exemption—whether due to fuel or other reasons—it will not receive credit for those hours and the resource's SAC accreditation will be lower as a result. Arguably, MISO's availability-based SAC proposal brings conventional Schedule 53 generators and intermittent accreditation closer together in this regard, as MISO's current accreditation construct assumes 100% fuel availability for conventional generators. However, to the extent that Clean Energy Coalition is concerned that certain gas or coal units are overvalued because they have not able to contribute in emergency periods due to fuel supply issues, we believe that MISO's proposal should alleviate, rather than exacerbate, those concerns.

283. Contrary to Industrial Customers' argument that MISO's proposal to increase the minimum number of required interruption calls for LMR DRs to receive 100% capacity accreditation for the full Planning Year from 10 to 16 per Planning Year is unjust and unreasonable, we find that MISO's proposal, in conjunction with the move to a seasonal

[458] In PJM's ELCC proposal, the Commission explicitly found that PJM, which uses a rating based on UCAP for unlimited resources, "need not extend the ELCC framework to Unlimited Resources to demonstrate that its filing is just and reasonable." *PJM Interconnection*, 176 FERC ¶ 61,056 at P 70.

[459] Clean Energy Coalition Response to MISO Deficiency Letter Response at 6.

resource adequacy construct, is just and reasonable and sufficiently supported. MISO's current requirement of a minimum of 10 interruption calls during a Planning Year for LMR DRs to receive 100% capacity accreditation is based on an annual resource adequacy construct. As an initial matter, increasing the number of interruption calls on LMR DRs to receive full capacity accreditation from the status quo is not in and of itself unjust and unreasonable. Such an increase occurred in 2020, when the Commission accepted MISO's proposal to increase the minimum number of required interruption calls for LMR DRs to receive 100% capacity accreditation from 5 to 10 per Planning Year based on "a reasonable methodology through its reliability analysis to account for [LMR DR] potential unavailability."[460] Here too, we find that MISO has developed a reasonable methodology to account for LMR DR unavailability. However, MISO now does so on a seasonal basis. To receive 100% capacity accreditation in a particular Season under the proposed seasonal resource adequacy construct, LMR DRs are, required to allow for at most five interruption calls per Season. Under this proposal, an LMR DR is able to receive a level of capacity accreditation below 100% if it allows the minimum number of interruption calls for a particular Season, as opposed to the current construct which requires at least five interruption calls in a Planning Year to receive 80% capacity accreditation (LMR DRs that do not allow for at least five interruption calls in a Planning Year do not receive any capacity accreditation). Furthermore, we find that the 16-call requirement (to receive 100% capacity accreditation for all four Seasons) is consistent with the 2020 LOLE Analysis that MISO cites to support the need for 15 annual calls to receive 100% accreditation, while allowing for consistency among Seasons.

284. We disagree with the Mississippi Commission argument that MISO's proposal marginalizes state decisions regarding generation investment and construction, and thus would be beyond the Commission's authority to accept. Our acceptance of MISO's proposal does not prevent states from exercising their jurisdiction to make generation-related decisions under FPA section 201.[461] As the Commission has held:

> The Commission does not interfere with the states' authority over generation facilities, local reliability, retail sales or other matters the FPA reserved to the states merely by implementing wholesale rules affecting matters within the states' jurisdiction. We recognize that the FPA reserves to the state decisions concerning

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[460] LMR DR Accreditation Order, 172 FERC ¶ 61,138 at P 49.

[461] *See, e.g.*, *Calpine Corp.*, 169 FERC ¶ 61,239, at P 174 n.345 (2019) ("States may choose to acquire whatever generation resources they like, but it remains the duty of this Commission to ensure that those choices do not cause unjust, unreasonable, or unduly discriminatory or preferential rates for wholesale transactions in interstate commerce." (citing *Conn. Dept. of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009)).

> generation; but the FPA provides the Commission with the jurisdiction and authority to regulate rates for wholesale sales made by those generation resources, and we are obligated to ensure that such rates are just and reasonable and not unduly discriminatory or preferential.[462]

285. In response to Duke Energy's argument that MISO has not shown how the proposed SAC accreditation calculation will accurately account for jointly owned units, we are not persuaded that additional clarity is needed at this time. MISO's current Tariff provisions do not explicitly account for jointly owned units, and we do not find that MISO's Schedule 53 Resource accreditation provisions requires any additional explanation.

3. Capacity Replacement

a. MISO Filing

286. MISO states that its current capacity replacement requirements are limited to suspensions and retirements of resources and carry no specific financial non-compliance provisions. MISO argues that these limited requirements are no longer sufficient as the performance and availability of committed capacity to meet seasonal requirements will be critical. MISO proposes to require replacement for any Planning Resource that will be on planned outage or planned derate for more than 31 days in a Season in which they clear. MISO states that it is also proposing provisions allowing the replacement of resources that have experienced catastrophic outages, enabling such resources to maintain class average accreditation upon return to service.[463]

287. MISO proposes a Capacity Replacement Non-Compliance Charge for Resource owners that do not replace Planning Resources that retire or suspend during a Season, or are on planned outage or planned derate for more than 31 days in a Season. MISO states that the Capacity Replacement Non-Compliance Charge will be a daily charge, equal to the amount of ZRCs that failed to be replaced multiplied by sum of the Auction Clearing Price and the daily CONE value. MISO states that the Capacity Replacement Non-Compliance Charges will be distributed to Market Participants representing LSEs on a *pro rata* basis, based upon the LSE's share of total Reserve Requirements for the MISO Region.[464]

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[462] *N.Y. State Pub. Serv. Comm v. N.Y. Indep. Sys. Operator, Inc.*, 173 FERC ¶ 61,060, at P 37 (2020) (footnotes omitted).

[463] Transmittal at 14.

[464] *Id.* at 15.

b. Comments and Protests

288. OMS contends that it is entirely reasonable for MISO to require resources that receive capacity credit and capacity payments to be available to offer energy for a large part of a given Season.[465]

289. Clean Energy Coalition argues that MISO's proposed capacity replacement provisions invalidate the proposed methodology for availability-based accreditation, since there may not be a strong correlation between a resource's historic performance at peak times and its future inclination to perform.[466] Clean Energy Coalition also argues that the replacement methodology fails to consider transmission constraints of the replacement resource and provides replacement resources with a class average rating even if it were not historically available.[467] COMPP argues that existing Tariff provisions that prevent Capacity Resources from participating in the Auction or being included in a FRAP if they are on outages expected to last 90 or more days of the first 120 Calendar Days in the Planning Year is not a creature of intentional physical withholding but rather the result of litigation stemming from resources committing capacity, getting paid to provide capacity, and then going on outage for an extended period and not being available for MISO dispatch. COMPP suggests that MISO's proposal would allow resources to commit capacity despite advanced knowledge of being unavailable for more than one-third of a Season and reinstate a similar flaw to its previously fixed construct.[468]

290. Several entities argue that MISO has not justified requiring replacement of capacity for outages lasting more than 31 days in a Season.[469] The Louisiana Commission suggests that the 31 day cutoff is random and imposes a discriminatory impact on generating units that require regular maintenance exceeding 31 days.[470] COMPP argues that MISO's blanket 31 day availability exemption is inconsistent with MISO's stated objectives of better aligning resource commitments with periods of

[465] OMS Comments at 4.

[466] Clean Energy Coalition Protest at 16.

[467] *Id.* at 17.

[468] COMPP Protest at 9 (citing 2020 Summer Outage Order, 170 FERC ¶ 61,066).

[469] Mississippi Commission Protest at 7-8; MISO TOs Comments at 7; Louisiana Commission Protest at 3-4; Duke Energy Comments at 7-8; COMPP Protest at 10; Entergy Coalition Protest at 15; Midwest TDUs Protest at 26; IPL Protest at 3.

[470] Louisiana Commission Protest at 3-4.

resource availability.[471] COMPP recommends instead that the Commission preclude Capacity Resources from committing capacity to a Season in which a planned or forced outage is expected to exceed 20 days, and to provide a physical withholding exemption to Capacity Resources unavailable due to a planned or forced outage for 20 days or more in each Season. Alternatively, COMPP proposes that the Commission install eligibility rules that permit outages for 40 days in the Spring and Fall, and 20 days in the Winter and Summer.[472] Entergy Coalition contends that MISO has not provided any support, explanation or demonstration for its claim that planned outages more than 31 days in duration are causing system reliability issues. Entergy Coalition has requested MISO provide this type of analysis, but MISO has yet to do so.[473] IPL proposes that the 31-day threshold be changed to 45-days.[474]

291. MISO TOs contend that the accelerated timeframe of developing MISO's proposal did not allow for a complete assessment of modeling the expected extended planned outages and simulation of the Auction to indicate the amount of capacity available for capacity replacement transactions.[475] MISO TOs state that resource owners who are short of capacity will have approximately eight months to add capacity, and that it is unclear whether market participants will "reserve" capacity for replacement or rely on the capacity market, which may be short.[476] MISO TOs assert that explicit Tariff language is necessary for market participants to incorporate the risk of replacement capacity within capacity offers without the reservation being treated as withholding.

292. Midwest TDUs, MISO TOs, and Entergy argue that, if an outage is planned in accordance with the Tariff to receive an outage exemption, then there is no reason to assume that the planned outage will materially increase system reliability risk and therefore, it is unreasonable to penalize the resource.[477] Midwest TDUs add that MISO's proposed requirements for Planned Outage exemptions for accreditation purposes do not include any 31-day limit, yet MISO proposes to subject such resources to replacement

[471] COMPP Protest at 10.

[472] *Id.* at 12.

[473] Entergy Coalition Protest at 15.

[474] IPL Protest at 3.

[475] MISO TOs Comments at 7.

[476] *Id.* at 8.

[477] Midwest TDUs Protest at 26-27; MISO TOs Comments at 7; Entergy Coalition Protest at 16-17.

capacity requirements and associated penalties, even if they schedule planned maintenance more than 120 days in advance and during times of adequate maintenance margin.[478]

293. Entergy Coalition and Midwest TDUs contend that planned outages that exceed 31 days can provide efficiencies and benefits that cannot be realized by shorter duration outages.[479] Entergy Coalition states that, based on its experience with steam units, for example, 7-10 days of the outage is associated with a cool down time required for the turning gear before primary maintenance work can start, and a 2-3 day post-outage start-up preparation. Entergy Coalition explains that this means that 29% to 42% of the 31-day planned outage period would be consumed by complying with original equipment manager asset protection guidelines instead of performing primary maintenance activities.[480] Entergy Coalition states that, in contrast, if a planned outage period longer than 31 days is used, then a higher percentage of the outage period is being used to perform primary maintenance work instead of prep-work and post-outage startup tasks. Entergy Coalition states that MISO's more-than-31-days outage rule is at odds with industry experience and will restrict generation owners' ability to perform necessary planned maintenance activities in the most cost-effective manner.[481] Midwest TDUs argue that imposition of the capacity replacement requirement is inconsistent with the basis for MISO's Planning Reserve Margin, as MISO's Tariff expressly requires MISO to consider long outages when it sets the Planning Reserve Margin applied to LSEs. Midwest TDUs contend that, because the Planning Reserve Margin is set at a level to assure sufficient capacity to cover long outages, it is unnecessary and inappropriate to additionally require a resource experiencing an extended planned outage to replace that resource or pay Capacity Replacement Non-Compliance Charges. Midwest TDUs state that MISO's filing does not justify the need to procurement of capacity above and beyond the amount MISO determined was required in establishing its Planning Reserve Margin.[482]

294. Others allege that the lack of a robust and transparent bilateral market for replacing ZRCs create the potential for the exercise of market power.[483] Ameren states

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[478] Midwest TDUs Protest at 26.

[479] Entergy Coalition Protest at 17; Midwest TDUs Protest at 26.

[480] Entergy Coalition Protest at 17.

[481] *Id.* at 17-18.

[482] Midwest TDUs Protest at 27.

[483] Ameren Protest at 6; Midwest TDUs Protest at 34.

that, while MISO's proposal assumes there is a robust and liquid market for replacement capacity, Ameren's experience in finding replacement capacity under the current construct is already challenging because liquidity is often low. Ameren submits that it has no confidence that moving to a shorter period to find replacement capacity will improve liquidity or that there will be interest in selling replacement capacity for days and not weeks or months. Ameren argues that MISO fails to acknowledge the lack of liquidity in the bilateral replacement market and thus the potential for the exercise of market power. [484] Midwest TDUs add that the limitation to procure replacement capacity to capacity deliverable to the same Zone raises market power concerns, as well. [485]

295. East Texas asserts that MISO has not justified the new capacity replacement requirements for facilities with planned outages greater than 31 days, nor why such an approach would not provide incentives for owners with a planned extended outage to simply withhold the unit from the seasonal auction, thereby artificially tightening the planning margin. [486]

296. Entergy Coalition argues that MISO's proposal systematically and unreasonably penalizes nuclear resources. Entergy Coalition submits that MISO's own data provided in the stakeholder process shows that over 50% of historic nuclear planned outages exceed 31 days. [487] Entergy Coalition states that focused outages at nuclear plants make these plants even more efficient because they offer the opportunity to perform maintenance that would be more difficult if the plant remained online, and that by conducting inspections and performing maintenance at the same time as refueling, workers can eliminate the need to power down the plant at other times to perform the same work. Entergy Coalition states that this allows nuclear plants to produce electricity continuously for months and even years at a time—a feature no other electricity source provides. [488]

297. Energy Coalition states that it is concerned that MISO's proposal will create additional risks of supply shortfalls and CONE pricing because it allows generation owners to withhold a resource from a Season's Auction if that resource is scheduled to have a planned outage that exceeds 31 days during that Season. Entergy Coalition further states that in addition to concerns about supply shortfalls and elevated CONE pricing, it

[484] Ameren Protest at 6.

[485] Midwest TDUs Protest at 33.

[486] East Texas Protest at 9-10.

[487] Entergy Coalition Protest at 16-17.

[488] *Id.*

is also concerned that the auction withholding option may allow some market participants to manipulate Auction clearing prices and result in less generation being available to meet system reliability needs.[489]

298. Midwest TDUs submit that MISO's Tariff language is inconsistent with its proposal as described. As one example, Midwest TDUs note that MISO explains that Capacity Replacement Non-Compliance Charges apply when a resource exceeds the 31-day outages threshold and fails to replace the ZRCs associated with those days; however, elsewhere in the same proposed Tariff provision, MISO states that "ZRC replacement shall have no impact on settlements from the [Auction] and FRAPs, including any assessed Capacity Replacement Non-Compliance Charges."[490] Midwest TDUs assert that this wording suggests that capacity replacements "have no impact" on Capacity Replacement Non-Compliance Charges, contrary to other proposed language in the Tariff and the purpose of the charge.[491]

299. Midwest TDUs assert that MISO's proposal is arbitrary in that it treats outages differently depending on whether they occur in a single Season or span across Seasons. According to Midwest TDUs, a 32-day planned outage in one Season would be treated more harshly than a 60-day planned outage that falls evenly across two Seasons. Midwest TDUs argue that this distinction creates perverse incentives for resources to seek to schedule planned outages to fall over two Seasons, which could undermine MISO's reliability goals. Midwest TDUs contend that this is particularly discriminatory with respect to smaller LSEs. Midwest TDUs state that smaller LSEs tend to participate as minority owners in larger plants to take advantage of economies of scale, and that minority interest may constitute a significant portion of its resource portfolio. Midwest TDUs add that the majority owner typically has authority to operate the resource and schedule planned outages, and minority owners generally have no control over planned outage scheduling. Midwest TDUs state that MISO's proposal could impose harsh penalties and disproportionate burdens on smaller LSEs based on factors beyond their control.[492]

300. Midwest TDUs state that MISO's filing exposes LSEs to additional burdens and charges when their resources are unavailable due to planned or reasonably anticipated unplanned outages exceeding 31 days in a Season, regardless of whether the LSE had a

[489] *Id.* at 18.

[490] Midwest TDUs Protest at 25 (citing MISO, FERC Electric Tariff, Module E-1 § 69A.3.1.h.b.i (39.0.0) (proposed)).

[491] *Id.*

[492] *Id.* at 27-28.

choice in the matter. Midwest TDUs submit that this proposal would effectively remove such an LSE from the benefits of MISO's reserve-sharing pool, contrary to long-established precedent. Midwest TDUs argue that MISO frequently touts the benefits of reserve sharing, yet MISO's proposal leaves an LSE to fend for itself when it faces outages in excess of 31 days in a Season.[493]

301. Midwest TDUs contends that nothing in MISO's proposed Tariff provides any information about how MISO will distinguish unplanned outages that are subject to the capacity replacement obligation from those that are not. Midwest TDUs contend that the Commission should direct MISO to include all significant elements of its proposal in the Tariff itself.[494] Midwest TDUs add that MISO proposes to replace existing physical withholding provisions, found in section 64.1.1.g.xi of the Tariff, with one stating that a Market Participant submitting an outage for greater than 31 days of a Season can ask the Market Monitor for a determination ahead of the Auction allowing it to forego offering excess ZRCs from the resource without being deemed to have engaged in physical withholding. Midwest TDUs state that neither MISO's proposed Tariff language nor its filing explains what criteria the Market Monitor will use to make this determination. Midwest TDUs argue that this information should be included in the Tariff because the outcome of this determination may be relevant to the decision on whether and when to take a planned outage that exceeds 31 days.[495]

302. Some entities argue that it may be difficult for resources to replace their capacity. Midwest TDUs state that even if the resource has sufficient notice of an outage exceeding 31 days within a Season such that it could seek to line up replacement capacity in advance of the Auction, the resource may be competing with those seeking ZRCs for a full Season, rather than a more limited period. Midwest TDUs further state that, because replacement ZRCs must be from a resource that is not scheduled for a planned outage during the period when the resources at issue needs to be replaced, the replacement process is more complicated because maintenance schedules are confidential.[496] IPL contends that market participants should be authorized to hold some reasonable quantity of capacity as a reserve or hedge against non-performance of a cleared capacity to avoid non-performance penalties. IPL contends that a safe harbor percentage above the

[493] *Id.* at 28-29.

[494] *Id.* at 45-46.

[495] *Id.* at 46-47.

[496] *Id.* at 33-34.

existing 50 MW physical withholding threshold quantity for Planning Resources designated to satisfy resource adequacy requirements should be authorized.[497]

303. Midwest TDUs contend that MISO's replacement capacity requirement for resources with outages exceeding 31 days in a Season penalizes the resource owner when combined with the proposed accreditation rules, creating a "double-whammy" effect. Midwest TDUs state that, unless the outage is exempted, a planned outage exceeding 31 days could both: (1) trigger Capacity Replacement Non-Compliance Charges if the capacity is not replaced; and (2) impact future accreditation, particularly if the resource was not available during RA Hours. Midwest TDUs explain that, on top of paying Capacity Replacement Non-Compliance Charges, a resource subject to a planned outage exceeding 31 days in a Season that did not satisfy accreditation exemption requirements would be deemed unavailable during the outage period, thus reducing its accredited capacity for that Season for the next three years. Midwest TDUs state that an unplanned outage that MISO retrospectively deems could have been reasonably anticipated would never qualify for a Tier 2 Planned Outage exemption for accreditation purpose and thus would always impact accreditation if such an outage happens to occur in an RA Hour.[498] Midwest TDUs argue that resources experiencing an extended outage should be able to avoid adverse impacts on accreditation if they replace the capacity. Midwest TDUs state that Seasonal RA Hours will exclude Tier 2 Planned Outage exemptions, as well as periods where the resource was not committed for capacity under Module E-1 of the Tariff. Midwest TDUs state that this could be read to exclude from RA Hours the period where a Capacity Resource on a non-exempt outage beyond 31 days had, by securing a replacement, transferred its commitment for the relevant period to the replacement resource, so the resource at issue was not considered "committed capacity" for that period. Midwest TDUs state that, if MISO intends for these provisions to protect against adverse accreditation impacts for resources on extended outage that procure replacement resources, MISO should be required to revise them to clarify. Midwest TDUs contend that the Tariff should expressly describe the relationship between replaced capacity and Schedule 53's accreditation calculation, as well as consistently include the unplanned outages to which MISO proposes to apply the capacity replacement requirements.[499] IPL agrees that, if a Capacity Replacement Non-Compliance Charge has been assessed, then there should be no further penalty.[500]

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[497] IPL Protest at 6.

[498] Midwest TDUs Protest at 35-36.

[499] *Id.* at 36-37.

[500] IPL Protest at 3.

c. MISO February 10 Answer

304. In response to arguments against MISO's proposal to require replacement for any Planning Resource that will be on planned outage or planned derate for more than 31 days in a Season, MISO asserts that an after the fact review of MaxGen Events often shows the significant contribution of planned and maintenance outages to unit unavailability during times of realized LOLE risk—typically from many resources designated to satisfy resource adequacy requirements. MISO states that it originally proposed a requirement that would bar Auction participation for resources that expect to be on outage more than 30 days in a Season, which mirrored the provision added to the Tariff in 2020 that a resource not be on planned outage more than 90 days of the first 120 days of the Planning Year. MISO states that a number of stakeholders sought flexibility in Auction participation and outage planning, opposing the prohibition of participation and instead suggesting a capacity replacement requirement with a corresponding financial penalty, a proposal which MISO adopted from stakeholders.[501]

305. In response to arguments regarding the proposed Capacity Replacement Non-Compliance Charge, MISO states that the Capacity Replacement Non-Compliance Charges is modeled on the GVTC Deferral Non-Compliance Charge that was accepted by the Commission in 2016.[502]

306. MISO disputes COMPP's argument that a threshold of 20 days in each Season or up to 40 days in the Spring and Fall would be reasonable, arguing that MISO has experienced more MaxGen Events in the shoulder Seasons than it has in the Summer and that a 31-day threshold provides a reasonable amount of flexibility in a Season for resources to take needed planned and maintenance outages. In response to IPL's argument that the threshold should be 45 days, MISO asserts that the proposed requirement is 31 days in a Season and that there is no proposed restriction to arbitrarily limit outages from spanning more than one Season, a method which could be used to accommodate longer outages while still incentivizing capacity designated to satisfy resource adequacy requirements in a Season to be available for most of that Season.[503]

307. In response to Midwest TDU's argument that MISO is imposing Capacity Replacement Non-Compliance charges on LSEs, MISO notes that this is only the case when an LSE owns the resource that fails to replace or has obtained contractual rights to the capacity and submitted its ZRCs via a FRAP such that MISO is not settling capacity

[501] MISO February 10 Answer at 9-10.

[502] *Id.* at 11 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 154 FERC ¶ 61,094 (2016)).

[503] *Id.* at 12.

charges and credits with the owner of the resource directly. MISO asserts that this is just and reasonable, as the proposed capacity replacement requirement is aligned with the interest of LSEs by helping them demonstrate that they will have access to the capacity needed to meet resource adequacy requirements in line with the one-day-in-10-year reliability planning standard. MISO states that requiring LSEs to pay for the procurement of resources that expect to, or later decide to, become largely unavailable during the Season is inconsistent with the proposed resource adequacy reforms in the SAC filing, which seek to ensure sufficient resources will be available during times of need.[504] MISO further adds that, despite Midwest TDU's assertion that MISO's existing Tariff, which states "ZRC replacement shall have no impact on settlements from the [Auction]," is inconsistent and made confusing with the addition of Capacity Replacement Non-Compliance Charges, the original and enduring meaning of this language is that the settlement of capacity charges and credits will remain with the original Market Participant whose ZRCs are being replaced. MISO states that the financial obligation will not be shifted to a different market participant, where applicable, that registered the uncleared resource used to replace the originally designated resource.[505]

308. MISO states that, in response to comments from Midwest TDUs related to outage modeling in the annual LOLE study, MISO notes that, while the LOLE study does account for historical planned outages, the study largely optimizes their timing to have little impact to LOLE. MISO adds that the study does not account for future resource behavior that deviates from the 5-year historical average used in LOLE. MISO states that the proposed outage provisions, including the exemptions and replacement requirements, further close a gap in the current rules to create incentives for market participants to optimize planned outages and their impacts to reliability and resource adequacy. MISO states that an accredited unit with high historical availability, such as a nuclear unit, can clear in a Season in which it plans to be on a refueling outage and still be relied upon to meet the Reserve Requirements even though it will not be available when needed. MISO states that in such a situation, it is reasonable for the resource not to clear, to fit the outage within the 31-day threshold, or to replace the ZRCs for outage periods exceeding the threshold.[506]

309. Regarding too many resources potentially seeking outages in the Spring and Fall, MISO states that it has shown Reserve Requirement targets tend to be significantly lower than the status quo annual Reserve Requirements that is currently enforced all year. MISO asserts that its analysis has shown that its proposed resource adequacy

[504] *Id.*

[505] *Id.* at 13.

[506] *Id.*

enhancements will result in lower Reserve Requirements and higher aggregate excess Planning Reserve Margins outside the Summer Season, which should provide significant amounts of uncleared ZRCs for use as replacement capacity where supply is in excess of the capacity needed.[507]

310. In response to concerns about a "double whammy," MISO notes that the Capacity Replacement Non-Compliance Charge applies when a resource designated for resource adequacy submits planned outages greater than 31 days in a Season, thus depriving LSEs from the benefit of the availability procured in the Auction. MISO adds that accreditation impacts for Schedule 53 Resources are about future expectations of resource availability, noting that if the outage is submitted with lengthy notice and if the outage is sufficiently coordinated, then the fact that the resource is not available during a planned outage will not impact accreditation. MISO states that, in contrast, if an outage is submitted with short notice or during a time when too many MW of capacity have already submitted outages, then it is reasonable to consider how the insufficiently coordinated planned outage might help predict future resource availability. MISO argues that it does not propose exemptions for unplanned outages since, by definition, unplanned outages are not timely or coordinated to ensure sufficient Maintenance Margin. Further, MISO notes that resources that have been replaced are not designated for resource adequacy and Schedule 53 has language explicitly excluding those hours in Tier 1 and Tier 2 of the SAC calculations.[508]

311. MISO argues that its proposal does not need to allow a percentage of seasonal capacity to be held in reserve for replacement capacity purposes and would not create an artificial supply shortage. MISO suggests that predetermining a percentage of seasonal capacity to be held in reserve could lead to some Zones in certain Seasons being short capacity and having to pay CONE.[509]

312. MISO states that its proposed Tariff revisions do not violate the rule of reason, nor is a Generation Outage that was not planned but was known or could have been reasonably anticipated at the time of the Auction a term or condition of service that must be included in the Tariff. MISO states that, consistent with Commission precedent, MISO's determination of what entails Generation Outages that were not planned but were known or could have reasonably anticipated are correctly viewed as implementation details that may be properly included in MISO's BPM rather than the Tariff. MISO

[507] *Id.* at 14-15.

[508] *Id.* at 15-16.

[509] *Id.* at 41.

contends that the rule of reason states that only those provisions significantly affecting rates, terms, and conditions of service must be filed for Commission approval.[510]

313. In response to Midwest TDUs' argument that neither the proposed Tariff language nor MISO's filing explain what criteria the Market Monitor will use to determine whether a resource that has submitted an outage for greater than 31 days of a Season has engaged in physical withholding, MISO states that, while the section referenced by Midwest TDUs, section 64.1.1.g.xi of the Tariff, does not contain the criteria for determining when resources will have been deemed to have engaged in physical withholding, those thresholds are contained elsewhere in Section 64.1.1.1, and there is no reason to include them again in Section 64.1.1.g.xi.[511]

d. Answers to MISO February 10 Answer

314. Entergy argues that MISO's answer did not address its concerns. Entergy states that planned outages provide some contribution towards periods of elevated LOLE risk but argues that MISO has not shown that planned outages exceeding 31 days are a source of higher system risk.[512] Entergy argues that describing nuclear units as "not being available when needed" because of refueling is flawed. Entergy argues that, if a non-nuclear generating unit were to take a 30-day planned outage every Season over a 2-year period it, would be unavailable for 240 days in total and this unit would not be subject to any capacity replacement requirements under MISO's SAC proposal. Entergy then argues that, if a nuclear unit were offline only once over this same 2-year period for a 40-day planned refueling outage, MISO argues that the unit is "not available when needed" and would subject the resource owner to the replacement capacity requirement, even though the unit was available for 200 more days over the 2-year period than the unit in the first example which was not subject to any capacity replacement requirements.[513] Entergy then argues that by conducting inspections and performing maintenance at nuclear plants at the same time as refueling eliminates the need to power down the nuclear plant at other times to perform the same work.[514] Entergy argues that MISO's

[510] *Id.* at 47 (citing *City of Cleveland*, 773 F.2d at 1376).

[511] *Id.* at 48.

[512] Entergy Answer at 8.

[513] *Id.* at 9.

[514] *Id.* at 9-10.

planned outage proposal is unjust and unreasonable and that MISO has not justified the application of the more-than-31-days proposal to nuclear plants.[515]

315. Midwest TDUs argue that MISO fails to demonstrate the just and reasonableness of its capacity replacement proposal as applied to planned outages.[516] Midwest TDUs assert that MISO's characterization of its proposal as "mirror[ing]" the prohibition of planned outages extending more than 90 of the first 120 days of the Planning Year overlooks that it only applies to extended outages planned for the Summer Season in a resource adequacy construct that is singularly focused on the resources needed during that specific period.[517] Midwest TDUs claim that MISO's proposed 31-day seasonal capacity replacement obligation would significantly burden or penalize shorter planned outages.[518] Midwest TDUs state that MISO's 90-day threshold for banning Summer peak period planned outages highlight the unreasonableness of the 31-day limitation, and that MISO should encourage longer outages that may be necessary to maintain resources in good working order with high availability.[519] Midwest TDUs also argue that MISO's suggestion to schedule longer outages across Seasons creates incentives for scheduling longer outages into the Summer and Winter Seasons to the maximum extent permitted by the Maintenance Margin despite the higher risk, rather than scheduling in other Seasons.[520] According to Midwest TDUs, MISO's suggestion that resources not participate in the Auction for an entire Season if they have a 32-day planned outage artificially reduces the resources MISO can call upon to meet MaxGen Events.[521]

316. Midwest TDUs argue that MISO fails to explain its proposal's inconsistency with the basis for its Planning Reserve Margin and reserve sharing fundamentals.[522] Midwest TDUs assert that the MISO Tariff already considers long outages when establishing Reserve Margins and that MISO fails to demonstrate the need for additional capacity procurement, especially when the LOLE study accounts for historical planned outages by

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[515] *Id.* at 10.

[516] Midwest TDUs Answer at 13.

[517] *Id.* at 14.

[518] *Id.* at 15.

[519] *Id.*

[520] *Id.* at 16 (citing MISO February 10 Answer at 12)

[521] *Id.* at 16-17.

[522] *Id.* at 17.

using a 5-year historical average.[523] Midwest TDUs state that MISO attempts to discount the LOLE study factors by describing the LOLE study as optimizing the timing of planned outages to have little impact on LOLE, but according to Midwest TDUs, MISO fails to account for recent improvements to its LOLE study methodology as well as its obligation to accurately account for planned outages.[524] Midwest TDUs claim that MISO's capacity replacement proposal would require procurement that would produce availability far exceeding the historical availability on which the Reserve Requirement targets are based.[525] Midwest TDUs also state that MISO fails to acknowledge the concern that its capacity replacement proposal effectively eliminates LSEs' benefits of MISO's reserve sharing pool.[526]

317. According to Midwest TDUs, MISO fails to acknowledge concerns that replacement is not a realistic option for planned outages, especially for smaller LSEs.[527] Midwest TDUs assert that MISO also did not address concerns about the potential for exercise of market power in the bilateral market.[528] Midwest TDUs claim that, contrary to MISO's assertion that plenty of replacement capacity will be available outside the Summer Season, MISO's analyses show that securing capacity replacement during non-Summer Seasons will not be easy and that Spring may be very challenging.[529]

318. Midwest TDUs argue that MISO fails to meet its burden that its replacement capacity and related non-compliance charge proposal is just and reasonable.[530] For example, Midwest TDUs state that MISO fails to justify imposing a capacity replacement obligation on unplanned outages greater than 31 days, given the lack of Tariff parameters or procedures governing how the Market Monitor will make a subject determination as to whether an outage could have been reasonably anticipated.[531] Midwest TDUs assert that

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[523] *Id.*

[524] *Id.* at 18.

