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 121

Witmeier 2025 ERAS Testimony

TAB C

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	**)** **)**	**Docket No. ER25-___-000**

PREPARED DIRECT TESTIMONY OF ANDREW WITMEIER

ON BEHALF OF THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

June 6, 2025

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	**)** **)**	**Docket No. ER25-___-000**

PREPARED DIRECT TESTIMONY OF ANDREW WITMEIER

I. PROFESSIONAL BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, CURRENT POSITION AND YOUR BUSINESS ADDRESS.

A. My name is Andrew Witmeier. I am the Director of Resource Utilization for the Midcontinent Independent System Operator, Inc. ("MISO"). My business address is: 720 City Center Drive, Carmel, IN 46032-7574.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I joined MISO in 2003 after graduating from Purdue University with a bachelor's degree in electrical engineering. I spent the first 17 years of my career in various positions in MISO Operations. During that time, I worked as a North American Electric Reliability Corporation ("NERC") certified system operator in scheduling, engineering, and as a reliability coordinator. I also led several groups within MISO Operations as a manager in engineering, reliability coordination, and seams administration. In January 2020, I was appointed to my current position where I have remained for the past five years.

Q. PLEASE DESCRIBE YOUR JOB RESPONSIBILITIES WITH MISO AS THEY RELATE TO THIS FILING.

A. As the Director of Resource Utilization, I am responsible for the administration of MISO's Generator Interconnection Procedures ("GIP"), which are set forth in Attachment X of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff" or "MISO Tariff").[1] I oversee MISO's generation interconnection queue, including the negotiation and execution of Generator Interconnection Agreements ("GIAs"), which are based on MISO's *pro forma* GIA set forth in Appendix 6 of the GIP. I also oversee the group that manages and processes generation retirement, generator replacement, and Surplus Interconnection Service requests for generators connected to MISO's Transmission System. I have been directly involved in the preparation and development of the current proposals.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. I have provided testimony in a number of proceedings before the Commission. The most recent testimonies are as follows:

- In March 2025, I provided testimony in Docket No. ER25-1674-000 to support MISO's original Expedited Resource Addition Study ("ERAS") proposal.
- In November 2024, I provided testimony in Docket No. ER25-507-000 to support MISO's generator interconnection cap proposal.

[1] Unless otherwise indicated in my Testimony, all capitalized terms used herein have the meaning as set forth in the Tariff or the proposed Tariff revisions, as applicable.

- In August 2024, I provided testimonies supporting the JOA and MISO Tariff revisions implementing the JTIQ initiative in Docket No. ER24-2797-000 and ER24-2871-000.
- In November 2023, I sponsored testimony in Docket Nos. ER24-340-000 and ER24-341-000 supporting a package of reforms of MISO's generator interconnection process.
- In December 2021, I submitted testimony in Docket No. ER22-661-000 on issues relating to MISO's generator queue reform and resource utilization.

II. OVERVIEW AND PURPOSE OF TESTIMONY

Q. ARE YOU SUBMITTING YOUR TESTIMONY ON BEHALF OF MISO?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony supports the updated Tariff revisions that MISO is submitting in this docket to file certain urgent improvements to the GIP. MISO is proposing the creation of a new process—the Expedited Resource Addition Study ("ERAS")—to facilitate the addition of projects to address certain near-term resource adequacy and reliability needs. This process will be separate from MISO's generator interconnection queue process, which is referred to as the Definitive Planning Phase ("DPP") process. As further discussed below, while MISO has been actively improving the efficiency of its generator interconnection queue with recent reforms, it will take several years for the impact of these changes to be fully realized and for MISO to reduce queue processing time to an approximately one-year timeframe. MISO has refined its original ERAS process, which will be more fully explained and addressed in my testimony.

Q. CAN YOU BRIEFLY EXPLAIN THE REFINEMENTS THAT WERE MADE TO MISO'S ORIGINAL ERAS PROPOSAL?

A. Yes. At a high level, MISO is now implementing a cap on ERAS projects to 68 total with carve outs for a maximum of 8 projects to serve retail choice load and a maximum of 10 projects from Independent Power Producers ("IPPs"). MISO is also implementing a requirement to only study 10 projects per ERAS Quarterly Study cycle.[2] In addition to the cap, MISO is changing the Relevant Electric Retail Rate Authority ("RERRA") notification requirement to a RERRA verification so that the ERAS project will be more closely targeted to a resource adequacy and/or reliability need in the RERRA's footprint. MISO is also limiting proposed ERAS project's interconnection service to 150% of the identified MW need, is requiring the project to be in the same Local Resource Zone ("LRZ") as the load need it is addressing (unless the project applicant can demonstrate that the use of a Generating Facility not in the same LRZ was included in a resource filing or other submission made to the relevant RERRA), and is now requiring additional information in the ERAS Interconnection Request application. Finally, MISO has proposed tariff language to incorporate the retail states into the ERAS process. In the rest of my testimony, I go into further detail and background on these refinements.

Q. HOW DO THESE FILINGS RELATE TO MISO'S COMPLIANCE OBLIGATIONS UNDER ORDER NO. 2023/2023-A?

A. At the time of this submission, MISO submitted its Order No. 2023-2023-A compliance filings pursuant to the independent entity variation requirements set forth in Order Nos.

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[2] MISO is requiring that projects proposed by IPPs must be with entities other than Load Serving Entities ("LSEs").

2003 and 2023.[3] If the Commission accepts the proposed revisions, they will become part of the MISO Tariff.

Q. IS MISO REQUESTING AN INDIVIDUAL ENTITY VARIATION?

A. Yes. ERAS is a new and temporary process that is intended to exist separately from MISO's DPP cluster-based queue process. Unlike the DPP, ERAS will not employ a 3-phase process, cluster studies, use the same withdrawal penalties, or employ many of the other mechanisms associated with the DPP process. Given the unique nature of ERAS, the limited timeframe for which it will be in effect, and the comparatively small number of projects that MISO expects to process through ERAS, MISO submits ERAS as a necessary independent entity variation to MISO's compliance with Order No. 2023-2023-A.

Because ERAS is a standalone process, it should be viewed as one large independent entity variation with a defined rule set rather than individual independent entity variations for the numerous differences between the cluster-based process outlined in Order 2023-2023-A and ERAS serial-based study approach. This said, I briefly describe some of the more salient differences below and explain why these are appropriate.

- Serial study: Studying ERAS Interconnection Requests individually in serial fashion will increase the speed of analysis, remove uncertainty caused by other requests being included in those analyses, and allows Interconnection Customers to better replicate study results prior to submission. Cluster studies are more complex with increased uncertainty due to

[3] *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008), *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 (2023), order on reh'g, Order No. 2023-A, 186 FERC ¶ 61,199 (2024).

withdrawal concerns since projects are reliant on those in front of them or within their cluster in the review process.

- Different timelines: Individual analysis of ERAS Interconnection Requests allows for a significantly reduced timeline to complete the process and allows for an Expedited Generator Interconnection Agreement ("EGIA") to be executed in months rather than years.
- Higher deposits: ERAS requires higher non-refundable fees and higher milestone payments that must be made at application submission. The financial commitment required for ERAS ensures the level of certainty that the project is ready to move forward and the higher non-refundable fee is necessary to support the additional overhead MISO needs to facilitate the ERAS process.
- Financial commitment to fund Network Upgrades at EGIA: To further validate the certainty of ERAS Interconnection Requests and prevent impact on Interconnection Requests in the DPP that are relying on Network Upgrades identified in the ERAS process, ERAS Interconnection Requests will be required to fund all Network Upgrades once the EGIA is executed, even if that EGIA is later terminated.
- Enhanced Site Control: ERAS Interconnection Requests must present evidence of all necessary Site Control to ensure the project can be built on the generator site as well reach its Point of Interconnection ("POI") on the transmission system.
- RERRA Verification: Interconnection Requests eligible to utilize ERAS must have a written verification from a RERRA, who is ultimately responsible for resource adequacy as noted in the Federal Power Act, that (i) the new, incremental load addition is valid and

is not currently included in a plan or other procedure under the RERRA's purview or (ii) the Generating Facility will address an identified resource adequacy deficiency.

- Off-taker agreement: ERAS Interconnection Requests are required to show that the generation has an agreement with a specific load or is a Load Serving Entity ("LSE") to ensure that generation will be utilized for known load.

Q. IS MISO PROPOSING ANY TRANSITION PROVISIONS FOR THE ERAS FILING?

A. Yes. The transition provisions are included in proposed section 5.13 of the GIP. Generally, the proposed reforms will apply only to ERAS Interconnection Requests submitted after the requested effective date of the reforms, which is August 6, 2025.

III. THE CURRENT MISO QUEUE AND THE ERAS PROCESS

A. ERAS is Necessary to Address Resource Adequacy and Reliability Needs

Q. PLEASE DESCRIBE THE CURRENT STATUS OF MISO'S GENERATOR INTERCONNECTION QUEUE.

A. As of June 5, 2025, MISO's generator interconnection queue contains 1,573 active Interconnection Requests comprising 291 GW of proposed new generator interconnection capacity. This considerable backlog of applications is spread over all five of MISO's study regions and includes queue cycles going back to 2019. The queue size continues to be extraordinary and unprecedented—the 2023 queue cycle, the last to close in 2024, alone is 123 GW. Notably, almost 70% of the total generation capacity that entered the 2017 and 2018 queue cycles was eventually withdrawn. The remaining 30% obtained GIAs, but the actual amount of generating capacity that will be completed and energized will be less than

30% due to financial and construction challenges. Similar withdrawal rates are occurring in the later cycles as well.

Q. DO YOU EXPECT THE CURRENT QUEUE DELAY TRENDS TO CONTINUE?

A. Yes, as I noted in my previous ERAS testimony, I expect the delays to continue in the short-term, as the bulk of the recent proposed generating resources from the unprecedented queue sizes (e.g., the 2022 study cycle included over 956 application submittals totaling approximately 171 GW) continue through the MISO interconnection queue process, and only the 2023 study cycle takes advantage of the queue reforms approved in January 2024 under Docket No. ER24-341-000. Queue delays caused by restudies due to late-stage withdrawals are one of the latest issues negatively impacting Interconnection Customers' ability to timely execute a GIA. Additionally, ongoing delays to resource additions with signed interconnection agreements are caused by supply chain bottlenecks, permitting delays and commercial challenges. To further demonstrate this unprecedented backlog, MISO recently published a COD dashboard to help stakeholders determine when resources might attain commercial operation.[4] These resulting delays are currently interfering with the ability to plan for meeting growing resource adequacy needs and ultimately creates a major reliability concern. The ERAS proposal will help address some of these needs in the short term.

While MISO has taken targeted actions to help manage a highly active generator interconnection queue with process improvements and leveraging technology to speed up processing and studying of new interconnections requests, a temporary solution is required

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[4] MISO Generator Interconnection, *COD Report: Overview*, https://app.powerbigov.us/view?r=eyJrIjoiOTU1ODlhNTktMjZjZC00N2I2LWJhYjMtMDEwOGNmZDM5ODk0IiwidCI6IjYwNDA5MTViLTlkZmYtNGQ0Ny1iYjM1LThhYzljOWE1ZGMxOCJ9&pageName=983a2cc8ca3ccf63608a.

in the short-term to address the immediate and urgent capacity needs until the queue backlog and study timelines are reduced.

Q. IS ERAS A SEPARATE PROCESS FROM MISO'S QUEUE?

A. Yes. ERAS is not a part of MISO's Definitive Planning Phase ("DPP") process. ERAS is also not another interconnection queue that will supplant the generator interconnection process. MISO understands the concerns that ERAS is enabling queue jumping but ERAS is a unique and separate process from the DPP process that is limited in size and scope. The process has extremely stringent eligibility requirements that will limit the projects that can participate in it to those with commercial viability, RERRA verification, and the ability to come online in the next few years. MISO sees ERAS as a complementary process to the generator interconnection queue and a solution that will assist in addressing resource adequacy and reliability needs in the next few years.

Q. PLEASE DESCRIBE WHY ERAS IS NECESSARY.

A. There is a growing critical reliability challenge facing the industry, which has been documented and highlighted in various MISO and non-MISO reports. Examples of such reports include:

1. MISO Futures Report Series 1A: posted in November 2023 and utilized for Long Range Transmission Planning Tranche 2.1 portfolio.[5]
2. MISO's Reliability Imperative Report: 2024 MISO Regional Resource Assessment (RRA).[6]

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[5] *MISO Futures Report, Series 1A* (November 1, 2023), available at: https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

[6] *2024 Regional Resource Assessment*, A Reliability Imperative Report (January 2025), available at: https://cdn.misoenergy.org/2024%20RRA%20Report_Final676241.pdf.

3. The 2024 NERC Long-Term Reliability Assessment (LTRA).[7]
4. The 2024 OMS-MISO Survey: As in previous years, MISO and the Organization of MISO States (OMS) completed a volunteer survey on resource adequacy to identify potential future resource adequacy needs in the MISO region.[8] The 2025 OMS-MISO Survey will be published on the same day as this refined ERAS filing and indicates a similar resource adequacy and/or reliability need trajectory.[9]
5. NERC's 2025 Summer Reliability Assessment.[10]
6. Comments from FERC's Technical Conference on Resource Adequacy.[11]

The reports all include the following elements:

- The increasingly significant challenges facing the MISO footprint in meeting state energy goals and expectations.
    - The RRA report noted that the MISO members and states may need to add capacity at 17 GW/year for 20 years.

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

[8] *2024 OMS-MISO Survey Results* (June 20, 2024), available at: https://cdn.misoenergy.org/OMS%20MISO%20Survey%20Results%20Workshop%20Presentation628355.pdf.

[9] *See 2025 OMS-MISO Survey Results* (Updated June 2025), available at: https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[10] 2025 Summer Reliability Assessment, North American Electric Reliability Corporation, May 2025, ("NERC 2025 Assessment"), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.

[11] Comments of Todd Ramey on behalf of MISO at 9, Docket No. AD25-7, May 28, 2025 ("MISO RA Tech Conference Comments"); Prefiled Statement of Jim Robb, President and CEO of North American Electric Reliability Corporation at 1, Docket No. AD25-7, May 19, 2025 ("NERC RA Tech Conference Comments").

- The critical timeframe and urgent need for resources on the horizon as demand growth continues to accelerate.
  - The 2024 OMS-MISO Survey found that additional actions would be needed as soon as possible to expedite the addition of new capacity, coordinate resources for new load additions, and potentially moderate the pace of resource retirements.
  - The 2025 OMS-MISO Survey indicates that "[a]t least 3.1 GW of new resources are needed by summer 2026/27 to avoid a resource deficiency, with greater needs in future years."[12] The survey also states that survey responses show "increasing load forecasts year-over-year and are close to the high end of MISO Long-Term Load Forecast."[13]
- Indications that MISO is at "high risk" for meeting upcoming resource adequacy requirements.
  - The NERC LTRA report highlights that based on potential delays to generator construction, there is a potential in MISO's footprint to see a 2.7 GW shortfall by 2029 if not earlier.

In further recognition of this issue, the Department of Energy recently introduced the GRID Modernization Initiative, which "envisions a fully integrated electric system from generation to transmission to load consumption … with an emphasis on maintaining the

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[12] 2025 OMS-MISO Resource Adequacy Survey Results, Fact Sheet, available at: https://cdn.misoenergy.org/2025%20OMS-MISO%20Survey%20Fact%20Sheet702641.pdf.

[13] *2025 OMS-MISO Survey Results* (June 6, 2025) at 10.

reliability and resilience of the grid."[14] Concerns about resource adequacy in the MISO footprint have only increased since the publication of these reports. For instance, MISO initiated the process to redesign the Futures, last finalized in November 2023, as MISO and stakeholders have determined that the load forecasts represented in those Futures are too low. On February 28, 2025, MISO held the first of several workshops to redesign the assumptions within the Futures.[15]

In light of these industry-wide challenges, MISO realized it needed a more responsive process to work with the states to address these resource adequacy needs. The refined ERAS is intended to help maintain resource adequacy integrity within this short timeframe until it sunsets on August 31, 2027, or the completion of sixty-eight ERAS Interconnection Request studies, whichever occurs first. Ultimately, the purpose of ERAS is to provide a mechanism for addressing these resource adequacy and/or reliability needs within this short timeframe, rather than waiting until it is too late.

Q. DOES MISO HAVE ADDITIONAL EVIDENCE TO SUPPORT ITS CLAIM FOR IMMEDIATE RESOURCE ADEQUACY NEEDS?

A. Yes. MISO's internal data supports the general claims about resource adequacy needs. The need for generation to serve load additions through the Expedited Project Review ("EPR") illustrates this challenge and is addressed later in my testimony. MISO has been very vocal about communicating and presenting this impending concern. Simply glossing over this inevitable emerging need for generation only confuses the issue. Additionally,

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[14] *Grid Modernization Initiative*, U.S. Department of Energy (July 2024), available at: https://www.energy.gov/sites/default/files/2024-12/Grid%20Modernization%20Strategy%202024.pdf.

[15] MISO, *Futures Redesign Workshop* (Feb. 28, 2025), available at: https://www.misoenergy.org/events/2025/futures-redesign-workshop---february-28-2025/.

this issue of resource adequacy concerns has been the subject of numerous discussions throughout the MISO stakeholder process for some time now with considerable stakeholder support. MISO submitted comments prior to FERC's Technical Conference on the challenge of resource adequacy in RTO and ISO regions, noting that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, insufficient transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[16] MISO also recently published material from its System Planning Committee, which included updates to the Reliability Imperative.[17] The update noted that "[t]here is no single type of investment that will support all system needs; the necessity for near-term but large-scale transmission to support these large load additions recently came to the forefront."[18] The 2025 OMS-MISO Survey will be published on the same day as this filing and its projection are in alignment with the resource adequacy and reliability needs that MISO has referenced in this filing.[19] The survey identifies ERAS as an in-progress initiative and one that will help address resource adequacy challenges.[20]

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16 *Id.*

17 *Reliability Imperative: Transmission Evolution*, System Planning Committee of the Board of Directors, Jun. 10, 2025, https://cdn.misoenergy.org/20250610%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2005%20Reliability%20Imperative_Transmission%20Evolution701586.pdf.

18 *Id.* at 5.

19 *See 2025 OMS-MISO Survey Results* (June 6, 2025).

20 *Id.* at 16.

Q. WHY WON'T ERAS PROJECTS BENEFIT FROM THE DPP QUEUE?

A. As detailed in the following testimony and substantiated by multiple examples, a need exists in the near term to accelerate the interconnection process for resource adequacy and/or reliability projects that are unable to benefit from the impact of the recent MISO GIP improvements or Order No. 2023. These resource adequacy concerns are driven by the following: 1) significant growth in spot load; 2) the inability to study new necessary resources immediately upon entering the queue; 3) the accelerated retirement of generation resources; 4) the ongoing delays to resource additions with signed interconnection agreements due to supply chain bottlenecks, permitting delays, and commercial challenges; and 5) the continued large volumes of Generator Interconnection Queue requests and accumulating backlog. The increasing impact of these factors requires urgent improvements to the current GIP to ensure that MISO can meet the challenge. Accepting the proposed ERAS revisions will contribute to ensuring that MISO has sufficient new resources to meet these impending challenges in the coming years.

Q. WHY ISN'T THE CURRENT QUEUE SUFFICIENT TO ADDRESS THESE RESOURCE ADEQUACY NEEDS?

A. MISO successfully implemented several queue reforms improving various aspects of the generator interconnection queue or DPP process. Despite these efficiency updates, MISO's interconnection queue continues to experience significant delays. Due to the aforementioned delays in bringing resources online, the current interconnection queue jeopardizes the short-term availability of resource adequacy projects that are stuck in the queue or are yet to be submitted into the queue. The current DPP queue process will not ensure a timely executed GIA with known Network Upgrades until the backlog is cleared and a new cycle can be processed with a yearly cadence. MISO is proposing the ERAS process to fill the gap in the short-term by expediting the approval of new generation needed to address resource adequacy and reliability needs.

B. ERAS Projects Will Not Harm DPP Queue Projects

Q. WILL ACTIVE DPP PROJECTS STILL BE ABLE TO TRANSFER TO THE ERAS PROCESS?

A. Yes. If the projects meet the eligibility requirements to enter the ERAS interconnection process, DPP projects in active DPP cycles at or before Decision Point 2 (anticipated only 2022 and 2023 cycles) may transfer to the ERAS process. MISO will not allow Interconnection Requests to transfer from the existing interconnection queue after Decision Point 2 to avoid the Phase 3 restudies due to late withdrawals, which contribute to ongoing queue delays. If an Interconnection Request is beyond Decision Point 2, then it can still drop out of the DPP process; however, it cannot enter ERAS until a year has passed since the withdrawal. This limitation was implemented to maintain the integrity of the DPP process. Allowing active projects in the current queue to transfer to ERAS process also enables the faster completion of studies for projects that can address resource adequacy and/or reliability needs in the short term.

Q. DOES MISO KNOW OF ANY EXISTING PROJECTS IN THE QUEUE THAT PLAN TO TRANSFER TO ERAS?

A. Yes. MISO is aware of several projects that are interested in participating in ERAS and can meet the eligibility requirements. Upon transferring from the DPP process to ERAS, the projects will be subject to all existing withdrawal penalties and/or harm calculations stated in the Tariff. Based on stakeholder feedback, MISO determined that projects withdrawing from the DPP to enter ERAS should not provide undue impact on Interconnection Requests remaining in the DPP process. That is why withdrawals can only occur at the existing off ramps (i.e. Decision Point 1 and/or Decision Point 2) and that they should be subject to any Automatic Withdrawal Penalty or harm calculation.

Q. WHY ISN'T MISO EVALUATING PROJECTS IN THE DPP QUEUE TO DETERMINE WHETHER THEY CAN ADDRESS RESOURCE ADEQUACY AND/OR RELIABILITY NEEDS?

A. MISO does not believe it is appropriate for it to decide which generation projects address an identified need. MISO is not the resource planner. Ultimately it is the states/RERRAs processes that determine which generation is utilized to meet a resource adequacy and/or reliability need. ERAS provides a means to determine Network Upgrades necessary to aid the states/RERRAs in their determination processes by providing a timely process to study certain Interconnection Requests that the RERRA has acknowledged. Without ERAS, the states/RERRAs need to make their determination after an Interconnection Request is out of the DPP process, which may be too late, or with unknown or incomplete transmission upgrade costs.

Q. WILL ERAS TAKE NECESSARY RESOURCES AWAY FROM THE DPP QUEUE?

A. No. ERAS will not take away resources from the DPP Queue as MISO is requiring significantly increased financial commitments from ERAS participants. First, the D1 payment is $100,000 and is non-refundable. The funds from this payment will provide the additional financial resources needed to help MISO manage the ERAS process. These resources may include additional software tools and enhancements to process ERAS.

Second, MISO has committed to hiring additional personnel or contractors as needed to help manage the ERAS requests. MISO is actively monitoring the workload and need for additional support to effectively process both ERAS and the DPP queue. The cap on 10 projects per ERAS cycle will also make MISO's workload and resource needs easier to forecast and manage. While MISO believes that it has sufficient resources to manage ERAS even without the project cap, MISO recognizes that the project cap will further assist it in efficiently managing both the ERAS and DPP processes. No resources or staff time will be diverted from the DPP queue to ERAS or vice versa.

Q. DO YOU AGREE WITH CLAIMS THAT ERAS WILL REDUCE THE TRANSMISSION CAPACITY HEADROOM AVAILABLE TO PROJECTS IN THE DPP QUEUE?

A. No. As I previously explained in my testimony, ERAS projects will ultimately be studied on a different MTEP base case than projects currently in the MISO queue. An ERAS project that is studied in September 2025 will use the MTEP 2024 base case that is supplemented with changes since that base case was built with both approved EPR projects and new generators with signed GIAs. The 2022 DPP cycle that kicked off in March 2023 used the 2022 base case from when the projects joined the queue. Those DPP projects will have access to the headroom existing in the 2022 base case, which is not impacted at all by the ERAS process.

Q. WILL ERAS PROJECTS SHIFT OR INCREASE UPGRADE COSTS TO CUSTOMERS CURRENTLY IN THE DPP QUEUE?

A. No. This speaks to a misunderstanding of how MISO will create the model for the serially studied ERAS projects. In building the model for new ERAS interconnection projects, MISO will rely on the latest MTEP base case, including any recently approved EPR projects. In the normal DPP process, the base case is never updated once the study process is kicked off except for changes due to projects withdrawing at the Decision Points or generator retirements, which limits the Network Upgrades to only those introduced as part of the ERAS project.

Q. WHY ARE PHASE 3 PROJECTS NOT INCLUDED IN THE BASE CASE FOR ERAS?

A. MISO does not include Phase 3 projects in the base case for any study process because doing so would require it to deviate from its standard practice. MISO only includes projects that have obtained a GIA in the subsequent base model. MISO does not want to assume that these Phase 3 projects will obtain a GIA, then include them in the model, only to be proven wrong and negatively impact the base model. MISO does not consider projects to be "real" until they have obtained a GIA, at which point they are included in the next base case model.

Q. WHY ARE LATE-STAGE DPP PROJECTS PROHIBITED FROM PARTICIPATING IN ERAS?

A. Late-stage DPP projects are prohibited from participating in ERAS to prevent negative impacts on the DPP queue. To maintain the integrity of the queue, MISO must protect the projects already in the DPP process. Allowing late-stage DPP projects to transfer into ERAS would require their removal from the DPP queue, triggering re-studies. These re-studies would cause delays and adversely affect the remaining projects in the queue.

Q. IN LIGHT OF THE RECENT QUEUE REFORMS, WHY IS IT NECESSARY TO IMPLEMENT ERAS NOW?

A. The recent queue reforms are essential and will result in beneficial changes to the DPP queue, but on a longer time frame than is needed to address current resource adequacy and reliability needs. MISO views the refined ERAS process as complementary to the recent queue reforms but argues that it addresses a more imminent problem. ERAS is not redundant to the existing DPP queue as its purpose and structure is completely different. Several protestors to the original ERAS filing suggested that the SUGAR Software that MISO has been working to implement will solve the problem. However, these claims fail to consider that MISO is currently implementing the SUGAR software only for increasing the speed of the Phase 1 Study of the MISO DPP process, not for the more in-depth Phases 2 and Phase 3, portions. MISO anticipates that it will utilize SUGAR for the later phases, but the software as currently developed is not designed to run the Phase 2 or Phase 3 studies.

Q WHY SHOULDN'T MISO UTILIZE PROVISIONAL GIAs TO ADDRESS THE RESOURCE ADEQUACY AND/OR RELIABILITY NEEDS?

A. A Provisional Generator Interconnection Agreement or PGIA is another tool for Interconnection Customers to achieve a timely interconnection agreement; however, it is insufficient to address the problem on the scale or in the time frame that is needed. Provisional interconnection service, while available for interconnection projects to request as soon as they enter the DPP process, only provides for limited operation, and is conditional on DPP studies for full deliverability that 1) may not be available to recognize the new capacity and 2) can still take several years to finalize. Having a PGIA poses a substantial risk on generator projects depending on the projects in the queue that may never go commercial or may not be built due to not having an off-taker or a load to serve. Some of the benefits of PGIAs such as increased financial commitments and an expedited timeframe to getting an EGIA were incorporated into the ERAS process. Ultimately, only the ERAS process will ensure that all the Network Upgrades on the MISO transmission system that are necessary to provide deliverability across the system are identified by the time the EGIA is executed.

V. <u>THE REFINED ERAS PROPOSAL</u>

Q. WHY IS MISO REFINING THE ERAS PROCESS?

A. Following the Commission's review of MISO's original ERAS process, it rejected MISO's proposal and made several recommendations for how to ameliorate the issues it identified in the original ERAS proposal. Thanks to this guidance from the Commission, MISO has changed several aspects of its original proposal and is now seeking Commission approval of its refined ERAS process. As explained earlier in my testimony, ERAS is MISO's solution to the near-term resource adequacy and reliability needs within its footprint. Due to unforeseen circumstances related to unexpected and dramatic load growth, MISO needs to implement a process that can enable the completion of projects addressing resource adequacy and/or reliability needs in the next few years. ERAS is not another interconnection queue; rather, it is a separate process that the states may utilize to address short-term resource adequacy and/or reliability needs.

Q. HOW WAS THIS NEW ERAS PROPOSAL DEVELOPED?

A. Following the Commission's Order on MISO's original ERAS filing and other stakeholder feedback, MISO worked quickly to refine its Expedited Resource Addition Study to address the concerns identified by the Commission and to propose a framework for the accelerated study of generation projects that can address urgent resource adequacy and reliability needs in the near term. With the Commission's guidance, MISO made critical changes to its original ERAS proposal including adding a total project cap with carve outs for retail states and independent power producers. MISO has also added several requirements to establish a stronger connection between the proposed ERAS projects, and the resource adequacy needs that the projects will be addressing.

MISO developed this process and the accompanying Tariff language based on its resolve to address its urgent short-term resource adequacy needs and has provided extensive opportunities for all interested parties to comment during the stakeholder process. It should be noted though that these issues are complex and there is no set of reforms that will flawlessly meet the needs of every stakeholder affected by these updates, but the final ERAS proposal that MISO is submitting today incorporates many of the comments and recommendations we received through this process.

Q. PLEASE DESCRIBE THE STAKEHOLDER PROCESS USED TO DEVELOP THIS PROPOSAL.

A. MISO engaged in an extensive stakeholder process throughout the development of the original ERAS proposal. MISO obtained feedback through the Planning Advisory Committee (PAC), conducted dozens of calls with stakeholders across the MISO sectors, and received multiple rounds of both formal and informal written feedback. During the stakeholder process, MISO considered the advantages and disadvantages of multiple approaches for addressing the identified challenges and risks, collaborating with stakeholders on identifying areas where flexibility could be increased. MISO revised its initial proposal considerably, incorporating the input received.

The key milestones of the original ERAS proposal stakeholder process were as follows:

- November 13, 2024: MISO presented an initial ERAS proposal to the PAC and requested written formal feedback from stakeholders from this meeting be included with feedback from the November 18th workshop.
- November 18, 2024: MISO and stakeholders participated in a special ERAS-specific workshop in which the parties continued to discuss ERAS details. MISO sought feedback on the ERAS proposal.
- December 6, 2024: MISO and stakeholders participated in a second ERAS-specific workshop in which the parties continued to discuss ERAS details. MISO sought written formal feedback on the updated proposal.
- January 22, 2025: MISO presented an updated ERAS proposal at the PAC.
- February 19, 2025: MISO posted proposed tariff redlines, presented an updated ERAS proposal, and sought written formal feedback at the PAC.
- March 7, 2025: MISO posted updated proposed tariff redlines and presented the final ERAS proposal at a special PAC meeting scheduled to review the final details of the ERAS proposal.

The key milestones for the refined ERAS proposal stakeholder process were as follows:

- May 28, 2025: MISO presented its refined ERAS proposal at the PAC.[21] MISO received feedback from this presentation through its informal feedback tool.[22]
- MISO conducted dozens of calls with stakeholders across the MISO sectors.

Q. WHAT WAS MISO'S RESPONSE TO CONCERNS AND RECOMMENDATIONS FROM STAKEHOLDERS ON MISO'S ORIGINAL ERAS PROPOSAL?

A. MISO supported many of the concerns and objectives identified by the stakeholders while crafting the original ERAS proposal and was committed to working with stakeholders to incorporate elements of their proposals to meet those objectives. MISO also considered the concerns and recommendations of stakeholders following the Commission's rejection of its original ERAS proposal. The figure below demonstrates how MISO has worked with stakeholders to address concerns related to ERAS implementation and how its revised proposal responds to these concerns and Commission guidance.

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21 *See Expedited Resource Addition Study (ERAS) Next Steps* (May 28, 2025), https://cdn.misoenergy.org/20250528%20PAC%20Item%2008%20Expedited%20Resource%20Addition%20Study%20(ERAS)%20Next%20Steps%20(PAC-2023-1)699836.pdf.

22 *Informal Feedback (2025)*, MISO, available at: https://www.misoenergy.org/engage/stakeholder-feedback/2025/informal-feedback-2025/.

Figure 1: ERAS Proposal Changes from First Iteration

	Where we began	Original ERAS filing	Refined ERAS filing
Cap	N/A	N/A	No more than 10 projects studied per quarter and no more than 68 projects studied overall with an 8 project carve out for restructured states and a 10 project carve out for IPPs with agreements with entities other than LSEs
Applicants	Load Serving Entities	LSEs, IPPs, and DPP transfer projects meeting all requirements	No change
Process timeline	Project studied and GIA issued in 60 days	Quarterly cadence following established MISO timelines, receiving GIA in ~90 days	No change
Required documentation	RERRA acknowledgement	RERRA acknowledgement and one of the following: • LSE acknowledgment to self-supply • PPA between IC and load or its LSE • Build-Own-Transfer Agreement • Other agreement between applicant and load, or its LSE, stating project will meet RA or reliability need	RERRA verification and one of the following: • LSE acknowledgment to self-supply • PPA between IC and load or its LSE • Build-Own-Transfer Agreement • Other agreement between applicant and load, or its LSE, stating project will meet RA or reliability need
Identification of need	N/A	Description of need in ERAS application	IC must identify specific load addition and/or RA deficiency the project will address (MW value band, approximate location, etc.) and this information will be made public
Locational requirement	N/A	N/A	Project and RA and/or reliability need must be within the same Local Resource Zone
Size requirement	N/A	N/A	Interconnection Service must not exceed 150% of the identified MW need
Commercial Operation Date	Expected COD with 2-5 years	2025/26 applicants: 3 years from submission plus 3-year grace period; 2027/28 applicants: 12/31/2028 COD plus 3-year grace period	All applicants must have a COD within 3 years of submission plus a 3-year grace period
Penalties	Requested feedback after first PAC	Projects transferring from DPP process will be subject existing tariff language (e.g. AWP and Harm Calculations)	No change
Sunset	2028 / 2029	12/31/2028 or on the completion date of the 2027 DPP queue cycle, whichever first	ERAS will sunset at the earlier of the completion of the sixty-eighth ERAS study or on August 31, 2027

Q. DID MISO CONSIDER ANY ALTERNATIVE ERAS PROPOSALS?

A. Yes. During the stakeholder process in January and February of 2025, two parties submitted alternative ERAS proposals in the PAC meetings. Those proposals focused on improvements to the existing queue process and many suggestions were not relevant to the serial approach of ERAS as MISO has envisioned it. MISO believes the feedback was extremely beneficial but focused on improvements that MISO can make to its current cluster process and not the ERAS process. The refined ERAS proposal does align with a number of items from the Developer Coalition Counterproposal (February 12, 2025), including limiting the number of ERAS projects allowed to participate and ensuring those projects are tied to a specific need.[23]

The proposals also recommended that MISO utilize a scoring system to evaluate ERAS Interconnection Requests. MISO has not adopted this recommendation because the states have authority over resource adequacy needs and MISO should not be ranking or selecting ERAS Interconnection Requests. It is not appropriate for MISO to be second guessing a RERRA determination that a project should be studied in ERAS.

Q. PLEASE DESCRIBE THE CONCERNS RAISED BY THE COMMISSION'S ORDER AND HOW MISO IS RESPONDING TO THEM.

A. The Commission raised numerous concerns when addressing MISO's original ERAS proposal. The Commission found that MISO's ERAS proposal was not "a just and reasonable and not unduly discriminatory or preferential approach for addressing MISO's stated resource adequacy and reliability needs."[24] The Commission identified two main concerns with ERAS: (1) there was "no limit on the number of projects that could be entered into the ERAS process,"[25] and (2) "the proposal does not sufficiently describe how the ERAS process is sufficiently targeted to study only interconnection requests needed to meet the anticipated shortfall in generating capacity described by MISO."[26] The Commission also recognized that it was "appropriate for RERRAs to communicate to

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[23] *See Developer Coalition: ERAS Counter Proposal (February 12, 2025)* https://cdn.misoenergy.org/20250219%20PAC%20Item%2008%20ERAS%20Alternative%20from%20Developer%20Coalition679607.pdf.

[24] *See Midcontinent Independent System Operator, Inc.*, 191 FERC ¶ 61,131 at P 197 (2025) ("ERAS Order").

[25] *Id.* at P 199.

[26] *Id.* at P 201.

MISO their resource adequacy and reliability needs, as well as their support for including interconnection requests in the ERAS process, to ensure that the RERRA's needs are met in a timely fashion."[27] Each of the Commissioners also filed individual statements urging MISO to revise and refile its ERAS proposal.[28]

MISO is extremely grateful for the Commission's guidance on how to better craft its ERAS proposal and has worked swiftly to develop a refined ERAS process that addressed the Commission's concerns. MISO is now proposing a refined ERAS process that can be implemented by September 2, 2025, to quickly address the looming resource adequacy and reliability needs that it highlighted in its original ERAS filing.

A. <u>Implementing an ERAS Cap</u>

Q. WHY IS MISO IMPLEMENTING A CAP ON ERAS PROJECTS?

A. After receiving feedback from stakeholders and guidance from the Commission in its ERAS order, MISO is implementing a cap on the total number of projects that can participate in ERAS. The Commission was concerned that MISO's original ERAS proposal was unlimited in size and asked that MISO place additional guardrails around ERAS.[29] MISO is now proposing to cap the total number of ERAS projects studied to 68 Interconnection Requests. In addition, MISO is creating a carve out of a maximum of 8 Interconnection Requests (of the total 68) that may be submitted to serve retail choice load and a carve out of a maximum of 10 Interconnection Requests (of the total 68) that may be

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27 *Id.* at P 203.

28 ERAS Order at P 3 (Christie, Comm'r, dissenting); P 6 (Rosner, Comm'r, concurring); P 8 (See, Comm'r, concurring).

29 ERAS Order at P 203.

submitted by IPPs with agreements with entities other than LSEs. The remaining 50 Interconnection Requests may be utilized by the remaining states and developers for non-retail states. MISO recognizes that PJM's Reliability Resource Initiative similarly capped its program at 50 projects and MISO is providing additional carve outs for certain groups that would otherwise have difficulty participating in ERAS. The Commission has previously recognized that an appropriately structured cap used in the interconnection processes can be consistent with open access principles.[30]

Q. IS THERE A LIMIT ON THE NUMBER OF ERAS PROJECTS STUDIED PER CYCLE?

A. Yes. MISO is also going to limit the number of projects studied *per* ERAS quarterly study cycle to 10 projects no matter who submits them. MISO believes that 10 projects per study cycle is a manageable number of projects for its team to study on a quarterly basis. This will allow MISO to spread the number of projects over a longer period of time, which will also help with the expedited review and management of MISO's internal resources to serve ERAS.

Q. HOW WILL THE 10 PROJECTS BE SELECTED FOR THE STUDY?

A. Once the ERAS process is approved, MISO will process the ERAS Interconnection Requests using a serial "first-come, first-served" approach based on the date and time the application was submitted. The first ten projects to submit applications to be studied in ERAS will be tentatively selected until MISO has finalized its screening process of all ten projects to ensure that they (1) meet the ERAS eligibility requirements, and (2) are not

[30] *Id.*

geographically located near another project in the group or impacting the same constraints. After the ten projects in a cycle are finalized, the remaining projects that applied in the cycle will be deferred to the next available ERAS cycle in order of submission time. Since only ten projects will be studied at a time, serial review of the applications will expedite the review process. MISO expects the ERAS Interconnection Requests to apply when they are ready and meet all the necessary eligibility requirements to participate. All application deadlines and ERAS Interconnection Requests will be posted on the MISO public website in a timely fashion.

Q. WHY WILL MISO CREATE A WAITLIST OF ERAS PROJECTS?

A. Projects that apply in a certain cycle but are not the first ten projects that are submitted will be studied in a future ERAS Quarterly Study Period and will remain on an ERAS "waitlist" until MISO has completed a screening process of the first ten projects. After the first ten projects are validated, the remaining projects on the waitlist will be deferred to the next available study quarter in order of when each project was submitted. As soon as the remaining ERAS applicants have gone through the screening process and are accepted into ERAS, MISO will publish the projects and their assigned quarters on the ERAS webpage.

Q. WHAT DOES THE ERAS SCREENING PROCESS INVOLVE?

A. MISO will complete a screening analysis to verify that the projects in a single ERAS study cycle are not in the same geographic area or do not impact the same constraints. If they are in the same area or do impact the same constraints, then the projects will be placed in different quarterly study cycles as separate serial studies. The first submitted project will be processed first, and the next highest priority project (based on submission time) will be processed in a future quarter study cycle.

Q. WHAT IF MULTIPLE ERAS REQUESTS HAVE CONTRACTS TO SERVE THE SAME LOAD?

A. There is a possibility that a very large load will need multiple generators to serve it and would potentially sign agreements with more than one generator. It is incumbent upon the load to determine whether it has negotiated for a sufficient amount of generation and to not rely upon the RERRA to match exact load amounts with generation amounts. It is important to note that these projects cannot be studied together in the ERAS serial process. Thus, the projects would be split over multiple ERAS quarterly study periods in order of submission time even if they are submitted within the same quarter and will serve the same load. MISO recognizes that this is less than ideal from a load need perspective, but in order to ensure that ERAS remains an expedited process that enables the efficient study of ERAS Interconnection Requests in serial order, it must spread out proposed requests that impact the same constraints or serve the same load. This also means that MISO could process a lower queued project ahead of one of these projects if it is a later submitted project that is not similarly situated geographically or if it does not impact any of the same constraints as a higher queued project.

Q. WILL DEFERRED ERAS PROJECTS LOSE THEIR NON-REFUNDABLE D1 PAYMENT?

A. No. MISO will hold their D1, D2, and M2 in order for them to continue to be active requests that are not deficient. But proposed projects that do not meet the ERAS eligibility requirements and are rejected from the ERAS process will lose their D1 payment, but MISO will refund the remaining study and milestone deposits if they withdrawal. Otherwise, they will be automatically transferred into the DPP process. The ERAS projects will be studied serially in order of submission time. MISO conducts a similar process for the queue cap and will be able to efficiently study the ten projects submitted per ERAS cycle.

B. <u>Updating the RERRA Notification Requirement</u>

Q. WHY DID MISO CHANGE THE RERRA NOTIFICATION REQUIREMENT?

A. Following the guidance provided in the Commission's rejection of MISO's original filing, MISO drafted updated language to better tailor and connect the resource adequacy needs with the ERAS projects as verified by the relevant RERRA. The Commissioners indicated that the previously proposed RERRA notification was insufficient to establish a true connection to the resource adequacy and/or reliability need. MISO is also now requiring that the load being addressed by the ERAS project be in the same LRZ region as the RERRA providing the verification, unless the project applicant can demonstrate that the use of a Generating Facility not in the same LRZ was included in a resource filing or other submission made to the RERRA. An example of a resource filing that was submitted to a RERRA is an Integrated Resource Plan. This is another way to more closely tie the ERAS project to the identified resource adequacy and/or reliability need.

Q. HOW DID THE RERRA NOTIFICATION REQUIREMENT CHANGE?

A. Following the Commission's order, MISO recognized that it needed to change the RERRA requirement and has proposed updated language in the tariff. The Commission noted in its order that "MISO has not demonstrated that the proposed Tariff language is tailored to ensure that only those resources capable of addressing identified near-term resource adequacy or reliability needs are eligible for expedited study through the ERAS process."[31] Under the new language, the ERAS Interconnection Request must be accompanied by a written verification from a RERRA that either the new, incremental load addition is valid and not otherwise included in a resource plan, or the Generating Facility proposed will address a resource adequacy deficiency as determined by the RERRA.[32] MISO changed the language to better tailor the RERRA notification requirement to a new resource adequacy and/or reliability need. The verification may only come from the RERRA where the load to be served is located and the Generating Facility must be in the same LRZ as the load needed as described above.

Q. WHY IS IT REASONABLE TO REQUIRE A RERRA TO VERIFY TO MISO THAT A PROJECT SHOULD BE CONSIDERED FOR THE ERAS PROCESS?

A. First and foremost, MISO is not a resource planner. It is the reliability and market operator for 15 states and one Canadian province. It is the state or RERRA that has jurisdiction over and determines the resource adequacy needs and/or policies that governs the retail electric service to end-customers. Rather, as noted in the Federal Power Act, the states are the ultimate authority for resource adequacy, hence their necessary inclusion in the ERAS process to address the need for these critical projects to maintain resource adequacy. In order to ensure that the proposed ERAS projects will address a resource adequacy and/or reliability need claimed by an Interconnection Customer, MISO needs the RERRA (or its documented representative) where the load is located to provide a written verification as described above for MISO to study the generation expected to serve that need.

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[31] ERAS Order at P 202.

[32] *See* Tab A Redlines, GIP Section 3.3.1.

This requirement will prohibit the submission of projects that have no connection to a verified load need thereby increasing the certainty that the project will reach completion and prevent speculative projects from using the ERAS process.

Q. WHY IS MISO REQUIRING THE ERAS PROJECT AND THE IDENTIFIED RESOURCE ADEQUACY AND/OR RELIABILITY NEED BE LOCATED IN THE SAME LOCAL RESOURCE ZONE?

A. MISO is requiring the load being addressed by the ERAS project be in the same LRZ as the Generating Facility unless the project applicant can demonstrate that the use of the Generating Facility was included in a resource filing made to the relevant RERRA. Requiring the proposed ERAS project to be located in the same LRZ as the RERRA-verified new, incremental load or resource adequacy deficiency ensures that the generation is going to support the load need in that area. This requirement also ensures that the proposed ERAS project is closely tied to a specific spot load or resource adequacy need. This requirement strengthens the nexus between the new load and the ERAS generation project and will serve as MISO's location criterion, which other RTOs have utilized in their similar proposals.[33]

Q. DOES THE RERRA VERIFICATION CONSTITUTE EVIDENCE OF A DESIGNATION OF NEED OR A FINDING OF APPROPRIATENESS BY THE RERRA?

A. No. The following language was included in the proposed tariff redlines as part of the RERRA verification requirement:

> A RERRA's written verification is not intended to constitute or provide evidence of any final determination of need or suitability of the project for

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[33] ERAS Order at P 202.

> any purpose by the issuing entity beyond requesting that the Transmission Provider apply the ERAS process for such project.[34]

The purpose of the verification requirement is to confirm to MISO that the new, incremental load addition is valid and is not currently included in a plan or other procedure under the RERRA's purview or the Generating Facility will address an identified resource adequacy deficiency. After lengthy conversations with the states during the development of MISO's first ERAS filing, MISO understands that each RERRA has its own process and timeline for formally determining needs and approval processes and that part of these processes by necessity occur after the project has been studied by MISO.

It is important that the RERRA verification not prejudice the ability of the RERRA to make later determinations in accordance with applicable laws and regulations. The purpose of ERAS is to enable the states to meet their resource adequacy needs, while not acting as an impediment to their approval processes. For MISO's purposes, what is important is that it knows which projects to study on an expedited basis and to ensure any Network Upgrades identified in the study, and listed in an EGIA are constructed to provide certainty to later planning processes. The Tariff language meets this need while protecting the rights of the RERRA to make determinations in accordance with its own processes. This language was included to ensure that the RERRA's written verification to MISO that the new, incremental load addition is valid and is not currently included in a plan or other procedure under the RERRA's purview or the Generating Facility will address an identified resource adequacy deficiency could not be used by the Interconnection Customer in a subsequent state or RERRA regulatory process as proof or evidence that the project must be approved.

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[34] Section 3.9.1.

The RERRAs reserve the right to make a judgement on the need for a project after MISO has studied the project through ERAS as applicable state regulatory processes and approvals still apply. This ensures that MISO's acceptance of the project into ERAS cannot be interpreted as MISO *directing* the state or RERRA to approve the project through their independent regulatory review process. The intention of the language noted above was also to ensure the notification does not pre-determine the outcome of any applicable state process.

In addition, any Network Upgrades identified in the ERAS process and included in an executed EGIA, or filed unexecuted EGIA, will be constructed regardless of whether that EGIA is later terminated due to the ERAS Interconnection Request not being constructed. This adds an additional layer of responsibility to the ERAS Interconnection Request to ensure its certainty and ensures that MISO can utilize that Network Upgrade(s) in later planning processes. For instance, projects within the DPP process can rely on approved MTEP projects, including Network Upgrades approved through the ERAS process, to mitigate constraints identified with the DPP process.[35]

Q. HOW DOES THE ERAS REVIEW PROCESS ALIGN WITH STATE REGULATORY REVIEW PROCESSES?

A. State processes are expected to commence during the ERAS submission window and then work in parallel to ERAS, as presented in Figure 2. These processes may be completed after MISO has finalized the study and issued the EGIA, or potentially complete before the execution of an EGIA. If the state processes and ERAS are done in parallel it may allow

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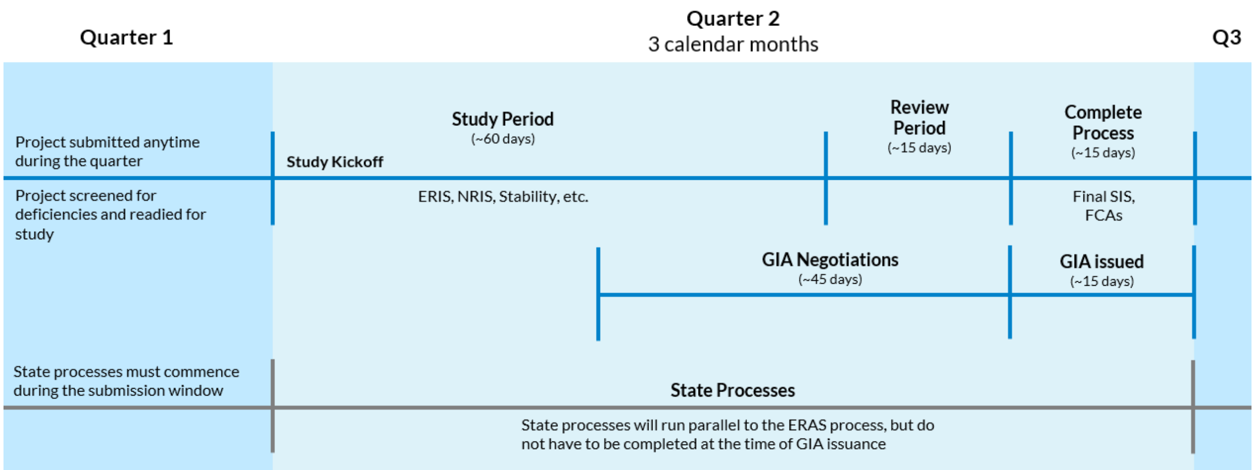
[35] Generator Interconnection Business Practices Manual (BPM-015), Section 6.1.1.1.

for even distribution of work and ensures these critical, time-sensitive projects can proceed efficiently and come online as necessary.



Study will consist of stability, short circuit, voltage analysis, and IC Interconnection Facilities

Figure 2: ERAS Quarterly Study Period Example

Q. WILL MORE THAN ONE RERRA NEED TO PROVIDE A VERIFICATION FOR A SINGLE PROJECT?

A. No. MISO is only requiring verification from one RERRA for ERAS participation. The RERRA providing the written verification for the project must be the RERRA responsible for the load that the project is proposed to serve. Per the resource adequacy definition of a RERRA, an identified load can only be regulated by one RERRA.

C. ERAS for Illinois and Part of Michigan

Q. WILL THE REFINED ERAS PROCESS INCLUDE ILLINOIS AND THE RESTRUCTURED PARTS OF MICHIGAN?

A. Yes. MISO has drafted proposed language to incorporate the restructured states into the ERAS process. If an Interconnection Customer's new Generating Facility will address resource adequacy and will either: "(1) serve retail choice load located in a state that limits the amount of load that can select retail choice to a percentage of the electric utility's average weather-adjusted retail sales; or (2) serve retail choice load and/or be located in a retail choice state other than one that limits the amount of load that can select retail choice to a percentage of the electric utility's average weather adjusted retail sales", the Generating Facility may qualify to participate in ERAS, given it meets all other ERAS requirements.[36] In these instances, the Interconnection Customer will indicate the specific retail choice load on the Interconnection Request and provide evidence of the determination of need, but will not be required to include a verification from a RERRA. MISO is proposing these changes to include Illinois and a small part of Michigan in the ERAS process.

Q. WILL MISO'S PROPOSED LANGUAGE FOR ILLINOIS AND MICHIGAN GIVE PROJECTS AN ADVANTAGE OVER OTHER PROJECTS HOPING TO PARTICIPATE IN ERAS?

A. No. Due to the way that Illinois is structured, it does not have a RERRA that could verify the resource adequacy and/or reliability need like the other states. At first glance, removing the RERRA verification requirement for retail states would seem to give these areas an advantage over other states in the MISO footprint. But MISO has crafted other limitations in the ERAS process that will limit the number of projects that can be proposed from developers in Illinois and Michigan that serve retail choice load. First, only 8 ERAS projects will be accepted to serve retail choice load and only 10 ERAS projects will be studied per cycle. Additionally, those studied within the same quarter cannot be geographically located near other projects or impact the same constraint. Second, the

[36] *See* Tab A Redlines, GIP Section 3.9.1.

ERAS projects will be limited to LRZ regions where the need is located, which will further reduce the number of projects that can be proposed from retail choice states. Interconnection Customers will also still have to provide evidence of determination of need as outlined in the Tariff. MISO is working to level the playing field between the states in its footprint and also wants to ensure that the projects are spread out among the states to better address the resource adequacy and/or reliability needs that they may have.

Q. DO ERAS PROJECTS IN RETAIL CHOICE STATES HAVE A DIFFERENT CAP?

A. Yes. ERAS projects submitted in accordance with Section 3.9.1(1) will be separately limited to a maximum of 8 projects for resource adequacy deficiencies until the sunset of the ERAS process. Retail choice states are a small subset of the MISO footprint and require an ERAS process that is not bound by a RERRA verification due to the need to host an open auction process within those states. Since a RERRA will not be involved in providing a verification for projects proposed in restructured states, MISO needed to ensure that this restructured ERAS process was limited in scope. After an internal analysis and discussion with retail choice states, MISO determined that a cap of eight projects strikes the proper balance between the portion of MISO that the retail choice states represent and the number of projects that will be accepted into the ERAS process. These eight projects will be studied in addition to the 10 accepted by IPPs to serve non-LSE load and the 50 projects allocated for the remaining needs in the MISO footprint, but they will still be limited by the 10 project per quarterly study cycle cap. A member of the IPP sector proposed that MISO set aside a specific number of projects for IPPs to submit with agreements with non-

LSE load and MISO believes that 10 projects is an appropriate balance similar to the retail choice cap above.

D. <u>Changes to the Interconnection Application</u>

Q. HOW HAS THE INTERCONNECTION REQUEST APPLICATION CHANGED FOR ERAS?

A. MISO is requiring additional information from ERAS applicants as compared to other generation Interconnection Requests in order to better tie the ERAS project to the load need and the associated RERRA in the relevant LRZ. As part of the ERAS application process, project applicants will be required to supply a non-confidential summary of the following information: the developer of the ERAS project, the MW range of need the ERAS project is addressing, what LRZ region the project is located in, and a general description of what the load is serving (i.e., a data center, manufacturing plant, a reliability need, etc.). This information will provide MISO will the full picture of the proposed project including fuel source and MW size, details about the load it is serving, and what RERRA is involved in the project's proposal to ERAS. MISO is also planning to publish what cycles the ERAS projects will be studied in and which carve out they are requesting, if applicable. This information will be published on MISO's ERAS webpage as well.

Q. WHY IS MISO IMPLEMENTING THESE CHANGES TO THE APPLICATION FOR ERAS?

A. To further create a tight nexus between the load need and the Generating Facility addressing the need, MISO is requiring additional information be submitted with the ERAS application. MISO is aiming to closely tailor the proposed ERAS project to the verified resource adequacy and/or reliability need and in a more transparent manner. These changes aim to better connect the ERAS project with the need and the generator addressing that need. With the Interconnection Request application, along with the RERRA verification and the executed agreement, MISO will have a full picture of the ERAS project, the resource adequacy or reliability need it is proposing to address, and all the relevant parties involved with the project. MISO is making the ERAS process more transparent and believes that the additional information required on the Interconnection Request application will serve this purpose.

Q. WHAT DOCUMENTS ARE REQUIRED WITH THE ERAS APPLICATION?

A. Each ERAS applicant will need to submit the following: (1) the Interconnection Request application with detailed information regarding the project, the developer, and the load that will be served; (2) the RERRA verification validating the specific driver (new, incremental load or resource adequacy deficiency) in its footprint; and (3) an executed agreement that the project submitted for ERAS is intended to be used by the entity with an identified resource adequacy or reliability need. As explained above, the ERAS applicants are also required to submit a non-confidential summary of the proposed project that will be published on MISO's webpage.

V. <u>THE ERAS ELIGIBILITY REQUIREMENTS</u>

Q. WHAT ENTITIES CAN SUBMIT PROJECTS TO PARTICIPATE IN ERAS PROCESS?

A. Initially, MISO proposed that only LSEs could apply to participate in ERAS due to their responsibility to serve their load customers. However, based on stakeholder input during the development of the original ERAS proposal, MISO changed course and recognized that the vast majority of the Interconnection Requests, including those that would be submitted through ERAS, may not be initially submitted by the LSE that ultimately used the resource to serve their load, but rather an Independent Power Producer ("IPP") that would eventually transfer the resource over to an LSE via an offtake agreement. Given the importance of maintaining the inclusivity and open-access aspects of ERAS, MISO updated the eligibility requirements accordingly to ensure that any project developer can apply to participate in ERAS as long as the project meets all of the ERAS eligibility requirements. The refined ERAS proposal has not changed this.

Q. PLEASE DESCRIBE THE ELIGIBILITY REQUIREMENTS FOR INTERCONNECTION SERVICE VIA ERAS.

A. In determining what the necessary eligibility requirements were for ERAS, MISO established requirements that would allow a project to efficiently move through a study process while still being considered "shovel ready." Based on multiple rounds of feedback from stakeholders and additional analysis, MISO is proposing the following technical requirements for ERAS that must be met at the time of application submission:

1. The project must be for new capacity.
2. The project must request Network Resource Interconnection Service (NRIS).
3. Evidence of a written verification from the RERRA where the load to be served is located by the Generating Facility that the new, incremental load addition is valid and is not currently included in a plan or other procedure under the RERRA's purview or the Generating Facility will address an identified resource adequacy deficiency.

4. Evidence substantiating an executed agreement that the project submitted for ERAS is intended to be used by the entity with an identified resource adequacy or reliability need.
5. D1 and M2 payments will ensure increased financial commitment when the ERAS Interconnection Request is submitted. The D1 will be a $100,000 non-refundable fee and the M2 will be $24,000 per MW.
6. 100% Site Control for the generator as well as 100% Interconnection Customer's Interconnection Facilities (ICIF) Site Control will be required when the application is submitted.
7. COD requested in the ERAS application that is no more than 3 years from submission.
8. The project's requested Interconnection Service must not exceed 150% of the identified MW need.
9. The project and the identified resource adequacy and/or reliability need must be in the same Local Resource Zone (LRZ), unless as previously noted.

I provide additional details on each requirement below.

Q. WHY IS MISO REQUIRING AN EXECUTED AGREEMENT TO ADDRESS THE RESOURCE ADEQUACY AND/OR RELIABILITY NEED?

A. Requiring executed documentation by an authorized representative of the entity submitting an ERAS Interconnection Request is reasonable because it allows MISO to balance the appropriate level of "shovel ready" certainty for the critical project. The executed agreement with an off-taker requirement also reduces speculative projects and connects a specific project with a claimed resource adequacy and/or reliability need. Additionally, it helps verify the accuracy of the information set forth in the ERAS application, which will ensure that MISO will be able to expeditiously transition to studying the project.

Q. WHAT IS THE PURPOSE OF THE BROAD AGREEMENT DOCUMATENTION LANGUAGE IN PROPOSED TARIFF SECTION 3.9.1.2.d?

A. The following language was added to the executed agreement requirement:

> d. <u>Other agreement between the entity submitting the Interconnection Request, including the RERRA verification letter as appropriate, and the entity with the load to be served (including, but not limited to, an Alternative Retail Electric Supplier, or its Load Serving Entity), stating that the ERAS project will be used to meet an identified resource adequacy and/or reliability need.</u>

MISO recognizes this language is broad, but the intent of this subsection was to establish a minimum requirement that an arrangement exists between the driver of the need and the project to address that need. As MISO developed this language through the stakeholder process, we determined that requiring a "PPA" or other specified form of agreement, or specific terms, may prove too onerous, especially in jurisdictions where need determinations or commercial commitments are contingent on identified project costs or previous MISO study. What is important is a demonstration that an ERAS Interconnection Request is the solution intended by the entity with the need. The language balances two goals: 1) it prevents speculative requests by entities that are merely hoping to be selected to address a need later, and do not have buy in from the need driver, and 2) it avoids requirements for MISO to evaluate the details of commercial arrangements that may still be in development, which would frustrate use of the ERAS process in many cases. The addition of Alternative Retail Electric Supplier specifically allows agreements with such entities operating in retail choice states.

Q. WHY IS MISO LIMITING ERAS PROJECTS TO 150% OF THE IDENTIFIED MW NEED BASED ON NAMEPLATE CAPACITY?

A. In working to refine the ERAS process, MISO looked at how SPP, CAISO, and PJM structured their corresponding processes. The CAISO proposed a cap of 150% of total available transmission capacity for each of its Deliverable Zones arguing that the "percentage-based nature of the cap ensures that the studies are scaled to the resource and transmission planning completed by the State and local regulatory authorities, while still enabling competition."[37] SPP took a different route – it plans to calculate a maximum amount of capacity that each LRE may propose for inclusion in ERAS and will use a "LRE Ceiling Capacity," which is calculated using "the sum of the LRE's projected capacity, and RAR obligations to obtain the Projected LRE Deficiency and then multiplying that number by the Ceiling Multiplier of 1.25 (i.e., 125%)."[38]

MISO is proposing to limit ERAS projects to 150% of the identified need because MISO's goal is to tighten the nexus between the load need and the proposed ERAS project. Understanding that accredited capacity, depending on the fuel type, is generally lower than 100% for many resources, MISO wanted to establish a closer connection between what is needed and what is being proposed by the ERAS project. The limitation of 150% of identified MW need will strike the proper balance between having a sufficient amount of interconnection service advancing through the study process to support the identified spot

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[37] *California Independent System Operator Corporation*, Docket No. ER24-2671-000, CAISO's Transmittal Letter at 6 (filed Aug. 1, 2024).

[38] *Southwest Power Pool*, "Tariff Revisions to Implement the Expedited Resource Adequacy Study" at 29, Docket No. ER25-2296-000 (filed May 22, 2025).

load or resource adequacy deficiency and preventing the overbuilding of resources through ERAS.

Q. HOW IS MISO MEASURING THE 150% OF THE IDENTIFIED MW NEED?

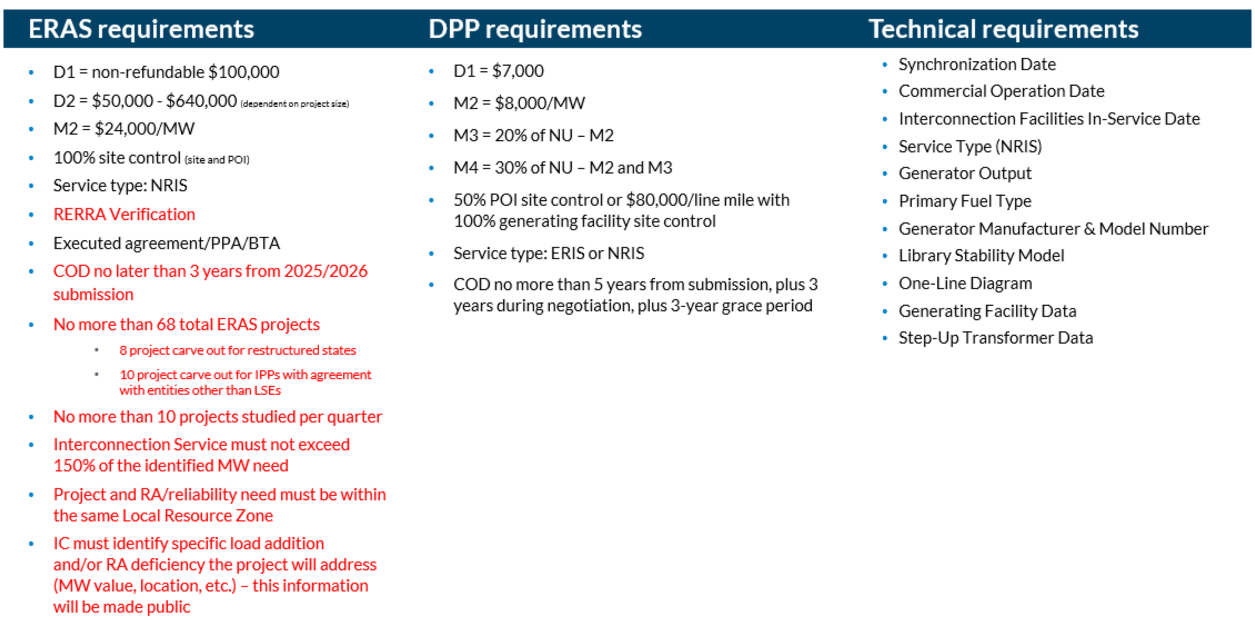
A. MISO is measuring the identified MW need the amount of Interconnection Service requested. Interconnection studies are based on the amount and type of interconnection service requested and they do not assess a generator's potential accreditation. Also, the accreditation of a generator associated with any particular interconnection service may change over time based on the operating characteristics of the generator, the generators attributes, and whether surplus or replacement service is utilized. Additionally, the load an ERAS request will service could have some level of demand response and the ERAS process is fuel agnostic both of which can impact eventual accreditation needs. Based on these different elements, MISO determined that the maximum amount of Interconnection Service that can be associated with an ERAS request would be linked to the amount of load being served rather than on the generator's potential accreditation.

Q. WHY IS MISO STILL REQUIRING HIGHER FINANCIAL COMMITMENTS TO PARTICIPATE IN THE ERAS PROCESS?

A. First, a higher D1 application fee is necessary to implement the temporary ERAS process and cover costs related to processing ERAS Interconnection Requests such as tools improvement, including improvements to MISO's application portal, and/or any additional staffing. This higher and non-refundable application fee will also increase the financial obligations of the applicants, which will ensure that only "shovel ready" projects will be submitted to ERAS.

Second, it is critical that ERAS Interconnection Customers have a greater financial stake upfront for ERAS Interconnection Requests beyond study deposits spent in the study process, as it will encourage a higher level of due diligence and commercial readiness. The increased M2 financial exposure of $24,000 per MW is based on the existing MISO Provisional Interconnection Service's milestones requirements as it represents the same level of upfront commitment for M2, M3, and M4 an Interconnection Customer would make in the DPP three phased process (i.e. $8,000 per MW per phase). Figure 3 presented below demonstrates the differences between the refined ERAS proposal and existing DPP financial requirements. The red font indicates what requirements were added or changed since the original ERAS proposal.

Figure 3: ERAS, DPP, and Common Requirements



Q. WOULD ERIS REQUESTING NRIS QUALIFY UNDER ERAS?

A. No. One of the eligibility requirements for ERAS is that it must represent new incremental capacity. In the instance of an interconnection request with ERIS working to add NRIS to their request, this would not represent new capacity but rather an uprate to existing interconnection service. This type of request does qualify for an exemption to the queue cap though and can proceed through the next DPP cycle automatically.

Q. CAN EXTERNAL GENERATING RESOURCES REQUESTING NEW INCREMENTAL NEW CAPACITY REQUEST ERAS?

A. Yes. An ERAS request associated with an external generating resource, requesting External NRIS, would be studied under the standing NRIS study procedures covered under the proposed section 3.9.3 of Attachment X. This proposed project must still meet all the other ERAS eligibility requirements including providing a RERRA verification.

Q. WHY IS MISO STILL REQUIRING 100% SITE CONTROL FOR ERAS PROJECTS?

A. The increased gating requirements involving Site Control and financial milestones for ERAS Interconnection Requests are reasonable because they reflect the importance of preserving the integrity and certainty of these projects. It also helps to ensure that MISO will not get inundated with projects that are not shovel ready even with the new ERAS cap. Requiring 100% Site Control to the POI with the ERAS application submittal, along with the existing requirement of 100% Site Control for the Generating Facility encourages only shovel ready project applicants apply to ERAS. ERAS Interconnection Requests must address a resource adequacy and/or reliability need in the short-term, which essentially requires the project to be shovel ready in the next few years. The 100% Site Control requirement is also designed to discourage speculative and non-ready projects from entering ERAS. To that end, MISO also determined that there would be no Financial Security option for the POI Site Control like is available within the DPP process.

Q. WHY DOES AN ERAS INTERCONNECTION REQUEST NEED TO HAVE AN ACCELERATED COMMERCIAL OPERATIONS DATE ("COD")?

A. Under the current DPP timeline requirements, to use an example, an Interconnection Request submitted in the 2025 DPP study cycle would not need to come online before 2036. First the applicant into the DPP process can have a COD that is no more than 5 years out. Second, during GIA negotiations the Tariff allows the IC to extend the application COD by an additional 3 years. And finally, the *pro forma* GIA allows for a 3 year grace period beyond the COD documented in the GIA for a total of 11 years after initial submission.

Given the urgent resource adequacy needs identified earlier, another tool or mechanism is needed to ensure that the ERAS Interconnection Requests come online as soon as possible. MISO is requiring that ERAS projects have a COD within 3 years of their ERAS submission date unless the project is deferred to a later quarter at which point the COD can be adjusted during GIA negotiations to be no more than 3 years from the kickoff of that project's ERAS quarterly study cycle. Interconnection Service granted through ERAS would continue to have an additional grace period of 3 years from the COD date in the EGIA to become commercial as noted in MISO Appendix 6 Generator Interconnection Agreement (i.e. the *pro forma* GIA). This COD requirement in addition to other eligibility requirements, including increased financial commitments and obtaining 100% Site Control, will ensure that only projects that can achieve commercial operations quickly participate in ERAS.

Q. HAVE STAKEHOLDERS OR OTHER INTERESTED PARTIES EXPRESSED CONCERNS REGARDING THE COD REQUIREMENT?

A. Yes. ERAS has ultimately been crafted in a transparent and collaborative manner to achieve a near term resource adequacy goal to maintain reliable grid operations. MISO worked to balance the end date to enable projects at differing points in the preparation process to participate in ERAS – some projects will be ready to participate this year, while others are working to have their projects ready to participate in 2026 or later. MISO will allow an extension on an ERAS project's COD deadline if it is deferred to a later study quarter.

Q. HAS MISO CONSIDERED THAT ERAS INTERCONNECTION REQUESTS WILL BE SUBJECT TO THE POTENTIAL DELAYS (SUPPLY CHAIN, REGULATORY, SITE CONTROL, ETC.) THAT DPP PROJECTS ARE SUBJECT TO?

A. Yes. MISO has taken these concerns into consideration. During the original ERAS discussions, we continued to hear from our Interconnection Customers that these issues persist. For this reason, MISO is proposing that Interconnection Service granted through ERAS would utilize the same grace period of 3 years from the COD date in the ERAS application to become commercial that all other Interconnection Customers have as noted in the MISO *pro forma* GIA. MISO recognizes there are numerous industry challenges outside of developers control and wanted to provide a sufficient amount of time for the developers to get their projects ready within this context. The current timeframe proposed for ERAS should be sufficient to provide developers with time to overcome any supply chain or other unknown delays.

It should also be noted that as previously mentioned, given the increased gating requirements (Site Control, increased financial commitment), this ultimately helps to ensure that MISO will not get inundated with projects that are not shovel ready.

Q. HOW WILL MISO CLOSE OUT THE ERAS PROCESS?

A. The ERAS process will sunset at the earlier of the completion of sixty-eight ERAS Interconnection Request studies or by August 31, 2027. This time limitation also applies to the projects proposed by the retail choice states – if the eight projects are not submitted by the sunset date, the ERAS process will still close on August 31, 2027. The same is true for the projects proposed under the carve out for IPPs with agreements with entities other than LSEs – if the ten projects are not submitted by the sunset date, the ERAS process will still close as planned. MISO will only accept applications to be included in the last Quarterly Study Period prior to the sunset date. MISO will post the application deadline for each Quarterly Study Period on the MISO public website.

VI. ERAS PROCESS COORDINATION

A. Coordinated Study Processes

Q. PLEASE DESCRIBE THE EXPEDITED PROCESSING OF THE EGIA.

A. The refined ERAS process will still enable all parties to move expeditiously through EGIA negotiations. Because of the critical reliability need for ERAS Interconnection Requests and to ensure an overall expedited process for commercial operations, the EGIA follows an expedited timeline. The drafting of the EGIA by the MISO team will begin as soon as possible. Additionally, under the EGIA timing requirements for ERAS, MISO will tender a draft EGIA within five (5) Business Days after the Interconnection Customer provides notice to proceed to EGIA negotiations. Following this, an EGIA would be tendered in less than 30 business days.

Q. HOW WILL MISO PROVIDE INTERCONNECTION CUSTOMERS SUFFICIENT TIME TO EXECUTE A GIA?

A. In crafting the ERAS process, MISO recognized the need to implement a shorter timeframe for the EGIA negotiation process to ensure that the overall ERAS process could be completed within 90 days. To that end, MISO will begin drafting an EGIA document as soon as possible. This ultimately enables the EGIA negotiation process to work in parallel with the study process and therefore the EGIA draft will be substantially further along at the end of the ERAS study process. As a result, after the Interconnection Customer issues their notice to proceed, an EGIA can be tendered for the execution in less than 30 business days.

Q. CAN INTERCONNECTION CUSTOMERS WITHDRAW FROM ERAS?

A. While there is a critical need for these ERAS Interconnection Requests, the proposed requirements still allow the Interconnection Customers an opportunity to withdraw once they are aware of the Network Upgrade costs. Moreover, it is possible that an Interconnection Customer may discover various issues with the proposed site in the ERAS process that would influence their desire to withdraw, or the RERRA could ultimately deny the project through their own processes. If the Interconnection Customer withdraws and terminates its EGIA after execution by all parties or after the EGIA is filed unexecuted, the Interconnection Customer will remain liable for the Network Upgrades documented in the EGIA and corresponding Facilities Construction Agreements ("FCAs") or Multi-Party

Facilities Construction Agreements ("MPFCAs"), including those Network Upgrades arising from the Affected System Study process. If the ERAS Interconnection Request is withdrawn prior to EGIA execution, then there is no agreement to fund Network Upgrades and no impact on downstream planning processes. In these cases, the Interconnection Customer would be refunded their M2 payment and any remaining D2 payments not utilized to perform the study.

The increased penalties for Interconnection Customer withdrawals after the execution of the EGIA, along with the other requirements like the off-taker agreement and the RERRA notification, will help ensure that only critical projects needed for maintaining reliability and/or resource adequacy will apply to ERAS. Under the current effective GIP and DPP process, when an Interconnection Request is potentially withdrawn from the queue, there would be minimal financial exposure to the Network Upgrades. Given the urgent need for ERAS projects, MISO is requiring increased penalties to discourage Interconnection Customers from withdrawing from the ERAS process. More stringent requirements have the added benefit of reducing the potential speculation of the ERAS Interconnection Requests. Fewer speculative projects entering the ERAS process will result in shorter timelines for completing the ERAS Interconnection Studies. This requirement will also motivate developers to run their own studies beforehand.

Q. PLEASE DESCRIBE HOW INTERCONNECTION SERVICE GRANTED THROUGH ERAS WILL BE STUDIED AND HOW IT WILL COORDINATE WITH THE CURRENT DPP PROCESS.

A. The ERAS process will kick off starting September 2, 2025, and will integrate with existing processes without disrupting the ongoing DPP process. As explained previously in my testimony, Interconnection Requests submitted through ERAS will be studied in a regional serial "first-come, first served" fashion based on the order the projects were submitted. It will follow a quarterly cadence established by proposed MISO timelines, ultimately culminating in the project receiving an EGIA in approximately 90 days. MISO proposes to utilize the existing engineering study process utilized in the DPP for ensuring full generator deliverability to the load. During the ERAS model build, all Existing Generating Facilities, included those from completed DPP cycles, the ERAS Interconnection Request, and the latest MTEP base case with all approved MTEP projects, including any recently approved Expedited Project Request ("EPR") projects. This is the same process utilized for the DPP process except the DPP models include all higher queued Interconnection Requests from early cycle and all Interconnection Requests within that DPP cycle. ERAS studies will not include Interconnection Requests currently in the generator interconnection queue that do not have a GIA. This is important as many of the projects within the queue are speculative in nature given that more than 70% of the Interconnection Requests submitted into the DPP withdrawal or never get built.

Before every ERAS cycle, all Interconnection Requests with a GIA approved since the last base case was created will be added to the base case for the following ERAS cycle but are not included in any ongoing DPP studies. The base case for each DPP cycle is never updated once the study process is kicked off except for generation changes due to Interconnection Request withdraws or generator retirements. This ensures that the transmission capacity made available for DPP projects is not being taken away by ERAS Interconnection Requests approved outside of the DPP cycle.

Once the DPP cycle has concluded, the output from that process, and any completed ERAS and EPR projects will be used to populate a new MTEP base case. Any transmission issues identified by reconciling the cases will thus be addressed through the existing MTEP process. The next DPP cycle will then use the latest approved MTEP base case that has reconciled the models. This insulates existing DPP projects from negatives impacts or cost shifts due to the existence of the ERAS process. The contingent facilities listed in the EGIA would only be those facilities in the model used for the ERAS study and those Network Upgrades that come up as part of the ERAS study.

Q. WILL ERAS PROJECTS NEGATIVELY IMPACT EXISTING PROJECTS IN THE GENERATOR INTERCONNECTION QUEUE?

A. No. Under this model framework, the standing MISO DPP three phase process will not be impacted by ERAS as ERAS Interconnection Requests will not be included in ongoing DPP studies thereby not utilizing any available transmission capacity in those studies. The normal DPP process uses the most up to date MTEP base case when the study is kicked off and is not modified to include later approved MTEP projects or ERAS Interconnection Requests. Although these projects approved after the kickoff the DPP process are not included in the study, there is an existing process that allows these projects to mitigate constraints within the DPP process with MTEP projects. Network Upgrades approved through the ERAS process will also be used to mitigate constraints in the DPP process. ERAS will only positively impact the Network Upgrade identification process of these other processes.[39] This coordinated process is demonstrated in Figure 4 below.

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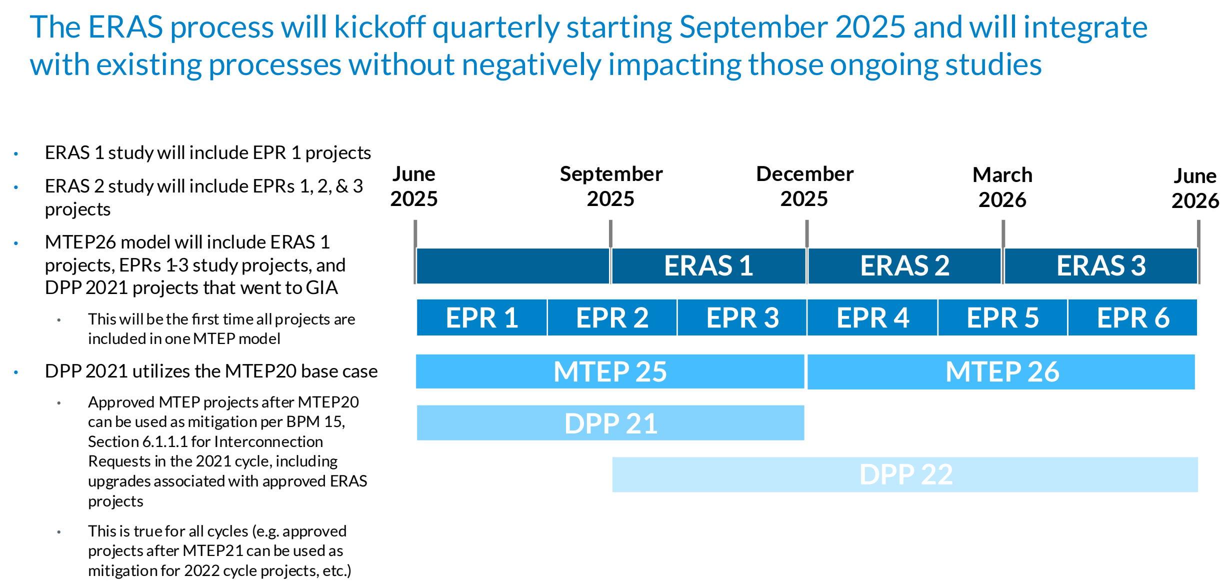
[39] This is further addressed in section 6.1.1.1 of the BPM-015 Generator Interconnection Business Practice Manual.

Figure 4: MISO Coordinated Study Processes



Q. WHAT WILL HAPPEN IF TRANSMISSION CAPACITY IS OVERALLOCATED DUE TO AN APPROVED INTERCONNECTION REQUEST IN ERAS AND THE DPP?

A. On the rare occasion that overallocation may occur, it would be discovered as part of the standing MTEP Deliverability Analysis. The process has been structured so that there cannot be any negative impact to the projects currently in the DPP process, but this can lead to a potential occasion of overallocation. There will be no negative implications for either the DPP Interconnection Request or the ERAS Interconnection Request due to this rare occurrence. Both will be allowed to proceed, and neither will be required to pay additional costs due to the overallocation. MISO performs generator deliverability analysis as a part of the current MTEP process to ensure continued deliverability of generating units with Network Resource Interconnection Service. Results of the assessment are based on an analysis of near-term (5-year) and long-term (10-year) summer peak scenarios. Any constraints that are identified as needing mitigation would be formalized in a future MTEP project.

Q. WHO IS ASSIGNED THE COST OF THE MTEP PROJECT APPROVED TO MITIGATE ANY OVERALLOCATION SCENARIO?

A. The cost of the MTEP project will be allocated based on the existing Tariff rules, which is likely to be the load within the transmission pricing zone where the transmission upgrade is located. However, it is also expected that this load will include the load that is benefiting from the ERAS and DPP Interconnection Requests and benefits from the Network Upgrades that were funded by the generators that went through those processes. In addition, the cost shift is consistent with existing processes. In particular, MTEP projects that are approved after the start of a DPP cycle or even MTEP projects that are approved after the execution of a GIA, can be utilized to mitigate constraints identified in the DPP process. Therefore, an Interconnection Request can be contingent on that MTEP project instead of relying on the original Network Upgrade identified through the DPP process to mitigate that DPP constraint. As a result, the elimination of that Network Upgrade, the Interconnection Customer will not have to pay those costs. This is a cost shift where the load will pay for the MTEP project instead of the Interconnection Request paying for the Network Upgrade.

Q. ARE THERE OTHER INSTANCES WHERE PREVIOUS PARALLEL STUDIES CAN RESULT IN NEW CONSTRAINTS THAT ARE IDENTIFIED LATER IN A FUTURE MTEP PROCESS?

A. Yes. MISO has multiple planning processes, many performed in parallel. These processes have their own unique modeling assumptions that are vetted through the stakeholder process. These processes also have different cost allocation methodologies based on “but for” and “beneficiary pay” principles that are vetted through the stakeholder process. Some examples are Baseline Reliability Projects, identified to meet standards for both NERC and regional reliability; Market Efficiency Projects, which address economic driven congestion; Multi-Value Projects, identified through the Long Range Transmission Planning process; Transmission Deliverability Service Projects, identified to support transmission service; Interregional Transmission Projects, identified to improve reliability and/or economic driven congestion within MISO and a neighboring RTO; Other Projects, identified to support local reliability issues like those identified to add load in the EPR process; Generator Interconnection Projects, which are Network Upgrades identified to reliably connect new Interconnection Requests; and new Generating Facilities that are approved through the DPP, surplus or replacement processes.

After all these projects are approved through their relevant processes, they are then included in the base cases of subsequent studies based on the modeling assumptions for those studies. It is not uncommon for new constraints to arise in subsequent studies driven by all of the approved transmission and generation projects, as well as due to new load growth, and the retirement of generation. Constraints could also be negatively impacted by similar processes in neighboring Transmission Providers. As these new constraints are identified new mitigation is identified, which could include another new transmission project necessary to ensure reliability.

B. ERAS and the EPR Process

Q. WHY IS THERE AN EPR GENERATION SHORTAGE?

A. Expedited Project Reviews ("EPRs") are requests by a Transmission Owner for MISO to quickly review the impacts of a proposed transmission project on the MISO Transmission System. A Transmission Owner requests these reviews when it determines that system conditions warrant the urgent development of system enhancements that would be jeopardized unless MISO performs an expedited review of the impacts of the project.[40] By default, MISO reviews such projects for inclusion in MTEP within a thirty-day timeframe. EPR requests generally reflect an emergent need on the Transmission System that must be evaluated more quickly than the normal MTEP planning process and timeline allow. The announcement of a large and concentrated load addition at a given point on the Transmission System, such as a data center, is a common driver for EPRs. The EPR process reflects the fact that this load must be served and that doing so may require rapid enhancements to the transmission system. Recently, MISO has had to rely on increased transfers to serve these large loads due to the lack of local generation to serve the load, thereby increasing the amount of transmission upgrades necessary to support the load additions. Additionally, Transmission Owners have been unable to support the full amount

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[40] EPRs are governed by Appendix B, Section VII of the Transmission Owners' Agreement, Section I.D.1.c of Attachment FF to the Tariff and Section 4.1.4 of Business Planning Manual 20 (Transmission Planning).

of load a customer would want to connect at a particular location due to the inability to quickly add local generation to support the load.

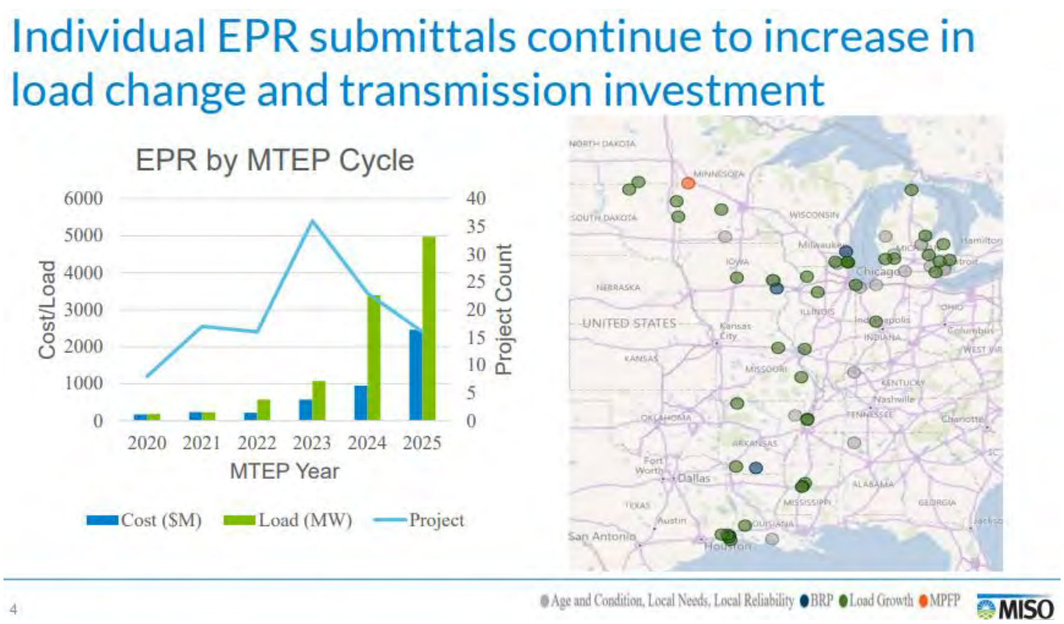
Q. HOW ARE EPRs CONNECTED TO ERAS?

A. While EPRs address the transmission development demands associated with large load additions, these additions may also require a corresponding need to evaluate generation on an expedited basis to serve this load. The EPR process models generation that has a signed GIA, but there is no guarantee that new generation will be interconnected to the Transmission System at a point that can reliably and cost effectively serve the emergent load need. In fact, given the length of MISO's DPP queue delays and the typical generation development timeframe, it is unlikely such load demand was known at the time that any generation projects with a GIA were originally submitted into the queue. Thus, it is unlikely that a generating unit with a high degree of certainty of being online by the needed date of that load driver also happened to be situated in a place where it could reliability serve the emergent load need without significantly extending the length (and cost) of the EPR in order to connect at a point on the Transmission System where excess generation is available. This is especially true given the fact that the EPR can be the first and only connection from that load source to the Transmission System. The EPR process is about approving the transmission necessary to support new load growth, but not the load itself. The EPR process allows for a faster study method to allow these loads to connect sooner than going through the traditional MTEP process. A similar expedited process is needed to study new generation that is necessary to serve spot loads added through EPR. ERAS supplies this previously missing and much needed connection that complements the EPR process.

Q. HOW OFTEN DOES MISO RECEIVE EPRs?

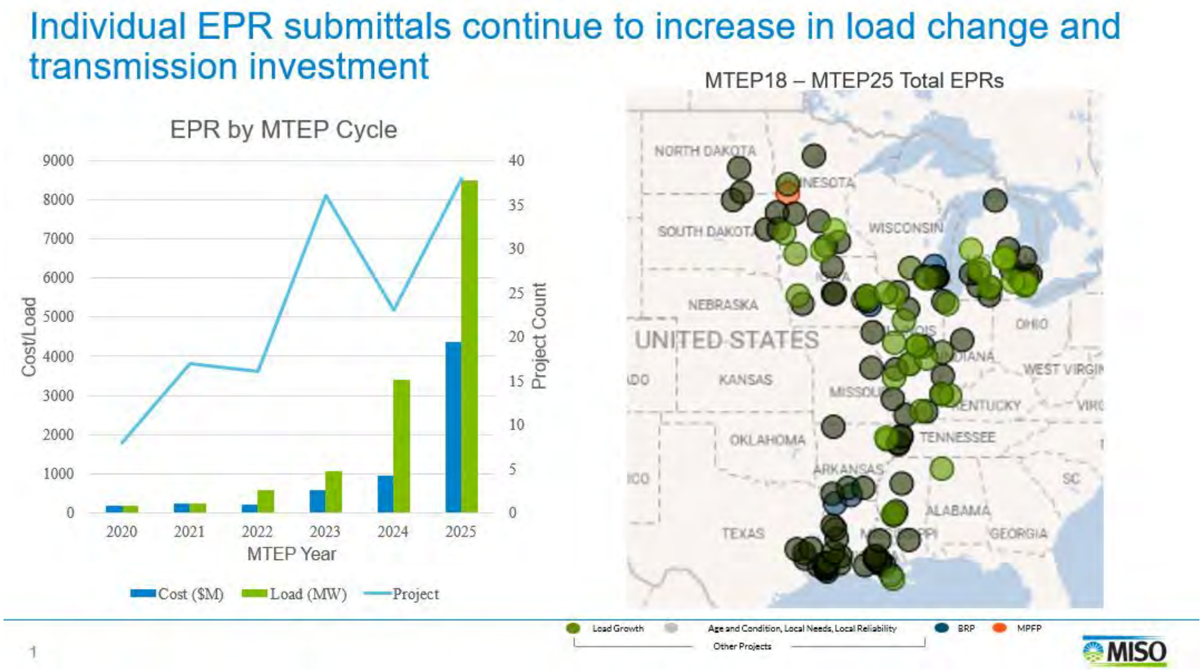
A. In the past, EPRs were comparatively uncommon. However, MISO's most recent data shows a sharp increase in the number of EPRs being submitted in the last few years. As an example, simply comparing the difference from the January PAC Meeting EPR presentation to the current version as of April PAC Meeting EPR presentation, which takes into account the new EPR projects that have recently been submitted, the following figures demonstrate the huge increase and the need for generation to cover this immediate spot load growth.

Figure 5: January 2025 PAC EPR Presentation[41]



[41] MISO EPR Process Improvement Update, PAC-2024-1, Planning Subcommittee, Jan. 29, 2025, available at: https://cdn.misoenergy.org/20250129%20PSC%20Item%2004%20EPR%20Process%20Improvement%20(PAC-2024-1)674593.pdf.

Figure 6: April 2025 PAC EPR Presentation[42]



The data in these figures demonstrates two important trends. First, there has been a substantial increase in the number of EPRs being submitted to MISO. In MTEP 20 and MTEP 21, MISO received only 8 and 17 EPRs respectively. However, MISO has already received more than 38 such requests for MTEP 25. Second, this increase in EPRs is linked to a significant increase in the associated Network Upgrade costs needed to accommodate the EPRs – jumping from an average of $13.7 million in 2022 to $175 million so far in 2025 as shown in the graphics above. This is in part because there is insufficient local generation to serve this load.[43] Absent an accelerated process like ERAS, it is unlikely that

[42] *MISO Sharing and Coordinating MTEP and DPP to Accommodate Large Loads*, PAC 2024-7, Planning Subcommittee, Apr. 23, 2025, available at: https://cdn.misoenergy.org/20250423%20PSC%20Item%2005%20Sharing%20and%20Coordinating%20MTEP%20and%20DPP%20to%20Accommodate%20Large%20Loads%20(PAC-2024-7)692381.pdf.

[43] A further compilation of some of these projects was recently presented at the April PAC meeting. *Expedited Project Reviews*, Planning Advisory Committee (PAC), Apr. 16, 2025, available at: https://cdn.misoenergy.org/20250416%20PAC%20Item%2004a%20Expedited%20Projects%20Reviews690477.pdf.

the generation needed to support spot load will be located in close proximity to the load being added, thus increasing the need for and cost of additional transmission to bring in generation from remote areas.

Q. WHY IS LOCAL GENERATION PREFERABLE WHEN ADDING LARGE SPOT LOADS?

A. Local generation is preferable when adding large spot loads for multiple reasons. First, local generation will reduce the need for large transmission upgrades to support the new load and generation. Instead of making transmission investments around the remote generation to support the generation exports or making transmission investments to support importing power to serve the load, the load and generation rely on each other and negate the needed transmission investment. Second, there is a limited amount of import capabilities between Local Resource Zones. Relying on generation within the same zone will remove the need to import power from another zone, which benefits and helps all load within the zone. Third, relying on generation within the same zone removes price divergences between the load and generation. The EPR process uses whatever generation it can to support that load addition. ERAS will help reduce network upgrade costs by providing a process to quickly add local generation that the EPR process can rely on. The new LRZ requirement in the refined ERAS process will also ensure that the new generation is local to the resource adequacy and/or reliability need.

Q. WHY IS ERAS NEEDED TO ADDRESS THE EPR GENERATION SHORTAGE?

A. Some protestors in the original MISO ERAS filing argued that MISO should not attempt to meet the load need by its anticipated need-by date. Instead, they argue that MISO should wait and utilize the existing 53 GWs or more of generation with signed GIAs that are currently delayed in coming online in the time period needed to address the imminent resource adequacy and/or reliability needs.[44] I have evaluated this approach and have concluded it is impractical and unreasonable for several reasons.

First, the EPR process already includes in its models any generation units with signed GIAs that may or may not come online in time. Thus, even with MISO taking into account these GIAs, there is still a local generation deficiency to meet the load need. Second, it is not reasonable to assume in all cases that generation coming online will meet the specific needs of emerging spot load. For example, while a superficial glance at the number of units with signed GIAs may suggest that there is a sufficient number of MW somewhere on the MISO system, these specific units may not always be sufficient to meet the load need. For instance, if a data center with a 2 GW load need plans to run continuously (or mostly at night), the fact that there are 2 GW of uncommitted solar with a near term Commercial Operation Date is likely insufficient to reliably meet this need. Third, these generation units with signed GIAs may not be geographically situated in proximity to the spot load and, due to the nature of their agreements, are precluded from modifying their designated Points of Interconnection. Finally, there is no guarantee that these units with a near-term Commercial Operation Date will actually come online by that necessary start date. I have observed a significant increase in the number of units with GIAs that are not in service by their Commercial Operation Date and are using or expect to use much of the three-year grace period allowed by the *pro forma* GIA.[45] In addition, an increasing number of these

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[44] A dashboard of this 50 GW in generation is available in MISO Generator Interconnection COD Report: Overview, last updated June 5, 2025.

[45] *MISO Generator Interconnection COD Report: Overview*, last updated June 5, 2025, available at: https://app.powerbigov.us/view?r=eyJrIjoiOTU1ODlhNTktMjZjZC00N2I2LWJhYjMtMDEwOGNmZDM5OD

units are requesting extensions of their Commercial Operation Date through waivers. These facts lead me to conclude that there is an urgent need for a specialized interconnection process that can deliver highly certain generation that is tailored towards the specific load need and already has some level of commercial arrangement to serve it, on an accelerated basis. Absent the ERAS tool, I expect to see: (1) a continued escalating number of EPR submissions relying on remote generation; (2) increasing Network Upgrade costs associated with EPRs; (3) and instances where load that cannot be served as of the date it plans to come online.

Q. WHAT CAN BE DONE TO IMPROVE THIS IMPENDING SITUATION?

A. It is necessary for MISO to establish a new process from the existing that can enable Interconnection Customers to work with RERRAs to identify load needs and work with LSEs or other developers to address them. After working together to develop the best project to address a resource adequacy and/or reliability need, the Interconnection Customers can propose highly certain projects to participate in ERAS and ideally be brought online on an expedited basis to meet the load need. A new process is needed that will enable potential Interconnection Customers to confer with RERRAs and load drivers about urgent reliability or resource adequacy needs; scope and present their proposed projects to the RERRA and need/driver or LSE; and then come to MISO with highly certain projects that can be studied and brought online on an expeditated basis to meet the load need. While MISO expects that the vast majority of Interconnection Customers and resource adequacy needs will not require such a process, as they will continue to rely on

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the DPP queue, MISO still requires a temporary and specialized process to rapidly study those few projects that are slated to address those critical and urgent needs. MISO cannot force generation to come online, or cherry pick which generation projects should be expedited over others. But what it can do is create a pathway for generation that is shovel ready, slated to meet specific needs that the applicable RERRA has validated, and for which MISO should study on an accelerated basis. This process should have the guardrails proposed in this refined ERAS filing to ensure that the process is available to those critically needed projects with commercial certainty without otherwise becoming a substitute for the DPP.

C. <u>ERAS and the Affected System Studies Process</u>

Q. WHAT IS THE PROCESS FOR CONDUCTING ERAS AFFECTED SYSTEM STUDIES?

A. The refined ERAS proposal was designed with the expectation that MISO would utilize existing affected system studies processes. MISO is actively working with multiple seams partners to develop additional seams procedures to incorporate the ERAS process. MISO is committed to and planning to be able to deliver those on an expedited basis consistent with ERAS even before specific processes are addressed and would follow the existing tariff language and does not prevent MISO from doing this faster.

Q. IS MISO CONTINUING TO IMPROVE QUEUE COORDINATION WITH INTERCONNECTION CUSTOMERS AND TRANSMISSION OWNERS?

A. Yes. MISO always seeks proactive continuous improvement of its interconnection queue. In addition to these proposed Tariff changes, MISO has multiple efforts underway to enhance the queue experience. Examples of ongoing or completed initiatives include the queue reforms approved in January 2024 to increase readiness, the queue cap approved in January 2025, implementation of SUGAR software to automate and increase the speed of the Phase I study, further improvements to the generator interconnection portal which automates some manual processes in the interconnection application process, and the Commercial Operation Date tracker, which debuted in early 2025 and provides greater transparency into the status of future Generating Facilities in MISO.[46] These initiatives will strengthen Interconnection Customer workflow throughout the Interconnection Request lifecycle. MISO is coordinating the development of these enhancements through the stakeholder process and outside vendors. MISO is also working to identify additional processes and tool improvements to improve the overall DPP process.

Q. WILL ERAS INTERCONNECTION REQUESTS GO THROUGH THE AFFECTED SYSTEM EVALUATION PROCESS?

A. Yes. MISO must coordinate the impact of these projects with its existing Affected Systems partners to ensure they do not cause reliability impacts on non-MISO transmission systems. The Affected System Studies analysis is an important part of the standing interconnection process and must be performed as part of this evaluation. Subsequently, where available, MISO will incorporate the results of the associated Affected System Studies analysis in the EGIA. For those instances where the results from the Affected System Study analysis are not available to incorporate, given the accelerated timeframe for ERAS, the results will be provided at a later date.

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[46] MISO, *SUGAR Implementation* (Mar. 4, 2025), available at: https://cdn.misoenergy.org/20250304%20IPWG%20Item%2005%20SUGAR%20Implementation682016.pdf MISO, *Liaison Report* (Mar. 4, 2025), available at: https://cdn.misoenergy.org/20250304%20IPWG%20Item%2002%20Liaison%20Report681818.pdf.

It should be noted that in the event that the Interconnection Customer withdraws and terminates its EGIA after execution of the EGIA by all parties or after EGIA is filed unexecuted, the Interconnection Customer will be liable for the Network Upgrades documented in the EGIA and corresponding Facilities Construction Agreements or Multi-Party Facilities Construction Agreements, including those Network Upgrades arising from the Affected System Study process. This will ensure that MISO will be able to expeditiously process the shovel ready ERAS Interconnection Requests while providing a protection mechanism to the existing Affected Systems coordination process. Additionally, ERAS Interconnection Requests will be subject to JTIQ requirements if they meet the criteria for inclusion in the JTIQ Screening Group or Participation Group on the same basis as projects in the DPP. Participation in JTIQ will serve as Affected System process with the Southwest Power Pool ("SPP").

Q. WILL THE AFFECTED SYSTEM STUDIES BE CONDUCTED IN A CLUSTER?

A. MISO will request that these studies be completed on a serial basis, but MISO is unable to control how an affected system will perform its own studies or on what timeframe. MISO will explicitly request that these be studied on a serial basis and MISO will transfer ERAS projects to the affected system serially and not as a cluster in order to enable the affected system to study the proposed projects serially. At the end of the day, only the affected system can determine for itself how and when it will carry out these studies. MISO will work with its seams partners to determine if changes to relative queue priority are necessary for ERAS. For those seams partners that utilize a close of study phase or decision point to establish queue priority, MISO will assert a queue priority date of when the ERAS quarterly study cycle is kicked off.

Q. DOES REQUIRING ERAS CUSTOMERS TO SIGN EGIAS WITHOUT POTENTIALLY HAVING THE AFFECTED SYSTEM STUDY RESULTS VIOLATE ORDER NO. 2023?

A. No. This is a separate limited process that was created outside the traditional DPP process and thus is out of scope of Order No. 2023, which is designed for cluster-based studies. ERAS is not a traditional queue process but is still consistent with the goals of Order No. 2023 which included enabling reforms of current generator interconnection procedures. Moreover, ERAS project participants are aware of the EGIA requirements prior to submitting their projects to the ERAS process. As MISO noted in its transmittal letter, because ERAS is a standalone process, it should be viewed as one large independent entity variation with a defined rule set rather than individual independent entity variations for the numerous differences between the cluster-based process outlined in Order 2023-2023-A and ERAS serial-based study approach.

D. <u>A Transparent ERAS Process</u>

Q. WILL MISO PUBLICIZE THE ERAS INTERONNECTION REQUESTS?

A. Yes. MISO commits to transparency in the refined ERAS process due to the critical nature of these projects. Similar to the EPR process, the ERAS information will be posted on the ERAS webpage located on the MISO public website, including the name of the Interconnection Customer that has submitted the ERAS Interconnection Request along with other details of the ERAS projects.

Q. WHAT INFORMATION DOES MISO PLAN TO POST ON ITS ERAS WEBPAGE?

A. On the newly created ERAS webpage, MISO plans to publish an informational guide regarding the requirements and process for participation in ERAS. After the first submission deadline for an ERAS quarterly study cycle, MISO plans to publish all ERAS projects that have been reviewed and accepted into the ERAS process. MISO will provide information similar to that found in its GI Interactive Queue for DPP projects, including items like the project number, request status, application in-service date, and fuel type.[47] And as previously explained in my testimony, MISO will additionally publish the non-confidential summary of the following information supplied by the applicant: the developer of the ERAS project, details of the need the ERAS project is addressing, what cap carve out was requested (if applicable), what LRZ region the project is located in, and a general description of what the load it is serving (i.e., a data center, manufacturing plant, a reliability need, etc.). MISO is also planning to publish what quarters each of the approved ERAS projects will be studied in.

Q. HOW DID YOU ACCOUNT FOR OPEN ACCESS REQUIREMENTS WHEN DEVELOPING THE ERAS PROCESS?

A. The ERAS requirements are facially neutral, fuel agnostic and allow for the potential inclusion of any resource regardless of technology. These are shovel ready projects to meet

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[47] *MISO GI Interactive Queue*, last updated June 5, 2025, available at: https://www.misoenergy.org/planning/resource-utilization/GI_Queue/gi-interactive-queue/.

an urgent resource adequacy and/or reliability need within the MISO footprint. MISO also expanded who could apply to ERAS to include a wide variety of applicants.

ERAS Interconnection Requests will be subject to more stringent criteria than projects entering the generator interconnection queue. MISO's ERAS requirements will inevitably limit entry which strikes a reasonable balance between allowing project developers to help address the urgent reliability needs of the MISO footprint, while avoiding an influx of projects that could overwhelm the normal DPP queue and lead to further delays, exacerbating the current inability of projects to come online.

Q. WHAT ARE THE BENEFITS OF ESTABLISHING AN ERAS PROCESS?

A. If the proposed temporary requirements for the refined ERAS process are adopted, MISO expects to comprehensively address significant near-term resource adequacy and reliability concerns in the MISO footprint. ERAS is a temporary process designed to help speed up the time to obtain an executed EGIA so urgent reliability projects can be built more quickly until the DPP interconnection queue process improved timeliness takes effect. The queue will remain the standard way to add new resources to the system; ERAS is a temporary and targeted process to complement the generator interconnection queue process. With ERAS, MISO will be able to efficiently and effectively address near-term resource adequacy and/or reliability needs with specific projects that are tied to those needs.

IV. <u>CONCLUSION</u>

Q. IN YOUR OPINION, IS MISO'S FILING JUST AND REASONABLE?

A. Yes. This Filing addresses certain specific needs that MISO, the state Commissions, and the stakeholder process identified. To ensure that MISO is on the right track to resolving its resource adequacy shortfall potential, MISO requests that the Commission approve this proposal. The proposed Tariff revisions enable MISO to take the necessary steps to ensure reliability on the Transmission System.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes, it does.

Affidavit of Andrew Witmeier

COUNTY OF HAMILTON)
)
STATE OF INDIANA)

Andrew Witmeier, being duly sworn, deposes and states that he prepared the Prepared Direct Testimony of Andrew Witmeier, and the statements contained therein are true and correct to the best of his knowledge and belief.

Andrew Witmeier

SUBSCRIBED AND SWORN BEFORE ME, this 4th day of June, 2025.

Kandi Hahn

Kandi Hahn

SEAL
NOTARY PUBLIC
INDIANA
KANDI HAHN
Notary Public, State of Indiana
Marion County
Commission Number NP0740038
My Commission Expires
March 23, 2030

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

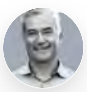
Federal Power Act Section 202(c)	)	
Emergency Order: Midcontinent	)	Order No. 202-25-9
Independent System Operator	)	
(MISO)	)	
	)	

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

Exhibit 122

GridLab Report

GridLab Analysis: Department of Energy Resource Adequacy Report



Ric OConnell

Rethinking Reliability

July 11, 2025

Overview:

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

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

Bottomline of the DOE report:

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

Bottomline of GridLab analysis:

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

DOE Report Analysis – Key Takeaways:

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

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

DOE Report Assumptions vs. U.S.

Energy Information Administration Data:

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

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

Conclusion:

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

GridLAB

hello@gridlab.org

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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 123

Duke University Rethinking Load Growth Study

Duke NICHOLAS INSTITUTE *for* ENERGY, ENVIRONMENT & SUSTAINABILITY

Rethinking Load Growth

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

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

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Acknowledgments

The authors would like to thank Jessalyn Chuang and Wendy Wen for their research assistance.

Citation

Norris, T. H., T. Profeta, D. Patino-Echeverri, and A. Cowie-Haskell. 2025. *Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems*. NI R 25-01. Durham, NC: Nicholas Institute for Energy, Environment & Sustainability, Duke University.
https://nicholasinstitute.duke.edu/publications/rethinking-load-growth

Cover image courtesy Gerville via iStock

Nicholas Institute for Energy, Environment & Sustainability

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

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CONTENTS

INTRODUCTION

A New Era of Electricity Demand

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

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

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

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

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

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

Summary of Analysis and Findings

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

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

Key results include (see Figure 1):

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

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

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

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

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

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

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

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

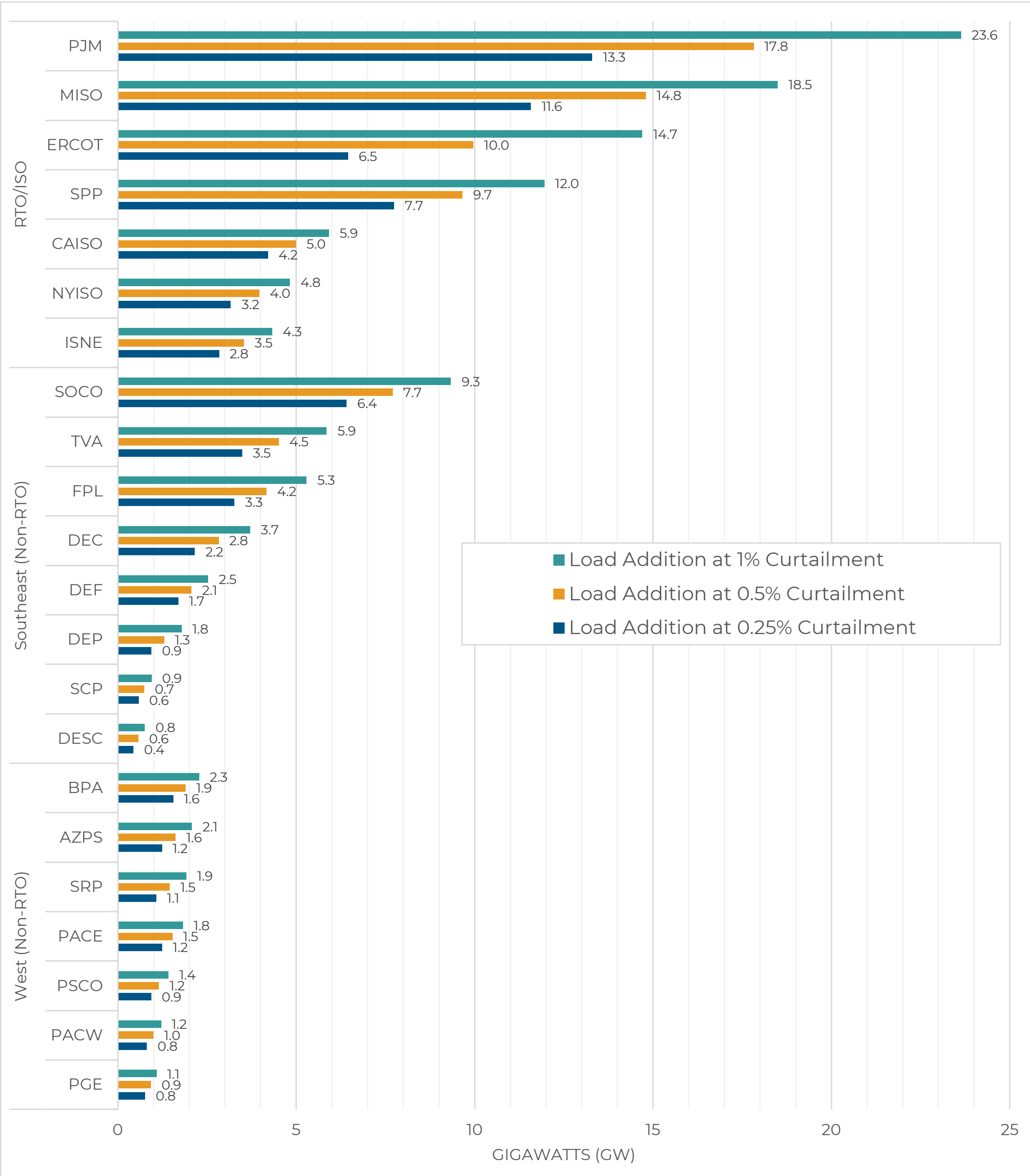
This paper proceeds as follows: the following section provides background on the opportunities and challenges to integrating large new data centers onto the grid. It explores how load flexibility can accelerate interconnection, reduce ratepayer costs through higher system utilization, and expand the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

BACKGROUND

Load Flexibility Can Accelerate Grid Interconnection

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

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



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

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

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

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

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

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

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

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

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

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

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

Ratepayers Benefit from Higher System Utilization

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

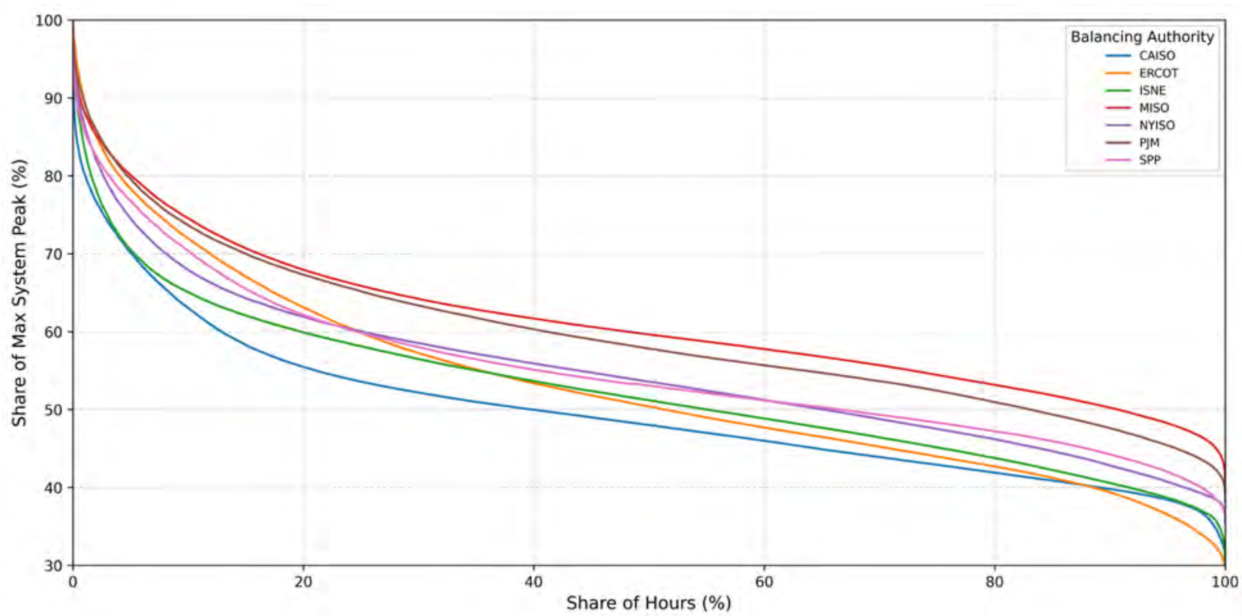
The power system is designed to handle the highest demand peaks, which in some cases may occur less than once per year, on average, due to extreme weather events. As a result, the bulk of the year sees demand levels well below that peak, leaving substantial headroom in installed capacity. Seasonal shifts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

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

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

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

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



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

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

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

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

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

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

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

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

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

Demand Response and Data Centers

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

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

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

9 RTO/ISO and retail data may overlap.

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

The Participation Gap: Data Centers and Demand Response

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

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

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

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

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

Table 1. Key Data Center Terms

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

Rethinking Data Centers with AI-Driven Flexibility

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

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

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

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

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

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

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

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

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

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

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

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

Table 2. Trends Enabling Data Center Load Flexibility

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

Table 3. Implementations of Computational Load Flexibility

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

ANALYSIS OF CURTAILMENT-ENABLED HEADROOM

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

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

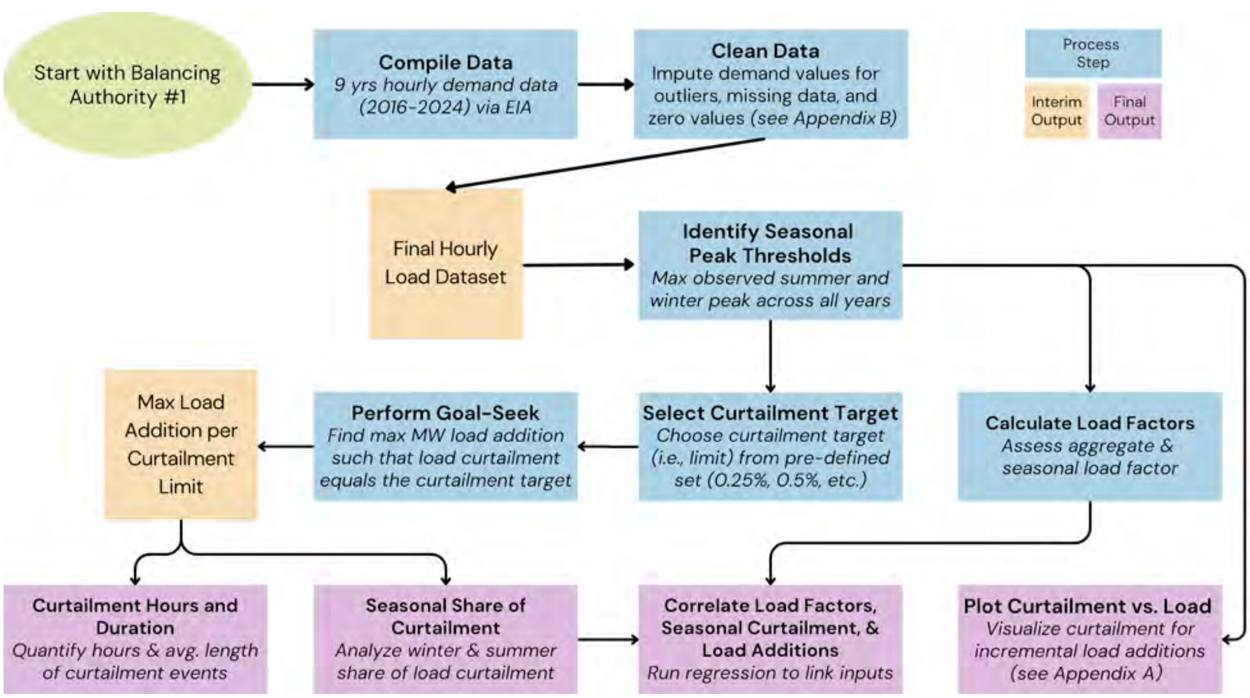
ceptable new load curtailment rates. In this context, *curtailment* refers to instances where the new load temporarily reduces its electricity draw—such as by using on-site generation resources, shifting load temporally or spatially, or otherwise reducing operations—to ensure system demand does not exceed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

Data and Method

Data

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

Figure 3. Steps for Calculating Headroom and Related Metrics



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

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

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

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

Determining Load Additions for Curtailment Limits

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

Load Curtailment Definition and Calculation

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

Peak Thresholds and Seasonal Differentiation

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

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

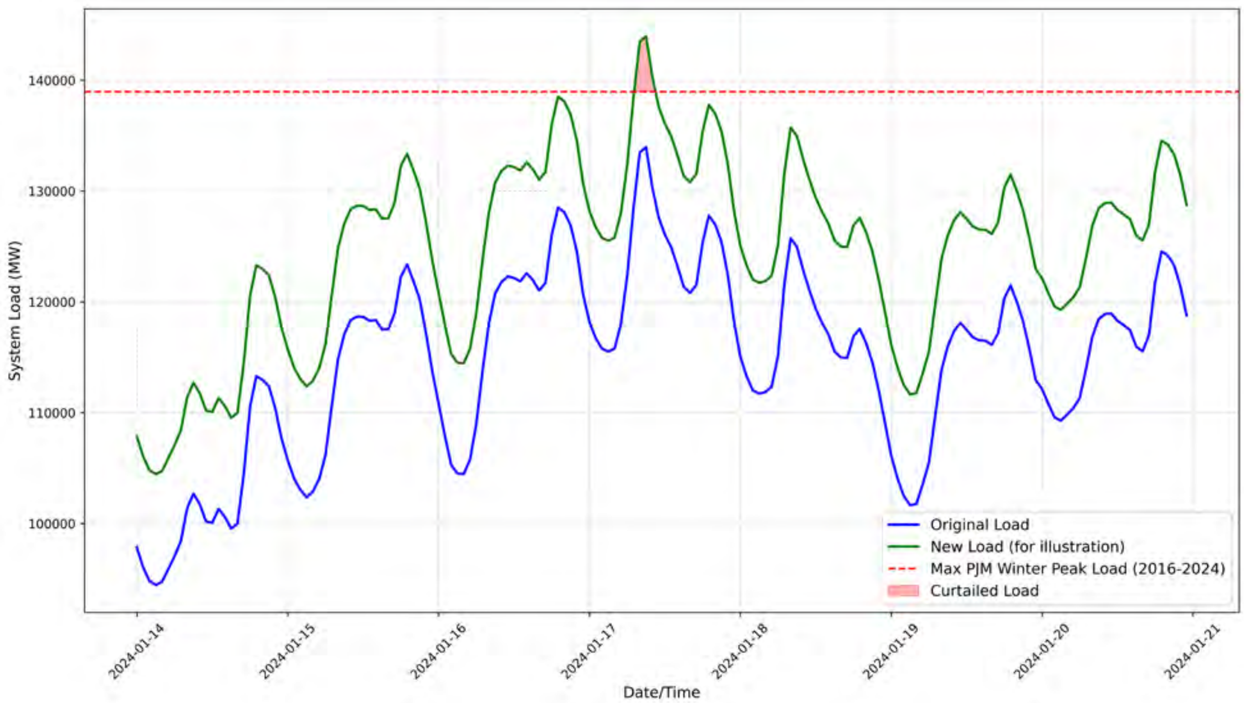
17 Fewer than half of the year's load hours were available, making the data unsuitable for inclusion.