[525] *Id.* at 19.

[526] *Id.*

[527] *Id.* at 20-21.

[528] *Id.* at 21.

[529] *Id.* at 22.

[530] *Id.* at 24.

[531] *Id.* at 23.

MISO's explanation that such implementation details may be included in the BPMs "flies in the face of the Commission's FPA Section 205 obligation to ensure just and reasonable rates."[532] Midwest TDUs also assert that MISO does not address how applying a capacity replacement obligation "after-the-fact" on such unplanned outages nullifies the opportunity to replace that capacity.[533] Midwest TDUs claim that MISO never explains why an appropriately planned 28-day outage should be subjected to a replacement requirement if the resource incurs a four-day unplanned outage in that same Season.[534] According to Midwest TDUs, MISO's proposal is an unavoidable Capacity Replacement Non-Compliance Charge penalty, even assuming capacity replacement was realistic in the planned outage context.[535]

319. Midwest TDUs argue that MISO's proposed Tariff revisions will not work as intended, and that the Commission should require corrections and clarifications to the Tariff.[536] Regarding the treatment of replacement capacity that has been secured, Midwest TDUs state that MISO fails to clarify the impact on Capacity Replacement Non-Compliance Charges.[537] Midwest TDUs also state that MISO intends to treat a resource that has been replaced as not designated for resource adequacy during that period, however MISO refers to language that excludes resources not designated for resource adequacy from the accreditation calculation, but does not make the connection between such exclusion and successful capacity replacement.[538]

e. Deficiency Letter Response and Responsive Pleadings

320. In response to a question requesting additional support for the Capacity Replacement Non-Compliance penalty value, MISO states that it is appropriate to model the penalty after ICAP Deferral Non-Compliance Charge because a resource that offers

[532] *Id.*

[533] *Id.*

[534] *Id.* at 24.

[535] *Id.*

[536] *Id.*

[537] *Id.* at 25.

[538] *Id.* at 25-26.

and clears capacity for a Season but then chooses not to make it available for much of that Season should forfeit the capacity revenues received.[539]

321. In response to a question regarding the relationship between MISO's proposed Capacity Replacement Non-Compliance Charge and MISO's LOLE studies, MISO states that the results of LOLE studies would largely remain the same as current LOLE studies assume the use of replacement capacity for all outages, not just those over 31 days. MISO states that under its proposal, where a resource clears for a Season but decides to go on planned outage for greater than 31 days in that Season, the obligation to replace or pay a non-compliance charge creates incentives for the Market Participant to provide the availability the resource was otherwise cleared to supply. MISO submits that this helps ensure the Reserve Requirement planning targets are being satisfied.[540]

322. In response to a question regarding whether the Capacity Replacement Non-Compliance Charge may incent withholding resources as a hedge against the penalty, MISO states that it has no intention to disincentivize participation in the bilateral markets. MISO states that it is reasonable to expect that bilateral trading for replacement capacity will be much more robust under the new construct than it is today. MISO adds that its models indicate that the move to seasonal Auctions will result in nearly double the amount of uncleared ZRCs in non-Summer Seasons, providing liquidity to the market for replacement capacity.[541]

323. In response to a question asking MISO to describe the expected methodology that the Market Monitor will employ to determine whether unplanned outages could be reasonably anticipated at the time of the Auction, MISO states that the proposed Tariff language indicates that details necessary to implement the capacity replacement requirement will be included in the Market Monitoring and Mitigation BPM, which MISO believes to be the appropriate place.[542]

324. MISO's Deficiency Letter Response clarifies that the availability of replacement resources does not contribute to the SAC value for the replaced resource but does contribute to the Tier 1 and Tier 2 SAC value of the replacement resource. MISO states that Schedule 53 only considers offers during times when a resource was designated for

[539] MISO Deficiency Letter Response at 27.

[540] *Id.*

[541] *Id.* at 27-28.

[542] *Id.* at 29.

resource adequacy, and when a resource is replaced it is no longer designated for resource adequacy as that obligation has been transferred to the replacement resource.[543]

325. Midwest TDUs argue that MISO has not provided sufficient clarity that resources designated for RAR but later replaced are considered by MISO as not designated for RAR. Midwest TDUs argue that this ambiguity is amplified by other confusing Tariff language related to capacity replacement. Midwest TDUs state that Tariff language suggesting that ZRC replacement shall have no impact on settlements from the Auction and FRAP, including any Capacity Replacement Non-Compliance Charge suggests that capacity replacement may not protect a resource on a greater than 31-day outage from Capacity Replacement Non-Compliance Charges. Midwest TDUs state that it is not reasonable to include Tariff language regarding the effect of capacity replacement on Capacity Replacement Non-Compliance Charges that can be read in a manner contrary to other proposed language.[544]

326. Midwest TDUs suggest that MISO's Deficiency Letter Response reinforces concerns about the practicality and consequences of MISO's proposed capacity replacement provisions. Midwest TDUs argue that MISO's proposal may incent resources to not offer excess ZRCs into the bilateral market as a hedge against the penalty. Midwest TDUs argue that MISO has provided no evidence that today's limited, non-transparent bilateral market will become robust and therefore make capacity replacement feasible.[545]

327. Midwest TDUs argue that MISO has provided no guidance on how it would have the Market Monitor make the determination that an unplanned outage could have reasonably been anticipated at the time of the Auction. Midwest TDUs allege that MISO fails to explain why broad considerations for such a determination are not included in the Tariff and instead simply asserts that it believes the BPM to be the appropriate place. Midwest TDUs contend that MISO's unsupported belief cannot trump the FPA and well-established Commission policies.[546] Duke Energy further requests that the Commission direct MISO to document, prior to the next outage, how the Market Monitor will determine whether unplanned outages could have been reasonably anticipated at the time of the Auction. Duke Energy submits that it is imperative that market participants understand in advance of the auction how reasonably anticipated unplanned outages will

[543] *Id.*

[544] Midwest TDUs Response to MISO Deficiency Letter Response at 15.

[545] *Id.* at 16-20.

[546] *Id.* at 23 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,251, at P 89 (2004)).

be determined, yet MISO makes no commitment as to the timing of the stakeholder process to clarify this important detail.[547]

328. Midwest TDUs state that MISO's response on the relationship between LOLE studies and the Capacity Replacement Non-Compliance provision demonstrates that MISO is not proposing to change the LOLE analysis to account for its new requirement. Midwest TDUs add that MISO's response suggests that it conducts its current LOLE studies on the assumption that all capacity will be replaced, meaning, according to Midwest TDUs, that MISO's current LOLE analysis somehow simulates the case in which capacity beyond the Planning Reserve Margin is available to backfill any outages, even though that capacity is not committed to do so. Midwest TDUs submits that MISO's response makes it unclear whether its LOLE studies are appropriately determining the Planning Reserve Margins needed to achieve MISO's reliability targets.[548] Midwest TDUs state that, if MISO's response is accurate, it would suggest that MISO has been mismanaging its resource adequacy construct because it has failed to require the capacity replacement that is presumed in the LOLE analysis, which in turn determines the Reserve Margin. Midwest TDUs state that it logically cannot be the case that the current LOLE analysis formulation yields the correct Planning Reserve Margin under both: (1) its current Tariff, in which no capacity replacement obligation is imposed for any planned or unplanned outages; and (2) its proposed Tariff, in which capacity replacement is required for a subset of outages. Midwest TDUs concludes that as a result, MISO's description of its LOLE process cannot support the justness and reasonableness of its capacity replacement proposal.[549]

329. Entergy argues that the Capacity Replacement Non-Compliance Charge creates incentives for market participants to not offer excess capacity into the bilateral capacity market to ensure they have a hedge against the risk that an extended outage could subject their own resources to the Capacity Replacement Non-Compliance Charge. Entergy states that the end result could be a very weak bilateral capacity replacement market, making it difficult for market participants to shore up capacity, leaving some generators with no choice but to pay the Capacity Replacement Non-Compliance Charge.[550]

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[547] Duke Energy Response to MISO Deficiency Letter Response at 3.

[548] Midwest TDUs Response to MISO Deficiency Letter Response at 25-26.

[549] *Id.* at 26.

[550] Entergy Response to MISO Deficiency Letter Response at 7-8.

f. MISO May 20 Answer to Responsive Pleadings

330. MISO states that it provided support that its capacity replacement obligation improves resource adequacy while setting Reserve Requirement targets specific to each Season which are expected to increase the amount of uncleared ZRCs that can be used for replacement in most Seasons and locations. MISO states that where uncleared ZRCs are not available, it is even more important that capacity designated for resource adequacy not be unavailable for greater than 31 days in a Season for reasons that can be controlled. MISO states that the capacity replacement obligation is not only feasible, it exists and is required under the current Tariff for suspended and retired units and is an option for units that suffer a catastrophic outage.[551]

331. MISO states that it has established its Capacity Replacement Non-Compliance charge as just and reasonable. MISO explains that this charge was requested by the Market Monitor to disincentivize ZRC offers from resources that were not expected to be available for a significant portion of the Season. MISO states that requiring LSEs to pay for the procurement of resources that expect to, or later decide to, become largely unavailable during the Season is inconsistent with the proposed resource adequacy reforms in the filing.[552]

332. MISO states that it has worked with the Market Monitor to draft language that will be included in the BPM for Market Monitoring and Mitigation that addresses the application of capacity replacement obligations to unplanned outages. MISO states that the language is intended to protect against ZRCs being offered that are not reasonably expected to be available. MISO states that the proposed language will be added to section 5.15 of the BPM and reads:

> Resources that clear in a given [Auction], and subsequently are in full or partial unplanned (i.e., urgent, emergency, or forced) outages or derates below their commitment amount for more than 31 days in a Season and were not replaced with uncleared ZRCs must submit documentation of such circumstances to the [Market Monitor]. [Market Monitor] review of the documentation seeks to determine if the outage/derate durations could have been reasonably expected at the time of the closing of the [Auction]. If the outage/derate durations in the judgement of the [Market Monitor] could have been reasonably expected, a Capacity Replacement Non-Compliance Charge may be assessed by the

[551] MISO May 20 Answer at 11-12.

[552] *Id.* at 14-15.

> Transmission Provider pursuant to the Tariff. This provision applies to changes in equipment status, operation limitations and/or resource reliability known prior to the closing of the [Auction] window but are too recent to be captured in the last three (3) years of history of the applicable Season used in the Seasonal Accredited Capacity Calculations. One example of such a case would be a participant who offered and cleared a generation resource in the [Auction] for the summer season despite knowing that the generator would be unavailable to that offer amount for most of the summer after suffering a substantial or even catastrophic outage or derate prior to the closing of the [Auction] window.
>
> If prior to the [Auction], a Market Participant does not have a reasonable expectation that outages or derates will be less than 32 days in the Season, it can request an exemption of the capacity in question per the Tariff (Section 66.1.1.g.xi) and not include it in a ZRC transaction or FRAP, and not offer it into the [Auction].

MISO states that it believes this level of implementation detail is appropriately included in the BPM.[553]

g. Midwest TDUs June 6 Answer

333. Midwest TDUs argue that MISO's May 20 Answer does not justify requiring capacity replacement in situations where outages exceed the 31-day threshold due to, in whole or in part, unplanned outages deemed reasonably anticipatable. Midwest TDUs further contend that MISO's May 20 Answer reinforces the filing's fundamental failure to provide any criteria or process governing the Market Monitor's rate-critical determination as to whether an unplanned outage could have been reasonably anticipated. Midwest TDUs argue that, as an initial matter, the draft BPM language provided by MISO belongs in the Tariff, rather than a BPM, because it directly affects rates. Midwest TDUs further argue that the draft language provides no methodology or even broad considerations governing how the Market Monitor is to determine whether an outage could have been reasonably anticipated, instead leaving that determination to the judgment of the Market Monitor. Midwest TDUs contend that the language therefore provides no guidance whatsoever on how the Market Monitor will determine if an

[553] *Id.* at 17-18.

unplanned outage could have been reasonably been anticipated at the time of the Auction.[554]

h. Commission Determination

334. We find MISO's proposed Capacity Replacement Non-Compliance Charge to be just, reasonable, and not unduly discriminatory or preferential. MISO's proposed capacity replacement provisions reflect a reasonable expectation that a Planning Resource receiving capacity payments for a given Season should not be unavailable for a significant portion of that Season. In the 2020 Summer Outage Order, the Commission noted that MISO's Tariff did not, at the time, contemplate consequences for resources that clear the Auction but expected to be unavailable. The Commission found MISO's proposal to preclude resources that are unavailable for 90 days or more of the first 120 days in the Planning Year from participation in the Auction or in a FRAP as a just and reasonable method to ensure that resources do not clear the Auction, receive capacity payments, and are subsequently unavailable for the majority of the Summer, which is MISO's highest risk period.[555] We find that MISO's proposal builds on the provisions accepted by the Commission in the 2020 Summer Outage Order by requiring Planning Resources that will be on a planned outage or derate for more than 31 days in a Season to either not offer into that Season's Auction or to procure replacement capacity for days beyond the 31-day threshold.

335. We find that MISO has demonstrated that the 31-day threshold in a given Season is reasonable. While we recognize that other thresholds could also be just and reasonable, we find that MISO's proposed 31-day threshold appropriately balances providing flexibility to resource owners to plan needed and prudent maintenance and/or requiring a minimum amount of expected future availability to receive capacity payments in a given Season. We also find that MISO has demonstrated that the 31-day threshold reasonably ensures LSEs are receiving the benefits of those resources in the Seasons for which they were procured.

336. We are not persuaded that more time is needed to accommodate resource-owning LSEs. Market participants have had 17 months from the time of the filing to assess the impact of MISO's filing on their business and operating decisions. We find MISO TOs' argument that it is unclear whether market participants will "reserve" capacity for replacement or rely on the capacity market, which may be short, to be speculative. Mitigation provisions that require unused capacity to be offered into the Auction at an economic price prevent such concerns. The only "reserving" would be limited to resources that did not clear in the Auction or external resources, both of which resource

[554] Midwest TDUs June 6 Answer at 6-8.

[555] *See* 2020 Summer Outage Order, 170 FERC ¶ 61,066 at P 37.

owners have always had wide latitude to decide how to use. Similarly, MISO TOs have not demonstrated that it is necessary to allow market participants to incorporate the risk of replacement capacity within their capacity market without being treated as withholding. Doing so would circumvent physical withholding thresholds, would raise market power concerns, and would reduce the amount of resources offered into the Auction, potentially affecting both Auction prices and resource adequacy.

337. Protestors contend that it may be difficult for resource owners to find replacement ZRCs to cover a short time period. As an initial matter, we agree with MISO that, under its proposal, Reserve Requirements will generally be lower in non-Summer Seasons, meaning that resource owners are likely to have excess ZRCs for those Seasons that they are willing to sell as replacement capacity. Moreover, we note that the capacity replacement provisions provide additional flexibility to resource owners that will allow a resource to go on outage for more than 31 days without penalty, if they are able to replace those ZRCs for the time period beyond the 31-day threshold. To the extent that a resource owner believes that it may be unable to find replacement ZRCs for an outage that exceeds 31 days in a Season, the optimal choice for that resource owner may be to forego participation in capacity Auction for that Season. Similarly, we are unpersuaded that MISO's proposal creates market power concerns in bilateral markets to purchase replacement capacity. LSEs have long used bilateral agreements to acquire capacity, including replacement capacity, under MISO's current construct, and nothing in the record indicates that such bilateral contracting will be unavailable during the planning year for capacity replacement for resources on outages exceeding 31 days in a Season.[556]

338. We disagree with arguments that suggest that, if a planned outage receives an exemption for purposes of accreditation, it is unreasonable to penalize that resource if it remains on outage for more than 31 days. We agree with MISO that it is unreasonable for an LSE to be burdened with the full cost of procuring capacity if that Capacity Resource is expected to be, or otherwise becomes, unavailable for more than 31 days in a Season, even if that time period occurs in a period with relatively low reliability risks.

339. Some protestors suggest that restricting a planned outage to 31 days may limit efficiencies gained by longer maintenance periods, leading to increased costs. Although we recognize that resources may vary in their maintenance patterns, we find that MISO's proposal appropriately balances the need for flexibility with the need to ensure that a resource is available for a Season to which it commits. We further find that MISO's capacity replacement provisions afford resource owners sufficient flexibility, as it permits

[556] Currently, Planning Resources with cleared ZRCs that retire, suspend, or are otherwise unable to meet the performance requirements applicable to the Planning Resource must replace the cleared ZRCs with uncleared ZRCs. *See* MISO, FERC Electric Tariff, § 69A.3.1.h (38.0.0).

them to determine whether it is more cost effective to: (1) perform necessary maintenance within the 31-day period; (2) opt out of participating in the capacity market for a Season and perform maintenance over the course of that Season; or (3) perform maintenance for a period longer than 31 days and procure replacement ZRCs for the time period beyond the 31-day threshold. In addition, we note that MISO's proposal permits a resource owner to schedule maintenance straddling two Seasons, which would allow for a resource be on a 62-day outage while still participating fully in both Seasons. This may be particularly useful for resources with longer maintenance periods that are planned far in advance. Similarly, we do not find that MISO's capacity replacement provision unduly discriminates against particular resource types. To the extent that certain resource types require maintenance periods beyond 31 days, we find that it is appropriate for resource owners to determine which option is best for those particular units.

340. We find that it is appropriate for a resource on a planned outage that has not received an exemption that lasts more than 31 days in a Season to both trigger the Capacity Replacement Non-Compliance Charge and to receive a reduction to its capacity accreditation. The proposed Capacity Replacement Non-Compliance Charge and MISO's proposed accreditation exemptions for planned outages serve distinct purposes. As MISO explains, while the capacity replacement provisions are intended to ensure that a resource expected to be unavailable for a significant portion of a Season does not participate in the capacity markets absent the procurement of replacement capacity, MISO's SAC provisions value resources based on their historical availability. We find that it is reasonable to exempt resources that follow MISO's planned outage requirements and receive a Tier 2 exemption from accreditation reductions because there is no reason for that outage to affect future expectations of availability. In contrast, should a resource experience an unplanned outage that lasts longer than 31 days in a Season, it is reasonable for MISO to require that resource to replace the capacity that it is receiving payments for, and, because the outage is unplanned and uncoordinated with MISO, for MISO to adjust its expectations of that resource's future availability and thus reduce its accreditation accordingly.

341. We are not persuaded by Entergy Coalition's argument that MISO's proposal could create additional risks of supply shortfalls. To the contrary, we find that MISO's proposal will help to increase supply availability certainty. Under MISO's current provisions, some Capacity Resources can clear the Auction and receive capacity payments for the entire year even if they expect to be unavailable for 89 days in the Summer. For these units, the capacity payments they receive may not accurately reflect reliability contribution that they bring to MISO. Under MISO's proposal, all market participants will have additional confidence that Capacity Resources that clear the Auction expect to be available for at least 66% of each Season. While this could potentially result in a lower amount of capacity being available to offer into the Auction, we believe that it is critical that MISO be able to depend on such resources, even if such dependability corresponds with fewer resources available for the Auction or FRAPs.

342. We do not find MISO's proposed Tariff language regarding settlements to be inconsistent. As MISO explains, this language explains that the settlement of capacity charges and credits will remain with the original market participants whose ZRCs are being replaced, and that the financial obligation will not be shifted to a different market participant that registered uncleared ZRCs to replace the original Capacity Resource.

343. We disagree that MISO's Tariff should provide further detail regarding MISO's determination as to whether an outage could have been reasonably anticipated. We find, similar to our discussion regarding the "rule of reason" in the above section, that these determinations are implementation details that may be included in the BPM and are consistent with the level of detail of other areas that are found in MISO's Tariff where MISO or Market Monitor has discretion.[557]

4. Stakeholder Engagement

a. MISO Filing

344. MISO states that it has proactively engaged with its stakeholders to develop the proposal and mitigate its resource adequacy challenges.[558] MISO states that stakeholders have passed three motions for MISO to delay the filling, citing the need for additional time to understand MISO's proposal. MISO states that, in response, MISO provided stakeholders with an additional two months to continue discussions. MISO further states that it has modified its proposal in response to stakeholder feedback, including: (1) implementing a transition period to the full 80% Tier 2 weighting; (2) adopting the UCAP/ISAC ratio; and (3) including Auction Clearing Price adjustments during rare circumstances. MISO states that its proposal reasonably accommodates concerns raised in the stakeholder process.[559]

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[557] *See, e.g.*, MISO, FERC Electric Tariff, Module D, § 64.2.2 (31.0.0) ("Pending the development of the capability to use the market models, the [Market Monitor] shall determine the effect on prices of questioned conduct using the best available data and such models and methods, as it shall deem appropriate."); *see also* MISO, FERC Electric Tariff, Module D § 64.1.4.h (65.0.0) ("If cost data or other information submitted by a Market Participant indicates to the satisfaction of the [Market Monitor] that the Reference Levels for that Market Participant should be changed, revised Reference Levels shall be determined, communicated to the Market Participant, and implemented, as soon as practicable.").

[558] MISO Transmittal at 6.

[559] *Id.* at 22-23.

b. Comments and Protests

345. Manitoba Hydro asserts that MISO has made concerted and lengthy efforts to address stakeholder concerns and made several improvements to its original proposal.[560] However, some protestors argue that MISO's proposal is not just and reasonable because MISO did not adequately address stakeholder concerns. The Mississippi Commission contends that MISO has not incorporated stakeholder feedback in its White Papers, and that MISO will use its unvetted White Papers to justify future steps to address a problem that may not exist.[561] According to the Mississippi Commission, MISO has not proactively engaged with stakeholders and MISO has routinely ignored or marginalized concerns raised with the SAC proposal.[562] The Mississippi Commission states that Order No. 719 established four criteria—(1) inclusiveness; (2) fairness in balancing diverse interests; (3) representation of minority interests; and (4) ongoing responsiveness—intended to "balance customers' and other stakeholders' need for effective access to the boards of RTOs and ISOs, with the need for the independent management of each RTO and ISO."[563] The Mississippi Commission argues that MISO ignored stakeholder feedback; therefore, MISO's SAC proposal violates Order No. 719.[564]

346. DTE Electric claims that the proposal was challenged extensively in stakeholder meetings with minimal response from MISO to valid concerns.[565] East Texas states that MISO stakeholders had to evaluate a significant new resource adequacy construct where the details of the proposal were in considerable flux until shortly before this filing was submitted, and, because of this, MISO's proposal still poses a number of conceptual and operational concerns. According to East Texas, nor did MISO provide all of the relevant information to stakeholders so they could scrutinize it and ensure that it would garner the desired benefits.[566] East Texas adds that market participants have not reliably assessed its intended or unintended consequences, let alone the potential cost of those

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[560] Manitoba Hydro Comments at 3.

[561] Mississippi Commission Protest at 9.

[562] *Id*.

[563] *Id*. at 29 (citing *Wholesale Competition in Regions with Organized Elec. Mkts.*, Order No. 719, 125 FERC ¶ 61,071 (2008), *order on reh'g*, Order No. 719-A, 128 FERC ¶ 61,059, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009)).

[564] *Id*.

[565] DTE Electric Protest at 3.

[566] East Texas Protest at 3.

consequences. East Texas asserts that the fundamental problem is that one cannot presently grasp what repercussions MISO's various changes will have on its capacity market, and thus, MISO is unable to establish that its proposal is just and reasonable under section 205 of the FPA.[567]

347. Industrial Customers assert that MISO failed to consider a reasonable modification to MISO's proposal presented by Industrial Customers in the MISO stakeholder process. Industrial Customers state that, within the MISO stakeholder process, they participated in joint End-Use Sector comments to MISO pointing out the same concerns with MISO's proposal that they raise in their protest. Industrial Customers assert that they offered a constructive solution that would allow MISO to move forward with its proposed seasonal allowed calls on LMRs without violating 10 calls per Planning Year, but MISO ignored their suggestion. Industrial Customers argue that MISO's failure to reasonably consider stakeholder feedback (that would have allowed MISO to move forward with the underlying objectives in its proposal) is another reason to reject MISO's proposal in this proceeding.[568]

c. MISO February 10 Answer

348. MISO contends that its filing reflects substantial engagement with stakeholders over the last several years and particularly in 2021, noting that it conducted six workshops, in addition to monthly RASC meetings, in May, August, September, October, and November of 2021. MISO further contends that the proposal was modified in several areas compared to the original proposal based on stakeholder discussions, including: rules related to Auction participation, outage exemptions, converting SAC to UCAP, including offered availability in all hours, and transition provisions, which provide stakeholders three years from the requested effective date to adjust to the proposal.[569]

349. MISO argues that the Commission should dismiss arguments suggesting that MISO violated Commission policy by ignoring stakeholder feedback. MISO argues that nothing in Order No. 719 requires MISO or any other RTO/ISO to implement or take action on any and all issues raised during the stakeholder feedback process. MISO contends that despite the Mississippi Commission's claim that MISO ignored stakeholder feedback, MISO has responded to more than 150 questions, comments, and requests in its Q&A document, held a multitude of stakeholder meetings specifically focused on addressing stakeholder questions and feedback, and has provided a forum for

[567] *Id*.

[568] Industrial Customers Protest at 11-12.

[569] MISO February 10 Answer at 6-7.

stakeholders to provide comments directly to the MISO Board of Directors on multiple occasions.[570]

d. Answers to MISO February 10 Answer

350. WEC Utilities argues that MISO is misleading when using the number of stakeholder meetings as evidence that further stakeholder engagement is not necessary when this is instead evidence of the level of complexity of the proposal and transition.[571] WEC Utilities states that several stakeholder identified issues remain unresolved.[572] WEC Utilities claims that MISO exaggerated the ability of stakeholders to discuss the proposal with the Board of Directors, asserting that such opportunities were limited to public comment periods that did not allow for a constructive dialogue.[573]

351. The Mississippi Commission claims that there was near unanimous opposition to MISO moving forward with the SAC proposal, including four motions against advancing that were approved by stakeholders in the RASC.[574] The Mississippi Commission further contends that MISO focuses on form over function in the stakeholder process.[575] The Mississippi Commission asserts that MISO inaccurately characterizes how their concerns were addressed and notes that they were not presented with any detail to the Board of Directors in a public meeting in 2021.[576] The Mississippi Commission cites the statement in MISO's February 10 Answer that additional stakeholder engagement is necessary prior to implementing the SAC proposal as evidence that the proposal was incomplete.[577]

e. Commission Determination

352. We are not persuaded by protestor arguments that MISO's proposal fails to adequately consider stakeholder concerns expressed in the stakeholder process, as

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[570] *Id.* at 49-50.

[571] WEC Utilities Answer at 2-3.

[572] *Id.* at 3.

[573] *Id.*

[574] Mississippi Commission Answer at 2.

[575] *Id.* at 3.

[576] *Id.* at 3-4.

[577] *Id.* at 4-5.

required by Order No. 719. In Order No. 719, the Commission adopted the proposed rule to require each RTO or ISO to increase its responsiveness to the needs of customers and other stakeholders.[578] In particular, the Commission found that RTOs and ISOs must provide an avenue for customers and other stakeholders to present their views on RTO and ISO decision-making and to have those views considered.[579] Here, we find that MISO's stakeholder process satisfied those requirements of Order No. 719 with respect to the instant proposal. MISO has worked with stakeholders on the proposal for several years, holding numerous meetings since at least March 2020. Stakeholders have been on notice of the proposed Tariff changes since November 30, 2021, thus giving them nearly 17 months to prepare for the 2023/2024 Auction in the Spring of 2023. Moreover, MISO incorporated some stakeholders' suggestions into the eventual proposal. In addition, with respect to MISO's statement that additional stakeholder engagement is necessary prior to implementation of the proposal, we do not consider that to be a flaw in the stakeholder process that renders the proposal unjust and unreasonable.

5. Other Comments

a. Comments

353. Joint Commenters submitted comments attaching their comments on MISO's MCO Filing. In their comments on MISO's MCO Filing, Joint Commenters argue that MISO failed to adequately evaluate the effects of the 50% threshold or the 50 MW exemption and that such failure becomes even more significant when one considers the impact of the 31-day replacement capacity requirement in MISO's availability-based resource accreditation proposal. Joint Commenters also express concern that the relationship between the MCO Filing and the instant seasonal construct filing will produce costly unintended consequences that were not adequately evaluated by MISO. Joint Commenters express concern that these changes will lead to increased costs for LSEs without a tangible increase in reliability.[580]

354. MidAmerican is concerned that the policies contained in MISO's proposal do not have corresponding market commitment changes that will allow MidAmerican to be successful under the new paradigm. MidAmerican contends that MISO needs to further improve its forecasting tools and market clearing processes in order to effectively stage generators for real-time operations in advance of potential weather events or capacity shortfalls. MidAmerican argues that, with the increased penetration of intermittent

[578] Order No. 719, 125 FERC ¶ 61,071 at PP 481, 502.

[579] *Id.* P 503.

[580] Joint Commenters Comments, attach. A (citing Joint Commenters' Comments in Docket No. ER22-496-000 (filed Jan. 14, 2022)).

resources, MISO must recognize that solving for these increasing levels of forecast error in the real-time market will become increasingly difficult and will need to be managed on a day ahead basis. MidAmerican contends that, without additional consideration for day-ahead forecast uncertainty, the number of resources MISO will need to call on in the real-time market will increase, further putting pressure on the intraday gas market and gas storage capability, and, ultimately, penalizing resources for their inability to acquire the necessary fuel due to the limited time frame in which MISO is attempting to dispatch a large number of resources.[581]

355. COMPP agrees with MISO that capacity market reform is necessary but argues that MISO has failed to demonstrate that the proposed Tariff changes will be sufficient to solve MISO's ongoing reliability problems. COMPP avers that MISO's revisions have not been shown to be just and reasonable and, if the Commission does not reject the proposal, it should hold a technical conference on the shortfalls of MISO's capacity market to establish a record.[582] Specifically, COMPP argues that MISO's proposal does not include mechanisms to measurably improve resource performance.

356. COMPP argues that, as it argues in the MISO MCO proceeding in Docket No. ER22-495-000, a sloped demand curve in the seasonal Auction would provide the economic signals and winterization incentives MISO needs. COMPP contends that the Market Monitor has found that the Auction has not produced meaningful prices that reflect the actual marginal value of reliability. COMPP requests the Commission to direct MISO to make a subsequent filing implementing a downward sloping demand curve and/or explore the implementation of a sloped demand curve in a larger technical conference covering MISO Resource Adequacy issues.[583]

b. Commission Determination

357. We reject these protests. First, we note that, concurrently with this order, we are issuing an order rejecting MISO's MCO Filing.[584] Second, while MidAmerican raises concerns that MISO needs to update its market commitment tools and processes, MidAmerican does not provide any specific evidence to suggest that MISO's proposal is unjust and unreasonable absent those updates. Because we are accepting MISO's instant proposal, we reject COMPP's request to institute a technical conference on MISO's capacity reforms. Finally, we find that COMPP's request for the Commission to direct

[581] MidAmerican Protest at 3.