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

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

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

Figure 4. Illustrative Load Flexibility in PJM



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

Year-by-Year Curtailment Analysis

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

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

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

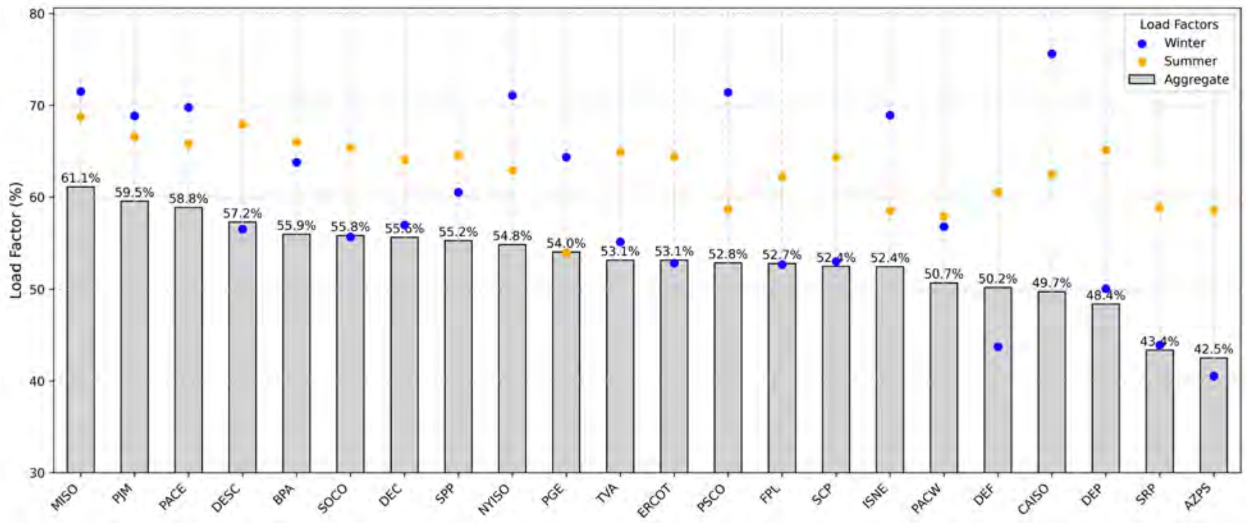
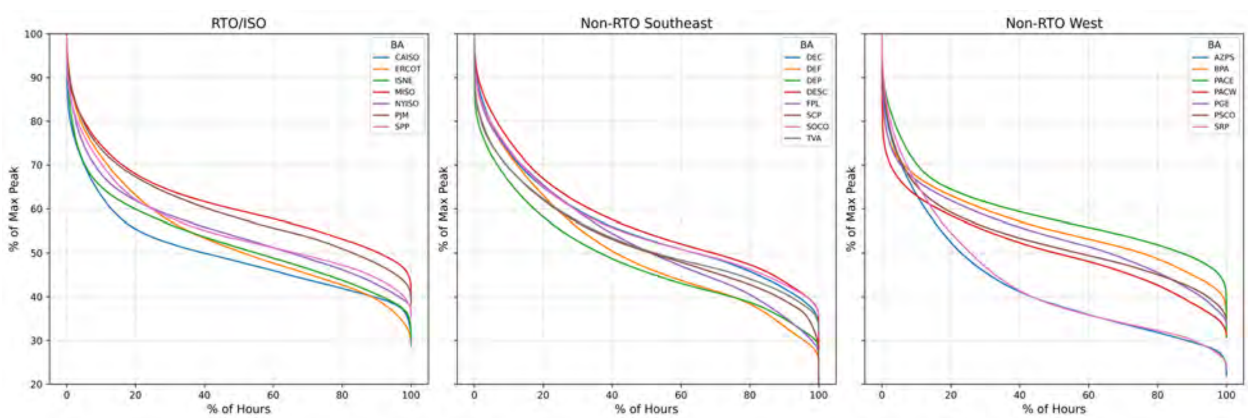


Figure 6. Load Duration Curves by Balancing Authority, 2016–2024



Results

Load Factor

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

Headroom Volume

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

Figure 7. Headroom Enabled by Load Curtailment Thresholds, GW

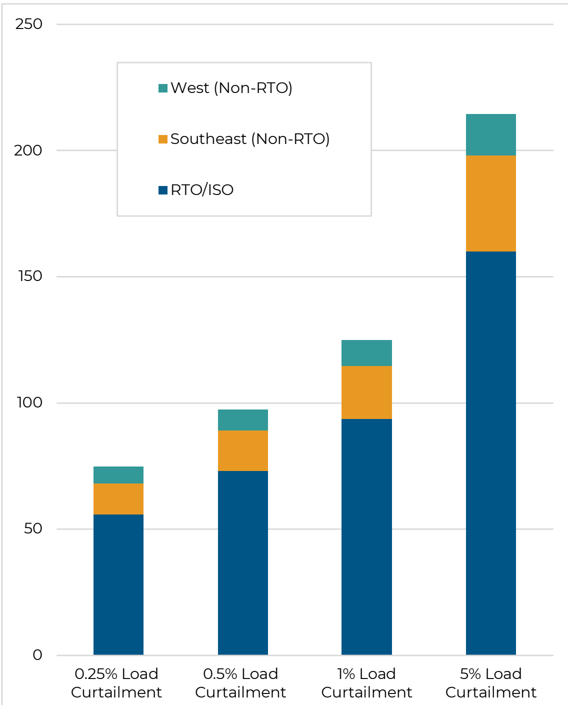


Figure 8. Headroom Enabled by 0.5% Load Curtailment by Balancing Authority, GW

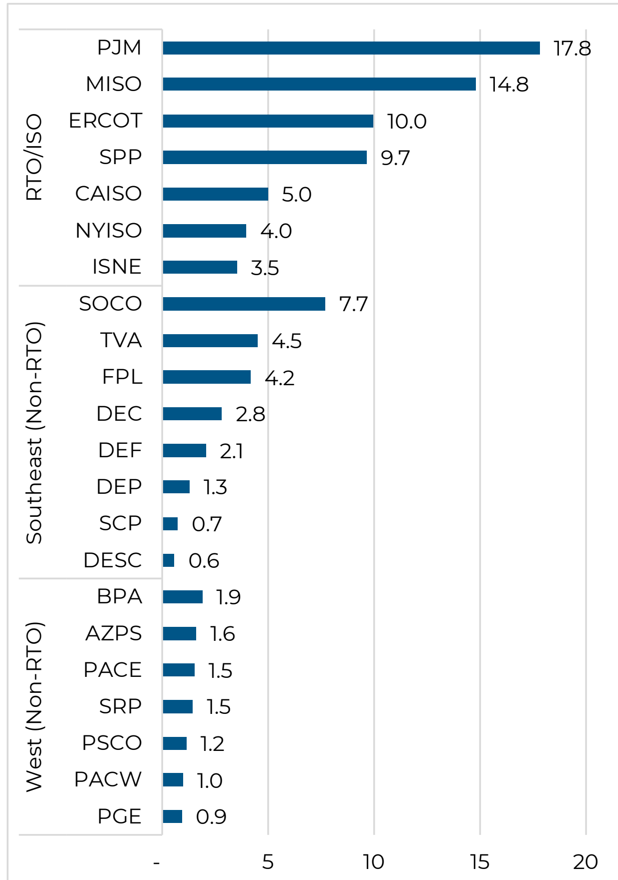
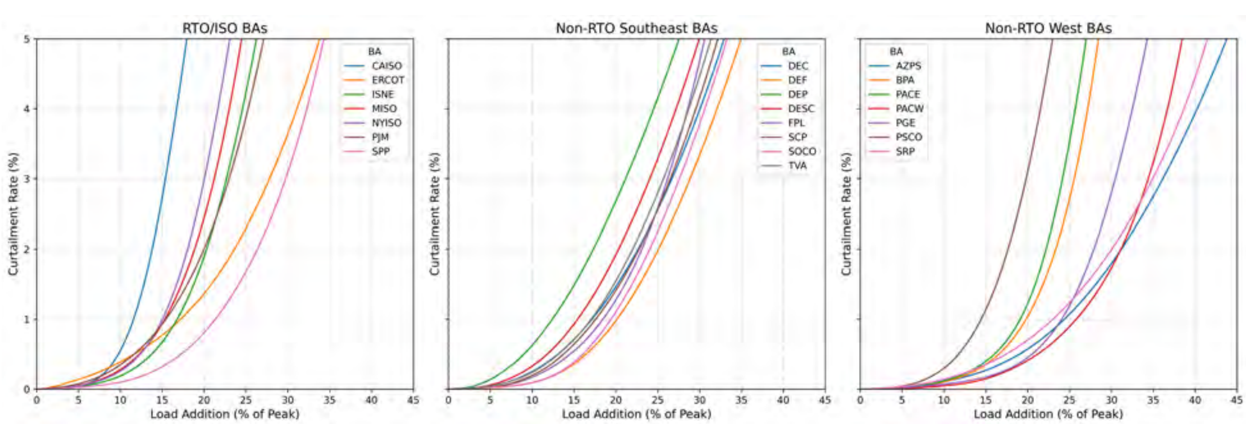


Figure 9. Load Curtailment Rate Due to Load Addition, % of System Peak



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

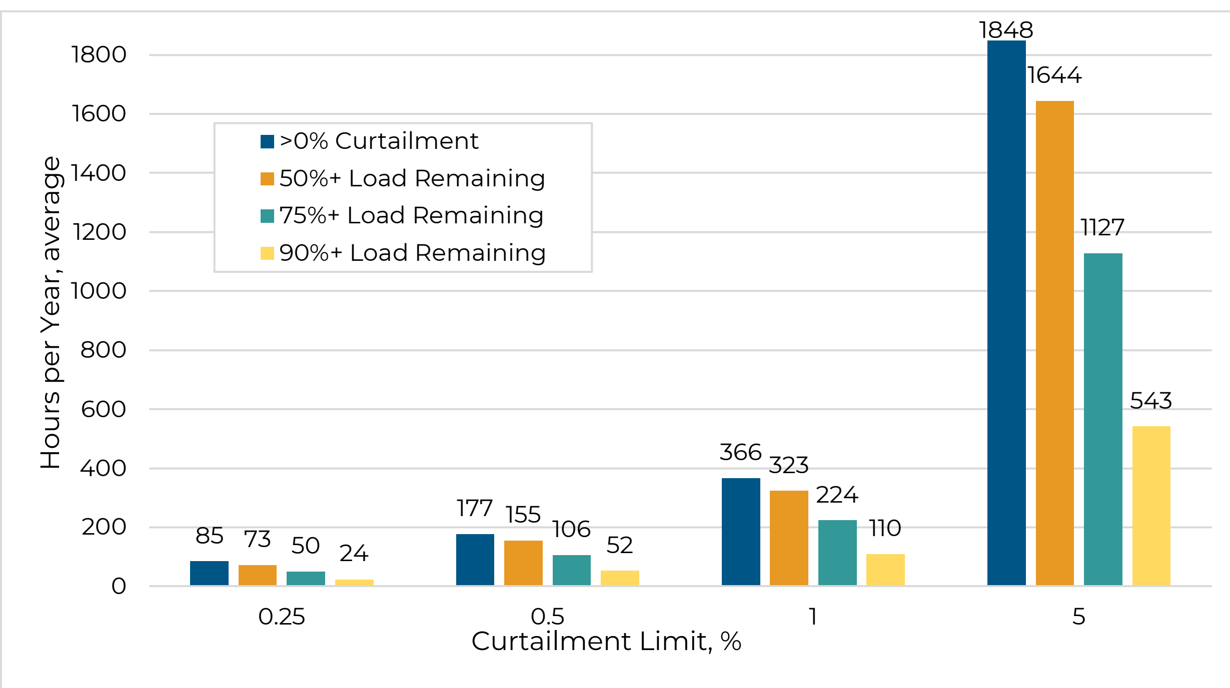
Curtailment Hours

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

Curtailment Duration

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

Figure 10. Hours of Curtailment by Load Curtailment Limit



Seasonal Concentration of Curtailment

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

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

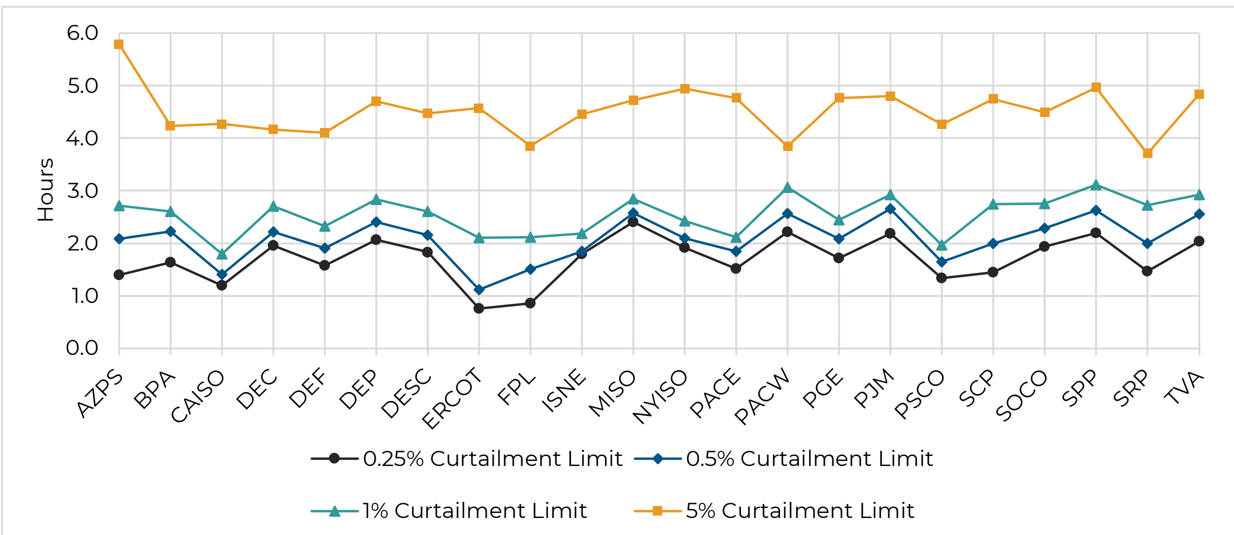
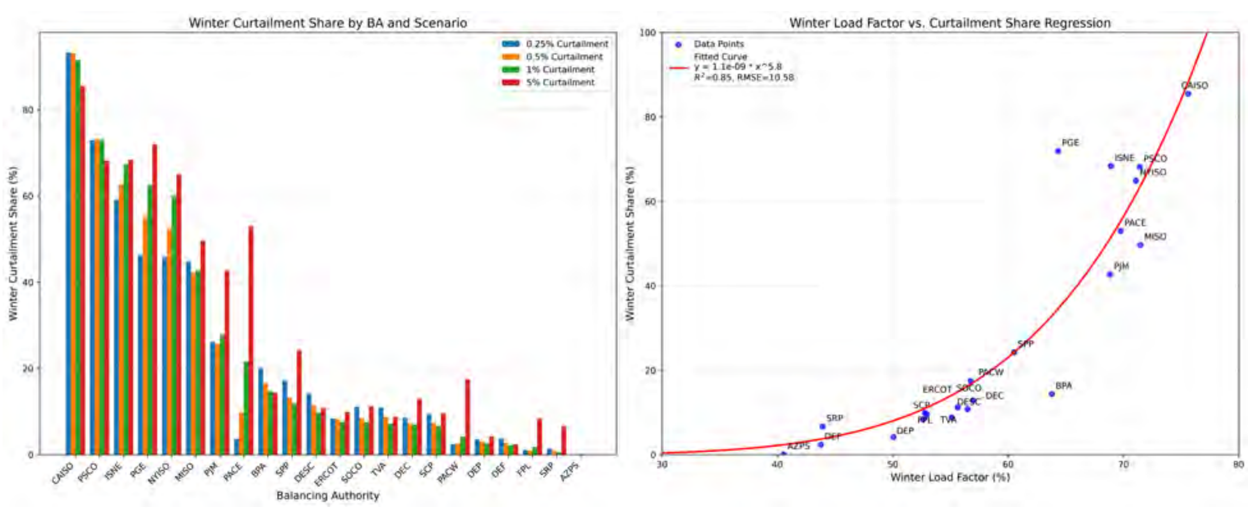


Figure 12. Seasonal Curtailment Analysis



(a) (b)

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

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

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

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

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

Discussion

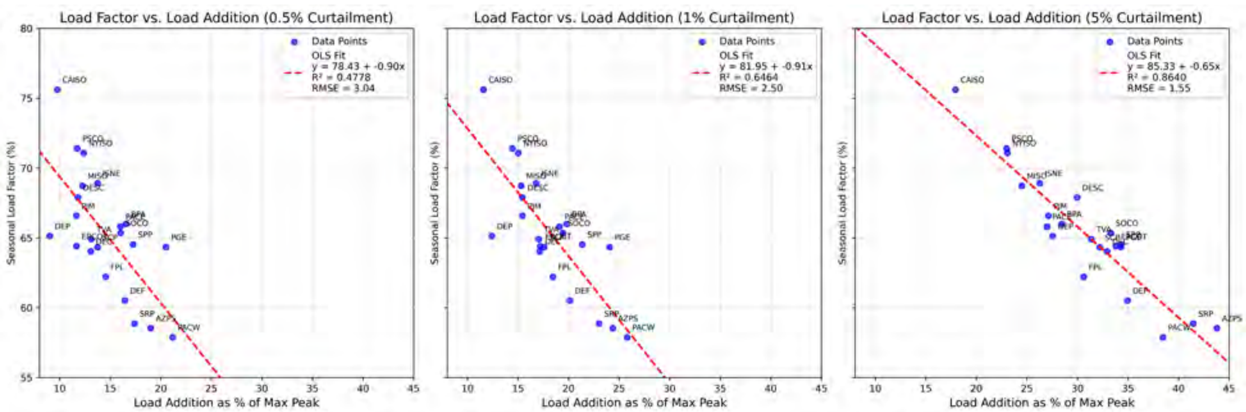
The results highlight that the significant headroom in US power systems—stemming from their by-design low load factors—could be tapped to enable the integration of substantial load additions with relatively low rates of load curtailment. They also underscore substantial variation in flexibility across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

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

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

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

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



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

Limitations

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

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

Future Analysis

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

Network Constraints

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

Intertemporal Constraints

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

Loss of Load Expectation

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

CONCLUSION

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

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

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

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

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ABBREVIATIONS

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

APPENDIX A: CURTAILMENT-ENABLED HEADROOM PER BALANCING AUTHORITY

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

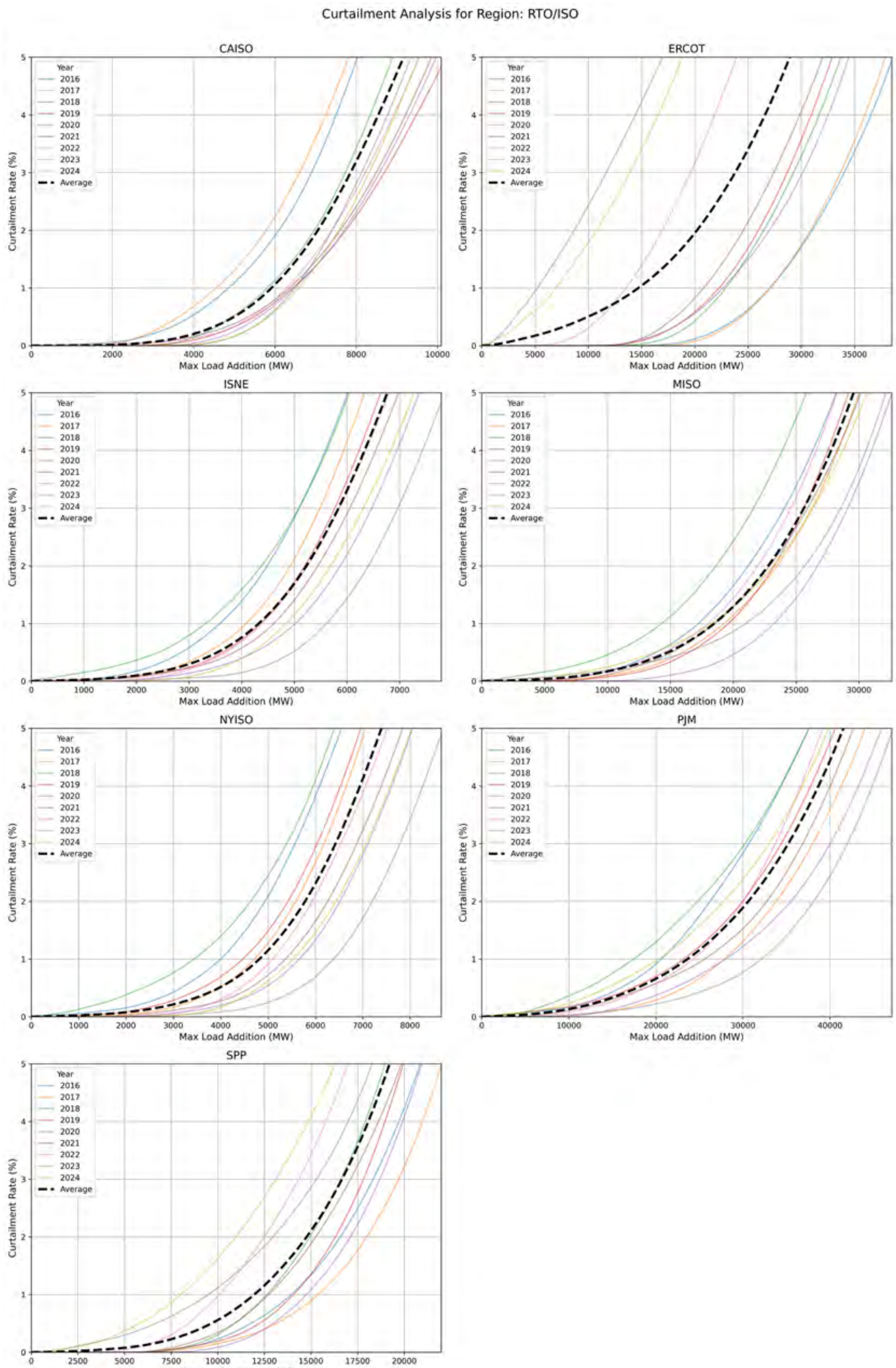


Figure A.2. Curtailment Rate Versus Load Addition by Non-RTO Southeastern Balancing Authority, MW

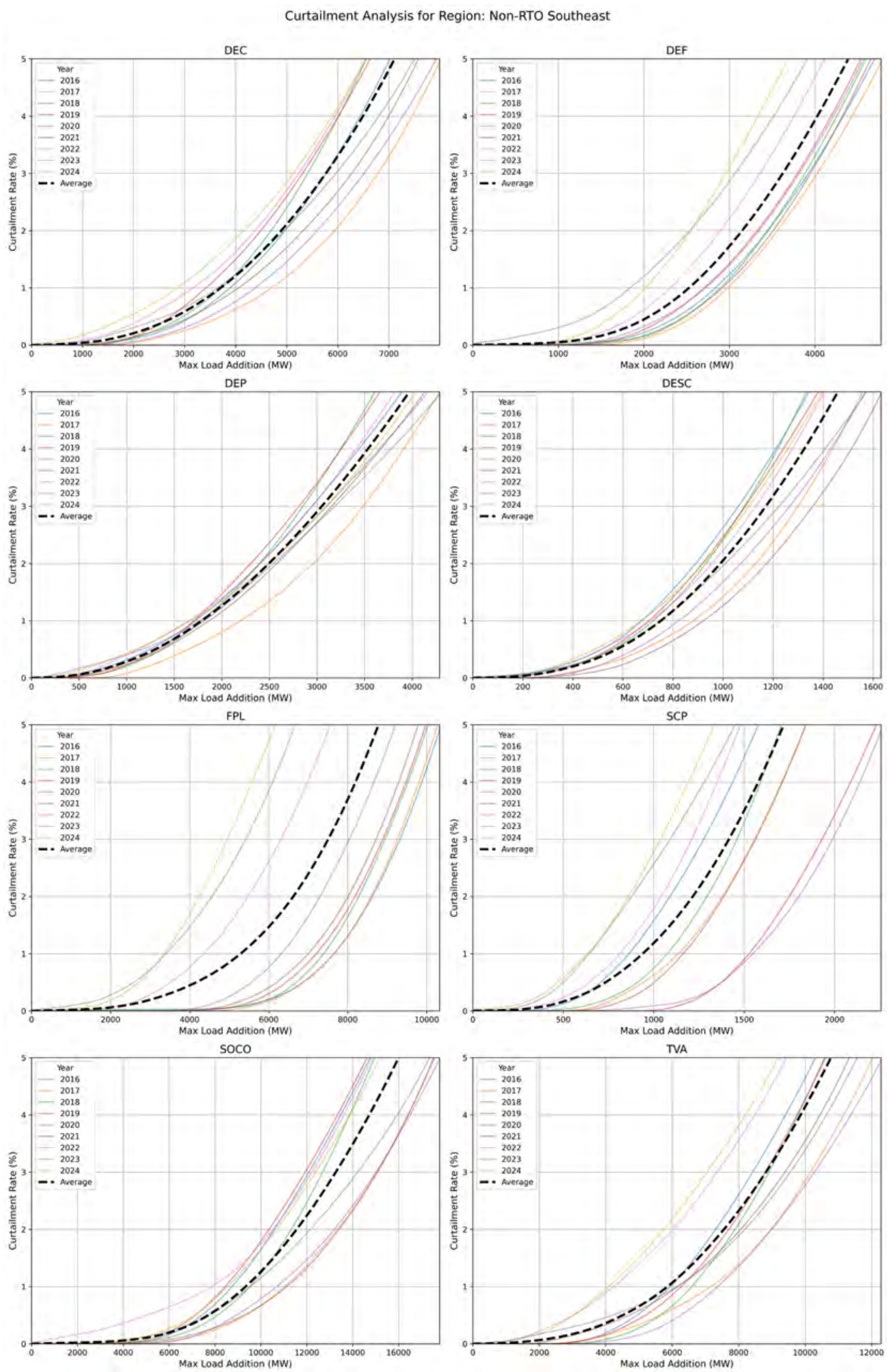
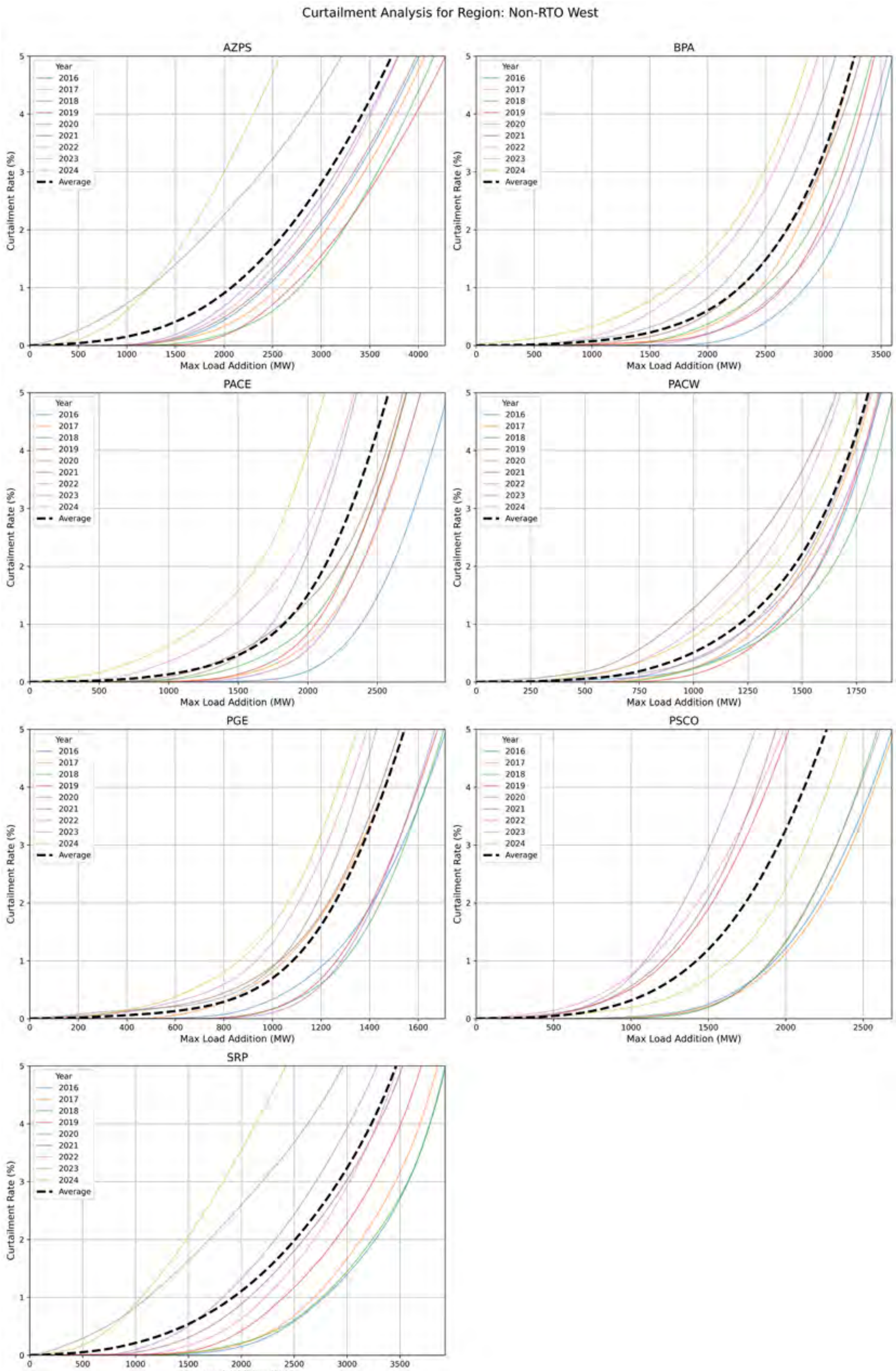


Figure A.3. Curtailment Rate Versus Load Addition by Non-RTO Western Balancing Authority, MW



APPENDIX B: DATA CLEANING SUMMARY

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

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

APPENDIX C: CURTAILMENT GOAL-SEEK FUNCTION

Mathematically, the function can be expressed as

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

where

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

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

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

where

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

These hourly curtailments are aggregated to find the total annual curtailment

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

where

T_y	=	all hours in year y.

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

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

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 124

November Order

Department of Energy
Washington, DC 20585

Order No. 202-25-9

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

Order Nos. 202-25-3 and 202-25-7

J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, MI. In 2021, Consumers announced that it planned to implement a "speed closure" of the Campbell Plant fifteen years before the end of its scheduled design life.[3] Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant's retirement and discontinue its operations on May 31, 2025.

Order No. 202-25-3, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until August 21, 2025. Subsequently, Order No. 202-25-7, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, until November 19, 2025. Those orders were based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO). Specifically, I determined that MISO likely faced tight reserve margins during the summer 2025 period, particularly during periods of high demand or low generation resource output. I determined that the continued operation of the Campbell Plant would provide additional generation capacity during these periods which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety. I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability. My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. §7151(b).
[3] *See Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation*, Consumers Energy (June 23, 2021), https://www.consumersenergy.com/news-releases/newsrelease-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-cleanenergy-transformation.

Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[4] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.[5]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[6] Additionally, EIA stated, "[t]ypically, Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[7] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. The Palisades plant remains unavailable, although according to a recent news report, "Holtec International expects the Palisades plant in Michigan to resume service early next year…."[8]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts and Consumers acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."[9]

Fourth, MISO's Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which include Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[10] While the results "demonstrated sufficient

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[4] *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, at 16 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf (NERC 2025 Summer Reliability Assessment).

[5] *Id.*

[6] *Michigan State Profile and Energy Estimates*, U.S. Energy Info. Admin. (Oct. 17, 2024), https://www.eia.gov/state/print.php?sid=MI.

[7] *Id.*

[8] *Nuclear plants face decadelong timeline to meet AI energy needs*, Los Angeles Times. (Nov. 13, 2025), https://www.latimes.com/business/story/2025-11-13/despite-80-billion-commitment-nuclear-plants-face-decade-long-timeline-to-meet-ai-energy-needs.

[9] NERC 2025 Summer Reliability Assessment at 16.

[10] *Planning Resource Auction—Results for Planning Year 2025–2026*, Midcontinent Independent System Operator, Inc., 13 (May 29, 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf. (MISO Planning Resource Auction – Results for Planning Year 2025-26).

capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and these results "reinforce the need to increase capacity."[11]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order Nos. 202-25-3 and 202-25-7 continue, both in the near and long term.[12] The production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO. According to the U.S. Environmental Protection Agency's data, the plant has generated an average of approximately 509,000 MWh per month, from June 2025 through September 2025,[13] providing vital generation capacity to the region. Additionally, between June 11 and November 5, MISO issued dozens of alerts to manage grid reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits.

MISO's year-round resource adequacy concerns are well documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[14] MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round concern."[15] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[16]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[17] Among other things, this report described changes in the time of year during

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[11] *Id*. at 2,12. For further information regarding the determination that emergency conditions existed, *see* Order No. 202-25-7.

[12] Further, as noted in Order No. 202-25-7, as a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Consumers were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.

[13] *See, Custom Data Download, EPA CAMPD (Clean Air Markets Program Data),* https://campd.epa.gov/data/custom-data-download *(search criteria to produce these results could include Emissions >> Monthly >> Unit (default) >>Apply >>"2025" and "June, July, August, September." The data can then be filtered to only include the JH Campbell Plant.)*

[14] 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).

[15] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).

[16] Id. at 3-4.

[17] *Attributes Roadmap*, MISO (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf

which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projects that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[18]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative.*"[19] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[20]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

While the 2025 – 2026 NERC Winter Reliability Assessment has not yet been released as of the date of this Order, two recent winter studies (2024 – 2025 NERC Winter Reliability Assessment[21] and the 2023 – 2024 NERC Winter Reliability Assessment[22]) have assessed the MISO assessment area as an elevated risk, with the "potential for insufficient operating reserves in above-normal conditions." Specifically, the 2024 – 2025 Winter Reliability Assessment noted that "[ge]nerating capacity is 10 GW lower (-6.8%) compared to the prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity."[23]

The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased

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[18] *Id.* at 11.
[19] *MISO's Response to the Reliability Imperative*, MISO (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf
[20] *Id.* at 12.
[21] 2024 – 2025 NERC Winter Reliability Assessment at 5, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf
[22] 2023 – 2024 NERC Winter Reliability Assessment at 5, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf
[23] 2024 – 2025 NERC Winter Reliability Assessment at 15, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf

accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Michigan.[24]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[25] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[26] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[27] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[28]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[29] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[30]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[31] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.[32] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are

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[24] MISO Planning Resource Auction – Results for Planning Year 2025-26 at 13.
[25] *OMS-MISO Survey Results*, OMS and MISO (Updated June 6, 2025) https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf
[26] *Id.* at 2.
[27] *Id.* at 7.
[28] *Id.* at 9
[29] *Id.* at 7, 9.
[30] *Id.*
[31] M*idcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).
[32] 192 FERC ¶ 61,064 at P 84.

likely to further hinder rapid construction and exacerbate reliability concerns.[33] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order Nos. 202-25-3 and 202-25-7 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[34] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[35] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[36]

The Department's July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[37] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[38] In addition, as just one example,

[33] *See generally, US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P Global (May 2025), US gas-fired turbine wait times as much as seven years; costs up sharply | S&P Global. "With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."

[34] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliabilityand-security-of-the-united-states-electric-grid/.

[35] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[36] *Id*.

[37] *See also Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy (July 2025), at 1, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[38] Ekku Jokinen, *Top 21 Artificial Intelligence Companies in Michigan*, (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[39]

Grid operators — including MISO itself — have also acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[40] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[41] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[42]

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[43] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has

[39] *See Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center*, Data Center Dynamics (August 05, 2025), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-toprovide-1gw-of-power-to-new-hyperscale-data-center/ (quoting Consumers Energy CEO Garrick Rochow).

[40] Keeping the Lights On: Examining the State of Regional Grid Reliability Before the House Committee on Energy and Commerce, Subcommittee on Energy, 119th Cong. (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), at 5, https://democratsenergycommerce.house.gov/sites/evo-subsites/democrats-energycommerce.house.gov/files/evo-mediadocument/witness-testimony_curran_eng_grid-operators_03.25.2025.pdf

[41] *Id.* at 6.

[42] *Id.* at 7.

[43] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-3 and 202-25-7 will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the increased demand and determined shortage and serve the public interest under FPA section 202(c).

To ensure the Campbell Plant will be available if needed to address emergency conditions, the Campbell Plant shall remain in operation until February 17, 2026.[44]

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

A. From November 19, 2025, MISO and Consumer Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Campbell Plant has operated in compliance with the allowances contained in this Order.

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

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[44] 16 U.S.C. § 824a(c)(4).

D. By December 3, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Consumers is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

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

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Campbell Plant shall not be considered a capacity resource.

H. This Order shall be effective from 00:00 Eastern Standard Time (EST) on November 19, 2025, and shall expire at 00:00 EST on February 17, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 5:58PM EST on this 18th day of November 2025.

Chris Wright

Chris Wright
Secretary of Energy

cc:

FERC Commissioners
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Michigan Public Service Commissioners
Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

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 125

Public Interest Organizations' September Rehearing Request

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator (MISO)	)))))	Order No. 202-25-7

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, Union of Concerned Scientists, the Ecology Center and Urban Core Collective (collectively, "Public Interest Organizations")

I. Introduction

J.H. Campbell spent the Summer sputtering along, racking up costs for no good reason. The power plant was not needed: Even at peak demand last Summer, the regional grid operator maintained an unused surplus of resources greater than *ten times* the power provided by Campbell. Ex. 70 at ¶¶ 16–17 (Konidena Decl.). And—as would be expected from an aging plant slated for retirement—Campbell units suffered multiple lengthy outages, demonstrating their unreliability to meet any unexpected shortfall that could have arisen. Ex. 69 at 5–7 (Powers Sept. Declaration). All the while the bill grew, with a "net financial impact" of $29,000,000 set to hit wallets across eleven states. *See* Ex. 73 at 62 (Consumers' July 2025 10-Q). That financial hit only covers the plant's activities for about 39 days through June 30. The harm to ratepayers is likely to grow with Campbell's continued operation; for most of the last year (79% of hours from July 2024 through June 2025), market prices were below Campbell's operating costs. *See* Ex. 68 at 5–6 (Grid Strategies Sept. Report).

The Department of Energy and Secretary Wright ("Department") now renew the emergency order requiring continued operation of J.H. Campbell Generating Plant ("Campbell Plant" or "Campbell")—an extraordinarily expensive, unreliable, and polluting plant that was, until the Department's intervention, slated for retirement pursuant to a settlement approved by the Michigan Public Service Commission (the "Michigan Commission"), and agreed to by a wide array of stakeholders. The Department has issued that renewal (Order No. 202-25-7, or the "August Order") despite the absence of any request from the Midcontinent Independent System Operator ("MISO") or any other party, and even though the Campbell Plant proved (contrary to the Department's claims) wholly unnecessary to sustain grid operations during the summer period covered by the Department's order issued last May.

The August Order is, like the Department's original order (Order No. 202-25-3, or the "May Order"), unlawful. Its main premise—a "longer term resource adequacy" deficiency arising sometime after 2027, Ex. 67 at 4–5 (August Order)—would not be an "emergency" within the meaning of Section 202(c) of the Federal Power Act, even if it existed. Section 202(c) authorizes the Department to mandate generation when faced with an imminent, near-term shortfall; it does not permit the Department to override the Act's separate procedures addressing long-term reliability. And the Department's claim of a long-term energy shortfall ignores the steps MISO and others are taking pursuant to those statutory processes—steps that promise to ensure long-term resource adequacy without the expense and pollution of Campbell's continued operation.

The August Order half-heartedly claims a near-term need for Campbell. But it does not—and cannot—offer more than general speculation that such an energy shortfall might arise somewhere within MISO. That speculation does not describe any imminent exigency that could justify the exercise of the Department's Section

202(c) authority. Moreover, the Department's assertions misstate the sources on which they rely; MISO has maintained, and continues to maintain, more than adequate resources to render Campbell's continued operation unnecessary. In fact, MISO's risk of shedding load for the Fall, Winter, and Spring seasons is less than or equal to one expected event in the next 100 years, an order of magnitude more protective than the already conservative industry standard.

The August Order also contains many of the same flaws that made its original May Order unlawful. There is no reason to believe that ordering Campbell's continued operation—which was unable to operate for large portions of the past summer—would be the "best" means of addressing the resource shortfalls claimed by the Order (even if they existed). 16 U.S.C. § 824a(c)(1). The order imposes requirements that are beyond the Department's authority. And it lacks the conditions required by Section 202(c)(2) where, as here, the Department orders operations that may conflict with federal, state, or local environmental requirements. *Id.* § 824a(c)(2).

At root the August and May Orders represent an effort to transform a statutory system designed to achieve resource adequacy through State and market-led decision-making, subject to carefully constrained federal oversight, into one of centralized command-and-control by the Department of Energy. That effort is contrary to law and unsupported by the facts. And it is deeply unwise. It will dramatically increase costs to the rate-paying public and badly exacerbate pollution—all to sustain an aging, outdated fossil-fuel plant incapable of providing reliable generation. The Department should withdraw the Order and allow Campbell to retire.

II. Statement of Issues and Specification of Error

The undersigned Public Interest Organizations move to intervene and request rehearing and a stay pursuant to Section 313(a) of the Federal Power Act, 16 U.S.C. § 825*l*(a), and the applicable rules of practice and procedure, 18 C.F.R. §§ 385.203, .214, .713; *see* Ex. 8 (Cooke Email 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.").[1]

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[1] Until sometime after June 18, 2025, the Department maintained a webpage with procedures for intervention and rehearing requests. U.S. Dep't of Energy, *DOE 202(c) Order Rehearing Procedures* (visited June 18, 2025), https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures (attached as Ex. 30) [hereinafter "DOE Rehearing Procedures"]. The Public Interest Organizations relied on that webpage in challenging the May Order. *See, e.g.*,

Public Interest Organizations' motion and requests are based upon the following errors and issues:

A. The Department has not demonstrated that an emergency exists in any portion of the Midwest region of the United States as required by Section 202(c) of the Federal Power Act; nor has the Department demonstrated that an emergency exists as defined in the implementing regulations for Section 202(c). *See, e.g.*, 16 U.S.C §§ 824(a)–(b), 824a(a)–(c); 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); *Otter Tail Power Co. v. Federal Power Commission*, 429 F.2d 232 (8th Cir. 1970); *Richmond Power & Light v. FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978); *Duke Power Co. v. Fed. Power Com.,* 401 F.2d 930, 938 (D.C. Cir. 1968).

B. 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." *See, e.g.*, 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*

Ex. 71 at 4, 50 (Public Interest Organizations' June Rehearing Request). The webpage with those procedures is no longer accessible. Public Interest Organizations have not been notified of any change to the procedures or any repudiation by the Department of the DOE Rehearing Procedures. The Department maintains another website which currently states, "All public comments and requests related to FPA section 202(c) should be sent via email to AskCR@hq.doe.gov. . . . 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." U.S. Dep't of Energy, *DOE's Use of Federal Power Act Emergency Authority* (last visited Sept. 7, 2025), https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority (attached as Ex. 74) [hereinafter "DOE 202(c) Webpage"]. Public Interest Organizations' instant motion and requests are also pursuant to the DOE 202(c) Webpage and the DOE Rehearing Procedures.

& 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. 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).

C. The Order's availability requirements and the Order's override of Campbell's tariff-defined capacity treatment each exceed the Department's authority. *See, e.g.*, 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 August 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; there is no indication that the Department consulted with the primary Federal agency with expertise in the environmental interests protected by the laws and/or regulations with which the operations required by the August Order may conflict; and the Department has not included in the August Order or made public any conditions that may have been submitted by that Federal Agency, explained why such conditions might prevent the order from adequately addressing the emergency, or made that explanation public. *See, e.g.*, 16 U.S.C. §§ 824a(c)(2), 824a(c)(4)(B); *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).

III. Intervenors' Interests

As further discussed below, each of the Public Interest Organizations has interests that may be directly and substantially affected by the outcome of this proceeding. Each party may therefore intervene in this proceeding. 18 C.F.R. § 385.214; *see* Ex. 30 (DOE Rehearing Procedures); Ex. 74 (DOE 202(c) Webpage); Ex. 8 (Cooke Email to Alle-Murphy).

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); 18 C.F.R. §§ 385.203, 385.713; Ex. 30 (DOE Rehearing Procedures); Ex. 74 (DOE 202(c) Webpage); Ex. 8 (Cooke Email to Alle-Murphy).

A. Sierra Club

As of July 2025, 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 coal trains delivering coal to the plant. In addition, Sierra Club members include people who pay for electricity from Consumers Energy Company ("Consumers Energy" or "Consumers").

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, including the 2021 Integrated Resource Plan proceeding that resulted in the settlement agreement requiring Campbell to retire by May 31, 2025. 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. Sierra Club supported the settlement agreement because it would advance the organization's and its members' interests in reducing pollution and energy bills. By denying these and other benefits of the Campbell Plant's retirement, the Order harms Sierra Club and its members.

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. Toward this goal, NRDC works to achieve clean energy solutions that will lower consumer energy bills, meet U.S.

carbon reduction goals, accelerate the use of renewable energy, and ensure that clean energy is affordable and accessible to all. NRDC has approximately 5,960 members in Michigan, including members who pay for electricity from Consumers Energy and who live and recreate near the Campbell Plant, where they are harmed by the plant's pollution.

NRDC has a longstanding organizational commitment to protecting the interests of its members and 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, including Consumers Energy's 2021 Integrated Resource Plan proceeding. NRDC was a party to the 2022 settlement agreement that required Consumers Energy to close the Campbell Plant and end the utility's use of coal by May 31, 2025. NRDC supported the settlement agreement because it furthered the organization's and its members' interests in reducing costs to ratepayers and transitioning from fossil fuels to cheaper and more sustainable clean energy. By denying these and other benefits of the Campbell Plant's retirement, the Order harms NRDC and its members.

C. Michigan Environmental Council

Michigan Environmental Council ("MEC") is a statewide environmental nonprofit organization founded in 1980 and based in Lansing, Michigan. MEC pays for electricity from a utility located in MISO Zone 7. MEC has over 100 member groups and a collective membership of over 300,000 people. MEC's membership includes people who consume energy in MISO Zones 2 and 7 and who live and recreate near the Campbell Plant and are harmed by the plant's pollution. 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 that required Consumers Energy to close the Campbell Plant and end the utility's use of coal by May 31, 2025. MEC supported the settlement agreement because it would provide both cost and health benefits to MEC members and would further MEC's and its members' interest in developing a cheaper, less-polluting electric grid. The settlement agreement was designed to provide reliable energy at significantly lower cost while also improving public health and reducing harmful environmental impacts. The Order harms MEC and its members because it deprives them of these and other benefits by delaying the Campbell Plant's retirement.

D. Environmental Defense Fund

The Environmental Defense Fund ("EDF") is a nonprofit membership organization with hundreds of thousands of members nationwide, including more than 1,200 members who live within 50 miles of the Campbell Plant. EDF's members include people who pay for and consume electricity in MISO Zones 1-7, and who are harmed by pollution from the Campbell Plant. EDF's 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 Campbell Plant's retirement would help create an affordable, reliable, and low pollution energy system. Because the Order denies these and other benefits of the plant's retirement, the Order harms EDF members.

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. ELPC's members include Michiganders who pay for electricity from Consumers Energy and own property and recreate near the Campbell Plant, where they are harmed by the plant's pollution. ELPC also has an office and pays for electricity in Des Moines, Iowa, located in MISO Zone 3.

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. With respect to the Campbell Plant, 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. ELPC supported the settlement agreement because it would advance the organization's and its members' interests in reducing pollution in a cost-effective way. By denying these and other benefits of the Campbell Plant's retirement, the Order harms ELPC and its members.

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.

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. Vote Solar is not a trade organization, nor does it have corporate members. Vote Solar is committed to promoting clean, renewable energy and transitioning away from coal generation. Toward this goal, Vote Solar seeks to promote the development of solar at every scale across the country, including in Michigan.

Vote Solar has over 90,000 members nationally and over 2,700 members in Michigan, including members who pay for electricity from Consumers Energy and are harmed by pollution from the Campbell Plant. Vote Solar has provided testimony and comments in many regulatory dockets in front of the Michigan Commission, including the 2021 Integrated Resource Plan proceeding that resulted in the settlement agreement requiring the Campbell Plant's retirement. Vote Solar signed the settlement agreement because it furthered the organization's and its members' interests in reducing air pollution, reducing energy burden, and ensuring regulatory processes reflect cost-effective, community-supported energy planning. By denying these and other benefits of the Campbell Plant's retirement, the Order harms Vote Solar and its members.

G. 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 in Michigan, including members who use electricity and pay electric bills in Consumers Energy's service territory and who live and recreate near the Campbell Plant and are harmed by the plant's pollution.

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 the Campbell Plant. UCS signed the settlement agreement because it furthered the organization's and its members' interests in reducing pollution in a cost-effective way. By denying these and other benefits of the Campbell Plant's retirement, the Order harms UCS and its members.

H. The Ecology Center

The Ecology Center is a Michigan-based nonprofit organization headquartered in Ann Arbor, Michigan, with additional offices in Detroit, Michigan. The Ecology Center has approximately 450 members in Michigan, including members who use electricity and pay electric bills in Consumers Energy's service territory and who are harmed by pollution from the Campbell Plant. The Ecology Center's mission is to improve environmental quality and protect human health, particularly in Michigan. Toward that goal, the organization fights for clean air throughout the state and advocates before the Michigan Commission to accelerate the shift to clean energy and reduce energy burden for residential ratepayers.

The Ecology Center has participated in cases at the Michigan Commission involving Consumers Energy's power plants since 2015, including by intervening in Consumers' 2021 Integrated Resource Plan proceeding. The Ecology Center signed the settlement agreement that required Consumers to retire the Campbell Plant by May 31, 2025 because it supported the organization's and its members' interest in reducing air pollution in a cost-effective way. By denying these and other benefits of the Campbell Plant's retirement, the Order harms UCS and its members.

I. Urban Core Collective

The Urban Core Collective ("UCC") is a non-profit organization with three member groups. UCC's main office is in Grand Rapids, Michigan, where the organization receives and pays for electricity from Consumers Energy. UCC advocates for strengthening democracy, leadership development, education reform, and climate and environmental justice. Much of UCC's work has involved advocating for policies that move Michigan toward a transition from fossil fuels to renewable energy sources that are affordable, reliable, and do not contribute to climate change. UCC advocates for those affected first and most severely by pollution from fossil fuels, including coal.

UCC regularly participates in Michigan Commission cases, including by intervening in Consumers Energy's 2021 Integrated Resource Plan proceeding. During that proceeding, UCC was heavily involved in engaging community members, collaborating with other stakeholders, and advocating for the Campbell Plant's retirement. UCC signed the settlement agreement that required the Campbell Plant's retirement because it furthered the organization's interest in promoting environmental justice, reducing pollution, and advancing the transition to cleaner energy sources. By denying these and other benefits of the Campbell Plant's retirement, the Order harms UCC.

IV. Background

A. *The Primary Actors in the Electric Industry Already Protect Resource Adequacy Without Intrusion from the Department.*

1. *The Federal Energy Regulatory Commission Regulates Wholesale Electricity Markets and Mechanisms that Acquire Adequate Resources.*

FERC regulates wholesale sales and transmissions of electric energy in interstate commerce. 16 U.S.C. § 824(b)(1). Federal authority over the electric grid dates back at least to 1935, when the Federal Power Act became law and the Federal Power Commission administered the Act.

Congress did not give the federal agency plenary authority over the electric grid. Instead, Congress provided that federal regulation shall "extend only to those matters which are not subject to regulation by the States" and provided that "[t]he Commission" does not have jurisdiction, "except as specifically provided in [the Federal Power Act], over facilities used for the generation of electric energy." *Id.* at § 824(a)–(b)(1). As such, authority over generation facilities belongs to the states. *See id.*

In 1977, through the Department of Energy Organization Act, Congress reorganized the agencies that administer the Federal Power Act. Congress created the Department of Energy and FERC. 42 U.S.C. §§ 7131, 7171(a). Congress also transferred certain functions of "the Commission" in the Federal Power Act to the Department and other functions to FERC, thereby abolishing the Federal Power Commission. *See id.* §§ 7151(b), 7172(a)(1). FERC retained authority over rates and charges for the transmission or sale of electric energy, and the non-emergency interconnection of facilities for the generation, transmission, and sale of electric energy. *Id.* § 7172(a)(1)(B). The Department's authority over functions of "the Commission" in the Federal Power Act include certain functions under Section 202 of the Act. *See id.* § 7151(b). The 1977 reorganization did not expand the role of the "the Commission" at the expense of state authority or shrink states' authority over generation facilities. *See, e.g.*, *id.* at § 7113 ("Nothing in this chapter shall affect the authority of any State over matters exclusively within its jurisdiction.").

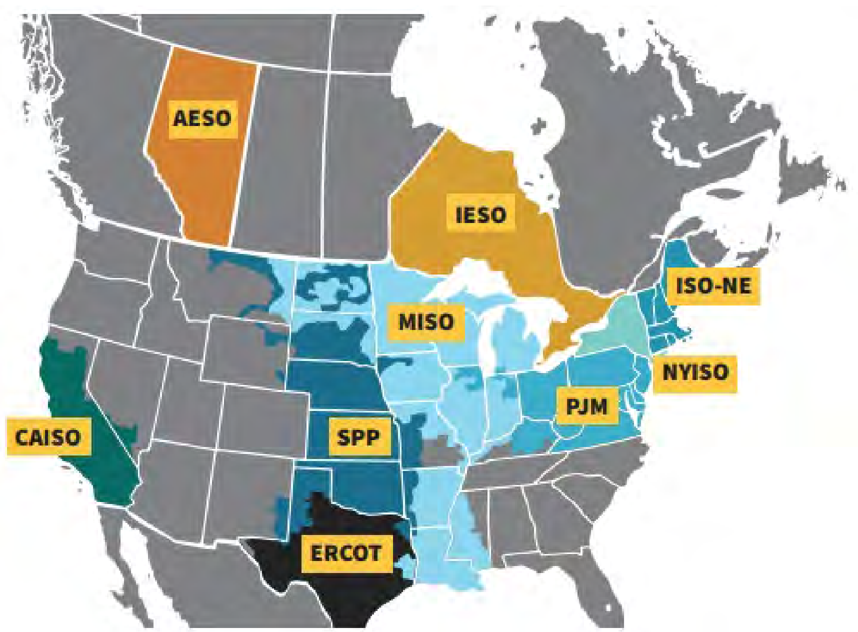
As part of its regulatory oversight, FERC has promoted the role of nonprofit entities, known as Independent System Operators or Regional Transmission Organizations. *See Fed. Energy Regul. Comm'n v. Elec. Power Supply Ass'n*, 577 U.S. 260, 267 (2016); *Regional Transm. Orgs.*, Order No. 2000, 65 Fed. Reg. 810, 811 (Jan. 6, 2000); *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transm. Servs. by Pub. Utils. and Recovery of Stranded Costs by Pub. Utils. and Transm. Utils.*, Order No. 888, 61 Fed. Reg. 21,540, 21,542 (May 10, 1996). FERC generally regulates these entities pursuant to its authority over rates and charges for wholesale sales and transmissions of electric energy. *See, e.g.*, Order

No. 2000, 65 Fed. Reg. at 811. These entities, referred to here as Independent System Operators or RTOs, perform a variety of functions, including:

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

Ex. 46 at 53 (FERC Energy Primer). Some Independent System Operators "also operate capacity markets, which, along with underlying resource adequacy rules, ensure sufficient capacity is available." *Id.* at 68.

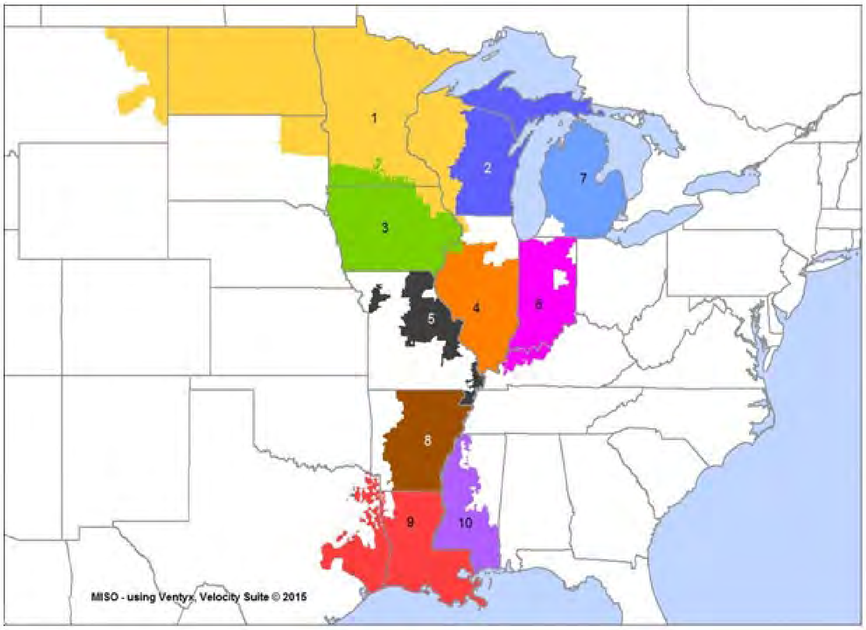
The Independent System Operators now span much of the country, excluding portions of the Southeast, Southwest, and Northwest regions of the country. *See id.* at 37. The map below depicts the geographic footprint of the various Independent System Operators.



Source: Ex. 46 at 67 (FERC Energy Primer).

2. *MISO Protects Resource Adequacy Through FERC-Regulated Reserve Margin Requirements and a Residual Capacity Auction.*

MISO is an Independent System Operator and 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.



Source: Ex. 75 (MISO Tariff Zonal Map).

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. *See* Ex. 58 (MISO Tariff Module E-1). 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 day with a loss of load event every ten years. *See* Ex. 2 at 2–5 (Grid Strategies June 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 (as currently effective), *available at* https://etariff.ferc.gov/TariffBrowser.aspx?tid=1162 (defining "Load Serving Entity"). And the Reserve Margin Requirement for each zone is, roughly speaking, the sum of all load-serving entities' obligations in that zone.

Finally, 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 or in the Planning Resource Auction to achieve 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.

Once MISO (1) establishes the regional Reserve Margin, (2) converts it to a Reserve Margin Requirement for each zone using peak demand projections, (3) apportions each zone's Reserve Margin Requirement among load-serving entities, and (4) determines 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" or "PRA").

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 each 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 June 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).

3. MISO Also Continuously Monitors the Grid to Balance Supply and Demand, and to Prevent Blackouts Using an Escalating Sequence of Real-Time Alerts that Activate Reserve Resources in a Specific, Predetermined Order.

In addition to annually securing the set of resources it has determined will meet its regional reliability standard, MISO also operates the grid on a daily and hourly basis to match the resources it has available with load (*i.e.*, demand) over the course of each day. During normal operational periods, MISO uses its energy markets to receive information from every potential resource in the region (generators, batteries, etc.) about how much power they believe they can create and at what price, and then to issue instructions to the set of resources it needs to meet projected demand at least cost to the system. *See generally Elec. Power Supply Ass'n*, 577 U.S. at 268 (citation omitted) ("Each administers a portion of the grid, providing generators with access to transmission lines and ensuring that the network conducts electricity reliably. And still more important for present purposes, each operator conducts a competitive auction to set wholesale prices for electricity. These wholesale auctions serve to balance supply and demand on a continuous basis, producing prices for electricity that reflect its value at given locations and times throughout each day.").

On occasion, the total electric generation that is freely offered in MISO's day-ahead market is less than the MISO region's projected demand. That mismatch between projected demand and voluntary supply does not, however, of itself produce any disruption to the grid. In these instances, MISO implements a well-defined process to identify additional resources until the projected shortfall is addressed.

MISO has enshrined its process for securing extra resources to address projected shortfalls, which it deems "Max Gen Emergencies," in its operational tariff. Ex. 33 at §§ 4.2–4.3 (MISO Market Capacity Emergency) (describing Max Gen Emergency Event procedures). As described there, MISO often can address any shortfall simply by issuing a capacity advisory to double check its numbers, followed by a so-called "max-gen" alert to facility operators to suspend any optional maintenance or other activities that might be interfering with resources' power output (*i.e.*, to achieve maximum generation from all available resources). *Id.* at §§ 4.1, 4.2.2. MISO can then issue a warning of a potential shortfall and start curtailing exports and coordinating with its neighbors to bring in imports from adjacent regions. *Id.* at

§ 4.2.3. If these preliminary measures don't address the shortfall, MISO will then proceed step by step through a series of five steps with subparts (labeled "1a" through "5") of increasingly stringent mitigation measures to increase generation or reduce usage of electricity during the period at issue. Only on the final step (step "5) does any involuntary load shedding (*i.e.*, a blackout) occur; Steps "1a" through "4b" describe an increasing list of mitigation measures MISO will employ, including requesting power transfers from neighboring regions, turning on backup generators, utilizing contracted demand response resources, and asking the public for voluntary reductions. The following table, prepared by MISO, describes these steps (without delineating between "step 1a," "step 1b," etc.).

Attachment 8 — Summary of Market Capacity Emergency Procedure Steps

MARKET CAPACITY EMERGENCY PROCEDURE STEPS

	Step	Description	Pricing
	Normal Operations		Normal Pricing
	Capacity Advisory	Advance notice of forecasted capacity shortage, requests Stakeholders update offer data	
MAXIMUM GENERATION	Alert	Define boundaries/suspend maintenance	Emergency Pricing Tier 0
	Warning	Schedule in external resources, curtail export transactions, activate reconfiguration	Emergency Pricing Tier I Offer Floor
	Event Step 1	Commit emergency resources, declare NERC (Energy Emergency Alert) EEA 1, activate emergency limits	
	Event Step 2	Declare NERC EEA 2, implement Load Modifying Resources (LMRs), Load Management Measures (LMMs) Stage 1, commit Emergency Demand Response (EDR) resources, emergency energy purchases, public appeals	Emergency Tier II Offer Floor
	Event Step 3	Utilize operating reserves and LMMs Stage 2	
	Event Step 4	Reserve call and emergency reserve purchases	
	Event Step 5	Declare NERC EEA 3, firm load shed, and set Locational Marginal Prices (LMPs) and Market Clearing Prices (MCPs) to the VOLL	Value of Lost Load (VOLL) Pricing
	Termination	Terminate Max Gen and possibly Capacity Advisory	Normal Pricing

Source: Ex. 33 at 41 (MISO Market Capacity Emergency).

Through a combination of responsible grid management and capacity retention policies, MISO has avoided the need to utilize the full ten steps of its emergency process in recent years. MISO has not faced a Market Footprint Maximum Generation Emergency Event Step of 3 or higher since 2009, according to the most recent summation available (through June 2024)—and there was also not one in the summer 2025 season that just concluded. *See* Ex. 32 at 4–27 (MISO Emergency Declarations); Ex. 68 at 3–4 (Grid Strategies Sept. Report).

4. *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 governs its electricity market to ensure that its citizens enjoy ample supply from generators at reasonable cost, and in keeping with the state's other policy preferences.

The Michigan Commission regulates certain aspects of the energy industry in Michigan. It exercises key authorities of the state to, among other things, ensure resource adequacy and choose the state's preferred mix of energy generation resources. *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."). The Michigan Commission performs this function through, *inter alia*, review of utilities' Integrated Resources Plans. *See* MCL § 460.6t.

Michigan state law requires that electric utilities file an Integrated Resource Plan with the Michigan Public Service Commission at least every five years. *Id.* 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. 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.

Id. § 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); *see also* Ex. 27 at PDF 14–15, 26–27, 38–39 (Consumers 2028/2029 Capacity Demonstration) (showing that Consumers meets resource adequacy requirements, including in Summer, Fall, and Winter 2025).

5. NERC Protects Reliability via Standards and Regular Assessments

NERC is the "Electric Reliability Organization" under section 215 of the Federal Power Act. *N. Am. Elec. Reliab. Corp.*, 116 FERC ¶ 61,062, at P 3, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006); *see* 16 U.S.C. § 824o(a)(2). This role dates back to 2005, after Congress added Section 215 to the Act and FERC certified NERC as the Electric Reliability Organization. Energy Policy Act of 2005, Pub. L. No 109-58, Title XII, Subtitle A, section 1211(a), 119 Stat. 594, 941 (2005), 16 U.S.C. 824o (2000 & Supp. V 2005); 116 FERC ¶ 61,062, at P 3.

As the Electric Reliability Organization, NERC is responsible for establishing and enforcing reliability standards for the Bulk-Power System. 16 U.S.C. § 824o(a)(2); 18 C.F.R.§ 39.1. NERC's reliability standards are subject to FERC's review and approval. 16 U.S.C. § 824o(d); Ex. 2 at 7 (Grid Strategies June Report).

The NERC-developed and FERC-approved reliability standards apply to all users, owners, and operators of the Bulk–Power System within the continental United States. 16 U.S.C. § 824o(b)(1); 18 C.F.R. §§ 39.2, 40.1(a), 40.2(a); *see id.* § 39.1 (defining "Bulk–Power System"). Each reliability standard identifies the types of entities that must comply with the standard, like generator owners, transmission owners, or transmission operators. *Reliability Standard Compliance and Enforcement in Regions with Regional Transm. Orgs. or Indep. Sys. Ops.*, 122 FERC ¶ 61,247, at P 4 (2008); *e.g.*, *Emergency Ops.*, EOP-011-4, *available at* https://www.nerc.com/pa/Stand/Reliability%20Standards/EOP-011-4.pdf (stating requirements applicable to, *inter alia*, balancing authorities, reliability coordinators, and transmission operators for the purpose of "address[ing] the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements"). Independent System Operators like MISO must comply with applicable NERC standards, and they are subject to penalties for noncompliance. 122 FERC ¶ 61,247, at PP 1, 5, 16; *see also* MISO's FERC-Approved Tariff at Schedule 34, *available at* https://etariff.ferc.gov/TariffBrowser.aspx?tid=1162 (setting forth allocation costs associated with monetary penalties assessed against MISO for violation of NERC standards).

NERC performs other functions in addition to development and enforcement of reliability standards. For instance, NERC annually assesses seasonal and long-term reliability of the bulk power system and monitors system performance. Ex. 2 at 7–8 (Grid Strategies June Report); *see also* 18 C.F.R. § 39.11. As part of these assessments, 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* Ex. 42 at PDF 74, 124, 170, 218 (2019–24 NERC Summer Reliability Assessments). 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).

B. *The Evidence Shows No Resource Adequacy Crisis in MISO for Summer 2025, Fall 2025, and Thereafter.*

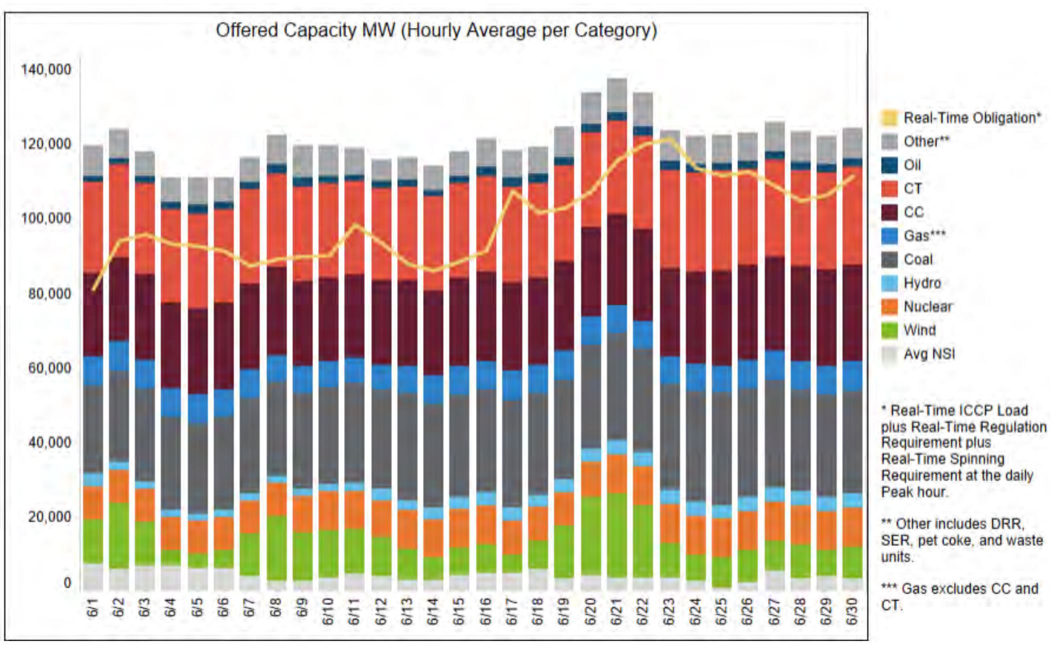
1. *There Is No Evidence of a Resource Adequacy Crisis in Summer 2025.*

The Department's August Order purported to address "resource adequacy problems" for the Summer 2025 season, although only 11 days remained in the Summer season as defined by MISO (from June 1 to August 31) when the Order was issued. *See* Ex. 67 at 2–3 (August Order). The Summer 2025 season was demonstrated in advance to have adequate supplies, which has been borne out by the past three months of experience.

As previously discussed in response to the May Order, the 2025–2026 Planning Resource Auction "secured [for Summer 2025] an overall 9.8% Reserve Margin—almost two percentage points more than the 7.9% target that MISO determined was needed to meet resource adequacy requirements." Ex. 71 at 24–25 (Public Interest Organizations' June Rehearing Request) (citing Ex. 31 at 5 (MISO 2025–26 Auction Results)). Public Interest Organizations also described how Local Resource Zone 7 (Michigan's Lower Peninsula) had local capacity offers within the recent Planning Resource Auction totaling "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 25 (citing Ex. 31 at 18 (MISO 2025–26 Auction Results)); *see generally* Ex. 34 (Ramey MISO Comments) (testifying that no capacity deficits have materialized in 2025).

The August Order also notes that "MISO issued alerts for the Central Region on at least 40 of the 69 days between June 11 and August 18." Ex. 67 at 3 (August Order). However, none of these alerts cited by the Department progressed past the Max Gen Event Step 1b, meaning MISO did not even need to access previously contracted demand response and other resources to address the shortfall, and was several steps away from actually needing to shed firm load (Step 5). Ex. 68 at 3–4 (Grid Strategies Sept. Report); *see supra* sec. IV.A.2.ii. In other words, MISO's system did not come close in Summer 2025 to an actual generation shortfall.

Throughout June 2025, MISO received supply offers more than sufficient to meet each day's peak load. MISO receives these offers shortly before the generators are to supply power, making them a reliable and conservative indicator of available resources. Ex. 70 at ¶ 13 (Konidena Decl.). MISO recently demonstrated the excess offers on each day of June over and above that day's peak load, as shown in the graph below.



Ex. 111 at 33 (MISO June Operations Report).

Examining real-time operations on the tightest-margin day of the Summer—June 23, when MISO declared an EEA 1b emergency—is instructive here. At peak load, which occurred between 4PM to 5PM Eastern, MISO had more than enough resources offered into its markets to meet demand. As Public Interest Organizations' expert engineer Rao Konedina explains, MISO had 3,323 MW of surplus offers above what it needed to meet demand:

	Offered Supply	122,635 MW
-	Peak Load	119,312 MW
=	Surplus	3,323 MW

Ex. 70 at ¶ 14 (Konidena Decl.).