[582] COMPP Protest at 2.

[583] *Id.* at 17-19.

[584] *Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,142.

MISO to make a subsequent filing to institute a downward sloping demand curve and/or explore the implementation of a sloped demand curve in a technical conference is beyond the scope of the instant filing.[585]

The Commission orders:

(A) MISO's Filing is hereby accepted, effective September 1, 2022, as requested, subject to condition, as discussed in the body of this order.

(B) MISO is hereby directed to submit a compliance filing within 30 days of this order, as discussed in the body of this order.

(C) MISO is hereby directed to submit an informational report within 90 days of the conclusion of the 2025/2026 Planning Year, as discussed in the body of this order.

By the Commission. Commissioner Danly is concurring with a separate statement attached.
Commissioner Clements is dissenting with a separate statement attached.
Commissioner Christie is concurring with a separate statement attached.

(S E A L)

Debbie-Anne A. Reese,
Deputy Secretary.

[585] *See, e.g.*, *Qualifying Facility Rates & Requirements; Implementation Issues Under the Publ. Util. Regul. Policies Act of 1978*, Order No. 872, 172 FERC ¶ 61,041, at PP 202, 524, 568, 594, 596 (denying requests for Commission actions as beyond the scope of the proceeding), *order on reh'g*, Order No. 872-A, 173 FERC ¶ 61,158 (2020). *See also, e.g.*, *PJM Interconnection, L.L.C.*, 146 FERC ¶ 61,127, at P 26 (2014) (in finding the protestors' argument beyond the scope of the proceeding, the Commission held that while the protestors' recommended revisions to the applicants' filing might have been an improvement, the existing proposal was not unjust, unreasonable or unduly discriminatory without them).

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc. Docket Nos. ER22-495-000
ER22-495-001

(Issued August 31, 2022)

DANLY, Commissioner, *concurring*:

1. I join the Commission's decision to accept Midcontinent Independent System Operator, Inc.'s (MISO) proposed tariff revisions, effective September 1, 2022, subject to condition.[1] As an initial matter, I agree with MISO that changes are needed to its resource adequacy construct in light of "[t]he MISO Region . . . experiencing significant shifts in generation resource retirement, increased reliance on intermittent resources, significant weather events with correlated generator outages, and declining excess reserve margins."[2]

2. I have become increasingly concerned by MISO's ever-decreasing excess reserve margins[3] and MISO's apparent inability to retain sufficient dispatchable generation to

[1] *See Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141 (2022).

[2] Transmittal at 2.

[3] *See 2022 Summer Reliability Assessment*, N. Am. Elec. Reliability Corp., at 4 (May 2022), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf ("Midcontinent ISO (MISO) faces a capacity shortfall in its North and Central areas, resulting in high risk of energy emergencies during peak summer conditions."); *id.* ("Capacity shortfall projections reported in the *2021 [Long-Term Reliability Assessment (LTRA)]* and as far back as the *2018 LTRA* have continued. Load serving entities in 4 of 11 zones entered the annual planning resource auction (PRA) in April 2022 without enough owned or contracted capacity to cover their requirements."); *id.* ("More extreme temperatures, higher generation outages, or low wind conditions expose the MISO North and Central areas to higher risk of temporary operator-initiated load shedding to maintain system reliability."); *id.* at 15 ("Tighter than normal operating conditions are anticipated, particularly in the MISO North/Central region[s], which cleared too little capacity in the 2022–2023 PRA. The PRA capacity shortfall of 1,230 MW signals a potential for operating risk during peak summer conditions."); *id.* ("Expected resources do not meet operating reserve requirements under normal peak-demand and outage scenarios.").

ensure reliability and resource adequacy. MISO's interconnection queue, which is composed almost entirely of intermittent generation,[4] shows that MISO is unlikely to obtain much more dispatchable generation any time soon. Right now, the combined effects of the market's price signals and the state and federal policies under which the market must operate has brought MISO to the point where the total quantity of nameplate capacity is rising, but the quantity of accredited capacity is decreasing.[5] This is a problem that should not be ignored, and the need for dispatchable generation cannot be overstated.[6] A market's failure to procure sufficient capacity with the needed characteristics is a flaw so fundamental that it calls the justness and reasonableness of a market's resulting rates into question. Perhaps, given this systemic failure, Vistra Corp. was correct in describing MISO's capacity market as "irreparably dysfunctional."[7]

3. And perhaps the Commission should consider action pursuant to Federal Power Act section 206.[8] While I think that further action is needed, even with the Commission's approval of this proposal, to address the reliability and resource adequacy

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[4] *See Managing Reliability Risk in the MISO Footprint*, MISO, at 8 (June 16, 2022), https://cdn.misoenergy.org/20220616%20Board%20of%20Directors%20Item%2008a%20Reliability%20Imperative625168.pdf.

[5] *See id.* at 5.

[6] *See 2021 State of the Market Report for the MISO Electricity Markets*, Potomac Economics (The Independent Market Monitor for MISO), at 22 (June 2022), https://www.potomaceconomics.com/wp-content/uploads/2022/06/2021-MISO-SOM_Report_Body_Final.pdf (explaining "the importance of having sufficient dispatchable resources available to satisfy the system demands when intermittent generation is not available").

[7] *Vistra Accelerates Pivot to Invest in Clean Energy and Combat Climate Change*, Vistra Corp., https://investor.vistracorp.com/2020-09-29-Vistra-Accelerates-Pivot-to-Invest-in-Clean-Energy-and-Combat-Climate-Change (Sept. 29, 2020) (announcing that Vistra Corp. "expects to retire seven Luminant power plants, of which the company owns a combined capacity of more than 6,800 MW, between 2022 and 2027," explaining that "[t]hese plants, especially those operating in the irreparably dysfunctional MISO market, remain economically challenged"); *see also* Edward Klump, E&E News, *Vistra touts major zero-carbon push as it unplugs coal*, E&E News (Sept. 30, 2020), https://www.eenews.net/articles/vistra-touts-major-zero-carbon-push-as-it-unplugs-coal/ ("Vistra pointed to a number of issues, including what it called a systematic failure of the MISO capacity market to provide Illinois power plants with adequate revenues.").

[8] 16 U.S.C. § 824e.

risks faced by the MISO region, MISO's decision to establish a seasonal resource adequacy construct is a just and reasonable step in the right direction to mitigate the effects on reliability of MISO's increasing reliance on intermittent generation and the decreasing excess reserve margins. And the question before the Commission is not whether there are other changes that should be made to MISO's construct, or whether this proposal is better than MISO's existing tariff; rather, the question is whether MISO has demonstrated that this proposal is just and reasonable[9]—which indeed it has.

For these reasons, I respectfully concur.

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James P. Danly
Commissioner

[9] *See Neb. Pub. Power Dist. v. FERC*, 957 F.3d 932, 943 (8th Cir. 2020) (recognizing that "courts have made it clear that FERC 'restricts itself to evaluating the confined proposal'" and "[t]herefore, FERC 'need only find the *proposed* rates to be just and reasonable.'") (citations omitted); *Advanced Energy Mgmt. All. v. FERC*, 860 F.3d 656, 662 (D.C. Cir. 2017) ("When acting on a public utility's rate filing under section 205, the Commission undertakes 'an essentially passive and reactive role' and restricts itself to evaluating the confined proposal.") (quoting *City of Winnfield v. FERC*, 744 F.2d 871, 875-76 (D.C. Cir. 1984)).

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc. Docket Nos. ER22-495-000
ER22-495-001

(Issued August 31, 2022)

CLEMENTS, Commissioner, *dissenting*:

1. I dissent from today's order accepting a suite of resource adequacy reforms filed by Midcontinent Independent System Operator (MISO) because I cannot conclude they will yield just and reasonable rates for capacity in the region. While I agree that reforms are needed, I believe critical design details of MISO's proposal are flawed such that capacity may not be accredited consistent with its availability during times of greatest reliability risk. In addition, MISO's support for its proposed mitigation revisions contains an inconsistency that I fear could provide a loophole for excessive customer costs.

2. Because MISO's proposal addresses reliability risks present in the current tariff and offers the potential to better align capacity payments with services provided, I would have rejected MISO's filing with specific guidance and given MISO the opportunity to expeditiously re-file with necessary revisions. I note, however, that MISO's chosen path to a seasonal construct, the Seasonal Accredited Capacity (SAC) methodology, is not well aligned with the Expected Load Carrying Capability (ELCC) methodology it currently uses for calculating the seasonal accreditation of wind resources and plans to use for solar resources. As MISO takes next steps beyond the market changes proposed herein, I urge MISO to rethink this misalignment and provide a more consistent framework that fairly credits all resource types.

3. I have spoken publicly about the need for the Commission to focus on emerging reliability challenges driven by the changing resource mix and increasing extreme weather and to show leadership in fostering market-based solutions to those challenges.[1] The wind, solar, storage, and hybrid resources entering the market have different operating characteristics and capabilities than the thermal resources that have dominated the electric system for decades. Many of those thermal resources are also retiring, adding to the pace of generation fleet change. At the same time, extreme weather events are

[1] *See, e.g.*, July 2022 Commission Meeting: Opening Remarks of Commissioner Allison Clements, available at www.ferc.gov/news-events/news/july-2022-commission-meeting-opening-remarks-commissioner-allison-clements.

becoming more frequent, disrupting fuel delivery systems, stressing generator performance, and causing correlated generator outages.[2] With these factors converging, it comes as no surprise that the services, attributes, and resource performance required to maintain grid reliability are also changing.

4. In some cases these changes have driven RTOs/ISOs to modify energy and ancillary services market rules,[3] and the Commission has recognized a potential need for broader adoption of such revisions.[4] In other cases these changes have motivated resource adequacy reforms, including a ramp product in CAISO,[5] penalties when capacity resources fail to deliver energy during emergencies in ISO New England[6] and

[2] *See, e.g.*, National Oceanic and Atmospheric Administration, National Centers for Environmental Information "U.S. Billion-Dollar Weather and Climate Disasters" (2022), available at https://www.ncei.noaa.gov/access/billions/.

[3] For example, the Commission has approved a number of energy and ancillary services market reforms in recent years, including new ramp products. *See, e.g.*, *Midcontinent Independent System Operator, Inc.*, 149 FERC ¶ 61,095 (2014) (conditionally accepting, subject to a compliance filing, MISO's proposal to introduce a new ramp capability product); *Midcontinent Independent System Operator, Inc.*, 170 FERC ¶ 61,075 (2020) (accepting MISO's proposal to implement a 30-minute Short-Term Reserve product in its Day-Ahead and Real-Time Market); and *Southwest Power Pool, Inc.*, 180 FERC ¶ 61,088 (2022) (accepting SPP's proposal to implement an Uncertainty Reserve product).

[4] At two technical conferences held in September and October 2021, the Commission heard extensive testimony about operators' increasing need for operational flexibility, market mechanisms already employed to seek to acquire that flexibility, and ideas for additional market reforms to address the growing need for flexibility. *See* Supplemental Notice of Technical Conference on Energy and Ancillary Services in the Evolving Electricity Sector, Docket No. AD21-10 (filed Sept. 3, 2021); Supplemental Notice of Technical Conference on Energy and Ancillary Services in the Evolving Electricity Sector, Docket No. AD21-10 (filed Oct. 7, 2021).

[5] *California Independent System Operator Corporation*, 156 FERC ¶ 61,226 (2016).

[6] *ISO New England Inc.*, 147 FERC ¶ 61,172 (2014).

PJM,[7] and effective load carrying capability capacity accreditation changes in PJM,[8] NYISO,[9] and SPP.[10] While I have not agreed with the specific path taken in some of these proposals, it is essential that grid operators update their market rules to adapt to changing market conditions, and this diversity of efforts demonstrates that there is no single, one-size-fits all fix across all regions. At the same time, however, the Commission must review each particular proposed rule change in detail, ensuring that it does not create unjust and unreasonable, or unduly discriminatory rates. It is not sufficient that a proposal represents an improvement over the status quo, which itself may no longer be just and reasonable in light of current and future market conditions.

5. Here, MISO proposes two significant resource adequacy reforms: a new capacity accreditation methodology for Schedule 53 resources, which include thermal and demand response resources,[11] and a shift to seasonal capacity auctions. MISO states that the reforms in this filing are part of MISO's broader "Reliability Imperative" effort and fit within the "Market Redefinition" pillar of that effort, which aims "to ensure that resources with needed capabilities and attributes will be available during the highest risk periods across the year."[12] MISO explains that its objectives include providing a deeper assessment of system needs in the highest risk periods, including required capabilities such as flexibility; improving how resources are accredited for capacity; and developing market products that provide the right incentives for resources to maintain system reliability.[13] MISO asserts that it "cannot reliably operate the system if the resources it depends on do not or cannot perform (that is, do not provide energy or reserves) during

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[7] *PJM Interconnection, L.L.C.*, Docket No. ER15-623-000 (March 31, 2015) (delegated order).

[8] *PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,056 (2021).

[9] *New York Independent System Operator, Inc.*, 179 FERC ¶ 61,102 (2022).

[10] *Southwest Power Pool, Inc.*, 180 FERC ¶ 61,074 (2022). I note that I dissented from this order because SPP failed to submit tariff revisions that comported with the rule of reason and thus it was impossible to conclude that SPP's proposal was just and reasonable. Also, as is the case in MISO's proposal, I was concerned that SPP did not adequately justify certain aspects of its proposal. *See id.* (Clements, Comm'r, dissenting).

[11] *See* Majority Order at P 91 (discussing MISO's definition for Schedule 53 resources).

[12] Wright Testimony at 13.

[13] *Id.* at 13-14.

periods of highest reliability risk."[14] It argues that its proposed reforms will foster efficient investment decisions by capacity resource owners consistent with resource performance during times of need.[15]

6. MISO's justification for its proposed reforms is therefore that they will value capacity consistent with its actual availability during periods of highest reliability risk and will incentivize capacity resource owners to invest and maintain their facilities so that they are more likely to be available during those periods.

7. Properly calibrated, I agree that MISO's proposal could satisfy these objectives and produce just and reasonable capacity rates. However, while the general thrust of MISO's proposal is appropriate, it contains several design flaws that will impede the proposal's ability to satisfy these objectives, and result in compensation for resources that does not match their true capacity contribution to the region. It also contains ambiguous tariff language inconsistent with MISO's expert testimony that creates the potential for the exercise of market power. Considering the significance of MISO's proposal, the Commission's duty to engage with the details to ensure grid reliability and consumers are protected was particularly important. But the Majority Order glosses over these critical details. While a narrow rejection order could have set the stage for MISO to return with an improved proposal that addresses these issues, today's order cements flaws into the region's market design, thereby undermining a just and reasonable outcome.

VII. Seasonal Accredited Capacity Methodology

8. In transitioning to a seasonal market, MISO's proposal devises a new method of crediting resources for each season based on their historical performance during 65 hours when emergency conditions or tight operating conditions were present. While MISO justifies this general framework, it includes several unsupported design features that cause MISO to look to the wrong set of hours, and to credit resources that are unlikely to be capable of performing when called upon. These flaws threaten system reliability and make for a poor foundation on which MISO's new proposal rests.

9. MISO argues that "[r]esource accreditation should reflect the anticipated capability and availability of Planning Resources during times when they are most needed,"[16] but unfortunately its SAC methodology for valuing thermal resources falls short of this goal. The SAC methodology seeks to measure each resource's anticipated availability by assessing its prior performance during 65 hours of emergency or other

[14] *Id.* at 14.

[15] Smith Testimony at 19-20.

[16] McFarlane Testimony at 17.

tight operating conditions, which MISO calls "RA Hours." Critical design decisions include (1) determining what constitutes an RA Hour; (2) determining what constitutes "availability" during each of those RA Hours, particularly if the resource was offline at the time; and (3) determining under what circumstances a resource that was on outage during RA Hours will be exempted from having its future accreditation reduced due to its unavailability. Each of these elements of MISO's proposal has flaws, as identified by MISO's Independent Market Monitor (IMM) and other stakeholders.

10. I recognize that the IMM supports MISO's overall proposal despite these flaws. The IMM states that "MISO made a number of changes in the course of the stakeholder process that are likely to reduce the benefits" of the proposal, but the IMM clarifies that it is supporting the proposal nonetheless "because we believe they are improvements over MISO's current market design and rules."[17] While I agree that, on balance, MISO's proposal likely provides a better framework than the status quo, a rate revision submitted pursuant to section 205 of the Federal Power Act is not necessarily just and reasonable solely because it is an improvement to the existing rate.[18] Rather, the filing utility bears the burden to demonstrate that the rate revision is itself just and reasonable.[19] Because MISO has failed to demonstrate through substantial evidence and sound economic logic that the market design choices discussed above are just and reasonable, the Commission's duty is to reject the proposal. Rejecting with guidance would have created the opportunity for MISO to revise it and submit an improved proposal that is truer to MISO's intent to accredit capacity consistent with its likely availability during periods of greatest reliability risk.

A. MISO looks to the wrong set of hours to determine capacity performance

11. With regard to setting RA Hours, MISO acknowledges that in many seasons, particularly non-summer seasons, it is unlikely there will be 65 hours of emergency conditions. MISO proposes to backfill the remainder with other historical hours that saw the tightest operating margins.[20] The calculation of operating margin (i.e. resource

[17] IMM Comments at 2.

[18] *See PJM Interconnection, L.L.C.*, 180 FERC ¶ 61,089, at P 47 n.111 (2022) (finding that even if PJM's contention that its Intelligent Reserve Deployment proposal is an improvement over its current approach is correct, that does not render the proposal just and reasonable).

[19] 16 U.S.C. § 824d(e).

[20] McFarlane Testimony at 20-21. While the Commission finds this approach of defining RA hours for seasonal auctions in part based on hours from different seasons to be just and reasonable, I note that this determination is specific to the context of MISO

supply minus demand at any given point in time) is therefore of great consequence because it will determine in which hours each resources' availability is evaluated. MISO proposes to include in operating margin the capacity of any offline resource with a lead time of 12 hours or less. But offline capacity with a lead time of more than 6 or 8 hours is not "available" in any given hour, so MISO's approach inaccurately excludes some tighter hours from the "RA Hours" designation by overcounting supply, while including as RA Hours some periods where operating margin is comparatively less tight.

12. As the IMM and Clean Energy Coalition argue, unexpectedly tight hours typically arise on a shorter timeframe, requiring a response time faster than many of the resources counted within that operating margin can deliver.[21] As the IMM explains, a 2-6 hour lead time is appropriate, because that "is the timeframe in which MISO often recognizes that emergency conditions are developing."[22] Resources with lead times as long as 12 hours "are not relevant" to the reliability threat during these events "because the conditions were not recognized 12 hours in advance."[23]

13. Defining tight operating conditions assuming that resources with a 12-hour lead time are available, as MISO does, could cause MISO to ignore hours where offline resources with a lead time between 6 and 12 hours are comparatively abundant, when in fact uncertainties like load forecast errors, wind forecast errors, large unit forced outages, and other factors that are not known far in advance pose a reliability risk for the system for which these resources are of no use. MISO's approach thereby inappropriately shifts RA Hours toward more foreseeable conditions where operating conditions are not truly as

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applying it to schedule 53 resources and the evidence put forth to demonstrate alignment of its choice of hours with the historical availability of those resources. *See* Majority Order at P 246. Continuing this approach would not necessarily be just and reasonable if the SAC methodology were to be extended beyond schedule 53 resources, which may have greater variation between seasons. As DTE, MISO TOs, and Minnesota Power argue, using hours from other seasons undermines the seasonality of the construct. DTE Protest at 14; MISO TOs Comments at 9; Minnesota Power Comments at 2. And while a thermal resource's performance during tight hours in one season may strongly correlate with performance in tight hours in another season, that may not be the case for other types of resources such as wind and solar, whose performance may be more closely linked to the weather.

[21] *See* IMM Comments at 9; Clean Energy Coalition Comments at 11.

[22] IMM Comments at 8. *See also* Clean Energy Coalition Comments at 11 (arguing that MISO's approach "fails to consider how unexpectedly tight hours typically arise in the range of 2 to 8 hours because reality diverges from forecasts").

[23] IMM Comments at 9.

tight, while excluding hours that are in fact tighter when considering the system's true ability to respond to uncertainties. The IMM notes that as the uncertainties on the system grow, the adverse effect of MISO's 12-hour lead time assumption are likely to increase.[24]

14. While MISO must necessarily make some qualitative judgments in determining how to design its seasonal capacity mechanism (including whether to use such an "RA hour" construct and, if so, which RA hours to look at), it fails to offer sufficient defense of its 12-hour lead time rule. In support of the 12-hour threshold, MISO's witness only emphasizes that its starting point was an even longer 24-hour lead time threshold, which it shortened based on the feedback from the IMM.[25] But in endorsing the IMM's general logic, MISO provides no explanation as to why it did not choose a shorter lead time threshold that better matched likely system conditions contributing to the concerns this construct is intended to address.

B. MISO's capacity accreditation does not match resource contribution to system reliability

15. MISO repeats this same mistake of crediting resources incapable of contributing to system reliability when determining resource availability for purposes of accreditation. MISO proposes to credit a resource as having been available during an RA Hour if it was offline but had a lead time of 24 hours or less. But as the IMM explains, this lax crediting includes many resources that will not be able to deliver any value when called upon.[26] Further, MISO's attempted rationale to justify the inconsistency of its approach of using a longer 24-hour window for resource accreditation while using a shorter 12-hour lead time used for purposes of determining RA Hours does not make sense. MISO argues that while the 12-hour threshold better represents "times of need," the 24-hour threshold "better reflects whether MISO could have reasonably committed a resource in its Day-Ahead Market or Forward Reliability Assessment Commitment processes."[27]

16. But examining whether a resource *could* have been committed answers the wrong question. As the IMM explains:

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[24] *Id.*

[25] McFarlane testimony at 23. The Majority Order likewise justifies the 12-hour threshold as superior to a 24-hour threshold, but does not explain why it finds 12 hours to be reasonable in light of the criticisms that a shorter threshold was necessary to align with resources' true ability to serve the system. *See* Majority Order at P 255.

[26] IMM Comments at 10.

[27] McFarlane testimony at 24.

> [MISO's] logic is flawed . . . If most of the threats to reliability emerge during the operating day, only offline resources that can [be] started once the threat is recognized can contribute to reliability. Offline resources that could theoretically have been committed the prior day, but whose lead time is too long for them to start to mitigate the reliability threat provide no value in such events.[28]

17. In other words, whether a resource could have been committed if MISO knew about a reliability situation in advance is beside the point when assessing contribution to tight operating hours that arise on a shorter timeframe.[29] By MISO's own admission, "[h]istorically most MaxGen Events have been driven by events occurring after the Day-Ahead Market clears."[30]

18. The majority declares that "[r]esources that can be committed through the Day-Ahead or Forward Reliability Assessment Commitment process contribute to MISO's resource adequacy needs." Majority Order at P 275. But this runs contrary to the evidence in the record that *offline* resources with response times longer than 6 or 8 hours are incapable of contributing to the system during times of need. The majority hypothesizes that there may be capacity needs that could be identified with longer than 12 or even 24 hours of advanced notice, "such as resources being out on an extended planned or forced outage . . . or certain meteorological events forecast 24 or more hours in advance."[31] But those events, to the extent they may exist, could be responded to by resources with a lead time of longer than 24-hours, making the 24-hour requirement arbitrary. In setting a lead time of 24 hours, MISO divorces its accreditation determination from the question whether a resource contributes to reliability during RA

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[28] IMM Comments at 10.

[29] *See* IMM Comments at 10 ("It is irrelevant whether MISO theoretically 'could have reasonably committed a resource' through the day-ahead process. If most of the threats to reliability emerge during the operating day, only offline resources that can started once the threat is recognized can contribute to reliability.").

[30] MISO February 10 Answer at 43. While this supports declining to offer credit to resources with lead times in excess of 24 hours, it runs contrary to MISO's decision to credit resources with lead times between 6 and 24 hours, and also does not explain the inconsistency between the lead time threshold used for measuring RA hours and the threshold used for accreditation.

[31] Majority Order at P 276. It is notable that neither MISO nor any party in the record makes this argument, meaning that the majority's contention is only a guess as to why such resources may have value.

Hours. This is at odds with the design of its proposal and lacks any reasonable basis in the record.[32] It is worth noting that were a shorter response time requirement implemented, this would not give slow-response resources zero capacity credit. Rather, resources that were online during RA Hours and therefore contributing to resource adequacy would still get credit for contributing to system needs.[33]

19. Over-valuing less flexible units is unjust and unreasonable not only because it gives resources more credit than they deserve, but also because pursuant to the SAC's design it will necessarily under-value more flexible and available resources.[34] This misalignment between payment and reliability contribution is unjust and unreasonable due to its financial implications, and also because it undermines system reliability. The IMM suggests a reasonable alternative of a sliding scale, which would "recognize that certain units (e.g., fast-starting units) provide more reliability value than other units (long-lead time units)," and measure windows with tight operating conditions accordingly.[35] While MISO was not required to propose this alternative, it does have the burden under section 205 of justifying why the threshold it has chosen properly credits resources for their contribution to reliability and is therefore just and reasonable. It has not done so.

C. MISO's outage framework is unjust and unreasonable

20. Another significant flaw in MISO's proposed framework is its proposal to exempt resources from negative impacts to their accreditation if the resource owner provides 120-days' notice of the outage to MISO and MISO determines there is an adequate "maintenance margin." This proposal is logically inconsistent and inadequately

[32] To the extent MISO seeks to serve a different need besides contribution to RA Hours, such as the hypothetical need for resources to provide energy adequacy for events that are known long in advance, it has not demonstrated such a need in this record, nor justified why a 24-hour lead time requirement is the right threshold to accredit capacity for serving such a need.

[33] The majority confusingly states that "a resource being unavailable within 12 (or fewer) hours because MISO did not select it through a day-ahead or FRAC commitment process is not a reasonable basis to penalize that resource by assigning it a zero SAC accreditation value for those hours." Majority Order at P 276. This is hard to understand, given that when a resource with a long lead time is not selected it does not and cannot contribute to resource adequacy during RA Hours, whereas a resource that is selected does contribute.

[34] IMM Comments at 10.

[35] *Id.*

supported. As the IMM states, "[r]esources that schedule more frequent or longer-duration outages are less likely to be available during reliability events than resources that take less frequent or shorter-duration outages."[36] Further, as the IMM asserts, MISO's maintenance margin calculation is incapable of accounting for any and all unexpected factors and conditions that may lead to reliability risk, including extreme weather, system contingencies, unusual intermittent output levels, and load forecast errors.[37] In approving an outage—and the attendant accreditation exemption—MISO will have no way of knowing months in advance if challenging operating conditions will arise and the resource will be needed. Indeed, the very need for an exemption suggests the opposite. If in fact MISO could be sure that tight operating conditions would not occur where it has "maintenance margin," then resources could schedule during that period without fear that RA Hours would occur and their accreditation would be penalized. But the truth is that MISO may find itself short during those periods.

21. MISO does not adequately justify why it proposes to give full credit to resources as though they are providing reliability value during these periods when that is not the case. The Majority Order accepts MISO's rationale, that it "appropriately balances the need for resources to have flexibility to schedule planned outages and the need for MISO to have such visibility."[38] But as Clean Energy Coalition argues, MISO's framework "offer[s] little motivation for a resource owner—even one with a commitment under the Planning Resource Auction—to think twice before scheduling an outage, even at peak times."[39] And MISO provides no information to suggest that full accreditation is necessary in order to incent resources to give MISO adequate notice as to planned outages, or to engage in necessary maintenance activities.

22. To the contrary, the Majority Order's own logic suggests that the accreditation rules themselves give resources ample built-in incentive to perform maintenance: "Given the functional relationship between resource accreditation and resource availability," resources likely "will not risk delaying necessary maintenance" even if that means losing some accreditation in the short run because that could "result in resource underperformance, unavailability, or forced outages, which would negatively impact that resource's future accreditation."[40] In other words, the accreditation rules "encourage resource owners to appropriately balance maximizing short-term availability when it is

[36] *Id.* at 12.

[37] *Id.*

[38] Majority Order at P 265.

[39] Clean Energy Coalition Comments at 16.

[40] Majority Order at P 265.

most needed and perform[ing] maintenance, which requires scheduling planned outages, to ensure long-term resource performance."[41] Neither MISO nor the majority explain why an outage exemption is necessary given the presence of these incentives, much less reason why resources should be given full credit as opposed to a more limited incentive to provide advanced outage notification.

23. Moreover, beyond overcompensating resources when they are not contributing to system reliability, MISO's proposed maintenance framework also draws arbitrary lines that many market participants have rightly protested as lacking a logical basis. For example, several entities note that MISO has not explained how the proposed 120-day notice cutoff would increase resource availability during RA Hours,[42] pointing out that the proposal provides a relative disincentive against short to medium term maintenance.[43] They persuasively argue that this framework arbitrarily discourages non-consecutive outage days, as well as conducting any maintenance during each 120-day window even if there is an adequate maintenance margin during that time.[44] Others ask why, when resources that fully de-power are eligible for full credit, are those that de-rate for a period subject to an accreditation haircut?[45] MISO's framework also includes a capacity replacement obligation for any resource whose outage lasts more than 31 days in a single season,[46] providing an incentive for resources to arbitrarily stack outage requests at the

[41] *Id.*

[42] *See* Majority Order at P 129 (citing Consumers Energy Limited Protest at 2, East Texas Protest at 9).

[43] Consumers Energy Limited Protest at 1. The majority cannot have it both ways. If accreditation rules provide ample incentive for short to medium term maintenance without an exemption, then they should also be expected to adequately incent long term maintenance on their own.

[44] Midwest TDUs Protest at 15-17.

[45] *See* Duke Energy Comments at 4-5; MISO TOs Comments at 8. MISO justified the lack of eligibility of de-rates merely by stating that its current outage coordination process does not contemplate de-rates, which have traditionally been submitted with little advanced warning. *See* MISO Deficiency Letter Response at 10. But given MISO's changes to its accreditation framework and the opportunity for resource owners to receive an exemption for a scheduled outage, MISO has an obligation to explain why such a process should not be available for de-rates beyond merely invoking past practice in a different regulatory context.

[46] *See* Majority Order at P 286.

last 31 days of the season leading into the first 31 days of the next, regardless of whether that timing is appropriate from the perspective of grid reliability.

24. As with the elements discussed above, the negative effects of MISO's decision to credit unavailable resources as though they were serving the system are likely to grow in the future "[s]ince reliability events are increasingly likely to occur when they are not expected because of the uncertainties described earlier" such as load forecast errors, wind forecast errors, large unit forced outages, and other factors that are not known far in advance.[47]

D. The Commission should have rejected MISO's proposal given its capacity accreditation design flaws

25. By choosing to support its SAC accreditation on the grounds that it aligns accreditation with resources' likely availability in the future during times of greatest reliability risk, MISO bears the burden of demonstrating how these critical design choices support that objective or otherwise lead to just and reasonable outcomes. Using assumptions that over-value less flexible, longer lead-time resources and under-value more flexible, shorter lead-time resources undercuts MISO's justification. So, too, does an outage exemption approach that ignores that resources that require more frequent or longer outages provide less reliability value than those that require less frequent or shorter planned outages. By failing to accredit resources consistent with their actual value in time of greatest reliability risk, these design choices will hinder efficient capacity procurement, cause unjust and unreasonable capacity rates, and pose a threat to system reliability.

26. Rejecting MISO's proposal for its failure to properly align capacity credit with reliability value is supported by precedent, as the Commission has previously found that rules that do not adequately align capacity payment with a resource's true contribution to system reliability are not just and reasonable.[48]

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[47] IMM Comments at 12.

[48] *ISO New England, Inc.*, 147 FERC ¶ 61,172, at P 23 (2014) (finding ISO New England's capacity market rules unjust and unreasonable because they failed to provide adequate incentives for resource performance, thereby threatening reliable operation of the system and forcing consumers to pay for capacity without receiving commensurate reliability benefits); *see also PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208, at P 22 (2015) (approving a proposal to better align capacity payment with true contribution to system reliability).

VIII. Seasonal Capacity Auctions

27. MISO's proposal is also flawed because it may provide an opportunity for capacity sellers to exercise market power and potentially expose consumers to unjust and unreasonable capacity prices. MISO proposes to conduct auctions for all four seasons simultaneously, which requires revisions to its market power mitigation framework. I am not convinced by the record before us that the revisions MISO has offered protect consumers against inflated capacity prices.

28. MISO's proposal to conduct four seasonal auctions simultaneously for each Planning Year is novel. NYISO, the only RTO with an existing seasonal auction framework, conducts sequential auctions.[49] Conducting four auctions simultaneously adds complexity beyond that involved in conducting a single annual auction or sequential seasonal auctions. A capacity seller must determine how to offer into each seasonal auction without knowing the results—whether its resource cleared and at what price—of the other three.

29. A critical question for purposes of market mitigation under these circumstances is what constitutes an economic offer that allows a resource's costs of providing capacity (i.e., its "avoidable" or "going-forward" costs) to be reflected and adequately compensated while preventing excessive compensation. MISO's proposal and accompanying testimony send mixed signals as to how this critical question will be answered. As explained below, the tariff appears to prevent excessive compensation, but MISO's testimony suggests that it may be permissible. Given the complexity introduced by MISO's proposed simultaneous auction process, I fear that this ambiguity may provide a basis for excessive market offers, leading to unjust and unreasonable costs for consumers.

30. Part of MISO's proposed mitigation framework involves calculating a facility-specific reference level under certain circumstances (i.e. it requires calculating an "economic" offer from the unit). Tariff Module D, Section 64.1.4.f details what going-forward costs are permissible in a facility-specific reference level. It states, in relevant part:

> The Going-Forward Costs of a Planning Resource . . . shall be calculated by determining the costs that can be avoided by the . . . seasonal operation of the Planning Resource. Thus, Going-Forward Costs are equal to the costs that will be borne by a Planning Resource supplier by either maintaining in, or

[49] *See* NYISO Market Services Tariff § 2.3 (defining a winter and summer Capability Periods, for which auctions are conducted no later than 30 days prior to the start of each such period).

> returning a Planning Resource to, commercial operation for a specific Season of a Planning Year minus the costs that would be borne by such supplier resulting from retiring, suspending, or keeping a Planning Resource in suspension.

31. This appears to say that going-forward costs—and by extension a seller's seasonal auction offer price—may only include costs associated with providing capacity *for that season*.

32. However, MISO's testimony suggests something different. MISO's expert witness Shawn McFarlane, testifying in support of the proposal, states: "[Capacity] Offers may not reflect the actual costs of providing capacity if a Planning Resource clears in multiple Seasons but *its annual costs are compressed into each season's [capacity] Offer to ensure recovery if the Resource only clears in a single Season*."[50]

33. So here is what I am worried about: If, contrary, to the wording of section 64.1.4.f.iii, a seller may include in *each* of its seasonal auction offers up to its *annual* going-forward costs, and that seller clears multiple auctions, it could receive in excess—potentially up to two, three, or four times—its legitimate costs of providing capacity.[51] Even worse is if that resource sets the clearing price, such that all cleared resources would be paid not based on the marginal cost of providing capacity for the season, but based on a multiple thereof. Such an outcome cannot constitute just and reasonable rates for capacity.

34. MISO's proposal includes other mechanisms to limit under- and over-compensation that can result from its simultaneous auction design: a clearing price adjustment coupled with a new make-whole payment.[52] But as MISO acknowledges, there is a scenario where those mechanisms are not triggered despite the potential for auction revenues to exceed CONE on a per-MW basis,[53] in which case prices could unjustly and unreasonable rise to excessive levels should MISO's facility-specific

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[50] McFarlane Testimony at 44 (emphasis added).

[51] It appears this could occur when the clearing price adjustment is not triggered, meaning there is no *ex post* curb on compensation.

[52] *See* Majority Order at P 37 (discussing these design features).

[53] MISO's witness Shawn McFarlane explains that this will occur "whenever the Planning Resource Auction clears at least one Season, but fewer than all Seasons with Auction Clearing Prices above the daily value of CONE." McFarlane Testimony at 41-42.

reference calculation allow resources to make offers that would recoup up to that resource's annual costs in each of the four seasonal auctions as Mr. McFarlane suggests.

35. This is not the only case of inconsistency between MISO's proposed tariff and Mr. McFarlane's testimony. The Majority Order highlights another such inconsistency, regarding the applicability of Tariff section 69A.7.1.c.x governing the pricing for Zones in ZRC Shortage and Near-Shortage Conditions, and in that case reasons that the approach in the McFarlane testimony is more appropriate and orders MISO to file revised tariff sheets reflecting the testimony.[54] While the absence of such clarification with regard to facility-specific reference levels should dictate that the tariff governs, the McFarlane testimony presents concerns about how it will be applied in practice. Before approving MISO's proposal, the Commission should have insisted on obtaining a clear answer to this question from MISO. I dissent from the decision to approve such a significant market change in the face of this ambiguity on a critical consumer protection measure.

36. The Commission's approval of MISO's ambiguous proposal is especially discouraging because, as NYISO's experience shows, a proven alternative market design is readily available: sequential auctions that take place at different times in advance of each particular season.[55]

IX. MISO's proposal further entrenches disparate treatment between Schedule 53 non-Schedule 53 resources

37. As discussed above, but for the flaws I have identified, I would have approved MISO's proposal as a reasonable near-term mechanism to enhance system reliability. At the same time, however, I am concerned that the proposal may set MISO on a course that makes it more difficult to arrive at a future system of capacity accreditation and market design that treats all resources equally.

38. Clean Energy Coalition urges the adoption of three principles in order to prevent discrimination between different technologies: (1) "a resource that mitigates more risk should receive higher accreditation"; "(2) two resources that mitigate the same level of risk should receive the same accreditation"; and (3) "accreditation of each resource should be the same, regardless of the order in which resources' accreditation is calculated

[54] *See* Majority Order at PP 84-85.

[55] The IMM suggests approaches that would be more similar to the NYISO construct and accordingly derive similar benefits: offering "prompt seasonal auctions," or at minimum conducting each seasonal auction sequentially, even if all such auctions are carried out in a single time period far in advance of some of the relevant seasons. *See* IMM Comments at 4-5.

and accounted for."[56] While our precedent has traditionally permitted the application of different capacity accreditation methodologies to different resource types as not undue discrimination given the different characteristics of various technologies,[57] the Clean Energy Coalition rightly highlights that equal treatment should be the goal to the extent it is achievable.

39. Grid operators have gained extensive experience with wind and solar resources over the past decade, and are beginning to rapidly integrate energy storage resources in the wake of market developments and the Commission's Order No. 841.[58] As methodologies for valuing these resources mature, and as grid operators engage in efforts to more accurately value thermal and demand response resources, it becomes reasonable to expect grid operators to move toward methodologies that are more consistent across resource types. And even where uniformity is not fully achieved, the Commission should assess valuation methodologies side by side to ensure that even if different, the methodologies when taken together treat different resource types fairly relative to one another.

40. Many of the changes proposed in MISO's new SAC methodology are motivated by the same fundamental concern underlying ELCC methodologies that are being pursued in other regions: the need to value capacity more accurately. But as Clean Energy Coalition points out, MISO's chosen "*ex post* approach based on actual historical performance" is at odds with MISO's ELCC valuation methods that use an *ex ante* approach "based on a statistical expected value."[59] MISO's proposal therefore creates a significant concern that it may further entrench the differences between Schedule 53 and non-Schedule 53 resource accreditation in a manner that makes it more and not less difficult to arrive at a consistent framework for all resources.

41. Further, MISO's chosen approach entails the use of a UCAP/ISAC ratio "to ensure continued alignment between MISO's UCAP-based Reserve Requirements and its SAC proposal," but declines to apply this same ratio to non-Schedule 53 resources because those resources "will not experience the same level of accreditation reduction as Schedule

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[56] Clean Energy Coalition Response to MISO Deficiency Letter Response at 7.

[57] *See, e.g., PJM Interconnection*, 176 FERC ¶ 61,056 at P 70 (finding that PJM "need not extend the ELCC framework to Unlimited Resources to demonstrate that its filing is just and reasonable").

[58] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators* (Order No. 841), 162 FERC ¶ 61,127 (Feb. 15, 2018).

[59] Majority Order at P 149 (citing Clean Energy Coalition Protest at 5).

53 Resources."[60] But while MISO justifies this approach as a reasonable mechanism to avoid raising demand to a level not necessary to maintain system reliability, a natural consequence of it is that it does not change the relative valuation of Schedule 53 versus non-Schedule 53 resources despite the acknowledged shortcomings of the capacity valuation methodology MISO is applying to Schedule 53 resources before the proposed tariff changes go into effect. If MISO's current method over-credits Schedule 53 resources as compared to non-Schedule 53 resources, MISO's proposal accepted by the Commission today does not address that concern. Further, should MISO undertake future efforts to more accurately value non-Schedule 53 resources, unfairness could be introduced if MISO does not employ a similar ratio for those resources, or address the relative valuation of Schedule 53 and non-Schedule 53 resources in a different way. While the Majority Order finds that the Clean Energy Coalition has not provided evidence demonstrating that Schedule 53 resources are over-credited as compared to non-Schedule 53 resources,[61] that finding does not preclude a conclusion that the tariff is unjust and unreasonable should the Clean Energy Coalition or another stakeholder bring forth such evidence in the future.

42. MISO is not alone in proposing a new capacity accreditation method that raises potential fairness concerns with regard to relative treatment of different resource types. SPP's recently-accepted ELCC methodology raises a similar concern, as it reduces the credit given to wind, solar, and run-of-the-river hydroelectric resources while leaving an outdated Installed Capacity methodology in place for other resources.[62] The Commission should keep a keen eye on this fairness issue as capacity valuation methodologies develop across regions, gathering data and potentially interceding as appropriate to ensure just and reasonable and not unduly discriminatory rates.

43. Ultimately, whether MISO initiates changes itself or is forced to do so through a section 206 proceeding, MISO's long run direction should be toward equal treatment of all resources across capacity types. It is therefore lamentable that, in making a much-needed shift toward a seasonal capacity construct that more accurately values resources' contributions to the system, MISO has chosen an approach that sets Schedule 53 and non-Schedule 53 resources on different courses. In the coming months and years, it should work to bring its divergent resource valuation techniques into alignment.

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[60] *Id.* at P 278.

[61] *Id.*

[62] *See Southwest Power Pool, Inc.*, 180 FERC ¶ 61,074 (2022) (Clements, Comm'r, dissenting, at PP 12-14).

X. Conclusion

44. I conclude by highlighting the difficult position the Commission is in with regard to responding to MISO's proposal and similar recent initiatives to improve capacity valuation. In the wake of the D.C. Circuit's decision in *NRG v. FERC*,[63] the Commission faces a significant temptation to accept rather than reject any rate proposal that improves upon the status quo, even where a portion of such a proposal is unjust and unreasonable or unduly discriminatory. The reality is that the Commission does not have the capacity to open a section 206 investigation in every instance where an existing rate may be unjust and unreasonable or unduly discriminatory. Even if it did, modifying rates via section 206 processes is time consuming, contentious, and triggers *ex parte* rules that make open discussion of challenging issues more difficult. So, it is understandable that accepting a proposal despite its flaws is compelling.

45. The temptation to accept rate proposals is particularly strong where they address reliability challenges, given the Commission's paramount responsibility of ensuring system reliability. But giving in to this temptation does not ensure proposals will be sufficient to address any given reliability challenge, and risks significant costs. Today's decision and the recent decision accepting Southwest Power Pool's ELCC valuation methodology[64] have together set a low bar for RTO filings. Together, they effectively say that omissions and inconsistencies in tariff filings will be tolerated, with the Commission doing the work of the RTO to fill in the gaps in the filing and push it across the finish line. They leave stakeholders guessing as to the meaning of critical provisions even after the Commission issues its decision, depriving them of notice and due process in responding to proposed changes. Even more concerningly, today's order suggests that, when it comes to reliability, market design flaws are permissible. In my view the opposite is true: the Commission should be particularly insistent that market design is sound in carrying out our bedrock responsibility of ensuring a reliable grid.

46. Today's decision bakes troubling flaws into MISO's capacity rules that may jeopardize reliability for years to come. While the majority urges MISO to continue working to improve its capacity rules,[65] it is not clear how some of these improvements could be made within the confines of MISO's stakeholder process absent Commission action forcing such an outcome. Taking just one example, the IMM observes that MISO's proposed outage "exemptions were introduced in response to stakeholder

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[63] 862 F.3d 108 (D.C. Cir. 2017).

[64] *Southwest Power Pool, Inc.*, 180 FERC ¶ 61,074 (2022).

[65] *See* Majority Order at P 269 ("[W]e encourage MISO to continue to evaluate whether its current outage coordination process could be improved. . . .").

feedback from entities concerned that such outages would reduce their accreditation."[66] The Commission has no reason to believe that these stakeholder dynamics will change such that MISO will better align capacity payments with system value in the future. Today's order therefore puts a flawed short-term improvement ahead of long-term results, leaving it to industry to regulate themselves. In my view, it would be better for us to insist the job is done right. "Measure twice, cut once," as the old adage goes.

For these reasons, I respectfully dissent.

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Allison Clements
Commissioner

[66] IMM Comments at 12.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	Docket Nos.	ER22-495-000 ER22-495-001
Midcontinent Independent System Operator, Inc.	Docket Nos.	ER22-496-000 ER22-496-001

(Issued August 31, 2022)

CHRISTIE, Commissioner, *concurring*:

1. I support accepting MISO's proposed seasonal resource adequacy construct in Docket Nos. ER22-495-000 and ER22-495-001. It is now a truism, established through numerous Commission precedents,[1] that in an FPA section 205 filing, we are not looking for the perfect proposal, or even one that we may prefer as relatively better than the specific one proposed in the filing. Instead, we look to see if the specific proposal filed

[1] *E.g.*, *City of Winnfield v. FERC*, 744 F.2d 871, 875-76 (D.C. Cir. 1984); *PJM Interconnection, L.L.C.*, 170 FERC ¶ 61,243, at P 57 (2020) (citing *Petal Gas Storage, L.L.C. v. FERC*, 496 F.3d 695, 703 (D.C. Cir. 2007); *Cities of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984); *Cal. Indep. Sys. Operator Corp.*, 128 FERC ¶ 61,282, at P 31 (2009)); *see also Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141, at P 79 (2022) (citations omitted).

meets the "just and reasonable" rates requirement of section 205.[2] I believe MISO's proposal herein meets that standard.[3]

2. I also support rejecting MISO's proposed Minimum Capacity Obligation (MCO) in Docket Nos. ER22-496-000 and ER22-496-001 because I believe the Market Monitor's concerns about the potential exercise of market power cast sufficient doubt on the proposal's claim to meet the section 205 standard.[4] However, I emphasize that we are rejecting only the MCO proposal before us and that we are not prejudging a future MCO filing by MISO.

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[2] I agree generally with the concern expressed by Commissioner Clements in paragraphs 44 and 45 of her dissent to the order, which I understand to mean that we are constrained by the precedents related to section 205 filings, including, of course, *NRG v. FERC*, 862 F.3d 108 (D.C. Cir. 2017), that do not let us make non-minor improvements to RTO proposals. I also agree that trying to address every existing market design flaw through individual section 206 proceedings may simply not be workable. I would favor a more comprehensive approach to evaluating threats to reliability that are increasingly becoming evident in RTO markets, and in a manner not subject to the *ex parte* communications limits of contested individual filings. As I note herein in P 3 and Note 6, among the issues that should be examined in such a general proceeding should be the continued use of single-clearing price mechanisms in RTO markets. The European Union is already re-evaluating such mechanisms in light of skyrocketing prices in EU power markets. *See* Sam Fleming and Valentina Pop, *EU to unveil emergency measures to curb soaring prices: Pressure grows for bloc to reform markets by cutting link between electricity and the cost of gas*, FINANCIAL TIMES, August 29, 2022 ("Wholesale electricity costs reflect the price of the last unit of energy bought via auctions held in member states. In practice, this currently mirrors the price of natural gas rather than renewable energy or nuclear power. . . . However, [EU President Ursula] von der Leyen hinted in June that the commission would have to reconsider the system."), https://www.ft.com/content/02f848fc-3b80-4ddc-ba4f-26109d79db89.

[3] I note that the Organization of MISO States, Inc. (OMS) supports the seasonal resource adequacy filing, along with Michigan and Indiana individually. Louisiana supports the concept of a seasonal resource adequacy construct, but not the details of the proposal filed. Mississippi opposes the proposal. I also note that, while critiquing aspects of the filing, the MISO Independent Market Monitor (Market Monitor) overall supports it.

[4] *See* Market Monitor Protest, Docket No. ER22-496-000, at 13-18. I further note that OMS has filed no comments at all in the MCO proceeding, whether in support or opposition. Only two individual states filed comments, with Indiana in support and Illinois opposed.

3. Both cases serve to illustrate a much bigger issue: Regardless of the details of the market designs of the various RTOs/ISOs — which are not true markets at all but administrative constructs using an increasingly opaque, complex and questionable pricing mechanism [5] — it is the *states* which retain the primary responsibility to ensure their load-serving entities (LSEs) have adequate resources to serve their states' consumers. While regional system operators — RTOs and ISOs — are responsible for balancing the system on a real-time operational basis to keep the lights on, RTOs/ISOs are not regional long-term Integrated Resource Plan (IRP) planners of generating or other resources. Rather, it is the states which have the ultimate authority to decide which resources get built and which get retired and whether and how their regulated LSEs have sufficient generating capacity or demand-side programs to ensure that the lights stay on for their states' residents. Yes, the market design of federally regulated RTO/ISO markets certainly affects the entry or exit of generating resources from those markets, but even in RTOs/ISOs the states still retain their inherent police-power authority to direct their LSEs to achieve resource adequacy in ways other than through RTO/ISO markets — including various forms of self-supply, such as rate-basing, or purchased power agreements or other bilateral arrangements.

4. This is particularly true in MISO. No one disputes that the MISO capacity market has always been a purely *residual* option; it is not the primary option for an LSE to obtain the resources needed to ensure reliability.[6] Importantly, states need to focus on their own

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[5] For an excellent analysis of the theory behind Locational Marginal Pricing (LMP) and how it is supposed to work in RTO markets (and why it increasingly may not work any longer), see Tony Clark and Vince Duane, *Stretched to the Breaking Point: RTOs and the Clean Energy Transition* (July 2021), https://www.wbklaw.com/wp-content/uploads/2021/07/Wholesale-Electricity-Markets-White-Paper-07.08.21.pdf.

[6] As the Commission has explained:

> Notably, 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." Moreover, 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

authority to ensure adequate generating resources to serve their citizens and not default to an administrative construct regulated by FERC.[7] I am encouraged by recent efforts by the Organization of MISO States to address this critical issue.[8]

For the reasons given above, I respectfully concur.

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Mark C. Christie
Commissioner

> Auction is not—*and has never been*—the primary mechanism for its LSEs to procure capacity.

Midcontinent Indep. Sys. Operator, Inc., 170 FERC ¶ 61,215, at P 13 (2020) (emphasis in original) (quoting MISO, FERC Electric Tariff, Module E-1, § 68A (33.0.0)); *see also Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,142, at P 110 (2022) (citation omitted).

[7] Indeed, although the MISO tariff provides that MISO will calculate the Planning Reserve Margin Requirements (Reserve Requirements) for LSEs, the MISO tariff also provides that, if a state regulatory authority establishes an alternate Planning Reserve Margin, MISO will use the alternate Planning Reserve Margin to calculate LSEs' Reserve Requirements for the geographic area under that state's jurisdiction. MISO, FERC Electric Tariff, Module E-1, § Module E-1, § 68A.7 (Establishing Planning Reserve Margin Requirements) (32.0.0).

[8] *See* OMS Resource Adequacy Summit (Aug. 8-10, 2022), https://www.misostates.org/index.php/meetings/other-meetings/2-uncategorised/380-ra-summit; *see also* Darren Sweeney, *Midwest Utilities Delay Plant Retirements To Offset Reliability, Cost Concerns*, S&P Global Market Intelligence, Aug. 19, 2022, https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/articleabstract?id=71797391.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-9

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

Exhibit 80

MISO 2023-24 LOLE Study Report



Planning Year 2023-2024 Loss of Load Expectation Study Report

MISO — Resource Adequacy

Highlights

- MISO's seasonal construct, accepted by FERC in September 2022, introduces seasonal requirements to the Planning Resource Auction (PRA) to account for the unique risk profile of each season.

- MISO made several modeling improvements to the LOLE study to support the new seasonal construct.

- MISO's annual Loss of Load Expectation (LOLE) study sets the system-wide Planning Reserve Margin and the zonal Local Reliability Requirements for each season of the upcoming Planning Year.

Update (5/1/2023): outyear Planning Reserve Margin (PRM) and Local Reliability Requirement (LRR) results added to study report

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Executive Summary

Midcontinent Independent System Operator (MISO) conducts an annual Loss of Load Expectation (LOLE) study to determine a Planning Reserve Margin Unforced Capacity (PRM UCAP), zonal per-unit Local Reliability Requirements (LRR), Zonal Import Ability (ZIA), Zonal Export Ability (ZEA), Capacity Import Limits (CIL) and Capacity Export Limits (CEL) for each season (Summer, Fall, Winter, & Spring) of the upcoming Planning Year. The results of the study and its deliverables supply inputs to the MISO Planning Resource Auction (PRA).

The Planning Year 2023-2024 (PY 2023-2024) LOLE Study:

- Establishes PRM UCAP for each season to be applied to the Load Serving Entity (LSE) seasonal coincident peaks for the Planning Year starting June 2023 and ending May 2024:
    - Summer 2023 PRM UCAP of 7.4%
    - Fall 2023 PRM UCAP of 14.9%
    - Winter 2023-2024 PRM UCAP of 25.5%
    - Spring 2024 PRM UCAP of 24.5%
- Uses the Strategic Energy Risk Valuation Model (SERVM) software for Loss of Load analysis to provide results applicable across the MISO market footprint.
- Provides zonal ZIA, ZEA, CIL and CEL for each Local Resource Zone (LRZ) (Figure ES-1). These values may be adjusted in March 2023 based on changes to MISO units with firm capacity commitments to non-MISO load, and equipment rating changes since the LOLE analysis. The Simultaneous Feasibility Test (SFT) process can further adjust CIL and CEL to ensure the resources cleared in the auction are simultaneously reliable.
- Determines a minimum planning reserve margin for each season of the studied Planning Year that would result in the MISO system experiencing a less than one-day loss of load event every 10 years, as per the MISO Tariff.[1] The MISO analysis shows that the system would achieve this reliability level for the summer 2023 season when the amount of installed capacity available (considering external support) is 1.159 times that of the MISO system summer 2023 coincident peak.
- Sets forth initial zonal-based (Table 1-1) PRA deliverables in the LOLE charter.

The stakeholder review process played an integral role in this study. The MISO staff would like to thank the Loss of Load Expectation Working Group (LOLEWG) for its assistance and input. There were several process improvements made to the LOLE study this year including updated transfer limits due to improved redispatch and four major LOLE modeling enhancements: seasonal outage rates, wind and solar hourly profiles, probabilistic modeling of non-firm support, and correlated cold weather outages.

[1] A one-day loss of load in 10 years (0.1 day/year) is not necessarily equal to 24 hours loss of load in 10 years (2.4 hours/year).

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Summer 2023 PRM UCAP	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%
LRR UCAP per-unit of LRZ Peak Demand	1.139	1.120	1.299	1.212	1.333	1.172	1.171	1.473	1.157	1.538
Capacity Import Limit (CIL) (MW)	5,301	3,477	6,108	7,884	3,576	8,492	5,087	4,139	5,268	3,064
Capacity Export Limit (CEL) (MW)	3,959	2,550	4,310	No Limit Found[2]	No Limit Found	2,703	3,953	5,503	1,574	1,794
Zonal Import Ability (ZIA) (MW)	5,299	3,477	6,043	6,992	3,576	8,092	5,087	4,091	4,456	3,064
Zonal Export Ability (ZEA) (MW)	3,961	2,550	4,375	No Limit Found	No Limit Found	3,109	3,953	5,551	2,386	1,794

Table ES-1: Initial Planning Resource Auction Deliverables — Summer 2023

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Fall 2023 PRM UCAP	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%	14.9%
LRR UCAP per-unit of LRZ Peak Demand	1.274	1.218	1.408	1.254	1.452	1.247	1.345	1.490	1.278	1.619
Capacity Import Limit (CIL) (MW)	6,528	4,411	14,375[2]	5,173	5,380	6,070	4,285	4,705	6,045	2,425
Capacity Export Limit (CEL) (MW)	3,804	3,577	4,354	4,878	1,992	1,701	3,990	5,080	1,526	2,878
Zonal Import Ability (ZIA) (MW)	6,526	4,411	14,310[2]	4,281	5,380	5,670	4,285	4,657	5,233	2,425
Zonal Export Ability (ZEA) (MW)	3,806	3,577	4,419	5,770	1,992	2,101	3,990	5,128	2,338	2,878

Table ES-2: Initial Planning Resource Auction Deliverables — Fall 2023

[2] "No Limit Found" reflects no valid constraint identified.

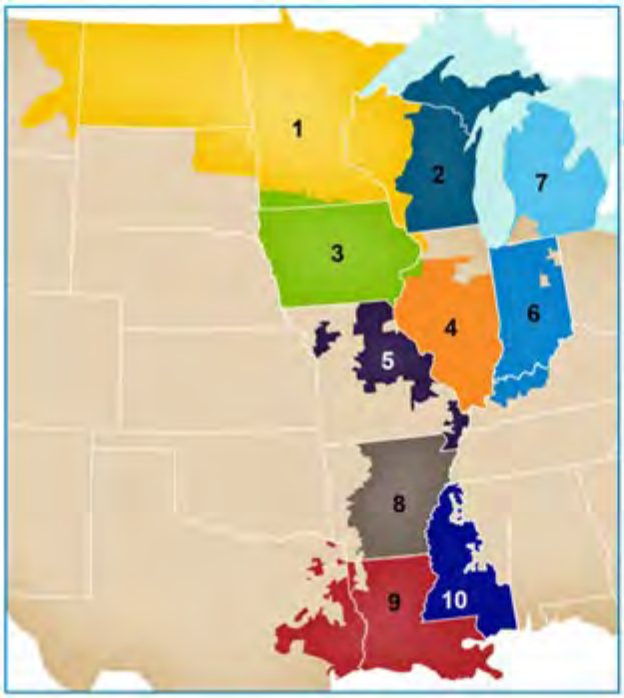
PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Winter 23-24 PRM UCAP	25.5%	25.5%	25.5%	25.5%	25.5%	25.5%	25.5%	25.5%	25.5%	25.5%
LRR UCAP per-unit of LRZ Peak Demand	1.403	1.422	1.850	1.365	1.474	1.301	1.573	1.503	1.323	1.777
Capacity Import Limit (CIL) (MW)	4,937	4,905	11,039[2]	3,928	3,811	8,818	6,340	4,729	6,080	2,396
Capacity Export Limit (CEL) (MW)	3,501	4,198	7,002	3,445	6,348	1,242	4,350	5,351	877	1,980
Zonal Import Ability (ZIA) (MW)	4,935	4,905	10,974[2]	3,036	3,811	8,418	6,340	4,681	5,268	2,396
Zonal Export Ability (ZEA) (MW)	3,503	4,198	7,067	4,337	6,348	1,642	4,350	5,399	1,689	1,980

Table ES-3: Initial Planning Resource Auction Deliverables — Winter 2023-2024

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Spring 2024 PRM UCAP	24.5%	24.5%	24.5%	24.5%	24.5%	24.5%	24.5%	24.5%	24.5%	24.5%
LRR UCAP per-unit of LRZ Peak Demand	1.375	1.267	1.623	1.454	1.610	1.320	1.329	1.627	1.315	1.747
Capacity Import Limit (CIL) (MW)	6,185	4,454	7,675	5,906	3,881	8,162	5,559	4,606	6,250	2,144
Capacity Export Limit (CEL) (MW)	4,321	3,679	6,173	3,745	3,724	2,344	4,413	5,472	2,240	2,720
Zonal Import Ability (ZIA) (MW)	6,183	4,454	7,610	5,014	3,881	7,762	5,559	4,558	5,438	2,144
Zonal Export Ability (ZEA) (MW)	4,323	3,679	6,238	4,637	3,724	2,744	4,413	5,520	3,052	2,720

Table ES-4: Initial Planning Resource Auction Deliverables — Spring 2024

LRZ3 Fall and Winter ZIA and CIL were updated after the final results were presented at the October LOLEWG. Both studies resulted in No Limit found and the equation was updated to include Tier 2, the October 3rd 2022 LOLEWG presentation has also been updated accordingly.



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, HMPL, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

Figure ES-1: Local Resource Zones (LRZ)

1 LOLE Study Process Overview

In compliance with Module E-1 of the MISO Tariff, MISO performed its annual LOLE study to determine, for each season of Planning Year 2023-2024, the system unforced capacity (UCAP) Planning Reserve Margin (PRM) and the per-unit Local Reliability Requirements (LRR) of Local Resource Zone (LRZ) Peak Demand.

In addition to the LOLE analysis, MISO performed seasonal transfer analyses to determine seasonal Zonal Import Ability (ZIA), Zonal Export Ability (ZEA), Capacity Import Limits (CIL) and Capacity Export Limits (CEL). CIL, CEL, and ZIA are used, in conjunction with the LOLE analysis results, in the Planning Resource Auction (PRA). ZEA is informational and not used in the PRA.

The PY 2023-2024 per-unit seasonal LRR UCAP multiplied by the updated LRZ seasonal Peak Demand forecasts submitted for the 2023-2024 PRA determines each LRZ's seasonal LRR. Once the seasonal LRR is determined, the ZIA values and non-pseudo tied exports are subtracted from the seasonal LRR to determine each LRZ's seasonal Local Clearing Requirement (LCR) consistent with Section 68A.6 of Module E-1[3]. An example calculation pursuant to Section 68A.6 of the current effective Module E-1 shows how these values are reached (Table 1-1).

Local Resource Zone (LRZ) EXAMPLE	Example LRZ	Formula Key
Installed Capacity (ICAP)	17,442	[A]
Unforced Capacity (UCAP)	16,326	[B]
Adjustment to UCAP (1d in 10yr)	50	[C]
Local Reliability Requirement (LRR) (UCAP)	16,376	[D]=[B]+[C]
LRZ Peak Demand	14,270	[E]
LRR UCAP per-unit of LRZ Peak Demand	114.8%	[F]=[D]/[E]
Zonal Import Ability (ZIA)	3,469	[G]
Zonal Export Ability (ZEA)	2,317	[H]
Proposed PRA (UCAP) EXAMPLE	**Example LRZ**	**Formula Key**
Forecasted LRZ Peak Demand	14,270	[I]
Forecasted LRZ Coincident Peak Demand	13,939	[J]
Non-Pseudo Tied Exports UCAP	150	[K]
Local Reliability Requirement (LRR) UCAP	16,376	[L]=[F]x[I]
Local Clearing Requirement (LCR)	12,757	[M]=[L]-[G]-[K]
Planning Reserve Margin (PRM)	7.4%	[N]
Zone's System Wide PRMR	14,970	[O]=[1.074]x[J]
PRMR	14,970	[P]=Higher of [M] or [O]

Table 1-1: Example LRZ Calculation

[3] https://www.misoenergy.org/legal/tariff
Effective Date: November 1, 2018

The actual effective PRM Requirement (PRMR) for each season of Planning Year 2023-2024 will be determined after the updated LRZ Seasonal Peak Demand forecasts are submitted by November 1, 2022, for the 2023-2024 PRA. The ZIA, ZEA, CIL and CEL values are subject to updates in March 2023 based on changes to exports of MISO resources to non-MISO load, changes to pseudo tied commitments, and updates to facility ratings following the completion of the LOLE study.