Additionally, MISO had over 7,000 MW of emergency headroom resources (*i.e.*, additional generation it could obtain from resources that can meet the grid's needs by surpassing a limit placed for economic purposes). *Id.* at ¶ 16. Some of those resources were instantaneously available to MISO operators if needed (committed emergency headroom) and some were available on short notice, mostly less than 4 hours (uncommitted emergency headroom). *Id.* The offered supply and emergency headroom was well more than needed to cover peak load and ensure MISO could cover contingencies through its operating reserves of 2,710 MW, as the expert engineer further demonstrates:

	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**

Id. at ¶¶ 15–16.

By comparison, Campbell Units 1 and 2 were completely offline when demand peaked on MISO's system, and Unit 3's contribution maxed out at around 760 MW. *See* Ex. 68 at 5 (Grid Strategies Sept. Report); Ex. 104 (CAMPD Campbell Hourly Emissions Data). This is consistent with Campbell's general history of only having 70% of its capacity available for MISO max generation events in recent years. Ex. 68 at 4 (Grid Strategies Sept. Report). It also means that MISO's surplus of 7,941 MW was over 10 times greater than the amount of power Campbell was providing at the time. Ex. 70 at ¶ 17 (Konidena Decl.). Thus, even at its peak demand, MISO did not need Campbell to have sufficient supply to maintain reliability for the region. *Id.*

In fact, among the resources available to MISO were 8,610 MW of demand response programs, called Load Modifying Resources, that can help reduce peak demand by, for example, cycling air conditioning loads and using behind-the-meter generation. *Id.* at ¶ 21. The demand response programs have varying notification times, which gives MISO flexibility to react as conditions develop. *Id.* at ¶¶ 21–22. And MISO can even ask for voluntary load reductions if needed. *Id.* at ¶ 23. MISO could have even requested or directed some resources on planned outage to return to service sooner than scheduled. *Id.* at ¶¶ 20, 23. Thus, the evidence strongly suggests that MISO's system would have operated just fine without Campbell.

In addition to the information about Summer 2025 market conditions available to the Department at the time of the August Order, a simple review of the weather forecast on August 20, the day before the Department issued the August Order, could have allayed any concerns about resource adequacy in the final 11 days of MISO's summer season. A weather report issued on that day indicated that "[t]emperatures [were] expected to run 10 to 25 degrees below average from the Plains to the Midwest—and even reach into parts of the South," and predicted that these below average temperatures would last through the end of August across the majority of MISO's footprint. Ex. 88 at 2–3 (August 20 weather report). This is noteworthy because summer-season strain to the grid is near-universally caused by heat waves.

Finally, it is instructive to retrospectively examine the performance of the MISO system in the final days of the Summer season, *following* the August Order. MISO issued Capacity Advisories—a step that precedes Max Gen status and the multi-step process discussed *supra* sec. IV.A.3—for each of August 27–30, based on forced generation outages in the MISO South subregion. However, MISO announced no real-time operations notifications covering MISO North/Central in that time period.[2] At no point this past summer, including in the final 11 days, did MISO come close to an actual loss of load.

In sum, there were no looming "resource adequacy problems" for the remainder of the Summer 2025 season in MISO at the time the Department issued the August Order.

2. There is No Evidence of a Resource Adequacy Crisis in Fall 2025.

MISO is also entering the Fall 2025 season having secured more than enough capacity to meet its resource needs. Specifically, in the 2025–2026 Planning Auction, the RTO exceeded its Fall 2025 procurement target (in megawatts), the

[2] MISO, Real Time Operations Notifications, https://www.misoenergy.org/markets-and-operations/notifications/real-time-operations-notifications (last visited Sept. 3, 2025).

Reserve Margin Requirement,[3] by 2.6%, meaning that MISO entered the fall season (as it did the summer) with *more* resources than its own analysis has indicated are actually needed to ensure grid reliability. Ex. 31 at 19 (MISO 2025-26 Auction Results); *see also* Ex. 59 (MISO 2025–2026 Prelim. PRA Report with Final Results). In MISO North (Zones 1–7 in Ex. 75 (MISO Tariff Zonal Map)), the offers to supply capacity also exceeded the Reserve Margin Requirement by about 4,000 MW. *Id.* By itself, this fact is sufficient evidence to conclude that MISO does not face a resource adequacy shortfall for the season.

The August Order suggests that this Fall season is part of the "year-round" risk that MISO identified as a future possibility nearly *four years ago.* Ex. 67 at 3 n.16 (August Order) (citing Ex. 77 (MISO Transmittal Letter dated Nov. 30, 2021)). However, when placed in context unexamined in the August Order, the 2021 letter comes nowhere near supporting the notion of a resource adequacy crisis this Fall. In fact, MISO actually expected to procure enough resources during non-Summer seasons to be ten times more protective than the industry standard. When MISO first introduced its new seasonal resource adequacy structure to FERC, its expert described its modeling of seasonal LOLE as follows:

> MISO proposes to round [Loss of Load Expectation] 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.

Ex. 78 at 11:12–15 (McFarlane Testimony). In other words, MISO contemplated that its Monte Carlo modeling exercise might predict that MISO experiences *less than a hundredth* of a day of lost load every year in non-Summer seasons, which is equivalent to less than a single day of lost load *every 100 years*. Nowhere in that filing did MISO express any expectation that the Fall season risk would even approach that of the Summer season anytime soon. And FERC approved this aspect of MISO's seasonal modeling (together with the remainder of MISO's seasonal capacity construct) the following year, indicating its general agreement. Ex. 79 at P 87 (MISO 2022 Accreditation Order).

In the years since that statement was made, MISO has had the chance to calculate actual seasonal risks with the benefit of additional data. The extensive quantitative analyses of resource adequacy MISO has published in the intervening

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[3] For the 2025–2026 Planning Auction, following FERC's order in Docket No. ER23-2977-000, MISO introduced for the first time a concept called the "Final PRMR" in addition to "Initial PRMR," where the latter was synonymous with the PRMR as determined for all prior Planning Resource Auctions. Public Interest Organizations here use the term "Reserve Margin Requirement" to mean Initial PRMR.

years uniformly confirm MISO's initial expectations and find no near-term material risk outside of Summer.

The clearest evidence of the absence of non-Summer risk in the MISO system comes from the most recent iterations of MISO's LOLE study. *See supra* sec. IV.A.2.i (explaining the loss of load expectation study process). All of MISO's recent LOLE simulations since it shifted to a seasonal resource adequacy construct find extremely low risk of loss of load in the Fall season, far below the industry standard risk tolerance of 1 day in 10 years. In 2023, MISO's LOLE analysis calculated that, for the MISO-wide region, there would be *zero* risk of outages in the Fall, Winter and Spring seasons; per its seasonal accreditation policy MISO manually adjusted the LOLE for these non-Summer seasons up to .01 days of LOLE/year (or 1 outage every 100 years). Ex. 80 at 33 (MISO 2023-24 LOLE Study Report); Ex. 81 at 49:15–17 (Joundi Testimony). MISO's 2024 and 2025 LOLE studies posted the same .01 LOLE (likely similarly adjusted upward) in the non-Summer seasons. Ex. 82 at 33 (MISO 2024-25 LOLE Study Report); Ex. 83 at 34 (MISO 2025-26 LOLE Study Report); *see also* Ex. 68 at 2 (Grid Strategies Sept. Report). Notably, MISO's 2025 analysis was conducted with the expectation—dating back to 2022—that Campbell would retire on May 31, 2025, at the outset of the 2025–2026 planning year. *Accord* Ex. 67 at 2 (August Order) (acknowledging that "MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts").

MISO has reached the same conclusions regarding risk in the lower peninsula of Michigan. Its zonal-specific modeling in the 2025 LOLE also posted .01 LOLE (1 event per 100 years) for this Fall and the coming Winter and Spring (which were also likely adjusted upward). Ex. 83 at 34–35 (MISO 2025-2026 LOLE Study Report) (noting that "a minimum seasonal LOLE criterion of 0.01 will be used to calculate the LRR in seasons with less than 0.01 LOLE risk under the annual case"). *Id.* Thus, there is also no basis for concern in the immediate region around Campbell.

3. There Is No Evidence of a Resource Adequacy Crisis After Fall 2025.

The MISO system is also set up to operate smoothly for years beyond the 90-day timeframe of the August Order. There is ample evidence demonstrating that this is true for the remainder of the 2025–2026 planning year that MISO has already secured; for the next couple years after that; and even out through the 2030 time horizon that the Department identifies as a long-term source of concern.

First and most directly, MISO has secured the stability of its grid through at least the end of May 2026 by operation of its 2025–2026 Planning Auction. As explained above, the auction secures in April of each year the resources necessary to ensure grid reliability individually for each of the four subsequent seasons. *See supra* sec. IV.A.2.ii. The 2025–2026 Planning Auction exceeded its target Reserve

Margin Requirements for the Winter and Spring seasons by 6.1% and 1.5% respectively, meaning that (as it did for the Summer and Fall seasons) MISO will enter those seasons with *more* resources than its own analysis has indicated are actually needed to ensure grid reliability. Ex. 31 at 5 (MISO 2025-26 Auction Results). Furthermore, as with the Fall season, MISO's modeling in conjunction with its shift to a seasonal resource adequacy construct indicated that the loss of risk in Winter and Spring (as with Fall) is very low. Ex. 81 at 49:15–17 (Joundi Testimony); *see also* Ex. 82 at 33 (MISO 2024-25 LOLE Study Report); Ex. 83 at 34 (MISO 2025-26 LOLE Study Report). Thus, there is no basis for any resource adequacy concern for either the Winter or Spring seasons. And of course, all of this is recently confirmed by MISO itself, which has noted that "MISO's 2025–2026 Planning Resource Auction indicated adequate resources to meet anticipated demand." Ex. 117 (RTO Insider Article on August Order).

Second, although MISO has not yet conducted its 2026–2027 Planning Auction (or the auctions for subsequent years), there is not a single projection that indicates the possibility of a regional resource adequacy shortfall through May 2027. MISO's joint annual survey with the Organization of MISO States ("OMS"), which forecasts generation capacity supply and system load (the "OMS-MISO Survey"), evaluates a range of potential outcomes years into the future, using a set of assumptions ranging from extremely conservative to a match of utility projections. *See infra* sec. V.A.2.ii. The most recent edition of that survey, completed June 2025, predicts a *surplus* of between 1.4 and 6.6 gigawatts ("GW") for Planning Year 2026–2027 (*i.e.*, June 2026–May 2027), and its projection range for Planning Year 2027–2028 ranges from a surplus of 6.4 GWs to a small deficit of 1.4 GWs. Ex. 89 at 7 (2025 OMS-MISO Survey). In other words, the survey provides no basis for any concern about MISO's ability to meet resource adequacy needs through at least May 2027. And a series of unlikely events would have to occur for the region to see even a minor (1–2 GW) deficit through May 2028, as further explained below. MISO's system is robust, and even without significant intervention (also discussed below), it was on track as of early June 2025 to ensure that its grid remains robust for approximately the next three years. And this is also true in the local region where Campbell is located: 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 (2028/2029 Michigan Commission Staff Capacity Demonstration Results).

Third, although MISO has spoken publicly about its long-term resource adequacy concerns heading into Summer 2028 and beyond, those concerns remain extremely remediable through policy measures and other strategies to ensure any projected shortfall is addressed before it becomes a meaningful problem. And MISO is not standing still in this regard: as MISO has explained:

> "State regulators along with utilities have the responsibility of ensuring resource adequacy. MISO remains focused on reliably operating the grid

> using the resources our members provide, while working closely with stakeholders and regulatory partners, providing visibility into system needs and sending market signals to inform long-term resource planning."

Ex. 117 at 3 (RTO Insider Article on August Order). Generally speaking, from FERC down to stakeholders everyone working regularly in the energy regulatory world recognizes that the industry is dynamic, and everyone is engaging to ensure there are adequate resources going forward. Just three months ago, FERC hosted a technical conference where MISO, the market monitor, and other contributors highlighted that the system is in good shape today, and outlined plans to ensure that remains the case down the road. *See, e.g.*, Ex. 35 at 1 (Patton MISO Comments) ("The resource adequacy challenges and risks in MISO are not nearly daunting as portrayed by MISO planning reports or the NERC 2024 Long-Term Reliability Assessment."); *see also* Ex. 62 at 13 (FERC Technical Conference Notice).

In fact, MISO has already taken tangible steps to address what it perceived to be a potential for resource adequacy shortfalls down the road: it developed, and secured FERC approval for, an Expedited Resource Addition Study (ERAS) pathway for generator interconnection. *See generally* Ex. 90 at 1 (MISO ERAS Transmittal Letter); Ex. 91 at P 1 (MISO ERAS Decision). The ERAS proceeding demonstrates how effectively the system already works: in response to somewhat conjectural resource adequacy shortfall projections, MISO launched an entirely new interconnection process that is currently underway and even at just over two-thirds full is projected to add over 26.5 GW of new capacity to the system, most of which will be provided by gas plants. Ex. 109 at 1 (MISO ERAS News Release). That 26.5 GW of nameplate capacity by itself would more than cover the OMS-MISO Survey's maximum projected needs under the most conservative assumptions. (The survey did not account for ERAS projects because it predated FERC's approval of ERAS.) Thus, MISO does not simply have a plan to address the possibility of shortfalls three-plus years down the road: a key pillar of its plan is already underway.

C. Campbell Should Retire ASAP.

1. Campbell Is a Power Plant in Michigan Originally Built in 1962.

Campbell is a power plant originally commissioned in 1962. It is located in West Olive, Michigan, 30 miles west of Grand Rapids and alongside Lake Michigan.

Source: Google Maps.

Campbell 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).


Source: Garrett Ellison, *Consumers Energy Agrees to Retire Full Campbell Plant, End Coal by 2025* (Apr. 20, 2022), https://www.mlive.com/public-interest/2022/04/consumers-energy-agrees-to-retire-full-campbell-plant-end-coal-by-2025.html.

2. *Consumers Energy, an Investor-Owned Utility in Michigan, Is Campbell's Majority Owner.*

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. It is a wholly owned subsidiary of CMS Energy Corp., a publicly traded corporation. *See* Ex. 73 at 16 (Consumers' July 2025 10-Q).

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.

Consumers wholly owns Campbell Units 1 and 2. Ex. 73 at 5 (Consumers' July 2025 10-Q). 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).

3. *Campbell Is Old, Unreliable, Inflexible, Dirty, and Expensive.*

   i. *Campbell Is Old and Unreliable.*

Campbell Units 1 and 2 are beyond the typical operational life of coal units, Ex. 3 at 15 (Powers June 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 Bill Powers 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. (For reference, there are 8,760 hours in a year.)

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"[4]). *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.*

New data from EPA indicates that Campbell has continued to operate unreliably since the Department issued its May Order. As explained in an updated declaration from Mr. Powers, both Campbell Units 1 and 2 experienced long outages in June 2025, the first full calendar month of operation under the May Order. Ex. 69 at 5

[4] Consumers Energy typically uses the phrase "random outage rate" in place of "forced outage rate."

(Powers Sept. Decl.). Unit 1 experienced an outage on June 23 and remained offline the rest of the month. *Id.* (citing Ex. 102 (CAMPD Campbell Daily Emissions Data)). Unit 2 produced power on *only four* of 30 days in June. *Id.* (citing Ex. 102 (CAMPD Campbell Daily Emissions Data)). The unit originally was "out of service" due to repairs and maintenance work on May 23 through June 25 and went offline again due to a "water intake issue" starting on July 4. *Id.* 5–6 (citing Ex. 101 at Question 4 (Consumers June Responses to AG) and Ex. 103 (July 17 Email from Consumers to EGLE)). Ultimately, Unit 2 produced more than nominal amounts of power on *only three* days total in June—June 28, 29, and 30—and, even then, operated at approximately 50 percent of its rated capacity. *Id.* at 5 (citing Ex. 102 (CAMPD Campbell Daily Emissions Data)). In short, "Units 1 and 2 demonstrated they [could not] stay online continuously in June 2025 and that they [had to] stop and start, with long outages between stops, due to their unreliable condition." *Id.* at 7.

This pattern of unreliable operations is unsurprising considering Consumers significantly decreased capital expenditures and maintenance in Campbell since the 2022 settlement. As Mr. Powers detailed in his June declaration and reiterates in his September declaration, Consumers transitioned from a preventative approach to a "fix it if it breaks" approach at Campbell in recent years. *Id.* at 4; Ex. 3 at 15–17 (Power June Decl.). Consumers' filings with the Michigan Commission show that the company reduced its capital spending by approximately 91 percent across Campbell Units 1, 2, and 3 compared to the amount the company projected to spend if Units 1 and 2 had continued operating until 2031 and Unit 3 until 2039. Ex. 69 at 3 (Powers Sept. Decl.); Ex. 3 at 5–6 (Powers June Decl.) (citing Consumers' filings with the Michigan Commission); *see also* Ex. 101 at Question 1 (Consumers June Responses to AG) (stating that Consumers "has not recorded any capital expenditures at the Campbell plant in the two-year period prior to May 31, 2025"). Likewise, Consumers reduced its major maintenance spending by approximately 62 to 78 percent across Units 1, 2, and 3 compared to the amount the company projected to spend if Units 1 and 2 had operated until 2031 and Unit 3 until 2039. Ex. 69 at 3 (Powers Sept. Decl.); Ex. 3 at 5–6 (Powers June Decl.) (citing Consumers' filings with the Michigan Commission). All told, Consumers cancelled $161 million in planned capital and major maintenance projects at Campbell in recent years. Ex. 69 at 7 (Powers Sept. Decl.). As a result, "it is unlikely Campbell can be depended upon to operate reliably." *Id.*

ii. Campbell Is Inflexible.

On top of Campbell's reliability problems, the plant also takes significant time to start up from a cold condition, as shown in the following table.

Unit 1	**Unit 2**	**Unit 3**
24 hours	36 hours	72 hours

Id. at 6; *see also* Ex. 101 at Question 5 (Consumers June Responses to AG). These startup times are very long, even for coal units. Ex. 69 at 6 (Powers Sept. Decl.); *see* Ex. 118 (RMI Analysis of Coal Plants' Threats to Reliability) (stating that the average coal plant takes 12 hours to reach max capacity from a cold start); Ex. 55 (IEA Flexibility Report) (similar). Even if Campbell could provide power reliably—and it cannot—the units' long start times mean the plant is ill-suited to provide peaking power during periods of high demand. Ex. 69 at 6 (Powers Sept. Decl.). In other words, Campbell's inflexibility makes it unsuitable for providing power during precisely the kind of periods the plant is supposed to be operating pursuant to the August Order.

iii. Campbell Is Dirty.

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. Envtl. Prot. Agency ("EPA"), ECHO, https://echo.epa.gov/air-pollutant-report?fid=110000411108 (last visited Sept. 3, 2025); *see also* EPA, eGRID, https://www.epa.gov/egrid/egrid-pm25 (Jan. 15, 2025). In fact, Campbell 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 June Decl.) (*citing* Ex. 48 (2021 CWA Permit)). In 2023, for example, the plant discharged approximately 96,000 pounds of pollution into Lake Michigan, including 10,000 pounds of toxic metals. EPA, ECHO, https://echo.epa.gov/detailed-facility-report?fid=110000411108 (last visited Sept. 3, 2025). Additionally, burning coal at Campbell 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 Coal Ash Inspection Report).

Recent information shows that Campbell continues to be a significant source of pollution. In just one month (June 2025) of operation pursuant to the May Order, Campbell emitted approximately 694,696 pounds of sulfur dioxide, 483,868 pounds of nitrogen oxides, and 1,453,247,200 pounds of carbon dioxide. Ex. 69 at 11 (Powers Sept. Decl.) (citing Ex. 102 (CAMPD Campbell Daily Emissions Data)). Between June 1 and July 31, Campbell also withdrew approximately 40 billion gallons of water from Lake Michigan and discharged approximately the same amount back into the lake. *Id.* (citing Campbell's discharge monitoring reports).

Campbell's air pollution harms its neighbors. When nitrogen oxide and sulfur dioxide are emitted into the air, they can irritate the lungs and harm respiratory systems. *Id.* at 11; *see also* EPA, *Basic Information about NO2*, https://www.epa.gov/no2-pollution/basic-information-about-no2 (last visited Sept. 3, 2025); EPA, *Sulfur Dioxide Basics*, https://www.epa.gov/so2-pollution/sulfur-dioxide-basics (last visited Sept. 3, 2025). Nitrogen oxide is also a precursor to ozone formation, and sulfur dioxide contributes to the formation of acid rain. *Id*. Particulate matter emissions can cause serious health problems when inhaled, and can also contribute to haze that impacts visibility. EPA, *Particulate Matter (PM) Basics*, https://www.epa.gov/pm-pollution/particulate-matter-pm-basics (last visited Sept. 3, 2025). Emissions of volatile organic compounds also harm human health and air quality. EPA, *Volatile Organic Compounds' Impact on Indoor Air Quality*, https://www.epa.gov/indoor-air-quality-iaq/volatile-organic-compounds-impact-indoor-air-quality (last visited Sept. 3, 2025). 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 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.

Campbell's water usage and pollution also causes harm. For example, coal plants' withdrawal and discharge of water—like the 40 billion gallons from Lake Michigan Campbell used and discharged in June through July—can harm marine life. Ex. 69 at 11 (Powers Sept. Decl.). Marine animals can be caught up and cycled through water circulation pumps at the point of water intake and subjected to much higher water temperatures at the point discharge. *Id*.

Campbell's pollution adds to and exacerbates significant other burdens on nearby communities. 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 the tract 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 Sept. 3, 2025); *see also* Mich. Dep't of Env't, Great Lakes, and Energy, MiEJScreen Factsheet, https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OEJPA/MiEJScreen/MiEJScreen-Factsheet.pdf (last visited Sept. 3, 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.*

As Public Interest Organizations' expert engineer concludes based on his review of the new air emission and water discharge data from June and July: "In my professional opinion, and based on my 40 years of experience in coal boiler air emissions assessment and utility resource planning . . . the [] emissions and discharge data show substantial and unnecessary environmental impact caused by operation of Campbell when lower-emitting, lower cost alternatives are available." Ex. 69 at 12 (Powers Sept. Decl.).

iv. Campbell Is Expensive.

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 2021. 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).

As Public Interest Organizations' expert analyst Michael Goggins explains, the available data demonstrates that Campbell "operated at an overall loss even during a high-demand summer period that included the June 23 event." Ex. 68 at 6 (Grid Strategies Sept. Report). And there is good reason to believe this will continue; looking to Campbell's recent operating costs, Mr. Goggins determines,

> 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. Thus, in 79% of hours, Campbell could not earn enough to cover its operational costs.

Id. (footnote omitted).

Consumers Energy recently reported on part of the tremendous economic burden caused by Campbell's operation under the May Order. In just first five weeks of operations under that Order (from May 23 through June 30, 2025), Consumers' "net financial impact of complying with the order was $29 million." Ex. 73 at 62 (Consumers' July 2025 10-Q); *see* Consumers Energy Co., FERC Form 3-Q Quarterly Financial Report at 120–21 (Aug. 14, 2025), Accession No. 20250814-8001, https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250814-8001&optimized=false&sid=1e90ede4-da17-4482-8e6d-e346192d0609 [hereinafter [Consumers' FERC 3-Q"] (same). Consumers further makes clear that, for this amount, "recovery will be sought through FERC in a subsequent proceeding after a modification to the MISO Tariff is established." Ex. 73 at 62 (Consumers' July 2025 10-Q); Consumers' FERC 3-Q at 120–21. And as Consumers has explained: "For the avoidance of doubt, Consumers Energy only seeks to recover its Order Costs net of market revenues earned from the Campbell Plant's operation." *Consumers Energy v. Midwestern Independent Sys. Operator, Inc.*, Complaint Requesting Fast Track Processing, FERC Docket No. EL25-90, at 13 (June 6, 2025), Accession No. 20250606-5231; *accord id.* at 2 & 2 n.7, 4–6, 12, 17, 20, 22. As such, there is good reason to believe that the $29,000,000 "net financial impact" reflects Consumers' costs caused by the Department's order *after* accounting for any revenues the utility earned.

The bills for the Department's Campbell orders are set to hit ratepayers across eleven states in the MISO footprint. *Consumers Energy Co. v. Midcontinent Indep. Sys. Op., Inc.*, 192 FERC ¶ 61,158, at PP 39–40 (2025); *see also* Ex. 16 at 2 (DOE Letter to FERC) (stating that the Department is referring to FERC the rate issues relating to the May Order).

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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.

4. *Campbell's May 31, 2025 Retirement Has Been Carefully Planned and Well Executed to Ensure Resource Adequacy.*

   i. *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 Campbell 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 Public Service 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, the Ecology Center, the Union of Concerned Scientists, 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%, raised concerns about resource adequacy. The Michigan Public Power Agency, the other joint owner of Unit 3, 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).

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).

ii. MISO Approved Campbell's May 31, 2025 Retirement Upon Finding No Local 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 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 (MISO Tariff Section 38.2.7).

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.

iii. 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 June Decl.). Public Interest Organizations' expert engineer Bill Powers provides the following summary of the significant decline in capital expenditures 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 capital expenditures, 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 *supra* sec. IV.C.3.i, the Campbell units have demonstrated their inability to consistently perform in recent years and even during June 2025, including on the very day—June 23—highlighted in the August Order as justification for the order. This unreliability reflects the impact of worn and difficult-to-repair or replace components, causing outages that tended to be long and recurrent. Ex. 69 at 2–8 (Powers Sept. Decl.); Ex. 3 at 4 (Powers June 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 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).

iv. 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, Consumers had surplus resources. Ex. 27 at PDF 14 (Consumers 2028/2029 Capacity Demonstration). Consumers has sufficient resources for the Fall and Winter 2025 seasons too. *Id.* at PDF 26–27, 38–39. 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 (2028/2029 Michigan Commission Staff Capacity Demonstration Results). 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.*

D. The Department Persists in Preventing Campbell's Retirement Through Another Unneeded, Expensive, and Harmful Misstep.

In its May 23, 2025 order, the Department mandates that MISO and Consumers "take all measures necessary to ensure that" Campbell "is available to operate" and directs 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 (May Order). The Department's August 20, 2025 order mandates "continued additional dispatch of the Campbell Plant." Ex. 67 at 7 (August Order). In doing so, the Department largely ignores all of the foregoing, much of which was provided to the Department by the Public Interest Organizations' request for reconsideration of the May Order. *See* Ex. 71 at *passim* (Public Interest Organizations' June Rehearing Request); Ex. 72 (Department's July Notice).

The Department's August Order mandates Consumers and MISO take the same steps as the May Order. As before, the entities are directed to "take all measures necessary to ensure that the Campbell Plant is available to operate" and "take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers." Ex. 67 at 8 (August Order). The August Order serves to renew the May Order, resting in large part on the claim that "the emergency conditions that led to issuance of [the May Order] continue," and (like the May Order) asserting as its main predicate 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." *Id.* at 1 (August Order); *see* Ex. 1 at 1

(May Order) (claiming a shortage of facilities for the generation of "electric energy" instead of "electricity"). The August Order, like the May Order, does not explain the location of those "portions of the Midwest region."

In addition to asserting that the claimed emergency underlying the May Order continues, the August Order sets its horizon to both "the near and long term." Ex. 67 at 2 (August Order). The August Order points to, among other things, portions of: (1) past conditions on the MISO grid during Summer 2025; (2) past weather forecasts; (3) changes to the MISO capacity market to procure capacity on a seasonal rather than annual basis; (4) an assortment of MISO planning documents; (5) two executive orders; and (6) a July 7 report from the Department. *See id.* at 2–7.

At bottom, the August Order selectively cites projections of retiring generation capacity and projections of increasing electricity demand and expresses the Department's dissatisfaction with the steps taken by the Michigan and MISO to meet those projections. It deems that dissatisfaction an "emergency," and on that basis replaces the resource-planning regime currently being implemented by the state and RTO with a command-and-control generation mandate. That commandeering of state authority and private economic choices takes place against a backdrop of a larger effort by the current Presidential Administration to favor the fossil-fuel industry at the expense of cleaner, cheaper, and more modern competitors—an effort that has ranged from asserting that the modernization of the American electric grid is an "emergency," Exec. Order 14156 of Jan. 20, 2025, *Declaring a National Energy Emergency*, 90 Fed. Reg. 8,433, 8,433 (Jan. 29, 2025) (Energy Emergency EO), to declaring national policy to utilize particular types of generators, Exec. Order 14262 of Apr. 8, 2025, *Strengthening the Reliability and Security of the U.S. Electric Grid*, 90 Fed. Reg. 15,521, 15,521 (Apr. 14, 2025) (Grid EO), to seeking regulatory means to hinder the growth of cheaper alternatives, Exec. Order of Apr. 8, 2025, *Reinvigorating America's Beautiful Clean Coal Industry and Amending Exec. Order 14241*, 90 Fed. Reg. 15,517, 15,517 (Apr. 14, 2025), to attempting to transgress state energy authority, Exec. Order 14260 of Apr. 8, 2025, *Protecting American Energy from State Overreach*, 90 Fed. Reg. 15,513, 15,513 (Apr. 14, 2025). The May and August Orders—like the Administration's broader campaign to force continued use of economically non-competitive fossil fuels—are unnecessarily and unlawfully increasing ratepayer burdens across MISO, and subjecting nearby residents to continued, and devastating, pollution.

V. REQUEST FOR REHEARING

The August Order is a manifestation of the Department's overarching policy to systematically misapply Section 202(c) of the Federal Power Act to preserve fossil-fueled power plants that otherwise would be retired. That policy aims to bolster the fossil energy industry, irrespective of need, expense, and harm. In its zeal to implement its policy through issuance of the August Order, (1) the Department has exceeded the authority Congress gave it, using its "emergency" powers in the absence of any real shortfall to impose federal control of basic generation and supply decisions; and (2) the Department has done so without reasoned decision-making and on the basis of facts that are not, and could not be, supported by any credible record. *See Allentown Mack Sales & Serv., Inc. v. Nat'l Labor Rel. Bd.*, 522 U.S. 359, 374 (1998) (explaining agency obligation to undertake reasoned-decision-making); *Motor Vehicle Mfrs. Assn. of United States, Inc. v. State Farm Mut. Automobile Ins. Co.,* 429 U.S. 29, 43 (1983) *same); *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962) ("The agency must make findings that support its decision, and those findings must be supported by substantial evidence."); *Butte Cnty. v. Hogen*, 613 F.3d 190, 194 (D.C. Cir. 2010) ("[A]n agency cannot ignore evidence contradicting its position."); *Michigan v. EPA*, 268 F.3d 1075, 1081 (D.C. Cir. 2001) (explaining that, absent statutory authorization, an agency's action is contrary to law). Numerous examples of the Department's APA violations are described throughout section V. The only plausible explanation for these repeated legal foot faults is that the Department has prioritized implementing its policy over compliance with law.

Congress never conferred on the Department the broad authority over the country's mix of power generation resources that the Department seeks to wield under the pretense of responding to claimed "emergencies." To the contrary, as explained below, Congress explicitly reserved authority over resource adequacy and grid reliability to the states, FERC, and NERC. *See, e.g.*, 16 U.S.C. §§ 824(a)–(b), 824o; *Pac. Gas & Elec.*, 461 U. S. at 205. Both the policy and the August Order exceed the Department's authority and are therefore contrary to law.

Before tackling the August Order's legal faults and issues, *see infra* secs. V.A through V.D, it is useful to understand the broader context of the Department's policy. The Department acknowledges that its Order is based on a government-wide policy—dictated by Executive Order—of promoting fossil-based energy through the use of any and all emergency powers executive departments and agencies could find. Ex. 67 at 6 (August Order). The August Order relies upon the Energy Emergency EO, 90 Fed. Reg. 8,433, which directs the heads of all executive departments and agencies to use "emergency authorities" and "other lawful authorities" to facilitate the production, extraction, creation, and generation of coal and other fossil fuels. *Id.* (relying on Ex. 92 (Energy Emergency EO)).

The August Order also relies on another executive order, the Grid EO. *Id.* (relying on Ex. 93 (Grid EO)). The Grid EO was issued at the same time as three other executive actions aimed at supporting the coal industry, and was announced at a White House political event focused on promoting coal. Ex. 94 (NY Times Coal Article). In essence, the Grid EO calls on the Department to assume the authority for resource adequacy and grid reliability decision-making that the Federal Power Act reserves to others, and to "systemize" the issuance of Section 202(c) orders for that improper purpose. *See* Ex. 93, 90 Fed. Reg. at 15,521–22 (Grid EO) (directing the Department to "streamline, systemize and expedite" the issuance of Section 202(c) orders; to develop a "uniform methodology" for assessing reserve margins and a protocol to retain generators the Secretary deems critical to system reliability; and to prevent certain generators from leaving the bulk-power system or converting to a different fuel source).

The Department's words and actions following issuance of the Grid EO reveal its efforts to unlawfully arrogate for itself others' lawful authority through systematic misapplication of Section 202(c) to prop up fossil-burning power plants. The Department's initial steps included issuing a Section 202(c) order to prevent Campbell's well-planned retirement. *See* Ex. 1 at *passim* (May Order). The Department's order was clear on one point—Campbell cannot be allowed to retire—but left many scratching their heads about almost everything else in the order. *See, e.g.*, *Consumers Energy Co. v. Midcontinent Indep. Sys. Op., Inc.*, 192 FERC ¶ 61,158, at PP 39–40 (2025) (recognizing the variety of interpretations of the order and settling on "the most reasonable reading of the DOE Order's intended scope"). The May Order failed to make clear even where the grid supposedly needs Campbell, much less examine the sources the Department selectively quoted or heed Congress' explicit limitations on the Department's Section 202(c) powers. Ex. 71 at *passim* (Public Interest Organizations' June Rehearing Request).

After preventing Campbell's retirement, the Department continued to act on its policy. It issued another Section 202(c) order to prevent another fossil-burning plant's retirement. Ex. 95 (Eddystone May Order). Then, on July 7, 2025, the Department published the "methodology" required by the Grid EO, which the Department explained will "guide reliability interventions," including the use of Section 202(c) orders. Ex. 96 at vi (July Resource Adequacy Report); *see also* Ex. 97 (DOE July 7 Press Release) ("The methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act."). The report identifies no present or imminent emergency; at most, using deeply flawed methodology, it identifies a theoretical shortfall of generation in 2030. *See infra* sec. V.A.2.ii.c.

The Department has now extended both the Campbell and Eddystone emergency orders for another 90 days. Ex. 67 at *passim* (August Order); Ex. 98 (Eddystone August Order). Similar to the July Resource Adequacy Report on which it relies, the

August Order focuses on a longer term, purely theoretical resource adequacy shortfall and lacks evidentiary support for its emergency finding.

Taken together, the Energy Emergency EO, Grid EO, July Resource Adequacy Report, and the Department's recent Section 202(c) orders reflect a policy to promote the long-term preservation of fossil-powered electric generation by using the Department's emergency authority under Section 202(c). To the extent these actions left any room for doubt that the Department has such a policy, Energy Secretary Wright's own words have removed it. In a recent visit to Morgantown, West Virginia, Secretary Wright said he intends to stop the closure of up to forty coal plants slated to retire this year and has the authority to do so. *See* Ex. 76 (Secretary Wright's West Virginia Remarks).

A. *The Department Has Not Demonstrated, and Cannot Demonstrate, an Emergency Permitting the Department to Control Generation Under Section 202(c).*

1. *Legal Framework: Section 202(c) Empowers the Department Only to Respond to Imminent, Certain, and Unexpected Shortfalls in Electricity Supply.*

The Order invokes Section 202(c) of the Federal Power Act, which provides:

> During the continuance of any war in which the United States is engaged, or whenever the Commission 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 of transmission of electric energy . . . the Commission shall have authority . . . with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, deliver, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.

16 U.S.C. § 824a(c)(1). That authority was transferred to the Department by the Department of Energy Organization Act. *See* 42 U.S.C. § 7151(b).

Section 202(c)'s text and context establish that an "emergency" enabling the Department to over-ride state and private decision-making must be an event that is imminent, certain, and unexpected. 16 U.S.C. § 824a(c). The constrained scope of Section 202(c)'s emergency authority is confirmed by the broader statutory context—in particular, the separate regime delineating federal authority over bulk-system reliability in Section 215 of the Federal Power Act, *id.* § 824o—as well the Department's regulations, caselaw applying Section 202(c), and the Department's consistent past practice.

i. The Text and Context of Section 202(c) Confine an Emergency to Imminent, Certain, and Unexpected Events

Section 202(c)'s text empowers the Department to require generation only in an "emergency." *Id.* § 824a(c). Both the ordinary meaning of the term (which the statute does not expressly define) and statutory context limit the Department's emergency authority to imminent, unexpected, and certain events. At the time Congress enacted Section 202(c), Webster's New International Dictionary of the English Language (1930) defined "emergency" as, with emphasis added here, a "*sudden* or *unexpected* appearance or occurrence… An *unforeseen* occurrence or combination of circumstances which calls for *immediate* action or remedy; *pressing* necessity; exigency." Contemporary dictionaries similarly define "emergency" as demanding imminence: an emergency is "an *unforeseen* combination of circumstances or the resulting state that calls for *immediate* action." Merriam Webster's Dictionary 407 (11th ed. 2009) (emphasis added); *see* 3 Oxford English Dictionary 119 (1st ed. 1913) (defining emergency similarly as "a state of things *unexpectedly* arising, and urgently demanding *immediate* action" (emphasis added)); *see also* 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").

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 Power & 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").

The text's use of the present tense accentuates its focus on imminent and certain shortfalls: It empowers the Department to act only where "an emergency *exists*." 16 U.S.C. § 824a(c) (emphasis added). The Section's title and text both emphasize that it provides a "temporary" authority, further emphasizing that its emphasis on immediate—not far-distant—needs. *Id.* § 824a(c), (c)(1); *see Dubin v. United States*, 599 U.S. 110, 120–21 (2023) (cleaned up) ("The title of a statute and the heading of a section are tools available" to resolve "the meaning of a statute," and "a title is especially valuable where it reinforces what the text's nouns and verbs independently suggest."). That near-term focus precludes use of Section 202(c) to pursue broader or long-term energy-policy goals, such as "fear of overdependence" on foreign oil supplies, *Richmond Power & Light*, 574 F.2d at 617, or "energy independence," Ex. 96 at 1 (July Resource Adequacy Report); *see also Richmond Power & Light*, 574 F.2d at 614 (Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply and not those in which supply is adequate but a means of fueling its production is in disfavor.").

Section 202's overall structure further highlights Section 202(c)'s emphasis on imminent, near-term concerns. The preceding subsections 202(a) and (b) together define and limit the tools by which the federal government may pursue "abundant" energy supplies in the normal course. 16 U.S.C. § 824a(a) (seeking "abundant supply of electric energy" by directing the federal government to "divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy"); *id.* § 824a(b) (allowing federal government to order "physical connection . . . to sell energy to or exchange energy" upon application, and after an opportunity for hearing). The resulting statutory "machinery for the promotion of the coordination of electric facilities" comprises the following: in subsection (a), an instruction to establish a general framework meant to facilitate "coordination by voluntary action;" in subsection (b), "limited authority to compel interstate utilities to connect their lines and sell or exchange energy," subject to defined procedural and substantive requirements, when "interconnection cannot be secured by voluntary action;" and in subsection (c), "much broader" but "temporary" authority "to compel the connection of facilities and the generation, delivery, or interchange of energy during times of war or other emergency." S. Rep. No. 74-651 at 49 (1935).

That tiered structure—placing primary emphasis on voluntary resource adequacy planning, 16 U.S.C. § 824a(a), specifying limited authority where that voluntary system fails, *id.* § 824a(b), and allowing for "temporary" central command-and-control only in case of "emergency," *id.* § 824a(c)—requires that Section 202(c) remain narrowly bounded to instances of an immediate and unavoidable "break-down in electric supply," S. Rep. No. 74-651 at 49 (1935), rather than mere want of more abundant supply in the future, *cf.* Ex. 67 at 7 (August Order) (emphasis added) (pointing to conditions offered in support for the May Order that "will continue in the near term" and "*likely* to continue in *subsequent years*" that "*could* lead to the *potential* loss of power . . . in the areas that *may* be affected by curtailments or outages, presenting a *risk* to public health and safety"). That structure authorizes increasingly intrusive federal intervention, but under increasingly narrow circumstances. Interpreting Section 202(c)'s "emergency" powers to permit the Department to compel generation based merely on generalized "challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape," or concerns over "potential longer term resource adequacy," Ex. 67 at 4 (August Order), would unwind the careful balance of voluntary, market-driven action and federal power set out in Sections 202(a) and 202(b). Such an interpretation cannot be squared with the statutory text and structure. *See Otter Tail Power Co. v. Fed. Power Comm'n*, 429 F.2d 232, 233–34 (8th Cir. 1970) (holding that Section 202(c) "enables the Commission to react to a war or national disaster," while Section 202(b) "applies to a crisis which is likely to develop in the foreseeable future").

ii. Congress' Enactment of a Specific, Cabined Scheme to Address Reliability Concerns Confirms That Generalized or Long-Term Bulk-Power System Reliability Concerns Are Not an "Emergency" Under Section 202(c).

That the Department's Section 202(c) emergency powers do not extend to general supervision of bulk-power-system reliability is confirmed by Section 215 of the Federal Power Act—which specifically and directly delineates the scope of federal authority to enforce mandatory reliability requirements for the bulk-power system. 16 U.S.C. § 824o. Congress added Section 215 to the Federal Power Act in 2005 precisely because the Act as it then existed—including Section 202—did not provide the federal government with the power to enforce measures designed to ensure bulk-system reliability. *See Rules Concerning Certification of the Elec. Reliab. Org.; and Procedures for the Establishment, Approval, and Enforcement of Elec. Reliab. Standards*, 70 Fed. Reg. 53,117, 53,118 (Sept. 7, 2005) ("In 2001, President Bush proposed making electric Reliability Standards mandatory and enforceable," leading to enactment of Section 215 in 2005); *Report of the Nat'l Energy Pol'y Dev. Grp.* at page 7-6 (May 2001), https://www.nrc.gov/docs/ml0428/ml042800056.pdf (noting that "[r]egional shortages of generating capacity and transmission constraints combine to reduce the overall reliability of electric supply in the country" and that "one factor limiting reliability is the lack of enforceable reliability standards" because "the reliability of the U.S. transmission grid has depended entirely on *voluntary* compliance," and then recommending "legislation providing for enforcement" of reliability standards (emphasis added)); S. Rep. No. 109-78 at 48 (2005) (stating that Section 215 "changes our current voluntary rules system" for bulk-system reliability "to a mandatory rules system"); *see also 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").

By enacting Section 215, Congress provided a comprehensive and carefully circumscribed scheme to empower the federal government to enforce bulk-system reliability requirements. That statutory scheme strikes a careful balance between state and federal authority, and between private, market-driven decisions and top-down control. Reliability standards are devised by NERC independent "of the users and owners and operators of the bulk-power system" but with "fair stakeholder representation." 16 U.S.C. § 824o(c)–(d); *see also id.* § 824o(a)(3) (defining reliability standards as "a requirement . . . to provide for reliable operation of the bulk-power system"). FERC may approve or remand those standards (but not replace them with its own) and is required to "give due weight" to NERC's "technical expertise" while independently assessing effects on "competition." *Id.* § 824o(d)(2)–(4). Section 215 provides specified enforcement mechanisms and procedures for reliability standards—which mechanisms conspicuously exclude the power to command specific generation resources to remain operational. *Id.* § 824o(e). And Section 215 carefully preserves state authority over "the construction of additional generation" and in-state resource adequacy, establishing regional advisory boards to ensure appropriate state input on the administration of reliability standards. *Id.* § 824o(i)–(j).

Interpreting Section 202(c) to permit the Department to mandate generation based on its own unfettered assessment of bulk-system reliability needs would effectively allow the Department to bypass Section 215's procedural safeguards, constraints on federal authority, and protection of state power. Such a bypass would impermissibly "contradict Congress' clear intent as expressed in its more recent," reliability-specific legislation, enacted "with the clear understanding" that the Department had "no authority" to address long-term reliability through Section 202(c). *See FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 142 & 149 (2000); s*ee also Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 401–02 (D.C. Cir. 2004) ("Congress's specific and limited enumeration of [agency] power" over a particular matter in one Section of the Federal Power Act "is strong evidence that [a separate Section] confers no such authority on [agency]."). Congress has, in Section 215, directly established the mechanisms (and limitations) by which the federal government may compel action to ensure the reliability of bulk-power electric system. In so doing, it has confirmed that the Department may not, through Section 202(c) "emergency" orders, use those reliability concerns to mandate the generation it views as required to address broad "resource adequacy problems," Ex. 67 at 4 (August Order); its emergency authority is confined to specific and imminent supply shortfalls requiring immediate response.

iii. The Department's Regulations Similarly Establish that Section 202(c) Emergency Authority Can Only Be Invoked to Address Imminent, Certain Supply Shortfalls Requiring Immediate Response.

The Department's regulations demonstrate its own long-standing understanding that Section 202(c)'s emergency authority is confined to imminent, certain and unavoidable resource shortages, and does not provide a mechanism to address broad, long-term concerns as to the reliability of the bulk-power system. The regulations recognize that an emergency under Section 202(c) requires, first, "a *specific* inadequate power supply situation." 10 C.F.R. § 205.371 (emphasis added). The Department's non-specific dissatisfaction with regional power planning does not, consequently, empower the Department to override that planning by emergency order. The need for both specificity and certainty is repeated in the Department's regulations defining an inadequate energy supply: "A system may be considered to have" inadequate supply when "the projected energy deficiency . . .

will cause the applicant [for a 202(c) Order] to be unable to meet its normal peak load requirements based upon use of all of its otherwise available resources so that it *is* unable to supply adequate electric service to its customers." 10 C.F.R. § 205.375 (emphasis added). The same provision suggests that an emergency will generally exist only when "the projected energy deficiency . . . without emergency action by the [Department], will equal or exceed 10 percent of the applicant's then normal daily net energy for load." *Id.*

The regulations further recognize that Section 202(c) does not provide a means of planning against months-off expectations or risks. They define an emergency as "an *unexpected* inadequate supply of electric energy which may result from the *unexpected* outage or breakdown" of generating, transmission, or distribution facilities—not a tool to ensure future energy abundance, or override state and private planning that the Department deems inadequate. 10 C.F.R. § 205.371 (emphasis added). Emergencies are characterized by shortages produced by "weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent." *Id*. Where the culprit is increased demand, it must be "a *sudden* increase in customer demand," *id.* (emphasis added), rather than demand projections producing non-immediate reliability concerns.

And while the regulations suggest that "inadequate planning or the failure to construct necessary facilities can result in an emergency," they recognize that the Department may not utilize a "continuing emergency order" to mandate long-term system planning. *Id.* The regulations also recognize that "where a shortage of electricity is projected due solely to the failure of parties to agree to terms, conditions, or other economic factors" there is no emergency "unless the inability to supply electric service is *imminent*." *Id.* (emphasis added). An emergency may exist where past planning failures produce an immediate, present-tense shortfall (that is where, a shortfall *results* from insufficient planning); the Department has no authority to commandeer bulk-system reliability planning merely because it deems current plans inadequate. *See* 10 C.F.R. § 205.375 (requiring present inability to meet demand to demonstrate inadequate energy supply). As the Department stated when it promulgated those regulations, the statute allows the Department to provide "assistance [to a utility] during a period of unexpected inadequate supply of electricity," but does not empower it to "solve long-term problems." *Emergency Interconnection of Elec. Facilities and the Transfer of Elec. to Alleviate an Emergency Shortage of Elec. Power,* 46 Fed. Reg. 39,984, 39,985–86 (Aug. 6, 1981).

iv. Courts Have Uniformly Held that Section 202(c) Can Be Invoked Only in Immediate Crises.

Caselaw applying Section 202(c) further supports the narrow circumstances under which it permits the Department to seize command of the power system. *Richmond Power and Light* arose out of the 1973 oil embargo. The Federal Power Commission responded by calling for voluntary transfer for electricity from non-oil power plants to areas of the country that relied heavily on oil, such as New England. 574 F.2d at 613. The New England Power Pool was not convinced that the voluntary program would work and petitioned the Commission for a 202(c) order. *Id*. Rather than issue such an order, the Commission facilitated an agreement between state commissions and supplying utilities, which satisfied the New England Power Pool and it withdrew its petition. *Id*. A dissatisfied utility sought judicial review of the Commission's decision to allow the withdrawal of the Section 202(c) petition. *Id*. at 614.

The court easily upheld the Commission's decision not to invoke Section 202(c). *Id*. Though the oil embargo had ended, the utility argued that the "high cost and uncertain supply of imported oil" justified an emergency order. *Id*. The Commission countered that the voluntary program had worked, the New England Power Pool never interrupted service, there was no need for a Section 202(c) order, and the court agreed. *Id*. at 615. The utility alternatively argued that "dependence on imported oil leaves this country with a *continuing* emergency." *Id*. (emphasis added). The court observed that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances." *Id*. Interpreting this statutory language, the court upheld the Commission's view that Section 202(c) cannot be used when "supply is adequate but a means of fueling its production is in disfavor." *Id*. Section 202(c) is not an appropriate means to implement long-term national policy to switch fuels. It is only a temporary fix for a temporary problem.

The Eighth Circuit has similarly held that Section 202(c) can only be used to respond to immediate crises. In *Otter Tail Power*, a utility insisted that the only way for the Federal Power Commission to properly order the utility to connect to a municipal power provider was to issue a Section 202(c) order. 429 F.2d at 234. Demand for electricity in the city had increased, and the peak load of the municipal power provider was getting to be so high that both of its two generators would likely need to be used simultaneously in the near future, "causing a possible loss of service should one malfunction during a peak period." *Id*. at 233–34. To avoid this possible loss of service, the Federal Power Commission issued a Section 202(b) order, requiring the utility to connect the municipal power provider. The utility argued that the Federal Power Commission used the wrong Section and should have used Section 202(c) instead.

The court explained that Section 202(c) "enables the Commission to react to a war or national disaster" by ordering "immediate" interconnection during an "emergency." *Id*. at 234 (citing 16 U.S.C. § 824a(c)). For non-emergency situations, "[o]n the other hand, Section 202(b) applies," including when there is a "crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission." *Id*. The court upheld the Commission's use of Section 202(b) instead of Section 202(c) because there was no immediate emergency. The case law uniformly supports the interpretation that Section 202(c) can only be used in acute, short-term, urgent emergencies.

v. The Department's Prior Orders Recognize that Section 202(c) Does Not Confer Plenary Authority Over Bulk-System Resource Adequacy.

The Department's consistent application of Section 202(c) further corroborates the urgency of the emergency conditions that are the necessary predicate for any Department intervention under that Section. *See Fed. Trade Comm'n v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941) ("[J]ust as established practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it is equally significant in determining whether such power was actually conferred."). The Department has (outside wartime) consistently used Section 202(c) to address specific, imminent, and unexpected shortages—not to address longer-term reliability concerns or demand forecasts. *See, e.g.*, Ex. 5 at 1 (DOE Order No. 202-22-4) (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between Christmas Eve and Boxing Day); Ex. 17 at 1–2 (DOE Order No. 202-20-2) (responding to shortages produced by ongoing extreme heat and wildfires); Ex. 105 at 1 (DOE Order No. 202-08-1) (ordering temporary connection of facilities in response to "massive devastation caused by Hurricane Ike," leaving "large portions" of Texas "without electricity"); *see also* Rolsma, 57 Conn. L. Rev. at 803–04 (describing "sparing[]" use of Section 202(c) outside of war-time shortages during the twentieth century).[5] Public Interest Organizations are not aware of any instance in which the Department has utilized Section 202(c) to mandate generation the Department views as necessary to ensure long-term resource sufficiency, or in response to generalized regional risks that have not produced any particular, defined generation shortfall, and for good reason: Any such use would exceed the Department's statutory authority.

[5] The Department has also narrowly tailored the remedies in Section 202(c) orders to ensure that the orders only address the stated emergency, to limit the order to the minimum period necessary, and to mitigate violations of environmental requirements and impacts to the environment. *See, e.g.*, Ex. 5 at 4–7 (DOE Order No. 202-22-4) (limiting order to the 3 days of peak load, directing PJM to exhaust all available resources beforehand, requiring detailed environmental reporting, notice to affected communities, and calculation of net revenue associated with actions violating environmental laws); Ex. 17 at 3–4 (DOE Order No. 202-20-2) (limiting order to the 7 days of peak load, directing CAISO to exhaust all available resources beforehand, requiring detailed environmental reporting).

2. *The Order 's Primary Focus is Long-Term Bulk-System Reliability, Which Is Not a Basis to Mandate Generation Under Section 202(c)*

The August Order primarily relies upon assertions of long-term bulk-system reliability concerns. Ex. 67 at 4–7 (August Order). Those concerns—even if fully substantiated—would not be a sufficient basis to mandate Campbell's continued operation. And they are not adequately substantiated. As the August Order acknowledges, MISO and others are taking steps to address those concerns before any resource shortfall arises.

i. *Even If Supported by Evidence, 2026-Onwards Concerns Are Too Distant To Be an "Emergency" Within the Meaning of 202(c).*

The August Order claims "a potential longer term resource adequacy emergency in MISO," acknowledging a "capacity surplus for the summer of 2026," but citing projections of possible "insufficient capacity to meet the peak demand for electricity in each of the following summers"—that is, arising no earlier than the summer of 2027. Ex. 67 at 5 (August Order) (also noting "surplus of generation capacity" in the winter of 2026, "followed by increasing deficits for the following four years."). Even if those "deficits" were established (they are not), reliability concerns arising in 2027—two full years in the future—are not an emergency under Section 202(c). None of those 2027-onwards deficits are imminent, and they cannot plausibly be an "emergency" characterized a "*sudden* increase in the demand for electric energy." 16 U.S.C. § 824a(c)(2). Nor do they suggest any exigent "shortage" in electric energy, generation, or transmission that could qualify as an "emergency." *Id.* That is all the more so for claimed shortfalls arising even further in the future—for example, the 2030-onwards resource concerns purportedly described by the Department's July 2025 Resource Adequacy Report. Ex. 67 at 6 (August Order). *See generally* Ex. 99 (PIOs' RFR of July Resource Adequacy Report).

At most the August Order describes long-term trends that may affect the reliability of the bulk power system—matters for which Section 215 defines, and limits, the scope of federal regulatory authority. 16 U.S.C. § 824o(a)(3)–(4). The Order purports to mandate generation, based upon the Department's assessment of the bulk-power system's long-term reliability needs—a power Congress chose not to provide *any* federal agency. *See* 16 U.S.C. § 824o(e) (specifying enforcement mechanisms for federal reliability standards). And what authority Congress has authorized to implement mandatory reliability standards, it provided to FERC—not the Department. *Alcoa v. FERC,* 564 F.3d at 1344. Reliability concerns two years in the future are not an emergency within the meaning of Section 202(c).

The August Order's references to "projected demand for manufacturing, re-industrialization, and data centers driving artificial (AI) innovation," August Order at 6, may express the Department's belief that future electricity supplies will be insufficiently abundant to meet its policy preference. But Section 202(a)—not

Section 202(c)—provides the statutory tools by which the federal government may further "an abundant supply of electric energy," and those tools do not include the power to seize command-and-control authority over generating resources like Campbell. 16 U.S.C. § 824a(a). Absent imminent exigency—which cannot be shown by potential reliability issues two years in the future—the Department cannot invoke Section 202(c)'s emergency powers.

Section 202(c) provides an explicitly "temporary" authority, 16 U.S.C. § 824(a)(2), preventing any interpretation of its terms that might encompass a "potential longer term resource adequacy emergency," Ex. 67 at 4 (August Order). That expansive interpretation of the Department's emergency power to compel generation is further precluded by the Federal Power Act's express background principles of permitting "Federal regulation" only of "matters which are not subject to regulation by the States," and disavowing "jurisdiction, except as specifically provided" over "facilities used for the generation of electric energy." 16 U.S.C. § 824(a)-(b)(1). *See Duke Power Co. v. Fed. Power Com.,* 401 F.2d 930, 938 (D.C. Cir. 1968) (explaining that the Federal Power Act's policy declarations are "relevant and entitled to respect as a guide in resolving any ambiguity or indefiniteness in the specific provisions which purport to carry out its intent").

The Order's fundamental claim is that "demand for electricity is projected to increase at an accelerating pace," and that even though "MISO has been taking steps to address these projected deficits," the Department deems those steps insufficient to secure adequate "resource adequacy." Ex. 67 at 5 (August Order)—largely based on the Department's views as to "reliance on foreign energy" and exposure to "swings within international commodity markets," *id.* at 6, as well a desire to privilege the coal industry over other cleaner and less expensive fuels, Executive Order 14261, 90 Fed. Reg. 15,517 (Apr. 14, 2025); Executive Order 14156, 90 Fed. Reg. 14,156 (Jan. 20, 2025). The Department thereby expressly seeks to override the decisions of MISO and private utilities pursuant to the mechanisms established by Congress to ensure abundant electricity supplies and the reliability of the bulk-electric system. 16 U.S.C. §§ 824a(a)–(b), 824o.

Section 202(c) does not permit that effort to transform the statutory scheme from one driven primarily by market-based and State decision-making to one of centralized command-and-control. And it especially does not permit that transformation in service of the Department's desire to dictate "how much coal-based generation there should be over the coming decades"—a power that the Supreme Court has found Congress "highly unlikely" to have left to agency discretion. *West Virginia v. EPA*, 597 U.S. 697, 729 (2022).

ii. *The Order Does Not Demonstrate Any Resource Adequacy Concerns that Are Not Already Being Addressed Through Statutorily Approved Channels.*

In addition to being an invalid basis for Department action under Section 202(c), the August Order's discussion of long-term resource adequacy concerns is inaccurate, both because it overestimates the potential of a shortfall and because it underestimates the ability of existing processes to address any projected shortfall. The following sections examine the several bases for the Department's claim of a long-term emergency; as they explain, none of those bases provide any actual evidence that Department intervention is necessary.

a. *The Department Misinterprets the OMS-MISO Survey.*

One of the Department's principal citations for its claim that MISO faces a long-term shortfall is the OMS-MISO Survey. Ex. 67 at 4–5 (August Order) (discussing Ex. 89 at 2, 7, 9 (2025 OMS-MISO Survey)). As discussed above, *supra* sec. IV.B.3, the Survey is structured to evaluate a range of potential outcomes, including a worst-case scenario that relies on extremely conservative assumptions about how much of the new generation that utilities have actively planned for is able to become operational. *See* OMS-MISO Survey at 5-6. Unfortunately, the Department's description of the OMS-MISO Survey is fundamentally flawed, because it cherry-picks the data in the Survey that confirm its own biases (exclusively that based on the survey's most conservative assumptions), and studiously ignores the rest. Broadly speaking, the purpose of the OMS-MISO Survey is to explore a wide range of potential outcomes based on current trends, to ensure that MISO is aware of the full spectrum of possibilities (including remote ones) for which it may need to secure adequate resources to ensure grid reliability. In keeping with that purpose, the Survey applies assumptions to the bottom end of its forecasts that are extremely unlikely to reflect reality. But in attempting to create the illusion of a long-term emergency, the Department cites only to this bottom edge, studiously ignoring the rest of the range of outcomes that were considered.

No example of the Department's selective interpretation of the evidence is more obvious than the Department glossing over the fact that the OMS-MISO Survey projects a near-certain surplus of resources through at least May 2027. Order at 5. In other words, the Department's own citation provides no basis to think that Campbell is needed *for almost two years*. The Department attempts to undermine this projection by calling it "potential" and suggesting that "at least 3.1 GW of additional generation capacity" would need to be added," Order at 5. But this phrasing is not consistent with the study, whose *most conservative* estimate concludes there will be a surplus in 2026; and it ignores the reality that new resources are built in MISO every year: 3.1 GW is fewer resources than came online per year over the past three years, and that was before utilities began accelerating new resource development in response to increasing load projections. The

Department's claim that MISO needs *at least* 3.1 GW of new generation is also factually incorrect because it ignores 1.4 GW of existing resources that are *not* currently committed to retire, but which were excluded from the Survey's projections because they were identified as having a "low certainty" of continued operation in 2026—if even one of those resources doesn't end up retiring, it would reduce the need for new resources below 3.1 GW. Ex. 89 at 5, 7 (2025 OMS-MISO Survey).

The Department's discussion of later-year projections is even more misleading. The OMS-MISO Survey examines MISO's resource adequacy projections using two alternate assumptions for how quickly new resources can be built: a "historical" projection that predicts 3.5 GW of new resources per year based on a three-year historical average (plus 1.2 GW of replacement resources based on historical levels); and an "emerging" projection that predicts 6.2 GW per year of new additions "based on member submittals to the OMS-MISO Survey" (*i.e.* what utilities have told OMS-MISO they are actually planning to build) and 2.4 GW per year of replacements. Ex. 89 at 5–6 (2025 OMS-MISO Survey). The Survey's "historical" projection also assumes that only half of utilities' planned upgrades to existing facilities will actually take place. *Id.*

The Department cites exclusively to the "historical projection, ignoring the "emerging" projection entirely—but this paints an excessively pessimistic picture of the future. The Survey's estimated 1.4 to 8.2 GW deficits from 2027/28 to 2030/31 in the historical projection are more than matched by its forecast 6.4 to 11.4 GW surpluses over the same period in its emerging projection. Ex. 89 at 7 (2025 OMS-MISO Survey). And again, both of these projections ignore entirely the possibility that any of the 1.4 to 3.8 GW of "potentially unavailable resources" turns out to in fact still be available. The Department's decision to ignore the half of the OMS-MISO Survey that is inconsistent with its emergency declaration has no basis in the structure of the Survey: the two projections are explicitly presented as "bookend capacity forecasts." OMS-MISO Survey at 6.

In ignoring the emerging projection, the Department unreasonably fails to take into account several key factors that support that projection. First, the historical 2022-24 new capacity build rate is not likely to be reflective of future build because the scope of the need for new generation only became clear in the past year or two: indeed, MISO added almost 5 GW of new resources in 2024, which was about 50 percent more than the MISO region had ever built before. OMS-MISO Survey at 6]. Second, the historical projection underestimates future contributions of storage, because MISO currently only has roughly 164 MW of operational storage,[6] meaning that the historical trend still does not account for the coming influx of battery storage resources. And third, the historical projection's assumption that only half of utilities' "replacement" and "surplus" projects will actually occur has no actual historical basis, because these are new categories of projects that MISO therefore has no historical data on. Ex. 89 at 5 (2025 OMS-MISO Survey) (indicating that replacement and surplus projects were not considered for the 2024 Survey).

The Department has also ignored other information in the OMS-MISO Survey that indicates the possibility of even more new generation coming online than either of the two projections in the Survey anticipate. For instance, the survey indicates that 54 GW of projects have a signed generator interconnection agreement but are waiting to interconnect. OMS-MISO Survey at 6. A review of historic trends is instructive here: ninety percent of projects with signed generator interconnection agreements ultimately get built. *See* Ex. 120 at 6 n.* (2024 OMS-MISO Survey). Assuming that trend continues—and the circumstances of increasing demand provide good reason to think it will—48 GW of the total 54 GW projects currently with signed generator interconnection agreements will come online. [7]

Additionally, there are about 291 GW of projects currently in MISO's interconnection queue. Ex. 121 at 7:15–17 (Witmeier 2025 ERAS Testimony). MISO's historic interconnection queue completion rate is twenty-one percent, *see* Ex. 112 at 21:2–5 (Witmeier 2024 Queue Cap Testimony), which would equate to another 61 GW (291 GW × 21% = 61.1 GW) of new projects interconnecting from the current queue. Together, those two groups represent more than 109 GW of new resource additions that MISO could reasonably expect to come online in the next several years.

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[6] MISO, *Storage*, at 4 (Mar. 12, 2025) ("AC Board Storage Presentation"), https://cdn.misoenergy.org/20250312%20AC%20Item%2006%20Session%20with%20the%20Board%20of%20Directors%20-%20Storage%20_%20Introduction684557.pdf (Presentation before the Advisory Committee Session with the Board of Directors).