Finally, the simultaneous feasibility test (SFT) is performed as part of the PRA where cleared generation is tested to ensure transmission reliability and if constraints arise, they are mitigated by adjusting CIL and CEL values as needed.

1.1 Study Improvements

The Planning Year 2023-2024 LOLE study incorporated a number of study improvements as a result of the approved seasonal construct. These improvements include seasonal outage rates, correlated cold weather outages, probabilistic distribution of non-firm support, and hourly wind and solar profiles.

Historically, the LOLE model utilized a 5-year average EFORd, based on historic GADS data, which was constant throughout the simulated year for all resources. This year, seasonal EFORd was calculated using the same GADS data but outages were classified by season to produce four unique seasonal EFORd values for each resource. This change better captures the seasonal availability of resources observed in operations.

Additional outages are added to the model during times of extreme cold temperatures to better capture the magnitude of correlated outages observed. The magnitude of forced outages added increases as temperatures decrease based on the relationship between outages and temperature determined from historic GADS and weather data. Each LRZ has a unique outage/temperature curve based on actual performance. The incremental cold weather outages are not assigned to a particular resource but instead represent the aggregate impact on the system for coal and gas resources.

For the last several years MISO has accounted for non-firm support in the LOLE process by simply reducing the PRM by a fixed amount on a 1-for-1 MW basis. This year's study incorporated seasonal distributions of non-firm support directly in the model which are based on historic Net Scheduled Interchange (NSI) data. As the model steps through time chronologically, SERVM will randomly draw import values from this distribution to be used to serve load.

In previous LOLE studies, wind resources were modeled as perfect units with a constant output equal to their monthly ELCC values while solar resources were modeled as perfect units with constant output equal to their capacity credit. For Planning Year 2023-2024, wind and solar resources were modeled as variable energy resources with 30 unique hourly profiles corresponding to the 30 unique weather years within SERVM.

2 Transfer Analysis

2.1 Calculation Methodology and Process Description

Transfer analyses determined CIL and CEL values for LRZs in each season for Planning Year 2023-2024. Annual adjustments are made for Border External Resources (BERs) and Coordinating Owner Resources (COs) to determine the ZIA and ZEA in each season. Further adjustments are made for exports to non-MISO Loads to arrive at the CIL and CEL values. The objective of transfer analysis is to determine constraints caused by the transfer of capacity between zones and the associated transfer capability. Multiple factors impacted the analysis when compared to previous studies, including:

- 3.7 GW of Retirements / Suspensions
- New Intermittent Resources
- Base Model Dispatch in MISO and Seams

2.1.1 Generation Pools

To determine an LRZ's import or export limit, a transfer is modeled by ramping generation up in a source subsystem and ramping generation down in a sink subsystem. The source and sink definitions depend on the limit being tested. The LRZ studied for import limits is the sink subsystem and the adjacent MISO LBA's are the source subsystem. The LRZ studied for export limits is the source subsystem and the rest of MISO is the sink subsystem. These are the same in all seasons for the upcoming Planning Year.

Transfers can cause potential issues, which are addressed through the study assumptions. First, an abundantly large source pool spreads the impact of the transfer widely which can cause differences in studied zones transfer capabilities and constraints identified. Second, ramping up generation from remote areas could cause electrically distant constraints for any given LRZ, which should not determine a zone's limit. For example, export constraints due to dispatch of LRZ 1 generation in the northwest portion of the footprint should not limit the import capability of LRZ 10, which covers the MISO portion of Mississippi.

To address these potential issues, the transfer studies limit the source pool for the import studies to the Tier 1 and Tier 2 adjacent LBA's to the study zone. Since the generation that is ramped up in export studies are contained in the study LRZ, these issues only apply to import studies. Generation within the zone studied for an export limit is ramped up and constraints are expected to be near or in the study zone.

2.1.2 Redispatch

Limited redispatch is applied after performing transfer analyses to mitigate constraints. Redispatch ensures constraints are not caused by the base dispatch and aligns with potential actions that can be implemented for the constraint in MISO operations. Redispatch scenarios can be designed to address multiple constraints as required and may be used for constraints that are electrically close to each other or to further optimize transfer limits for several constraints requiring only minor redispatch. The redispatch assumptions include:

- The use of no more than 10 conventional fuel plants or intermittent resources
- Redispatch limit at 2,000 MW total (1,000 MW up and 1,000 MW down)
- No adjustments to nuclear units
- No adjustments to the portions of pseudo-tied units committed to non-MISO load

2.1.3 Generation Limited Transfer for CIL/CEL and ZIA/ZEA

When conducting transfer analysis to determine import or export limits, the source subsystem might run out of generation to dispatch before identifying a valid constraint caused by a transmission limit. MISO developed a Generation Limited Transfer (GLT) process to identify transmission constraints in these situations, when possible, for both imports and exports.

After running the First Contingency Incremental Transfer Capability (FCITC) analysis to determine limits for each LRZ, MISO will determine whether a zone is experiencing a GLT (e.g. whether the first constraint would only occur after all the generation is dispatched at its maximum amount). If the LRZ experiences a GLT, MISO will adjust the base model depending on whether it is an import or export analysis and re-run the transfer analysis.

For an export study, when a transmission constraint has not been identified after dispatching all generation within the exporting system (LRZ under study) MISO will decrease load and generation dispatch in the study zone. The adjustment creates additional capacity to export from the zone. After the adjustments are complete, MISO will rerun the transfer analysis. If a GLT reappears, MISO will make further adjustments to the load and generation of the study zone.

For an import study, when a transmission constraint has not been identified after dispatching all generation within the source subsystem, MISO will decrease load and generation in the source subsystem. This increases the export capacity of the adjacent LBA's for the study zone. After the adjustments are complete, MISO will run the transfer analysis again. If a GLT reappears, MISO will make further adjustments to the model's load and generation in the source subsystem.

FCITC could indicate the transmission system can support larger thermal transfers than would be available based on installed generation for some zones. However, large variations in load and generation for any zone may lead to unreliable limits and constraints. Therefore, MISO limits load scaling for both import and export studies to 50 percent of the zone's load. In a GLT, redispatch, or GLT plus redispatch scenario, the FCITC of the most limiting constraint might exceed Zonal Export/Import Capability. If the GLT does not produce a limit for a zone(s), due to a valid constraint not being identified, or due to other considerations as listed in the prior paragraph, MISO shall report that LRZ as having no limit and ensure that the limit will not bind in the first iteration of the Simultaneous Feasibility Test (SFT).

2.1.4 Voltage Limited Transfer for CIL/CEL and ZIA/ZEA

Zonal imports may be limited by voltage constraints due to a decrease in the generation in the study zone. Voltage constraints might occur at lower transfer levels than thermal limits determined by linear FCITC. As such, LOLE studies may evaluate Power-Voltage curves for LRZs with known voltage-based transfer limitations identified through existing MISO or Transmission Owner studies. Such evaluation may also occur if an LRZ's import reaches a level where the majority of the zone's load would be served using imports from resources outside of the zone. MISO will coordinate with stakeholders as it encounters these scenarios. For Planning Year 2023-2024, all seasons only Zones 1, 4 and 7 import analysis included voltage screening and study. Only LRZ4 Summer identified a voltage limit with lower transfer capability than the thermal limit.

2.2 Powerflow Models and Assumptions

2.2.1 Tools Used

MISO used the Siemens PTI Power System Simulator for Engineering (PSS/E) and Transmission Adequacy and Reliability Assessment (TARA) for analysis tools.

2.2.2 Inputs Required

Thermal transfer analysis requires powerflow models and related input files. MISO used contingency files from MTEP[4] reliability assessment studies. Single-element contingencies in MISO/seam areas were also evaluated.

MISO developed a subsystem file to monitor its footprint and seam areas which was used for all seasons. LRZ definitions were developed as sources and sinks in the study. See Appendix B for tables containing adjacent area definitions (Tiers 1 and 2) used for this study. The monitored file includes all facilities under MISO functional control and single elements in the seam areas of 100 kV and above.

2.2.3 Powerflow Modeling

The MTEP22 models were built using MISO's Model on Demand (MOD) model data repository, with the following base assumptions (Table 2-1).

Scenario	Effective Date	Projects Applied	External Modeling	Load and Generation Profile	Wind %	Solar %
Summer 2023	July 15th	MTEP Appendix A and Target A	2021 Series 2023 Summer ERAG MMWG	Summer Peak	Capacity Credit ~15.5%	50%
Fall 2023	October 15th	MTEP Appendix A and Target A	2021 Series 2023 Summer ERAG MMWG	Fall Peak	32%	28.5%
Winter 2023-2024	January 15th	MTEP Appendix A and Target A	2021 Series 2023 Summer ERAG MMWG	Winter Peak	67%	0%
Spring 2024	April 15th	MTEP Appendix A and Target A	2021 Series 2023 Summer ERAG MMWG	Spring Peak	28.5%	32%

Table 2-1: Model Assumptions

MISO excluded several types of units from the transfer analysis dispatch—these units' base dispatch remained fixed.

- Nuclear dispatch does not change for any transfer
- Wind and solar resources can be ramped down, but not up
- Pseudo-tied resources were modeled at their expected commitments to non-MISO load, although portions of these units committed to MISO could participate in transfer analyses

System conditions such as load, dispatch, topology, and interchange have an impact on transfer capability. The model was reviewed as part of the base model build for MTEP22 analyses, with study files made available on MISO

[4] Refer to the Transmission Planning BPM (BPM-20) for more information regarding MTEP input files. https://www.misoenergy.org/legal/business-practice-manuals/

ShareFile. MISO worked closely with transmission owners and stakeholders in order to model the transmission system accurately, as well as to validate constraints and redispatch. Like other planning studies, transmission outage schedules were not included in the analysis. This is driven partly by limited availability of outage information as well as current transmission planning standards. Although no outage schedules were evaluated, single element contingencies were evaluated. This includes BES lines, transformers, and generators.

Contingency coverage covers most of category P1 and some of category P2 outlined in Table 1 of TPL-001: (https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf).

2.2.4 General Assumptions

MISO uses TARA to process the powerflow model and associated input files to determine the import and export limits of each LRZ in each season by determining the transfer capability. Transfer capability measures the ability of interconnected power systems to reliably transfer power from one area to another under specified system conditions. The incremental amount of power that can be transferred is determined through FCITC analysis. FCITC analysis and base power transfers provide the information required to calculate the First Contingency Total Transfer Capability (FCTTC), which indicates the total amount of transferrable power before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability (Equation 3-1). All published limits are based on the zone's FCTTC and may be adjusted for capacity exports.

$$First\ Contingency\ Total\ Transfer\ Capability\ (FCTTC) = FCITC + Base\ Power\ Transfer$$

Equation 2-1: Total Transfer Capability

FCITC constraints are identified under base case situations in each season or under P1 contingencies provided through the MTEP process. Linear FCITC analysis identifies the limiting constraints using a minimum transfer Distribution Factor (DF) cutoff of 3 percent, meaning the transfer must increase the loading on the overloaded element, under system intact or contingency conditions, by 3 percent or more.

A pro-rata dispatch is used, which ensures all available generators will reach their maximum dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit's base model generation dispatch from its maximum dispatch, which reflects the available capacity of the unit.

Table 2-2 and Equation 2-2 show an example of how one unit's dispatch is set, given all machine data for the source subsystem.

Machine	Base Model Unit Dispatch (MW)	Minimum Unit Dispatch (MW)	Maximum Unit Dispatch (MW)	Reserve MW (Unit Dispatch Max – Unit Dispatch Min)
1	20	20	100	80
2	50	10	150	100
3	20	20	100	80
4	450	0	500	50
5	500	100	500	0
			Total Reserve	**310**

Table 2-2: Example Subsystem

$$\textbf{\textit{Machine 1 Incremental Post Transfer Dispatch}} = \frac{\textbf{\textit{Machine 1 Reserve MW}}}{\textbf{\textit{Source Subsystem Reserve MW}}} \times \textbf{\textit{Transfer Level MW}}$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = \frac{80}{310} \times 100 = 25.8$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = 25.8$$

Equation 2-2: Machine 1 Dispatch Calculation for 100 MW Transfer

2.3 Results for CIL/CEL and ZIA/ZEA

Study constraints and associated ZIA, ZEA, CIL, and CEL for each LRZ for each season were presented and reviewed through the LOLEWG with final results for Planning Year 2023-2024 presented at the October 3rd, 2022 meeting. Table 2-3 below shows the Planning Year 2023-2024 CIL and ZIA with corresponding constraint, GLT, and redispatch (RDS) information.

All zones had an identified ZIA this year. If there is no valid constraint identified the following equation will be used where the FCITC will be replaced by the Tier 1 & 2 capacity.

$$\textbf{\textit{ZIA}} = \textbf{\textit{FCITC}} + \textbf{\textit{AI}} - \textbf{\textit{Border External Resources and Coordinating Owners}}$$

Equation 2-3: Zonal Import Ability (ZIA) Calculation

LRZ1	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2023	North Appleton - Werner W 345kV	North Appleton - Morgan 345kV	15%	494MWx2	5299	5301
Fall 2023	North Appleton - Werner W 345kV	North Appleton - Morgan 345kV	None	636MWx2	6526	6528
Winter 2023/24	Council Bluffs - Sarpy County 345kV	Arbor Hill - Raccoon Trail 345kV	None	681MWx2	4935	4937
Spring 2024	North Appleton - Werner W 345kV	North Appleton - Morgan 345kV	None	328MWx2	6183	6185
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Elk Mound - Wheaton 161kV	King - Eau Claire 345kV	10%	1000MWx2	3477	3477
Fall 2023	Arpin - Sigel 138kV	Rocky Run - Arpin 345kV	None	1000MWx2	4411	4411
Winter 2023/24	Arpin - Sigel 138kV	Rocky Run - Arpin 345kV	None	1000MWx2	4905	4905
Spring 2024	Arpin - Sigel 138kV	Rocky Run - Arpin 345kV	None	603MWx2	4454	4454
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	S3458 3 - S3456 3 345kV	S3455 - S3740 345kV	10%	113MWx2	6043	6108
Fall 2023	No Limit Found		None	None	14,310	14,375
Winter 2023/24	No Limit Found		None	None	10,974	11,039
Spring 2024	Prairie Island - North Rochester 345kV	North Rochester - Hampton Corner 345kV	None	345MWx2	7610	7675
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Bus 636410 Sub P Iowa City 161kV	Hills 345/161kV Transformer	None	None	6992	7884
Fall 2023	Marblehead 161/138kV Transformer	Herlman - Maywood 345kV	None	1000MWx2	4281	5173
Winter 2023/24	Marblehead 161/138kV Transformer	Herlman - Maywood 345kV	None	1000MWx2	3036	3928
Spring 2024	Marblehead 161/138kV Transformer	Herlman - Maywood 345kV	None	935MWx2	5014	5906
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Pike - Cryene 161kV	Maywood - Spencer Creek 345kV	10%	81MWx2	3576	3576
Fall 2023	Mississippi Tap - Sioux 138kV	Loss of Sioux Generation	15%	708MWx2	5380	5380
Winter 2023/24	Overton 345/161kV Transformer	Mc Credie - Overton 345kV	None	1000MWx2	3811	3811
Spring 2024	Calif - Apache Tap 161kV	Mc Credie - Montgomery 345kV	None	244MWx2	3881	3881
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Cayuga Sub - Cayuga 345kV	Kansas - Sugar Creek 345kV	20%	619MWx2	8092	8492
Fall 2023	Jord - West Frankfort 138kV	Mount Vernon - West Frankfort 345kV	None	1000MWx2	5670	6070
Winter 2023/24	Cayuga Sub - Cayuga 345kV	Kansas - Sugar Creek 345kV	None	923MWx2	8418	8818
Spring 2024	Cayuga Sub - Cayuga 345kV	Kansas - Sugar Creek 345kV	None	620MWx2	7762	8162
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Argenta - Tompkins 345kV	Argenta - Battle Creek 345kV	15%	1000MWx2	5087	5087
Fall 2023	Benton Harbor - Segreto 345kV	Cook - Segreto 345kV	None	1000MWx2	4285	4285
Winter 2023/24	Stillwell 345kV/138kV Transformer	Dumont - Stillwell 345kV	None	1000MWx2	6340	6340
Spring 2024	Benton Harbor - Segreto 345kV	Cook - Segreto 345kV	None	1000MWx2	5559	5559
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Lyon - Jonestown 115kV	Crossroads - Moonlake 230kV	None	180MWx2	4091	4139
Fall 2023	Moon Lake - Ritchie 230kV	Clarksdale - Crossroads 230/115kV Transformer	None	372MWx2	4657	4705
Winter 2023/24	Mount Olive - Vienna 115kV	Mount Olive - El Dorado 500kV	None	1000MWx2	4681	4729
Spring 2024	Mount Olive - Vienna 115kV	Mount Olive - El Dorado 500kV	None	181MWx2	4558	4606

LRZ9	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2023	Bogalusa - Barkers Corner 230kV	McKnight - Franklin 500kV	None	1000MWx2	4456	5268
Fall 2023	Braswell - Franklin 500kV	Franklin - Grand Gulf 500kV	None	325MWx2	5233	6045
Winter 2023/24	Camden - Smackover 115kV	McNeil - Camden 115kV	None	963MWx2	5268	6080
Spring 2024	Boogalusa 500/230kV Transformer	McKnight - Franklin 500kV	None	1000MWx2	5438	6250
LRZ10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2023	Braswell - Northside 230kV	Braswell - Lakeover 500kV	None	38MWx2	3064	3064
Fall 2023	Braswell - Northside 230kV	Braswell - Lakeover 500kV	None	33MWx2	2425	2425
Winter 2023/24	Adams Creek - Angie 230kV	Slidel - Logtown 230kV	None	134MWx2	2396	2396
Spring 2024	Hernando - Coldwater 115kV	Moonlake - Ritchie 230kV	None	31MWx2	2144	2144

Table 2-3: Planning Year 2023–2024 Import Limits

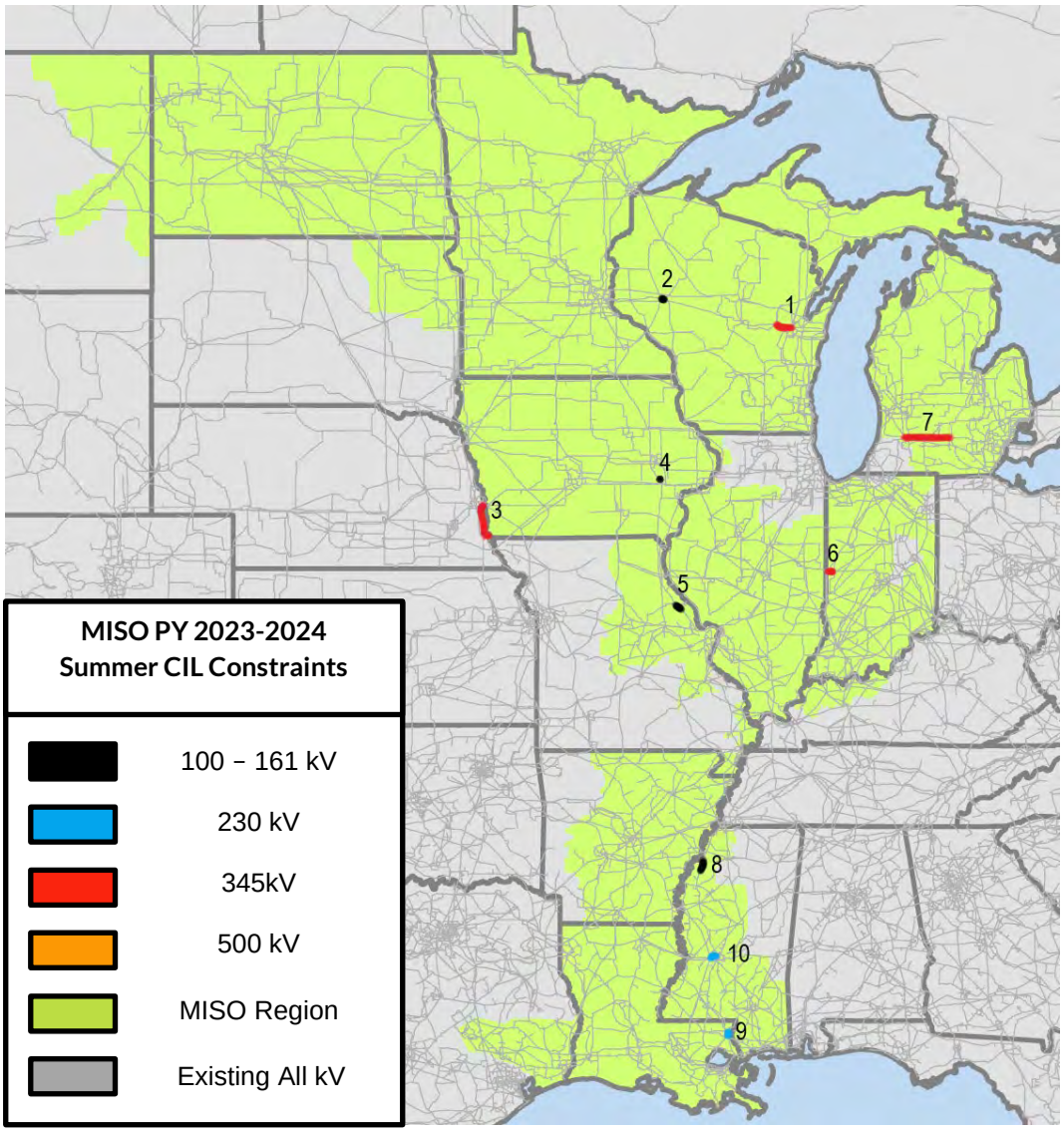


Figure 2-1: Planning Year 2023-2024 Summer Capacity Import Constraints Map

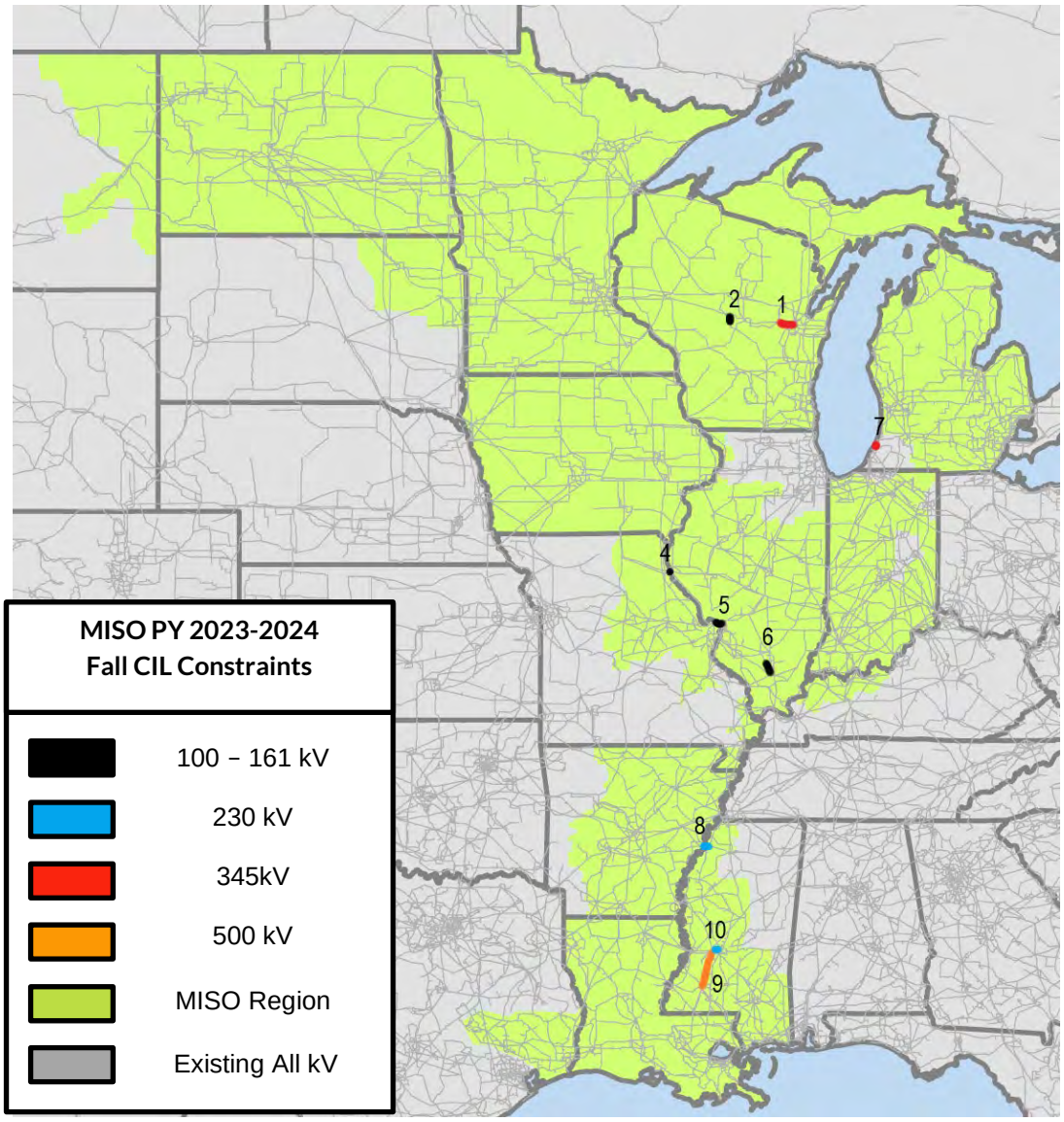


Figure 2-2: Planning Year 2023-2024 Fall Capacity Import Constraints Map

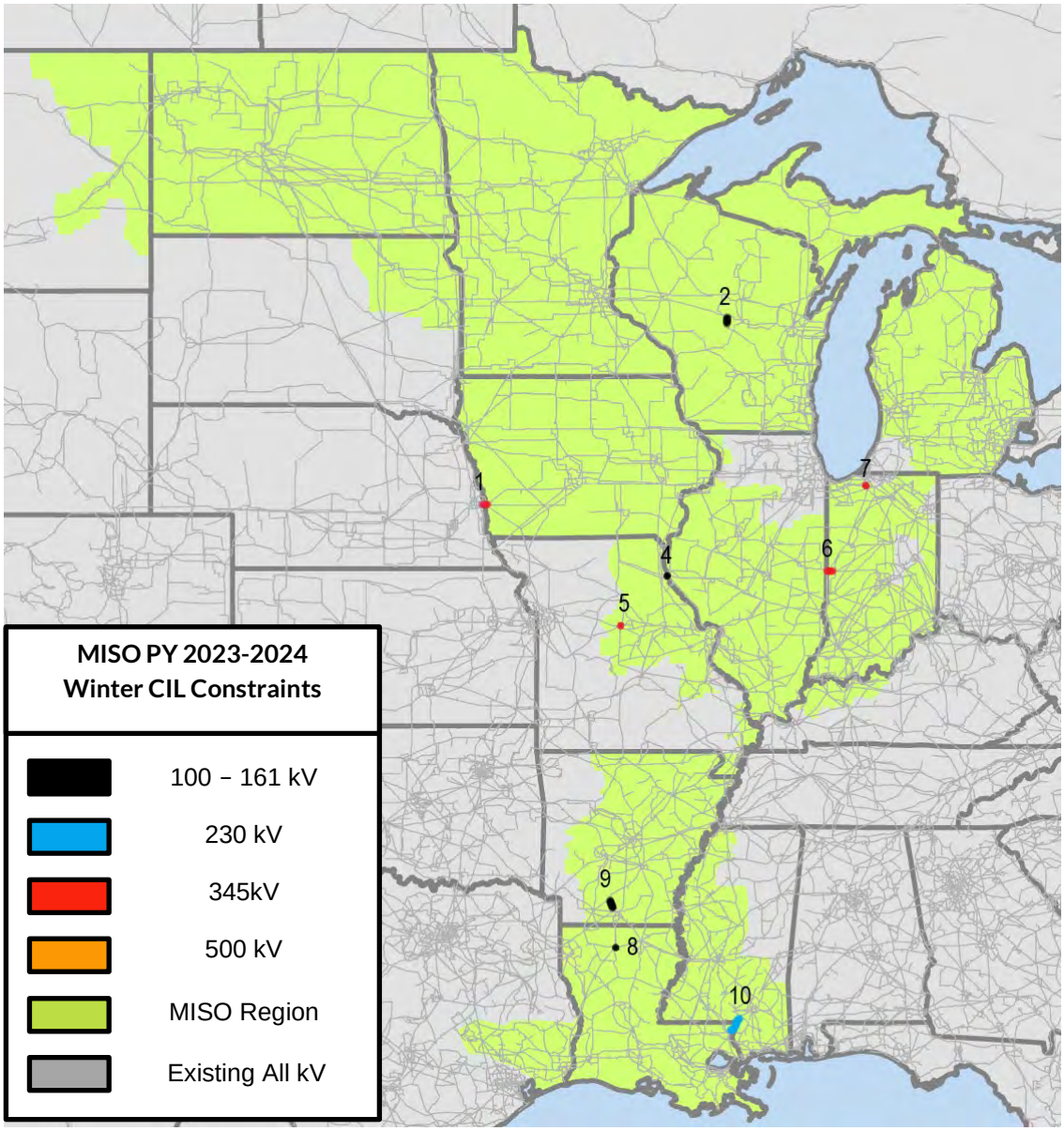


Figure 2-3: Planning Year 2023-2024 Winter Capacity Import Constraints Map

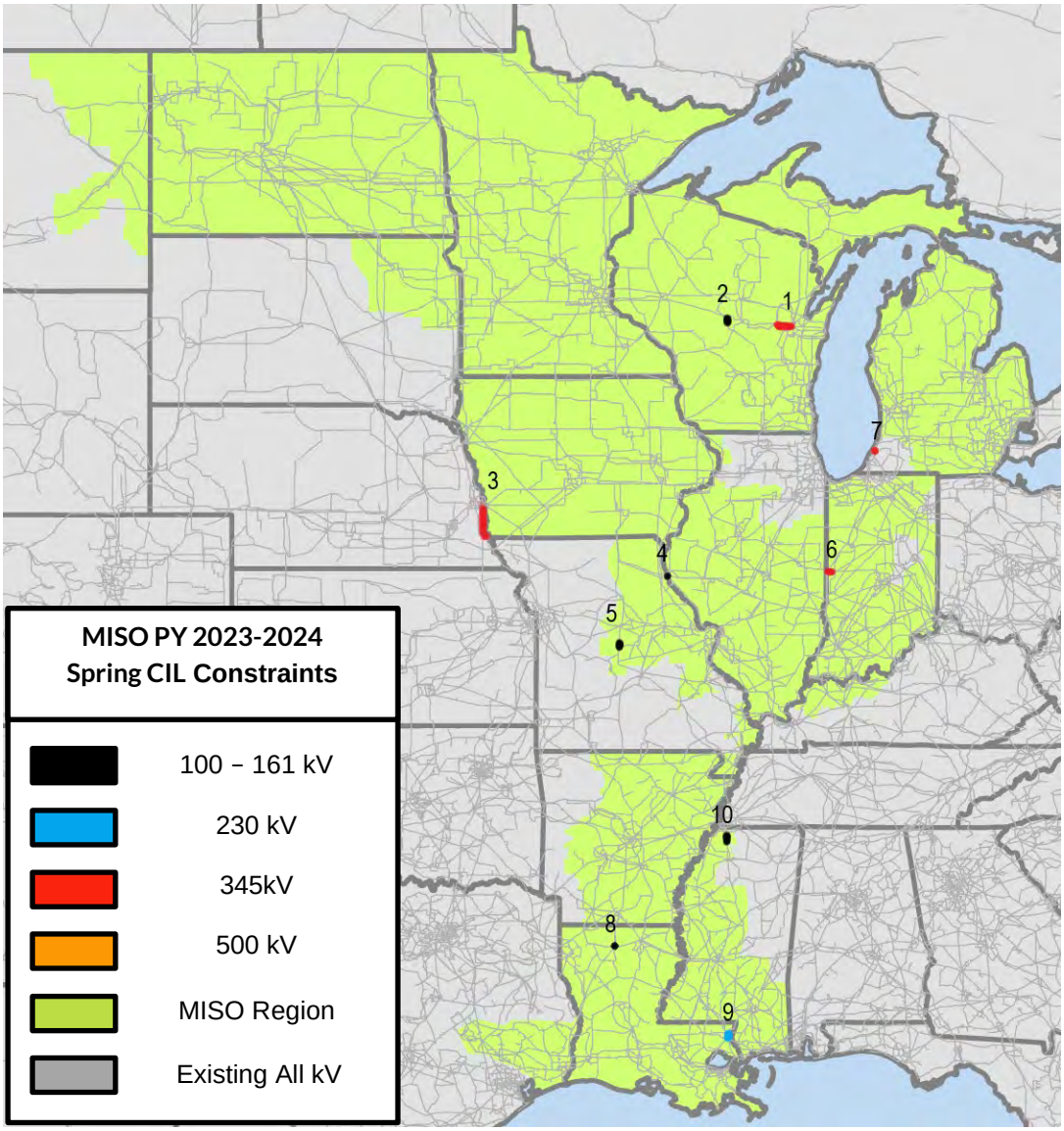


Figure 2-4: Planning Year 2023-2024 Spring Capacity Import Constraints Map

Capacity Exports Limits are found by increasing generation in the study zone and decreasing generation in the rest of the MISO footprint to create a transfer. Table 2-4 below shows the Planning Year 2023-2024 CEL and ZEA with corresponding constraint, GLT, and redispatch information.

LRZ1	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2023	Granville - Butler 138kV	Granville - Arcadian 345kV	15%	None	3961	3959
Fall 2023	Arpin - Sigel 138kV	Rocky Run - Arpin 345kV	None	18MWx2	3806	3804
Winter 2023/24	Arpin - Sigel 138kV	Rocky Run - Arpin 345kV	None	29MWx2	3503	3501
Spring 2024	Rocky Run - Werner 345kV	Highway 22 - Gardner Park 345kV	None	21MWx2	4323	4321
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Wempletown 345/138kV Transformer	Cherry Valley - Wempleton 345kV	20%	None	2550	2550
Fall 2023	Elm Road - Racine 345kV	Base Case	None	None	3577	3577
Winter 2023/24	Pleasant Prairie - Zion EC 345kV	Pleasant Prairie - Zion 345kV	15%	None	4198	4198
Spring 2024	Elm Road - Racine 345kV	Base Case	None	None	3679	3679
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Mercer - Sandburg 161kV	Sandburg - Oak Grove 345kV	45%	None	4375	4310
Fall 2023	Prar Creek - Marion 115	Prar Creek - Bertram 115kV	None	147MWx2	4419	4354
Winter 2023/24	Sandburg 161/138kV Transformer	Sandburg - Oak Grove 345kV	None	109MWx2	7067	7002
Spring 2024	Sandburg 161/138kV Transformer	Sandburg - Oak Grove 345kV	40%	None	6238	6173
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	No CEL Found	No CEL Found	50%	None	9999	9999
Fall 2023	No CEL Found	No CEL Found	50%	None	9999	9999
Winter 2023/24	No CEL Found	No CEL Found	50%	None	9999	9999
Spring 2024	No CEL Found	No CEL Found	50%	None	9999	9999
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	No CEL Found	No CEL Found	45%	None	9999	9999
Fall 2023	Jord - West Frankfort 138kV	Mount Vernon - West Frankfort 345kV	None	None	1992	1992
Winter 2023/24	Miles Avenue - Moro 138kV	Roxford - Moro 345kV	35%	121MWx2	6348	6348
Spring 2024	Mass 345/161 kV Transformer	Joppa - Mass 345kV	None	None	3724	3724
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Franscisco - Duff 345kV	AB Brown - Reid 345kV	15%	206MWx2	3109	2703
Fall 2023	Newtonville - Coleman 161kV	Duff - Coleman 345kV	None	493MWx2	2101	1701
Winter 2023/24	Newtonville- Grandview 138kV	Cutley - Dubois 138kV	None	42MWx2	1642	1242
Spring 2024	Newtonville - Coleman 161kV	AB Brown - Reid 345kV	None	65MWx2	2744	2344
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Monroe - Lulu 345kV	Monroe - Lallendorf 345kV	25%	None	3953	3953
Fall 2023	Monroe - Lulu 345kV	Monroe - Lallendorf 345kV	None	None	3990	3990
Winter 2023/24	Monroe - Lulu 345kV	Monroe - Lallendorf 345kV	None	None	4350	4350
Spring 2024	Monroe - Lulu 345kV	Monroe - Lallendorf 345kV	None	None	4413	4413
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Cash - Jonesboro 161kV	Ises - Powerlane Road 500kV	50%	218MWx2	5551	5503
Fall 2023	Arklahoma - HS EHV 115kV 2	Arklahoma - HS EHV 115kV 2	None	177MWx2	5128	5080
Winter 2023/24	Cash - Jonesboro 161kV	Ises - Powerlane Road 500kV	25%	134MWx2	5399	5351
Spring 2024	Cash - Jonesboro 161kV	Ises - Powerlane Road 500kV	None	177MWx2	5520	5472

LRZ9	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2023	Adams Creek - Angie 230kV	Slidel - Log Town 230kV	None	None	2386	1574
Fall 2023	Wrightsville - Keo 500kV	White Bluff - Keo 500kV	None	None	2338	1526
Winter 2023/24	Adams Creek - Angie 230kV	Slidel - Log Town 230kV	None	None	1689	877
Spring 2024	Adams Creek - Angie 230kV	Slidel - Log Town 230kV	None	None	3052	2240
LRZ10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2023	Andrus 230/115kV Transformer	Andrus - Indianola	None	510MWx2	1794	1794
Fall 2023	Clarksdale - Lyon 115kV	Crossroads - Moon Lake 230kV	None	284MWx2	2878	2878
Winter 2023/24	Batesville - Tallahachie 161kV	Choctaw - Clay 500kV	None	690MWx2	1980	1980
Spring 2024	Clarksdale - Lyon 115kV	Crossroads - Moon Lake 230kV	None	535MWx2	2720	2720

Table 2-4: Planning Year 2023–2024 Export Limits

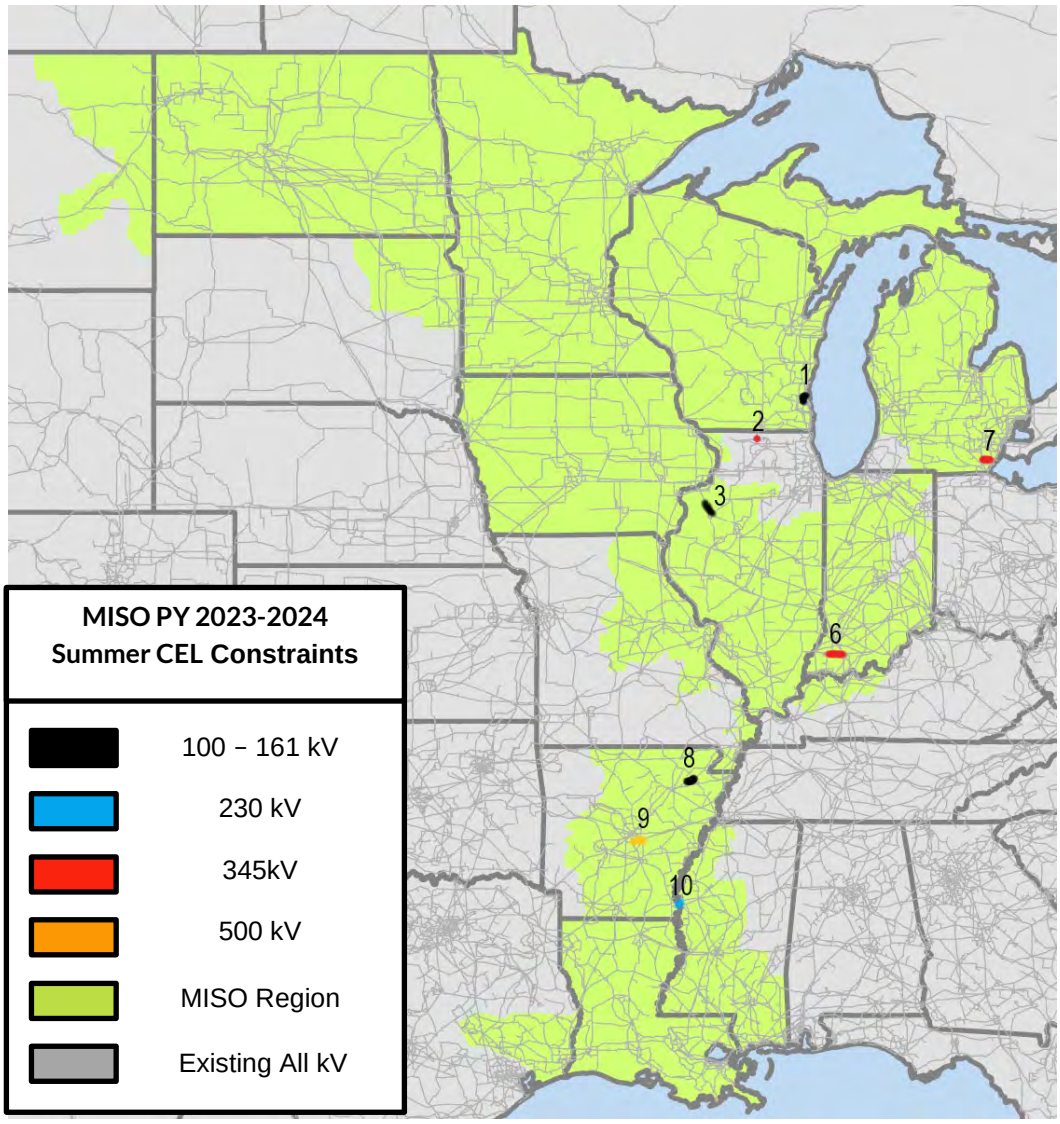


Figure 2-5: Planning Year 2023-2024 Summer Export Constraint Map

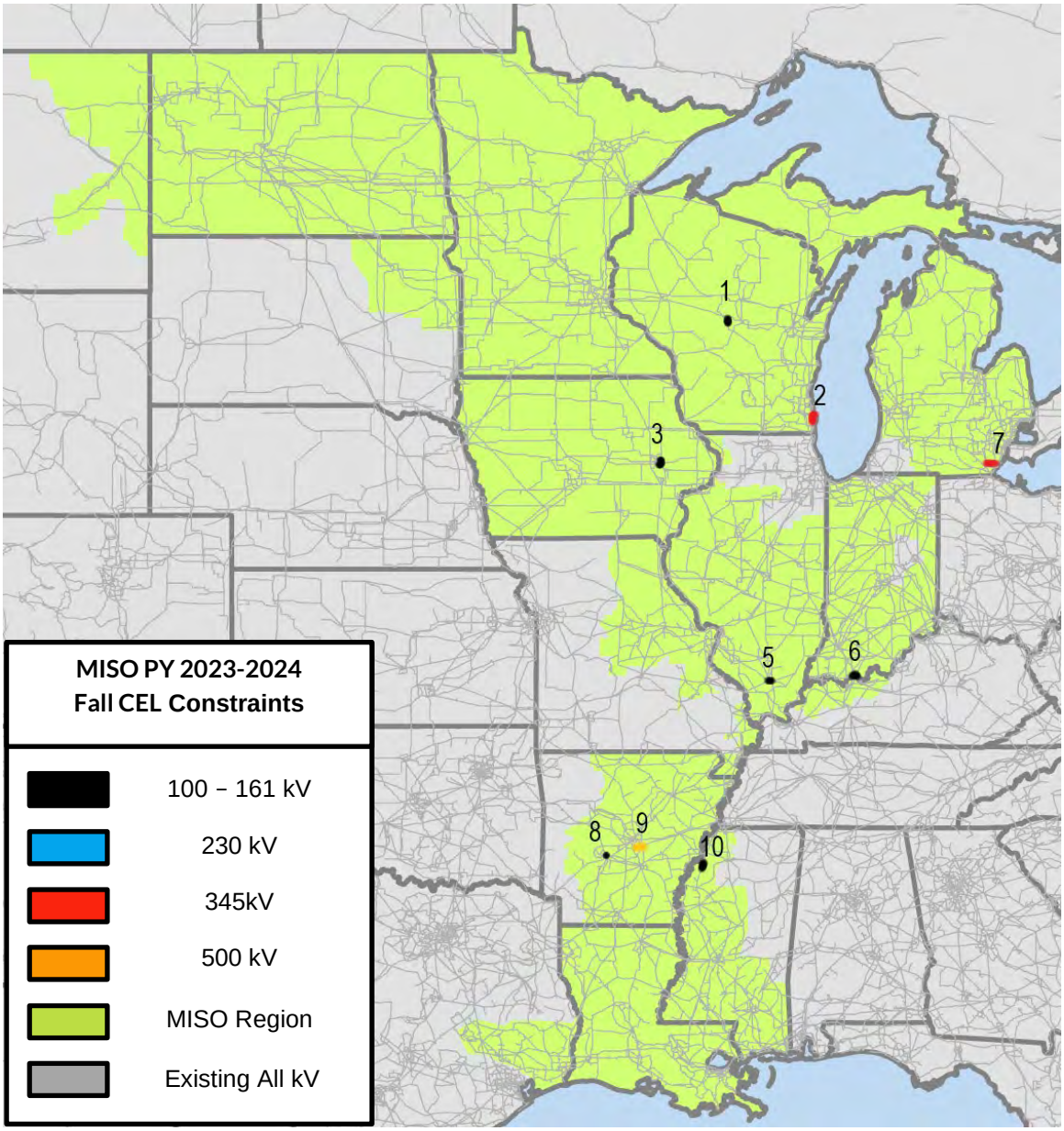


Figure 2-6: Planning Year 2023-2024 Fall Export Constraint Map

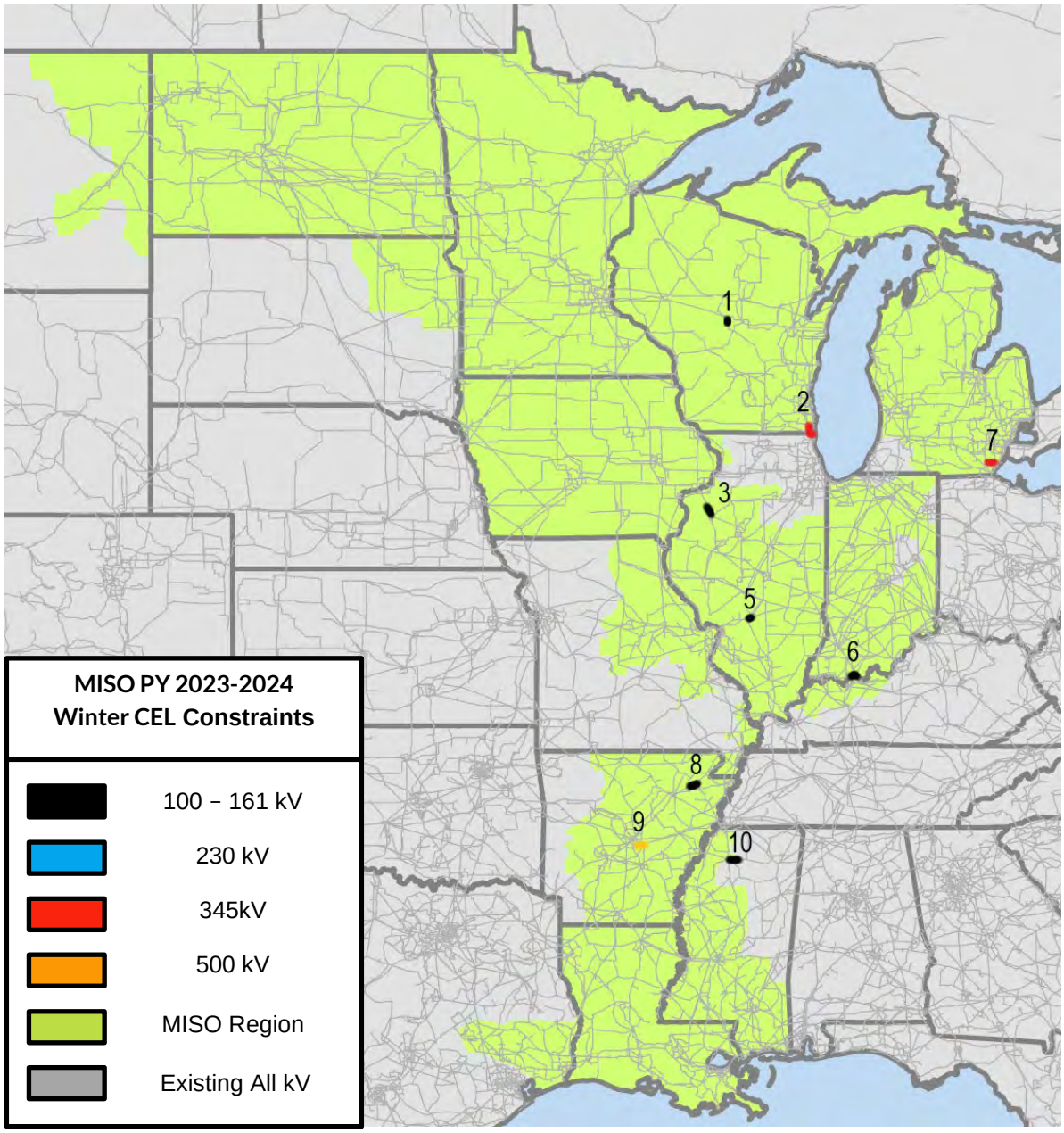


Figure 2-7: Planning Year 2023-2024 Winter Export Constraint Map

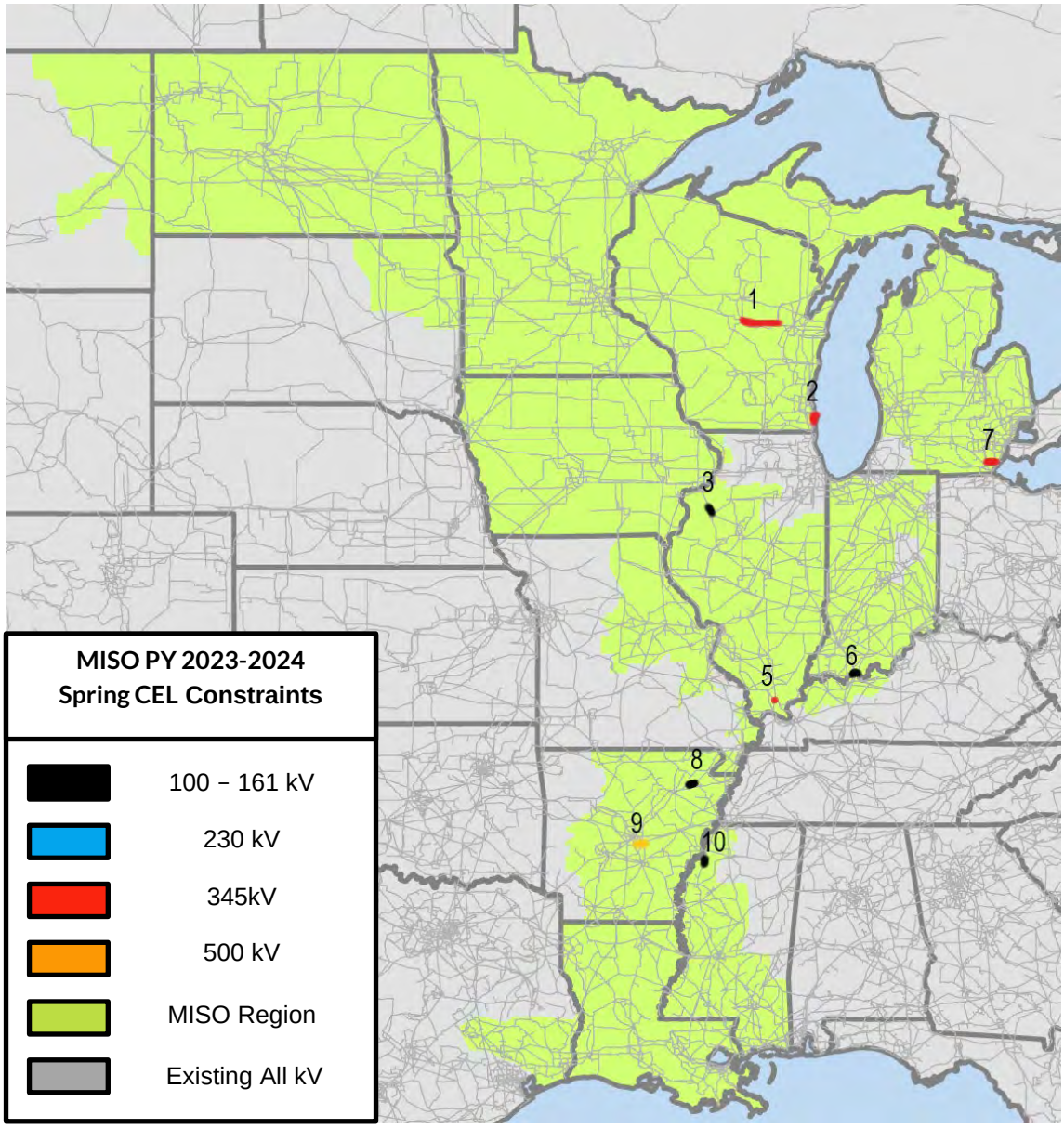


Figure 2-8: Planning Year 2023-2024 Spring Export Constraint Map

2.3.1 Outyear Analysis

In 2018, MISO and its stakeholders redesigned the outyear LOLE transfer analysis process through the LOLEWG and Resource Adequacy Subcommittee (RASC). The outyear analysis is now performed after the prompt Planning Year analyses are complete. The outyear results are informational only. The zones identified for outyear analysis are determined by BPM-011 criteria. The results will be documented outside of the LOLE report and recorded in RASC meeting materials in Q2 of 2023 and memorialized at a later date as an addendum to the LOLE report in 2023.

3 Loss of Load Expectation Analysis

3.1 LOLE Modeling Input Data and Assumptions

MISO uses a program managed by Astrapé Consulting called Strategic Energy & Risk Valuation Model (SERVM) to calculate the LOLE for the applicable Planning Year. SERVM uses a sequential Monte Carlo simulation to model a generation system and to assess the system's reliability based on any number of interconnected areas. SERVM calculates the LOLE for the MISO system and each LRZ by stepping through the year chronologically and taking into account generation, load, load modifying and energy efficiency resources, equipment forced outages, planned and maintenance outages, weather and economic uncertainty, and external support.

Building the SERVM model is the most time-consuming task of the LOLE study. Many scenarios are built in order to determine how certain variables impact the results. The base case models determine the seasonal MISO PRM Installed Capacity (ICAP), PRM UCAP, and the LRRs for each LRZ for future Planning Years one, four and six.

3.2 MISO Generation

3.2.1 Thermal Units

The Planning Year 2023-2024 LOLE study used the 2022-2023 PRA converted capacity as a starting point for which resources to include in the study. This ensured that only resources eligible as a Planning Resources were included in the LOLE study. An exception was made for resources with a signed GIA with an anticipated in-service date for PY 2023-2024—these resources were also included. All internal Planning Resources were modeled in the LRZ in which they are physically located. Additionally, Coordinating Owners and Border External Resources were modeled as being internal to the LRZ in which they are committed to serving load.

Forced outage rates and planned maintenance factors were calculated over a five-year period (January 2017 to December 2021) and modeled as four seasonal values for each unit. Some units did not have five years of historical data in MISO's Generator Availability Data System (PowerGADS)—however, if they had at least 3 consecutive months of seasonal data, unit-specific information was used to calculate their seasonal forced outage rates and maintenance factors. Units with fewer than 3 consecutive months of seasonal unit-specific data were assigned the corresponding MISO seasonal class average forced outage rate and seasonal planned maintenance factor based on their fuel type. The overall MISO ICAP-weighted seasonal class average forced outage rate and seasonal planned maintenance factor are applied in lieu of class averages for classes with fewer than 30 units. When the units are populated into the LOLE model, the weighted outage rate in SERVM may be different from the calculated MISO-wide weighted average because the MISO-wide weighted average excludes units with insufficient operating history. Therefore, the weighted outage rate is recalculated to include units that were assigned class average outage rates to gauge how SERVM views the MISO-wide weighted average. This value is for information only and is not assigned to any units.

Each nuclear unit has a fixed maintenance schedule, which was pulled from publicly available information and was modeled for each of the study years.

The historical class average outage rates as well as the MISO system-wide weighted average forced outage rate are provided in Table 3-1 to show the year-over-year trends, as well as in Table 3-2 on a seasonal basis.

Pooled EFORd GADS Years	2017-2021 (%)	2016-2020 (%)	2015-2019 (%)	2014-2018 (%)	2013-2017 (%)	2012-2016 (%)
LOLE Study Planning Year	**PY 2023-2024 LOLE Study – Summer 2023**	**PY 2022-2023 LOLE Study**	**PY 2021-2022 LOLE Study**	**PY 2020-2021 LOLE Study**	**PY 2019-2020 LOLE Study**	**PY 2018-2019 LOLE Study**
Combined Cycle	5.54	5.85	5.52	5.70	5.370	4.62
Combustion Turbine (0-20 MW)	23.40	35.20	36.38	40.39	23.18	29.02
Combustion Turbine (20-50 MW)	6.30	13.65	14.20	15.29	15.76	13.48
Combustion Turbine (50+ MW)	4.07	4.36	4.76	4.65	5.18	6.19
Diesel Engines	12.79	7.25	10.05	23.53	10.26	10.42
Fluidized Bed Combustion	*	*	*	*	*	*
Hydro (0-30 MW)	*	*	*	*	*	*
Hydro (30+ MW)	*	*	*	*	*	*
Nuclear	*	*	*	*	*	*
Pumped Storage	*	*	*	*	*	*
Steam - Coal (0-100 MW)	*	*	*	5.33	4.60	5.14
Steam - Coal (100-200 MW)	*	*	*	*	*	*
Steam - Coal (200-400 MW)	*	*	10.47	10.16	9.82	9.77
Steam - Coal (400-600 MW)	*	*	*	*	*	*
Steam - Coal (600-800 MW)	*	*	*	*	8.22	7.90
Steam - Coal (800-1000 MW)	*	*	*	*	*	*

Steam - Gas	11.26	11.84	12.91	12.54	11.56	11.94
Steam - Oil	*	*	*	*	*	*
Steam - Waste Heat	*	*	*	*	*	*
Steam - Wood	*	*	*	*	*	*
MISO Weighted System-wide	8.23	9.04	9.36	9.24	9.28	9.16
MISO Weighted as seen in SERVM	7.64	8.95	9.17	9.22	9.18	-

**MISO system-wide weighted forced outage rate used in place of class data for those with less than 30 units reporting 12 or more months of data*

Table 3-1: Historical Class Average Forced Outage Rates

Pooled EFORd GADS Years	**2017-2021 (%)**	**2017-2021 (%)**	**2017-2021 (%)**	**2017-2021 (%)**
LOLE Study Planning Year 2023-2024	**Summer 2023**	**Fall 2023**	**Winter 2023-2024**	**Spring 2024**
Combined Cycle	5.54	8.32	4.70	6.19
Combustion Turbine (0-20 MW)	23.40	53.44	42.92	58.75
Combustion Turbine (20-50 MW)	6.30	16.79	56.52	25.23
Combustion Turbine (50+ MW)	4.07	6.60	9.68	4.81
Diesel Engines	12.79	9.32	14.84	8.07
Fluidized Bed Combustion	*	*	*	*
Hydro (0-30 MW)	*	*	*	*
Hydro (30+ MW)	*	*	*	*

Nuclear	*	*	*	*
Pumped Storage	*	*	*	*
Steam - Coal (0-100 MW)	*	*	*	*
Steam - Coal (100-200 MW)	*	*	*	*
Steam - Coal (200-400 MW)	*	*	*	*
Steam - Coal (400-600 MW)	*	*	*	*
Steam - Coal (600-800 MW)	*	*	*	*
Steam - Coal (800-1000 MW)	*	*	*	*
Steam - Gas	12.48	13.66	8.28	11.26
Steam - Oil	*	*	*	*
Steam - Waste Heat	*	*	*	*
Steam - Wood	*	*	*	*
MISO Weighted System-wide	8.23	9.48	12.47	11.42

**MISO system-wide weighted forced outage rate used in place of class data for those with less than 30 units reporting 12 or more months of data*

Table 3-2: Planning Year 2023-2024 Seasonal Class Average Forced Outage Rates

3.2.2 Behind-the-Meter Generation

Behind-the-Meter Generation data came from the Module E Capacity Tracking (MECT) tool. Behind-the-Meter Generation backed by thermal resources were explicitly modeled just as any other thermal generator with a monthly capacity and forced outage rate. Performance data was pulled from PowerGADS. Behind-the-Meter Generation backed by wind or solar resources had their hourly generation tied to the hourly wind and solar profiles in the model.

3.2.3 Attachment Y

MISO obtained information on generating units with approved suspensions or retirements (as of June 1, 2022) through MISO's Attachment Y process. Any unit with approved retirement or suspension in Planning Year 2023-2024

was excluded from the year-one analysis during the months the unit has been approved to be out-of-service for. This same methodology is used for the four- and six-year analyses.

3.2.4 Future Generation

Future thermal generation and upgrades were added to the LOLE model based on unit information in the MISO Generator Interconnection Queue. The LOLE model included units with a signed generator interconnection agreement (as of June 1, 2022). These new units were assigned seasonal class average forced outage rates and planned maintenance factors based on their particular unit class. Units upgraded during the study period reflect the megawatt increase for each month, beginning the month the upgrade was finished. The LOLE analysis also included future wind and solar generation, tied to the same hourly wind and solar profiles used for existing wind and solar resources in the model.

3.2.5 Intermittent Resources

Intermittent resources such as run-of-river hydro, biomass, wind and solar were explicitly modeled as demand-side resources. Run-of-river hydro and biomass provide MISO with a minimum of 3 years and up to 15 years of historical output data during seasonal peak hours, defined as hours ending 15, 16, & 17 EST for summer, fall, and spring, and hours ending 8, 9, 19, & 20 for winter. This data is averaged at the seasonal level and modeled in the LOLE analysis as UCAP for all months within a given season. Each individual unit is modeled and put in the corresponding LRZ.