[7] This statistic is particularly noteworthy because, as it did last year, the OMS-MISO Survey includes resources with signed Generator Interconnection Agreements in its definition of "potential new capacity," even though such projects are more likely than most to come online. OMS-MISO Survey at 6. This further underscores the conservative nature of even the "emergent" version of the Survey's new capacity projections.

b. *Neither The Energy Emergency Executive Order nor the Grid Reliability Executive Order provides a valid basis to declare an emergency under Section 202(c).*

The Department also cites to the Energy Emergency EO and the Grid EO claiming that there is an energy emergency and that the grid is being stressed by unprecedented demand. Neither of these executive orders is valid evidence of an actual energy emergency. If the Orders' reference to a national energy emergency is meant to serve as evidence of an emergency as defined under Section 202(c), it is insufficient. Claims recited in an Executive Order are not substantial evidence supporting agency action. Substantial evidence is "such relevant evidence as a reasonable mind might accept as adequate to support a conclusion." *Chritton v. Nat'l Transp. Safety Bd.,* 888 F.2d 854, 856 (1989) (internal quotation marks omitted). And an emergency under Section 202(c) must be a *specific* inadequate power supply situation. *See supra* sec. V.A.1; *e.g.*, 10 C.F.R. § 205.371 (emphasis added). In the quoted passages from the Energy Emergency EO, the President offered his perspective on issues relating to the nexus between energy usage and "our Nation's economy, national security, and foreign policy." But these themes are simply not relevant to assessing whether an "emergency" has occurred under Section 202(c)(1) and the Department's regulations under 10 C.F.R. § 205.371. Thus, the Orders provide no specific evidence of inadequate generation nationwide, let alone in Michigan or even in MISO specifically. Nor does it explain how the retirement of a single power plant in a single state—Michigan—supports the existence of an emergency in the MISO region, let alone the whole country. An emergency under Section 202(c) also must be imminent. *See supra* sec. V.A.1. But even the Department's other cited evidence demonstrates clearly that there is nothing imminent about even the most tenuous projected shortfalls.

Even if the declared national energy emergency were legitimate, a presidential declaration of an emergency does not unlock unlimited agency powers. *See Biden v. Nebraska*, 600 U.S. 477, 500-01 (2023) (presidential declaration of national emergency does not change the limitations on agency's emergency authority as written into statute). President Trump issued the Energy Emergency EO pursuant to authority from the National Emergencies Act.[8] Congress explained that the

[8] Under the National Emergencies Act, no emergency powers unlocked by a Presidential declaration of a national emergency "shall be exercised unless and until the President specifies the provisions of law under which he proposes that he, or other officers will act." 50 U.S.C. § 1631 (emphasis added). The Energy Emergency EO does not adhere to this requirement. Ex. 92, 90 Fed. Reg. at 8,434 (Energy Emergency EO) (generically directing agencies to "identify and exercise any lawful emergency authorities available to them, as well as all other lawful authorities they may possess, to facilitate the . . . generation of domestic energy resources.").

National Emergencies Act "is not intended to enlarge or add to Executive power. Rather, the statute is an effort by Congress to establish clear procedures and safeguards for the exercise by the President of emergency powers conferred on him by other statutes." S. Rep. No. 94-1168, 3 (1976), (emphasis added). But Section 202(c)'s authority is not triggered by a Presidential emergency declaration; the statute requires that "the *Commission* determine[] that an emergency exists." 16 U.S.C. § 824a (emphasis added).[9] Thus, the burden is on the Department to demonstrate that there is an emergency pursuant to the narrow language of Section 202(c); simply pointing to the Energy Emergency EO or the Grid Reliability EO without providing actual evidence that an emergency exists results in an arbitrary and capricious order.

c. The Department's July Resource Adequacy Report does not substantiate its claim of a long-term resource adequacy shortfall.

The Order also briefly cites to the Department's July Resource Adequacy Report as evidence of a potential emergency years down the road. Ex. 67 at 6 (August Order) (citing Ex. 96 (July Resource Adequacy Report)). But that Report does not credibly project conditions in 2030 because of its many inaccurate assumptions and methodological errors.[10]

Most glaringly, the Report overestimates demand growth and expected facility retirements while underestimating the likelihood of new entry. This biases the entire report in the direction of over-identifying resource adequacy concerns. Ex. 113 at 21–25 (Inst. Pol'y Integrity Report); *see also* Ex. 68 at 7 (Grid Strategies Sept. Report) (explaining that the July Resource Adequacy Report relies on load growth and capacity retirement assumptions that are "drastically higher" than those provided by the U.S. Energy Information Administration, the arm of the Department tasked with "independent statistics and analysis"); Ex. 122 at 2–3 (GridLab Report) (noting that the July Resource Adequacy Report fails to account for the potential flexibility of data center load additions; that the Report assumes double the retirements and only a quarter of the firm resource additions assumed by the Energy Information Administration; and that the report ignores "fast-track" interconnection processes recently approved by FERC for multiple RTOs); Ex. 99 at 34-35 (PIOs' RFR of July Resource Adequacy Report) (citing multiple expert reports and initiatives demonstrating the potential for flexibility of large data center loads, including Ex. 123 (Duke University Rethinking Load Growth Study)).

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[9] The Department has exercised certain powers under Section 202(c) since the DOE Organization Act of 1977. 42 U.S.C. § 7151(b).

[10] A subset of PIOs have raised several concerns with this order in a separate rehearing request. *See generally* Ex. 99 (PIOs' RFR of July Resource Adequacy Report).

The Report also "departs from best [modeling] practices by using a deterministic modeling rather than a probabilistic approach," and thereby fails to account for necessary uncertainties. Ex. 113 at 19 (Inst. Pol'y Integrity Report). And in many places the Department simply does not explain its own methodology. The report states that its model is derived from NERC's Interregional Transfer Capability Study, which is focused on the ability of the transmission system to transfer power between regions. Ex. 96 at 2 (July Resource Adequacy Report). However, the report inexplicably excludes new transmission projects from its analysis, ignoring that transmission improvements can be the most cost-effective way to improve grid reliability. The Department's report also appears to misunderstand certain principles of statistical reasoning, calling out PJM for failing loss-of-load criteria under *one* realization of a possible weather year that would include Winter Storm Elliott, without considering that a system's LOLE is averaged across all simulated weather years. Ex. 113 at 19 (Inst. Pol'y Integrity Report); Ex. 96 at 7, 9, 27 (July Resource Adequacy Report). The Department also added more "perfect capacity" (in megawatts) within its modeling than actually needed to bring regions to its targeted Normalized Unserved Energy level. Ex. 113 at 26 (Inst. Pol'y Integrity Report); Ex. 96 at 19, 27, 30, 32, 40. These analytical failings in and of themselves disqualify the report as a viable source of evidence for an emergency finding.

The lack of evidence for a long-term emergency is underscored by the fact that the Department's own analysis premises a resource adequacy shortfall on a type of demand increase (large load buildout), Ex. 96 at 2–3, 15–17 (July Resource Adequacy Report), that the report goes on to admit would likely never actually be allowed to destabilize the grid. Specifically, the report notes that its analysis "is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system." *Id.* at 14. In other words, even taking the report at face value, it does not identify a shortfall of a type and nature that could ever justify invocation of the Department's Section 202(c) emergency authority. At best, the report highlights that data centers cannot be built at projected rates unless new generation is built, which is far from the type of emergency situation that could ever provide the basis for a Section 202(c) order.

Finally, on its opening page, the report acknowledges that its analysis is general in nature, looking at the country as a whole, and that the various "entities responsible for the maintenance and operation of the grid" have information "that could further enhance the robustness of reliability decisions" in the sections of the grid they administer. *Id.* at i. This type of generalized analysis based on incomplete information is simply insufficient to justify a Section 202(c) emergency finding for MISO or any other specific region.

d. The Generic Testimony of a Single MISO Executive on which the Department Relies Is Contradicted by Numerous and More Concrete Other Statements by MISO.

Finally, the Order cites to testimony by Jennifer Curran, a current MISO executive, that speaks in general terms about MISO's need for capacity. Ex. 67 at 6–7 (August Order) (citing Ex. 100 (Curran Testimony)). As an initial matter, Ms. Curran's testimony is sufficiently vague that it is open to any number of interpretations. Her testimony provides no timeline for the risk she communicates, nor does it state how great the reliability risk is, or how much bigger it could get, from the various systemic trends she discusses. *See* Ex. 100 at 4–6 (Curran Testimony). This generic testimony is expected from an opening statement to Congress; it is also several steps removed from the concrete, tangible, and specific evidence that is necessary for the Department to find that there is a resource adequacy emergency.

The August Order's treatment of Ms. Curran's testimony is a prime indicator of unreasoned decision-making because it misrepresents aspects of the testimony, cherry-picks only favorable statements while omitting unfavorable statements, and wholly ignores related evidence undercutting the Department's position. For example, the August Order misrepresents Ms. Curran's testimony in suggesting she "acknowledged the Nation's current energy crisis." Ex. 67 at 6 (August Order). In fact, Ms. Curran never said or implied that there is any "crisis" or emergency. Moreover, the Department conspicuously omits elements of her testimony cutting against the Department's invocation of Section 202(c) authority. For example, Ms. Curran testified that "[i]mproving existing market and operations processes tool is a cost-effective and timely way to improve reliability in an efficient manner." Ex. 100 at 7 (Curran Testimony). She further testified that the risks of generation plant retirements can be addressed by allowing *local* reliability requirements to determine the pace of retirements. *Id.* Ms. Curran's recommendations for future action do not include the Department's use of Section 202(c) orders, nor do they include coal-fired power generation. *See id.* at 9-10.

The August Order also fails to mention or consider statements by other MISO executives rebutting the Department's conclusion that there is a resource adequacy deficiency. For instance,

> In a statement, MISO said it will "continue coordinating with Consumers Energy to comply with the order." But MISO again stressed that J.H. Campbell did not clear the planning resource auction and is unnecessary for resource adequacy in the 2025/26 planning year. "MISO's 2025-2026 Planning Resource Auction indicated adequate resources to meet anticipated demand. . . .," MISO spokesperson Brandon Morris said in a statement to RTO Insider.

Ex. 117 (RTO Insider Article on August Order). It further ignores testimony from MISO's Internal Market Monitor at a recent FERC technical conference that MISO "is more than adequate" for the Summer of 2025 and that the IMM has no substantial resource adequacy concerns "in the near term." Ex. 35 at 2 (Patton MISO Comments). Finally, the August Order fails to consider that MISO has never requested that a 202(c) order be issued to Campbell; and it has never expressed support for the Department's first Campbell order.

e. MISO has designed its ERAS proposals to address claimed shortfalls and has not suggested that any further generation/capacity is needed

There is one place where MISO has projected a resource adequacy need: in the course of requesting FERC approval for its proposed Expedited Resource Addition Study, which FERC approved in July 2025. Ex. 90 at 6, 13–17 (MISO ERAS Transmittal Letter); Ex. 91 (MISO ERAS Decision). But as explained above, *supra* sec. IV.B.3, that projected need spurred MISO to initiate a process that will add at least 26.5 GW (and likely more) of new capacity to MISO's system over the next several years.

The Department minimizes the import of this approval by suggesting that the projects won't reach commercial operation for at least three years and could be further delayed by supply chain constraints. Ex. 67 at 5 (August Order). But the Department's first statement is factually incorrect—projects that are selected for ERAS could begin operation sooner than three years from the application date; they just have up to six years of leeway—and its second statement is far too conjectural to provide a basis for an emergency declaration. Ex. 91 at P 84 (MISO ERAS Decision). The Department cannot defensibly declare an emergency justifying use of its 202(c) authority based on a concern that the expedited interconnection process MISO has established specifically to meet projected resource adequacy needs won't work—absent substantial and specific evidence of that fact, it is pure conjecture.

3. The Order's Secondary Basis of Near-Term (Summer/Fall) Resource Adequacy Concerns Is Not, and Could Not Be, Sufficient to Warrant Invocation of the Department's 202(c) Authority.

i. The Described Concerns Are Insufficiently Specific and Certain to Meet the Statutory Definition of an Emergency.

The August Order gestures at the possibility of electricity shortfalls in the "near" term. It offers no plausible evidence of such shortfalls. *See infra sec.* V.A.3.ii. That failure to adduce plausible evidence to one side, the generalized, speculative risks described by the August Order are neither specific nor certain enough to qualify as an "emergency" within the meaning of Section 202(c). 16 U.S.C. 824a(c). For the remainder of the summer, the August Order recites: a purported need for Campbell "last June"; a series of "alerts" that did not implicate the plant; and a "40-50%

chance" of "above-normal temperatures." Ex. 67 at 2–3 (August Order). That notional suggestion of *some* possible shortfall, which might (or might not) require Campbell's generation, is not a "specific inadequate power supply situation" enabling the use of the Department's Section 202(c) authority. 10 C.F.R. § 205.371. The fact that contemporaneous weather reports indicated that the final 10 days of MISO's summer season would be marked by a pronounced cooling trend, as explained above *supra* sec. IV.B.1, underscores the problem with relying on general statements like those the Department cites to demonstrate a likelihood of risk over a specific 11-day period.

For the remainder of the August Order's term—which extends into the fall—the Department states only that "MISO's resource adequacy problems are not limited to the summer." Order at 3. The Order does not find that those unspecified "resource adequacy problems" will produce any shortfall in supply implicating Campbell over the term of the Order. At most this conclusory statement asserts the possibility that some resource inadequacy might (or might not) emerge somewhere in MISO—but that does not, and cannot, demonstrate that "an emergency *exists* by reason of a sudden increase in the demand for electric energy" or an identified "shortage of electric energy" or of particular "facilities for the generation or transmission of electric energy." 16 U.S.C. § 824a(c)(1) (emphasis added). *See also Louisville & N.R. Co. v. Sullivan,* 617 F.2d 793, 795 (D.C. Cir 1980) (where statute permits emergency orders based on determination that a "facility or piece of equipment is in unsafe condition and thereby creates an emergency situation," agency may not issue order based on "a generalized poor safety record" without showing of "particular" safety hazard). The Order does not describe or provide support for—even taken on its own terms—any imminent, specific, or certain electricity shortfall. It therefore does not describe an "emergency" within the meaning of Section 202(c). *Id.*

ii. The Claimed Shortfall Is Unreasoned and Not Supported by Substantial Evidence.

a. MISO's Grid Stewardship During the Past 90 Days Demonstrates that the May Order Was Not, and the August Order Is Not, Necessary to meet Summer 2025 Needs.

The Department's claim that MISO faced "resource adequacy problems" in Summer 2025 was specious in both May and August, and could not support an order to operate Campbell under Section 202(c) to bridge a Summer 2025 supply gap. As discussed above in sec. IV.B.1, system performance for Summer 2025 (June through August) was consistent with MISO's advance forecasts of adequate supplies (even without Campbell) and low risk for the season, and with its having cleared adequate resources to maintain resource adequacy through its 2025-2026 Planning Auction.

While the Order asserts that "the production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO this summer," Ex. 67 at 2 (August Order), it offers no evidence in support of that assertion. Most troublingly, after the Order correctly notes that Campbell ran at a 61% capacity factor in June 2025, and that MISO declared a Max Gen Event Step 1b on June 23 (*id.* at 3), it then fails to note that Unit 2 was completely offline from June 1 through June 27 or that Unit 1's production dropped to zero on June 23, in the middle of the Max Gen event. Ex. 68 at 5 (Grid Strategies Sept. Report); Unit 1 remained offline through the end of June. *Id.* This is another a prime indicator of arbitrary and capricious decision-making, because the Department again here misrepresents aspects of the readily available data, cherry picking factoids and ignoring related evidence that would undercut the Department's position.

Furthermore, the Order declines to explain how much excess generation was available but not dispatched in the MISO system during the relatively tight periods this summer, which is crucial to establish that the production of Campbell was necessary to maintain system supply adequacy at any particular time. That Campbell may have been dispatched in particular hours, which would be consistent with the "economic dispatch" that the Department explicitly required MISO to enable in the May Order, does not establish that Campbell's absence would have left the system with insufficient resources. In fact, as established by Public Interest Organizations' expert engineer Rao Konidena, even at peak load on the tightest day of the Summer, MISO had at least 7,941 megawatts of unused surplus resources, which was over ten times what Campbell provided at the time. Ex. 70 at ¶¶ 16–17 (Konidena Decl.); *supra,* sec. IV.B.1. MISO had more than enough resources to meet demand, maintain an operating reserve to cover contingencies, and still have room to spare, and had available to it the use of Load Modifying Resources like demand response. Ex. 70 at ¶¶ 14–23 (Konidena Decl.). Even at peak demand this Summer, MISO did not need Campbell to have sufficient supply to maintain reliability for the region. *Id.*

Public Interest Organizations' expert analyst Michael Goggin also establishes that MISO's declaration of various levels of "Max Gen" events at times when system margins grew relatively smaller is a feature, not a bug, of MISO's resource adequacy management. Ex. 68 at 3–4 (Grid Strategies Sept. Report). And this past summer, MISO's Max Gen event declarations only rose to the first "Max Gen" level out of five. *Id.*; *see supra* secs. IV.A.3, IV.B.1. MISO's protocols allow it to call on several tranches of resources, including Load Modifying Resources, Voluntary Load Reduction, resources currently on outage, and emergency headroom, as needed. Ex. 70 at ¶¶ 10–23 (Konidena Decl.). In short, MISO effectively stewarded all the resources at its disposal this summer to avoid a true grid emergency, exactly as the RTO (and protesters) predicted it would.

b. None of the MISO Proceedings and Reports Cited by the Order Support Its Claim that the Midwest Faces a Fall 2025 Resource Adequacy Emergency.

The August Order offers no substantive evidence that it is needed to ensure resource adequacy in the Fall 2025 season (which is most of the period it covers). Instead, it reviews and recites information from several MISO documents, misinterpreting and misrepresenting the materials to allege a resource adequacy crisis that simply does not exist. Its conclusions thus fail to reflect reasoned decision-making.

The first example of this flawed reasoning is the August Order's repetition of a statement it erroneously cited in the May Order: namely, MISO's statement in its 2025–2026 Planning Auction results 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." Ex. 67 at 4 (August Order); *see* Ex. 1 at 1 (May Order). As it did in May, the Department fails to note that this statement referred only to the netting of additions and subtractions causing total North/Central offers[11] to decrease in absolute terms from Summer 2024 to 2025. Overall resource offerings in MISO North/Central were ***not*** insufficient relative to the Reserve Margin Requirement, which also decreased from 2024 to 2025. *Compare* Ex. 84 at 16 (MISO 2024-25 Auction Results) (showing a Summer 2024 Reserve Margin Requirement of 100,710 MW in Zones 1-7), *with* Ex. 31 at 18 (MISO 2025-26 Auction Results) (showing a Summer 2025 Reserve Margin Requirement of 99,770.5 MW in Zones 1–7).

This result also tracks MISO's Planning Auction results, which, as explained above, *supra* secs. IV.A.2.ii, IV.B.2, resulted in MISO securing more resources for Fall 2025 than it felt were necessary to ensure resource adequacy. In short, it was clear when MISO released its 2025-2026 Planning Auction results in April of this year—well before the August Order—that the MISO system had no resource adequacy crisis after accounting for Campbell's retirement.

The August Order also gestures to various recent reports in which MISO has forecasted an increasing resource adequacy risk in non-Summer seasons. However, the Department does not appear to have carefully examined what MISO was actually saying in any of these materials. First, it quotes from MISO's 2021 capacity accreditation filing, in which MISO described a shift of reliability risks "from 'Summer only' to a year-round concern," for the proposition that the fall season also experiences meaningful systemic risks. Ex. 67 at 3–4 (August Order) (quoting Ex. 77 at 3–4 (MISO 2021 Transmittal Letter)). The implicated graph in the 2021

[11] Offers in the Planning Auction are stated in terms of accredited megawatts of capacity or "UCAP."

Transmittal Letter shows an incidence of MaxGen events across all four seasons from 2014 through 2022 but says nothing about how serious these events were. A simple review of MISO's actual MaxGen events would have revealed that only two fall days have ever experienced events exceeding the "MaxGen Warning" level—in 2017 and 2018—and neither of those ascended to the level (MaxGen Event Step 5) that entails manual shedding of load. Ex. 32 at 3, 11, 14 (MISO Emergency Declarations); *see supra* sec. IV.A.3, IV.B.1.

Next, the August Order cites MISO's 2023 Attributes Roadmap, which (according to the Order) established that "by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons." Ex. 67 at 4 (August Order) (citing Ex. 85 at 11 (MISO Attributes Roadmap)). But again, the Order fails to discuss the magnitude of risk at issue. The implicated graph on page 11 of the MISO Attributes Roadmap identifies loss of load risks that peak around hour 20 with around 150 hours of expected lost load—but those 150 hours (from 3,750 runs of the model)[12] correspond to a LOLE risk of .05 days/year, or 50% under the industry-standard target of 0.1 days per year. Ex. 86 at 7, 19 (MISO Attributes Roadmap Technical Appendix); *see* Ex. 2 at 2 (Grid Strategies June Report). The Department thus failed to make a reasoned determination, because its discussion of "equal" risk fails to mention that the absolute risk in both seasons remains extremely low.

Furthermore, the graph the Order cites in the MISO Attributes Roadmap doesn't even refer to the present Fall season. It refers to projected risk in Fall 2027 and makes clear that there was minimal such risk in Fall 2023; but it is entirely silent as to the risk profile in Fall 2025, which is the only Fall season that is relevant to the Order's claim of a near-term emergency. And the resource mix for Fall 2025 looks *much* more similar to that in Fall 2023 (when risk was not concentrated in the Fall season) than to MISO's projected Fall 2027 mix—so the 2023 chart is a much more useful predictor of likely risk allocation in Fall 2025. Ex. 68 at 1–2 (Grid Strategies Sept. Report). As discussed further below, the Order may not simply use the possibility of risks in future Fall seasons as evidence that actual risks exist in the current Fall season—particularly where, as here, there is concrete evidence demonstrating that no such risk exists.

Finally, the August Order gestures to MISO's 2024 Reliability Imperative Report, which vaguely mentions "risks in non-summer months that rarely posed challenges in the past." Ex. 67 at 4 (August Order) (quoting Ex. 87 at 12 (MISO's Response to the Reliability Imperative)). But the "Response to the Reliability Imperative" offers no specific information about Fall season risks other than that

[12] For a given season, 15 weather years and 250 random outage samples per weather year are modeled. Ex. 86 at 7 (MISO Attributes Roadmap Technical Appendix). 15 × 250 = 3,750.

single vague line, and offers little ballast on which to build a legally sound finding of emergency conditions. *See generally* Ex. 87 at *passim* (MISO's Response to the Reliability Imperative).

Notably, while the August Order attempts without justification to sow doubt about resource adequacy in fall seasons generally, the Order does not provide any evidence indicating any actual risk of inadequate supply in the Fall 2025 season. Indeed, the word "Fall" is mentioned only twice in the August Order, both times on page 4, and neither in reference to 2025. This is a staggering abdication of the Department's obligation to provide sound evidentiary backing for its emergency declarations, and further confirms that there is no remotely plausible reason to be concerned about resource adequacy shortfalls in Fall 2025.

c. No Other Evidence Cited in the Report Supports Its Claimed Emergency.

The August Order contains several other citations to expert and official documents that purportedly support a finding of an "emergency" in the MISO system, but every remaining piece of evidence is of little to no weight. For example, the August Order relies on NERC's Summer 2025 Reliability Assessment as evidence of "elevated risk of operating reserve shortfalls [in MISO] during periods of high demand or low resource output" with the "period of highest energy shortfall risk [having] shifted from July to August." Ex. 67 at 1–2 (August Order) (quoting Ex. 41 at 5 (NERC 2025 Summer Reliability Assessment)). Putting aside that only 11 days remained in the Summer season after the issuance of the August Order, the fact remains that the same NERC Summer 2025 report provides the following very pertinent statement: "Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load-modifying resources (demand response) when operating reserve shortfalls are projected." Ex. 41 at 16 (NERC 2025 Summer Reliability Assessment). This is consistent with the information offered by the Konidena Declaration, discussed *supra* sec. IV.B.1, showing how over 8,000 megawatts of load modifying resources were available to MISO operators during the tightest conditions in Summer 2025. The Department acted arbitrarily and capriciously by citing this NERC document as supposed support for the claimed grid "emergency" without enquiring further into NERC's characterization of conditions. See also Ex. 71 at § IV.A.2.iii (Public Interest Organizations' June Rehearing Request) (detailing the infirmities of the Department's reliance on the NERC 2025 Summer Reliability Assessment).

Meanwhile, any attempt by the Department to rely on the July Resource Adequacy Report as evidence of a Fall 2025 emergency would be inapposite: the Report actually contradicts the Department's emergency finding in the August Order because it concludes that, under the Department's own recommended standards, there is no current or imminent resource adequacy problem anywhere in the United States, with the exception of ERCOT. *See* Ex. 96 at 7 (July Resource

Adequacy Report) (analysis based on loss of load hours (LOLH) and normalized unserved energy (NUSE) standards).

B. The Order Fails to Set Terms that Best Meet the Emergency and Serve the Public Interest.

1. Section 202(c)(1) Authorizes the Department to Require Only 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.[13]

The Department's obligation to exercise reasoned decision-making further requires consideration of alternatives. The Department 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).

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[13] 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." *Id.* § 205.373(g)–(h); Ex. 5 at 4 (DOE Order No. 202-22-4).

The Department may then choose only 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 August Order determines that additional dispatch of Campbell is necessary to best meet the emergency and serve the public interest. Ex. 67 at 7 (August Order). But the August Order provides no rational basis for that determination. The August Order does not address all of the reasons why Campbell is not the best means to meet the claimed emergency and serve the public.

Most of these reasons are already in the record and already before the Department, as they were part of the Public Interest Organizations' challenge to the May Order. *See, e.g.*, Ex. 3 at 4–17 (Powers June Decl.); Ex. 71 at 36–41 (Public

Interest Organizations' June Rehearing Request). Specifically, and as further discussed below, the August Order continues to:

- not address Campbell's limitations or explain how, in light of those limitations, Campbell could even meet the claimed emergency;
- not examine the expense of—and/or environmental damage caused by—running Campbell, both relevant factors which cause additional dispatch of the plant to harm, rather than serve, the public interest; and
- not address readily available and obvious alternatives which, in point of fact, would better address the claimed emergency.

Additionally, the August Order provides no reasoned basis for determining that Campbell best meets the claimed emergency years away. Transmission and myriad other facilities are available over the multi-year span addressed by the August Order. And the August Order contains nothing to suggest that Campbell is geographically "best," in part because the order fails to identify a resource shortfall that is imminent and specific enough to identify any best-placed resource. Consequently, and for the reasons further discussed in the following subsections, the Order is without support in the record, unreasoned, and unlawful. *Allentown Mack*, 522 U.S. at 374; *State Farm*, 463 U.S. at 42–43, 51; *Burlington Truck Lines*, 371 U.S. at 168; *Butte Cnty.*, 613 F.3d at 194.

i. The August Order Does Not Address Campbell's Continued Demonstration of Its Unreliability.

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. In fact, forcing the unreliable Campbell to continue operating actually threatens grid reliability.

The August Order fails to address Campbell's continued showing that it is unreliable. This despite evidence of such unreliability existing in the public record, *e.g.*, Ex. 103 (July 17 Email from Consumers to EGLE) (describing continued failures of Campbell Unit 2); Ex. 104 (CAMPD Campbell Hourly Emissions Data) (showing that Campbell Unit 1 abruptly stopped producing power shortly before MISO load peaked in June 2025), which the Department itself relies on for the August Order, Ex. 67 at 3 n.10 (August Order) (relying on CAMPD data). The evidence of Campbell's unreliability is also potentially in data submitted to the Department. *See* Ex. 1 at 3 (May Order) (requiring daily and periodic information from MISO on Campbell's operations, availability, and economic dispatch).

Even before the planned retirement in May 2025, Campbell suffered from poor reliability. Ex. 3 at 4 (Powers June 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 capital expenditures and maintenance 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 June 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 capital expenditures and maintenance 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 June 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.*

Campbell's poor performance in June 2025, discussed in detail *supra* sec. IV.C.3.i, makes clear that the plant continues to be unreliable. Units 1 and 2 both experienced long outages and were offline during much of the first full month Campbell was supposed to be available to operate pursuant to the May Order. Ex. 69 at 5 (Powers Sept. Decl.); Ex. 102 (CAMPD Campbell Daily Emissions Data).

Indeed, Unit 2 produced power on just four of thirty days in June. *Id.* The August Order does not address this evidence of Campbell's persistent unreliability.

The August Order also fails to come to grips with the dangers to grid reliability that it creates. An unreliable coal plant like Campbell is particularly likely to cause grid disturbances and the "loss of power to homes and local businesses in the areas that may be affected by curtailments or outages." Ex. 67 at 7 (August Order).

> Cold snaps, heat waves, and storms have all exposed coal's fragility during grid stress events. Reliability is not just about being dispatchable, it's about delivering performance under stress. Coal plants struggle to do that consistently. For coal plants to truly meet the constant demands of data centers, they would need to run at high-capacity factors and avoid major outages, all of which fly in the face of current performance trends. If a large coal plant trips offline while supporting a cluster of data centers, the sudden loss of supply could lead to cascading failures across the grid. This is because generation must equal load at all times, datacenter or no datacenter. As a result, relying on coal plants to support these high-density digital loads doesn't enhance reliability, it endangers it. And it's not a matter of *if* the coal plant will fail, but *when*.

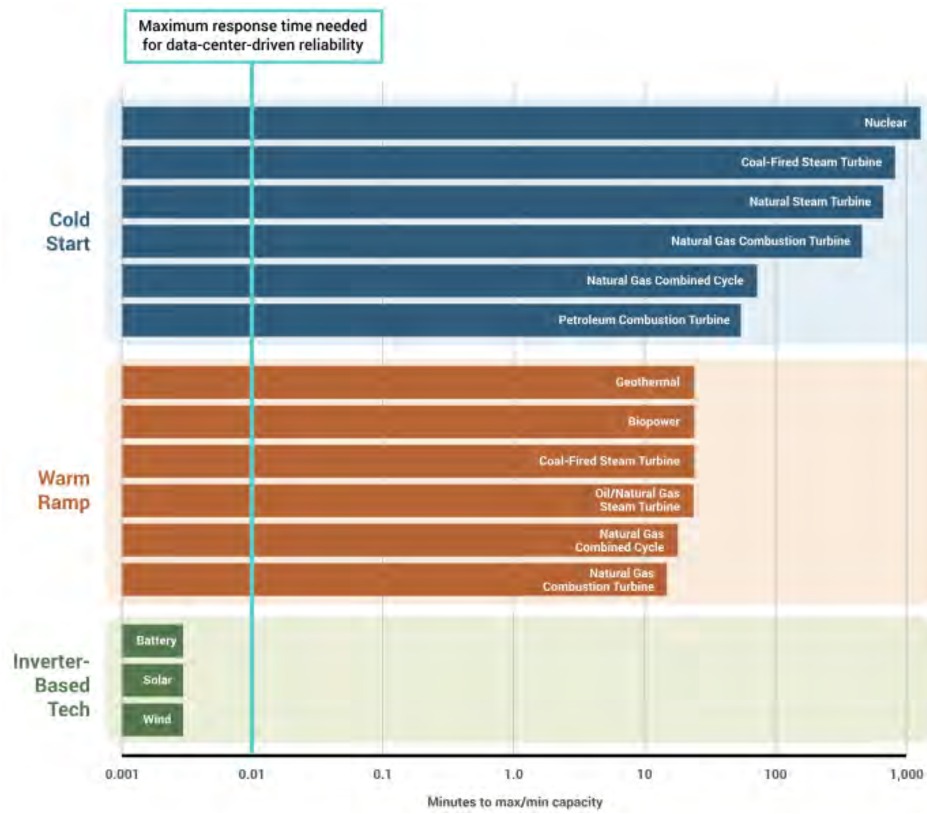
Ex. 118 (RMI Analysis of Coal Plants' Threats to Reliability). The Department avers that it is concerned with the grid disturbances, yet puts forward no analysis to address the likelihood that it is actually creating the (otherwise unproven) problem it is supposedly trying to address. This ostrich-like approach to record evidence and public evidence is not reasoned decision-making. *Butte Cnty.*, 613 F.3d at 194; *cf. Ky. Mun. Energy Agency v. FERC*, 45 F.4th 162, 177 (D.C. Cir. 2022) (rejecting "ostrich-like approach" to agency decision-making).

ii. The August Order Does Not Address Campbell's Continued Demonstration of Its Inability to Meet the Claimed Emergency.

Separately, the August Order provides no reasoned basis to conclude that Campbell, even if fully maintained and operational, could meet the claimed emergency, let alone that it is the best way to do so.

Campbell is not designed to turn on quickly in response to times of extreme demand. As discussed *supra* sec. IV.C.3.ii, Campbell's three units take between one to three days to turn on from a cold condition. Ex. 69 at 6 (Powers Sept. Decl.); Ex. 101 at Question 5 (Consumers June Responses to AG). By comparison, the average coal plant takes 12 hours to reach max capacity from a cold start, Ex. 55 at 26 (IEA Flexibility Report); Ex. 118 (RMI Analysis of Coal Plants' Threats to Reliability), while "utility-scale battery storage can dispatch from a cold start to full power in a matter of seconds," Ex. 69 at 17 (Powers Sept. Decl.).

The August Order points to projections of demand growth, including from "data centers driving artificial intelligence." Ex. 67 at 6–7 (August Order). Even assuming *arguendo* the Department has authority under Section 202(c) to address that claimed circumstance (it does not), coal plants' "always-on nature" and "rigidity" are "a poor match for the dynamic and often unpredictable nature of data center demand." Ex. 118 (RMI Analysis of Coal Plants' Threats to Reliability). "[L]arge, voltage-sensitive loads like data centers require flexible, responsive grid solutions, not slow-ramping generators that can take 12 or more hours to come online." *Id.* (relying on NERC).



Source: Ex. 118 (RMI Analysis of Coal Plants' Threats to Reliability)

In short, the August Order fails to examine inherent mismatch between the problem it diagnoses and the mandate it imposes. This is not reasoned decision-making.

Besides, 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 Campbell 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.

iii. The August Order Does Not Address Campbell's Continued Demonstration of Its Expensive and Uneconomic Nature.

Further, the expense of operating Campbell renders it unable to serve the public interest, a topic the August Order does not address. As discussed *supra* secs. IV.C.3.iv and IV.C.4.iii, 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). And as Public Interest Organizations' expert analyst explains, Campbell operated at a loss in June 2025 and is likely to continue doing so going forward. Ex. 68 at 5–6 (Grid Strategies Sept. Report); *see supra* sec. IV.C.3.iv.

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 June 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. And while continually operating Campbell may avoid the costs of a cold start, that approach is uneconomic and expensive for other reasons.

Moreover, as discussed above, Consumers has significantly decreased expenditures 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 June 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* sec. IV.C.3.iii, Campbell's operation 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.

iv. The August Order Does Not Address or Reflect Consideration of Alternatives.

Other alternatives are available to the Department that better meet the claimed emergency and serve the public interest. MISO has access to robust transmission connectivity between itself and neighboring region to support the stability of its grid. *See, e.g.*, Ex. 35 at 2 (Patton MISO Comments). During the entire period of the August Order, MISO Zone 7 can import more than 4,000 MW. Ex. 37 at 13 (MISO 2025–2026 CIL/CEL Final Results); *see generally* Ex. 65 at 52–53 (DOE Transmission Planning Study) (documenting interregional variability in electricity demand); Ex. 66 at 22–35 (NERC 2024 Interregional Transfer Capability Study, Part 1) (describing transfer capabilities between MISO and other regions).

The Department has long recognized that power pools and utility coordination "are a basic element in resolving electric energy shortages." *Emergency Interconnection of Elec. Facilities and the Transfer of Elec. to Alleviate an Emergency Shortage of Elec. Power,* 46 Fed. Reg. 39,984, 39,985–86 (Aug. 6, 1981). And recent history bears out the important role of transmission connectivity along with imports and exports. *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."); *see also* Ex. 7 at 1 (DOE Order No. 202-02-1) (providing for usage of interregional transmission).

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 August 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).[14]

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The August Order includes no consideration of other alternatives to meet the claimed emergency. This is consistent with the May Order and its supporting memorandum. *See* Exs. 1, 4 (May Order & 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.

C. The August Order Exceeds Other Limits on the Department's Statutory Jurisdiction.

1. The Department Lacks Jurisdiction to Impose the Availability Requirements.

In directing MISO and Consumers Energy to take "all measures" to ensure that the Campbell Plant is "available to operate," Ex. 67 at 8 (August 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 undergoing closure pursuant to a state-approved retirement 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

[14] The Department must also 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). MISO has access to demand response and authority over generator outages. *See* Ex. 70 at ¶¶ 20–23 (Konedina Decl.).

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 v. Talen Energy Mktg., LLC*, 578 U.S. 150, 155 (2016), including the authority to order their closure, *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009) (explaining that 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 Elec. Power Supply Ass'n*, 577 U.S. at 281. 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 that 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. 67 at 8 (August Order). Nowhere does the statute empower the Department to order "all" steps that may be needed to resuscitate Campbell, 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 capital expenditures, 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 Campbell's closure. The Order therefore is unlawful and should be withdrawn.[15]

2. The Department Lacks Jurisdiction to Disallow Treatment of Campbell as a Capacity Resource.

The August Order also, unlike the May Order, includes an explicit provision that "[b]ecause 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." Ex. 67 at 8 (August Order). This provision serves only to increase costs to customers, who will be required to procure duplicative capacity as a result. It is also illegal. Section 202(c) authorizes the Commission to "require by order . . . temporary connections of facilities and . . . generation, delivery, interchange, or transmission of electric energy," and then shields facilities who operate pursuant to a Section 202(c) order from liability for unavoidable violations of federal, state, or local environmental laws or regulations. 16 U.S.C. § 824a(c)(1), (3). Nowhere does the Act suggest that the Department may predetermine or override the reasoned decisions of FERC in its determination of whether just and reasonable wholesale rates require an operating resource to be considered a capacity resource. Indeed, the very nature of 202(c) orders, which are limited to emergencies involving extant resource shortfalls (in which, by definition, there are no alternative capacity resources that might be displaced by the ordered generation) suggests that capacity resource treatment is well outside the Department's 202(c) authority.

The explanation the Order offers for this override, essentially that Campbell cannot be a capacity resource because the order does not deem it a capacity resource, is clearly circular. As a result, the true reasoning behind this provision remains unclear—but its clear effect is to prevent MISO from considering the continued existence of Campbell as it works to ensure resource adequacy across its footprint. MISO's tariff defines a "capacity resource" as any of several types of resources "that are available to meet demand," and its definition of "Planning Resource" makes clear that generators like Campbell must be a Capacity Resource in order to satisfy a region's Reserve Margin Requirement. MISO Tariff Sec. 71.0.0 (Definitions). The Tariff also establishes clear procedures for calculating capacity contribution from all resources. *Id.* at Schedule 53A, Extended Seasonal Accredited Capacity Calculation. Thus, the Order's elimination of capacity treatment for Campbell prevents MISO from following its own tariff in the wake of Campbell's

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[15] 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).

continued operation and the Department's apparent intention to force Campbell to remain operational indefinitely.

The Order also represents a significant and improper intrusion into FERC's authority to ensure that RTOs like MISO justly and reasonably ensure resource adequacy in their footprint; in particular it undermines years of FERC's regulatory oversight of MISO's resource adequacy construct, as codified in its FERC-approved tariff. It is within FERC's purview under Section 205 of the Federal Power Act to provide that oversight, 16 U.S.C. Sec. 824d; and it is within MISO's purview to apply its own tariff in the first instance and decide whether Campbell should qualify as a "Capacity Resource" within MISO's FERC-approved resource adequacy construct. 18 C.F.R. § 35.1(e) ("No public utility shall . . . impose any classification, practice, rule, [or] regulation . . . which is different from that provided in a rate schedule required to be on file with this Commission unless otherwise specifically provided by order of the Commission for *good cause shown*." (emphasis added)).

The Department's intrusion into the oversight relationship between FERC and the RTOs also runs afoul of the filed rate doctrine, which holds that "no change shall be made [in] any [approved] . . . rate, charge, classification, or service, or in any rule, regulation, or contract relating thereto, except after sixty days' notice to the Commission and to the public" in another filing with FERC. 16 U.S.C. § 824d(d); *Okla. Gas & Elec. Co. v. FERC*, 11 F.4th 821, 829 (D.C. Cir. 2021). Interference in MISO's capacity accreditation procedures effectuates a *de facto* change to its tariff, without the legally required notice. And more generally, "Congress rejected a pervasive regulatory scheme for controlling the interstate distribution of power in favor of voluntary commercial relationships. . . . governed in the first instance by business judgment and not regulatory coercion." *Otter Tail Power Co.*, 410 U.S. at 374 (1973). The Department's interference here in the core operational procedures of MISO's resource adequacy construct improperly upends that relationship.

More broadly, the unavoidable implication of the Order not allowing MISO to include Campbell in its resource adequacy planning is that the Department believes MISO will likely secure the resources it determines are needed to maintain grid security even without Campbell, pursuant to its FERC-approved tariff: the provision would be unnecessary if MISO truly had no alternatives. And that means that either 1) the Department does not trust MISO's assessment of MISO's resource adequacy; or 2) the Department does not trust its own assessment of MISO's resource adequacy.

In either case, the Department's actions are improper. The August Order provides no evidence that MISO cannot be trusted to ensure resource adequacy, so a Department determination that MISO cannot be trusted would be arbitrary and capricious. It would also conflict with the Department's heavy reliance on MISO's statements and studies in support of its assertion that the region faces an emergency in the first place. Conversely, if the Department does not have the confidence that its own dire predictions that the system does not have enough resources will come true, then it is well short of the confidence necessary for an emergency declaration under Section 202(c).

If left unchecked, this provision could impose completely avoidable cost increases on Michigan and MISO ratepayers. During the pendency of this Order, the principal effect of this provision will be to remove Campbell's ability to provide replacement capacity in the event one of the resources that cleared the auction suffers a catastrophic outage or is otherwise suspended, retired, or shut down for more than 31 days in a season. Midcontinent Independent System Operator, BPM-011-r31, Resource Adequacy Business Practices Manual, at 16 (Feb. 21, 2025); *see* Ex. 119 (ZRC Replacement). Eliminating this compensation pathway will increase the financial cost of the Order, by removing a potential income stream that might have offset Campbell's extremely high operational costs, and by forcing any other region that is impacted by an unexpected plant closure to look for potentially more expensive alternatives for replacement capacity.

Additionally, this provision will have an outsized impact in April 2026 if the Department continues renewing the Order every 90 days; that is when MISO conducts its 2026-27 Planning Auction. Campbell's exclusion from the list of facilities that might offer capacity would ensure that Michigan ratepayers and MISO ratepayers writ large are forced to pay for Campbell's continued operation without any countervailing benefits: they would miss out on a major revenue stream that would have reduced Campbell's operating losses, and by operation of MISO's sloped curve in the Planning Auction, which pays more for capacity the scarcer it is, consumers will end up paying a higher premium for any capacity their utilities secure from the Planning Auction.

In short, including this provision is yet another way in which the Department has misapplied the statute: its inclusion only further ensures that Campbell's principal impact will not be to plug a gap but rather to sabotage MISO's resource planning process.

D. The Order Fails to Provide the Conditions Necessary to Override Environmental Standards Under 202(c).

Where an order "may result in a conflict with a requirement of any Federal, State, or local environmental law or regulation, Section 202(c)(2) requires the Department to "ensure": (1) that the order compels "generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet the emergency and serve the public interest"; (2) that operations are "to the maximum extent practicable . . . consistent with any applicable Federal, State or local environmental law[s]"; and (3) that it minimizes any adverse environmental impact, regardless of the facility's compliance (or non-compliance) with environmental standards. 16 U.S.C § 824a(c)(2). And before renewing or reissuing such an order, the Department must (4) "consult with the primary Federal agency with expertise in the environmental interest protected by such law or regulation, and shall include in any such renewed or reissued order such conditions as such Federal agency determines necessary to minimize any adverse environmental impacts to the extent practicable," which conditions "shall be made available to the public." 16 U.S.C. § 824a(c)(4)(B). The August Order here violates those statutory obligations.

1. *The Order May Result in a Conflict with Federal, State, or Local Environmental Law or Regulation.*

Section 202(c)(2) imposes mandatory duties on the Department if a 202(c) order "may result in a conflict with a requirement of any Federal, State, or local environmental law or regulation." 16 U.S.C. § 824a(c)(2). The August Order may result in a conflict with environmental requirements.

The statute requires the Department to impose these precautions at the outset where there is a possibility of conflict—a forward-looking inquiry with a necessarily shallow threshold—which then provides a safe harbor if actual noncompliance/violation occurs to carry out the order. The word "may" in this context denotes a mere possibility, not a certainty. This is especially apparent when matched against the term "shall" used in Section 202(c)(2) and the other provisions added to Section 202(c) at the same time. *See* Fixing America's Surface Transportation Act of 2015, Pub. L. No. 114-94, 129 Stat. 1312 § 61002 (codified at 16 U.S.C. § 824a). Congress' use of the two disparate terms must be given effect. *See, e.g.*, *Kingdomware Techs., Inc. v. United States*, 579 U.S. 162, 172 (2016) (discussing significance of the words "may" and "shall" in the same statutory provision). Moreover, the consequences need not be "noncompliance" or "violation" of environmental law, both of which are terms Congress also used in 2015 adding other provisions to Section 202(c). A "conflict" suffices. *Cf. Crosby v. Nat'l Foreign Trade Council*, 530 U.S. 363, 372–73 (2000) (explaining that courts find "conflict" in the preemption context where, for instance, a law or order "stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress").

Taken together, anytime the Secretary's order causes circumstances that might obstruct the accomplishment or execution of environmental laws or regulations, the Department must comply with the Section 202(c)(2) duties. Congress' approach makes sense for a provision meant for responding to emergency situations. Congress was well aware of environmental issues stemming from 202(c) orders when it imposed the requirements in Section 202(c)(2). *See, e.g.*, Rolsma, 57 Conn. L. Rev. at 807–09 (discussing prior incidents of tension between environmental requirements and responses to emergencies on the grid, and congressional hearings addressing the matter as part of the passage of Section 202(c)(2)). Congress struck a reasonable balance so that environmental concerns are not left by the wayside while allowing the Department to respond to actual emergencies. Rather than requiring the Department to engage in a probing review of environmental permits at all levels of our federalist system before acting, Congress set a low threshold for imposition of the mandatory duties. And as discussed next in sec. V.D.2, the congressionally-imposed duties allow the Department to act while also limiting that authority to only what is necessary to meet the emergency, again reflecting Congress' regard for environmental concerns even in an emergency.

The Order here may result in a conflict with environmental requirements. The Department acknowledged the possible conflict in the May Order's imposition of the same availability and economic dispatch mandates included in the August Order. The August Order says nothing to indicate that the Department has backed away from that conclusion, and says nothing that would allow it to do so.

Indeed, the Department implicitly acknowledges the possible conflict. The August Order is limited to a 90-day duration. Ex. 67 at 7, 9 (August Order). That temporal limitation exists for a 202(c) order that may result in a conflict with environmental requirements. 16 U.S.C. § 824a(c)(4). And in imposing the 90-day duration, the Department relies on the statutory limitation for an order that may result in a conflict with environmental requirements. Ex. 67 at 7 n.43 (August Order) (citing 16 U.S.C. § 824a(c)(4)).

Moreover, the evidence shows that the August Order may result in a conflict with environmental requirements. For instance, Campbell's air permit requires air pollution control equipment to be "installed, maintained, and operated in a satisfactory manner and in accordance with the Michigan Air Pollution Control rules and existing law." Ex. 69 at 10 (Powers Sept. Decl.) (quoting Campbell's air permit, which is Attachment C to Exhibit 69). Campbell's air pollution control equipment includes selective catalytic reduction for managing nitrogen oxide emissions and pulse jet fabric filters for managing particulate matter emissions. *Id.* at 8. Failure to install, maintain, and operate these air pollution controls in a satisfactory manner can increase emissions. Specifically, over time, trace metals and fly ash from burned coal can poison and foul the catalysts used in selective catalytic reduction. *Id.* Likewise, over time, fly ash erodes and plugs the bags used in pulse jet fabric filters, causing the bags to degrade and potentially causing the bags to rupture. *Id.* When these catalysts and bags degrade, nitrogen oxide and particulate matter emissions increase. *Id.* at 8–9.

Requiring Campbell to operate may result in a conflict with the requirements in Campbell's air permit because Campbell's catalysts and bags may not be installed, maintained, and operated in a satisfactory manner. On June 10, during the time period covered by the May Order, Consumers reported the following:

- The catalysts in the selective catalytic reduction equipment for Campbell Units 2 and 3 were "at end of life." Ex. 101 at Question 2 (Consumers June Response to AG). Additional catalysts would be required if Campbell were forced to continue operating past the expiration date of the May Order, with one layer of catalyst at Unit 2 costing $3 million and one layer at Unit 3 costing $5 million. *Id.* "Catalyst purchases typically require six-to-twelve-month lead time." *Id.*

- Campbell Unit 3 was "overdue" for a pulse jet fabric filter bag replacement because the company cancelled a prior replacement project "due to expected site closure." *Id.* at Question 15. Without a "full bag changeout," costing between $7 million to $10 million, continuing to operate Campbell Unit 3's pulse jet fabric filter past the expiration date of the May Order could "negatively impact" the equipment's performance. *Id.*

Based on the current state of Campbell's selective catalytic reduction and pulse jet fabric filter equipment, Public Interest Organizations' expert engineer concludes:

> In my professional opinion, and based on the available information, Campbell's SCR [selective catalytic reduction] 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. [] 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.

Ex. 69 at 10 (Powers Sept. Declaration).

The August Order may result in additional conflicts with air pollution laws and regulations. For example, EPA has approved Michigan's regional haze state implementation plan revision. Ex. 114 (2025 EPA MI Haze SIP Approval). The federal Clean Air Act's regional haze program requires states to implement programs to reduce air emissions that cause haze and impair visibility, like nitrogen oxide emissions. Pursuant to the Clean Air Act and its implementing regulations, states must submit regional haze implementation plans to EPA every ten years setting forth how they will further reduce haze-causing air emissions within their borders. 40 C.F.R. § 51.308(f). EPA must then review, and approve or reject, those plans. 42 U.S.C. §§ 7410(k)(3), (l), 7491.

Relevant here, EPA is approving Michigan's plan even though it is based on the flawed assumption that Campbell's air emissions would cease upon retirement in summer 2025. Michigan's Department of Environment, Great Lakes, and Energy informed EPA in a March 2025 supplement to its SIP submittal:

> When retired sometime before May 31, 2025, the permanent shutdown of coal-fired Units 1, 2 and 3 at Consumers Energy – J.H. Campbell Power Plant will represent a reduction in emissions of 2,346 tpy [tons per year] NOX [nitrogen oxides] and 12,850 tpy SO2 [sulfur dioxide] based on the 2016 inventory.

Ex. 115 at 21–22 (Mar. 2025 MI SIP Supplement). The agency reaffirmed its assumption that Campbell would retire and its emissions would cease in a July 2025 Supplement, explaining that the May Order "has been written to expire on August 21, 2025, which [the agency] anticipates will prompt the retirement of the three coal-fired units at the plant on, or shortly thereafter, that date." Ex. 116 at 22–23 (July 2025 MI SIP Supplement). By requiring Campbell to continue operating, then, the August Order may conflict with Michigan's newly-approved regional haze implementation plan and its obligation under the Clean Air Act to reduce haze-causing emissions.

Additionally, Campbell is located directly to the south of Muskegon County and to the north of Allegan County. EPA has designated those two counties as areas in "Serious Nonattainment" with the Clean Air Act's National Ambient Air Quality Standards for ozone.[16] An area is in "non-attainment" when it does not meet federal air quality standards. Campbell emits air pollutants, like nitrogen oxides, that are ozone "precursors," meaning they form ozone in the atmosphere. Ex. 69 at 11 (Powers Sept. Decl.). This means Campbell's air emissions could contribute to Muskegon and Allegan counties' non-attainment with federal ozone standards. *Id.* Thus, by requiring Campbell to continue operating and emitting ozone precursors, the August Order may result in a conflict with air pollution laws and requirements.

2. *The Order Lacks the Conditions Required by Section 202(c).*

   i. *The August Order's Terms Fail to Require Generation Only During Hours Necessary to Meet the Purported Emergency.*

The August Order directly contradicts the Department's obligation to require generation "only during hours necessary to meet the emergency." 16 U.S.C. § 824a(c)(2). The Order instead states: "For the duration of this Order, MISO is

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[16] *See* EPA, *Michigan Nonattainment/Maintenance Status for Each County by Year for All Criteria Pollutants*, https://www3.epa.gov/airquality/greenbook/anayo_mi.html (updated Aug. 31, 2025); Michigan Department of Environment, Great Lakes, Energy, *Attainment Status for the National Ambient Air Quality Standards*, https://www.michigan.gov/-/media/Project/Websites/egle/Documents/Programs/AQD/monitoring/maps/naaqs-ambient-status-map.pdf?rev=d83ea7eae32b4a67b15f9e1da7cfb60f (updated Jan. 2025).

directed to take every step to employ *economic dispatch* of the Campbell Plant to *minimize cost* to ratepayers." Ex. 67 at 8 (August Order) (emphasis added). The "emergency" nominally described by the August Order is "the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages." *Id.* at 7. 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 Campbell's operation. 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 the Department). "Economic dispatch," in sharp contrast, requires "the lowest-cost resources [to] run first," in pursuit of "the lowest-cost energy available." *City of New Orleans v. FERC,* 67 F.3d 947, 948–49 (D.C. Cir. 1995)*; see also Fla. Power & Light Co. v. FERC,* 88 F.3d 1239, 1241 (D.C. Cir. 1996) (noting distinction between economic dispatch and reserve capacity rules).

By instructing MISO to pursue economic dispatch, the Order's terms permit (indeed, direct) operation of the Campbell Plant even when other—albeit potentially higher cost—resources are available that would prevent any "curtailments or outages"—that is, the claimed emergency. Ex. 67 at 7–8 (August Order). The Order's further instructions—limiting "dispatched units to the times and within the parameters as determined by MISO pursuant to paragraph A," *id.* at 8—just repeats that initial instruction to "employ economic dispatch," without any further limitation that would "ensure" that generation occurs "only during hours necessary to meet the emergency" described by the Order, *id.*; 16 U.S.C. § 824a(c)(2). As such, the August Order's terms fail to require operation "only during the hours necessary to meet the emergency" described by the August Order and violate Section 202(c)(2). 16 U.S.C. § 824a(c)(2).[17]

ii. The August Order Fails to Ensure Maximum Practicable Compliance with Environmental Rules and Minimize Adverse Environmental Impacts.

The August Order further fails to "ensure" that Campbell operates, "to the maximum extent practicable," in conformity with applicable environmental rules. *Id.* The August 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. 67 at 8 (August Order). It imposes no further conditions beyond requiring Consumers Energy to "pay fees or purchase offsets or allowances

[17] 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).

for emissions." *Id.* The direction to "comply . . . to the maximum extent feasible" is, as a result, wholly unenforceable; the August 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 5–7 (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 August Order does not meet the Department's statutory obligation to "*ensure*" the maximum feasible compliance with applicable environmental standards—an obligation that requires the Department to offer some discrete guidance as to the plant's operations, rather than merely parroting the statutory text. 16 U.S.C. § 824a(c)(2) (emphasis added).

In addition, the August Order fails 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 August Order claims to minimize impacts by "limit[ing] operation of dispatched units to the times and within the parameters determined by MISO pursuant" to the August Order's "Paragraph A." Ex. 67 at 8 (August Order). But Paragraph A contains only a command that MISO "take all measures necessary to ensure that the Campbell Plant is available to operate" and "employ economic dispatch . . . to minimize cost to ratepayers," and requires Consumers to comply with MISO's orders implementing those commands. *Id.*[18] An instruction minimizing ratepayer costs and demanding availability has no rational relationship to a requirement to minimize environmental impacts. And the Order includes no 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 9 (DOE Order No. 202-17-4 Summary of Findings) (permitting non-compliant operation only during specified hours, and requiring exhaustion of "all reasonably and practically available resources," including 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

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[18] To the extent the Order allows MISO to independently devise conditions limiting environmental impacts, that mere possibility, first, cannot satisfy the Department's own statutory obligation to "ensure" that its "order" minimizes environmental impacts (and limits hours to those necessary to meet the emergency, and mandates the maximum practicable compliance). 16 U.S.C. § 824a(c)(2). And even if it could, the August Order requires MISO to employ "economic dispatch" and "ensure that the Campbell Plant is available to operate—directions that are flatly inconsistent with the statute's requirements related to Campbell's environmental impacts. Ex. 67 at 8 (August Order).

inform affected communities" of non-compliant operations). At a minimum the statute requires the Department to include sufficiently detailed reporting obligations to ascertain what impacts result from emergency operations; without such reporting, the Department has no ability to "ensure" that adverse impacts are minimized. *See, e.g.*, Ex. 110 at 5 (DOE Order No. 202-24-1) (requiring detailed data on emissions of pollutants). The Order here instead only requires "such additional information" as the Department, in the future, may (or may not) "request[] . . . from time to time." Ex. 67 at 8 (August Order). 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).

iii. There is No Indication That the Department Has Conducted the Consultation Required by Section 202(c)(4)(B) or Adopted Conditions Resulting From Consultation.

Finally, there is no indication in the August Order or otherwise that the Department has, as Section 202(c)(4)(B) requires, "consult[ed] with the primary Federal agency with expertise in the environmental interest protected" by the laws with which the August Order may conflict. 16 U.S.C. § 824a(c)(4)(B). The August Order serves as a renewal or re-issuance of the Department's May Order; its claimed basis is that '[t]he emergency conditions that led to the issuance of Order No. 202-25-3 continue." Ex. 67 at 2 (August Order); *see id.* at 7 (basing order on claim that "the emergency conditions . . . supporting the issuance of Order No. 202-25-3 will continue"); *compare* Ex. 1 at 2 (May Order) (determining that "under the conditions specified below, additional dispatch of the Campbell Plant is necessary"), *with* Ex. 67 at 7 (August Order) (determining that "under the conditions specified below, *continued* additional dispatch of the Campbell Plant is necessary" (emphasis added)). But the Department has provided no evidence of consultation with the Environmental Protection Agency (or any other agency with expertise in Campbell's air and water pollution). *Cf.* Ex. 106 at 2 (DOE Order No. 202-22-2 Amendment No. 1) (stating that "the Department consulted with EPA… and EPA did not request any additional conditions"); Ex. 107 at 2 (DOE Order No. 202-22-1 Amendment No. 2) (same); Ex. 6 at 9–10 (DOE Order No. 202-17-4 Summary of Findings) (including EPA consultation in public record). Nor is there any evidence of "[t]he conditions, if any, submitted" by EPA (or any other agency) following consultation, or "an explanation of [the Department's] determination" that such conditions "would prevent the [August Order] from adequately addressing the emergency"—material that Section 202(c)(4)(B) requires the Department to make "available to the public." 16 U.S.C. § 824a(c)(4)(B); *see* Ex. 108 at 1 (Starfield Email to Hoffman) (made public by Department). If the Department has failed to consult and procure the required conditions, it has violated the statute. *Id.* If it has received and declined conditions, but refused to disclose them or an explanation of why the Department does not believe any such conditions are necessary, that too violates the law. *Id.*

VI. Request for Stay

Public Interest Organizations further move the Department for a stay of the Order until the conclusion of judicial review. 18 C.F.R. § 385.212.[19] 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 August 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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[19] Pursuant to FPA Section 313(c) and Rule 713(e) of the applicable rules, the filing of a request for rehearing does not automatically stay a Department Order. 16 U.S.C. § 825*l*(c); 18 C.F.R. § 385.713(e).

market and is producing energy when dispatched."); Ex. 73 at 62 (Consumers' July 2025 10-Q) ("Consumers has continued to make J.H. Campbell available in the MISO market").

As noted extensively *supra* sec. IV.C.3.iii, Campbell emits health- and environment-harming air pollutants like nitrogen oxides, sulfur dioxide, particulate matter, and volatile organic compounds. EPA, ECHO, https://echo.epa.gov/detailed-facility-report?fid=110000411108 (last visited Sept. 3, 2025). In June 2025 alone, Campbell emitted approximately 694,696 pounds of sulfur dioxide, 483,868 pounds of nitrogen oxides, and 1,453,247,200 pounds of carbon dioxide. Ex. 69 at 11 (Powers Sept. Decl.) (citing Ex. 102 (CAMPD Campbell Daily Emissions Data)). Michiganders' health and environment have already been profoundly and irreparably harmed by pollution from Campbell, which historically has had the highest emissions of sulfur dioxide, carbon dioxide, and volatile organic compounds of any plant in Consumers' generation fleet. Ex. 23 at 11 (Bilsback Direct Testimony). 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 million tons of carbon dioxide emissions per year based on 2019 operational levels. Ex. 23 at 11 (Bilsback Direct Testimony). This translates to ending 36–81 premature deaths and $389–$879 million in health impact costs *every year*. *Id.* at 15.

Compounding these pollution problems, recent evidence indicates Campbell's air pollution control equipment may be failing. Campbell uses selective catalytic reduction for managing nitrogen oxide emissions and pulse jet fabric filters for managing particulate matter emissions. Ex. 69 at 8 (Powers Sept. Decl.). On June 10, Consumers indicated that the catalysts in the selective catalytic reduction equipment for Campbell Units 2 and 3 were "at end of life," and that Campbell Unit 3 was "overdue" for a pulse jet fabric filter bag replacement, which could "negatively impact" the equipment's performance. Ex. 101 at Questions 2 and 15 (Consumers June Response to AG). As Public Interest Organizations' expert engineer explains: "A [selective catalytic reduction] 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." Ex. 69 at 10 (Powers Sept. Declaration). Campbell's continued operation is thus further likely to subject Public Interest Organizations', their members, and the public to increased and harmful levels of air pollution.

In addition to this air pollution, Campbell is also a major user and polluter of water in its area. Between June 1 and July 31, Campbell withdrew approximately 40 billion gallons of water from Lake Michigan and discharged approximately the same amount back into the lake. Ex. 69 at 11 (Powers Sept. Decl.) (citing Campbell's discharge monitoring reports). Historically, Campbell has used approximately one billion gallons of water per day from Lake Michigan while discharging significant amounts of contaminated wastewater back into the lake, including cooling water and toxic metals. *See* Ex. 3 at 21 (Powers June Decl.) (citing Ex. 48 (2021 CWA Permit)); EPA, ECHO, https://echo.epa.gov/detailed-facility-report?fid=110000411108 (last visited Sept. 3, 2025).

These health and environmental 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 the Order will be steep. Consumers has reported to the Securities and Exchange Commission that the net financial impact of complying with the May Order just through June 30, 2025, was $29 million. *See* Ex. 73 at 62 (Consumers' July 2025 10-Q). And Campbell is poised to incur continued losses; its June 2025 operating costs, for instance, exceed market prices in 79% of the hours from July 2024 through June 2025. Ex. 68 at 5–6 (Grid Strategies Sept. Report). The costs for complying with the Department's 202(c) orders to Campbell are to be allocated across eleven states in MISO Zones 1–7. *Consumers Energy Co. v. Midcontinent Indep. Sys. Op., Inc.*, 192 FERC ¶ 61,158, at PP 39, 43 (2025); *see* Ex. 75 (MISO Tariff Zonal Map).

Meanwhile, Campbell's planned retirement represents major cost savings for ratepayers. *See, e.g.*, *supra* secs. IV.C.3.iv, V.B.2.iii; 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.

There is no clear avenue for corrective relief of those economic injuries. FERC's order suggests that parties may request rehearing or take "other appropriate steps" to preserve arguments for refunds in the event the Department's Section 202(c) orders are modified, 192 FERC ¶ 61,159, at P 42, but there is no guarantee those arguments will be successful. Consequently, absent a stay, FERC's allocation order makes the exorbitant and unnecessary costs of keeping Campbell operational a Sword of Damocles hanging over the heads of ratepayers in MISO Zones 1-7. As such, 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; *see also* Ex. 52 at 4 (MI State Energy Profile) (discussing demographic and market data).

Additionally, without a stay, the Department creates other injuries too. It needlessly forces Consumers to continue 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 designed to benefit them and the public. 16 U.S.C. § 824; *see also Hughes*, 578 U.S. at 154 (cleaned up) ("Under the [Federal Power Act], 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."). 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."). And, in forcing ratepayers to reopen and operate an uneconomic, unreliable, and obsolete resource that the state, stakeholders, and owner want to close, *see supra* sec. IV.C, 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. U.S. Dep't of Energy, *Energy Reliability and Resilience,* https://www.energy.gov/eere/energy-reliability-and-resilience (last visited Sept. 7, 2025). There is no clear recourse to remedy those injuries either.

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* secs. IV.B–.C, V.A. Furthermore, because Consumers and MISO have both already planned for Campbell's closure, 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. 67 at 7–8 (August 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.

VII. Conclusion

For the reasons set forth above, the undersigned Public Interest Organizations respectfully request that the Department grant intervention; grant rehearing and rescind the Order (and any renewals of the Order); and stay the Order.

Filed on September 8, 2025

Submitted by:

[Continued for signatures.]

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Attachment: Index of Exhibits

Index of Exhibits

No.	Exhibit Name	Document Name	URL
1	May 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 June Report	Michael Goggin, *A Review of DOE's 202(c) Order for the Campbell Coal Plant* (June 18, 2025)	
3	Powers June 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
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

No.	Exhibit Name	Document Name	URL
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
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
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

No.	Exhibit Name	Document Name	URL
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
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

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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 Michigan Commission 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
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

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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

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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#
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

No.	Exhibit Name	Document Name	URL
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 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/
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

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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
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
60	MISO Tariff Section 38.2.7	MISO Tariff Section 38.2.7	https://docs.misoenergy.org/miso12-legalcontent/TariffAsFiledVersion.pdf

No.	Exhibit Name	Document Name	URL
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
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
67	August Order	DOE Order No. 202-25-7 (August 20, 2025)	https://www.energy.gov/sites/default/files/2025-08/MISO%20Order%20No.%20202-25-7.pdf
68	Grid Strategies Sept. Report	Michael Goggin, *A Review of DOE's Second 202(c) Order for the Campbell Coal Plant* (Sept. 2025)	
69	Powers Sept. Decl.	Declaration of Bill Powers, P.E. (Sept. 3, 2025) (including attachments)	
70	Konidena Decl.	Declaration of Rao Konidena (Sept. 3, 2025) (including attachment)	

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71	Public Interest Organizations' June Rehearing Request	Request for Rehearing of Sierra Club et al., Order No. 202-25-3 (June 18, 2025)	https://www.energy.gov/sites/default/files/2025-07/PIO%20Request%20for%20Rehearing%20of%20Order%20No.%20202-25-3.pdf
72	Department's July Notice	U.S. Dep't of Energy, *Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration*, Order No. 202-25-3A (dated July 28, 2025)	https://www.energy.gov/sites/default/files/2025-07/Notice%20of%20Denial%20of%20Rehearing%20by%20Operation%20of%20Law%20and%20Providing%20for%20Further%20Consideration%20-%20Order%20No.%20202-25-3A.pdf
73	Consumers' July 2025 10-Q	CMS Energy Corp. & Consumers Energy Co., Form 10-Q (July 31, 2025)	https://www.cmsenergy.com/investor-relations/regulatory-filings/Consumers-Energy-SEC-Filings/default.aspx
74	DOE 202(c) Webpage	U.S. Dep't of Energy, DOE's Use of Federal Power Act Emergency Authority (last visited Aug. 30, 2025), https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
75	MISO Tariff Zonal Map	MISO, Attachment VV to FERC-Approved Tariff	https://etariff.ferc.gov/TariffBrowser.aspx?tid=1162
76	Secretary Wright's West Virginia Remarks	Charles Young, West Virginia News, *Energy Secretary Chris Wright: Future of U.S. Coal is "long and bright"* (July 5, 2025)	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
77	MISO 2021 Transmittal Letter	Transmittal Letter, FERC Docket No. ER22-495-000 (Nov. 30, 2021), Accession No. 20211130-5166	https://elibrary.ferc.gov/eLibrary/filelist?accession_Number=20211130-5166
78	McFarlane Testimony	Testimony of Shawn McFarlane, FERC Docket No. ER22-495 (Nov. 30, 2021), Accession No. 20211130-5166 (Tab C)	https://elibrary.ferc.gov/eLibrary/filelist?accession_Number=20211130-5166
79	MISO 2022 Accreditation Order	*Midcontinent Indep. Sys. Op., Inc.*, 180 FERC ¶ 61,141 (Aug. 31, 2022)	https://elibrary.ferc.gov/eLibrary/filelist?accession_Number=20220831-3093
80	MISO 2023-24 LOLE Study Report	MISO, Planning Year 2023-2024 Loss of Load Expectation Study Report (May 2023)	https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf

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81	Joundi Testimony	Testimony of Zakaria Joundi, FERC Docket No. ER24-1638 (Mar. 28, 2024), Accession No. 20240328-5329 (Tab E)	https://elibrary.ferc.gov/eLibrary/filelist?accession_Number=20240328-5329
82	MISO 2024-25 LOLE Study Report	MISO, Planning Year 2024-2025 Loss of Load Expectation Study Report (April 2024)	https://cdn.misoenergy.org/LOLE%20Study%20Report%20PY%202024-2025631112.pdf
83	MISO 2025-26 LOLE Study Report	MISO, Planning Year 2025-2026 Loss of Load Expectation Study Report (April 2025)	https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401
84	MISO 2024-25 Auction Results	MISO, Planning Resource Auction Results for Planning Year 2024-25 (Corrected) (April 26, 2024)	https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%2020240425632665.pdf
85	MISO Attributes Roadmap	MISO Attributes Roadmap (Dec. 2023)	https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf
86	MISO Attributes Roadmap Technical Appendix	MISO, Technical Appendix: Attributes Roadmap (June 2024)	https://cdn.misoenergy.org/2023%20Attributes%20Technical%20Appendix631176.pdf
87	MISO's Response to the Reliability Imperative	MISO's Response to the Reliability Imperative (Feb. 2024)	https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf
88	August 20 weather report	Jennifer Gray, Taste of Fall On The Way: Here's Who Will Feel The Big Cooldown First, USA National Forecast (Aug. 20, 2025)	https://web.archive.org/web/20250820225303/https://weather.com/forecast/national/news/2025-08-20-first-taste-of-fall-plains-midwest-south-forecast
89	2025 OMS-MISO Survey	2025 OMS-MISO Survey Results (June 6, 2025)	https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf
90	MISO ERAS Transmittal Letter	Re: Midcontinent Independent System Operator, Inc. Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff Expedited Resource Addition Study Filing, Docket No. ER25-2454-000 (June 6, 2025), Accession No. 20250606-5228	https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250606-5228&optimized=false&sid=c2678d58-1762-48e9-bcca-059a2a848538

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91	MISO ERAS Decision	Order Accepting Tariff Revisions, Subject to Condition, 192 FERC ¶ 61,064 (July 21, 2025)	https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250721-3077&optimized=false&sid=c2678d58-1762-48e9-bcca-059a2a848538
92	Energy Emergency EO	Exec. Order No. 14,156, Declaring a National Energy Emergency	90 Fed. Reg. 8433 (Jan. 29, 2025)
93	Grid EO	Exec. Order No. 14,262, Strengthening the Reliability and Security of the U.S. Electric Grid	90 Fed. Reg. 15,521 (Apr. 14, 2025)
94	NY Times Coal Article	Brad Plumer & Mira Rojanasakul, *Trump Signs Orders Aimed at Reviving a Struggling Coal Industry*, NY Times (Sept. 3, 2025).	https://www.nytimes.com/2025/04/08/climate/trump-order-coal-mining.html
95	Eddystone May Order	DOE Order No. 202-25-4 (May 30, 2025)	https://www.energy.gov/sites/default/files/2025-05/Federal%20Power%20Act%20Section%20202%28c%29%20PJM%20Interconnection.pdf
96	July Resource Adequacy Report	DOE, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Grid (July 2025)	https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf
97	DOE July 7 Press Release	*DOE*, *Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security* (July 7, 2025)	https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security
98	Eddystone August Order	DOE Order No. 202-25-8 (Aug. 28, 2025)	https://www.energy.gov/sites/default/files/2025-08/202c%20Order%20No.%20202-25-8.pdf
99	PIOs' RFR of July Resource Adequacy Report	Motion to Intervene and Request for Rehearing of Natural Resources Defense Council, the Ecology Center, Environmental Defense Fund, Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar, DOE Resource Adequacy Report (Aug. 8, 2025).	https://sustainableferc.org/wp-content/uploads/2025/08/2025-08-06_NRDC-et-al-Request-for-Rehearing-DOE-Resource-Adequacy-Report.pdf

No.	Exhibit Name	Document Name	URL
100	Curran Testimony	Testimony of Jennifer Curran before the House Committee on Energy and Commerce, Subcommittee on Energy (March 25, 2025)	https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-CurranJ-20250325.pdf
101	Consumers June Responses to AG	Excerpt of Consumers Energy, Informal Response to Michigan Attorney General Questions re: Campbell (June 10, 2025)	
102	CAMPD Campbell Daily Emissions Data	EPA, Clean Air Markets Program Data (CAMPD), June daily emissions data by unit for the Campbell Plant (6/1/2025–6/30/2025)	https://campd.epa.gov/data/custom-data-download. To access daily emissions data, 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."
103	July 17 Email from Consumers to EGLE	Joseph Firlit, Consumers, email to April Lazzaro, EGLE, July 17, 2025	
104	CAMPD Campbell Hourly Emissions Data	EPA, Clean Air Markets Program Data (CAMPD), June hourly emissions data by unit for the Campbell Plant (6/1/2025–6/30/2025)	https://campd.epa.gov/data/custom-data-download. To access hourly emissions data, 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."
105	DOE Order No. 202-08-1	DOE Order No. 202-08-1 (Sept. 14, 2008)	https://www.energy.gov/sites/prod/files/202%28c%29%20order%20202-08-1%20September%2014%2C%202008%20-%20CenterPoint%20Energy.pdf
106	DOE Order No. 202-22-2 Amendment No. 1	DOE Order No. 202-22-2 Amendment No. 1 (Sept. 8, 2022)	https://www.energy.gov/sites/default/files/2022-09/Amendment%20No.%201%20to%20Order%20202-22-2%20sb%20A_S3%20Hogan.pdf

No.	Exhibit Name	Document Name	URL
107	DOE Order No. 202-22-1 Amendment No. 2	DOE Order No. 202-22-1 Amendment No. 2 (Sept. 8, 2022)	https://www.energy.gov/sites/default/files/2022-09/Amendment%202%20to%20Order%20202-22-1_FINAL_9.8.2022%20sb%20A_S3%20Hogan.pdf
108	Starfield Email to Hoffman	Email from Lawrence Starfield, EPA to Patricia Hoffman, DOE Re: DOE section202(c) order (Sept. 11, 2017)	https://www.energy.gov/sites/default/files/2017/09/f36/2017-9-11%20EPA%20consultation%20renewal.pdf
109	MISO ERAS News Release	MISO, Expedited Resource Addition Study Attracts Large, Diverse Applicant Pool (Aug. 26, 2025)	https://www.misoenergy.org/meet-miso/media-center/2025---news-releases/expedited-resource-addition-study-attracts-large-diverse-applicant-pool/
110	DOE Order No. 202-24-1	DOE Order No. 202-24-1 (Oct. 9, 2024)	https://www.energy.gov/sites/default/files/2024-10/Duke%20202%28c%29%20Order_100924%20FINAL_JMG%20signed.pdf
111	MISO June Operations Report	MISO Monthly Operations Report: June 2025	https://cdn.misoenergy.org/202506%20Market%20and%20Operations%20Report709571.pdf
112	Witmeier 2024 Queue Cap Testimony	Errata to Att. X Queue Cap Proposal and Exemptions to Queue Cap, Tab A, Prepared Direct Testimony of Andrew Witmeier, at 21:4, Docket No. ER25-507-000 (Nov. 21, 2024) ("Witmeier 2024 Queue Cap Testimony"), Accession No. 20241213-5063.	https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20241213-5063&optimized=false&sid=1e90ede4-da17-4482-8e6d-e346192d0609
113	Inst. Pol'y Integrity Report	Inst. Pol'y Integrity, Enough Energy: A Review of DOE's Resource Adequacy Methodology (July 2025)	https://policyintegrity.org/files/publications/IPI_EnoughEnergy_FinalReport.pdf
114	2025 EPA MI Haze SIP Approval	Air Plan Approval; Michigan; Second Period Regional Haze Plan, 90 Fed. Reg. 42833 (Sept. 5, 2025)	https://www.govinfo.gov/content/pkg/FR-2025-09-05/pdf/2025-17096.pdf
115	Mar. 2025 MI SIP Supplement	Excerpt of EGLE, Supplement to Michigan's August 23, 2021 Regional Haze State Implementation Plan Revision for the Second Planning Period (Mar. 2025)	

No.	Exhibit Name	Document Name	URL
116	July 2025 MI SIP Supplement	Excerpt of EGLE, Supplement to Michigan's August 23, 2021 Regional Haze State Implementation Plan Revision for the Second Planning Period (July. 2025)	
117	RTO Insider Article on August Order	John Cropley & Amanda Durish Cook, DOE Orders Mich. Coal Plant to Remain Available Another 90 Days, RTO Insider (Aug. 21, 2025).	https://www.rtoinsider.com/113044-doe-orders-mich-coal-plant-to-remain-available-another-90-days/
118	RMI Analysis of Coal Plants' Threats to Reliability	Gabriella Tosado, Ashtin Massie & Joe Daniel, *Reality Check: We Have What's Needed to Reliably Power the Data Center Boom, and It's Not Coal Plants*, RMI (Aug. 12, 2025)	https://rmi.org/reality-check-we-have-whats-needed-to-reliably-power-the-data-center-boom-and-its-not-coal-plants/
119	ZRC Replacement	ZRC replacement and instructions in the MECT, Resource Adequacy Subcommittee (May 5, 2023	https://cdn.misoenergy.org/20230524%20RASC%20Item%2004b%20ZRC%20Replacement628921.pdf
120	2024 OMS-MISO Survey	2024 OMS-MISO Survey Results (June 20, 2024)	https://cdn.misoenergy.org/20240620%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation635585.pdf
121	Witmeier 2025 ERAS Testimony	Prepared Direct Testimony of Andrew Witmeier, FERC Docket No. ER25-2454-000, (June 6, 2025), Accession No. 20250606-5228	https://elibrary.ferc.gov/eLibrary/filelist?accession_Number=20250606-5228
122	GridLab Report	GridLab Analysis: Department of Energy Resource Adequacy Report (July 11, 2025)	https://gridlab.org/gridlab-analysis-department-of-energy-resource-adequacy-report/
123	Duke University Rethinking Load Growth Study	Tyler H. Norris et al., Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems, Duke University Nicholas Institute for Energy, Environment & Sustainability (Feb. 2025)	https://nicholasinstitute.duke.edu/sites/default/files/publications/rethinking-load-growth.pdf

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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

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

Exhibit 126

CAMPD Campbell Daily Emissions Data July – Sept.

State	Facility Name	Facility ID	Unit ID	Associated Stacks	Date	Operating Time Count	Sum of the Operating Time	Gross Load (MWh)	Steam Load (1000 lb)	SO2 Mass (short tons)	SO2 Rate (lbs/mmBtu)	CO2 Mass (short tons)	CO2 Rate (short tons/mmBtu)	NOx Mass (short tons)	NOx Rate (lbs/mmBtu)	Heat Input (mmBtu)	Primary Fuel Type	Secondary Fuel Type	Unit Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Program Code
MI	J H Campbell	1710	1		7/1/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/2/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/3/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/4/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/5/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/6/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/7/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/8/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/9/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/10/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/11/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/12/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/13/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/14/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/15/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/16/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/17/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/18/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/19/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/20/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/21/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/22/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/23/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/24/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/25/2025	0	0										Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/26/2025	22	21.23	0		0	0	314.674	0.1049	0.106	0.0638	2997.218	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/27/2025	24	24	3251		4.809	0.2242	3956.8	0.105	3.813	0.2517	37727.2	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/28/2025	24	24	5130		7.429	0.2713	5744.1	0.105	3.997	0.146	54768.8	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/29/2025	24	24	5684		8.06	0.2712	6234.5	0.105	4.589	0.1534	59444.6	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/30/2025	24	24	6115		8.503	0.2694	6620.6	0.105	5.079	0.1609	63126.1	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		7/31/2025	24	24	6117		8.501	0.2733	6525.1	0.105	4.892	0.1573	62214.3	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/1/2025	24	24	6114		8.332	0.2684	6511.5	0.105	4.799	0.1546	62082.7	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/2/2025	24	24	6113		8.25	0.2699	6414.6	0.105	4.735	0.1548	61160	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/3/2025	24	24	6116		8.254	0.2712	6386	0.105	4.738	0.1556	60889.6	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/4/2025	24	24	5526		7.505	0.2694	5842.6	0.105	4.328	0.1551	55708	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/5/2025	24	24	6065		8.287	0.2699	6443.1	0.105	4.877	0.1588	61433.4	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/6/2025	24	24	5899		7.432	0.2504	6236.9	0.105	4.545	0.1524	59465.8	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/7/2025	24	24	6089		7.1	0.2302	6468.4	0.105	4.955	0.1607	61673.2	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/8/2025	24	24	6073		7.74	0.2467	6571.8	0.105	5.43	0.1733	62661	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/9/2025	24	24	6113		8.538	0.2703	6627.5	0.105	5.37	0.17	63192.9	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/10/2025	24	24	6099		8.538	0.2705	6621.8	0.105	5.567	0.1763	63136.6	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/11/2025	24	24	6099		8.52	0.2711	6593.1	0.105	5.636	0.1793	62863.3	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/12/2025	24	24	6025		8.036	0.262	6435.6	0.105	5.396	0.1758	61362	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/13/2025	24	24	6116		7.849	0.2506	6568.1	0.105	5.513	0.1761	62625.5	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/14/2025	24	24	6111		7.825	0.2505	6553.9	0.105	5.373	0.172	62488.8	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/15/2025	24	24	6111		7.832	0.249	6597	0.105	5.273	0.1677	62900.5	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/16/2025	24	24	5763		7.494	0.2521	6248.9	0.105	5.098	0.1707	59583.3	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/17/2025	24	24	6065		7.775	0.25	6522.5	0.105	5.38	0.173	62191.8	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/18/2025	24	24	5836		8.351	0.2826	6211.6	0.105	4.852	0.1634	59226.9	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/19/2025	24	24	6043		8.333	0.2715	6440.1	0.105	5.296	0.1725	61403.2	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/20/2025	24	24	6042		8.649	0.2825	6423.5	0.105	5.102	0.1666	61247.7	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/21/2025	24	24	6054		7.878	0.2563	6450.3	0.105	4.957	0.1612	61500.8	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/22/2025	24	24	6066		8.321	0.2703	6457	0.105	5.054	0.1642	61565.1	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/23/2025	24	24	6065		8.295	0.2714	6412.3	0.105	4.961	0.1623	61138	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/24/2025	24	24	6065		8.378	0.2736	6423.7	0.105	4.965	0.1621	61248.3	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/25/2025	24	24	6055		8.571	0.2843	6326.1	0.105	4.728	0.1568	60318.7	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/26/2025	24	24	4197		6.352	0.292	4565.6	0.105	3.108	0.1414	43528	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/27/2025	24	24	3734		5.461	0.2745	4175	0.105	2.766	0.139	39808.6	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/28/2025	24	24	3896		5.598	0.2713	4327.2	0.105	2.966	0.1438	41260.2	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/29/2025	24	24	3912		5.574	0.2694	4340.7	0.105	2.88	0.1392	41388	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/30/2025	24	24	3914		5.568	0.2681	4355.6	0.105	2.923	0.1408	41529.7	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		8/31/2025	24	24	3915		5.492	0.2634	4374.7	0.105	2.955	0.1417	41709.5	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/1/2025	24	24	3916		5.493	0.2636	4372.6	0.105	3.02	0.1449	41691.7	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/2/2025	24	24	3916		5.685	0.2672	4465.3	0.105	3.109	0.1462	42577.6	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/3/2025	24	24	3913		5.154	0.2415	4473.4	0.105	2.93	0.1374	42652.7	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/4/2025	24	24	3890		4.784	0.2306	4351.5	0.105	2.865	0.1381	41487	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/5/2025	24	24	3841		5.051	0.248	4270.7	0.105	2.913	0.1431	40718.6	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/6/2025	24	24	3844		5.192	0.2548	4276.9	0.105	2.817	0.1382	40778.2	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/7/2025	24	24	3841		5.122	0.2502	4294.1	0.105	2.806	0.137	40945	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/8/2025	24	24	3933		5.371	0.2568	4377.4	0.105	2.815	0.135	41735.6	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/9/2025	24	24	5272		6.613	0.2501	5551.1	0.105	3.92	0.1471	52927.9	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/10/2025	24	24	5611		6.996	0.2505	5859.4	0.105	4.45	0.1593	55869.4	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/11/2025	24	24	5610		7.328	0.2608	5897.3	0.105	4.433	0.1577	56228.3	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/12/2025	24	24	5610		7.214	0.2556	5920	0.105	4.554	0.1613	56445.8	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/13/2025	24	24	5612		7.024	0.2503	5887.9	0.105	4.557	0.1623	56139.9	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/14/2025	24	24	5192		6.719	0.2549	5525.6	0.105	4.239	0.1601	52685	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/15/2025	24	24	5632		7.22	0.2546	5949.9	0.105	4.689	0.1653	56728.6	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/16/2025	24	24	5636		7.108	0.2518	5923.7	0.105	4.474	0.1584	56483.3	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/17/2025	24	24	5632		7.81	0.2762	5929.3	0.105	4.539	0.1606	56535.3	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/18/2025	24	24	3807		5.821	0.2923	4174.9	0.105	3.274	0.1647	39806.7	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/19/2025	24	24	3313		4.79	0.2703	3711.7	0.105	3.438	0.1995	35389.7	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/20/2025	24	24	3115		4.508	0.2698	3504.6	0.105	4.191	0.2508	33416.2	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/21/2025	24	24	3115		4.489	0.2697	3491.6	0.105	4.13	0.2481	33288.9	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/22/2025	24	24	3115		4.567	0.2737	3500.4	0.105	4.327	0.2593	33375.8	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/23/2025	24	24	3116		4.534	0.2713	3507	0.105	4.231	0.253	33436.1	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/24/2025	24	24	3117		4.575	0.2743	3499.2	0.105	4.181	0.2506	33365.3	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/25/2025	24	24	4231		5.847	0.2688	4578.2	0.105	4.012	0.195	43652.9	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/26/2025	24	24	5584		7.656	0.2698	5957.3	0.105	4.527	0.1594	56800.7	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/27/2025	24	24	5586		7.702	0.2699	5988	0.105	4.739	0.166	57094.3	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/28/2025	24	24	5588		7.761	0.2711	6004.9	0.105	4.656	0.1626	57255	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/29/2025	24	24	5586		7.871	0.2737	6033.7	0.105	4.611	0.1603	57530.3	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	1		9/30/2025	24	24	5585		7.583	0.2629	6052.8	0.105	4.738	0.1642	57712.6	Coal		Tangentially-fired	Dry Sorbent Injection	Low NOx Burner Technology w/ Closed-coupled/Separated OFA	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/1/2025	24	24	4800		6.39	0.2635	5086.9	0.105	1.294	0.0534	48501.1	Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/2/2025	24	24	4798		6.134	0.2503	5137.4	0.105	1.31	0.0535	48986.3	Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/3/2025	24	24	4798		6.014	0.2478	5092.3	0.105	2.116	0.0871	48553.5	Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/4/2025	11	10.75	1889.75		2.416	0.2489	2037.65	0.105	1.25	0.1385	19429.5	Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/5/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/6/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/7/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/8/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/9/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/10/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/11/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/12/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS

State	Facility Name	Facility ID	Unit ID	Associated Stacks	Date	Operating Time Count	Sum of the Operating Time	Gross Load (MWh)	Steam Load (1000 lb)	SO2 Mass (short tons)	SO2 Rate (lbs/mmBtu)	CO2 Mass (short tons)	CO2 Rate (short tons/mmBtu)	NOx Mass (short tons)	NOx Rate (lbs/mmBtu)	Heat Input (mmBtu)	Primary Fuel Type	Secondary Fuel Type	Unit Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Program Code
MI	J H Campbell	1710	2		7/13/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/14/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/15/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/16/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/17/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/18/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/19/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/20/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/21/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/22/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/23/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/24/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/25/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/26/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/27/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/28/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/29/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/30/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		7/31/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/1/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/2/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/3/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/4/2025	4	2.18	0		0	0	29.564	0.079	0.002	0.0103	281.882	Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/5/2025	9	8.87	0		0.104	0.0773	241.543	0.105	0.121	0.0921	2303.137	Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/6/2025	24	24	2142		3.017	0.2199	2738.1	0.105	2.707	0.2025	26107.2	Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/7/2025	24	24	5157		6.188	0.2399	5411	0.105	1.514	0.0587	51592.3	Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/8/2025	24	24	5154		6.114	0.2392	5361.8	0.105	1.389	0.0543	51121.3	Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/9/2025	24	24	3129		4.041	0.2394	3553.6	0.105	0.87	0.0512	33882.8	Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/10/2025	7	6.88	701.64		0.993	0.2454	850.524	0.105	0.218	0.054	8109.584	Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/11/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/12/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/13/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/14/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/15/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/16/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/17/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/18/2025	13	10.76	0		0.002	0.0015	225.167	0.1047	0.089	0.0512	2147.505	Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/19/2025	24	24	3269		4.891	0.2015	3671.7	0.105	2.52	0.1499	35008.5	Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/20/2025	24	24	4772		6.549	0.2748	4962.9	0.105	1.352	0.0572	47321.2	Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/21/2025	24	24	2766		3.88	0.259	3142.3	0.105	0.945	0.0644	29962.5	Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/22/2025	2	1.22	106.54		0.148	0.2425	124.198	0.105	0.11	0.191	1184.53	Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/23/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/24/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/25/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/26/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/27/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/28/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/29/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/30/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		8/31/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/1/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/2/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/3/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/4/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/5/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/6/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/7/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/8/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/9/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/10/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/11/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/12/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/13/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/14/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/15/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/16/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/17/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/18/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/19/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/20/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/21/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/22/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/23/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/24/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/25/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/26/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/27/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/28/2025	0	0										Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/29/2025	11	10.4	0		0.076	0.0428	225.93	0.105	0.107	0.068	2153.514	Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	2		9/30/2025	24	24	2940		3.968	0.2051	3515.2	0.105	1.641	0.126	33515.8	Coal		Cell burner boiler	Dry Sorbent Injection	Low NOx Cell Burner | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/1/2025	24	24	18238		4.918	0.053	19510.8	0.105	5.578	0.06	186030.3	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/2/2025	24	24	16825		4.529	0.0512	18369.3	0.105	4.437	0.0504	175144.6	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/3/2025	24	24	17315		3.589	0.0386	19205.1	0.105	9.476	0.1018	183115	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/4/2025	24	24	18144		4.895	0.0513	19973.6	0.105	5.651	0.0594	190440.8	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/5/2025	24	24	18128		4.959	0.0527	19715.2	0.105	6.201	0.0661	187978.6	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/6/2025	24	24	18120		4.6	0.0494	19513.7	0.105	4.822	0.0518	186058.2	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/7/2025	24	24	18167		4.779	0.051	19666.5	0.105	4.459	0.0475	187516	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/8/2025	24	24	18056		4.775	0.0518	19289.5	0.105	4.917	0.0535	183919.8	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/9/2025	24	24	17210		3.817	0.0425	18831.9	0.105	4.648	0.0521	179556	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/10/2025	24	24	18181		4.732	0.0509	19439.6	0.105	4.197	0.0453	185352.2	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/11/2025	24	24	17937		5.588	0.0619	19111.9	0.105	5.305	0.058	182226.4	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/12/2025	24	24	18175		3.992	0.043	19516.9	0.105	5.556	0.0597	186089.5	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/13/2025	24	24	18182		4.747	0.0508	19595	0.105	5.207	0.0558	186831.2	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/14/2025	24	24	18183		4.685	0.0495	19894.3	0.105	4.776	0.0504	189684.2	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/15/2025	24	24	18073		5.014	0.0539	19715	0.105	3.848	0.041	187978.4	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/16/2025	24	24	15221		3.353	0.0409	17205.9	0.105	17.751	0.2164	164053.5	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/17/2025	24	24	15214		4.221	0.0503	17599.2	0.105	18.244	0.2175	167803.8	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/18/2025	24	24	16092		4.507	0.0521	18186	0.105	10.126	0.118	173397.9	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/19/2025	24	24	18207		4.684	0.0508	19416.3	0.105	4.9	0.053	185129.1	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/20/2025	24	24	18192		4.699	0.0507	19467.8	0.105	4.711	0.0508	185621.6	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/21/2025	24	24	18146		4.604	0.0489	19689.9	0.105	3.997	0.0426	187738.5	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/22/2025	24	24	18149		4.498	0.0478	19718.6	0.105	4.512	0.048	188012.6	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/23/2025	24	24	18164		4.545	0.0483	19697.4	0.105	5.324	0.0568	187809.9	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/24/2025	24	24	18178		5.201	0.0558	19558.4	0.105	5.01	0.0538	186483.4	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS

State	Facility Name	Facility ID	Unit ID	Associated Stacks	Date	Operating Time Count	Sum of the Operating Time	Gross Load (MWh)	Steam Load (1000 lb)	SO2 Mass (short tons)	SO2 Rate (lbs/mmBtu)	CO2 Mass (short tons)	CO2 Rate (short tons/mmBtu)	NOx Mass (short tons)	NOx Rate (lbs/mmBtu)	Heat Input (mmBtu)	Primary Fuel Type	Secondary Fuel Type	Unit Type	SO2 Controls	NOx Controls	PM Controls	Hg Controls	Program Code
MI	J H Campbell	1710	3		7/25/2025	24	24	18196		4.642	0.0492	19790.6	0.105	5.191	0.055	188694.5	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/26/2025	24	24	18210		4.86	0.0516	19778.1	0.105	6.315	0.067	188578.4	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/27/2025	24	24	17816		4.692	0.0503	19498.8	0.105	4.635	0.0496	185916.5	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/28/2025	24	24	17583		4.473	0.0479	19545.5	0.105	11.108	0.1203	186362.6	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/29/2025	24	24	17800		4.427	0.0469	19752.1	0.105	6.306	0.0664	188331.3	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/30/2025	24	24	17335		5.734	0.0635	19106.5	0.105	4.316	0.0475	182173.9	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		7/31/2025	24	24	18193		4.828	0.051	19903	0.105	4.998	0.0527	189769.6	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/1/2025	24	24	14659		3.747	0.0461	17021.6	0.105	4.097	0.0499	162294.8	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/2/2025	24	24	11661		5.691	0.0869	13776	0.105	2.461	0.0374	131350.5	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/3/2025	24	24	16842		4.233	0.0475	18784.2	0.105	4.368	0.0486	179103.9	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/4/2025	24	24	18180		4.478	0.0473	19838.8	0.105	5.509	0.0583	189157.2	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/5/2025	24	24	18166		5.062	0.0535	19888.1	0.105	5.776	0.061	189625.9	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/6/2025	24	24	14636		3.101	0.0404	16452.6	0.105	2.797	0.0343	156870.6	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/7/2025	24	24	13480		4.179	0.058	15119.6	0.105	2.114	0.0293	144159.6	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/8/2025	24	24	13633		4.377	0.0599	15308.1	0.105	2.274	0.031	145959.5	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/9/2025	24	24	18227		8.185	0.0906	19103.7	0.105	5.23	0.0575	182147.2	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/10/2025	24	24	18201		8.727	0.0982	18721.2	0.105	4.864	0.0545	178502.6	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/11/2025	24	24	18185		5.079	0.0558	19104.4	0.105	4.998	0.0549	182153.5	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/12/2025	24	24	18212		5.473	0.0595	19321.7	0.105	7.805	0.0846	184227.8	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/13/2025	24	24	15908		4.465	0.0527	17791.3	0.105	3.815	0.0451	169635.8	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/14/2025	24	24	17365		4.721	0.0518	19099.8	0.105	5.619	0.061	182110.7	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/15/2025	24	24	18103		4.56	0.0483	19846.8	0.105	10.586	0.1118	189233	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/16/2025	24	24	15224		3.785	0.0452	17583.1	0.105	4.39	0.0515	167648.6	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/17/2025	24	24	13538		3.735	0.049	16021.7	0.105	4.173	0.0546	152763.1	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/18/2025	24	24	13484		3.832	0.0508	15858.1	0.105	5.992	0.0793	151204	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/19/2025	24	24	13538		3.94	0.052	15897.3	0.105	8.405	0.1105	151577.9	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/20/2025	24	24	13525		3.906	0.0513	15985.9	0.105	1.9	0.0248	152419.6	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/21/2025	24	24	13513		3.725	0.0487	16082	0.105	0.747	0.0098	153336.5	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/22/2025	18	17.5	8647.5		5.857	0.1542	10257.55	0.105	2.606	0.0827	97801.95	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/23/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/24/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/25/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/26/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/27/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/28/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/29/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/30/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		8/31/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/1/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/2/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/3/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/4/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/5/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/6/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/7/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/8/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/9/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/10/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/11/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/12/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/13/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/14/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/15/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/16/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/17/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/18/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/19/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/20/2025	0	0										Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/21/2025	6	4.83	0		0.002	0.0053	48.4	0.07	0.004	0.0122	461.73	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/22/2025	24	24	0		0.01	0.0135	190.1	0.1049	0.027	0.0286	1810.7	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/23/2025	24	24	2590		8.407	0.3243	3476.2	0.105	3.013	0.168	33146.4	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/24/2025	24	24	8716		23.09	0.5037	9719.9	0.105	7.495	0.182	92675	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/25/2025	24	24	14451		20.978	0.282	15490.9	0.105	6.95	0.0934	147701	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/26/2025	24	24	13058		6.964	0.0982	14873.1	0.105	2.668	0.0376	141808.7	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/27/2025	24	24	13078		2.322	0.0326	15100.8	0.105	2.85	0.0396	143980.8	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/28/2025	24	24	14443		0.662	0.0082	16850.4	0.105	3.462	0.0429	160662.3	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/29/2025	24	24	17295		2.504	0.0284	18420.7	0.105	4.457	0.0507	175634.1	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS
MI	J H Campbell	1710	3		9/30/2025	24	24	18232		2.128	0.0239	18630.8	0.105	4.472	0.0504	177638.8	Coal		Dry bottom wall-fired b	Dry Lime FGD	Low NOx Burner Technology w/ Overfire Air | Selective Catalytic Reduction	Baghouse	Halogenated PAC Sorbent Injection	ARP, CSNOX, CSOSG2E, CSSO2G1, MATS

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 127

Michigan Commission 2025 Capacity Demonstration Order

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion, to open a docket for load serving entities in Michigan to file their capacity demonstrations for the 2028/2029 planning year as required by MCL 460.6w.	)	Case No. U-21775
In the matter, on the Commission's own motion, to open a docket for load serving entities in Michigan to file their capacity demonstrations for the 2029/2030 planning year as required by MCL 460.6w.	)	Case No. U-21907

At the August 21, 2025 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Daniel C. Scripps, Chair
Hon. Katherine L. Peretick, Commissioner
Hon. Shaquila Myers, Commissioner

ORDER

Background and Procedural History

Public Act 3 of 1939, as amended by Public Act 341 of 2016 (Act 341), MCL 460.6w(8) (Section 6w(8)), requires each electric utility, alternative electric supplier (AES), cooperative electric utility, and municipally owned electric utility to demonstrate to the Commission, in a format determined by the Commission, that each load serving entity (LSE) owns or has contractual rights to sufficient capacity to meet its capacity obligations as set by the appropriate independent system operator (ISO), or the Commission, as applicable.[1] This is known as a state reliability mechanism (SRM) capacity demonstration.

Act 341 states that regulated electric utilities' capacity demonstration filings are due by December 1 each year, with filings by AESs, cooperatives, and municipally owned electric utilities due by the seventh business day in February each year. MCL 460.6w(8)(a)-(b). However, the statute also allows the Commission to adjust these dates to ensure proper alignment with the ISO's procedures and requirements. MCL 460.6w(10). In the September 15, 2017 order in Case No. U-18197 (September 15 order), the Commission adopted a format for the capacity demonstration filings required by Section 6w(8), including templates for reporting and for affidavits.[2] Each year, the Commission opens a docket for the purpose of receiving those filings, and sets due dates for the filings and for the Commission Staff's (Staff's) report providing an analysis of the sufficiency of each LSE's capacity demonstration.

In the August 22, 2024 order in Case Nos. U-21393 *et al*. (August 22 order), the Commission opened the docket in Case No. U-21775 for the purpose of receiving the LSEs'

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[1] MCL 460.6w(12)(a) defines the appropriate ISO as the Midcontinent Independent System Operator, Inc. (MISO). MCL 460.6w(11) also states that "[n]othing in this act shall prevent the commission from determining a generation capacity charge under the reliability assurance agreement, rate schedule FERC [Federal Energy Regulatory Commission] No. 44 of the independent system operator known as PJM Interconnection, LLC [PJM]. . . ."

[2] The filing requirements have been slightly modified in the intervening years. *See*, September 13, 2018 order in Case No. U-20154. In the March 17, 2019 order in Case No. U-20154, the Commission also approved a protective order for use with capacity demonstration filings. That protective order may also be used in Case No. U-21907 for the 2029/2030 capacity demonstration.

capacity demonstrations for the 2028/2029 planning year (PY).[3] In response to a shift to a seasonal capacity auction and other developments at MISO, the Commission adjusted the capacity demonstration filing dates as permitted under Section 6w(10) and directed larger investor-owned utilities (IOUs)[4] to file by February 24, 2025; smaller IOUs to file by March 3, 2025; and AESs, cooperatives, and municipally owned utilities to file by March 17, 2025. The Commission also directed the Staff to file its analysis of the demonstrations no later than May 12, 2025.

On February 27, 2025, the Commission issued an order in Case Nos. U-21393 *et al*. (February 27 order) granting a motion for clarification filed by Energy Michigan regarding the requirements applicable to the capacity demonstrations filed by AESs pursuant to Section 6w(8)(b). In the February 27 order, the Commission clarified the wording in the Capacity Demonstration Process and Requirements document and General Affidavit to align with its previously expressed interpretation that Section 6w's four-year forward capacity demonstration requirement does not prevent an LSE from entering into other capacity agreements or contracts outside of the original capacity contract after the LSE has made its capacity obligation. Specifically, the Commission revised the language in the Capacity Demonstration Process and Requirements document and General Affidavit to read, "commitment

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[3] MCL 460.6w(8)(a) states that if an SRM is to be established, the Commission shall require, among other things, each electric utility to demonstrate by December 1 of each year that "for the planning year beginning 4 years after the beginning of the current planning year" that the utility owns or has contractual rights to sufficient capacity to meet its load obligations. Thus, the statute requires the capacity demonstrations to be four years out after the year the capacity demonstrations are required to be filed. As such, the capacity filings in Case No. U-21775 cover the 2028/2029 PY.

[4] A large IOU is considered to be an electric utility with one million customers or more, and a smaller IOU is considered to be an electric utility with less than one million customers.

to maintain the **contract** four years forward regardless of any early out provisions" rather than "commitment to maintain the **contracted amount** four years forward regardless of any early out provisions." February 27 order, p. 8 (emphasis in original to show revision); *see also*, *id*., Exhibits A, B, C, and D. The Commission also added language to the Capacity Demonstration Process and Requirements document, stating that "maintaining the contract four years forward" does not prohibit an LSE from selling surplus capacity to a buyer at some point in the future via a new contract. Additionally, the Commission included the following language in the revised Capacity Demonstration Process and Requirements document and General Affidavit to clarify that any surplus capacity sold must not be used by another LSE in that same year's demonstration to avoid the double counting of capacity: "Statements to achieve/maintain resources do not prohibit an LSE from entering into future transactions to sell surplus capacity provided that the same capacity is not used by another Michigan LSE as part of its capacity demonstration for the same planning year." February 27 order, pp. 8-9; *see also*, *id*., Exhibits A and B.

In compliance with Section 6w(8) and the August 22 order, all LSEs required to file capacity demonstrations by the directed deadlines have filed, and on May 12, 2025, the Staff filed its Capacity Demonstration Results: The Planning Year 2028/29 report (Staff Report).

Additionally, on April 29, 2025, the Staff filed the 2025 Statewide Energy Storage Target Calculation, which is the calculation that identifies each LSE serving customers in Michigan and its proportional share of the minimum statewide energy storage target, using peak load information for the previous five years filed in capacity demonstration filings under Section 6w. The Staff performed this calculation in accordance with the methodology approved by the Commission in the January 23, 2025 order in Case No. U-21571 (January 23 order). In the 2025

Statewide Energy Storage Target Calculation filing, the Staff explains that the calculation is to be used by LSEs filing either an energy storage plan or contracts for the necessary qualifying storage facilities in the current year, in accordance with Section 101 of Public Act 235 of 2023, MCL 460.1101. These calculations will be updated annually by the Staff to allow for LSEs filing in that year to use the most recent data. Future updates to the calculated storage capacity for each LSE will be filed by the Staff annually through 2029, in the open docket for LSE capacity demonstration filings, within 30 days after the completion of capacity demonstration filings as required under Section 6w for that year. *See*, Case No. U-21775, filing # U-21775-0057; *see also*, January 23 order, p. 29.

This order summarizes the Staff Report, addresses recommendations therein, and opens a new docket, Case No. U-21907, for the receipt of capacity demonstration filings for the 2029/2030 PY.

<u>The Commission Staff Report</u>

Following an executive summary of the Staff Report, the Staff explains that, as part of its pre-capacity demonstration process, it consulted with several LSEs to discuss the requirements of the capacity demonstration process.

Turning to the capacity demonstration filings, the Staff states that by February 24, 2025, DTE Electric Company (DTE Electric) and Consumers Energy Company (Consumers) filed capacity demonstrations; by March 3, 2025, Alpena Power Company, Indiana Michigan Power Company (I&M), Northern States Power Company, Upper Michigan Energy Resources Corporation, and Upper Peninsula Power Company filed capacity demonstrations; and by March 17, 2025, American Rural Cooperative, Bayfield Electric, Calpine Energy Solutions, LLC, City of Escanaba, City of Stephenson, City of Wakefield, Cloverland Electric Cooperative, CMS ERM Michigan LLC, Constellation NewEnergy Inc., Croswell Light and Power, Daggett Electric Department, NRG Energy Services LLC f/k/a Direct Energy Services LLC, Energy Harbor LLC, the Michigan Public Power Agency, Michigan South Central Power Agency (MSCPA), Newberry Water and Light Board, Union City Electric Department, Wolverine Power Supply Cooperative, Inc., and WPPI Energy filed capacity demonstrations. The Staff states that all LSEs, with the exception of MSCPA, discussed *infra*, were able to procure capacity necessary to demonstrate compliance in all four seasons of the 2028/2029 PY at the time of the LSE's filing. Per the Staff Report, two LSEs' filings indicated a shortage of capacity in the compliance year compared with projections of forecasted growth. However, Section 6w requires all LSEs to demonstrate enough resources to cover prompt-year obligations, and both LSEs met this requirement. Following a review of the two filings, the Staff determined that these entities demonstrated sufficient capacity. The Staff notes that both LSEs are in negotiations to acquire the appropriate amount of capacity needed to meet their forecasted growth. Staff Report, p. 6. The Staff adds that several AESs filed letters in the docket indicating that they are currently not serving customers in Michigan and, therefore, did not make a capacity demonstration filing.[5]

The Staff explains that it audited each capacity demonstration filing and requested more information when necessary. Per the Staff Report, each filing included the demonstration for the required compliance year (2028/2029 PY) and that most filings included an update for the 2025/2026 PY through the compliance year and complied with the Commission's directive in the

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[5] The AESs that filed letters in Case No. U-21775 indicating that they are currently not serving customers in Michigan include the following: AEP Energy Inc.; BP Energy Retail Company LLC; Dillon Power LLC; Direct Energy Services LLC; Energy Services Providers, Inc.; Interstate Gas Supply, LLC; Just Energy Advanced Solutions LLC; ENGIE Power and Gas LLC; Energy International Power Marketing Corporation; MidAmerican Energy Services, LLC; Nordic Energy Services, LLC; Texas Retail Energy, LLC; and UP Power Marketing LLC. Staff Report, p. 6, n. 8.

August 22 order for LSEs to include data for the prompt year (2025/2026 PY) and interim years (2026/2027 PY and 2027/2028 PY) in their capacity demonstrations. In the cases of municipal and cooperative utilities that provided only the compliance year, the Staff states that it was able to estimate the amount of capacity available for the prompt and interim years. The Staff recommends that the Commission continue to require LSEs to include updated prompt and interim year capacity obligation and resource obligation information in future filings as this information aids the Staff in tracking changes to load and resources and in projecting the zonal resources adequacy more accurately. Staff Report, pp. 6-7.

Turning to MSCPA, the Staff indicates that at the time of the filing of the Staff Report, MSCPA did not have rights to sufficient capacity to meet its capacity obligations. The Staff explains that MSCPA was in the process of negotiating a bilateral contract to meet the deficiency with the intent to submit a revised capacity demonstration by the self-imposed deadline of September 1, 2025, showing sufficient resources to meet its capacity requirements. The Staff states that it met with MSCPA on April 30, 2025, to discuss its capacity compliance and to encourage urgency in securing the capacity necessary to meet its obligations. Staff Report, p. 7. Subsequent to the filing of the Staff report on May 12, 2025, MSCPA filed under seal a revised capacity demonstration on July 23, 2025. *See*, Case No. U-21775, filing # U-21775-0059. On August 12, 2025, the Staff filed a memorandum in Case No. U-21775 indicating that it had reviewed MSCPA's confidential filing and confirming that MSCPA acquired a new capacity resource to meet its 2028/2029 PY capacity requirements for all four seasons. *See*, Case No. U-21775, filing # U-21775-0060.

The Staff Report also gives an overview of zonal resource adequacy for Michigan, which contains load that spans two regional transmission organizations (RTOs), MISO and PJM, with the majority of the state's load located in MISO's footprint. Beginning with MISO resource adequacy, the Staff explains that Michigan LSEs serve load in MISO local resource zones (LRZs or zones) 1, 2, and 7.[6] The Staff then explains MISO's resource adequacy construct as follows:

> MISO establishes capacity obligations for all LSEs based on peak load forecasts and a planning reserve margin [(PRM)] percentage [ ] necessary to meet the North American Electric Reliability Corporation's (NERC['s]) Loss of Load Expectation (LOLE) standard of 1 day in 10 years. LSEs within MISO can meet their capacity requirements either through a Fixed Resource Adequacy Plan (FRAP), self-schedule, Reliability Based Demand Curve (RBDC) opt-out (new this planning year [. . . .]), paying the capacity deficiency charge, or through the Planning Resource Auction (PRA). The PRA is a residual market for LSEs that choose not to utilize other participation options or do not have enough capacity resources, either owned or purchased bilaterally, to satisfy their capacity obligations, and thus need to purchase additional resources.
>
> Within MISOs [sic] resource adequacy construct, the Planning Reserve Margin Requirement [PRMR] and the LCR [local clearing requirement] must be satisfied to meet the LOLE. The PRMR is determined through LOLE modeling based on the coincident MISO peak forecast and resources adjusted as necessary to meet the standard. PRMR resources are not location specific, i.e. they can come from outside an LSE's zone. Individual LSEs are responsible for their own share of the zone's PRMR. The ability to use imports to meet PRMR makes it likely all zones will meet this requirement. Failure to meet PRMR would only occur if there were not enough resources available within all of MISO's footprint or in the subregion (MISO North/Central or MISO South) given subregional transmission constraints.

Staff Report, p. 9.

Explaining the LCR further, the Staff states that the LCR is the minimum required capacity to be located within a zone to meet the LOLE standard while accounting for the zone's ability to import. The LCR is for the entire zone, not an individual LSE. The Staff notes that, at this time,

[6] The majority of the Lower Peninsula falls into Zone 7, with the exception of the southwest corner that is located within PJM's territory. The majority of the Upper Peninsula falls within Zone 2, with the exception of a small area in the most western corner that falls into Zone 1.

there is no LCR requirement under MCL 460.6w applicable to individual LSEs in Michigan.[7]

The Staff explains that:

> [t]he LCR is determined by performing a LOLE analysis on each zone individually, to determine the Local Reliability Requirement (LRR), or the

[7] MCL 460.6w(8) requires an LCR as part of the SRM capacity demonstrations. In the September 15 order, the Commission indicated that it would open a contested case to establish the LCR for future capacity demonstrations beginning in 2022 and beyond. September 15 order, pp. 40-42. This order was appealed on two grounds: (1) that the Commission lacked the authority to impose an LCR on individual providers and (2) that if the Commission has the authority, it must implement the LCR pursuant to a rulemaking under the Administrative Procedures Act of 1969 (APA), MCL 24.201 *et seq*. While the September 15 order was on appeal, the Commission issued an order in Case No. U-18444 establishing a methodology to apply the LCR to individual energy providers. June 28, 2018 order in Case No. U-18444, pp. 122-131. On September 13, 2018, the Commission issued an order (September 13 order) granting a motion for stay in Case No. U-18444, putting a hold on the implementation of the LCR pending the outcome of the appeal of the September 15 order. September 13 order, pp. 9-13. The Michigan Court of Appeals subsequently ruled that the Commission did not have the authority under Act 341 to impose an LCR on individual providers. *In re Reliability Plans of Electric Utilities for 2017-2021*, 325 Mich App 207, 221; 926 NW2d 584 (2018). The Court of Appeals did not address the second point of the appeal, which was that if the Commission did have such authority, the LCR requirement should be implemented through a rulemaking pursuant to the APA. The Michigan Supreme Court reversed the Court of Appeals, finding that the Commission does have the authority pursuant to MCL 460.6w to impose an LCR on individual providers and remanded the case to the Court of Appeals for further review to determine the Commission's compliance with the APA in imposing the LCR. *In re Reliability Plans of Electric Utilities for 2017-2021*, 505 Mich 97, 102; 949 NW2d 73 (2020). On December 3, 2020, the Court of Appeals held that the September 15 order (imposing an LCR on AESs individually in Case No. U-18197) did not equate to administrative rules in violation of the APA and did not exceed the Commission's authority granted by the Legislature. *In re Reliability Plans of Electric Utilities for 2017-2021*, unpublished per curiam opinion of the Court of Appeals, issued December 3, 2020 (Docket Nos. 340600 and 340607).

Energy Michigan, Inc. (Energy Michigan) and the Association of Businesses Advocating Tariff Equity (ABATE) filed a complaint in federal district court challenging the constitutionality of the individual LCR. On February 24, 2023, the United States District Court for the Eastern District of Michigan issued a judgment in favor of the Commission dismissing with prejudice the complaint filed by Energy Michigan and ABATE and finding that the plaintiffs did not meet their burden to show that the individual LCR requirement discriminates against interstate commerce, while the defendants established the necessity and legitimate purpose of the LCR in ensuring grid reliability that cannot be accomplished via reasonable nondiscriminatory alternatives. On March 24, 2023, the plaintiffs filed a joint notice of appeal of the February 24, 2023 final judgment to the United States Court of Appeals for the Sixth Circuit. Given the appeal, litigation regarding the LCR requirements is currently pending at the federal level.

> resources a zone would need to meet the loss-of-load standard if it were separated from MISO. Separately, MISO determines the import and export limits for each zone by performing a seasonal transfer analysis study. The study produces Zonal Import Ability (ZIA) and Zonal Export Ability (ZEA) values, which are then adjusted by the amount of controllable exports to non-MISO load to determine Capacity Import Limits (CIL) and Capacity Export Limits (CEL). The ZIA is an input to the LCR calculation, and the LCR, CEL, and CIL, and subregional constraints are inputs to the PRA clearing process.

Staff Report, p. 9.

The Staff states that in the 2023/2024 PY, MISO implemented a seasonal resource adequacy requirement for each summer, fall, winter, and spring season and a seasonal accredited capacity (SAC) methodology for certain resources participating in MISO's PRA to align with real time availability and planned outages. The Staff explains that it reviewed these changes with participants in technical conferences per the June 22, 2022 order in Case No. U-21099. The August 22 order (the capacity demonstration docket for the 2027/2028 PY) directed LSEs in MISO to demonstrate seasonal capacity obligations based on MISO's seasonal resource adequacy construct. Staff Report, p. 10. Discussing other changes in MISO, the Staff states that on June 27, 2024, FERC accepted MISO's RBDC tariff revisions to incorporate sloped demand curves into the PRA. *Id.*; *see also*, *Order Accepting Tariff Revisions*, 187 FERC ¶ 61,202 (June 27, 2024).

If an LRZ does not have enough resources to meet its seasonal requirements, the entire zone clears at the seasonal cost of new entry (seasonal CONE). For the 2025/2026 PY, seasonal CONE (in dollars per megawatt- (MW-) day) is equal to $130,930 per MW-year divided by the number of days in the seasons experiencing shortage in Zone 7. The Staff clarifies that this resource adequacy construct is based on probabilistic determinations and that failure to meet the requirements would not necessarily mean that the LRZ will experience a loss of load event. Staff Report, p. 10.

Providing further detail regarding the RBDC, the Staff explains that MISO introduced sloped demand curves in its resource adequacy construct in the 2025 PRA. Per the Staff Report, the systemwide RBDC addresses overall reliability needs across the entire system, while the subregional RBDCs capture additional reliability requirements specific to each subregion. While delayed for the time being due to the complexity of adding another 10 curves per season, MISO ultimately seeks to develop RBDCs at the LRZ level. The Staff then explains how MISO develops each curve and its relation to reliability and pricing metrics. Staff Report, pp. 10-11 (referencing MISO's Reliability-Based Demand Curves Conceptual Design White Paper (September 2023), available at 20230906 RASC Item 02 Draft RBDC White Paper630104.pdf (last accessed August 21, 2025)).

The Staff further explains that:

> [t]he RBDCs fundamentally change the objective function of the PRA, from minimizing as-offered costs to minimizing the difference between supply offers and demand offers to maximize social surplus. The clearing quantities may vary from the initial PRMR, but the value of the reliability contribution of any additional MWs cleared must be greater than or equal to the cost of procuring those MWs. The PRA is conducted using an optimization to simultaneously complete the following tasks: (1) meet the supply demand balance both for MISO and for each of the two Planning Areas (MISO North/Central and MISO South); (2) meet the LCR for each LRZ; (3) efficiently use transmission transfer capability between LRZs; and (4) respect the Sub-Regional Power Balance Constraint. Step 1 of the auction clearing process solves an optimization problem to identify which type of RBDC produces a higher MW obligation for a given subregion, share-of-Systemwide or Subregional. Step 2 of the process solves the clearing and pricing problem based on the RBDC identified in step 1 and outputs both the resource clearing (Final PRMR) and the auction clearing price (ACP) for each LRZ and External Resource Zone. A final step verifies the solution found in step 2. The auction clearing price is determined by where the supply offer curve meets the applicable RBDC, and is equal to the marginal cost of capacity, the regional marginal cost of capacity, the marginal cost of financially binding LCR, CEL, and CIL for an LRZ, and the marginal cost of financially binding Subregional Export Constraints and Subregional Import Constraints. For more information on auction clearing under RBDC[,] see Appendix M of MISO's Business Practice Manual 11.

Staff Report, p. 11. The Staff adds that MISO included an RBDC Opt-Out mechanism that allows an LSE to opt-out provided it cannot then include a partial opt-out, the opt-out will be locked in for three consecutive years, and it must include the RBDC opt-out adder percentage in its obligation. *Id*.

Speaking to future resource adequacy construct changes, the Staff reports that MISO has recently filed or is currently working on FERC filings to address challenges related to demand side resources and that MISO intends to implement enhanced resource adequacy risk modeling and a Direct Loss-of-Load (DLOL) accreditation methodology beginning in planning year 2028/2029. Staff Report, p. 12 (citing FERC Docket No. ER24-1638-000 (application filed March 28, 2024)). Starting with the 2025/2026 PY, MISO has committed to publishing indicative accreditation results based on the DLOL methodology prior to each PRA. The Staff explains that these proposed reforms will align the PRMR with accreditation of all resource classes but given the ongoing work, the indicative PRMR values under DLOL are not yet available. The Staff recounts that several LSEs asked whether DLOL accreditation should be used in this instant capacity demonstration case since the demonstration year aligns with the first year of DLOL implementation (2025/2026 PY). The Staff recommends that LSEs follow the prompt-year MISO adequacy resource construct and also recommends that the Commission determine a timeline to implement MISO's DLOL accreditation changes into the state capacity demonstration process if it deems it necessary to implement these changes prior to MISO's tariff changes effective in PY 2028/2029.

For MISO Zone 7, the Staff provides a table showing the annual MISO LOLE report data, as well as another table showing a comparison of LRZ 7 aggregated resources demonstrated plus known undemonstrated resources likely to still be available for each season in PY 2028/2029 and

MISO's resource adequacy requirements for PY 2025/2026. *Id*., pp. 13-15. With the caveat that its findings are based on projections that are subject to change, the Staff concludes that Zone 7 has a surplus of resources compared to the projected LCR for all four seasons. Specifically, Zone 7's summer PRMR is 21,228 zonal resources credits (ZRCs) and the LCR is 19,681 ZRCs. The total LRZ 7 resources offered in the PRA for the summer season in the prompt year is 20,884 ZRCs, which exceeds the anticipated LCR by 2,203 ZRCs but falls short of the zone's portion of PRMR. *Id*., p. 16. The zone relied on 785.5 ZRCs of external resources to meet its resource adequacy requirement target. *Id*.

For the interim years, the Staff Report contends that again, while subject to change, LRZ 7 has a capacity surplus for both years compared to the projected LCRs. The Staff notes that the capacity margin appears tight in 2026/2027 across all four seasons with the tightest capacity position in the fall season. *Id*., pp. 16-17.

As to Zone 2, which encompasses most of Michigan's Upper Peninsula and parts of Wisconsin, the Staff notes that MISO does not define MW capacity import or export limits between states within the same MISO zone and therefore, the data available to the Staff is not comprehensive enough to project a zonal capacity position for Michigan's Zone 2 similar to Zone 7. However, the Staff was able to conclude that: (1) all Michigan LSEs in Zone 2 demonstrated sufficient capacity resources, and (2) the 2024 MISO PRA results indicated an installed capacity surplus in PY 2024/2025. The Staff also states that Zone 2 has CILs of 4,370 MW in summer; 6,537 MW in fall; 6,522 MW in winter; and 6,439 MW in spring. *Id*., p. 17.

Turning to Zone 1, which includes a small fraction of Michigan's Upper Peninsula, the Staff reports that all Zone 1 LSEs demonstrated sufficient capacity obligations for the compliance year and that the 2025/2026 MISO PRA shows sufficient capacity for each season in PY 2025/2026, adding that Zone 1 relied on a small amount of imports to meet its resource adequacy target in winter and spring. *Id*., p. 17.

For Michigan LSEs serving load within PJM, the Staff notes that only a few LSEs in Michigan serve load within the PJM territory but that these LSEs are still subject to the capacity requirements of Section 6w. LSEs in PJM must meet capacity obligations through participation in PJM's reliability pricing model base residual auction (BRA) or through PJM's fixed resource requirement (FRR) plan. I&M, the largest Michigan-serving LSE in PJM, uses the FRR and indicates in the instant capacity demonstration that it plans to continue to do so. The Staff Report includes a table presenting a summary of PJM's capacity demonstration, and the Staff states that all PJM LSEs have sufficient capacity and that it expects all PJM LSEs to continue to meet their capacity obligations with continued monitoring by the Staff. Staff Report, p. 18.

The Staff also notes that I&M's customer choice cap was reset to 10% on February 1, 2019, pursuant to MCL 460.10a(1)(c) and the July 12, 2017 order in Case No. U-16090 (July 12 order). July 12 order, p. 3. I&M is responsible for providing capacity for its choice program, but if its suppliers opt to self-supply capacity, the company will need to include this in its FRR plan. Per the Staff Report, NERC projects PJM to have sufficient electric supply and categorizes PJM as having an elevated risk level post 2026, with resource additions not keeping up with generator retirements and demand growth, and with winter replacing summer as the higher risk period because of generator performance and fuel supply issues. Lastly, the Staff notes delays in PJM's BRA schedule due to pending decisions from FERC related to the capacity auction. The Staff Report also provides the current BRA schedule, which is scheduled to take place every six months until the schedule is no longer delayed. Staff Report, pp. 18-19.

In compliance with the Commission's request in the September 15 order, the Staff provides a table in the report identifying the capacity by type for each individual electric provider (without revealing the provider's identity) with a breakdown for each provider included as Appendix A to the Staff Report. The table describes the supplier type and the percentage of their demonstrated capacity that is owned; derived from demand response (DR), a power purchase agreement, or ZRC contract; or acquired at auction. Staff Report, pp. 19-20.

Explaining DR as an optional source of capacity, the Staff describes DR as having a prominent role in LSEs' integrated resource plan (IRP) filings and the Staff's obligation to complete a statewide study of DR potential in Michigan every five years. The Staff states that Consumers and DTE Electric included DR in their respective IRP filings and capacity demonstrations and that the Staff will continue to monitor Consumers' and DTE Electric's DR as well as DR use across Michigan. *Id*., p. 20.

Noting the Commission's affirmation of an AES' ability to offer DR programs through curtailment service providers or third-party aggregators, the Staff states that it is aware of 85 ZRCs of DR offered into the 2025 MISO capacity market. The Staff continues to collaborate to ensure that aggregated DR load modification is accounted for when dispatched on MISO's coincident peak and to monitor FERC Order 2222[8] discussions. *Id*., p. 21.

As to ZRC contracts, the Staff recommends that forward ZRC contracts be used for capacity demonstration purposes to specify delivery of the ZRCs in the MISO Module E Capacity Tracking (MECT) tool prior to the applicable PRA auction. There was an increase in the

[8] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172 FERC ¶ 61,247 (September 17, 2020). FERC issued subsequent versions of FERC Order 2222, namely FERC Order 2222-A and FERC Order 2222-B. *See*, 174 FERC ¶ 61,197 (March 18, 2021) and 175 FERC ¶ 61,227 (June 17, 2021), respectively.

percentage of ZRC contracts utilized this year by utilities, municipal utilities, and cooperatives compared to last year's capacity demonstration. The Staff highlights the following:

> An important thing to note is that ZRCs are defined in MISO's tariff and are created in the prompt year when UCAP [unforced capacity] for supply-side and demand-side resources are converted into ZRCs in the MISO MECT. ZRCs for any year further out than the prompt year are projected and don't become ZRCs until the prompt year. ZRCs are fungible products that can be sold or transferred, and in some cases, sold more than once. The characteristics of ZRCs allow for them to be easily traded and tracked within the MISO MECT. MISO has a view into the source and transfers of those ZRCs that occur prior to the PRA in the prompt year, and those ZRC transfers are audited by Staff as a secondary check on the ZRC contracts utilized in the capacity demonstrations.

Staff Report, p. 21.

Following a brief explanation of its process for accounting for AES load switching, which was made more complex with the change to the seasonal construct, the Staff states that it continues to see an increase in load switching among LSEs. *Id*., pp. 21-22. The Staff recommends that LSEs that include load switching information in their filing include it within the Contracted Resources section on the spreadsheet templates provided for the capacity demonstration for the demonstration years as well as the interim years. The Staff also recommends that both the losing and the gaining suppliers have copies of the load switching affidavits in each of their filings, enabling the Staff to easily cross-reference that the load is being accounted for.

Lastly, the Staff includes a discussion of capacity retirements and additions, stating that NERC's 2024 Long Term Reliability Assessment shows added resource capacity on the Bulk Power System (BPS) falling short of industry projections the year prior, demonstrating an over-projection of natural gas, solar, and wind resources, and giving evidence to project delays. Additionally, the Lawrence Berkeley National Laboratory's April 2024 interconnection queue study showed that only 19% of the projects (and just 14% of their capacity) that submitted interconnection requests from 2000 to 2018 reached commercial operations by the end of 2023. *Id*., p. 22. Because of interconnection backlog issues, the Staff notes that some RTOs have taken steps to address these issues including PJM's Reliability Resource Initiative, both PJM's and MISO's work to reduce queue cycle times through automation, and MISO's Expedited Resource Addition Study (ERAS) process.[9] The Staff conveys that Michigan continues to follow national trends showing a tightening capacity position due to scheduled retirements outpacing replacement capacity buildout. The Staff notes that it met with LSEs to discuss their capacity concerns and explains that various factors could cause delays for new capacity additions, namely broad economic factors such as supply chain constraints, labor shortages, high component prices, and delays associated with obtaining permitting, regulatory approval, or interconnection queue delays. Per the Staff:

> The issue may be further exacerbated should demand increase faster than expected due to unanticipated loads such as data centers, as well as electrification of the building and transportation sectors. Staff has noted a significant number of planned resources used as demonstrated capacity in this case and recent previous cases that have not come to fruition in the demonstration year as planned, with estimates in the range of 900-1000 MW/year removed from the list of planned resources due to delays or cancellations. There are many instances of this occurring with IRP-identified resources, consequently Staff met with both large investor-owned utilities to discuss this issue in depth and determine what actions can be taken to overcome the delays. One of these utilities indicated they are in the process of quantifying project delays and terminations, and early estimates showed an average delay of ~1.5 years past Commercial Operation Date (COD) and a project failure rate greater than 25%.