As a process improvement to the LOLE model for this year's study, in collaboration with the SERVM vendor Astrapé, hourly wind and solar profiles were developed and introduced into the model to better simulate the variance in renewable generation on an hourly basis.

Using historical hourly wind data from 246 front-of-meter wind resources from 2013 to 2021, normalized hourly capacity profiles were developed and aggregated at the LRZ level to represent wind in the model. As a result of the LOLE analysis being based on 30 weather years (1992 – 2021), synthetic shapes were created for the 1992 – 2013 period based on historical wind performance and temperatures. Once the weather and wind performance matching has been performed, the data is analyzed as a function of load to ensure the variability around the load profiles is reasonable.

Solar profiles were developed using historical solar irradiance data from the NREL National Solar Radiation Database (NSRDB) from 1998 – 2021.

For more details, refer to the supporting documentation Astrapé provided for stakeholders at the LOLEWG detailing the development of the wind and solar profiles: MISO Seasonal Inputs for the 2022 LOLE Study

3.2.6 Demand Response

Demand response data came from the MECT tool. These resources were explicitly modeled as dispatch-limited resources. Each demand response program was modeled individually with a monthly capacity, limited to the number of times each program can be called upon, and limited by duration.

3.3 MISO Load Data

The Planning Year 2023-2024 LOLE analysis used a load training process with neural net software to create a neural-net relationship between historical weather and load data. This relationship was then applied to 30 years of hourly historical weather data to create 30 different load shapes for each LRZ in order to capture both load diversity and seasonal variations. The average monthly loads of the predicted load shapes were adjusted to match each LRZ's

Module E 50/50 monthly zonal peak load forecasts for each study year. The results of this process are shown as the MISO System Peak Demand (Table 4-1) and LRZ Peak Demands (Table 5-1, Table 5-2, Table 5-3, & Table5-4).

Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. These demand resources are implemented in the LOLE simulation before accumulating LOLE.

3.3.1 Weather Uncertainty

MISO has adopted a six-step load training process in order to capture the weather uncertainty associated with the 50/50 load forecasts. The first step of this process requires the collection of five years of historical real-time load modifying resource (LMR) performance and load data, as well as the collection of 30 years of historical weather data. Both the LMR and load data are taken from the MISO market for each LBA, while the historical weather data is collected from the National Oceanic and Atmospheric Administration (NOAA) for each LRZ. After collecting the data, the hourly gross load for each LRZ is calculated using the five years of historical data.

The second step of the process is to normalize the five years of load data to consistent economics. With the load growth due to economics removed from 5 years of historical LRZ load, the third step of the process utilizes neural network software to establish functional relationships between the five years of historical weather and load data. In the fourth step of the process the neural network relationships are applied to the 30 years of historical weather data in order to predict/create 30 years' worth of load shapes for each LRZ.

In the fifth step of the load training process, MISO undertakes extreme temperature verification on the 30 years of load shapes to ensure that the hourly load data is accurate at extremely hot or cold temperatures. This is required since there are fewer data points available at the temperature extremes when determining the neural network functional relationships. This lack of data at the extremes can result in inaccurate predictions when creating load shapes, which will need to be corrected before moving forward.

The sixth and final step of the load training process is to average the monthly peak loads of the predicted load shapes and adjust them to match each LR's Module E 50/50 monthly zonal peak load forecasts for each study year. In order to calculate this adjustment, the ratio of the first year's non-coincident peak forecast to the zonal coincident peak forecast is applied to future year's non-coincident peak forecast.

By adopting this new methodology for capturing weather uncertainty MISO is able to model multiple load shapes based off a functional relationship with weather. This modeling approach provides a variance in load shapes, as well as the peak loads observed in each load shape. This approach also provides the ability to capture the frequency and duration of severe weather patterns.

3.3.2 Economic Load Uncertainty

To account for economic load uncertainty in the Planning Year 2023-2024 LOLE model, MISO utilized a normal distribution of electric utility forecast error accounting for projected and actual Gross Domestic Product (GDP), as well as electricity usage. The historic projections for GDP growth were taken from the Congressional Budget Office (CBO), the actual GDP growth was taken from the Bureau of Economic Analysis (BEA), and the electric use was taken from the U.S. Energy Information Administration (EIA). Due to lack of statewide projected GDP data MISO relied on United States aggregate level data when calculating the economic uncertainty.

In order to calculate the electric utility forecast error, MISO first calculated the forecast error of GDP between the projected and actual values. The resulting GDP forecast error was then translated into electric utility forecast error

by multiplying by the rate at which electric load grows in comparison to the GDP. Finally, a standard deviation is calculated from the electric utility forecast error and used to create a normal distribution representing the probabilities of the load forecast errors (LFE) as shown in Table 3-3.

	LFE Levels				
	-2.0%	-1.0%	0.0%	1.0%	2.0%
Standard Deviation in LFE	Probability assigned to each LFE				
0.90%	4.8%	24.1%	42.1%	24.1%	4.8%

Table 3-3: Economic Uncertainty

As a result of stakeholder feedback MISO is exploring possible alternative methods for determining economic uncertainty to be used in the LOLE process.

3.4 External System

Firm imports from external areas to MISO are modeled at the individual unit level. The specific external units were modeled with their specific installed capacity amount and their corresponding Equivalent Forced Outage Rate demand (EFORd). This better captures the probabilistic reliability impact of firm external imports. These units are only modeled within the MISO PRM analysis and are not modeled when calculating the LRZ LRRs. Due to the locational Tariff filing, Border and Coordinating Owners External Resources are no longer considered firm imports. Instead, these resources are modeled as internal MISO units and are included in the PRM and LRR analysis. The external resources to include for firm imports were based on the amount offered into the Planning Year 2022-2023 Planning Resource Auction (PRA).

The LOLE analysis incorporates firm exports to neighboring regions where information was available. For units with capacity sold off-system, their monthly capacities were reduced by the megawatt amount exported. These values came from PJM's Reliability Pricing Model (RPM) as well as information on exports to other external areas taken from the Independent Market Monitor (IMM) exclusion list.

Firm exports from MISO to external areas were modeled the same as previous years. Capacity ineligible as MISO capacity due to transactions with external areas is removed from the model. Table 3-4 shows the amount of firm imports and exports in this year's study.

Contracts	Summer ICAP (MW)	Summer UCAP (MW)	Fall ICAP (MW)	Fall UCAP (MW)	Winter ICAP (MW)	Winter UCAP (MW)	Spring ICAP (MW)	Spring UCAP (MW)
Imports (MW)	1,731	1,673	1,734	1,672	1,874	1,819	1,803	1,755
Exports (MW)	2,543	2,287	2,543	2,287	2,543	2,287	2,543	2,287
Net	**-812**	**-614**	**-809**	**-615**	**-669**	**-468**	**-740**	**-532**

Table 3-4: Planning Year 2023-2024 Firm Imports and Exports

Non-firm imports in the Planning Year 2023-2024 LOLE study were modeled as a probabilistic distribution of capacity value. These distributions were developed using historic seasonal NSI data which accounted for imports into MISO during emergency pricing hours. Firm imports cleared in the PRA for each planning year were subtracted from the NSI data to isolate the non-firm values. An additional region was included in SERVM which contained 12,000 MW of perfect generation connected to the MISO system. A distribution of the regions export capability was modeled up to the upper and lower bounds. As SERVM steps through the hourly simulation, random draws on the export limits of the external region were used to represent the amount of capacity MISO could import to meet peak demand. The probability distribution of non-firm external imports used in the LOLE model has been provided in Table 3-5.

	Summer	Fall	Winter	Spring
p5	1,456	649	-	1,777
p10	2,663	1,259	205	2,144
p25	3,674	2,199	1,142	2,768
p50	4,708	3,393	3,143	4,031
p75	5,608	4,537	4,941	5,265
p90	6,465	5,453	7,249	6,271
p95	6,807	6,217	8,452	7,055

Table 3-5: Non-Firm External Import Distribution During Emergency Pricing Hours

3.5 Loss of Load Expectation Analysis and Metric Calculations

Upon completion of the annual LOLE study model refresh, MISO performed probabilistic analyses to determine the seasonal PRM ICAP and PRM UCAP for the Planning Year 2023-2024 as well as the seasonal Local Reliability Requirement for each of the 10 LRZs. These metrics were derived through probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the seasonal LOLE targets.

3.5.1 Seasonal LOLE Distribution

To determine the seasonal LOLE distribution that will be used to calculate the PRM and LRRs, MISO followed the process described in Section 68A.2.1 of Module E-1 of the MISO Tariff. This process involves first solving the LOLE model to an annual value of 0.1 and then checking the seasonal distribution of the annual LOLE of 0.1. If a season had an LOLE value of at least 0.01, then it met the minimum seasonal criteria and would be set to that LOLE. If a season had less than 0.01 LOLE, additional analysis was performed until the minimum seasonal criteria of 0.01 LOLE was met.

Example: Assume the model is solved to an annual LOLE of 0.1 with 0.05 occurring in both summer and winter while spring and fall had LOLE values of 0 from this simulation. In this case the summer and winter seasons would not need additional analysis since both had at least 0.01 LOLE naturally when the model was solved to an annual value of 0.1. Since spring and fall had 0 LOLE they would be assigned the LOLE minimum seasonal criteria of 0.01 and additional LOLE simulations would be performed until the minimum seasonal criteria was met.

The seasonal LOLE distribution determined in the Planning Year 2023-2024 LOLE study are shown in Table 3-6.

Region	Summer	Fall	Winter	Spring
MISO-wide	0.1	0.01	0.01	0.01
1	0.08	0.01	0.02	0.01
2	0.1	0.01	0.01	0.01
3	0.07	0.01	0.03	0.01
4	0.04	0.01	0.04	0.01
5	0.04	0.01	0.05	0.01
6	0.05	0.01	0.04	0.01
7	0.07	0.03	0.01	0.01
8	0.01	0.01	0.08	0.01
9	0.06	0.01	0.02	0.01
10	0.05	0.04	0.01	0.01

Table 3-6: Planning Year 2023-2024 Seasonal LOLE Distribution

3.7.1 MISO-Wide LOLE Analysis and PRM Calculation

MISO will determine the appropriate PRM for each season of the applicable Planning Year based upon probabilistic analysis of reliably serving expected demand. The probabilistic analysis will utilize a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations.

To determine the PRM, the LOLE model will initially be run with no adjustments to the capacity. If the LOLE is less than 0.1 day per year, a negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. This is comparable to adding load to the model. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year.

MISO's annual LOLE study will calculate the seasonal PRMs based on the LOLE targets identified in the previous section. The minimum seasonal PRM requirement will be determined using the LOLE analysis by either adding a zero EFORd, negative output unit or adding proxy units until a minimum LOLE of 0.01 day per season is reached.

The formulas for the PRM values for the MISO system are:

PRM ICAP % = (Installed Capacity + Firm External Support ICAP + ICAP Adjustment to meet LOLE target – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

PRM UCAP % = (Unforced Capacity + Firm External Support UCAP + UCAP Adjustment to meet LOLE target – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

Where Unforced Capacity (UCAP) = Installed Capacity (ICAP) x (1 – XEFORd)

3.7.2 LRZ LOLE Analysis and Local Reliability Requirement Calculation

For the LRZ analysis, each LRZ included only the generating units within the LRZ (including Coordinating Owners and Border External Resources) and was modeled without consideration of the benefit of the LRZ's import capability. Much like the MISO analysis, unforced capacity is either added or removed in each LRZ such that an LOLE of 0.1 day per year is achieved when solving for the annual target and a minimum LOLE at least 0.01 day per season when solving for a seasonal target. The minimum amount of unforced capacity above each LRZ's Peak Demand that was required to meet the reliability criteria was used to establish each LRZ's LRR.

The Planning Year 2023-2024 seasonal LRRs were determined using the LOLE analysis by first either adding or removing capacity until the annual LOLE reaches 0.1 day per year for the LRZ. If the LOLE is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year.

After solving each LRZ for to the annual LOLE target of 0.1 day per year, MISO will calculate each seasonal LRR such that the summation of seasonal LOLE across the year in each zone is 1 day in 10 years, or 0.1 day per year. An LOLE target of 0.01 will be used to calculate the LRR in seasons with less than 0.01 LOLE risk. The seasonal Local Reliability Requirement will be determined using the LOLE analysis by either adding a zero EFORd, negative output unit or adding proxy units until a minimum LOLE of 0.01 day per season is reached.

For Planning Year 2023-2024, only LRZ-1 had sufficient capacity internal to the LRZ to achieve any of the seasonal LOLE targets as an island. In the nine zones without sufficient capacity as an island, proxy units of typical size (160 MW) and class average seasonal EFORd were added to the LRZ. When needed, a fraction of the final proxy unit was added to achieve the exact seasonal LOLE target for the LRZ.

LRR UCAP % = (Unforced Capacity + UCAP Adjustment to meet LOLE target – Zonal Coincident Peak Demand)/Zonal Coincident Peak Demand

4 MISO System Planning Reserve Margin Results

4.1 Planning Year 2023-2024 MISO Planning Reserve Margin Results

For Planning Year 2023-2024, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin of 15.9 percent and a planning UCAP reserve margin of 7.4 percent for the summer season. Numerous values and calculations went into determining the MISO system PRM ICAP and PRM UCAP (Table 4-1).

MISO Planning Reserve Margin (PRM)	2023/2024 PY Summer	2023/2024 PY Fall	2023/2024 PY Winter	2023/2024 PY Spring	Formula Key
MISO System Peak Demand (MW)	123,711	111,012	103,455	99,113	[A]
Installed Capacity (ICAP) (MW)	144,268	144,992	150,673	145,366	[B]
Unforced Capacity (UCAP) (MW)	133,764	132,911	134,503	130,753	[C]
Firm External Support (ICAP) (MW)	1,731	1,734	1,874	1,803	[D]
Firm External Support (UCAP) (MW)	1,707	1,714	1,857	1,778	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-2,650	-7,100	-6,500	-9,150	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-2,650	-7,100	-6,500	-9,150	[G]
ICAP PRM Requirement (PRMR) (MW)	143,349	139,626	146,047	138,019	[H]=[B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	132,821	127,525	129,860	123,381	[I]=[C]+[E]+[G]
MISO PRM ICAP	**15.9%**	**25.8%**	**41.2%**	**39.3%**	[J]=([H]-[A])/[A]
MISO PRM UCAP	**7.4%**	**14.9%**	**25.5%**	**24.5%**	[K]=([I]-[A])/[A]

Table 4-1: Planning Year 2023-2024 MISO System Planning Reserve Margins

4.2 Comparison of PRM Targets Across 10 Years

Figure 4-1 compares the PRM UCAP values over the last 10 Planning Years. The last endpoint of the green line shows the Planning Year 2023-2024 Summer PRM value.

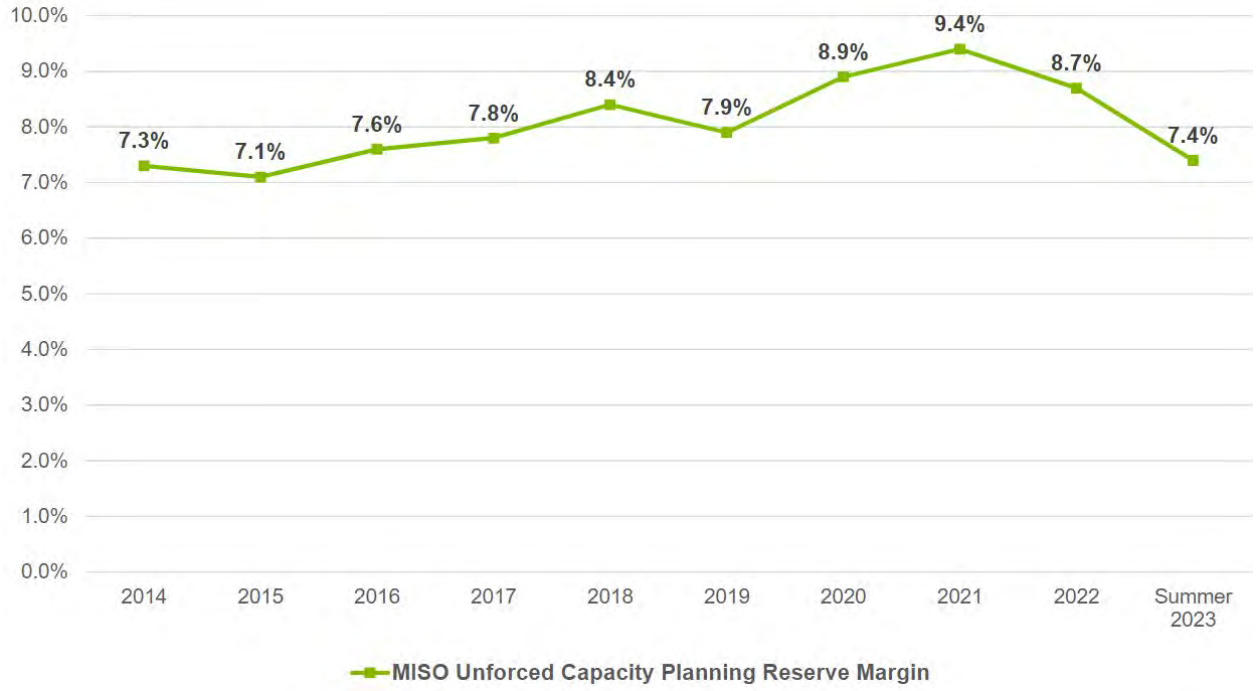


Figure 4-1: Comparison of PRM Targets Across 10 Years

4.3 Future Years 2023 through 2032 Planning Reserve Margins

Beyond the Planning Year 2023-2024 LOLE study analysis, an LOLE analysis will be performed for the four-year-out Planning Year of 2026-2027, as well as for the six-year-out Planning Year of 2028-2029. All other future Planning Years in scope will be derived from interpolation and extrapolation of the three modeled Planning Years.

5 Local Resource Zone Analysis – LRR Results

5.1 Planning Year 2023-2024 Local Resource Zone Analysis

MISO calculated the per-unit LRR of LRZ Seasonal Peak Demand for Planning Year 2023-2024 on a seasonal basis (Table 5-1, Table 5-2, Table 5-3, and Table 5-4). The UCAP values in the seasonal LRR tables reflect the assumed seasonal UCAP within each LRZ, including Border External Resources and Coordinating Owners. The adjustments to UCAP values are the megawatt adjustments needed in each LRZ so that the reliability criterion of 0.1 days per year LOLE is met. The LRR is the summation of the UCAP and adjustment to UCAP megawatts. The LRR is then divided by each LRZ's Seasonal Peak Demand to determine the per-unit LRR UCAP. The Planning Year 2023-2024 per-unit LRR UCAP values will be multiplied by the updated seasonal peak demand forecasts submitted for the 2023-2024 PRA to determine each LRZ's LRR. The zonal LRR LOLE targets have been provided for peak demand timestamps for all 30 weather years modeled in SERVM is shown in Table 5-5. These peak demand timestamps are the result of the SERVM load training process and are not necessarily the actual peaks for each year.

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2023-2024 Local Reliability Requirements – Summer 2023											
Installed Capacity (ICAP) (MW)	21,839	13,026	11,651	8,734	7,917	17,585	21,512	11,290	24,264	6,449	[A]
Unforced Capacity (UCAP) (MW)	20,843	12,145	11,225	7,986	7,410	15,973	20,476	10,866	21,097	5,743	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-255	2,062	1,583	3,242	2,859	4,844	3,952	403	2,897	1,209	[C]
LRR (UCAP) (MW)	20,588	14,207	12,808	11,228	10,269	20,817	24,428	11,269	23,994	6,952	[D]=[B]+[C]
Peak Demand (MW)	18,077	12,686	9,859	9,263	7,704	17,760	20,855	7,652	20,739	4,521	[E]
LRR UCAP per-unit of LRZ Peak Demand	**113.9%**	**112.0%**	**129.9%**	**121.2%**	**133.3%**	**117.2%**	**117.1%**	**147.3%**	**115.7%**	**153.8%**	[F]=[D]/[E]

Table 5-1: Planning Year 2023-2024 LRZ Local Reliability Requirements for Summer 2023

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2023-2024 Local Reliability Requirements – Fall 2023											
Installed Capacity (ICAP) (MW)	21,895	13,096	12,134	8,748	8,068	17,659	21,574	11,149	24,245	6,424	[A]
Unforced Capacity (UCAP) (MW)	20,460	12,097	11,545	7,787	7,201	16,014	20,269	10,190	21,787	5,561	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,230	1,289	1,046	3,138	2,625	4,170	3,848	28	2,821	1,177	[C]
LRR (UCAP) (MW)	19,230	13,386	12,591	10,925	9,825	20,184	24,117	10,218	24,607	6,738	[D]=[B]+[C]
Peak Demand (MW)	15,093	10,991	8,942	8,713	6,767	16,180	17,933	6,858	19,258	4,162	[E]
LRR UCAP per-unit of LRZ Peak Demand	**127.4%**	**121.8%**	**140.8%**	**125.4%**	**145.2%**	**124.7%**	**134.5%**	**149.0%**	**127.8%**	**161.9%**	[F]=[D]/[E]

Table 5-2: Planning Year 2023-2024 LRZ Local Reliability Requirements for Fall 2023

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2023-2024 Local Reliability Requirements – Winter 2023-2024											
Installed Capacity (ICAP) (MW)	22,449	13,578	14,291	9,028	8,528	18,244	21,710	11,298	24,921	6,626	[A]
Unforced Capacity (UCAP) (MW)	20,931	12,041	13,353	7,125	7,032	16,480	20,151	9,901	21,775	5,714	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-255	1,536	1,491	3,054	2,692	4,562	1,789	379	2,728	1,138	[C]
LRR (UCAP) (MW)	20,676	13,577	14,844	10,179	9,724	21,042	21,940	10,280	24,503	6,852	[D]=[B]+[C]
Peak Demand (MW)	14,738	9,549	8,025	7,456	6,599	16,173	13,945	6,839	18,523	3,856	[E]
LRR UCAP per-unit of LRZ Peak Demand	**140.3%**	**142.2%**	**185.0%**	**136.5%**	**147.4%**	**130.1%**	**157.3%**	**150.3%**	**132.3%**	**177.7%**	[F]=[D]/[E]

Table 5-3: Planning Year 2023-2024 LRZ Local Reliability Requirements for Winter 2023-2024

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2023-2024 Local Reliability Requirements – Spring 2024											
Installed Capacity (ICAP) (MW)	21,224	13,196	12,339	8,776	8,281	18,041	21,224	11,228	24,631	6,427	[A]
Unforced Capacity (UCAP) (MW)	19,769	11,963	11,601	7,265	7,342	16,150	19,638	9,700	21,470	5,856	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,330	626	1,147	2,907	2,371	3,615	1,836	152	2,601	726	[C]
LRR (UCAP) (MW)	18,439	12,590	12,748	10,172	9,713	19,765	21,475	9,852	24,071	6,582	[D]=[B]+[C]
Peak Demand (MW)	13,407	9,938	7,856	6,998	6,034	14,977	16,157	6,055	18,310	3,768	[E]
LRR UCAP per-unit of LRZ Peak Demand	**137.5%**	**126.7%**	**162.3%**	**145.4%**	**161.0%**	**132.0%**	**132.9%**	**162.7%**	**131.5%**	**174.7%**	[F]=[D]/[E]

Table 5-4: Planning Year 2023-2024 LRZ Local Reliability Requirements for Spring 2024

Weather Year Time of Peak Demand (ESTHE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
1992	7/9/92 16:00	8/9/92 17:00	8/10/92 18:00	7/8/92 17:00	7/2/92 15:00	7/2/92 17:00	1/16/92 8:00	7/2/92 16:00	7/16/92 17:00	7/11/92 18:00	7/12/92 17:00
1993	7/27/93 17:00	8/11/93 17:00	8/27/93 14:00	8/22/93 19:00	7/17/93 17:00	7/27/93 16:00	7/25/93 16:00	7/9/93 15:00	7/31/93 17:00	8/14/93 16:00	7/31/93 18:00
1994	7/6/94 15:00	6/14/94 17:00	6/15/94 17:00	7/19/94 17:00	7/5/94 17:00	7/19/94 18:00	1/19/94 6:00	6/18/94 17:00	6/29/94 18:00	8/14/94 17:00	7/5/94 17:00
1995	7/13/95 17:00	7/13/95 18:00	7/13/95 16:00	7/14/95 17:00	7/14/95 17:00	7/13/95 16:00	7/13/95 17:00	7/13/95 17:00	8/17/95 14:00	7/27/95 17:00	7/12/95 15:00
1996	6/29/96 17:00	8/6/96 17:00	6/29/96 17:00	7/18/96 17:00	7/18/96 18:00	7/18/96 17:00	7/19/96 17:00	8/7/96 15:00	7/20/96 15:00	2/5/96 7:00	7/3/96 18:00
1997	7/26/97 16:00	7/16/97 16:00	7/16/97 17:00	7/25/97 18:00	7/18/97 16:00	7/26/97 17:00	7/26/97 16:00	7/16/97 16:00	7/25/97 18:00	8/16/97 16:00	7/25/97 18:00
1998	7/20/98 16:00	7/13/98 16:00	6/25/98 18:00	7/20/98 18:00	7/20/98 18:00	7/19/98 16:00	7/19/98 17:00	6/25/98 18:00	7/6/98 17:00	8/28/98 18:00	8/27/98 15:00
1999	7/30/99 14:00	7/25/99 15:00	7/13/95 16:00	7/30/99 18:00	7/18/99 22:00	7/30/99 17:00	7/26/97 16:00	7/30/99 14:00	7/25/99 17:00	8/14/99 18:00	8/20/99 18:00
2000	8/31/00 16:00	6/8/00 19:00	9/1/00 17:00	8/31/00 16:00	9/1/00 15:00	8/17/00 16:00	9/1/00 15:00	9/1/00 14:00	7/19/00 17:00	8/30/00 16:00	8/30/00 17:00
2001	8/8/01 16:00	8/7/01 16:00	8/9/01 16:00	7/31/01 16:00	7/23/01 17:00	7/23/01 17:00	8/7/01 17:00	8/8/01 16:00	7/11/01 16:00	7/10/01 16:00	7/20/01 17:00
2002	7/3/02 16:00	7/6/02 18:00	8/1/02 15:00	7/20/02 18:00	7/5/02 17:00	8/1/02 16:00	8/3/02 16:00	7/3/02 16:00	7/9/02 17:00	8/2/02 19:00	10/4/02 15:00
2003	8/21/03 16:00	8/24/03 17:00	8/21/03 16:00	7/26/03 18:00	8/21/03 16:00	8/21/03 18:00	8/27/03 17:00	8/21/03 17:00	7/18/03 14:00	8/10/03 16:00	7/17/03 17:00
2004	7/22/04 16:00	6/7/04 17:00	7/22/04 16:00	7/20/04 17:00	7/13/04 17:00	7/13/04 16:00	1/31/04 9:00	7/22/04 16:00	7/14/04 17:00	7/24/04 17:00	7/25/04 15:00
2005	7/24/05 17:00	7/17/05 17:00	7/24/05 16:00	7/25/05 17:00	7/24/05 16:00	7/24/05 18:00	7/25/05 17:00	7/24/05 18:00	8/21/05 18:00	7/25/05 16:00	8/21/05 15:00
2006	7/31/06 17:00	7/31/06 17:00	8/1/06 17:00	7/19/06 18:00	7/31/06 18:00	7/31/06 16:00	7/31/06 16:00	7/31/06 16:00	7/31/93 17:00	8/15/06 18:00	7/16/06 15:00
2007	8/1/07 17:00	7/26/07 15:00	8/2/07 15:00	7/17/07 17:00	8/15/07 18:00	8/15/07 18:00	8/29/07 17:00	7/31/07 18:00	8/17/95 14:00	8/14/07 15:00	8/14/07 15:00

2008	7/16/08 17:00	7/11/08 18:00	7/17/08 17:00	8/3/08 17:00	7/20/08 17:00	7/20/08 16:00	8/23/08 16:00	8/24/08 12:00	8/17/95 14:00	7/20/08 17:00	7/27/08 16:00
2009	6/25/09 16:00	6/22/09 19:00	7/28/09 16:00	7/24/09 18:00	8/9/09 16:00	8/9/09 16:00	1/16/09 8:00	6/25/09 16:00	6/22/09 16:00	7/2/09 16:00	7/2/09 18:00
2010	8/10/10 17:00	8/8/10 18:00	8/20/10 14:00	7/17/10 19:00	7/15/10 15:00	8/3/10 16:00	8/2/91 18:00	9/1/10 17:00	8/17/95 14:00	8/1/10 17:00	8/2/10 17:00
2011	7/20/11 18:00	6/7/11 19:00	7/13/95 16:00	7/20/11 16:00	9/1/11 16:00	8/31/11 16:00	7/26/97 16:00	7/20/11 19:00	7/31/93 17:00	7/2/11 17:00	7/10/11 18:00
2012	7/6/12 17:00	7/6/12 18:00	7/13/95 16:00	7/7/12 16:00	7/7/12 17:00	7/25/12 18:00	7/26/97 16:00	7/6/12 17:00	7/30/12 17:00	6/26/12 16:00	7/3/12 15:00
2013	7/19/13 16:00	7/18/13 19:00	8/27/13 16:00	8/30/13 16:00	9/11/13 16:00	8/31/13 17:00	8/31/13 15:00	7/19/13 14:00	6/27/13 18:00	8/7/13 16:00	8/8/13 17:00
2014	7/22/14 16:00	7/22/14 17:00	7/22/14 16:00	7/22/14 16:00	9/5/14 16:00	7/26/14 15:00	2/7/14 9:00	7/22/14 17:00	7/27/14 17:00	8/23/14 16:00	7/26/14 17:00
2015	7/29/15 16:00	8/14/15 15:00	8/14/15 17:00	7/13/15 15:00	9/3/15 16:00	7/13/15 16:00	7/18/15 17:00	8/2/15 16:00	8/7/15 18:00	8/10/15 16:00	7/30/15 16:00
2016	7/20/16 15:00	7/21/16 17:00	8/10/16 17:00	7/22/16 16:00	9/22/16 16:00	7/23/16 17:00	6/11/16 14:00	8/10/16 14:00	7/20/16 13:00	9/1/16 16:00	7/20/16 15:00
2017	7/20/17 16:00	7/6/17 17:00	6/12/17 14:00	7/21/17 17:00	9/26/17 15:00	7/12/17 15:00	9/26/17 16:00	6/12/17 14:00	7/21/17 15:00	8/19/17 15:00	7/20/17 15:00
2018	6/29/18 15:00	6/29/18 15:00	6/29/18 15:00	5/28/18 14:00	9/5/18 15:00	8/6/18 16:00	9/5/18 16:00	9/5/18 15:00	1/17/18 6:00	1/17/18 6:00	9/19/18 16:00
2019	7/19/19 14:00	7/19/19 18:00	7/19/19 16:00	7/19/19 14:00	9/12/19 16:00	10/1/19 15:00	9/13/19 16:00	7/19/19 13:00	8/13/19 14:00	10/4/19 15:00	10/2/19 16:00
2020	7/9/20 15:00	7/2/20 17:00	8/27/20 14:00	7/8/20 14:00	7/8/20 15:00	7/11/20 15:00	8/25/20 15:00	7/9/20 15:00	7/12/20 15:00	7/11/20 15:00	9/4/20 16:00
2021	8/24/21 15:00	7/27/21 16:00	8/10/21 15:00	7/28/21 16:00	8/27/21 15:00	8/25/21 16:00	8/24/21 16:00	8/24/21 15:00	8/10/21 14:00	8/23/21 16:00	7/29/21 14:00

Table 5-5: Historical Peak Days/Hours by Local Resource Zone

6 Appendix A: Comparison of Planning Year 2022 to 2023

Multiple study sensitivity analyses were performed to compute changes in the PRM target on an UCAP basis, from Planning Year 2022-2023 to Planning Year 2023-2024. These sensitivities included one-off incremental changes of input parameters to quantify how each change affected the PRM result independently. Note the impact of the incremental PRM changes from Planning Year 2022-2023 to Planning Year 2023-2024 in the waterfall chart of Figure A-1. Summer was determined to be the season most comparable to the annual PRM from last year's study. The following subsections provide more details around each of the sensitivities.