[9] At the time the Staff Report was filed, MISO's ERAS process was pending approval before FERC. Following an initial rejection by FERC on May 16, 2025, and subsequent revisions to its ERAS proposal by MISO, FERC approved MISO's revised filing on July 21, 2025, in FERC Docket No. ER25-2454- 000, with the condition that MISO make a compliance filing by August 20, 2025, reflecting revised tariff language previously submitted by MISO. *See*, *Order Accepting Tariff Revisions, Subject to Condition*, 192 FERC ¶ 61,064 (July 21, 2025) (July 21 FERC order). FERC approved the ERAS tariff effective August 6, 2025. *See*, July 21 order, pp. 98, 135.

Staff Report, pp. 22-23. The Staff adds that some capacity from the Palisades Nuclear Power Plant was included in Michigan's capacity demonstration for Spring 2026 (the remainder of the capacity is being contracted by an LSE in Indiana). The Palisades capacity would provide resource adequacy benefits to Zone 7 and be counted towards meeting the LCR for Zone 7.[10] Staff Report, p. 23.

In its conclusions and recommendations, the Staff repeats that all LSEs have complied with their capacity demonstration obligations pursuant to Section 6w and expresses its appreciation for the cooperation of all LSEs. *Id.*, pp. 20-21. The Staff then presents a summary of its recommendations:

1. Staff recommends the Commission continue to direct all LSEs to include updated prompt year and interim year capacity obligation and resource information in future filings.

2. Staff recommends the Commission direct all LSEs to provide [an] MECT screenshot of their prompt load obligations (PRMR/PLC [peak load contribution]) to facilitate the Storage Target calculation used to comply with Public Act 235.

3. The Commission should determine a timeline to implement MISO's DLOL accreditation changes into the state capacity demonstration process if it deems it necessary to implement prior to MISO tariff changes effective PY 2028-29.

4. Staff recommends that filing entities who include load switching information in their filing include it within the Contracted Resources [section] on the spreadsheet templates provided for the capacity demonstration for the demonstration years as well as the interim years. Staff also recommends that both the losing and the gaining suppliers have copies of the load switching affidavits in each of their

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[10] At the time of the filing of the Staff Report, the re-start of the Palisades Nuclear Plant was pending approval before the U.S. Nuclear Regulatory Commission (NRC). On July 24, 2025, NRC granted some key approvals necessary to the re-start of the Palisades Nuclear Plant. Namely, NRC approved six exemptions from the requirements of Title 10 of the Code of Federal Regulations (10 CFR) Section 50.82(a)(2), "Termination of license," concerning the prohibition against operating the reactor and emplacing fuel into the reactor vessel for the Palisades Nuclear Plant. The exemptions will be effective on August 25, 2025. *See*, NRC Docket No. 50-255; NRC-2025-0346 (July 24, 2025). However, other licensing actions remain pending before NRC as of the date of this order.

filings, so Staff is able to cross check that the load is being accounted for.

Staff Report, p. 23.

Discussion

To begin, the Commission appreciates the efforts of the Staff in obtaining and analyzing the capacity information needed for this year's capacity demonstrations and for drafting the Staff Report as well as the filing of the 2025 Statewide Energy Storage Target Calculation. The Commission also appreciates the cooperation of all Michigan LSEs for their capacity demonstration filings.

Before addressing the Staff Report, the Commission takes this opportunity to note an update relevant to the state's capacity outlook that occurred after the filing of the Staff Report. On May 23, 2025, the U.S. Department of Energy (DOE) issued an emergency order to MISO in coordination with Consumers, pursuant to Section 202(c) of the Federal Power Act, to ensure that the J.H. Campbell Power Plant (Campbell Plant) in West Olive, Michigan remains available for operation to minimize any potential generation shortfall that could lead to unnecessary power outages. *See*, DOE, Order No. 202-25-3 (May 23, 2025). The Campbell Plant was scheduled to cease operations on May 31, 2025. The Commission notes that the retirement of the Campbell Plant was planned for in Consumers' 2022 IRP and replacement capacity has been procured through the purchase of a natural gas fired power plant in 2023, extending the retirement dates for two other fossil fuel units, increasing demand side resources such as DR and energy waste reduction, and adding renewable energy and energy storage resources through 2040. *See*, June 23, 2022 order in Case No. U-21090, pp. 5, 95 (approving a settlement agreement resolving all issues in the case); *see also*, *id*., Exhibit A, pp. 4-5. Consumers also filed its capacity demonstration on February 24, 2025, prior to the issuance of the DOE's emergency order and demonstrated sufficient capacity for the compliance PY. *See*, Case No. U-21775, filing # U-21775-0012; *see also*, Staff Report, pp. 6, 23.

Turning to the Staff Report, the Commission accepts the Staff Report's findings regarding resource adequacy in MISO LRZs 1, 2, and 7 and in the PJM market, the capacity demonstrations made by the LSEs, and the 2025 Statewide Energy Storage Target Calculation. The Commission also accepts the Staff's filing of a memorandum in this docket on August 12, 2025, confirming its review of MSCPA's revised capacity demonstration filing indicating that MSCPA has secured the capacity necessary to satisfy its capacity obligation under Section 6w. The Commission finds that MSCPA has resolved its capacity shortage issue and has now complied with the requirements of Section 6w.

As noted in last year's capacity demonstration report, the Staff stated in this year's report that most LSEs included updates for the 2025/2026 PY through the 2027/2028 PY. For the upcoming capacity demonstration in Case No. U-21907, the Commission agrees with the Staff's recommendation for LSEs to continue providing this additional information and thus, directs LSEs to provide capacity resource data for the prompt year (2026/2027) and interim years (2027/2028 and 2028/2029) in addition to the compliance year (2029/2030) data. The additional data is to be included in the upcoming February 24, March 3, and March 17, 2026 capacity demonstration filings opened by this order in Case No. U-21907. The Staff shall then file its 2029/2030 PY capacity demonstration report in Case No. U-21907 no later than May 12, 2026.

Before addressing the Staff's recommendations, the Commission notes that in the Staff Report, the Staff described the DLOL accreditation and referenced MISO's application for approval of the revised tariff to establish DLOL accreditation that was filed with FERC on March 28, 2024. The Commission adds that on October 25, 2024, FERC approved MISO's proposed tariff revisions to establish the DLOL accreditation methodology. *See*, 189 FERC ¶ 61,065 (October 25, 2024). As the Staff indicated, MISO will implement the DLOL accreditation methodology in the 2028/2029 PY and is continuing its work to provide the PRMR values under the DLOL methodology. The Staff recommended that the Commission determine a timeline to implement MISO's DLOL accreditation changes into Michigan's capacity demonstration process if the Commission finds such action to be necessary prior to the effective date of the revised MISO tariff in 2028/2029. The Commission finds that establishing such a timeline is not necessary at this time given MISO's ongoing work to establish the PRMR values that will be used in the DLOL methodology. Therefore, the Commission will continue to monitor MISO's progress in this area and will revisit this issue as more information becomes available. At this time, the Commission agrees with the Staff's recommendation to LSEs for the instant capacity demonstration and for future demonstrations that they should follow the prompt-year MISO resource adequacy construct.

Turning to the Staff's other recommendations, the Commission finds these recommendations to be reasonable and necessary to provide the Commission with comprehensive information regarding an LSE's capacity position for the prompt, interim, and compliance years and to satisfy the requirements of Section 6w. Therefore, with the exception of the establishment of a timeline to implement DLOL into Michigan's capacity demonstration process, the Commission adopts the Staff's recommendations set forth in the Staff Report. *See*, Staff Report, p. 23.

With this order, the Commission also opens the Case No. U-21907 docket for the purpose of receiving next year's capacity demonstrations from required LSEs pursuant to Section 6w. As mentioned above, electric utilities required to file capacity demonstrations pursuant to Section 6w(8)(a) for the 2029/2030 PY shall make that filing no later than 5:00 p.m. (Eastern time (ET)) on February 24 and March 3, 2026 in Case No. U-21907. LSEs required to file capacity demonstrations pursuant to Section 6w(8)(b) for the 2029/2030 planning year shall make that filing no later than 5:00 p.m. (ET) on March 17, 2026, in Case No. U-21907. Electric utilities and LSEs shall include in their respective filings capacity resource data for the prompt (2026/2027) and interim years (2027/2028 and 2028/2029) as well as the compliance year (2029/2030). All LSEs making required filings pursuant to Section 6w(8) shall utilize the Capacity Demonstration Filing Process and Requirements document, General Affidavit, and, as applicable, AES Load Switching Affidavit attached to this order as Exhibits A, B, and C, respectively. All filing LSEs shall also provide an MECT screenshot (or equivalent) of their prompt load obligations (PRMR/PLC) to facilitate the energy storage target calculation used to comply with Act 235. Lastly, LSEs who include load switching information in their capacity demonstration filing shall include such information within the Contracted Resources section on the spreadsheet templates provided for the capacity demonstration for the demonstration years as well as the interim years. Also, both the losing and the gaining suppliers in the load switching arrangement shall include copies of the AES Load Switching Affidavit, attached to this order as Exhibit C, in each of their capacity demonstration filings, enabling the Staff to easily cross-reference that the load is being accounted for.

THEREFORE, IT IS ORDERED that:

A. The Commission Staff's May 12, 2025 Capacity Demonstration Results Report and 2025 Statewide Energy Storage Target Calculation filed in Case No. U-21775 are accepted.

B. Electric utilities required to file capacity demonstrations pursuant to MCL 460.6w(8)(a) for the 2029/2030 planning year shall make that filing no later than 5:00 p.m. (Eastern time) on February 24 and March 3, 2026, in Case No. U-21907, as described in this order and in the

Capacity Demonstration Filing Process and Requirements document attached to this order as Exhibit A. Load serving entities required to file capacity demonstrations pursuant to MCL 460.6w(8)(b) for the 2029/2030 planning year shall make that filing no later than 5:00 p.m. (Eastern time) on March 17, 2026, in Case No. U-21907. Electric utilities and load serving entities shall include in their respective filings capacity resource data for the prompt (2026/2027) and interim years (2027/2028 and 2028/2029) as well as the compliance year (2029/2030), as described in this order. Load serving entities required to file capacity demonstrations pursuant to MCL 460.6w(8) shall utilize the Capacity Demonstration Filing Process and Requirements document and General Affidavit attached to this order as Exhibits A and B, respectively.

C. The Commission Staff shall file a report analyzing the sufficiency of the capacity demonstrations for the 2029/2030 planning year no later than 5:00 p.m. (Eastern time) on May 12, 2026, in Case No. U-21907.

D. The Commission Staff shall file in Case No. U-21907 the update to the energy storage capacity amounts for electric providers using the Statewide Energy Storage Target Calculation within 30 days after the completion of the capacity demonstrations for the 2029/2030 planning year required under MCL 460.6w.

E. Any load serving entity required to file capacity demonstrations pursuant to MCL 460.6w(8) for the 2029/2030 planning year shall provide a Module E Capacity Tracking screenshot (or equivalent) of its respective prompt load obligations (planning reserve margin requirement/peak load contribution) to facilitate the energy storage target calculation used to comply with Public Act 235 of 2023, MCL 460.1001 *et seq*., as described in this order.

F. Any load serving entity that includes load switching information in its capacity demonstration filing shall include it within the Contracted Resources section on the spreadsheet templates provided for the capacity demonstration for the demonstration years as well as the interim years. Both the losing and the gaining suppliers in the load switching arrangement shall include copies of the AES Load Switching Affidavit, attached to this order as Exhibit C, in their respective capacity demonstration filings.

G. The docket in Case No. U-21775 is closed, and the docket in Case No. U-21907 is opened for the purpose of receiving the capacity demonstration filings for the 2029/2030 planning year and the Statewide Energy Storage Target Calculations to be filed by the Commission Staff.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at LARA-MPSC-Edockets@michigan.gov and to the Michigan Department of Attorney General - Public Service Division at sheac1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

Daniel C. Scripps, Chair

Katherine L. Peretick, Commissioner

Shaquila Myers, Commissioner

By its action of August 21, 2025.

Lisa Felice, Executive Secretary

CAPACITY DEMONSTRATION PROCESS AND REQUIREMENTS

The Michigan Public Service Commission (MPSC or Commission) will open a new docket annually for capacity demonstrations filings. The Commission order opening the capacity demonstration docket will provide updated requirements for load serving entities (LSE) to follow in making demonstrations. The capacity demonstration filings shall include four years of load obligations and capacity resources. The capacity demonstration for year four will be used to determine if the LSE has met its capacity obligations, while the data filed for years one through three will be used for informational purposes only. For the demonstration year, each LSE's capacity obligation will be equal to its most recent capacity obligation as specified by the applicable Independent System Operator (ISO).

For LSEs in the Midwest Independent System Operator (MISO), the capacity obligation will be based on the MISO seasonal resource adequacy construct. LSEs will be obligated to demonstrate enough capacity (owned or contracted) to meet the LSE's capacity obligation for each season. The specific capacity obligation for each season will be the LSE's prompt year (upcoming year) Initial Planning Reserve Margin Requirement (PRMR) for each respective season. According to the MISO Tariff, the Peak Load Contribution (PLC) for each retail customer in the Electrical Distribution Company's (EDC) area – including the EDC's own LSE – includes the retail customer's demand at the time of MISO's peak demand for each prior season, transmission losses, planning reserve margin %, and an adjustment factor for the prompt year seasonal EDC forecasts. The Initial PRMR for each LSE for a season consists of the sum of the PLCs for the retail customers assigned to that LSE[1]. MISO LSEs will be obligated to demonstrate enough capacity for the demonstration year to meet its prompt year Initial PRMR MISO requirements[2].

For LSEs in PJM, the capacity obligation will be based on the PJM Reliability Pricing Model (RPM). LSEs in the PJM service territory can meet their Independent System Operator capacity obligations either through participation in PJM's (RPM) Base Residual Auction (BRA) or through PJM's Fixed Resource Requirement (FRR) capacity plan. The timing of PJM LSEs capacity demonstrations to the Commission will remain the same as those expected of MISO LSEs; however, PJM LSEs will be allowed to file an amended capacity demonstration two weeks after the completion of the BRA. The capacity demonstration should include the FRR capacity plan or BRA results. Meeting PJM's capacity obligations, including any applicable Percentage Internal Resources Required for the delivery year will constitute a satisfactory demonstration, and the demonstrating LSE should provide evidence that it has met PJM's capacity obligations.

LSEs shall provide documentation to Staff verifying the applicable capacity obligation from the LSEs ISO.[3]

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[1] The Initial PRMR determination for all LSEs, including the EDC's own LSE, shall be made according to the MISO tariff. See MISO tariff Module E-1, Section 69A.1.1.e and Section 69A.1.2.1.b.

[2] LSEs that develop their load forecasts based on forward year values may use these values instead of prompt year values for capacity demonstration requirements if they are higher than the prompt year requirements. LSEs obligations should not be reduced to an amount less then the prompt year requirements due to declining forecasts for forward years.

[3] Documentation could be included in the filing or shared in a meeting (virtual or in person) with Staff, similar to how resource contracts are shared.

Individual Locational Requirement

The individual locational requirement adopted by the MPSC in the June 28, 2018 Order in Case No. U-18444 remains stayed[4]. There is currently no individual locational requirement applicable to capacity demonstration filings.

Resource Demonstrations

As a default, resources shall be accredited as they are in their respective ISO.

For MISO LSEs, resources should be counted at the same seasonal accredited capacity value that they will receive in the prompt year for each season. If prompt year capacity value is not finalized, resources shall be counted at the seasonal accredited capacity level from the most recent information available.

For PJM LSEs, resources shall be based on the credited UCAP capacity value that they are credited within the PJM RPM for the demonstration year.

New resources (in either ISO) shall receive capacity credit they would reasonably receive within the various resource adequacy constructs. LSEs should provide documentation supporting the capacity accreditation of new resources.

Resource accreditation may vary from ISO accreditation if the LSE is able to provide reasonable support that the resource will be valued at a different capacity amount when the demonstration year becomes the delivery year. These variations will be evaluated by Staff on a case-by-case basis.

The minimum acceptable support for all resources submitted as part of a capacity demonstration is based upon the type of resource and is outlined below. Statements to achieve/maintain resources do not prohibit an LSE from entering into a future transaction to sell surplus capacity provided that the same capacity is not used by another Michigan LSE as part of its capacity demonstration filing for the same planning year.

Existing Generation (Owned)

The minimum acceptable support for existing generation that is included in a capacity demonstration include:

1) An affidavit from an officer of the company claiming ownership of the unit(s), including a commitment of the unit(s) to LSE load in the applicable demonstration year,
2) A copy of the existing resource qualification of the unit(s) from the applicable ISO, such as a MISO Module E Capacity Tracking Tool (MECT) screenshot in the MISO region, and;
3) If there are Michigan retail tariffs or customer contracts associated with the resources, copies shall be provided.

[4] Stayed by the September 13, 2018 Order in Case No. U-18444.

Existing Demand Response or Energy Efficiency Resources (that have not been netted against load)

The minimum acceptable support for existing demand response resources or energy efficiency resources that have not already been netted against load include:

1) An affidavit from an officer of the company outlining the resource(s), including a commitment to maintain at least that same level of resources four years forward,
2) A copy of the existing resource qualification of the resource(s) from the applicable ISO, such as a MISO MECT screenshot, and;
3) If there are Michigan retail tariffs or customer contracts associated with the resources, copies shall be provided.

New or Upgraded Generation (Owned)

The minimum acceptable support for proposed new generation include:

1) An affidavit from an officer of the company outlining the plans for the new generation including resources outlined in the utilities' most recent IRP,[5] milestones such as planned in-service date, expected regulatory approval date(s), planned date to enter the generator interconnection queue, expected date for generator interconnection agreement, construction timeline, etc.,
2) Documentation supporting the expected resource qualification from the ISO for the new unit(s), and;
3) If there are Michigan retail tariffs or customer contracts associated with the resources, copies shall be provided.

For new generation submitted as part of a capacity demonstration, the LSE shall update and submit the above information on an annual basis with each subsequent capacity demonstration until the unit(s) are in service.

New Demand Response or Energy Efficiency Resources (that have not been netted against load)

The minimum acceptable support for new demand response resources or energy efficiency resources that have not already been netted against load included in a capacity demonstration include:

1) An affidavit from an officer of the company outlining the plans for the resource(s), including a commitment to achieve and/or maintain at least that same level of resources four years forward,
2) Evidence that the customer's distribution utility has been notified of specific customers participating in the resource,
3) Specific plans to have the resource(s) qualified by the independent system operator, and;

[5] If including resources included in the utility's most recent approved IRP, the utility shall also file a status update in the next capacity demonstration docket.

4) If there are Michigan retail tariffs or customer contracts associated with the resources, copies shall be provided.

For new demand response or energy efficiency resources submitted as part of a capacity demonstration, the LSE shall update and submit the above information on an annual basis with each subsequent capacity demonstration until the resource(s) are in service. Final qualification / approval from the independent system operator should be submitted in a subsequent demonstration.

Capacity Contract

The minimum acceptable support for capacity contracts with existing generation include:

1) An affidavit from an officer of the company including a copy of the contract that specifies the unit(s) or pool of generation that is the source of the contract, including the location of the unit(s) or pool. The affidavit shall include a commitment to maintain the contract four years forward regardless of any early out clauses in the contract, and;
2) A copy of the existing resource qualification of the unit(s) or pool from the applicable ISO, such as a MISO MECT screenshot.

Forward ZRC contracts

For MISO LSEs that use ZRC contracts to meet capacity obligations. The minimum acceptable support for forward ZRC contracts includes an affidavit from an officer of the company including a copy of the contract that specifies the zonal location of the ZRCs. The affidavit shall include a commitment to maintain the contract four years forward regardless of any early-out clauses in the contract. A forward ZRC contract that does not specify the zonal location of the ZRCs will be deemed insufficient towards meeting any portion of a locational requirement, unless the LSE provides other alternative support for the location of the ZRCs.

Any LSE that utilized a ZRC contract as part of their previous capacity demonstrations must provide prompt-year ZRC transfer documentation (such as a MECT Module E screenshot) or provide Staff with the ability to confidentially review ZRC transfers in person at the Commission office.

If the Commission were to implement an individual locational requirement, ZRC contracts submitted in an LSE capacity demonstration to meet this forward locational requirement must clearly designate that the resources are coming from the applicable zone. LSEs must provide evidence to support this. For resources currently located outside of the LSE's zone that will (by the demonstration year) count towards meeting the Local Clearing Requirement of the LSE's zone should be supported by evidence provided by the demonstration LSE. Existing contracts specifically with resources outside of an LSE's MISO zone will count towards meeting forward locational requirements if they are for a period of at least twenty years and the contracts were entered into prior to MISO's implementation of local resource zones on June 1, 2013.

Aggregated EERs, Aggregated Storage, Aggregated DERs

The minimum acceptable support for aggregated energy efficiency resources (EERs), aggregated storage, and aggregated distributed energy resources (DERs) include:

1) An affidavit from an officer of the company outlining the resource(s), including a commitment to achieve and/or maintain at least that same level of resource(s) four years forward,
2) Documentation from the ISO showing resource accreditation in the prompt-year for the resource(s), such as a MISO MECT screenshot, and;
3) If there are Michigan retail tariffs or customer contracts associated with the resource(s), copies shall be provided.

MISO PRA Purchases

The amount of ZRCs planned to be purchased through the MISO Planning Resource Auction (PRA) process[6] that will be deemed prudent in an approved capacity demonstration will be limited to 5% of the LSE's total requirement. A capacity demonstration filed by an LSE that includes a plan to purchase ZRCs in the PRA four years in the future in excess of 5% will not constitute a demonstration that the LSE owns or has contracted resources to meet its future capacity obligations, unless those ZRCs are tied to specific identified resources that are committed to be offered in the PRA, by contract, on behalf of the LSE for the applicable planning year.

Interim Years[7]

Once the Commission has determined that the capacity demonstration made by an LSE is sufficient, it shall not be re-litigated or "trued-up" in the interim years. If, subsequent to its initial satisfactory capacity demonstration, an LSE experiences an unforeseen outage at one of its generation assets, or has variation in its total load obligations, these matters will be settled in the capacity auctions of the respective ISO. The LSE's initial capacity demonstration will not be re-examined to reconcile projected interim year load obligations or generating resource capacity ratings with actual values that are experienced in that interim year.

Additional Considerations for Capacity Demonstrations

Other types of documentation submitted as part of a capacity demonstration will be evaluated on a case-by-case basis. Because some of the documentation that is required to be filed in these proceedings is commercially sensitive, competitive information, it shall continue to be treated in a confidential manner, as has been done in the past. The Staff shall file a memo in the docket as directed by the Commission, outlining its findings from the demonstration filings, including a listing of any entities whose demonstration, in Staff's opinion, was insufficient.

In the case where a demonstration filing is deemed insufficient by Staff, Staff would recommend that the Commission open a contested case docket, whereby the LSE in question could attempt to prove that

[6] Since 2012, LSEs do not literally purchase ZRCs in the PRA. The current terminology in the MISO tariff of "purchase through the PRA process" means that MISO is charging an LSE more for capacity to satisfy the LSE's PRMR than it is paying the LSE for ZRCs submitted into the PRA.
[7] Year 1 (prompt year), Year 2, and Year 3 of the demonstration.

its capacity demonstration should be deemed acceptable. The outcome of that case would be a Commission order potentially authorizing Statewide Reliability Mechanism capacity charges to Retail Open Access customer load as well as a respective increase in capacity obligations assigned to the incumbent utility as the Provider of Last Resort for capacity service. Any contested demonstration cases will be opened as soon as practicable following the issuance of the Staff memo and be completed within six months.

If an LSE has met the capacity demonstration requirements, no contested case will be opened, and no further action will be taken regarding any capacity demonstration that has been deemed sufficient by Staff and accepted by the Commission.

Filing Timeline

Section 6w of Public Act 341 of 2016 gives specific filing dates for LSEs to make capacity demonstrations but gives the Commission the authority to adjust the dates if needed to properly align with the ISO procedures and requirements. The timeline below better aligns with the MISO PRA, allowing capacity obligations and resource accreditation to better match the values used by MISO in the prompt year.

For Demonstration Year 2029/2030	
Docket Opened by Commission	Summer/Fall 2025
Larger Investor-Owned Electric Utilities[8] Filing Due	February 24th, 2026
Smaller Investor-Owned Electric Utilities[9] Filing Due	March 3, 2026
All Other LSEs Filing Due	March 17th, 2026
Staff Report on Capacity Demonstration Findings	May 12th, 2026
Commission Order	Summer/Fall 2026

The specific filing dates will be established by the Commission in each subsequent capacity demonstration docket and will generally align with the filing timeline above. LSEs will be allowed to supplement filings after the filing date and prior to Staff's report, if changes at the ISO level, for capacity obligation or resource accreditation, necessitate updated filings[10].

Demonstration Format

In addition to all of the items outlined above, Staff shall provide updated capacity demonstration documents (Reporting Templates and Sample Affidavits)[11] to be utilized by each LSE when filing its demonstration.

[8] A large investor-owned utility is considered to be an electric utility with one million or more customers.
[9] A smaller investor-owned utility is considered to be an electric utility with less than one million customers.
[10] In this event, LSEs should notify Staff as soon as practicable that a supplemental filing is imminent and make the filing with sufficient time to allow Staff to review and incorporate those changes into the report.
[11] Documents will be posted to the MPSC Capacity Demonstration webpage (https://www.michigan.gov/mpsc/commission/workgroups/2016-energy-legislation/capacity-demonstration).

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion,	)	
to open a docket for load serving entities in	)	
Michigan to file their capacity demonstrations as	)	Case No. U-21775
required by MCL 460.6w.	)	
____	)	

AFFIDAVIT OF [Name of Company Officer]

STATE OF MICHIGAN

COUNTY OF (County name)

[NAME of Company Officer], being duly sworn, states that the following information and attached exhibits are true and accurate to the best of his/her reasonable knowledge and belief, regarding [the company's] satisfaction of its Michigan capacity demonstration requirements:

1. [Description of role and responsibilities within company]

2. [Overview of company]

3. [Overview of filing – if applicable for LSE, describe the load in each RTO, each local resource zone, and each service territory]

4. **Existing Generation - Owned** [Claim ownership of the unit(s), including a commitment of the unit(s) to LSE load in the applicable Michigan zone four years forward. (If this does not apply to your LSE, state that it is not applicable in planning year 20**-20**.)]

5. **Existing Demand Response or Energy Efficiency Resources (Not Netted Against Load)** [Outline the resource(s), including a commitment to maintain at least that same level of resources four years forward. If an AES has a LMR, describe how the transmission losses are applied in each service territory. (If this does not apply to your LSE, state that it is not applicable in planning year 20**-20**.)]

6. **Existing Demand Response or Energy Efficiency Resources (Netted Against Load)** [Outline what is netted against load, current programs, and how big these programs are.]

7. **New or Upgraded Generation – Owned** [Outline the detailed plans for the new generation including milestones such as planned in-service date, expected regulatory approval date(s), planned date to enter the MISO generator interconnection queue, expected date for MISO

generator interconnection agreement, construction timeline, etc. (If this does not apply to your LSE, state that it is not applicable in planning year 20**-20**.)]

8. **New Demand Response or Energy Efficiency Resources (Not Netted Against Load)** [Outline the plans for the resource(s), including a commitment to achieve and/or maintain at least that same level of resources four years forward. If an AES has a LMR, describe how the transmission losses are applied in each service territory. (If this does not apply to your LSE, state that it is not applicable in planning year 20**-20**.)]

9. **Existing Generation (Capacity Contract)** [Include a copy of the contract that specifies the unit(s) or pool of generation that is the source of the contract, including the location of the unit(s) or pool (can be filed confidentially) and state commitment to maintain the contract four years forward regardless of any early out clauses in the contract. In lieu of filing a copy of the contract(s), provide information set forth in the MPSC Order on Rehearing in Case No. U-18197, dated November 21, 2017, for Staff/Commission contract review. (If this does not apply to your LSE, state that it is not applicable in planning year 20**-20**.)]

10. **Forward ZRC Contracts** [Include a copy of the contract that specifies the zonal locations of the ZRCs. The affidavit should include a commitment to maintain the contract four years forward regardless of any early out clauses in the contract. In lieu of filing a copy of the contract(s), provide information set forth in the MPSC Order on Rehearing in Case No. U-18197, dated November 21, 2017, for Staff/Commission contract review. (If this does not apply to your LSE, state that it is not applicable in planning year 20**-20**.)]

11. **Planning Reserve Auction Purchases** (If this does not apply to your LSE, state that it is not applicable in planning year 20**-20**.)

____

NAME

SUBSCRIBED AND SWORN TO BEFORE ME on the _____ day of [month], [year].

____

Notary Public

My Commission Expires: _____________

EXHIBIT C

ALTERNATIVE ELECTRIC SUPPLIER LOAD SWITCHING AFFIDAVIT

State of __________

County of _________

[NAME], [title] of ("Receiving Supplier"), upon oath deposes and states that the following information is true and accurate to the best of his/her reasonable knowledge and belief:

("Receiving Supplier") will assume responsibility for an additional ______ MW in capacity peak load contribution values ("Additional PLC Value") associated with migrating customer load in _______ service territory for Planning Year 20** - 20**, over and above ("Receiving Supplier's") capacity demonstration obligation. ("Receiving Supplier") understands that the customer load reflected in this Additional PLC Value is currently the responsibility of ("Losing Supplier").

This Affidavit is being provided at the behest of the Michigan Public Service Commission Staff, in furtherance of implementation of Section 6w of Public Act 341.

____

NAME

SUBSCRIBED AND SWORN TO BEFORE ME on the _____ day of [month], [year].

____

Notary Public

My Commission Expires: ____________

P R O O F O F S E R V I C E

STATE OF MICHIGAN)

Case No. U-21775 *et al.*

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on August 21, 2025 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Brianna J. Brown

Brianna Brown

Subscribed and sworn to before me
this 21st day of August 2025.

Angela P. Sanderson

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2030

GEMOTION DISTRIBUTION SERVICE LIST

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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 128

Consumers' October 2025 10-Q

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 September 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 October 13, 2025:

CMS Energy Corporation:	
CMS Energy Corporation Common Stock, $0.01 par value	304,319,765
Consumers Energy Company:	
Consumers Common Stock, $10 par value, privately held by CMS Energy Corporation	84,108,789

CMS Energy Corporation

Consumers Energy Company

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

Table of Contents

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

GW
Gigawatt, a unit of energy equal to one billion watts

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

MCV Facility
A 1,647-MW natural gas-fueled, combined-cycle cogeneration facility operated by the MCV Partnership

MCV Partnership
Midland Cogeneration Venture Limited Partnership, a non-affiliated company

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

PSCR
Power supply cost recovery

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, or alternatively, the risk that anticipated demand growth from data center expansion may not materialize as expected
- 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

Index to Financial Statements

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.

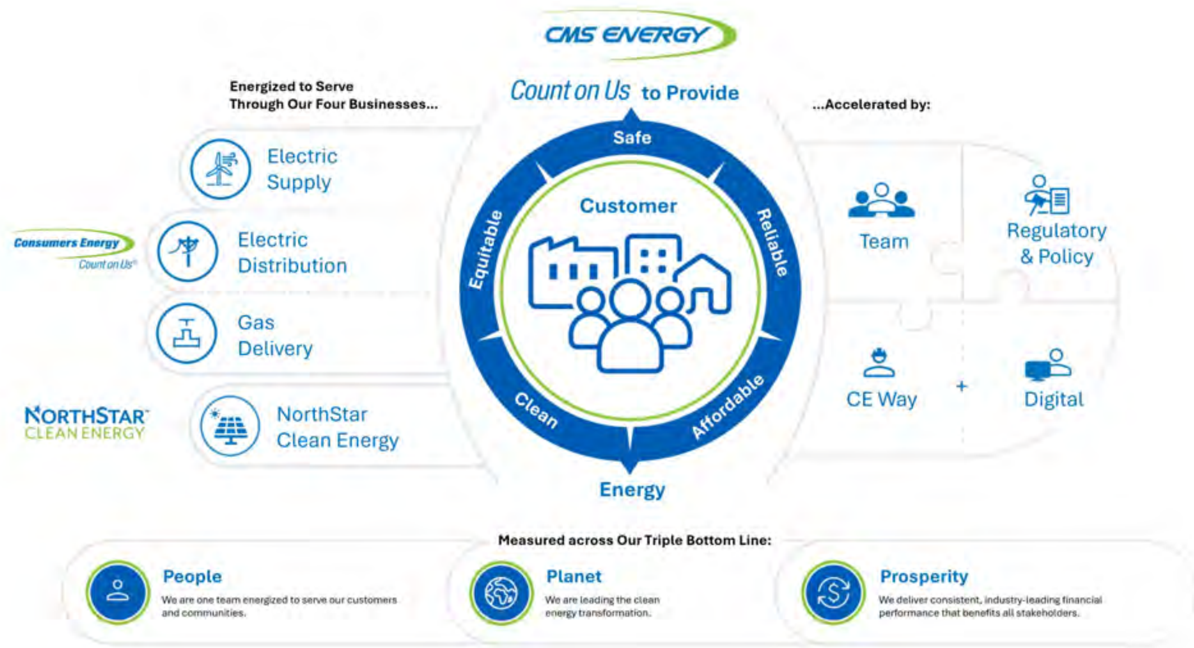
CMS Energy and Consumers manage their businesses by the nature of services each provides. CMS Energy operates principally in three business segments: electric utility; gas utility; and NorthStar Clean Energy, its non-utility operations and investments. Consumers operates principally in two business segments: 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' updates to its renewable energy plan, which were approved by the MPSC in September 2025, and planned updates to its Clean Energy Plan in 2026 will serve as a 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. As directed, Consumers continued to make J.H. Campbell available in the MISO market and 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 August 2025, FERC issued an order granting Consumers' requested relief and ordered MISO to file a revised tariff, which MISO filed in September 2025 and is pending at FERC.

On August 20, 2025, the U.S. Secretary of Energy issued a second emergency order requiring J.H. Campbell to continue operating for another 90 days, through November 19, 2025. Consumers is complying with the August 2025 emergency order and will seek recovery of its compliance costs at a later date, consistent with rate recovery sought for the May 2025 emergency order. The U.S. Department of Energy may issue more orders to require the continued operation of J.H. Campbell. Consumers cannot predict the long-term impact of these orders, litigation surrounding the orders, or additional orders or similar governmental actions, on the Clean Energy Plan.

Consumers' updates to its renewable energy plan include up to 9,000 MW of both purchased and owned solar energy resources and the addition of up to 2,800 MW of new, competitively bid wind energy resources. 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 through clean fuel alternatives or nature-based carbon removal pathways. 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 nine months ended September 30, 2025, CMS Energy's net income available to common stockholders was $775 million, and diluted EPS were $2.59. This compares with net income available to common stockholders of $731 million and diluted EPS of $2.45 for the nine months ended September 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

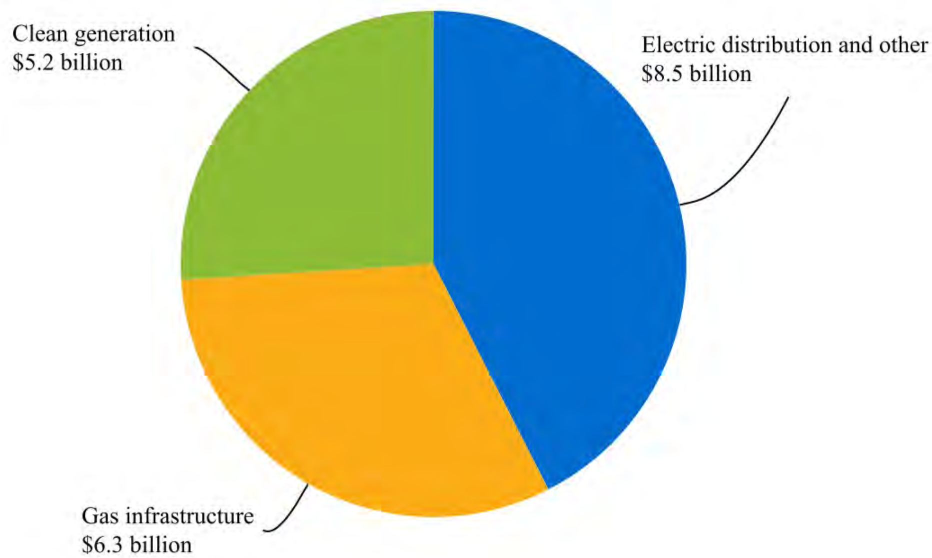
CMS Energy and Consumers remain committed to delivering safe, reliable, affordable, clean, and equitable energy in service of their customers and positively impacting the triple bottom line of people, planet, and prosperity. During 2025, CMS Energy and Consumers:

- reached an agreement with a new data center expected to add up to 1 GW of incremental load growth in our service territory, supporting long-term sales growth and delivering economic benefits for Michigan
- expanded the use of drone technology enabling faster, safer inspections of 400 miles of hard-to-reach power lines and infrastructure resulting in reduced average outage time per customer and improved storm recovery capabilities
- 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 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. In October 2025, Consumers revised its requested increase to $447 million. 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.In September 2025, the MPSC issued an order authorizing an annual rate increase of $157.5 million, based on a 9.80-percent authorized return on equity. The new rates become effective in November 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			Nine Months Ended		
September 30	2025	2024	Change	2025	2024	Change
Net Income Available to Common Stockholders	$ 275	$ 251	$ 24	$ 775	$ 731	$ 44
Basic Earnings Per Average Common Share	$ 0.92	$ 0.84	$ 0.08	$ 2.59	$ 2.45	$ 0.14
Diluted Earnings Per Average Common Share	$ 0.92	$ 0.84	$ 0.08	$ 2.59	$ 2.45	$ 0.14

In Millions

	Three Months Ended			Nine Months Ended		
September 30	2025	2024	Change	2025	2024	Change
Electric utility	$ 326	$ 273	$ 53	$ 617	$ 540	$ 77
Gas utility	—	11	(11)	238	195	43
NorthStar Clean Energy	11	6	5	15	53	(38)
Corporate interest and other	(62)	(39)	(23)	(95)	(57)	(38)
Net Income Available to Common Stockholders	$ 275	$ 251	$ 24	$ 775	$ 731	$ 44

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

In Millions

	Three Months Ended		Nine Months Ended	
September 30, 2024		$ 251		$ 731
Reasons for the change				
Consumers electric utility and gas utility				
Electric sales	$ 26		$ 41	
Gas sales	7		87	
Electric rate increase	99		179	
Gas rate increase, including gain amortization in lieu of rate relief	10		45	
Lower service restoration costs, net of 2025 deferred storm expense[1]	7		30	
Higher income tax expense	(45)		(83)	
Higher depreciation and amortization	(13)		(48)	
Higher interest charges	(14)		(30)	
Higher other maintenance and operating expenses	(13)		(26)	
Higher property taxes, reflecting higher capital spending	(9)		(23)	
Higher IT expenses, including early-phase ERP implementation costs	(7)		(17)	
Higher vegetation management cost	(2)		(15)	
Lower other income, net of expenses	(4)		(14)	
Absence of ASP revenue, net of expense, due to sale in 2024	—		(6)	
		$ 42		$ 120
NorthStar Clean Energy (see below for additional detail)		5		(38)
Corporate interest and other		(23)		(38)
September 30, 2025		$ 275		$ 775

[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 nine months ended September 30, 2025 versus 2024:

In Millions

	Three Months Ended		Nine Months Ended	
September 30, 2024		$ 273		$ 540
Reasons for the change				
Electric deliveries[1] and rate increases				
Rate increase, including return on higher renewable capital spending	$ 99		$ 179	
Higher revenue due primarily to higher sales volume	19		19	
Higher (lower) energy waste reduction program revenues	(3)		12	
Higher other revenues	7		22	
		$ 122		$ 232
Maintenance and other operating expenses				
Lower service restoration costs, net of 2025 deferred storm expense[2]	7		30	
Higher vegetation management cost	(2)		(15)	
Lower (higher) energy waste reduction program costs	3		(12)	
Higher IT expenses, including early-phase ERP implementation costs	(5)		(12)	
Higher other maintenance and operating expenses	(6)		(16)	
		(3)		(25)
Depreciation and amortization				
Increased plant in service, reflecting higher capital spending		(10)		(31)
General taxes				
Higher property taxes, reflecting higher capital spending		(6)		(13)
Other income, net of expenses		(1)		(8)
Interest charges		(10)		(21)
Income taxes				
Higher electric utility pre-tax earnings	(24)		(36)	
Absence of 2024 deferred tax liability reversals	(11)		(11)	
State deferred tax remeasurement[3]	—		(8)	
Higher other income taxes	(4)		(2)	
		(39)		(57)
September 30, 2025		$ 326		$ 617

1 For the three months ended September 30, deliveries to end-use customers were 10.4 billion kWh in 2025 and 10.1 billion kWh in 2024. For the nine months ended September 30, deliveries to end-use customers were 28.4 billion kWh in 2025 and 28.0 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 nine months ended September 30, 2025 versus 2024:

In Millions

	Three Months Ended		Nine Months Ended	
September 30, 2024		$ 11		$ 195
Reasons for the change				
Gas deliveries[1] and rate increases				
Rate increase	$ 8		$ 26	
Higher revenue due primarily to the absence of 2024 unfavorable weather	6		88	
Higher energy waste reduction program revenues	—		12	
Absence of ASP business revenue[2]	—		(19)	
ASP gain customer bill credit[2]	(2)		(20)	
		$ 12		$ 87
Maintenance and other operating expenses				
Amortization of ASP gain[2]	5		38	
Absence of 2024 ASP business expense[2]	—		13	
Higher IT expenses, including early-phase ERP implementation costs	(2)		(5)	
Higher energy waste reduction program costs	—		(12)	
Higher maintenance and other operating expenses	(7)		(10)	
		(4)		24
Depreciation and amortization				
Increased plant in service, reflecting higher capital spending		(3)		(17)
General taxes				
Higher property taxes, reflecting higher capital spending		(3)		(10)
Other income, net of expenses		(3)		(6)
Interest charges		(4)		(9)
Income taxes				
Lower (higher) gas utility pre-tax earnings	1		(18)	
Absence of 2024 deferred tax liability reversals	(5)		(5)	
State deferred tax remeasurement[3]	—		(4)	
Lower (higher) other income taxes	(2)		1	
		(6)		(26)
September 30, 2025		$ —		$ 238

1 For the three months ended September 30, deliveries to end-use customers were 30 Bcf in 2025 and 28 Bcf in 2024. For the nine months ended September 30, deliveries to end-use customers were 213 Bcf in 2025 and 186 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 nine months ended September 30, 2025 versus 2024:

In Millions

	Three Months Ended	Nine Months Ended
September 30, 2024	$ 6	$ 53
Reason for the change		
Higher (lower) earnings from renewable projects[1]	$ 3	$ (24)
Higher (lower) operating earning[2]	7	(16)
Lower (higher) other expense	2	(1)
Lower (higher) tax expense	(7)	3
September 30, 2025	$ 11	$ 15

[1] Reflects timing of achieving commercial operation during the nine months ended September 30, 2025 versus 2024.

[2] Reflects planned major outage at DIG during the nine months ended September 30, 2025 versus 2024.

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 nine months ended September 30, 2025 versus 2024:

In Millions

	Three Months Ended	Nine Months Ended
September 30, 2024	$ (39)	$ (57)
Reasons for the change		
Higher interest charges	$ (16)	$ (44)
Lower gains on extinguishment of debt	(20)	(18)
Lower other expense	5	14
Lower tax expense	8	10
September 30, 2025	$ (62)	$ (95)

Cash Position, Investing, and Financing

At September 30, 2025, CMS Energy had $432 million of consolidated cash and cash equivalents, which included $70 million of restricted cash and cash equivalents. At September 30, 2025, Consumers had $311 million of consolidated cash and cash equivalents, which included $69 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 nine months ended September 30, 2025 versus 2024:

In Millions

CMS Energy, including Consumers		
Nine Months Ended September 30, 2024	$	1,967
Reasons for the change		
Higher net income	$	68
Non-cash transactions[1]		89
Unfavorable impact of changes in core working capital,[2] due primarily to fluctuations in gas prices and higher undercollections of PSCR		(277)
Unfavorable impact of changes in other assets and liabilities, due primarily to higher service restoration expenditures[3]		(90)
Nine Months Ended September 30, 2025	$	1,757
Consumers		
Nine Months Ended September 30, 2024	$	2,014
Reasons for the change		
Higher net income	$	122
Non-cash transactions[1]		(42)
Unfavorable impact of changes in core working capital,[2] due primarily to fluctuations in gas prices and higher undercollections of PSCR		(271)
Unfavorable impact of changes in other assets and liabilities, due primarily to higher service restoration expenditures[3]		(49)
Nine Months Ended September 30, 2025	$	1,774

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 nine months ended September 30, 2025 versus 2024:

		In Millions
CMS Energy, including Consumers		
Nine Months Ended September 30, 2024	$	(2,101)
Reasons for the change		
Higher capital expenditures	$	(650)
Absence of proceeds from sale of ASP business in 2024		(124)
Other investing activities, primarily higher cost to retire property		(51)
Nine Months Ended September 30, 2025	$	(2,926)
Consumers		
Nine Months Ended September 30, 2024	$	(1,994)
Reasons for the change		
Higher capital expenditures	$	(390)
Absence of proceeds from sale of ASP business in 2024		(124)
Other investing activities, primarily higher cost to retire property		(61)
Nine Months Ended September 30, 2025	$	(2,569)

Financing Activities

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

		In Millions
CMS Energy, including Consumers		
Nine Months Ended September 30, 2024	$	353
Reasons for the change		
Higher debt issuances	$	1,064
Higher debt retirements		(95)
Lower repayments of notes payable		28
Higher issuances of common stock		90
Higher payments of dividends on common stock		(26)
Proceeds from sale of membership interests in VIEs		44
Other financing activities, primarily higher debt issuance costs		(35)
Nine Months Ended September 30, 2025	$	1,423
Consumers		
Nine Months Ended September 30, 2024	$	327
Reasons for the change		
Lower debt issuances	$	(174)
Lower debt retirements		222
Lower repayments of notes payable		28
Higher stockholder contribution from CMS Energy		375
Absence of return of stockholder contribution to CMS Energy in 2024		320
Higher payments of dividends on common stock		(105)
Other financing activities		(6)
Nine Months Ended September 30, 2025	$	987

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 nine months ended September 30, 2025, Consumers paid $649 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. During the nine months ended September 30, 2025, CMS Energy settled forward sale contracts issued under this program, resulting in net proceeds of $349 million. An additional settlement in October 2025 resulted in net proceeds of $147 million. Following these settlements, CMS Energy has $8 million in outstanding forward contracts under the program, maturing through November 30, 2026.

CMS Energy, NorthStar Clean Energy, and Consumers use revolving credit facilities for general working capital purposes and to issue letters of credit. At September 30, 2025, CMS Energy had $515 million of its revolving credit facility available, NorthStar Clean Energy had $62 million available under its revolving credit facility, and Consumers had $1.2 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 September 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 September 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 September 30, 2025, as presented in the following table:

	Limit	Actual
CMS Energy, parent only		
Debt to capital[1]	≤ 0.70 to 1.0	0.55 to 1.0
NorthStar Clean Energy, including subsidiaries		
Debt to capital[2]	≤ 0.50 to 1.0	0.13 to 1.0
Debt service coverage[2]	≥ 2.00 to 1.0	3.41 to 1.0
Pledged equity interests to aggregate commitment[2,3]	≥ 2.00 to 1.0	2.06 to 1.0
Consumers		
Debt to capital[4]	≤ 0.65 to 1.0	0.51 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 September 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.

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 to achieve the increased renewable energy standard; the MPSC approved updates in September 2025. 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. As directed, Consumers continued to make J.H. Campbell available in the MISO market and 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 August 2025, FERC issued an order granting Consumers' requested relief and ordered MISO to file a revised tariff, which MISO filed in September 2025 and is pending at FERC. For additional discussion of this FERC proceeding, see Notes to the Unaudited Consolidated Financial Statements—Note 1, Regulatory Matters.

On August 20, 2025, the U.S. Secretary of Energy issued a second emergency order requiring J.H. Campbell to continue operating for another 90 days, through November 19, 2025. Consumers is complying with the August 2025 emergency order and will seek recovery of its compliance costs at a later date, consistent with rate recovery sought for the May 2025 emergency order.

Following the May 2025 emergency order, 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 May 2025 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 May 2025 emergency order in federal court. The requests for rehearing were subsequently denied, and similar challenges to the August 2025 order are underway. The U.S. Department of Energy may issue more orders to require the continued operation of J.H. Campbell. While the timing and content of future orders and the outcome of third-party legal challenges are not yet known, Consumers is committed to pursuing cost recovery as provided for under applicable laws, orders, and proceedings.

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.

In September 2025, Consumers entered into a PPA with the MCV Partnership for the purchase of up to 1,240 MW of capacity and associated energy from the MCV Facility. The agreement is effective from June 1, 2030 through May 31, 2040. Under the terms of the agreement, Consumers will pay a monthly capacity charge of $5.00 per MWh of available capacity. Energy payments include a fixed component designed to recover non-fuel operating costs and a variable component based on the MCV Partnership's cost of production for energy delivered to Consumers. The agreement, which is subject to MPSC approval, supports Consumers' ongoing resource adequacy and energy supply planning efforts.

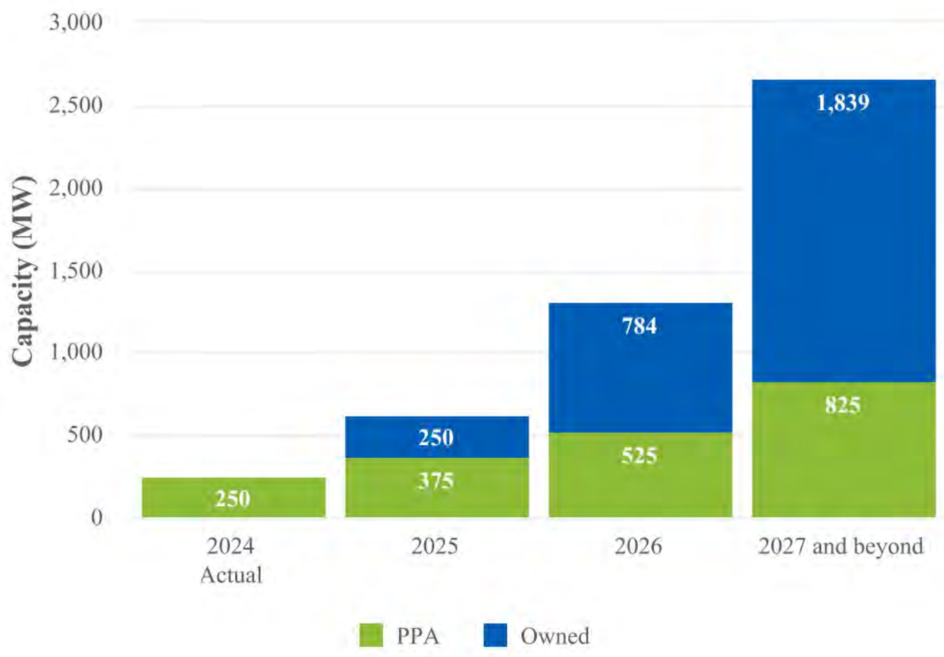
Consumers has also contracted to purchase 700 MW of capacity from battery storage facilities, which will be located in Michigan's Lower Peninsula and are expected to be operational by 2028. In an April 2025 report, the MPSC Staff indicated that Consumers' share of the 2,500-MW statewide energy storage target established by the 2023 Energy Law is 817 MW.

Under its Clean Energy Plan, Consumers bids new capacity and energy competitively and the actual composition of Consumers' future portfolio will reflect the results of that competitive bid process. 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.

Currently, over 15 percent of the electricity Consumers supplies to customers comes from renewable energy sources. Under its renewable energy 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.

Consumers' updates to its renewable energy plan, which were approved by the MPSC in September 2025, include up to 2,800 MW of new, competitively bid wind energy resources and up to 9,000 MW of both purchased and owned solar energy resources. Of the proposed solar energy resources, 1,060 MW will support Consumers' voluntary green pricing program that provides full-service electric customers with the opportunity to advance the development of renewable energy beyond present state requirements.

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 September 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.

Sale of Hydroelectric Facilities: In September 2025, Consumers signed an agreement to sell its 13 river hydroelectric dams, which are located throughout Michigan, to a non-affiliated company. Additionally, Consumers signed an agreement to purchase power generated by the facilities for 30 years, at a price that reflects the counterparty's acceptance of the risks and rewards of ownership of the facilities, including FERC licensing obligations. The agreements are contingent upon MPSC and FERC approval, which must be filed within 60 days of signing. Timing of the regulatory review process is uncertain and could extend 12 to 18 months or longer. In Consumers' most recent electric rate case, the MPSC approved deferred accounting treatment for costs of owning and operating the hydroelectric dams pending and until completion of the transaction. At September 30, 2025, the net book value of the hydroelectric facilities was immaterial.

To ensure necessary staffing at the hydroelectric facilities through the anticipated sale, Consumers has provided current employees at the facilities with a retention incentive program. Subsequently, to ensure continued safe operation of the facilities after the sale, the buyer will offer employment to the current hydroelectric employees for a period of at least a year. The retention incentive benefits are contingent upon MPSC and FERC approval of the sale transaction.

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.

In October 2025, Consumers revised its requested increase to $447 million. Presented in the following table are the components of the revised requested increase in revenue:

In Millions

Projected 12-Month Period Ending April 30		2027
Investment in rate base	$	192
Operating and maintenance costs		157
Cost of capital		67
Sales and other revenue		7
Subtotal	$	423
Surcharge		24
Total	$	447

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

Retention Incentive Program: Under its Clean Energy Plan, Consumers had planned to retire J.H. Campbell in 2025. In order to ensure necessary staffing at J.H. Campbell through the planned retirement, Consumers implemented a retention incentive program. The terms of and Consumers' obligations under this program have not been modified as a result of the U.S. Secretary of Energy's emergency orders requiring the continued operation of J.H. Campbell. Consumers will make final payments due under this retention plan in November 2025. The aggregate cost of the J.H. Campbell program is estimated to be $48 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. Should the U.S. Department of Energy issue additional emergency orders that require the continued operation of J.H. Campbell beyond November 2025, Consumers is prepared to implement additional retention measures to ensure appropriate staffing levels. For additional details on this program, see Notes to the Unaudited Consolidated Financial Statements—Note 12, Exit Activities and Asset Sales. For additional details on the emergency orders, see Notes to the Unaudited Consolidated Financial Statements—Note 1, Regulatory Matters.

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 proposed 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 emission 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 September 2025, the EPA proposed a rule to reconsider the Greenhouse Gas Reporting Program by eliminating the reporting obligations from numerous emission sources, including Consumers' electric generation sites and distribution equipment. Reporting of carbon dioxide to the EPA, however, will continue for sources subject to the Clean Air Act Acid Rain Program, which includes Consumers' fossil-fuel-fired electric generation. This change could result in inconsistent approaches in greenhouse gas accounting for industrial sources.

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 or 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 and then withdrawn by the EPA; the rule has since been republished for notice and comment. 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 completed an assessment of inactive facilities as required by the 2024 CCR rule, and did not identify any legacy impoundments. Consumers is continuing 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. 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. In September 2025, the MPSC issued an order authorizing an annual rate increase of $157.5 million, based on a 9.80-percent authorized return on equity. The new rates become effective in November 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 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 September 2025, the EPA proposed a rule to reconsider the Greenhouse Gas Reporting Program by removing the natural gas distribution segment from the reporting obligations under the petroleum and natural gas source category, and proposed to delay the reporting obligations until 2034 for the remaining sources in this category. This change could result in inconsistent approaches in greenhouse gas accounting for industrial sources.

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 Consumers Electric Utility Outlook and Uncertainties—Electric Environmental Outlook.

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 through clean fuel alternatives or nature-based carbon removal pathways. 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 2026 and is monitoring regulatory developments and market conditions closely as part of its ongoing evaluation of the projects. 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
- delays or difficulties in financing, constructing, and developing projects, including those arising from the performance of contractors, suppliers, or other counterparties
- 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

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 units 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 September 2025, the EPA proposed a rule to reconsider the Greenhouse Gas Reporting Program by eliminating the reporting obligations from numerous emission sources. Reporting of carbon dioxide to the EPA, however, will continue for sources subject to the Clean Air Act Acid Rain Program. This change could result in inconsistent approaches in greenhouse gas accounting for industrial sources.

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. In September 2025, Consumers and the United Steelworkers labor union ratified a new five-year contract for its Zeeland plant bargaining unit.

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. Based on guidance available to date, CMS Energy and Consumers evaluated the provisions of the OBBBA and concluded that the legislation is not expected to have a material impact on their respective financial statements. This conclusion is subject to change as additional guidance or interpretations become available.

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		Nine Months Ended	
September 30	2025	2024	2025	2024
Operating Revenue	$ 2,021	$ 1,743	$ 6,306	$ 5,526
Operating Expenses				
Fuel for electric generation	153	179	504	449
Purchased and interchange power	513	362	1,332	1,025
Purchased power – related parties	21	19	69	53
Cost of gas sold	42	32	549	449
Maintenance and other operating expenses	416	412	1,218	1,218
Depreciation and amortization	288	273	964	914
General taxes	107	99	378	356
Total operating expenses	1,540	1,376	5,014	4,464
Operating Income	481	367	1,292	1,062
Other Income (Expense)				
Non-operating retirement benefits, net	48	42	137	127
Other income	19	46	128	167
Other expense	(5)	(4)	(16)	(11)
Total other income	62	84	249	283
Interest Charges				
Interest on long-term debt	204	176	590	519
Interest expense – related parties	2	3	8	9
Other interest expense	—	4	(1)	11
Allowance for borrowed funds used during construction	(3)	(5)	(9)	(11)
Total interest charges	203	178	588	528
Income Before Income Taxes	340	273	953	817
Income Tax Expense	68	26	193	125
Net Income	272	247	760	692
Loss Attributable to Noncontrolling Interests	(5)	(6)	(22)	(46)
Net Income Attributable to CMS Energy	277	253	782	738
Preferred Stock Dividends	2	2	7	7
Net Income Available to Common Stockholders	$ 275	$ 251	$ 775	$ 731
Basic Earnings Per Average Common Share	$ 0.92	$ 0.84	$ 2.59	$ 2.45
Diluted Earnings Per Average Common Share	$ 0.92	$ 0.84	$ 2.59	$ 2.45

The accompanying notes are an integral part of these statements.

CMS Energy Corporation
Consolidated Statements of Comprehensive Income (Unaudited)

In Millions

	Three Months Ended		Nine Months Ended	
September 30	2025	2024	2025	2024
Net Income	$ 272	$ 247	$ 760	$ 692
Retirement Benefits Liability				
Amortization of net actuarial loss, net of tax of $—, $1, $—, and $1	1	—	1	1
Amortization of prior service credit, net of tax of $— for all periods	(1)	—	(1)	—
Other Comprehensive Income	—	—	—	1
Comprehensive Income	272	247	760	693
Comprehensive Loss Attributable to Noncontrolling Interests	(5)	(6)	(22)	(46)
Comprehensive Income Attributable to CMS Energy	$ 277	$ 253	$ 782	$ 739

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
Nine Months Ended September 30		2025		2024
Cash Flows from Operating Activities				
Net income	$	760	$	692
Adjustments to reconcile net income to net cash provided by operating activities				
Depreciation and amortization		964		914
Deferred income taxes and investment tax credits		171		103
Other non-cash operating activities and reconciling adjustments		(181)		(152)
Changes in assets and liabilities				
Accounts receivable and accrued revenue		114		185
Inventories		(134)		51
Accounts payable and accrued rate refunds		(6)		15
Other current assets and liabilities		103		(3)
Other non-current assets and liabilities		(34)		162
Net cash provided by operating activities		1,757		1,967
Cash Flows from Investing Activities				
Capital expenditures (excludes assets placed under finance lease)		(2,750)		(2,100)
Proceeds from sale of ASP business		—		124
Cost to retire property and other investing activities		(176)		(125)
Net cash used in investing activities		(2,926)		(2,101)
Cash Flows from Financing Activities				
Proceeds from issuance of debt		2,511		1,447
Retirement of debt		(884)		(789)
Decrease in notes payable		(65)		(93)
Issuance of common stock		373		283
Payment of dividends on common and preferred stock		(496)		(470)
Proceeds from the sale of membership interests in VIEs		44		—
Other financing costs		(60)		(25)
Net cash provided by financing activities		1,423		353
Net Increase in Cash and Cash Equivalents, Including Restricted Amounts		254		219
Cash and Cash Equivalents, Including Restricted Amounts, Beginning of Period		178		248
Cash and Cash Equivalents, Including Restricted Amounts, End of Period	$	432	$	467
Other Non-cash Investing and Financing Activities				
Non-cash transactions				
Capital expenditures not paid	$	586	$	387

The accompanying notes are an integral part of these statements.

CMS Energy Corporation
Consolidated Balance Sheets (Unaudited)

ASSETS

In Millions

	September 30 2025	December 31 2024
Current Assets		
Cash and cash equivalents	$ 362	$ 103
Restricted cash and cash equivalents	70	75
Accounts receivable and accrued revenue, less allowance of $28 in 2025 and $23 in 2024	922	1,049
Accounts receivable – related parties	12	14
Inventories at average cost		
Gas in underground storage	566	435
Materials and supplies	307	299
Generating plant fuel stock	30	35
Deferred property taxes	294	448
Regulatory assets	84	229
Prepayments and other current assets	98	103
Total current assets	2,745	2,790
Plant, Property, and Equipment		
Plant, property, and equipment, gross	36,583	34,932
Less accumulated depreciation and amortization	10,051	9,569
Plant, property, and equipment, net	26,532	25,363
Construction work in progress	3,158	2,098
Total plant, property, and equipment	29,690	27,461
Other Non-current Assets		
Regulatory assets	3,545	3,569
Accounts receivable	18	20
Investments	64	69
Postretirement benefits	1,744	1,627
Other	202	384
Total other non-current assets	5,573	5,669
Total Assets	$ 38,008	$ 35,920

LIABILITIES AND EQUITY

		In Millions
	September 30 2025	December 31 2024
Current Liabilities		
Current portion of long-term debt and finance leases	$ 1,162	$ 1,195
Notes payable	—	65
Accounts payable	1,141	1,085
Accounts payable – related parties	8	8
Accrued rate refunds	9	38
Accrued interest	204	156
Accrued taxes	200	654
Regulatory liabilities	89	111
Other current liabilities	239	209
Total current liabilities	3,052	3,521
Non-current Liabilities		
Long-term debt	16,774	15,194
Non-current portion of finance leases	137	112
Regulatory liabilities	4,104	4,067
Postretirement benefits	92	96
Asset retirement obligations	731	728
Deferred investment tax credit	119	122
Deferred income taxes	3,172	2,925
Other non-current liabilities	396	407
Total non-current liabilities	25,525	23,651
Commitments and Contingencies (Notes 1 and 2)		
Equity		
Common stockholders' equity		
Common stock, authorized 350.0 shares in both periods; outstanding 304.3 shares in 2025 and 298.8 shares in 2024	3	3
Other paid-in capital	6,355	6,009
Accumulated other comprehensive loss	(41)	(41)
Retained earnings	2,323	2,035
Total common stockholders' equity	8,640	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	8,864	8,230
Noncontrolling interests	567	518
Total equity	9,431	8,748
Total Liabilities and Equity	$ 38,008	$ 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		Nine Months Ended	
September 30	2025	2024	2025	2024
Total Equity at Beginning of Period	$ 8,971	$ 8,541	$ 8,748	$ 8,125
Common Stock				
At beginning and end of period	3	3	3	3
Other Paid-in Capital				
At beginning of period	5,998	5,991	6,009	5,705
Common stock issued	358	10	393	307
Common stock repurchased	(1)	—	(13)	(11)
Adjustment for sale of membership interests in VIEs	—	—	(34)	—
At end of period	6,355	6,001	6,355	6,001
Accumulated Other Comprehensive Loss				
Retirement benefits liability				
At beginning of period	(41)	(45)	(41)	(46)
Amortization of net actuarial loss	1	—	1	1
Amortization of prior service credit	(1)	—	(1)	—
At end of period	(41)	(45)	(41)	(45)
Retained Earnings				
At beginning of period	2,210	1,830	2,035	1,658
Net income attributable to CMS Energy	277	253	782	738
Dividends declared on common stock	(162)	(153)	(487)	(461)
Dividends declared on preferred stock	(2)	(2)	(7)	(7)
At end of period	2,323	1,928	2,323	1,928
Cumulative Redeemable Perpetual Preferred Stock, Series C				
At beginning and end of period	224	224	224	224
Noncontrolling Interests				
At beginning of period	577	538	518	581
Sale of membership interests in VIEs	—	—	78	—
Loss attributable to noncontrolling interests	(5)	(6)	(22)	(46)
Other changes in noncontrolling interests	(5)	(2)	(7)	(5)
At end of period	567	530	567	530
Total Equity at End of Period	$ 9,431	$ 8,641	$ 9,431	$ 8,641
Dividends declared per common share	$ 0.5425	$ 0.5150	$ 1.6275	$ 1.5450
Dividends declared per preferred stock Series C depositary share	$ 0.2625	$ 0.2625	$ 0.7875	$ 0.7875

The accompanying notes are an integral part of these statements.