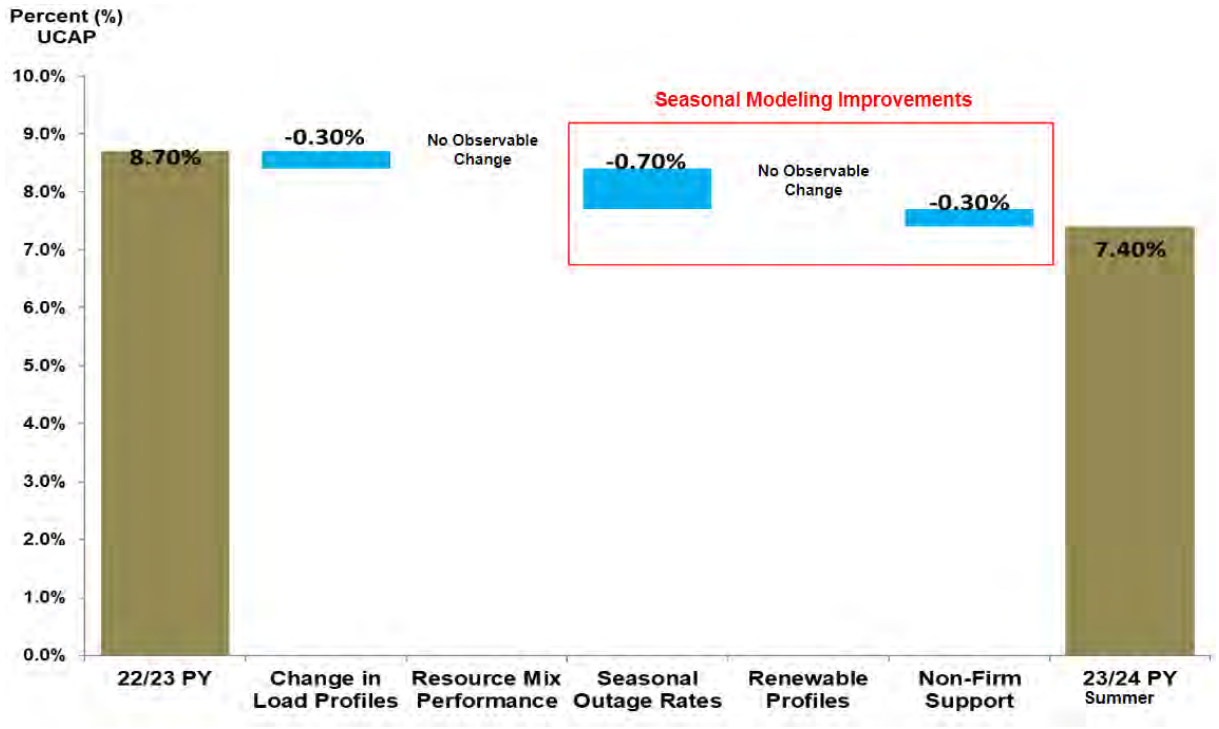


Figure A-1: Waterfall Chart of PY 2022-2023 Annual PRM UCAP to PY 2023-2024 Summer PRM UCAP

6.1 A.1 Waterfall Chart Details

6.1.1 A.1.1 Load

The MISO Coincident Peak Demand increased from the 2021-2022 planning year, which was driven by the updated actual load forecasts submitted by the LSEs. Overall, the magnitude of changes in the load profiles and economic uncertainty resulted in a slight decrease in the PRM.

6.1.2 A.1.2 Units

Changes from 2022-2023 planning year values are due to changes in Generation Verification Test Capacity (GVTC), seasonal EFORd or equivalent forced outage rate demand, new units, retirements, suspensions, and changes in the resource mix. The MISO fleet weighted average forced outage rate decreased from an annual 9.04 percent to a summer value of 8.23 percent from the previous study to this study. A general decrease in unit outage rates lead to a decrease in summer reserve margin. Non-firm support was included in the model which resulted in a slight decrease to the summer PRM.

7 Appendix B: Capacity Import Limit Tier 1 & 2 Source Subsystem Definitions

MISO Local Resource Zone 1

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
XEL / 600	ITCM / 627	WEC / 295
MP / 608	ALTE / 694	MIUP / 296
SMMPA / 613	WPS / 696	AMMO / 356
GRE / 615	MGE / 697	AMIL / 357
OTP / 620		MPW / 633
MDU / 661		MEC / 635
BEPC-MISO / 663		
DPC / 680		

MISO Local Resource Zone 2

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
WEC / 295	METC / 218	NIPS / 217
MIUP / 296	XEL / 600	ITCT / 219
ALTE / 694	MP / 608	SMMPA / 613
WPS / 696	DPC / 680	GRE / 615
MGE / 697		OTP / 620
UPPC / 698		ITCM / 627

MISO Local Resource Zone 3

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
ITCM / 627	AMMO / 356	DEI / 208	GRE / 615
MPW / 633	AMIL / 357	NIPS / 217	OTP / 620
MEC / 635	XEL / 600	CWLP / 360	ALTE / 694
	SMMPA / 613	SIPC/ 361	WPS / 696
	DPC / 680	GLHB / 362	MGE / 697
		MP / 608	

MISO Local Resource Zone 4

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
ITCM / 627	AMMO / 356	DEI / 208	GRE / 615
MPW / 633	AMIL / 357	NIPS / 217	OTP / 620
MEC / 635	XEL / 600	CWLP / 360	ALTE / 694
	SMMPA / 613	SIPC/ 361	WPS / 696
	DPC / 680	GLHB / 362	MGE / 697
		MP / 608	

MISO Local Resource Zone 5

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
CWLD / 333	AMIL / 357	DEI / 208	XEL / 600
AMMO / 356	GLHB / 362	NIPS / 217	SMMPA / 613
	ITCM / 627	CWLP / 360	MPW / 633
	MEC / 635	SIPC / 361	DPC / 680

MISO Local Resource Zone 6

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
HE / 207	METC / 218	ITCT / 219
DEI / 208	AMIL / 357	MIUP / 296
SIGE / 210	SIPC / 361	AMMO / 356
IPL / 216		CWLP / 360
NIPS / 217		GLHB / 362
BREC / 314		ITCM / 627
HMPL / 315		MEC / 635

MISO Local Resource Zone 7

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
HE / 207	METC / 218	ITCT / 219
DEI / 208	AMIL / 357	MIUP / 296
SIGE / 210	SIPC / 361	AMMO / 356
IPL / 216		CWLP / 360
NIPS / 217		GLHB / 362
BREC / 314		ITCM / 627
HMPL / 315		MEC / 635

MISO Local Resource Zone 8

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
HE / 207	METC / 218	ITCT / 219
DEI / 208	AMIL / 357	MIUP / 296
SIGE / 210	SIPC / 361	AMMO / 356
IPL / 216		CWLP / 360
NIPS / 217		GLHB / 362
BREC / 314		ITCM / 627
HMPL / 315		MEC / 635

MISO Local Resource Zone 9

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
LAGN / 332	EES-EMI / 326	Cooperative Energy / 349
EES / 351	EES-EAI / 327	
CLEC / 502		
LAFA / 503		
LEPA / 504		

MISO Local Resource Zone 10

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
EES-EMI / 326	EES-EAI / 327	LAGN / 332
Cooperative Energy / 349	EES / 351	CLEC / 502
		LAFA / 503

8 Appendix C: Compliance Conformance Table

Requirements under: Standard BAL-502-RF-03	Response
R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	The Planning Year 2023-2024 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2023 through May 2024 and beyond. Analysis of Planning Year 2023-2024 is in Sections 4.1 and 5.1. Analysis of Future Years 2024-2033 is in Section 10.
R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).	Section 3.5 of this report outlines the utilization of LOLE in the reserve margin determination. "These metrics were determined by a probabilistic LOLE analysis such that the LOLE for the planning year was one day in 10 years, or 0.1 day per year."
R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.	Section 3.3 of this report. "Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. These demand resources are implemented in the LOLE simulation before accumulating LOLE or shedding of firm load."
R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin).	Section 4.1 of this report. "…the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin…"
R1.2 Be performed or verified separately for each of the following planning years.	Covered in the segmented R1.2 responses below.
R1.2.1 Perform an analysis for Year One.	In Sections 4.1 and 5.1, a full analysis was performed for Planning Year 2023-2024.
R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.	Sections 4.3 and 5.1 show a full analysis was performed for future planning years 2025 and 2027.
R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.	Analysis was performed.
R1.3 Include the following subject matter and documentation of its use:	Covered in the segmented R1.3 responses below.

R1.3.1 Load forecast characteristics: • Median (50:50) forecast peak load • Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts). • Load diversity. • Seasonal Load variations. • Daily demand modeling assumptions (firm, interruptible). • Contractual arrangements concerning curtailable/Interruptible Demand.	Median forecasted load – In Section 3.3 of this report: "The average monthly loads of the predicted load shapes were adjusted to match each LRZ's Module E 50/50 monthly zonal peak load forecasts for each study year." Load Forecast Uncertainty – A detailed explanation of the weather and economic uncertainties are given in Sections 3.3 and 3.3.2. Load Diversity/Seasonal Load Variations — In Section 3.3 of this report: "The Planning Year 2023-2024 LOLE analysis used a load training process with neural net software to create a neural-net relationship between historical weather and load data. This relationship was then applied to 30 years of hourly historical weather data to create 30 different load shapes for each LRZ in order to capture both load diversity and seasonal variations." Demand Modeling Assumptions/Curtailable and Interruptible Demand — All Load Modifying Resources must first meet registration requirements through Module E. As stated in Section 3.2.6: "Each demand response program was modeled individually with a monthly capacity and was limited to the number of times each program can be called upon as well as limited by duration."
R1.3.2 Resource characteristics: • Historic resource performance and any projected changes • Seasonal resource ratings • Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area. • Resource planned outage schedules, deratings, and retirements. • Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration. • Criteria for including planned resource additions in the analysis.	Section 3.2 details how historic performance data and seasonal ratings are gathered, and includes discussion of future units and the modeling assumptions for intermittent capacity resources. A more detailed explanation of firm capacity purchases and sales is in Section 3.4.
R1.3.3 Transmission limitations that prevent the delivery of generation reserves	Annual MTEP deliverability analysis identifies transmission limitations preventing delivery of generation reserves. Additionally, Section 2 of this report details the transfer analysis to capture transmission constraints limiting capacity transfers.
R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis	Inclusion of the planned transmission addition assumptions is detailed in Section 2.2.3.

R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.	Section 3.4 provides the analysis on the treatment of external support assistance and limitations.
R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel. • Common mode outages that affect resource availability. • Environmental or regulatory restrictions of resource availability. • Any other demand (Load) response programs not included in R1.3.1. • Sensitivity to resource outage rates. • Impacts of extreme weather/drought conditions that affect unit availability. • Modeling assumptions for emergency operation procedures used to make reserves available. • Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.	Fuel availability, environmental restrictions, common mode outage and extreme weather conditions are all part of the historical availability performance data that goes into the unit's EFORd statistic. The use of the EFORd values is covered in Section 3.2.1. The use of demand response programs is mentioned in Section 3.2.6. The effects of resource outage characteristics on the reserve margin are outlined in Section 3.7.1 by examining the difference between PRM ICAP and PRM UCAP values.
R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included	Transmission maintenance schedules were not included in the analysis of the transmission system due to the limited availability of reliable long-term maintenance schedules and minimal impact to the results of the analysis. However, Section 2 treats worst-case theoretical outages by Perform First Contingency Total Transfer Capability (FCTTC) analysis for each LRZ, by modeling NERC Category P0 (system intact) and Category P1 (N-1) contingencies.
R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis	MISO internal resources are among the quantities documented in the tables provided in Sections 4 and 5.
R1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis	MISO load is among the quantities documented in the tables provided in Sections 4 and 5.
R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.	In Sections 4 and 5, the peak load and estimated amount of resources for Planning Years 2023-2024, 2026-2027, and 2028-2029 are shown. This includes the detail for each transmission constrained sub-area.

R2.1 This documentation shall cover each of the years in year one through ten.	Section 10.3 and Tables 10-3, 10-4, 10-5, and 10-6 show the three calculated study years, in-between years estimated by interpolation, and future outyears estimated by extrapolation. Estimated transmission limitations may be determined through a review of the PY 2023-2024 LOLE study transfer analysis shown in Section 2 of this report, along with the results from previous LOLE studies.
R2.2 This documentation shall include the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	Covered in Sections 10.1 and 10.2.
R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.	The 2023-2024 LOLE Study Report documentation is posted on November 1 prior to the planning year.
R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2.	In Sections 4 and 5, the difference between the needed amount and the projected planning reserves for Planning Years 2023-2024, 2026-2027, and 2028-2029 are shown in the adjustments to ICAP and UCAP in Table 4-1, Table 10-1, and Table 10-2.

9 Appendix D: Acronyms List Table

CEL	Capacity Export Limit
CIL	Capacity Import Limit
CPNode	Commercial Pricing Node
DF	Distribution Factor
EFORd	Equivalent Forced Outage Rate demand
ELCC	Effective Load Carrying Capability
ERZ	External Resource Zone
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
GADS	Generator Availability Data System
GLT	Generation Limited Transfer
GVTC	Generation Verification Test Capacity
ICAP	Installed Capacity
LBA	Local Balancing Authority
LCR	Local Clearing Requirement
LFE	Load Forecast Error
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LRR	Local Reliability Requirement
LRZ	Local Resource Zones
LSE	Load Serving Entity
MARS	Multi-Area Reliability Simulation
MECT	Module E Capacity Tracking
MISO	Midcontinent Independent System Operator
MOD	Model on Demand
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt hours
NERC	North American Electric Reliability Corp.

PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PRM ICAP	PRM Installed Capacity
PRM UCAP	PRM Unforced Capacity
PRMR	Planning Reserve Margin Requirement
PSS E	Power System Simulator for Engineering
RCF	Reciprocal Coordinating Flowgate
RDS	Redispatch
RPM	Reliability Pricing Model
SERVM	Strategic Energy & Risk Valuation Model
SPS	Special Protection Scheme
TARA	Transmission Adequacy and Reliability Assessment
UCAP	Unforced Capacity
XEFORd	Equivalent forced outage rate demand with adjustment to exclude events outside management control
ZIA	Zonal Import Ability
ZEA	Zonal Export Ability

10 Appendix E: Outyear PRM and LRR Results

Beyond the prompt Planning Year 2023-2024, LOLE analyses were performed for the four-year-out Planning Year of 2026-2027, and the six-year-out Planning Year of 2028-2029. Tables 10-1 and 10-2 show the capacity and demand values that went into the MISO system seasonal Planning Reserve Margin for outyears four and six, respectively. Tables 10-3, 10-4, 10-5, and 10-6 show the seasonal outyear PRM projections ten years out based on future capacity and demand assumptions. Tables 10-7, 10-8, 10-9, and 10-10 show the MISO zonal seasonal Local Reliability Requirements for outyear four while Tables 10-11, 10-12, 10-13, and 10-14 show the Local Reliability Requirements for outyear six.

10.1 Planning Year 2026-2027 MISO Planning Reserve Margin Results

For Planning Year 2026-2027, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin of 17.9 percent and a planning UCAP reserve margin of 8.8 percent for the summer season. Numerous values and calculations went into determining the four-year-out MISO system seasonal PRM ICAP and PRM UCAP (Table 10-1).

MISO Planning Reserve Margin (PRM)	**2026/2027 PY** Summer	**2026/2027 PY** Fall	**2026/2027 PY** Winter	**2026/2027 PY** Spring	**Formula Key**
MISO System Peak Demand (MW)	125,138	111,950	104,946	99,950	[A]
Installed Capacity (ICAP) (MW)	155,038	152,619	155,210	149,975	[B]
Unforced Capacity (UCAP) (MW)	144,623	139,494	138,423	133,904	[C]
Firm External Support (ICAP) (MW)	1,731	1,734	1,874	1,803	[D]
Firm External Support (UCAP) (MW)	1,707	1,714	1,857	1,778	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-9,200	-11,000	-9,200	-11,850	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-9,200	-11,000	-9,200	-11,850	[G]
ICAP PRM Requirement (PRMR) (MW)	147,569	143,353	147,884	139,928	[H]=[B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	136,130	130,208	131,080	123,832	[I]=[C]+[E]+[G]
MISO PRM ICAP	**17.9%**	**28.1%**	**40.9%**	**40.0%**	[J]=([H]-[A])/[A]
MISO PRM UCAP	**8.8%**	**16.3%**	**24.9%**	**23.9%**	[K]=([I]-[A])/[A]

Table 10-1: Planning Year 2026-2027 MISO System Planning Reserve Margins

10.2 Planning Year 2028-2029 MISO Planning Reserve Margin Results

For Planning Year 2028-2029, the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin of 18.4 percent and a planning UCAP reserve margin of 9.2 percent for the summer season. Numerous values and calculations went into determining the six-year-out MISO system seasonal PRM ICAP and PRM UCAP (Table 10-2).

MISO Planning Reserve Margin (PRM)	**2028/2029 PY** Summer	**2028/2029 PY** Fall	**2028/2029 PY** Winter	**2028/2028 PY** Spring	**Formula Key**
MISO System Peak Demand (MW)	125,794	112,548	105,525	100,486	[A]
Installed Capacity (ICAP) (MW)	157,656	155,189	157,826	152,532	[B]
Unforced Capacity (UCAP) (MW)	146,097	141,837	140,816	136,237	[C]
Firm External Support (ICAP) (MW)	1,731	1,734	1,874	1,803	[D]
Firm External Support (UCAP) (MW)	1,707	1,714	1,857	1,778	[E]
Adjustment to ICAP {1d in 10yr} (MW)	-10,400	-14,360	-10,400	-13,165	[F]
Adjustment to UCAP {1d in 10yr} (MW)	-10,400	-14,360	-10,400	-13,165	[G]
ICAP PRM Requirement (PRMR) (MW)	148,987	142,563	149,300	141,170	[H]=[B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	137,404	129,191	132,272	124,850	[I]=[C]+[E]+[G]
MISO PRM ICAP	**18.4%**	**26.7%**	**41.5%**	**40.5%**	[J]=([H]-[A])/[A]
MISO PRM UCAP	**9.2%**	**14.8%**	**25.3%**	**24.2%**	[K]=([I]-[A])/[A]

Table 10-2: Planning Year 2028-2029 MISO System Planning Reserve Margins

10.3 MISO Planning Reserve Margin Outyear Projections

Tables 10-3, 10-4, 10-5, and 10-6 show the outyear seasonal PRM projections. Years one, four, and six were probabilistically modeled. PRM projections in years two, three, and five are the result of interpolation of the years studied and years seven through ten are the resulting extrapolations of the outyear analyses.

Metric	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
PRM ICAP	15.9%	16.6%	17.2%	17.9%	18.2%	18.4%	19.6%	20.1%	20.7%	21.2%
PRM UCAP	7.4%	7.9%	8.3%	8.8%	9.0%	9.2%	10.1%	10.4%	10.8%	11.2%
Demand (GW)	123.7	124.3	124.9	125.5	125.7	125.8	126.9	127.3	127.8	128.2
ICAP (GW)	144.3	150.5	153.0	155.0	155.0	157.7	157.7	157.7	157.7	157.7

Table 10-3: MISO Summer Planning Reserve Margin Outyear Projections

Metric	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
PRM ICAP	25.8%	26.6%	27.3%	28.1%	27.4%	26.7%	27.8%	28.1%	28.3%	28.5%
PRM UCAP	14.9%	15.4%	15.8%	16.3%	15.6%	14.8%	15.4%	15.4%	15.5%	15.5%
Demand (GW)	111.0	111.3	111.7	112.0	112.3	112.5	113.1	113.4	113.8	114.1
ICAP (GW)	144.3	148.8	150.3	152.6	152.6	155.2	155.2	155.2	155.2	155.2

Table 10-4: MISO Fall Planning Reserve Margin Outyear Projections

Metric	23-24	24-25	25-26	26-27	27-28	28-29	29-30	30-31	31-32	32-33
PRM ICAP	41.2%	41.1%	41.0%	40.9%	41.2%	41.5%	41.4%	41.5%	41.5%	41.5%
PRM UCAP	25.5%	25.3%	25.1%	24.9%	25.1%	25.3%	25.0%	25.0%	24.9%	24.8%
Demand (GW)	103.5	104.0	104.4	104.9	105.2	105.5	106.4	106.8	107.2	107.6
ICAP (GW)	150.7	154.0	154.7	155.2	155.2	157.8	157.8	157.8	157.8	157.8

Table 10-5: MISO Winter Planning Reserve Margin Outyear Projections

Metric	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PRM ICAP	39.3%	39.5%	39.8%	40.0%	40.3%	40.5%	41.0%	41.2%	41.4%	41.7%
PRM UCAP	24.5%	24.3%	24.1%	23.9%	24.1%	24.2%	23.9%	23.8%	23.8%	23.7%
Demand (GW)	99.1	99.4	99.7	100.0	100.3	100.5	101.1	101.4	101.7	101.9
ICAP (GW)	145.4	148.9	149.9	150.0	150.0	152.5	152.5	152.5	152.5	152.5

Table 10-6: MISO Spring Planning Reserve Margin Outyear Projections

10.4 Planning Year 2026-2027 MISO Local Reliability Requirement Results

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2026-2027 Local Reliability Requirements – Summer 2026											
Installed Capacity (ICAP) (MW)	22,350	15,251	12,350	9,629	9,494	19,595	21,761	12,368	25,425	6,814	[A]
Unforced Capacity (UCAP) (MW)	21,349	14,232	11,903	8,881	8,690	17,946	20,388	11,944	22,182	6,108	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-317	48	2,369	3,060	2,235	3,935	4,012	278	2,230	1,113	[C]
LRR (UCAP) (MW)	21,032	14,280	14,272	11,942	10,925	21,881	24,400	12,222	24,412	7,221	[D]=[B]+[C]
Peak Demand (MW)	18,622	13,121	9,976	9,384	8,121	18,517	21,003	7,880	22,036	4,802	[E]
LRR UCAP per-unit of LRZ Peak Demand	**112.9%**	**108.8%**	**143.1%**	**127.3%**	**134.5%**	**118.2%**	**116.2%**	**155.1%**	**110.8%**	**150.4%**	[F]=[D]/[E]

Table 10-7: Planning Year 2026-2027 LRZ Local Reliability Requirements for Summer 2026

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2026-2027 Local Reliability Requirements – Fall 2026											
Installed Capacity (ICAP) (MW)	22,303	14,924	12,708	9,267	9,296	19,057	21,756	11,773	24,952	6,584	[A]
Unforced Capacity (UCAP) (MW)	20,862	13,680	12,104	8,306	8,124	17,356	20,120	10,815	22,406	5,721	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,150	-608	1,303	2,861	2,032	3,138	3,906	-296	2,172	1,083	[C]
LRR (UCAP) (MW)	19,712	13,072	13,407	11,167	10,156	20,495	24,026	10,519	24,577	6,805	[D]=[B]+[C]
Peak Demand (MW)	18,622	13,121	9,976	9,384	8,121	18,517	21,003	7,880	22,036	4,802	[E]
LRR UCAP per-unit of LRZ Peak Demand	**105.9%**	**99.6%**	**134.4%**	**119.0%**	**125.1%**	**110.7%**	**114.4%**	**133.5%**	**111.5%**	**141.7%**	[F]=[D]/[E]

Table 10-8: Planning Year 2026-2027 LRZ Local Reliability Requirements for Fall 2026

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2026-2027 Local Reliability Requirements – Winter 2026-2027											
Installed Capacity (ICAP) (MW)	22,576	15,148	14,708	9,272	9,380	19,027	21,721	11,471	25,252	6,654	[A]
Unforced Capacity (UCAP) (MW)	21,048	13,357	13,748	7,369	7,698	17,193	20,149	10,074	22,044	5,742	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-317	45	2,231	2,882	2,105	3,706	1,915	262	2,100	1,048	[C]
LRR (UCAP) (MW)	20,731	13,402	15,980	10,251	9,803	20,899	22,064	10,336	24,145	6,790	[D]=[B]+[C]
Peak Demand (MW)	18,622	13,121	9,976	9,384	8,121	18,517	21,003	7,880	22,036	4,802	[E]
LRR UCAP per-unit of LRZ Peak Demand	**111.3%**	**102.1%**	**160.2%**	**109.2%**	**120.7%**	**112.9%**	**105.0%**	**131.2%**	**109.6%**	**141.4%**	[F]=[D]/[E]

Table 10-9: Planning Year 2026-2027 LRZ Local Reliability Requirements for Winter 2026-2027

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2026-2027 Local Reliability Requirements – Spring 2027											
Installed Capacity (ICAP) (MW)	21,384	14,796	12,729	9,040	9,196	18,876	21,235	11,457	24,783	6,480	[A]
Unforced Capacity (UCAP) (MW)	19,924	13,355	11,985	7,528	7,922	16,950	18,781	9,929	21,622	5,908	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,085	-700	1,023	2,827	1,980	2,719	2,722	53	1,994	647	[C]
LRR (UCAP) (MW)	18,839	12,655	13,008	10,356	9,902	19,669	21,503	9,982	23,616	6,556	[D]=[B]+[C]
Peak Demand (MW)	18,622	13,121	9,976	9,384	8,121	18,517	21,003	7,880	22,036	4,802	[E]
LRR UCAP per-unit of LRZ Peak Demand	**101.2%**	**96.5%**	**130.4%**	**110.4%**	**121.9%**	**106.2%**	**102.4%**	**126.7%**	**107.2%**	**136.5%**	[F]=[D]/[E]

Table 10-10: Planning Year 2026-2027 LRZ Local Reliability Requirements for Spring 2027

10.5 Planning Year 2028-2029 MISO Local Reliability Requirement Results

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2028-2029 Local Reliability Requirements – Summer 2028											
Installed Capacity (ICAP) (MW)	22,350	16,418	12,350	9,629	9,494	19,595	23,212	12,368	25,425	6,814	[A]
Unforced Capacity (UCAP) (MW)	21,349	15,324	11,903	8,881	8,690	17,946	21,769	11,944	22,182	6,108	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-232	-463	1,981	3,089	2,294	4,020	2,628	39	2,283	1,132	[C]
LRR (UCAP) (MW)	21,117	14,861	13,884	11,970	10,983	21,967	24,398	11,983	24,465	7,240	[D]=[B]+[C]
Peak Demand (MW)	18,177	13,132	10,172	9,485	8,001	18,099	20,705	7,725	21,417	4,716	[E]
LRR UCAP per-unit of LRZ Peak Demand	**116.2%**	**113.2%**	**136.5%**	**126.2%**	**137.3%**	**121.4%**	**117.8%**	**155.1%**	**114.2%**	**153.5%**	[F]=[D]/[E]

Table 10-11: Planning Year 2028-2029 LRZ Local Reliability Requirements for Summer 2028

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2028-2029 Local Reliability Requirements – Fall 2028											
Installed Capacity (ICAP) (MW)	22,303	16,090	12,708	9,267	9,296	19,057	23,160	11,773	24,952	6,584	[A]
Unforced Capacity (UCAP) (MW)	20,862	14,727	12,104	8,306	8,124	17,356	21,415	10,815	22,406	5,721	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,035	-1,100	1,275	2,903	2,078	3,260	2,559	-281	2,223	1,102	[C]
LRR (UCAP) (MW)	19,827	13,627	13,379	11,209	10,202	20,616	23,975	10,534	24,629	6,823	[D]=[B]+[C]
Peak Demand (MW)	18,177	13,132	10,172	9,485	8,001	18,099	20,705	7,725	21,417	4,716	[E]
LRR UCAP per-unit of LRZ Peak Demand	**109.1%**	**103.8%**	**131.5%**	**118.2%**	**127.5%**	**113.9%**	**115.8%**	**136.4%**	**115.0%**	**144.7%**	[F]=[D]/[E]

Table 10-12: Planning Year 2028-2029 LRZ Local Reliability Requirements for Fall 2028

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2028-2029 Local Reliability Requirements – Winter 2028-2029											
Installed Capacity (ICAP) (MW)	22,576	16,326	14,708	9,272	9,380	19,027	23,159	11,471	25,252	6,654	[A]
Unforced Capacity (UCAP) (MW)	21,048	14,468	13,748	7,369	7,698	17,193	21,430	10,074	22,044	5,742	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-232	-463	1,866	2,909	2,160	3,786	1,301	289	2,150	1,066	[C]
LRR (UCAP) (MW)	20,816	14,005	15,614	10,278	9,858	20,980	22,731	10,363	24,194	6,808	[D]=[B]+[C]
Peak Demand (MW)	18,177	13,132	10,172	9,485	8,001	18,099	20,705	7,725	21,417	4,716	[E]
LRR UCAP per-unit of LRZ Peak Demand	**114.5%**	**106.6%**	**153.5%**	**108.4%**	**123.2%**	**115.9%**	**109.8%**	**134.2%**	**113.0%**	**144.4%**	[F]=[D]/[E]

Table 10-13: Planning Year 2028-2029 LRZ Local Reliability Requirements for Winter 2028-2029

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2028-2029 Local Reliability Requirements – Spring 2029											
Installed Capacity (ICAP) (MW)	21,384	15,965	12,729	9,040	9,196	18,876	22,622	11,457	24,783	6,480	[A]
Unforced Capacity (UCAP) (MW)	19,924	14,365	11,985	7,528	7,922	16,950	20,104	9,929	21,622	5,908	[B]
Adjustment to UCAP {1d in 10yr} (MW)	-1,030	-1,072	1,471	2,932	1,995	2,970	1,774	50	2,266	652	[C]
LRR (UCAP) (MW)	18,894	13,293	13,456	10,460	9,917	19,920	21,878	9,979	23,887	6,560	[D]=[B]+[C]
Peak Demand (MW)	18,177	13,132	10,172	9,485	8,001	18,099	20,705	7,725	21,417	4,716	[E]
LRR UCAP per-unit of LRZ Peak Demand	**103.9%**	**101.2%**	**132.3%**	**110.3%**	**123.9%**	**110.1%**	**105.7%**	**129.2%**	**111.5%**	**139.1%**	[F]=[D]/[E]

Table 10-14: Planning Year 2028-2029 LRZ Local Reliability Requirements for Spring 2029

11 Appendix F: Outyear CIL/CEL Results

MISO will not be conducting the outyear CIL/CEL study as part of the PY 2023-2024 LOLE study report. This has been communicated to stakeholders at the February 2023 RASC: https://cdn.misoenergy.org/20230228-0301%20RASC%20Item%2004d%20Out-Year%202027-28%20CIL-CEL%20Study%20Update627986.pdf

The usefulness and value created by the outyear CIL/CEL study is being evaluated by MISO. Any updates or changes to the outyear CIL/CEL study going forward will be communicated through the RASC and/or LOLEWG.