Consumers Energy Company
Consolidated Statements of Income (Unaudited)

In Millions

	Three Months Ended		Nine Months Ended	
September 30	2025	2024	2025	2024
Operating Revenue	$ 1,913	$ 1,661	$ 6,007	$ 5,291
Operating Expenses				
Fuel for electric generation	113	150	419	366
Purchased and interchange power	490	346	1,219	989
Purchased power – related parties	21	19	69	53
Cost of gas sold	40	31	545	447
Maintenance and other operating expenses	388	381	1,137	1,136
Depreciation and amortization	274	261	925	878
General taxes	104	95	369	346
Total operating expenses	1,430	1,283	4,683	4,215
Operating Income	483	378	1,324	1,076
Other Income (Expense)				
Non-operating retirement benefits, net	44	39	128	118
Other income	15	24	44	67
Other expense	(4)	(3)	(11)	(10)
Total other income	55	60	161	175
Interest Charges				
Interest on long-term debt	135	123	388	364
Interest expense – related parties	10	9	30	22
Other interest expense	3	3	6	8
Allowance for borrowed funds used during construction	(3)	(4)	(8)	(8)
Total interest charges	145	131	416	386
Income Before Income Taxes	393	307	1,069	865
Income Tax Expense	79	34	221	139
Net Income	314	273	848	726
Preferred Stock Dividends	—	—	1	1
Net Income Available to Common Stockholder	$ 314	$ 273	$ 847	$ 725

The accompanying notes are an integral part of these statements.

Consumers Energy Company
Consolidated Statements of Comprehensive Income (Unaudited)

In Millions

	Three Months Ended		Nine Months Ended	
September 30	2025	2024	2025	2024
Net Income	$ 314	$ 273	$ 848	$ 726
Retirement Benefits Liability				
Amortization of net actuarial loss, net of tax of $— for all periods	—	1	—	1
Other Comprehensive Income	—	1	—	1
Comprehensive Income	$ 314	$ 274	$ 848	$ 727

The accompanying notes are an integral part of these statements.

Consumers Energy Company
Consolidated Statements of Cash Flows (Unaudited)

In Millions

Nine Months Ended September 30	2025	2024
Cash Flows from Operating Activities		
Net income	$ 848	$ 726
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation and amortization	925	878
Deferred income taxes and investment tax credits	57	99
Other non-cash operating activities and reconciling adjustments	(111)	(64)
Changes in assets and liabilities		
Accounts and notes receivable and accrued revenue	124	184
Inventories	(137)	50
Accounts payable and accrued rate refunds	1	25
Other current assets and liabilities	121	(29)
Other non-current assets and liabilities	(54)	145
Net cash provided by operating activities	1,774	2,014
Cash Flows from Investing Activities		
Capital expenditures (excludes assets placed under finance lease)	(2,389)	(1,999)
Proceeds from sale of ASP business	—	124
Cost to retire property and other investing activities	(180)	(119)
Net cash used in investing activities	(2,569)	(1,994)
Cash Flows from Financing Activities		
Proceeds from issuance of debt	1,123	1,297
Retirement of debt	(100)	(322)
Decrease in notes payable	(65)	(93)
Stockholder contribution	695	320
Return of stockholder contribution	—	(320)
Payment of dividends on common and preferred stock	(650)	(545)
Other financing costs	(16)	(10)
Net cash provided by financing activities	987	327
Net Increase in Cash and Cash Equivalents, Including Restricted Amounts	192	347
Cash and Cash Equivalents, Including Restricted Amounts, Beginning of Period	119	56
Cash and Cash Equivalents, Including Restricted Amounts, End of Period	$ 311	$ 403
Other Non-cash Investing and Financing Activities		
Non-cash transactions		
Capital expenditures not paid	$ 453	$ 382

The accompanying notes are an integral part of these statements.

Consumers Energy Company
Consolidated Balance Sheets (Unaudited)

ASSETS

In Millions

	September 30 2025	December 31 2024
Current Assets		
Cash and cash equivalents	$ 242	$ 44
Restricted cash and cash equivalents	69	75
Accounts receivable and accrued revenue, less allowance of $28 in 2025 and $23 in 2024	890	1,019
Accounts and notes receivable – related parties	10	17
Inventories at average cost		
Gas in underground storage	566	435
Materials and supplies	299	291
Generating plant fuel stock	28	30
Deferred property taxes	294	448
Regulatory assets	84	229
Prepayments and other current assets	90	86
Total current assets	2,572	2,674
Plant, Property, and Equipment		
Plant, property, and equipment, gross	35,021	33,434
Less accumulated depreciation and amortization	9,772	9,310
Plant, property, and equipment, net	25,249	24,124
Construction work in progress	2,532	1,766
Total plant, property, and equipment	27,781	25,890
Other Non-current Assets		
Regulatory assets	3,545	3,569
Accounts receivable	24	26
Accounts and notes receivable – related parties	88	92
Postretirement benefits	1,622	1,514
Other	148	323
Total other non-current assets	5,427	5,524
Total Assets	$ 35,780	$ 34,088

LIABILITIES AND EQUITY

		In Millions
	September 30 2025	December 31 2024
Current Liabilities		
Current portion of long-term debt and finance leases	$ 579	$ 456
Notes payable	—	65
Accounts payable	984	917
Accounts payable – related parties	15	12
Accrued rate refunds	9	38
Accrued interest	147	130
Accrued taxes	290	678
Regulatory liabilities	89	111
Other current liabilities	204	185
Total current liabilities	2,317	2,592
Non-current Liabilities		
Long-term debt	11,537	10,818
Long-term debt – related parties	1,005	823
Non-current portion of finance leases	84	69
Regulatory liabilities	4,104	4,067
Postretirement benefits	67	70
Asset retirement obligations	696	694
Deferred investment tax credit	119	122
Deferred income taxes	3,185	3,053
Other non-current liabilities	342	349
Total non-current liabilities	21,139	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	8,869	8,174
Accumulated other comprehensive loss	(11)	(11)
Retained earnings	2,588	2,390
Total common stockholder's equity	12,287	11,394
Cumulative preferred stock, $4.50 series, authorized 7.5 shares; outstanding 0.4 shares in both periods	37	37
Total equity	12,324	11,431
Total Liabilities and Equity	$ 35,780	$ 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		Nine Months Ended	
September 30	2025	2024	2025	2024
Total Equity at Beginning of Period	$ 11,698	$ 10,893	$ 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	545	—	695	320
Return of stockholder contribution	—	—	—	(320)
At end of period	8,869	7,759	8,869	7,759
Accumulated Other Comprehensive Loss				
Retirement benefits liability				
At beginning of period	(11)	(15)	(11)	(15)
Amortization of net actuarial loss	—	1	—	1
At end of period	(11)	(14)	(11)	(14)
Retained Earnings				
At beginning of period	2,507	2,271	2,390	2,178
Net income	314	273	848	726
Dividends declared on common stock	(233)	(185)	(649)	(544)
Dividends declared on preferred stock	—	—	(1)	(1)
At end of period	2,588	2,359	2,588	2,359
Cumulative Preferred Stock				
At beginning and end of period	37	37	37	37
Total Equity at End of Period	$ 12,324	$ 10,982	$ 12,324	$ 10,982

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.

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 emergency order. 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.

On August 20, 2025, the U.S. Secretary of Energy issued a second emergency order requiring J.H. Campbell to continue operating for another 90 days, through November 19, 2025. Consumers is complying with the August 2025 emergency order. Also in August 2025, FERC granted Consumers' complaint seeking modification of the MISO Tariff and ordered MISO to revise its tariff accordingly. MISO submitted a compliance filing with FERC in September 2025, and FERC approval of the compliance filing remains pending. During the initial emergency order period, the net financial impact of compliance was $53 million after applying MISO revenues of $67 million. For the second emergency order period through September 30, 2025, the net financial impact of compliance was $27 million after applying MISO revenues of $17 million. Upon FERC approval of the requested tariff modification, Consumers intends to file for recovery and allocation of costs to comply with the emergency orders across the region specified by the emergency orders. The ultimate financial impact remains subject to the outcome of the FERC proceeding and any future guidance or interpretation.

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 September 30, 2025, Consumers had a $54 million regulatory asset recorded associated with these costs, recovery for which will be requested in a future 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 September 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	$ 1	$ 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 September 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 September 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 trial is scheduled to begin in the fourth quarter of 2025. 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. Consumers 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 September 30, 2025, Consumers had a recorded liability of $60 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	$ —	$ 3	$ 8	$ 25	$ 11	$ 3

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 September 30, 2025, Consumers had a regulatory asset of $85 million related to the MGP sites.

Guarantees

Presented in the following table are CMS Energy’s and Consumers’ guarantees at September 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	$	229	$	—
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 nine months ended September 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]	$ 179	variable	February 2025	Five years after conversion date[2]
Total NorthStar Clean Energy, including subsidiaries	$ 179			
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	$ 2,414			

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 nine months ended September 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 nine months ended September 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 during the nine months ended September 30, 2025, which was recorded in other income on CMS Energy’s consolidated statements of income. Interest expense related to the repurchased bonds was $8 million for the three months ended September 30, 2025 and $21 million for the nine months ended September 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 $69 million during the three months ended September 30, 2024 and $311 million during the nine months ended September 30, 2024, in exchange for cash of $49 million and $218 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 $20 million for the three months ended September 30, 2024 and a pre-tax gain of $90 million for the nine months ended September 30, 2024, which was recorded in other income on its consolidated statements of income. Interest expense related to the repurchased bonds was $5 million for the three months ended September 30, 2024 and $13 million for the nine months ended September 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 September 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	$ —	$ 35	$ 515
September 30, 2026	50	—	50	—
NorthStar Clean Energy, including subsidiaries				
May 30, 2028[2]	$ 250	$ 180	$ 8	$ 62
December 25, 2025[3]	37	—	37	—
Upon completion of construction project[4]	19	—	12	7
Consumers				
December 14, 2027[5]	$ 1,100	$ —	$ 10	$ 1,090
November 18, 2025[5]	250	—	112	138
March 31, 2028	50	—	42	8

1 There were no borrowings under this facility during the nine months ended September 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 September 30, 2025, the net book value of the pledged equity interests was $515 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 nine months ended September 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 September 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 September 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 September 30, 2025, obligations under this program accounted for as accounts payable on CMS Energy's consolidated balance sheets were $79 million.

Dividend Restrictions: At September 30, 2025, payment of dividends by CMS Energy on its common stock was limited to $8.6 billion under provisions of the Michigan Business Corporation Act of 1972.

Under the provisions of its articles of incorporation, at September 30, 2025, Consumers had $2.5 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 nine months ended September 30, 2025, Consumers paid $649 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.

Under the forward sales transactions, 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.

During the three months ended September 30, 2025, CMS Energy entered into forward sale agreements for approximately 2.1 million shares at a weighted average initial forward price of $72.42 per share. During the same period, CMS Energy settled forward sale contracts under this program by issuing approximately 5.0 million shares at a weighted average price of $70.52 per share, resulting in net proceeds of $349 million.

In October 2025, CMS Energy completed an additional settlement issuing approximately 2.0 million shares at a weighted average price of $72.73, resulting in net proceeds of $147 million. Following these transactions, outstanding forward contracts under the program have an aggregate sales price of $8 million, maturing through November 30, 2026.

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 September 30, 2025, it would have been required to deliver 21,313 shares or pay $2 million in 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	
	September 30 2025	December 31 2024	September 30 2025	December 31 2024
Assets[1]				
Cash equivalents	$ 75	$ 27	$ —	$ —
Restricted cash equivalents	70	75	69	75
Nonqualified deferred compensation plan assets	35	34	27	25
Derivative instruments	3	2	3	2
Total assets	$ 183	$ 138	$ 99	$ 102
Liabilities[1]				
Nonqualified deferred compensation plan liabilities	$ 35	$ 34	$ 27	$ 25
Derivative instruments	4	—	—	—
Total liabilities	$ 39	$ 34	$ 27	$ 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 less than $1 million for the three months ended September 30, 2025 and $4 million for the nine months ended September 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 September 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

	September 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	$ 6	$ —	$ —	$ 6	$ 9	$ 8	$ —	$ —	$ 8
Liabilities										
Long-term debt[2]	17,930	16,993	2,111	12,932	1,950	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	$ 6	$ —	$ —	$ 6	$ 9	$ 8	$ —	$ —	$ 8
Notes receivable – related party[4]	91	91	—	—	91	94	94	—	—	94
Liabilities										
Long-term debt[5]	12,109	11,132	—	9,182	1,950	11,270	9,940	—	8,034	1,906
Long-term debt – related party[6]	1,005	674	—	674	—	823	549	—	549	—
Long-term payables	2	2	—	—	2	4	4	—	—	4

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

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

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

4 Includes current portion of notes receivable – related party of $7 million at September 30, 2025 and December 31, 2024.

5 Includes current portion of long-term debt of $572 million at September 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		Nine Months Ended		Three Months Ended		Nine Months Ended	
September 30	2025	2024	2025	2024	2025	2024	2025	2024
CMS Energy, including Consumers								
Net periodic credit								
Service cost	$ 6	$ 7	$ 19	$ 21	$ 2	$ 2	$ 6	$ 8
Interest cost	27	26	81	78	10	10	32	32
Expected return on plan assets	(57)	(58)	(171)	(176)	(27)	(28)	(83)	(86)
Amortization of:								
Net loss	3	3	8	9	—	1	2	3
Prior service cost (credit)	1	1	3	3	(8)	(7)	(25)	(23)
Settlement loss	3	3	8	8	—	—	—	—
Net periodic credit	$ (17)	$ (18)	$ (52)	$ (57)	$ (23)	$ (22)	$ (68)	$ (66)
Consumers								
Net periodic credit								
Service cost	$ 6	$ 7	$ 18	$ 20	$ 2	$ 2	$ 6	$ 8
Interest cost	26	25	77	74	11	11	32	31
Expected return on plan assets	(54)	(56)	(162)	(166)	(26)	(26)	(78)	(80)
Amortization of:								
Net loss	2	3	7	8	—	1	2	3
Prior service cost (credit)	1	1	3	3	(8)	(8)	(25)	(23)
Settlement loss	3	3	8	8	—	—	—	—
Net periodic credit	$ (16)	$ (17)	$ (49)	$ (53)	$ (21)	$ (20)	$ (63)	$ (61)

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 September 30, 2025, CMS Energy, including Consumers, had deferred $1 million of pension costs and

$7 million of OPEB credits under this mechanism related to 2025 expense. At September 30, 2024, CMS Energy, including Consumers, had deferred $12 million of pension credits and $8 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:

Nine Months Ended September 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]	7.2	5.4
Renewable energy tax credits	(5.7)	(6.3)
TCJA excess deferred taxes	(3.5)	(3.8)
Deferred tax adjustment[2]	—	(1.9)
Taxes attributable to noncontrolling interests	1.2	1.1
Other, net	0.1	(0.2)
Effective tax rate	20.3 %	15.3 %
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]	6.5	5.0
Renewable energy tax credits	(3.6)	(4.4)
TCJA excess deferred taxes	(3.0)	(3.5)
Deferred tax adjustment[2]	—	(1.8)
Other, net	(0.2)	(0.2)
Effective tax rate	20.7 %	16.1 %

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.

2 In September 2024, Consumers recognized a $16 million tax benefit resulting from the expiration of the statute of limitations associated with audit points for the 2018 and 2019 tax years.

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 September 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. Based on guidance available to date, CMS Energy and Consumers evaluated the provisions of the OBBBA and concluded that the legislation is not expected to have a material impact on their respective financial statements. This conclusion is subject to change as additional guidance or interpretations become available.

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		Nine Months Ended	
September 30	2025	2024	2025	2024
Income available to common stockholders				
Income from continuing operations	$ 272	$ 247	$ 760	$ 692
Less loss attributable to noncontrolling interests	(5)	(6)	(22)	(46)
Less preferred stock dividends	2	2	7	7
Income from continuing operations available to common stockholders – basic and diluted	$ 275	$ 251	$ 775	$ 731
Average common shares outstanding				
Weighted-average shares – basic	299.7	298.0	298.8	297.5
Add dilutive nonvested stock awards	0.6	0.8	0.6	0.7
Add dilutive forward equity sale contracts	0.1	—	—	—
Weighted-average shares – diluted	300.4	298.8	299.4	298.2
Income from continuing operations per average common share available to common stockholders				
Basic	$ 0.92	$ 0.84	$ 2.59	$ 2.45
Diluted	0.92	0.84	2.59	2.45

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 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 September 30, 2025	Electric Utility	Gas Utility	NorthStar Clean Energy[1]	Consolidated
CMS Energy, including Consumers				
Consumers utility revenue	$ 1,675	$ 233	$ —	$ 1,908
Other	—	—	67	67
Revenue recognized from contracts with customers	$ 1,675	$ 233	$ 67	$ 1,975
Leasing income	—	—	41	41
Financing income	2	1	—	3
Consumers alternative-revenue programs	2	—	—	2
Total operating revenue – CMS Energy	$ 1,679	$ 234	$ 108	$ 2,021
Consumers				
Consumers utility revenue				
Residential	$ 842	$ 139		$ 981
Commercial	577	45		622
Industrial	204	6		210
Other	52	43		95
Revenue recognized from contracts with customers	$ 1,675	$ 233		$ 1,908
Financing income	2	1		3
Alternative-revenue programs	2	—		2
Total operating revenue – Consumers	$ 1,679	$ 234		$ 1,913

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 $28 million for the three months ended September 30, 2025.

In Millions

Three Months Ended September 30, 2024	Electric Utility	Gas Utility	NorthStar Clean Energy[1]	Consolidated
CMS Energy, including Consumers				
Consumers utility revenue	$ 1,443	$ 212	$ —	$ 1,655
Other	—	—	56	56
Revenue recognized from contracts with customers	$ 1,443	$ 212	$ 56	$ 1,711
Leasing income	—	—	26	26
Financing income	4	1	—	5
Consumers alternative-revenue programs	1	—	—	1
Total operating revenue – CMS Energy	$ 1,448	$ 213	$ 82	$ 1,743
Consumers				
Consumers utility revenue				
Residential	$ 707	$ 127		$ 834
Commercial	486	40		526
Industrial	169	5		174
Other	81	40		121
Revenue recognized from contracts with customers	$ 1,443	$ 212		$ 1,655
Financing income	4	1		5
Alternative-revenue programs	1	—		1
Total operating revenue – Consumers	$ 1,448	$ 213		$ 1,661

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 $15 million for the three months ended September 30, 2024.

In Millions

Nine Months Ended September 30, 2025	Electric Utility	Gas Utility	NorthStar Clean Energy[1]	Consolidated
CMS Energy, including Consumers				
Consumers utility revenue	$ 4,324	$ 1,665	$ —	$ 5,989
Other	—	—	182	182
Revenue recognized from contracts with customers	$ 4,324	$ 1,665	$ 182	$ 6,171
Leasing income	—	—	117	117
Financing income	7	5	—	12
Consumers alternative-revenue programs	6	—	—	6
Total operating revenue – CMS Energy	$ 4,337	$ 1,670	$ 299	$ 6,306
Consumers				
Consumers utility revenue				
Residential	$ 2,055	$ 1,146		$ 3,201
Commercial	1,468	374		1,842
Industrial	576	46		622
Other	225	99		324
Revenue recognized from contracts with customers	$ 4,324	$ 1,665		$ 5,989
Financing income	7	5		12
Alternative-revenue programs	6	—		6
Total operating revenue – Consumers	$ 4,337	$ 1,670		$ 6,007

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 $82 million for the nine months ended September 30, 2025.

In Millions

Nine Months Ended September 30, 2024	Electric Utility	Gas Utility	NorthStar Clean Energy[1]	Consolidated
CMS Energy, including Consumers				
Consumers utility revenue	$ 3,793	$ 1,480	$ —	$ 5,273
Other	—	—	158	158
Revenue recognized from contracts with customers	$ 3,793	$ 1,480	$ 158	$ 5,431
Leasing income	—	—	77	77
Financing income	8	5	—	13
Consumers alternative-revenue programs	5	—	—	5
Total operating revenue – CMS Energy	$ 3,806	$ 1,485	$ 235	$ 5,526
Consumers				
Consumers utility revenue				
Residential	$ 1,779	$ 998		$ 2,777
Commercial	1,279	311		1,590
Industrial	499	37		536
Other	236	134		370
Revenue recognized from contracts with customers	$ 3,793	$ 1,480		$ 5,273
Financing income	8	5		13
Alternative-revenue programs	5	—		5
Total operating revenue – Consumers	$ 3,806	$ 1,485		$ 5,291

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 $44 million for the nine months ended September 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 $10 million for the three months ended September 30, 2025 and $7 million for the three months ended September 30, 2024. CMS Energy and Consumers recorded uncollectible accounts expense of $30 million for the nine months ended September 30, 2025 and $24 million for the nine months ended September 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 $381 million at September 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 September 30, 2025	Electric Utility	Gas Utility	NorthStar Clean Energy	Segments Total	Other Reconciling Items	Consolidated
CMS Energy, including Consumers						
Operating revenue	$ 1,679	$ 234	$ 108	$ 2,021	$ —	$ 2,021
Operating expenses						
Power supply cost[1]	624	—	63	687	—	687
Cost of gas sold	—	40	2	42	—	42
Maintenance and other operating expenses	285	103	25	413	3	416
Depreciation and amortization	239	35	14	288	—	288
General taxes	81	23	3	107	—	107
Total operating expenses	1,229	201	107	1,537	3	1,540
Operating Income (Loss)	450	33	1	484	(3)	481
Other income	34	22	4	60	2	62
Interest charges	92	53	(1)	144	59	203
Income (Loss) Before Income Taxes	392	2	6	400	(60)	340
Income tax expense	66	2	—	68	—	68
Income (Loss) From Continuing Operations	326	—	6	332	(60)	272
Other segment items[2]	—	—	5	5	(2)	3
Net Income (Loss) Available to Common Stockholders	$ 326	$ —	$ 11	$ 337	$ (62)	$ 275
Property, plant, and equipment, gross	$ 21,095 [3]	$ 13,890 [3]	$ 1,568	$ 36,553	$ 30	$ 36,583
Total assets	21,917 [3]	13,720 [3]	2,229	37,866	142	38,008

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 September 30, 2025	Electric Utility	Gas Utility	Segments Total	Other Reconciling Items	Consolidated
Consumers					
Operating revenue	$ 1,679	$ 234	$ 1,913	$ —	$ 1,913
Operating expenses					
Power supply cost[1]	624	—	624	—	624
Cost of gas sold	—	40	40	—	40
Maintenance and other operating expenses	285	103	388	—	388
Depreciation and amortization	239	35	274	—	274
General taxes	81	23	104	—	104
Total operating expenses	1,229	201	1,430	—	1,430
Operating Income	450	33	483	—	483
Other income	34	22	56	(1)	55
Interest charges	92	53	145	—	145
Income (Loss) Before Income Taxes	392	2	394	(1)	393
Income tax expense	66	2	68	11	79
Net Income (Loss) Available to Common Stockholder	$ 326	$ —	$ 326	$ (12)	$ 314
Property, plant, and equipment, gross	$ 21,095 [2]	$ 13,890 [2]	$ 34,985	$ 36	$ 35,021
Total assets	21,972 [2]	13,762 [2]	35,734	46	35,780

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

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

In Millions

Three Months Ended September 30, 2024	Electric Utility	Gas Utility	NorthStar Clean Energy	Segments Total	Other Reconciling Items	Consolidated
CMS Energy, including Consumers						
Operating revenue	$ 1,448	$ 213	$ 82	$ 1,743	$ —	$ 1,743
Operating expenses						
Power supply cost[1]	515	—	45	560	—	560
Cost of gas sold	—	31	1	32	—	32
Maintenance and other operating expenses	282	99	27	408	4	412
Depreciation and amortization	229	32	12	273	—	273
General taxes	75	20	4	99	—	99
Total operating expenses	1,101	182	89	1,372	4	1,376
Operating Income (Loss)	347	31	(7)	371	(4)	367
Other income	35	25	3	63	21	84
Interest charges	82	49	2	133	45	178
Income (Loss) Before Income Taxes	300	7	(6)	301	(28)	273
Income tax expense (benefit)	27	(4)	(6)	17	9	26
Income (Loss) From Continuing Operations	273	11	—	284	(37)	247
Other segment items[2]	—	—	6	6	(2)	4
Net Income (Loss) Available to Common Stockholders	$ 273	$ 11	$ 6	$ 290	$ (39)	$ 251
Property, plant, and equipment, gross	$ 19,826 [3]	$ 12,840 [3]	$ 1,469	$ 34,135	$ 21	$ 34,156
Total assets	20,222 [3]	12,809 [3]	1,711	34,742	75	34,817

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 September 30, 2024	Electric Utility	Gas Utility	Segments Total	Other Reconciling Items	Consolidated
Consumers					
Operating revenue	$ 1,448	$ 213	$ 1,661	$ —	$ 1,661
Operating expenses					
Power supply cost[1]	515	—	515	—	515
Cost of gas sold	—	31	31	—	31
Maintenance and other operating expenses	282	99	381	—	381
Depreciation and amortization	229	32	261	—	261
General taxes	75	20	95	—	95
Total operating expenses	1,101	182	1,283	—	1,283
Operating Income	347	31	378	—	378
Other income	35	25	60	—	60
Interest charges	82	49	131	—	131
Income Before Income Taxes	300	7	307	—	307
Income tax expense (benefit)	27	(4)	23	11	34
Net Income (Loss) Available to Common Stockholder	$ 273	$ 11	$ 284	$ (11)	$ 273
Property, plant, and equipment, gross	$ 19,826 [2]	$ 12,840 [2]	$ 32,666	$ 29	$ 32,695
Total assets	20,279 [2]	12,852 [2]	33,131	29	33,160

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

2 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

Nine Months Ended September 30, 2025	Electric Utility	Gas Utility	NorthStar Clean Energy	Segments Total	Other Reconciling Items	Consolidated
CMS Energy, including Consumers						
Operating revenue	$ 4,337	$ 1,670	$ 299	$ 6,306	$ —	$ 6,306
Operating expenses						
Power supply cost[1]	1,707	—	198	1,905	—	1,905
Cost of gas sold	—	545	4	549	—	549
Maintenance and other operating expenses	806	331	73	1,210	8	1,218
Depreciation and amortization	682	243	39	964	—	964
General taxes	227	142	9	378	—	378
Total operating expenses	3,422	1,261	323	5,006	8	5,014
Operating Income (Loss)	915	409	(24)	1,300	(8)	1,292
Other income	97	64	7	168	81	249
Interest charges	263	152	(2)	413	175	588
Income (Loss) Before Income Taxes	749	321	(15)	1,055	(102)	953
Income tax expense (benefit)	131	83	(7)	207	(14)	193
Income (Loss) From Continuing Operations	618	238	(8)	848	(88)	760
Other segment items[2]	(1)	—	23	22	(7)	15
Net Income (Loss) Available to Common Stockholders	$ 617	$ 238	$ 15	$ 870	$ (95)	$ 775

[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

Nine Months Ended September 30, 2025	Electric Utility	Gas Utility	Segments Total	Other Reconciling Items	Consolidated
Consumers					
Operating revenue	$ 4,337	$ 1,670	$ 6,007	$ —	$ 6,007
Operating expenses					
Power supply cost[1]	1,707	—	1,707	—	1,707
Cost of gas sold	—	545	545	—	545
Maintenance and other operating expenses	806	331	1,137	—	1,137
Depreciation and amortization	682	243	925	—	925
General taxes	227	142	369	—	369
Total operating expenses	3,422	1,261	4,683	—	4,683
Operating Income	915	409	1,324	—	1,324
Other income	97	64	161	—	161
Interest charges	263	152	415	1	416
Income (Loss) Before Income Taxes	749	321	1,070	(1)	1,069
Income tax expense	131	83	214	7	221
Net Income (Loss)	618	238	856	(8)	848
Other segment items[2]	(1)	—	(1)	—	(1)
Net Income (Loss) Available to Common Stockholder	$ 617	$ 238	$ 855	$ (8)	$ 847

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

Nine Months Ended September 30, 2024	Electric Utility	Gas Utility	NorthStar Clean Energy	Segments Total	Other Reconciling Items	Consolidated
CMS Energy, including Consumers						
Operating revenue	$ 3,806	$ 1,485	$ 235	$ 5,526	$ —	$ 5,526
Operating expenses						
Power supply cost[1]	1,408	—	119	1,527	—	1,527
Cost of gas sold	—	447	2	449	—	449
Maintenance and other operating expenses	781	355	73	1,209	9	1,218
Depreciation and amortization	651	226	36	913	1	914
General taxes	214	132	10	356	—	356
Total operating expenses	3,054	1,160	240	4,454	10	4,464
Operating Income (Loss)	752	325	(5)	1,072	(10)	1,062
Other income	105	70	11	186	97	283
Interest charges	242	143	3	388	140	528
Income (Loss) Before Income Taxes	615	252	3	870	(53)	817
Income tax expense (benefit)	74	57	(3)	128	(3)	125
Income (Loss) From Continuing Operations	541	195	6	742	(50)	692
Other segment items[2]	(1)	—	47	46	(7)	39
Net Income (Loss) Available to Common Stockholders	$ 540	$ 195	$ 53	$ 788	$ (57)	$ 731

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

Nine Months Ended September 30, 2024	Electric Utility	Gas Utility	Segments Total	Other Reconciling Items	Consolidated
Consumers					
Operating revenue	$ 3,806	$ 1,485	$ 5,291	$ —	$ 5,291
Operating expenses					
Power supply cost[1]	1,408	—	1,408	—	1,408
Cost of gas sold	—	447	447	—	447
Maintenance and other operating expenses	781	355	1,136	—	1,136
Depreciation and amortization	651	226	877	1	878
General taxes	214	132	346	—	346
Total operating expenses	3,054	1,160	4,214	1	4,215
Operating Income (Loss)	752	325	1,077	(1)	1,076
Other income	105	70	175	—	175
Interest charges	242	143	385	1	386
Income (Loss) Before Income Taxes	615	252	867	(2)	865
Income tax expense	74	57	131	8	139
Net Income (Loss)	541	195	736	(10)	726
Other segment items[2]	(1)	—	(1)	—	(1)
Net Income (Loss) Available to Common Stockholder	$ 540	$ 195	$ 735	$ (10)	$ 725

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

	September 30, 2025	December 31, 2024
Current		
Cash and cash equivalents	$ 19	$ 18
Accounts receivable	3	4
Prepayments and other current assets	3	3
Non-current		
Plant, property, and equipment, net	1,028	1,024
Other non-current assets	6	3
Total assets[1]	$ 1,059	$ 1,052
Current		
Accounts payable	$ 9	$ 8
Accrued taxes	1	—
Non-current		
Non-current portion of finance leases	24	23
Asset retirement obligations	35	33
Other non-current liabilities	3	—
Total liabilities	$ 72	$ 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 $580 million at September 30, 2025 and $666 million at December 31, 2024. The carrying value of securitization bonds on Consumers' consolidated balance sheets was $600 million at September 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 $59 million at September 30, 2025 and $64 million at December 31, 2024.

12: Exit Activities and Asset Sales

J.H. Campbell Retirement: Under its Clean Energy Plan, Consumers had planned to retire J.H. Campbell in 2025. In order to ensure necessary staffing at J.H. Campbell through the planned retirement, Consumers implemented a retention incentive program. The terms of and Consumers' obligations under this program have not been modified as a result of the U.S. Secretary of Energy's emergency orders requiring the continued operation of J.H. Campbell. Consumers will make final payments due under this retention plan in November 2025. Should the U.S. Department of Energy issue additional emergency orders that require the continued operation of J.H. Campbell beyond November 2025, Consumers is prepared to implement additional retention measures to ensure appropriate staffing levels. For additional information on the emergency orders associated with J.H. Campbell, see Note 1, Regulatory Matters.

The aggregate cost of the J.H. Campbell program is estimated to be $48 million. The MPSC has approved deferred accounting treatment for these costs; these expenses are deferred as a regulatory asset. As of September 30, 2025, the cumulative cost incurred and deferred as a regulatory asset related to the J.H. Campbell retention incentive program was $47 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

Nine Months Ended September 30	2025	2024
Retention benefit liability at beginning of period	$ 14	$ 16
Costs deferred as a regulatory asset[1]	4	6
Retention benefit liability at the end of the period[2]	$ 18	$ 22

[1] Includes $1 million for the three months ended September 30, 2025 and $3 million for the three months ended September 30, 2024.

[2] Includes current portion of other liabilities of $18 million at September 30, 2025 and $9 million at September 30, 2024.

Sale of Hydroelectric Facilities: In September 2025, Consumers signed an agreement to sell its 13 river hydroelectric dams, which are located throughout Michigan, to a non-affiliated company. Additionally, Consumers signed an agreement to purchase power generated by the facilities for 30 years, at a price that reflects the counterparty's acceptance of the risks and rewards of ownership of the facilities, including FERC licensing obligations. The agreements are contingent upon MPSC and FERC approval, which must be filed within 60 days of signing. Timing of the regulatory review process is uncertain and could extend 12 to 18 months or longer. In Consumers' most recent electric rate case, the MPSC approved deferred accounting treatment for costs of owning and operating the hydroelectric dams pending and until completion of the transaction. At September 30, 2025, the net book value of the hydroelectric facilities was immaterial.

To ensure necessary staffing at the hydroelectric facilities through the anticipated sale, Consumers has provided current employees at the facilities with a retention incentive program. Subsequently, to ensure continued safe operation of the facilities after the sale, the buyer will offer employment to the current hydroelectric employees for a period of at least a year. The retention incentive benefits are contingent upon MPSC and FERC approval of the sale transaction.

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 September 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
July 1, 2025 to July 31, 2025	313	$ 69.41	—	—
August 1, 2025 to August 31, 2025	—	—	—	—
September 1, 2025 to September 30, 2025	2,862	70.23	—	—
Total	3,175	$ 70.15	—	—

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.

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
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)

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: October 30, 2025	By:	/s/ Rejji P. Hayes
		Rejji P. Hayes Executive Vice President and Chief Financial Officer
		CONSUMERS ENERGY COMPANY
Dated: October 30, 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 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: October 30, 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: October 30, 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: October 30, 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: October 30, 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 September 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:	October 30, 2025

/s/ Rejji P. Hayes

Name:	Rejji P. Hayes
Title:	Executive Vice President and Chief Financial Officer
Date:	October 30, 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 September 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:	October 30, 2025

/s/ Rejji P. Hayes

Name:	Rejji P. Hayes
Title:	Executive Vice President and Chief Financial Officer
Date:	October 30, 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 129

Energy Innovation Report

DODGING THE FIRM FIXATION FOR DATA CENTERS AND THE GRID

Eric G. Gimon

Senior Fellow, Energy Innovation

November 2025

ACKNOWLEDGEMENTS:

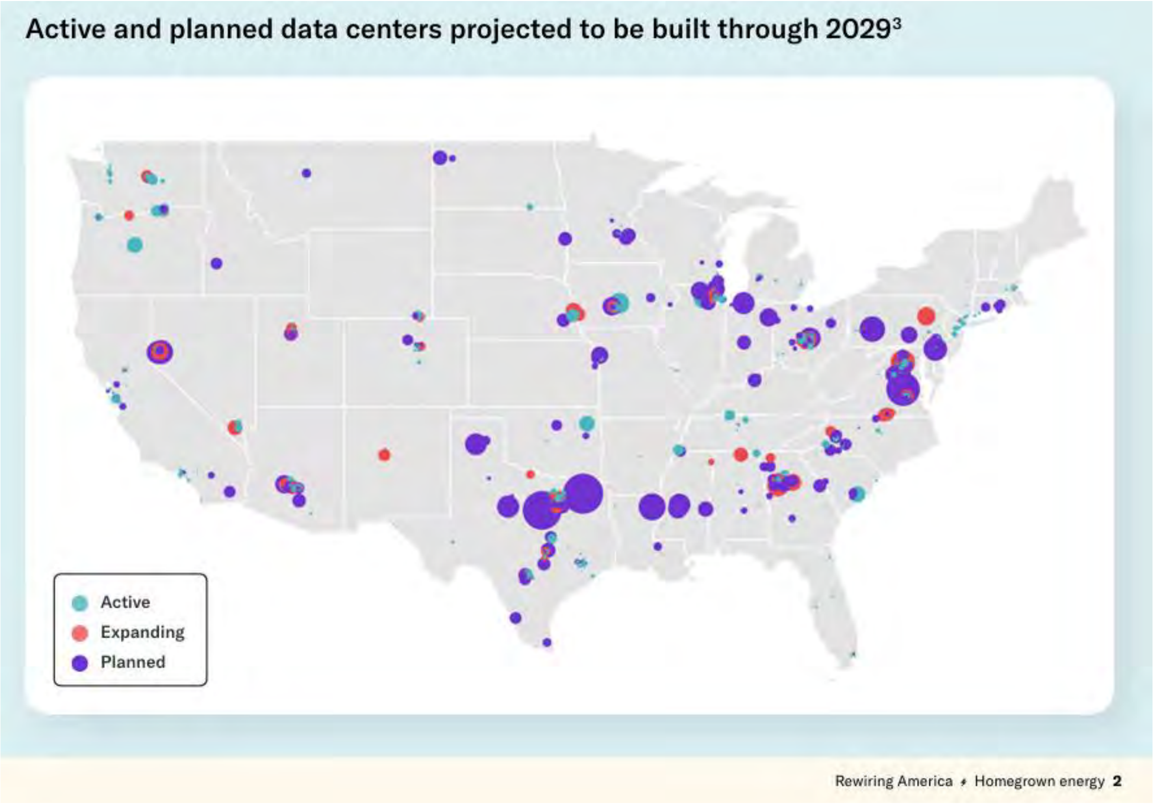
I would like to thank my Energy Innovation colleagues for their patient review and feedback on various drafts of this report. I would also like to acknowledge the Energy Systems Integration Group for their conferences, taskforce meetings, and webinars which helped me get started on my research.

TABLE OF CONTENTS

EXECUTIVE SUMMARY

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

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



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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

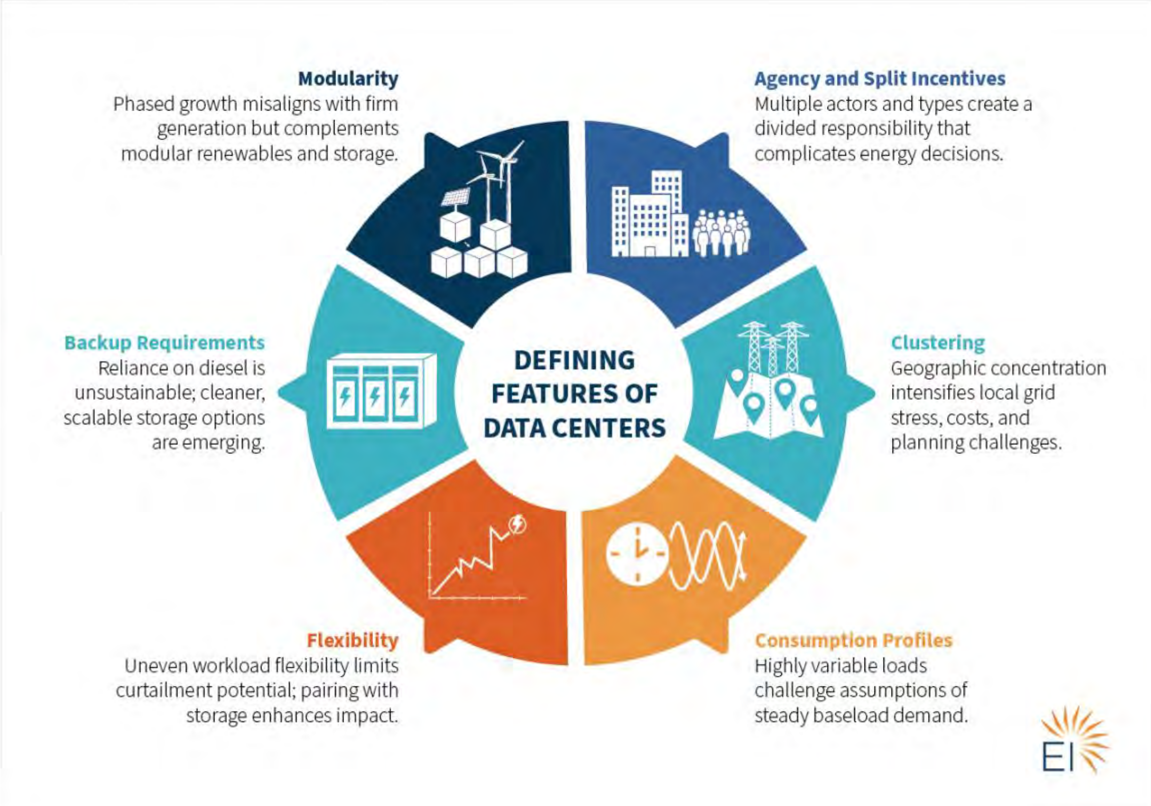
What began as a major strain on the grid can become the catalyst for building a smarter one, supporting both the digital economy's explosive growth and the clean energy transition.

COMMERCIAL AND INDUSTRIAL REALITIES THAT APPLY TO DATA CENTERS

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

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

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

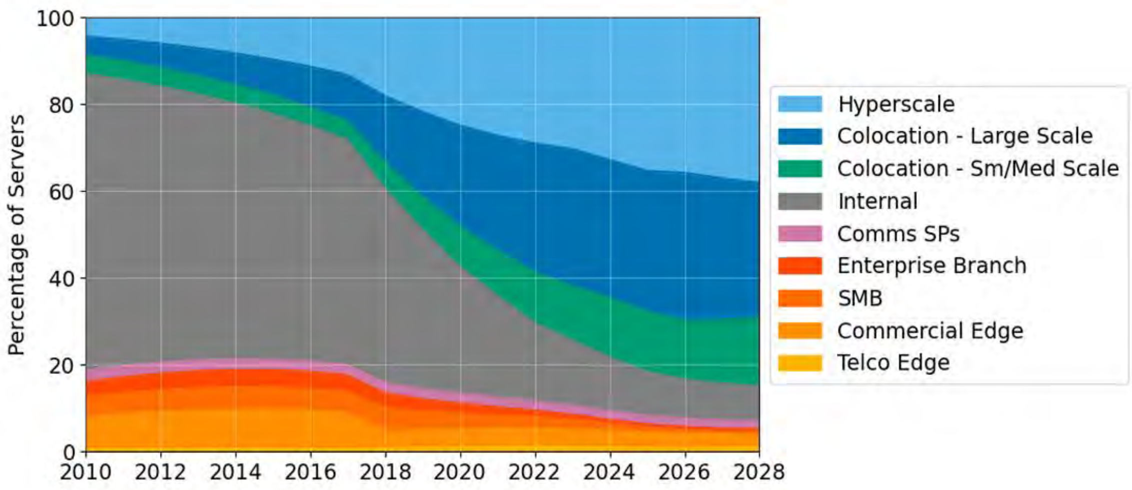


Data Center Feature 1: Agency and the split-incentive problem

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

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

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



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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

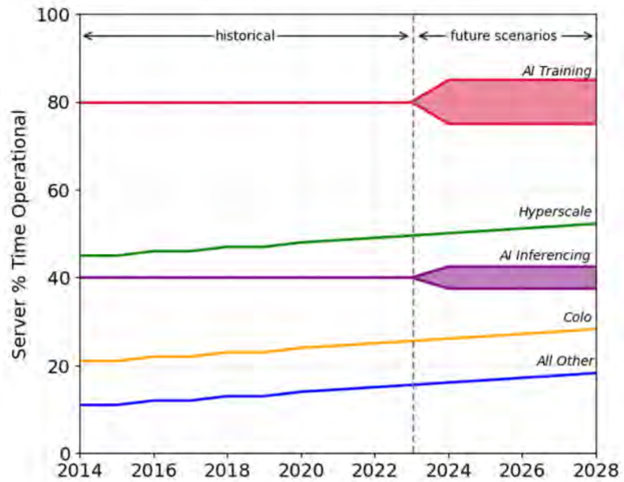
[iv] Under the decision, new data centers can access up to 50 percent capacity in the first year, 65 percent in the second, 80 percent in the third, and 90 percent in the fourth before getting full access to the grid.

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

Data Center Feature 3: Consumption profile

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

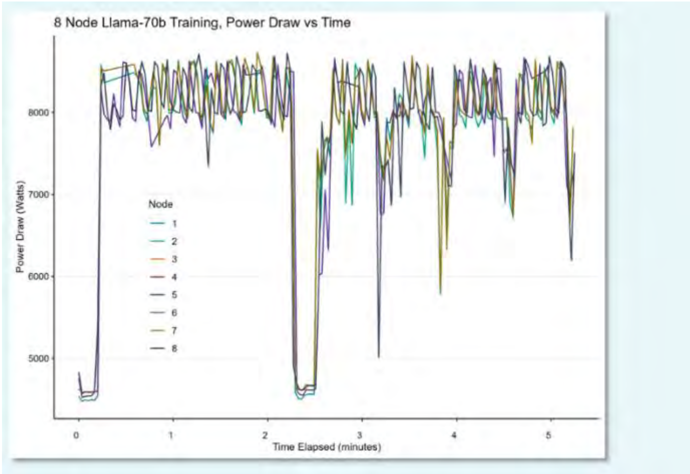
Figure 4 Server utilization by data center type. 2024 United States Data Center Energy Usage Report (LBNL).



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

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

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



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

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

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

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

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[v] See the GridLab report *Practical Guidance and Considerations for Large Load Interconnections*, with special attention to July 2024 Northern Virginia Data Center Event called out in Figure 1.2.

[vi] Some of these resonance issues can potentially be solved by on-chip energy management and storage. Rouslan Dimitrov et al., "How New GB300 NVL72 Features Provide Steady Power for AI," Nvidia, July 28, 2025, https://developer.nvidia.com/blog/how-new-gb300-nvl72-features-provide-steady-power-for-ai/?utm.

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

Data Center Feature 4: Flexibility, or the lack thereof

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

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

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

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

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

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

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

Data Center Feature 5: Backup needed for disturbances and outages

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Debunking the one-to-one matching myth

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

Single plants may not "play nice" with data centers

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

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

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

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

Captive power plants are not highly reliable alone

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

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

What happens when the power plant is no longer needed?

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

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

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

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

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

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

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

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

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

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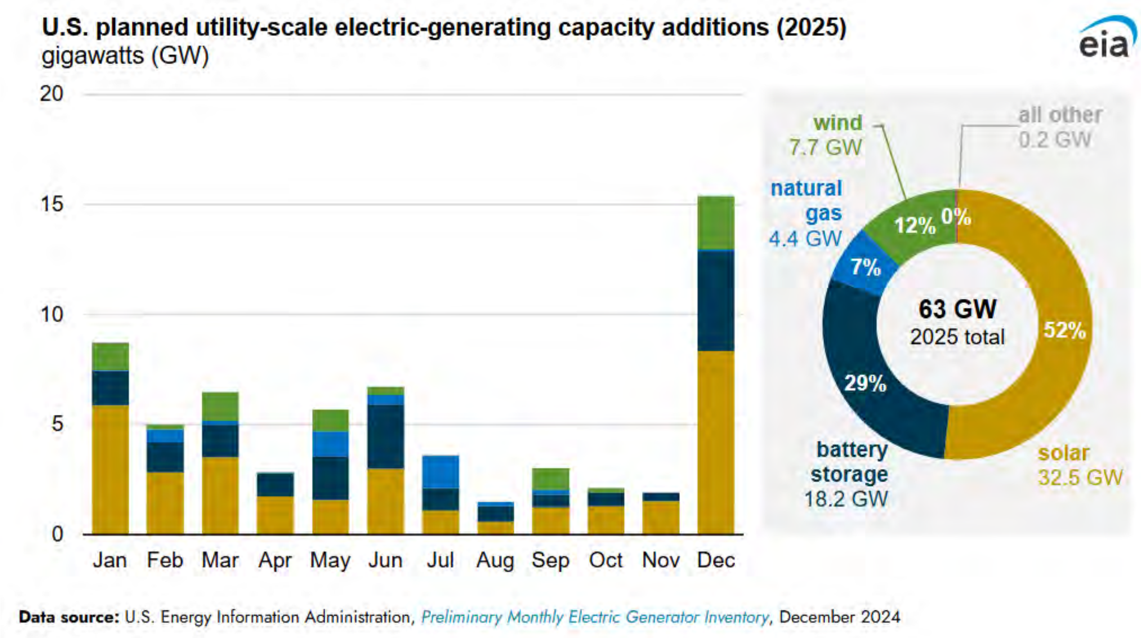
In 2024, Sierra Club and Environmental Integrity Project intervened in a case against Alcoa Warrick for "100+ permit violations" in 2022 and 2023, including releases of mercury, aluminum, chlorine, copper, fluoride, nickel, and zinc into the Ohio River. Environmental Integrity Project, "Groups Intervene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

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

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

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



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

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

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

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

New large data centers will require connection and network upgrades

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

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

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

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

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

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

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

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

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

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

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

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

Further consequences: Challenges and barriers specific to data centers

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

Connection challenges specific to data centers

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

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

flexibility or bridge power) tends to be dirty, leading to siting and local community environmental concerns.[59][60]
- **Modularity:** With a modular or phased build-out, a data center may ask up front for a large enough connection to accommodate all future phases, leading to stranded asset risk if all phases do not materialize.

Grid services challenges specific to data centers

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

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

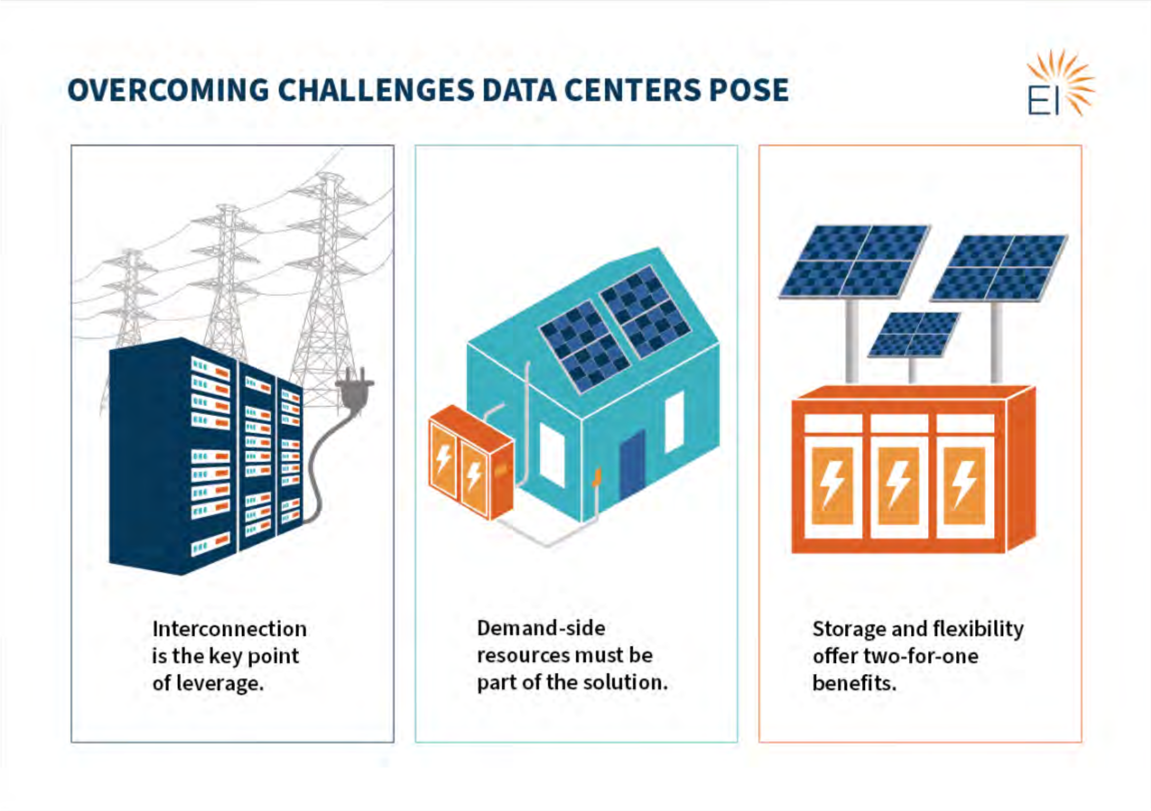
Bulk electricity challenges specific to data centers

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

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

TAKEAWAYS FOR POLICYMAKERS AND OTHER STAKEHOLDERS

Figure 7 Three key takeaways



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

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

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

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

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

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

Using other demand-side resources

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

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

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

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

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

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

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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 130

Department's October Notice

UNITED STATES OF AMERICA

Department of Energy

Washington, DC 20585

October 23, 2025

Midcontinent Independent System Operator, Inc. and Consumers Energy Company Regarding the J.H. Campbell Generation Facility

Order No. 202-25-7A

NOTICE OF DENIAL OF REHEARING BY OPERATION OF LAW AND PROVIDING FOR FURTHER CONSIDERATION

(October 23, 2025)

Rehearing has been timely requested of the Department of Energy's order issued on August 20, 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

Chris Wright
Secretary of Energy

[1] *Midcontinent Indep. Sys. Operator, Inc., and Consumers Energy Company*, Order No. 202-25-7 (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 131

Eddystone November Order

Department of Energy
Washington, DC 20585

Order No. 202-25-10

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

Order Nos. 202-25-4 and 202-25-8

The Eddystone Generating Station is a power plant owned by Constellation Energy Corporation (Constellation Energy) and located in Eddystone, PA. Units 3 and 4 (Eddystone Units), each with 380 MW of generation capacity, are subcritical steam boiler-turbine generator units that can run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order No. 202-25-4, issued pursuant to FPA section 202(c), required that the Eddystone Units remain in operation for 90 days, until August 28, 2025. Subsequently, Order No. 202-25-8, issued pursuant to FPA section 202(c), required the Eddystone Units remain in operation for 90 days, until November 26, 2025. Those orders were based on my determination that emergency conditions existed in the PJM region. I explained that there was a potential shortage of electric energy and a shortage of facilities for generation of electric energy. I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety. I determined that the operational availability and economic dispatch of the Eddystone Units was necessary to best meet the emergency and serve the public interest. My determination was based on a number of different facts.

First, in congressional testimony, PJM's president and CEO recently stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of dispatchable resources, and other factors.[3] Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics

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[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] *Keeping the Lights On: Examining the State of Regional Reliability,* Before the *H. Comm. on Energy and Com., S. Comm. on* Energy, 119th Cong. (Mar. 25, 2025) (testimony of Mr. Manu Asthana, President and CEO of PJM) (Asthana Test.) at 4-5, available at https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf.

of resources in PJM's interconnection queue.[4] Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."[5] In its February 2023 assessment "*Energy Transition in PJM: Resource Retirements, Replacements & Risks* (Four Rs Report)," PJM highlighted increasing reliability risks in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.[6]

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."[7]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-4 and Order No. 202-25-8 continue, both in the near and long term.[8] The production of electricity from the Eddystone Units will continue to be critical to maintaining reliability in PJM over the coming winter months. According to U.S. Environmental Protection Agency data, the Eddystone Units

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[4] *Id.*; *see also PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 15 (2025) (*PJM Interconnection*) (PJM states that, in 2023, "it found that generator retirements, load growth, the pace of new entry, and the operating characteristics of the intermittent and limited duration resources that make up a large part of PJM's interconnection queue pose increasing reliability risks through 2030.").

[5] *PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing* Risk, PJM. (May 9, 2025), https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/.

[6] *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, PJM (Four Rs Report) at 1, (Feb. 24, 2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjmresource-retirements-replacements-and-risks.ashx.

[7] *PJM Interconnection,* 190 FERC ¶ 61,084 at P 14.

[8] Further, it likely would be difficult for the oil-fired units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Further, if Constellation Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. Thus, continued operation is required in such cases so long as the Secretary determines that an emergency exists.

generated 26,434 MWh between June 2025 and September 2025,[9] providing vital generation capacity to the region. Over the course of the summer, PJM issued Hot Weather Alerts and/or Maximum Generation Alerts (EEA 1) to manage grid reliability covering a total of 20 days, including days in June, July, and August.[10]

PJM's resource adequacy concerns are well documented. In January 2025, PJM reached a new record peak for winter demand, exceeding the previous winter peak set in 2015[11] and in PJM's 2025 Long-Term Load Forecast, PJM noted that "20-year annualized growth rate in the 2025 Long-Term Load Forecast for the winter peak is up to 2.4%."[12] Further, PJM's risk profile continues to shift from the summer season to the winter season. For example, in a March 2025 presentation, PJM estimated that 87.8% of the expected unserved energy for the 2025/2026 delivery year falls in the winter season.[13]

The evidence also indicates that there is a potential longer term resource adequacy emergency in the PJM region.

In a news release expressing support for Order No. 202-25-4, PJM explained that it has "repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers."[14]

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[9] *See Custom Data Download, EPA CAMPD* (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (search criteria Emissions >> Monthly >> Unit (default) >>Apply >>*"2025" and "June, July, August, September."* The data can then be filtered to only include the Eddystone Generating Station.

[10] *See* PJM Emergency Procedures Postings for the period between June 1 and August 31, *Emergency Procedures*, https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf (search range set to: effective from 06/01/2025 until 08/31/2025).

[11] *Jan. 22 Update: Extreme Cold Produces PJM Record for Winter Electricity Demand*, PJM (Jan. 22, 2025), https://insidelines.pjm.com/jan-22-update-extreme-cold-produces-pjm-record-for-winter-electricity-demand/.

[12] *2025 Long-Term Load Forecast Report Predicts Significant Increase in Electricity Demand*, PJM Interconnection, L.L.C. (Jan. 30, 2025), https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/.

[13] *2026/27 BRA IRM, FPR, and ELCC Class Ratings: Shift Towards More Winter Risk*, PJM Resource Adequacy Planning Special Planning Committee, at 8 (Mar. 13, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf.

[14] *PJM Statement on the U.S. Dept. of Energy 202(c) Order of May 30*, PJM Interconnection, L.L.C. (May 31, 2025), https://insidelines.pjm.com/pjm-statement-on-the-u-s-department-of-energy-202c-order-of-may-30/. Further, PJM concluded, "In light of these concerns, PJM supports the U.S. Department of Energy's Order, issued May 30, pursuant to Section 202(c) of the Federal Power Act, to defer the retirements of certain generators operating in PJM's footprint . . . ." *Id*.

PJM has indeed voiced these concerns for years. In its February 2023 Four Rs Report, PJM cautioned that 40 GW of thermal generation are at risk of retirement by 2030.[15] PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for renewable projects is approximately five percent.[16] PJM determined that the pace of new capacity additions "would be insufficient to keep up with expected retirements and demand growth by 2030."[17] PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.

More recently, in its December 2024 RRI filing with FERC, PJM stated that "[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report . . . ."[18] PJM warned that its "resource adequacy concerns are increasing at an extraordinary pace."[19] PJM went on to explain, its "resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers" and that its preliminary analysis shows "substantial increases [in load additions] since the 2024 forecast" for both the summer and winter seasons.[20] According to PJM, "load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence."[21] Although the RRI process will help expedite the construction of needed new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.[22]

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM's Director, Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as "extraordinary" and "unprecedented," stating that it "could not have been foreseen as recently as a year ago."[23] Mr. Bielak expressed the opinion that the "rapid" retirement of thermal generation resources, "extreme" forecasted load growth, and "delays in new generation resources achieving commercial operation," would adversely affect resource adequacy throughout PJM's electricity grid.[24]

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[15] Four Rs Report at 2.
[16] *Id*.
[17] *Id.* at 16, Table 1.
[18] *PJM Interconnection, L.L.C.*, FERC Docket No. ER25-712, Tariff Revisions for Reliability Resource Initiative at 10 (Dec. 13, 2024).
[19] *Id*.
[20] *Id.* at 10-11. *See also id.* at 13 ("the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements . . . .").
[21] *Id.* at 14.
[22] *See id.*, Attachment C (Affidavit of Mr. Donald Bielak), at PP 18-19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, "could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner.").
[23] *Id*. at P 10.
[24] Id. at P 12.

On February 11, 2025, FERC accepted PJM's RRI filing.[25] In its order on rehearing, FERC concluded, "PJM identified increasing reliability risks arising in the next few years and significant resource adequacy issues anticipated by the 2030/31 delivery year. The record supports that these resource adequacy concerns are likely to manifest."[26]

NERC has raised similar concerns. According to NERC's 2024 Long Term Reliability Assessment, "PJM could face future resource adequacy challenges, impacting system reliability and PJM's ability to serve load."[27] NERC assessed the PJM region at an elevated risk starting in 2026,[28] explaining that "[r]esource additions are not keeping up with generator retirements and demand growth."[29] NERC stated that the loss of-load hour (LOLH) and expected unserved energy (EUE) risks are concentrated in the winter months (especially January), in both 2026 and 2028.[30]

Order Nos. 202-25-4 and 202-25-8 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[31] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[32] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[33]

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[25] *PJM Interconnection,* 190 FERC ¶ 61,084 at P 263.
[26] *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,085, at P 25 (2025).
[27] *Long-Term Reliability Assessment*, North American Electric Reliability Corporation, at 92 (Dec. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20 Assessment_2024.pdf at 92.
[28] *Id.* at 4.
[29] *Id.* at 7.
[30] *Id.* at 91-92.
[31] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (Strengthening the Reliability and Security of the United States Electric Grid), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-thereliabilityand-security-of-the-united-states-electric-grid/.
[32] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (Declaring a National Energy Emergency), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.
[33] *Id*.

The Department of Energy's (Department) July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. It concludes, "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[34] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.[35] As of December 2024, Dominion Energy has 40.2 GW of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.[36] Regarding the PJM region, the Department's analysis performed this year in collaboration with the national labs modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced coal, gas, and oil generation retirements.[37] Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a max unserved load of approximately 21.335 GW.[38]

Grid operators, including PJM, have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the United States House of Representatives Committee on Energy and Commerce, Manu Asthana, President and CEO, PJM, testified that there was a "growing resource adequacy concern . . . impacting a significant part of our country."[39] Mr. Asthana explained that the "rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from

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[34] *See also* Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, U.S. Department of Energy (July 2025), at 1, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[35] *See PPL Corporation Q2 2025 Investor Update*, PPLC Corporation, at 7 (July 31, 2025), https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINAL.pdf

[36] *See* Dominion Energy Virginia, Q4 2024 Earnings Call, at 18 (Feb. 12, 2025), https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slidesvTCII.pdf.

[37] *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, U.S. Department of Energy, at 28 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[38] *Id.* at 27.

[39] Asthana Test. at 4.

industrial growth."[40] Mr. Asthana noted that, though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening.[41] Therefore, Mr. Asthana stated that PJM "encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability."[42]

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[43] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-4 and 202-25-8 will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Eddystone Units is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes and serve the public interest under FPA section 202(c).

To ensure the Eddystone Units will be available if needed to address emergency conditions, the Eddystone Units shall remain in operation until February 24, 2026.[44]

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[40] *Id.*
[41] *Id.* at 9-10.
[42] *Id.* at 10.
[43] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).
[44] 16 U.S.C. § 824a(c)(4).

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

A. From November 26, 2025, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by PJM pursuant to paragraph A. PJM shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether the Eddystone Units has operated in compliance with the allowances contained in this Order.

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

D. By December 11, 2025, PJM is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

E. Constellation Energy is directed to file with the Federal Energy Regulatory Commission Tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

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

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Eddystone Units shall not be considered capacity resources.

H. This Order shall be effective from 00:00 PM Eastern Standard Time (EST) on November 26, 2025, and shall expire at 00:00 EST on February 24, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. at 2:30PM EST on this 25th day of November 2025.

Chris Wright

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Pennsylvania Public Utility Commissioners
Chairman Stephen M. DeFrank
Vice Chair Kimberly M. Barrow
Commissioner Kathryn L. Zerfuss
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora