NOT YET SCHEDULED FOR ORAL ARGUMENT

No. 25-1159
(Consolidated with 25-1160 and 25-1162)

IN THE UNITED STATES COURT OF APPEALS FOR THE DISTRICT OF COLUMBIA CIRCUIT

THE PEOPLE OF THE STATE OF MICHIGAN,
Petitioner,
v.
U.S. DEPARTMENT OF ENERGY, AND CHRIS WRIGHT, IN HIS OFFICIAL CAPACITY AS SECRETARY OF ENERGY,
Respondents.

ON PETITION FOR REVIEW OF FINAL ORDER OF THE DEPARTMENT OF ENERGY

INITIAL OPENING BRIEF OF THE STATES OF ILLINOIS, MICHIGAN, AND MINNESOTA

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CERTIFICATE AS TO PARTIES, RULINGS AND RELATED CASES

A. PARTIES

Petitioners:

25-1159: The People of the State of Michigan

25-1160: Sierra Club, Natural Resources Defense Council, Michigan Environmental Council, Environmental Defense Fund, Environmental Law and Policy Center, Vote Solar, Union of Concerned Scientists, Ecology Center, and Urban Core Collective

25-1162: The State of Illinois and the State of Minnesota

Respondents:

25-1159: U.S. Department of Energy and Chris Wright in his official capacity as Secretary of the U.S. Department of Energy.

25-1160: U.S. Department of Energy and Chris Wright in his official capacity as Secretary of the U.S. Department of Energy.

25-1162: U.S. Department of Energy and Chris Wright in his official capacity as Secretary of the U.S. Department of Energy.

Intervenors:

Midcontinent Independent System Operator, Inc.

Amici:

Consumers Energy Company.

Institute for Policy Integrity at New York University School of Law.

B. RULINGS UNDER REVIEW

The petitioners in Case Nos. 25-1159, 25-1160, and 25-1162 seek review of two orders from the U.S. Department of Energy and Secretary Chris Wright:

1. *Midcontinent Independent System Operator (MISO) 202(c) Order*, Order No. 202-25-3 (May 23, 2025); and
2. *Midcontinent Independent System Operator (MISO) 202(c) Order Addressing Arguments Raised on Rehearing*, Order No. 202-25-3B (Sept. 8, 2025).

C. RELATED CASES

The petitions on review in cases Nos. 25-1159, 25-1160, and 25-1162 have not previously been before this court. Case Nos. 25-1198 and 25-1202 pending in this Court are related to this set of petitions, as they arise from a renewal of the Order challenged in these petitions. Case No. 25-1285, also pending in this Court, is also related to this set of petitions because it arises from an order of the Federal Energy

Regulatory Commission issued in response to a complaint filed by Consumers Energy Company in response to the Order challenged in these petitions.

December 19, 2025

__/s/ Michael E. Moody__
Michael E. Moody

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GLOSSARY

EEA – Energy Emergency Alert

FPA – Federal Power Act

FPC – Federal Power Commission

MISO – Midcontinent Independent System Operator

MPSC – Michigan Public Service Commission

NERC –North American Electric Reliability Corporation

NOAA – National Oceanic and Atmospheric Administration

RTO – Regional Transmission Organization

INTRODUCTION

In the Order under review, the Department of Energy (DOE), seeks to usurp states' long-standing authority to regulate in-state power plants for the economic and environmental benefit of their citizens. Invoking a rarely used, temporary emergency power—FPA section 202(c)—the Order compels the continued operation of J.H. Campbell (Campbell), a dirty, aged, uneconomic coal-fired power plant that the plant operator had scheduled for retirement with the express approval of expert state regulators and the regional grid operator. By defining "emergency" beyond its ordinary spatial and temporal limits while continuously extending mandated operation, DOE grants itself unheralded new power to control the nation's generation mix.

Nearly a century old, section 202(c) gives DOE authority to intervene in times of war or similar emergency circumstances—e.g., when a hurricane threatens the supply of power or an extreme cold-snap might spike demand—by ordering such action as may best meet the emergency. Historically, DOE has used that authority narrowly and sparingly. But here, DOE asserts that a 15-state region of the country is in an energy "emergency" that, if upheld, would empower

DOE to order any and all power plants in the region to operate for "years."

Section 202(c) does not give DOE such power. Under the plain text, DOE may act only in response to an "emergency"—i.e., sudden, unexpected, imminent conditions requiring an immediate response. DOE made no attempt to demonstrate such an emergency here. Nor could it. The retirement of the coal-fired power plant entailed years of careful planning, and the expert regulators entrusted with ensuring the grid's reliability found—repeatedly—that the retirement would have no ill effects on the grid.

Instead, the Order is an attempt to subordinate the states' careful planning to the dictates of an Administration bent on propping up its favored generation resources. This Court should reject that unprecedented assertion of authority and set aside the Order.

JURISDICTIONAL STATEMENT

The FPA affords any party "aggrieved by an order" review of such order in the U.S. Court of Appeals for the District of Columbia Circuit. *See* 16 U.S.C. § 825*l*(b). Illinois, the People of the State of Michigan (Michigan), and Minnesota (the States) seek review of DOE's May 23, 2025, Order, Order 202-25-3 (the Order or Campbell I), JA____[DOE0001] and the subsequent order on rehearing, Order 202-25-3B (Rehearing Order), JA____[DOE0016].

The States were parties to the DOE proceeding, timely sought rehearing, 16 U.S.C. § 825*l*(a), and presented to DOE the objections raised herein, *id.* § 825*l*(b).

STATUTES & REGULATIONS

Pertinent statutes and regulations are reproduced in an addendum ("ADD").

STATEMENT OF THE ISSUES

1. Whether the Order is reviewable because it continues to have legally cognizable consequences and is part of an ongoing succession of short-duration emergency orders capable of repetition yet evading review.

2. Whether the Order violates section 202(c) of the FPA because it failed to identify an "emergency" within the meaning of the Act.

3. Whether the Order violates the FPA and Administrative Procedure Act (APA) because it failed to support its emergency

determination and remedy with substantial evidence and reasoned decision-making.

4. Whether the Order violates section 202(c) because, even if there were an emergency, it imposed a remedy that exceeds statutory limits.

STATEMENT OF THE CASE

A. The Federal Power Act entrusts states with responsibility for resource adequacy and defines a narrow role for DOE

Since its passage in 1935, the FPA has expressly reserved authority over electricity generation facilities to the states. 16 U.S.C. § 824(b)(1); *see NextEra Energy Res., LLC v. FERC,* 118 F.4th 361, 368 (D.C. Cir. 2024). Utilities and system operators, under regulatory supervision, ensure the system has adequate generation resources (e.g., power plants) through a long-term process of resource-adequacy planning. *See Devon Power*, 109 FERC ¶ 61,154, P 47 (2004) ("Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there."); *cf. Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205 (1983) ("Need for new power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the

States.”). Resource-adequacy planning involves evaluating technical, environmental, and economic considerations to determine what resources are added to the grid, what resources qualify as “capacity resources,” and what resources should retire and when. JA__[DOE0006_33n.117].

Some states have retained exclusive authority over resource adequacy. Others have directed or permitted their utilities to join RTOs that impose resource-adequacy requirements in tariffs subject to the just-and-reasonable review of the Federal Energy Regulatory Commission (FERC) under sections 205 and 206 of the FPA. 16 U.S.C. §§ 824d, 824e. *See generally Morgan Stanley Cap. Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cnty., Wash.*, 554 U.S. 527, 536 (2008) (describing role of RTOs). Some RTOs establish markets that allow participants to buy and sell capacity, thereby facilitating market entry and exit based on price signals. *See Conn. Dep’t of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009) (describing capacity markets and federal/state interplay).

In Michigan, regulation of resource adequacy has both a state and a federal aspect. The Midcontinent Independent System Operator

(MISO) is the FERC-regulated RTO responsible for managing the grid across a 15-state region of the country including all or much of Michigan, Minnesota, and Illinois. Like other RTOs, it establishes requirements designed to be complementary to the primary role of states in ensuring resource adequacy. *See MISO*, 119 FERC ¶ 61,311, 62,722 at P 75 (2007) ("From the beginning . . . the Commission has recognized the role that state resource planning plays in managing the resource adequacy of [MISO]"). Consumers Energy (Consumers), Campbell's operator and primary owner, is a MISO member and must maintain at least the amount of capacity required under the MISO tariff.

The Michigan Public Service Commission (MPSC) regulates the investment decisions of utilities in Michigan—including decisions about which generation resources to build and which to retire. The MPSC requires each utility to file periodically an Integrated Resource Plan to meet its projected electricity demand over 5-, 10-, and 15-year time horizons. Mich. Comp. Laws Ann. § 460.6t(3). Through that process, the MPSC ensures that utilities, including Consumers, obtain the capacity needed to meet their obligations under the MISO tariff. It also ensures that they do so at the best value to ratepayers, and with a composition of resources that complies with state law, including environmental requirements. *Id.* 460.6t(8)(a).

DOE has no statutory role in regulating long-term resource adequacy. Instead, it has a narrow, time-limited authority to command grid participants to take certain actions during an "emergency." Section 202(c) allows DOE to command certain action "[d]uring the continuance of any war in which the United States is engaged," or when the Secretary determines that "an emergency exists" due to "a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes . . . ." 16 U.S.C. § 824a(c)(1).[1]

When these extraordinary circumstances arise, section 202(c) permits DOE to respond unconstrained by the procedural safeguards and substantive limitations that undergird the rest of the FPA. For instance, while the rest of the FPA authorizes action only after

[1] Until 1977, the Federal Power Commission (FPC) exercised this authority.

opportunity for hearing,[2] section 202(c) allows DOE to act without notice. And in profound contrast to the rest of the FPA and general utility law principles, section 202(c) empowers DOE to require utilities to incur costs—through a command to provide generation or transmission service—without fully weighing the impact to ratepayers or whether the resulting rates will be just and reasonable.

B. Campbell was scheduled to retire as a result of a careful planning process approved by the MPSC and MISO

The J.H. Campbell Generating Plant is an inefficient, dilapidated coal-fired power plant in Michigan that began operating in 1962. JA__[DOE0006_11], JA__[DOE0008_25]. In 2021, Consumers announced it would retire the plant in May 2025 and replace it with other resources. JA__[DOE0006_12]. Consumers then executed that plan under the oversight of the state regulator, the MPSC, and with approval of the regional grid operator, MISO.

From 2021 to 2025, under the MPSC's oversight, Consumers implemented a plan to retire Campbell and replace it with newer resources that would increase available generation capacity, save

[2] *See, e.g.*, 16 U.S.C. §§ 824a(b), 824a(e), 824a-1(a), 824a-3(f), 824a-4, 824b(a)(4), 824c(b), 824d, 824e, 824f, 824i(b), 824j, 824j-1, 824k, 824m, 824o, & 824p.

ratepayers money, and reduce pollution. JA__[DOE0008_95-230]. For over a year, the MPSC reviewed the proposed retirement, including its effect on reliability, and ultimately approved it in a multi-party settlement agreement. JA__[DOE0008_95-230]. The agreement directed the Campbell retirement and the construction, procurement, and extended operation of other major generating resources. Those resources are now online and producing cleaner, lower-cost power. JA__[DOE0008_535,544-45]. The net effect was to substantially *increase* the total generating resources available in the region. JA__[DOE0006_17n.66].

MISO also determined through a detailed technical study that retiring Campbell would not harm reliability. JA__[DOE0006_166]. MISO's Tariff requires that a generator planning to suspend operations notify MISO at least 26 weeks in advance. MISO then performs a study to determine whether the resource is necessary for reliability. JA__[DOE0010_605-10]. In 2022, after studying its potential impacts to power system reliability, MISO approved the Campbell retirement. JA__[DOE0006_166].

In April 2025, MISO published the results of its 2025/2026 capacity auction. The capacity market allows utilities in MISO to "purchase commitments from generators to produce set amounts of electricity in the future." *Pub. Citizen, Inc. v. FERC*, 7 F.4th 1177, 1186 (D.C. Cir. 2021). The auction results, MISO reported, "demonstrated sufficient capacity at the regional, subregional and zonal levels." JA__[DOE0004_12].

C. The White House directs DOE to use Section 202(c) to assert authority over long-term resource adequacy

On April 8, 2025, the President announced four executive orders (EOs) to exert control over the mix of the Nation's electricity resources. Among them was EO 14,262, *Strengthening the Reliability and Security of the United States Electric Grid*, which directed DOE to develop within 90 days a methodology that would (1) second-guess the reserve margins[3] used by states and RTOs based on DOE's own "acceptable threshold," and (2) "accredit" capacity for different generator types (i.e., decide how much coal, gas, solar, etc. are each worth in capacity terms),

[3] Reserve margin is the amount of unused available capability of an electric power system (at peak load) as a percentage of total capability.

presumably without regard for the capacity accreditation rules applied by states and RTOs. 90 Fed. Reg. 15,521 (Apr. 8, 2025).

The EO also directed DOE to decide, based on the above methodology, which generation resources across the country may retire. *Id.* at 15,522. Again, the EO nowhere mentioned that states and RTOs currently oversee generator retirements—decisions DOE was presumably also expected to disregard. To prevent retirements, the EO directed DOE to use its emergency authority in FPA section 202(c). *Id.*

D. DOE issues the Order, the Rehearing Order, and extensions

On May 23, 2025, years after Campbell's retirement was approved by MISO and the MPSC, but just a week before its scheduled retirement, DOE issued the Order, claiming that an "emergency" existed in the 15-state MISO region "due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes . . . ." JA__[DOE0001_1]. DOE ordered Consumers and MISO to ensure the continued operation of Campbell for 90 days.

To justify an emergency, the Order pointed to "potential tight reserve margins during the summer 2025 period" in MISO, citing the North American Electric Reliability Corporation (NERC) 2025 Summer

Reliability Assessment finding that MISO is "at elevated risk of operational reserve shortfalls during periods of high demand or low resource output." JA__[DOE0001_1]. But the Order nowhere acknowledged that such potential conditions are commonplace in MISO and elsewhere and have never been the basis for any prior section 202(c) order. The Order then described the retirement of thermal generation capacity, including the retirement of approximately 2,700 MW of coal-fired capacity in Michigan since 2020. JA__[DOE0001_1]. The Order acknowledged Consumers' acquisition of replacement capacity and MISO's April 2025 conclusion that its auction resulted in "demonstrated sufficient capacity," JA__[DOE0001_2], but did not reference, let alone consider, the extensive processes that MISO and the MPSC undertook to evaluate and mitigate any reliability risk from the Campbell retirement. Nor did the Order describe or evaluate any actions that DOE, MISO, or Consumers had taken or could take to mitigate any alleged emergency conditions short of ordering the continued operation of the plant.

Instead, the Order concluded that "additional dispatch of the Campbell Plant" for the 90-day duration of the order "is necessary to best meet the emergency and serve the public interest." JA__[DOE0001_2]. The Order then mandated that: (i) MISO and Consumers take all necessary steps to ensure Campbell is available for dispatch; and (ii) MISO ensure "economic dispatch" of the plant and that Consumers comply with all such dispatch orders.

On June 18, 2025, the Michigan Attorney General requested rehearing at DOE, JA__[DOE0006], and on June 23, Minnesota and Illinois did, too. JA__[DOE0011]. On July 24, the Michigan Attorney General petitioned for review of the Order in this Court, and on July 25, Minnesota and Illinois did, too.

On July 7, DOE published the methodology called for in EO 14,262, entitled "*Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*" (*Report*). ADD7. The *Report* analyzed the grid under current system conditions and under projected 2030 conditions. As relevant here, the report found no resource adequacy problems under current system conditions, other than in Texas. ADD21.

On September 8, immediately before submitting the administrative record in this case, DOE issued a rehearing order

(Rehearing Order). JA__[DOE0016]. Although DOE had already denied rehearing of the Order by operation of law—i.e., by declining to respond—the Rehearing Order provided responses to some arguments, retroactively "modified" the Order in limited respects, and otherwise "sustained" the Order. JA__[DOE0016_24].

The Rehearing Order made plain DOE's intent to regulate resource adequacy for the long term. Relying on an unexplained "assessment" of expected generation retirement and additions, the Rehearing Order concluded that "most regions—including the MISO region relevant to the Emergency Order—will face unacceptable reliability risks *within five years*." JA__[DOE0016_¶42] (emphasis added). The Order, DOE asserted, "addresses that risk," even though, by its own terms, it lasted only 90 days. *Id.*

That intent has borne out. DOE has extended the Order's 90-day period twice. On August 20, DOE issued a second order, extending the mandate another 90 days. ADD81 (Order No. 202-25-7 (Campbell II)). Campbell II relied both on the prior evidence of an "emergency" purportedly justifying Campbell I as well as new "emergency" conditions "likely to continue" for "years." ADD81-88. On November

18, DOE issued a third order, extending the mandate until February 17, 2026. ADD91 (Order No. 202-25-9 (Campbell III)). Without any new evidence, DOE again claimed that "emergency conditions . . . continue, both in the near and long term," and are "likely to continue in subsequent years." ADD94, 99.

E. FERC proceedings

On June 6, 2025, in response to a directive in the Order, Consumers filed a complaint at FERC seeking to modify MISO's tariff to incorporate a mechanism to recover the costs of complying with the Order and any extension thereof. *Consumers Energy*, 192 FERC ¶ 61,158 at P 1 (Aug. 15, 2025). Consumers conceded that FERC's ratemaking authority under FPA sections 205 and 206 would limit it to prospective relief. *Id.* at P 14. Consumers therefore requested FERC act instead pursuant to section 202(c), which Consumers argued did not restrict FERC from imposing retroactive cost recovery. *Id.*

The States protested Consumers' complaint, arguing *inter alia* that the Order is *ultra vires* and therefore not a basis for cost recovery. On August 15, FERC granted Consumers' complaint. FERC determined that arguments that the DOE Order may be deemed unlawful to be "beyond the limited scope of this proceeding." *Id.* at P 42. FERC, however, also specified that parties "may take appropriate steps, such as requesting rehearing in this proceeding, to preserve arguments that if the DOE Order were to be modified, then the Commission should require refunds or otherwise revisit its approach . . . ." *Id.* The Michigan Attorney General timely requested rehearing of FERC's order to preserve its argument that the cost recovery mechanism is invalid or, alternatively, should be modified. FERC Docket No. EL25-90-001 (Sept. 15, 2025). On December 15, 2025, after its rehearing request was deemed denied by operation of law, Michigan petitioned for review in this Court. *See* Case No. 25-1285.

SUMMARY OF ARGUMENT

DOE is attempting to convert a temporary emergency authority into a long-term regulatory authority, usurping state control over electricity generation. The strategy has two steps. First, DOE stretches the meaning of "emergency" beyond recognition, purporting to identify a power sector emergency with no beginning and no end, across a 15-state region of the United States. Second, DOE strings together a succession of 90-day emergency orders to achieve its desired long-term regulatory outcome years into the future.

The Order under review, through which DOE initiated this strategy, is unlawful for three reasons.

First, it is unlawful because DOE exceeded its statutory authority under section 202(c) by purporting to address a potential, future, generalized lack of capacity on a long-term basis. The plain meaning of an "emergency" in the statutory text, which DOE has affirmed in implementing regulations, is a "sudden" or "unexpected" occurrence requiring "immediate action." But as even DOE appears to acknowledge, those circumstances are not present here. Instead, DOE has claimed complete discretion to find emergencies wherever it likes. But DOE is bound by the words of the statute; it may not transform a narrow emergency authority into a broad regulatory authority without a basis in statutory text.

Second, the Order is unlawful because DOE failed to provide substantial evidence and apply reasoned decision-making for its determination that an emergency existed. Among other deficiencies. DOE distorted NERC's Summer Reliability Assessment and MISO's auction results, failed to acknowledge the reliability reviews that MISO and the MPSC undertook, and failed to respond reasonably to petitioners' arguments about these sources on rehearing. DOE also failed to acknowledge that during the period of the Order, it published a Resource Adequacy Report intended to guide reliability interventions such as this one, which found no current capacity shortfalls in MISO, directly contradicting the findings in the Order.

Third, the Order is unlawful because the actions DOE commands do not adhere to statutory limits. Section 202(c) authorizes DOE to mandate only those actions that "best meet the emergency" and "only during hours necessary to meet the emergency." Yet the Order commands the plant to run based on economic criteria even when there is no emergency, which DOE has no authority to do. Further, DOE makes no showing that requiring an aging, unreliable, uneconomic coal plant to run during non-emergency hours for 90 days "best meets" the long-term, region-wide emergency that DOE claims to exist—insufficient capacity during particular hours when demand is at its peak.

STANDING

When the States filed their petitions for review, the Order had not expired and was continuing to mandate Campbell's operation. *See Lujan v. Defs. of Wildlife*, 504 U.S. 555, 569 n.4 (1992) (standing determined based on "the facts as they exist when the complaint is filed." (cleaned up)).[4] Since the Order's expiration, Campbell still cannot be retired because of the repeated, short-duration orders that evade this Court's review. The operation of the plant injures the States and their people in several ways:

First, the Order imposes costs on the States and their ratepayers. The Campbell retirement and its replacement with more cost-effective resources were elements of a careful plan expected to save Michigan ratepayers nearly $600 million. JA__[DOE0006_4n.2]. By ordering Campbell's continued operation, the Order ensures that ratepayers throughout MISO, including the States, will pay higher costs. Although the precise amount of costs remains unknown, Consumers noted a "net financial impact" of $53 million to continue operating the plant through

[4] Evidence relevant to establishing Petitioners' standing and to demonstrating that this case is not moot is included in Petitioners' Addendum, attached to this brief. *See Transunion LLC v. Ramirez*, 594 U.S. 413, 431 (2021); *Sierra Club v. E.P.A.*, 292 F.3d 895, 899 (D.C. Cir. 2002); D.C. Cir. L. Rule 28(a)(7).

August. ADD166.[5] As discussed below, resolution of the States' petitions will have a direct bearing on who bears those costs. *See Crowley Gov't Servs., Inc. v. Gen. Servs. Admin.*, 143 F.4th 518, 526 (D.C. Cir. 2025).

Second, at the time of the petition, the Order was causing (and ongoing operation of Campbell continues to cause) the States and their people to suffer environmental harms. Campbell burns coal, thereby emitting SO_2, NOx, and PM 2.5—all air pollutants harmful to human health. JA__[DOE0008_104]. As a result of the Order, Campbell continued operating; absent the Order, it would be shuttered and no longer emit harmful pollutants.

Pollution from Campbell is causing, and will continue to cause, harms to public health in the States. According to the U.S. EPA's COBRA tool, the harms from a year of Campbell's continued operation include 27 to 46 excess deaths as well as thousands of lost school- and work-days. ADD213. The effects from each 90-day order would be approximately one quarter of that. *Id.* For Michigan, Illinois, and

[5] Those costs continued to increase during Campbell II. *See* ADD166.

Minnesota alone, COBRA estimates effects from the Order that are the equivalent of $34.5 to $54.6 million in harms. *Id.*

Finally, the Campbell retirement was a critical element of a settlement agreement to which the Michigan Attorney General was a party. JA__[DOE0008_95-230]. Because the Order deprives the Michigan Attorney General of the benefit of her bargain under the settlement agreement, she suffers a discrete and separate harm. *See Belmont Mun. Light Dep't v. FERC*, 38 F.4th 173, 185 (D.C. Cir. 2022) (states have cognizable interest in "protecting their citizens and electric ratepayers in the traditional government field of utility regulation").

STANDARD OF REVIEW

The APA applies to review of agency actions under the FPA. *Kimball Wind, LLC v. FERC*, 140 F.4th 496, 499 (D.C. Cir. 2025). This Court sets aside any "agency action, findings, and conclusions" that are "in excess of statutory jurisdiction, authority, or limitations," "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law," or "unsupported by substantial evidence." 5 U.S.C. § 706(2)(A), (C), (E); *see* 16 U.S.C. § 825*l*(b); *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983).

"[W]hen addressing a question of statutory interpretation, [courts] begin with the text" and apply "the traditional tools of statutory construction." *Pac. Gas & Elec. Co. v. FERC*, 113 F.4th 943, 947-48 (D.C. Cir. 2024) (quotations omitted). If an agency's interpretation of a statute is "not the best, it is not permissible." *Loper Bright Enters. v. Raimondo*, 603 U.S. 369, 400 (2024).

ARGUMENT

I. This Case Is Not Moot, But Even If It Were, A Mootness Exception Applies

This case is not moot. "[A] case is moot when the issues presented are no longer 'live' or the parties lack a legally cognizable interest in the outcome." *Honeywell Int'l, Inc. v. Nuclear Regul. Comm'n*, 628 F.3d 568, 576 (D.C. Cir. 2010) (quoting *County of Los Angeles v. Davis*, 440 U.S. 625, 631 (1979)). But a case is not moot when resolution would affect the parties' interests in a parallel action. *Crowley*, 143 F.4th at 526; *see also Mine Reclamation Corp. v. FERC*, 30 F.3d 1519, 1523 (D.C. Cir. 1994) (case not moot where resolution could affect parallel agency adjudication). Here, even though the period of the Order has elapsed, the States retain a legally cognizable interest in the outcome of this case because the legal validity of the Order will determine who bears its costs.

FERC's authority to fix rates under FPA sections 205 and 206 is prospective only. *Consumers Energy*, 192 FERC ¶ 61,158 at P 14 (Aug. 15, 2025). The filed rate doctrine would prohibit FERC from requiring MISO to charge a rate other than that on file, regardless of any resulting inequities. *Oklahoma Gas & Elec. Co. v. FERC*, 11 F.4th 821, 832 (D.C. Cir. 2021) (filed rate doctrine "admits of no equitable adjustments by the Commission or this court.").

Only in the extraordinary context of an emergency under section 202(c) may FERC direct MISO to charge ratepayers retroactively for costs Consumers already incurred. FERC granted Consumers' complaint solely on the basis of section 202(c). *Consumers Energy*, 192 FERC at P 35. If this Court holds the Order unlawful, or requires DOE to modify it, the Court's ruling will directly affect Consumers' cost recovery at FERC. Vacatur of the Order enables the States to seek a refund of costs charged to their ratepayers (including the States themselves) and to eliminate the MISO cost-recovery mechanism altogether. Thus, even after the Order expired, its validity is a live matter affecting the States' interests.

Even if this case were moot, the Court should retain jurisdiction because "the dispute is capable of repetition yet evading review." *Trump v. Mazars USA, LLP*, 39 F.4th 774, 786 (D.C. Cir. 2022). The "challenged action was in its duration too short to be fully litigated prior to its cessation or expiration" and "there [is] a reasonable expectation that the same complaining party would be subjected to the same action again." *Id.* (quoting *Weinstein v. Bradford*, 423 U.S. 147, 149 (1975)).

The Order lasted 90 days. That is too short a period to litigate its validity, especially because the FPA required the States to seek rehearing and to present all objections before filing this petition, and afforded DOE at least 30 days to consider that rehearing request. 16 U.S.C. § 825*l*(a), (b); *see Honeywell*, 628 F.3d at 576 (order shorter than two years presumed to evade review). Thus, review in this Court could not be completed before the Order expired.

Further, "here, there is more than just a reasonable expectation that [DOE] would reissue the same [order]. It has already done so." *Trump*, 39 F.4th at 786. Indeed, it has done so twice. All three Orders concern the same generation facility and address the same purported "emergency"—an "ongoing" emergency characterized by "unacceptable reliability risks within five years." JA__[DOE0016_14]; *see* ADD88; ADD99.

II. The Order Exceeds DOE's Statutory Authority

Section 202(c) confers an extraordinary power, restricted to extraordinary circumstances—a sudden, unexpected, and imminent threat to the Nation's power grid. But DOE has exercised this authority to address only a potential, generalized deficiency in electric capacity that it claims may last for "years." Because section 202(c) grants only a more circumscribed power, the Order exceeds DOE's statutory authority. 5 U.S.C. § 706(2)(C).

A. Section 202(c) authorizes DOE to address emergencies, not to regulate the long-term resource adequacy of the electric power sector.

Section 202(c) authorizes DOE to act only in war or when DOE "determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes." 16 U.S.C. § 824a(c)(1). Traditional tools of statutory interpretation—including

DOE's own regulation, courts' interpretations, and DOE's longstanding practice—confirm that an emergency must be sudden, unexpected, and imminent. A general lack of electric capacity supposedly existing across a 15-state region of the country and expected to last for "years" is not an emergency. Finally, context makes plain that the best meaning of the FPA's emergency provision is *not* that it confers unheralded authority to transform the electricity sector.

"[B]egin with the text." *PG&E*, 113 F.4th at 948. The FPA does not define "emergency," but contemporaneous dictionaries elucidate its meaning. *See Bostock v. Clayton Cnty., Georgia*, 590 U.S. 644, 655 (2020) (relying on contemporaneous dictionaries to determine plain meaning of statutory text). Webster's New International Dictionary of the English Language (1930) defined "emergency" as a "sudden or unexpected appearance or occurrence . . . . An unforeseen occurrence or combination of circumstances which calls for immediate action or remedy; pressing necessity; exigency." Current dictionaries likewise define "emergency" as a circumstance "unexpectedly arising, and urgently demanding immediate attention." *See Acuity Ins. Co. v. McDonald's Towing & Rescue, Inc.*, 747 F. App'x 377, 381 (6th Cir.

2018) (addressing a statute that leaves "emergency" undefined and quoting dictionaries to supply a definition).

Section 202(c)'s text also suggests that an "emergency" must be imminent. Section 202(c)(1) articulates its required predicates in the present tense: DOE may act "[d]uring the continuance of any war" or when "an emergency exists." Likewise, Section 202(c)'s substantive provisions all pre-suppose an active emergency. Section 202(c)(1) empowers DOE to take actions that "best meet the emergency." And section 202(c)(4)(A) allows DOE to extend orders for additional 90-day periods so long as it is "necessary to meet the emergency." Those provisions would make little sense if the "emergency" to which they refer might not even arise for years. *Contra* JA__[DOE0016_14].

That an "emergency" must arise suddenly and unexpectedly is confirmed by DOE's own regulations implementing section 202(c):

> "Emergency," as used herein, is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power.

10 C.F.R. § 205.371. When it adopted that definition, DOE explained that it did not want to "replace prudent utility planning and system expansion." DOE, *Emergency Interconnection of Electric Facilities and*

the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39,984, 39,985 (Aug. 6, 1981). Rather, DOE's role would be limited to periods of "unexpected inadequate supply of electricity," not solving "long-term problems." *Id.*

The few courts that have opined on the meaning of "emergency" in section 202(c) have emphasized that the provision applies in very limited circumstances, and not as a tool to address longer-term concerns. In *Richmond Power and Light v. FERC*, this Court upheld the FPC's judgment that, after the 1973 oil embargo had ended, the lingering need for additional electricity to address the Nation's pressing but longer-term dependence on foreign oil—the dominant question in national energy policy at the time—was not an "emergency" noting that section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances." 574 F.2d 610, 615 (D.C. Cir. 1978).

Similarly, in *Otter Tail Power v. FPC*, the Eighth Circuit described section 202(c) as enabling the FPC to "react to a war or national disaster." 429 F.2d 232, 234 (8th Cir. 1970). The court also distinguished section 202(c) from section 202(b), which "applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission." Consistent with these differences in purpose, section 202(b) authorizes action only after a hearing, whereas section 202(c) "enables the Commission to proceed without notice or hearing" to address immediate crises. *Id.*

DOE's longstanding practice likewise confirms the limited scope of its powers. DOE used 202(c) just nineteen times from its founding in 1977 through 2024, mostly in response to extreme weather events such as hurricanes, extreme cold, and extreme heat. JA__[DOE0006_5]; *see* Benjamin Rolsma, *The New Reliability Override*, 57 Conn. L. Rev. 789, 838 (2025). In each of these cases, the emergency order was requested by the relevant system operator or responsible utility, or both, and DOE carefully limited its remedy to ensure that generation facilities were ordered to run only as necessary to address the emergency, and in a manner to minimize conflict with environmental requirements. JA__[DOE0006_6]. DOE thus limited the duration of those orders to the period necessary to address the emergency, often shorter than 10 days. *Id.*

The plain text, prior regulatory interpretation, judicial precedent, and longstanding practice all confirm a limited power applicable only to sudden, imminent conditions. Context makes that all the more plain. *See Food & Drug Admin. v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 133 (2000) (The "words of a statute must be read in their context and with a view to their place in the overall statutory scheme."). The Order proposes a transformative use of section 202(c): as a means to intervene in the regulatory landscape, displacing both state law and sections 205 and 206 of the FPA, under which FERC regulates regional grid operators' resource adequacy requirements. Had Congress intended to vest such a broad power in section 202(c) it would have stated so clearly. Indeed, it defies logic that Congress would grant DOE general authority over which power plants may retire across the country—a function with profound implications for rates, state sovereignty, and a broad array of stakeholder interests—without any obligation to assess the effect on ratepayers or seek public input.

The Supreme Court has emphatically rejected statutory interpretations whereby an agency "claim[s] to discover in a long-extant statute an unheralded power representing a transformative expansion in its regulatory authority." *W. Virginia v. Env't Prot. Agency*, 597 U.S. 697, 724-25 (2022) (internal quotations omitted); *cf. Whitman v. Am. Trucking Associations*, 531 U.S. 457, 468 (2001) ("Congress . . . does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions . . . ."). Yet what DOE attempts here is exactly that "extraordinary case[]," *W. Virginia*, 597 U.S. at 721 (cleaned up): the discovery—in a 90-year-old statutory provision used seldomly and only for limited purposes—of unheralded yet broad authority to transform the regulatory environment underpinning the electricity system by commanding the amount and type of generation on the grid. All without "clear congressional authorization," *id.* at 724, and notwithstanding that such authority has been reserved to and exercised by the States and, at their election, RTOs, for decades. *Cf. Biden v. Nebraska*, 600 U.S. 477, 501 (2023) ("The question here is not whether something should be done; it is who has the authority to do it"); *W. Virginia*, 597 U.S. at 744 (Gorsuch, J., concurring) (agency overreach "also risks intruding on powers reserved to the States").

B. DOE is bound by the text of section 202(c).

Confronted with section 202(c)'s plain text, DOE's response is that it is not bound by the meaning of the word "emergency" as it appears in the statute or as defined in its regulations. DOE asserted, without explanation, that the definition of emergency is "not persuasive" and that dictionary definitions "cannot limit the discretion Congress expressly delegated to the Secretary in section 202(c)." JA__[DOE0016_7].

To be clear, DOE did not adopt a different definition of the word "emergency." Nor did it provide reasons, using any other traditional tools of statutory construction, for disregarding the dictionary definition. DOE simply said that *it gets to decide what an emergency is*—the purest specimen of *ipse dixit* one is likely to encounter in the wild.

Whatever discretion DOE may have, it does not have discretion to ignore the words of the statute. Any delegation from Congress to DOE is necessarily constrained by "the words on the page." *Bostock*, 590 U.S. at 654. The statute directs the Secretary to determine whether an "emergency exists," but whatever discretion that affords "is not a roving license to ignore the statutory text. It is but a direction to exercise discretion within defined statutory limits." *Massachusetts v. EPA*, 549 U.S. 497, 533 (2007).

On rehearing, DOE also claimed to be unconstrained by its own regulatory definition of emergency, stating: "The definition of 'emergency' contained in DOE's regulations . . . does not supersede the discretion section 202(c) affords to the Secretary to 'determine[] that an emergency exists.'" JA__[DOE0016_7]. "It is axiomatic, however, that an agency is bound by its own regulations." *Nat'l Env't Dev. Assoc.'s Clean Air Project v. E.P.A.*, 752 F.3d 999, 1009 (D.C. Cir. 2014) (quotations omitted).

C. The Order impermissibly attempts to regulate long-term resource adequacy rather than address an "emergency" under section 202(c).

DOE made no effort to show that its claimed emergency was "sudden," "unexpected," or otherwise a genuine "emergency." Certainly, the Campbell retirement was neither sudden nor unexpected. MISO approved the retirement in March 2022 after concluding it would not harm reliability. JA__[DOE0006_166]. And in June 2022, both the retirement and the procurement of replacement resources were approved by the MPSC through a public proceeding, then carefully and timely executed over the ensuing years. JA __[DOE0008_95-230]. That DOE waited until the eve of the retirement to act does not transform a long-planned retirement into an emergency.

Nor did NERC's 2025 Summer Reliability Assessment, upon which the Order principally relied, describe a condition that was "sudden," "unexpected" or "imminent." That report designated MISO as at "elevated risk of operating reserve shortfalls." JA__[DOE0005_5]. But NERC's "elevated risk" designation—which falls below "high risk"—is broadly and routinely applied. The same report designated other large sections of the country as "elevated risk." JA__[DOE0005_6]. And, except for summer 2022 when MISO was "high risk," NERC had designated MISO as "elevated risk" in every summer and winter assessment since NERC began using those labels in 2021. JA__[DOE0006_29nn.105-06]. Thus, if NERC's "elevated" risk designation indicated an emergency, that means the 15 states of MISO—and other large swaths of the United States—have been in an uninterrupted, years-long state of emergency. Sudden and unexpected, that is not.

DOE also based its actions on, and attempted to remedy, concerns about resource adequacy that will not manifest, if at all, for years. The Rehearing Order adverts to an "assessment" of expected generation retirement and additions, which found (without explanation or substantiation) that "most regions—including the MISO region relevant to the Emergency Order—will face unacceptable reliability risks within five years." JA__[DOE0016_14]. But section 202(c) does not empower DOE to act based on circumstances that might arise years *after* its 90-day order expires.

The Order also fails to describe an emergency under DOE's regulations. After claiming to be unfettered by its regulatory definition of "emergency," DOE appeared to contend that it nonetheless met the definition. Without further explanation, DOE stated: "In any event, those regulations specifically provide that '[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations.'" JA__[DOE0016_7]. DOE takes this sentence out of context. DOE's regulations do not say that inadequate planning is *itself* an emergency. Inadequate planning (or a failure to construct facilities) could expose a utility to heightened *risk* of emergency. But the emergency itself must still qualify as an "unexpected inadequate supply of electric energy," which DOE made no effort to establish.

Further, DOE ignored the next sentence of its regulations, which limits how long an order caused by inadequate planning may extend: "In such cases, the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed." 10 C.F.R. § 205.371. DOE made no attempt to enforce this key provision. Nor could it, as Consumers had already made "firm arrangements" to replace the power from Campbell, JA__[DOE0008_95-230], and MISO had already procured adequate capacity to maintain reliability for Summer 2025, JA__[DOE0004_12].

Rather than a carefully tailored response to a sudden and unexpected condition, the Order is a power grab: it claims the authority to identify an "emergency" by secretarial say-so and where the supposed emergent conditions may not arise for years. But the FPA commits such long-term planning to the states, whose routine, intervening actions may prevent any future risk. The statute requires that the predicate for DOE's action, the substantive limits of its action, and the duration of its action all depend on the existence of an active emergency. The Order failed to show such an emergency existed here.

III. The Order Is Not Supported By Substantial Evidence

Under the FPA and APA, DOE must support its determinations with substantial evidence. 16 U.S.C. § 825*l*(b) (factual assertions in FPA orders must be supported by substantial evidence); *see, e.g.*, *Emera Maine v. FERC*, 854 F.3d 9, 22 (D.C. Cir. 2017) (FPA order must be "supported by substantial evidence" and based on methodology "consistent with past practice or adequately justified").

The Order falls well short of this standard. It does not substantiate an emergency, relying instead on evidence that is incomplete or taken out of context. And it ignores other essential facts, including DOE's own assessment of resource adequacy in MISO.

A. Neither The Order nor the Rehearing Order introduce facts to substantiate an emergency in MISO.

DOE's shifting rationales lack evidentiary support. The Order purported to identify a resource adequacy "emergency" by pointing to three sources of evidence: (1) NERC's 2025 Summer Reliability

Assessment, (2) capacity retirements in MISO, and (3) MISO's 2025/2026 Planning Resource Action. On rehearing, DOE tried to bolster its deficient record by pointing to assertions in Executive Orders, general statements from a MISO official, and *post hoc* justifications based on alerts MISO issued while the Order was in effect. None of these sources support DOE's conclusion that an emergency existed or would exist in the summer of 2025 or beyond.

The Order

The Order relied heavily on the NERC 2025 Summer Reliability Assessment's statements that MISO is "at elevated risk of operational reserve shortfalls" and that it has "potential tight reserve margins." JA__[DOE0001_1]. But the Order's discussion of the Assessment is both incomplete and unreasoned.

First, NERC's "elevated risk" designation falls *below* NERC's "high risk" designation and in no way signifies an emergency condition. JA__[DOE0005_10Tbl.1]. As the Rehearing Order acknowledged, JA__[DOE0016_11], NERC considers a region to be at "elevated" risk if there would be reliability concerns only in *extreme* scenarios (i.e., extreme demand or extreme generator outages)—but NERC did not assess the likelihood of such extreme supply or demand during the summer period.[6]

In MISO, designation of "elevated risk" represents an expectation of roughly 15 minutes of total outage over a year. JA__[DOE0005_12]. It is no surprise, then, that this designation is far from unusual. Except when it was designated "high" risk, MISO had been designated as "elevated" risk in every Summer Assessment—and every Winter Assessment—since NERC began using the current designations in 2021. JA__[DOE0006_29nn.105-06]. Nor is MISO an outlier. The Summer 2025 Assessment designated grid systems from Texas to New England as at "elevated risk." JA__[DOE0005_10tbl.2].

Second, the "*potential* tight reserve margins" identified in the Order did not constitute an emergency, even in Summer 2025. JA__[DOE0001_1] (emphasis added). NERC's calculation of anticipated reserve margin for Summer 2025 in MISO (24.7%) was the second highest level since 2020 and over 57% higher than its

[6] The Rehearing Order newly points to the National Oceanic and Atmospheric Administration Seasonal Outlook, finding the Midwest had a 33-50% chance of "above-normal" temperatures in summer 2025. JA___[DOE0016_12]. But NOAA classifies such risk as merely "leaning above" average temperatures. In fact, the Midwest had the lowest chance of above-average temperatures of the continental United States. JA___[DOE0005_9].

"Reference Margin Level" (the level that "meet[s] resource adequacy criteria") for MISO (15.7%). JA__[DOE0005_10tbl.2, 15, & 44]. This does not reasonably constitute a "significant strain on the grid," JA__[DOE0016_¶35]—much less an "emergency." Confronted with Petitioners' arguments that the NERC Assessment did not provide evidence of an emergency, DOE had nothing to say, other than to repeat NERC's definition of "elevated risk." JA__[DOE0016_11].

In addition to the NERC Assessment, the Order attempts to support its emergency finding by observing that various power plants have retired in Michigan. JA__[DOE0001_1]. But power plant retirements are a regular occurrence in the electric power sector; this fact fails to present even *prima facie* evidence of an emergency. It was also arbitrary to rely on capacity retirements in one state in isolation without also considering all the other factors that contribute to resource adequacy in MISO, including capacity additions and access to out-of-state resources.[7]

[7] Of course, MISO and the MPSC *did* consider all those factors: MISO, in its modeling to conclude that the Campbell retirement would not threaten reliability, JA__[DOE0006_39n.125], and the MPSC in its proceeding approving Consumers' Integrated Resource Plan. JA__[DOE0008_95-230]. Yet, as discussed below, DOE arbitrarily failed even to acknowledge these proceedings.

Finally, the Order cited MISO's April 2025 summary of its Planning Resource Auction, which reported results from MISO's 2025/2026 capacity auction. The Order picks out MISO's statement that for that planning year, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources." JA__[DOE0001_2]. But here MISO was simply noting that the total capacity of resources offered into the auction was lower than what was offered the prior year—primarily because MISO had changed its methodology to recognize that coal plants like Campbell contribute less to reliability than MISO had previously assumed, *see* JA__[DOE0004_13]—not that the total amount of capacity procured was inadequate. JA__[DOE0006_10].

If anything, the Planning Resource Auction severely undercuts the emergency determination. In that same document, MISO concluded that the auction had "demonstrated sufficient capacity at the regional, subregional and zonal levels." JA__[DOE0004_12]. MISO's statements acknowledging that additional capacity would be *beneficial* during the summer do nothing to rehabilitate DOE's claim that the auction somehow evidenced an *emergency* during summer 2025. *See* JA__[DOE00016_¶38]. The Rehearing Order did not engage with the substance of the States' arguments explaining the import of the Planning Resource Auction. *See id.*

The Rehearing Order

None of the Rehearing Order's new justifications constitute substantial evidence of an emergency. Conclusory statements about a "National Energy Emergency" in EO 14,156 and an "unprecedented surge in electricity demand" in EO 14,262, JA__[DOE0016_13], do not provide particularized facts that constitute evidence of an emergency for purposes of 202(c). The FPA does not allow DOE to substitute White House say-so for "substantial evidence."

Rather than demonstrate an emergency, the anticipatory statements from MISO's Jennifer Curran cited in the Rehearing Order, JA__[DOE0016_13-14], *see* JA__[DOE0021_5], show only the unremarkable fact that MISO takes its reliability function seriously. Curran's reference to "resource adequacy and reliability challenges" falls far short of claims that there is or will be an emergency. And her reference to "growing reliability risk" from "the rapid retirement of existing coal . . . [that] threatens to outpace the ability of new resources . . . to replace them," JA__[DOE0021_7], is clearly not a reference to Campbell, whose retirement was not "rapid," was replaced with equivalent resources, and was judged *by MISO* not to create a reliability risk. More relevant and timely assessments by MISO leadership—such as the May 2025 statement of its Senior Vice President of Markets and Digital Strategy that "[w]e are confident that the [MISO] footprint will continue to be resource adequate in the near and longer term," JA__[DOE0009_174]—make clear that DOE's reliance on Curran's testimony to support emergency action is misplaced.

Finally, DOE pointed to events that occurred during the period of the Order—i.e., *after* the Order was issued—to bolster its emergency determination retroactively. *Post hoc* evidence, even if it proved what DOE purports (which it does not), cannot substitute for substantial evidence *at the time* DOE issued the Order. *Cf. Dep't of Homeland Sec. v. Regents of the Univ. of California*, 140 S. Ct. 1891, 1907-08 (2020) (agency bolstering previous decision may provide "a fuller explanation of the agency's reasoning *at the time of the agency action,"* but "may not provide new [reasons]" (internal quotations omitted)).

Regardless, MISO's alerts do not constitute evidence that an emergency existed in summer 2025. On June 23, MISO issued an "Energy Emergency Alert" (EEA) Level 1. EEA Level 1 is the lowest level of EEA, issued when the grid is stable but a grid operator "is concerned about sustaining its required Contingency Reserves." JA__[DOE0009_490]. In other words, declaration of EEA Level 1 indicates concern, not emergency. DOE has never previously recognized EEA Level 1 as constituting a section 202(c) "emergency." To the contrary, numerous recent section 202(c) orders—before and after Campbell I's issuance—make clear that EEA Level 1 is insufficient, using EEA Level 2 as the *minimum* trigger for ordered operations.[8] The Rehearing Order also asserts that MISO issued "dozens of alerts to manage grid reliability" but does not specify what kinds of alerts, ignoring that MISO routinely issues non-emergency alerts, for example, as early notification that there *may* be a need in

[8] *See* DOE Order No. 202-25-5 at 4 (June 24, 2025); DOE Order No. 202-22-4 at 4 (Dec. 24, 2022); DOE Order No. 202-22-3 at 4 (Dec. 23, 2022); DOE Order No. 202-22-2 at 4 (Sept. 4, 2022); DOE Order No. 202-22-1 at 4 (Sept. 2, 2022); DOE Order No. 202-21-2 at 5 (Sept. 10, 2021).

coming days to bring additional generation on-line. *See* JA__[DOE0009_92-119]. MISO's successful management of grid reliability—its core job—using its normal communications tools does not evidence an "emergency."

B. DOE ignored relevant facts.

Not only did DOE rely on evidence insufficient to substantiate an emergency, but it also ignored critical evidence demonstrating the absence of an emergency. *See, e.g.*, *Windsor Redding Care Ctr., LLC v. NLRB*, 944 F.3d 294, 299 (D.C. Cir. 2019).

DOE failed to consider its own *Resource Adequacy Report*, which was intended to "identify at-risk region(s) and guide reliability interventions" such as this one. ADD14.[9] While the Order was issued prior to release of the *Report,* the Rehearing Order was not. Yet DOE declined even to acknowledge that the report *flatly contradicts* the Order's conclusion that there is a resource adequacy emergency in MISO: "In the current system model . . . MISO did not experience

[9] Although DOE has excluded the Report from the record, this Court may take judicial notice of the Department's own publication. *See* Fed. R. Evid. 201(b); *Nebraska v. E.P.A.*, 331 F.3d 995, 999 n.3 (D.C. Cir. 2003); *Manguriu v. Lynch*, 794 F.3d 119, 121 (1st Cir. 2015) ("[C]ourts normally can take judicial notice of agency determinations.").

shortfall events." ADD34. In other words, the study did not identify any capacity shortfalls in MISO under current system conditions.

DOE also ignored the reliability assessments of MISO and the MPSC. As noted above, MISO approved the Campbell retirement through a study process governed by its tariff. JA__[DOE0006_166]. As the system operator, MISO has more in-depth knowledge of its system and conducted significantly more thorough analysis than did DOE. So too does the MPSC, which concluded in its Michigan capacity demonstration proceedings that both Consumers and the relevant part of MISO had sufficient resources in 2025 and the years to follow. JA__[DOE0006_18n.70].

DOE needed to explain why it reached a different conclusion than MISO and the MPSC. Instead, DOE failed to mention the MPSC analysis entirely. DOE did not engage the substance of the MISO analysis but instead tried to dismiss it because it was issued before the 2025 NERC report. JA__[DOE0016_12]. But as discussed above, nothing in the NERC report was new or otherwise provided a basis to dismiss MISO's decision to approve the Campbell retirement.

These failures of reasoned decisionmaking—ignoring the conclusions of its own analysis and departing from the conclusions of the relevant expert bodies without explanation—render the Order arbitrary.

IV. Even If There Were an Emergency, the Order Would Still Violate Section 202(c)

Independent of its failure to substantiate an "emergency," DOE also violated the FPA and APA because the "economic dispatch" remedy exceeds its statutory authority, 5 U.S.C. § 706(2)(C), and its justification for compelling Campbell's operation was unreasoned, *id.* § 706(2)(A).

A. Section 202(c) does not authorize DOE to require "economic dispatch."

Even in response to a true emergency, DOE may only command generation that "will best meet the emergency and serve the public interest" and then "only during hours necessary to meet the emergency." 16 U.S.C. § 824a(c)(1), (2). Instead, the Order directs MISO to ensure the "economic dispatch of the Campbell Plant." That command exceeds DOE's authority under each statutory provision.

First, DOE's command to ensure "economic dispatch" of Campbell flatly contradicts section 202(c)(2)'s affirmative requirement that its order "requires generation . . . only during hours necessary to meet the emergency." "Economic dispatch" is the practice of operating an electric system so that the lowest marginal-cost generators are used first, followed by more expensive ones. *See* JA__-__[DOE0006_44-46]; 42 U.S.C. § 16432(b). In other words, "economic dispatch" requires the plant to run based on prevailing market prices, not based on criteria related to emergent need, and thus does not limit operation only to hours of emergency.

DOE acknowledged the Order "may result in a conflict with environmental standards and requirements," JA___[DOE0001_2], triggering applicability of section 202(c)(2), but never reconciled the Order with that subsection's terms. *See* JA__[DOE0016_14-15]. Instead, DOE defended its "economic dispatch" instruction by again appealing to the "discretion" afforded by section 202(c). JA__[DOE0016_16]. But appeals to discretion do not authorize DOE to invoke emergency powers for hours beyond the "emergency" in contravention of the statute.

Second, requiring economic dispatch violates section 202(c)(1) because it does not limit operation to that needed to "best meet" DOE's purported *capacity* emergency. *See* JA__[DOE0016_18]. Lack of capacity is a problem of inadequate energy during peak demand, i.e., only during periods of acute need. *See Conn.*, 569 F.3d at 479 (capacity market aim is "sufficient capacity to easily meet expected peaks in electricity demand"). DOE never shows how compelling Campbell to sell into the energy market (based on economic considerations), which covers needs for all hours of the day, solves a purported shortage during particular windows of acute need.

In the Rehearing Order, DOE defended economic dispatch as "reducing electricity costs and serving the public interest." JA__[DOE0016_16]. But DOE cannot order power plants to run under section 202(c) during hours when there is no emergency, even if doing so lowered electricity costs.

Regardless, DOE's determination that such operation will "minimize cost to ratepayers" is arbitrary and capricious because it lacked a basis to reach that conclusion. *See* JA__[DOE0001_2]. Coal plants are often uneconomical and require long ramp-up times JA__[DOE0008_39-40]. To be available to ramp up for peak demand, a plant like Campbell typically needs to operate during normal conditions when market prices are low—thus operating at a net loss. JA__[DOE0008_41]. Indeed, Campbell cost at least $120 million to operate, but only received $67 million in revenue during the period of the Order. *See* ADD166. Perversely, then, because of Campbell's operating limits, economic dispatch ensures Campbell will run at a net loss. States and other MISO ratepayers are left covering those losses.

The Rehearing Order contends that even if Campbell operates on a "must run basis" such operation minimizes cost to ratepayers because Campbell would be a "price taker" that "cannot increase" the market price. JA__[DOE0016_16]. That defense betrays DOE's fundamental misunderstanding: ratepayers are paying the market price *and* covering Campbell's net losses, so they are necessarily paying above market costs in total. *See Constellation Mystic Power*, *LLC*, 172 FERC ¶ 61,044, 61,393 at P 41 (2020) (where a market sale is competitive only because ratepayers are covering the generator's net losses "the entirety of that transaction does not benefit customers.").

The Order is also inconsistent with the public interest.[10] The practical consequence of requiring "economic dispatch" is that Campbell

[10] The requirement that actions ordered by DOE "best meet the emergency and serve the public interest" is conjunctive. DOE Order No. 202-18-1, Summary of Findings at 4 (Nov. 6, 2017).

will run more often. This will burn more coal and cause more pollution than it would if it remained on standby and dispatched only during emergency circumstances. Given Campbell's age and condition, it also risks additional and more expensive repairs. *See* JA__-__[DOE0008_26-27].

Finally, DOE fails to explain its choice to run Campbell near continuously during non-emergency conditions, rather than only during periods of grid strain, and only after other mitigating steps had been exhausted. Such operation imposes excess cost and harm to the public and is unnecessary to "best meet" the emergency. Indeed, in the few cases when DOE temporarily prevented a power plant retirement to meet an emergency, DOE did not order economic dispatch. Rather, DOE ordered the plants to run only under narrowly defined circumstances, such as when called upon by the grid operator for reliability purposes. JA__-__[DOE0006_47-48].

B. The Order fails to establish that *any* operation of Campbell "best meets the emergency."

Beyond the unlawfulness of the "economic dispatch" command, DOE's order is arbitrary and capricious because it fails to justify the determination that any operation of Campbell will "best meet" the emergency.

Campbell is an aging, uneconomic plant that amounts to less than 1% of generation in MISO. JA__[DOE0006_43]. DOE offers no reason to conclude that preventing Campbell's retirement best meets the 15-state, years-long emergency it claims to have identified. Petitioners submitted data, which DOE did not address, that Campbell is unreliable, JA__[DOE0008_26] (Campbell's outage rates greatly exceed average), and that it requires significant periods of maintenance to operate, JA__[DOE0008_27] (documenting more than 285 days of outages during 2024 alone). DOE claims that Campbell is needed for a regional emergency, yet offers no evidence to show that energy generated from Campbell is deliverable to any areas in the region that would be expected to face energy shortage during periods of strained grid operations. The absence of engagement on this point is notable, because DOE is aware that adequate replacement capacity within the grid zone where Campbell is located was already operating. JA__[DOE0016_11]; *see* JA__-__[DOE0008_118-19] (approved plan increased capacity in MISO Zone 7). With the record before it, DOE had no basis to conclude that Campbell would be capable of serving other zones within MISO that could experience shortages during periods of grid strain.

In short, DOE's sole basis to conclude that Campbell would "best meet" the emergency is that it is a dispatchable plant in MISO. By this logic, any dispatchable plant in MISO is equally the "best." But "best meets" is not equivalent to "any that meets." *Nat'l Cable Television Ass'n, Inc. v. F.C.C.*, 33 F.3d 66, 74 (D.C. Cir. 1994) (rejecting an interpretation that results in an "exception that excepts nothing" because a court "must, if possible, give effect to every phrase of the statute") (internal quotation omitted). It requires DOE to compare among alternatives to discern whether other options better resolve the purported region-wide shortage of capacity. *See Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208, 218 (2009) (interpreting "best" as requiring selection of the alternative that is "most advantageous" on some relevant metric).

DOE's defense is again that it is unconstrained by the statutory text. JA___[DOE0016_18] (section 202(c) "does not require the Secretary to engage in a lengthy weighing of options or explanation of the Secretary's actions prior to issuing an emergency order"). Rather, DOE asserts, the phrase "in its judgment" is an express delegation of the appropriate remedy to the Secretary. JA___[DOE0016_18]. But DOE's approach writes "best meets" out of the statute, in an apparent effort to avoid judicial review of DOE's conduct. *TRW Inc. v. Andrews*, 534 U.S. 19, 31 (2001) ("It is a cardinal principle of statutory construction that a statute ought, upon the whole, to be so construed that, if it can be prevented, no clause, sentence, or word shall be superfluous, void, or insignificant") (cleaned up). Moreover, agency judgment is still subject to review under the APA. *See e.g.*, *Murray Energy Corp. v. EPA*, 936 F.3d 597, 604 (D.C. Cir. 2019) (reviewing and vacating in part EPA air standards, where the requisite statutory standard is determined "in the judgment of" the EPA Administrator). DOE was required to reasonably consider whether compelling Campbell's operation would "best meet" the supposed region-wide, years-long emergency. It did not.

CONCLUSION

This Court should hold unlawful and set aside the Order.

Respectfully submitted,

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CERTIFICATE OF COMPLIANCE

1. This document complies with the type-volume limit of Federal Rule of Appellate Procedure 32(a) because this document contains 9,950 words, excluding the parts of the brief exempted by Federal Rule of Appellate Procedure 32(f).
2. This document complies with the typeface requirements of Federal Rule of Appellate Procedure 32(a)(5) and the type style requirements of Federal Rule of Appellate Procedure 32(a)(6) because it has been prepared in a proportionally spaced typeface using Microsoft Word in 14-point Century Schoolbook.

/s/ Michael Moody
Michael Moody
(DC Cir. 66350)

CERTIFICATE OF SERVICE

I hereby certify that, on December 19, 2025, I electronically filed the foregoing with the Clerk of Court for the United States Court of Appeals for the District of Columbia Circuit through this Court's CM/ECF system, which will serve a copy on all registered users.

/s/ Michael Moody
Michael Moody
(DC Cir. 66350)

Addendum

Contents

A. Federal Power Act, Section 202; 16 U.S.C. 824a

(a) Regional districts; establishment; notice to State commissions

For the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources, the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy, and it may at any time thereafter, upon its own motion or upon application, make such modifications thereof as in its judgment will promote the public interest. Each such district shall embrace an area which, in the judgment of the Commission, can economically be served by such interconnection and coordinated electric facilities. It shall be the duty of the Commission to promote and encourage such interconnection and coordination within each such district and between such districts. Before establishing any such district and fixing or modifying the boundaries thereof the Commission shall give notice to the State commission of each State situated wholly or in part within such district, and shall afford each such State commission reasonable opportunity to present its views and recommendations, and shall receive and consider such views and recommendations.

(b) Sale or exchange of energy; establishing physical connections

Whenever the Commission, upon application of any State commission or of any person engaged in the transmission or sale of electric energy, and after notice to each State commission and public utility affected and after opportunity for hearing, finds such action necessary or appropriate in the public interest it may by order direct a public utility (if the Commission finds that no undue burden will be placed upon such public utility thereby) to establish physical connection of its transmission facilities with the facilities of one or more other persons engaged in the transmission or sale of electric energy, to sell energy to or exchange energy with such persons: *Provided,* That the Commission shall have no authority to compel the enlargement of generating facilities for such purposes, nor to compel such public utility to sell or exchange energy when to do so would impair its ability to render adequate service to its customers. The Commission may prescribe the terms and conditions of the arrangement to be made between the persons affected by any such order, including the apportionment of cost between them and the compensation or reimbursement reasonably due to any of them.

(c) Temporary connection and exchange of facilities during emergency

(1) 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 or transmission of electric energy, or of fuel or water for generating facilities, or other causes, the Commission shall have authority, either upon its own motion or upon complaint, with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest. If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party.

(2) With respect to an order issued under this subsection that may result in a conflict with a requirement of any Federal, State, or local environmental law or regulation, the Commission shall ensure that such order requires generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, is consistent with any applicable Federal, State, or local environmental law or regulation and minimizes any adverse environmental impacts.

(3) To the extent any omission or action taken by a party, that is necessary to comply with an order issued under this subsection, including any omission or action taken to voluntarily comply with such order, results in noncompliance with, or causes such party to not comply with, any Federal, State, or local environmental law or regulation, such omission or action shall not be considered a violation of such environmental law or regulation, or subject such party to any requirement, civil or criminal liability, or a citizen suit under such environmental law or regulation.

(4)(A) An order issued under this subsection that may result in a conflict with a requirement of any Federal, State, or local environmental law or regulation shall expire not later than 90 days after it is issued. The Commission may renew or reissue such order pursuant to paragraphs (1) and (2) for subsequent periods, not to exceed 90 days for each period, as the Commission determines necessary to meet the emergency and serve the public interest.

(B) In renewing or reissuing an order under subparagraph (A), the Commission shall 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. The conditions, if any, submitted by such Federal agency shall be made available to the public. The Commission may exclude such a condition from the renewed or reissued order if it determines that such condition would prevent the order from adequately addressing the emergency necessitating such order and provides in the order, or otherwise makes publicly available, an explanation of such determination.

(5) If an order issued under this subsection is subsequently stayed, modified, or set aside by a court pursuant to section 825*l* of this title or any other provision of law, any omission or action previously taken by a party that was necessary to comply with the order while the order was in effect, including any omission or action taken to voluntarily comply with the order, shall remain subject to paragraph (3).

(d) Temporary connection during emergency by persons without jurisdiction of Commission

During the continuance of any emergency requiring immediate action, any person or municipality engaged in the transmission or sale of electric energy and not otherwise subject to the jurisdiction of the Commission may make such temporary connections with any public utility subject to the jurisdiction of the Commission or may construct such temporary facilities for the transmission of electric energy in interstate commerce as may be necessary or appropriate to meet such emergency, and shall not become subject to the jurisdiction of the Commission by reason of such temporary connection or temporary construction: *Provided,* That such temporary connection shall be discontinued or such temporary construction removed or otherwise disposed of upon the termination of such emergency: *Provided further,*That upon approval of the Commission permanent connections for emergency use only may be made hereunder.

(e) Transmission of electric energy to foreign country

After six months from August 26, 1935, no person shall transmit any electric energy from the United States to a foreign country without first having secured an order of the Commission authorizing it to do so. The Commission shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States or would impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of the Commission. The Commission may by its order grant such application in whole or in part, with such modifications and upon such terms and conditions as the Commission may find necessary or appropriate, and may from time to time, after opportunity for hearing and for good cause shown, make such supplemental orders in the premises as it may find necessary or appropriate.

(f) Transmission or sale at wholesale of electric energy; regulation

The ownership or operation of facilities for the transmission or sale at wholesale of electric energy which is (a) generated within a State and transmitted from the State across an international boundary and not thereafter transmitted into any other State, or (b) generated in a foreign country and transmitted across an international boundary into a State and not thereafter transmitted into any other State, shall not make a person a public utility subject to regulation as such under other provisions of this subchapter. The State within which any such facilities are located may regulate any such transaction insofar as such State regulation does not conflict with the exercise of the Commission's powers under or relating to subsection (e).

(g) Continuance of service

In order to insure continuity of service to customers of public utilities, the Commission shall require, by rule, each public utility to--

(1) report promptly to the Commission and any appropriate State regulatory authorities any anticipated shortage of electric energy or capacity which would affect such utility's capability of serving its wholesale customers,

(2) submit to the Commission, and to any appropriate State regulatory authority, and periodically revise, contingency plans respecting--

(A) shortages of electric energy or capacity, and

(B) circumstances which may result in such shortages, and

(3) accommodate any such shortages or circumstances in a manner which shall--

(A) give due consideration to the public health, safety, and welfare, and

(B) provide that all persons served directly or indirectly by such public utility will be treated, without undue prejudice or disadvantage.

B. 10 C.F.R. § 205.371 – Definition of emergency.

"Emergency," as used herein, is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected "entity" to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities. Actions under this authority are envisioned as meeting a specific inadequate power supply situation. Extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations. In such cases, the impacted "entity" will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed. Situations where a shortage of electric energy is projected due solely to the failure of parties to agree to terms, conditions or other economic factors relating to service, generally will not be considered as emergencies unless the inability to supply electric service is imminent. Where an electricity outage or service inadequacy qualifies for a section 202(c) order, contractual difficulties alone will not be sufficient to preclude the issuance of an emergency order.

C. U.S. Department of Energy, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid (July 7, 2025)

U.S. DEPARTMENT of ENERGY

Resource Adequacy Report

Evaluating the Reliability and Security of the United States Electric Grid

July 2025

Acknowledgments

This report and associated analysis were prepared for DOE purposes to evaluate both the current state of resource adequacy as well as future pressures resulting from the combination of announced retirements and large load growth.

It was developed in collaboration with and with assistance from the Pacific Northwest National Laboratory (PNNL) and National Renewable Energy Laboratory (NREL). We thank the North American Electric Reliability Corporation (NERC) for providing data used in this study, the Telos Corporation for their assistance in interpreting this data, and the U.S Energy Information Administration (EIA) for their dissemination of historical datasets. In addition, thank you to NREL for providing synthetic weather data created by Evolved Energy Research for the Regional Energy Deployment System (ReEDS) model.

DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level. The DOE study team built the methodology and analysis upon the best data that was available. However, entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience.

Historically, the nation's power system planners would have shared electric reliability information with DOE through mechanisms such as EIA-411, which has been discontinued. Thus, one of the key takeaways from this study process is the underscored "call to action" for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our collective economic and national security.

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Report on Evaluating U.S. Grid Reliability and Security

List of Acronyms

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

Report on Evaluating U.S. Grid Reliability and Security

Background to this Report

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

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

Executive Summary

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

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

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

Key Takeaways

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

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

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

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

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

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

Developing a Uniform Methodology

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

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

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

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

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

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

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

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

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

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

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

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

Reliability Standard

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

- **Duration of Outages:** No more than 2.4 hours of lost load in an individual year.[9] This translates into one day of lost load in ten years to meet the 1-in-10 criteria.
- **Magnitude of Outages:** No more than an NUSE of 0.002%.[10] This means that the total amount of energy that cannot be supplied to customers is 0.002% of the total energy demanded in a given year.

Achieving Reliability Standard

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

Key Results Summary

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

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

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

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

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

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

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

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

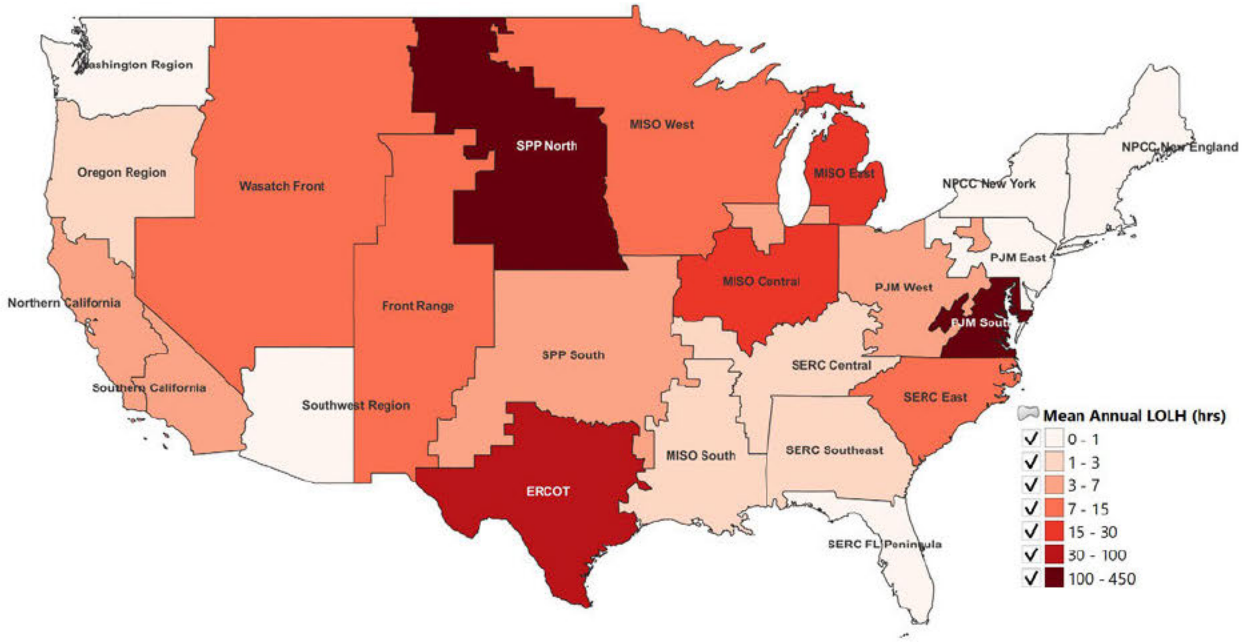


Figure 1. Mean Annual LOLH by Region (2030) – Plant Closures

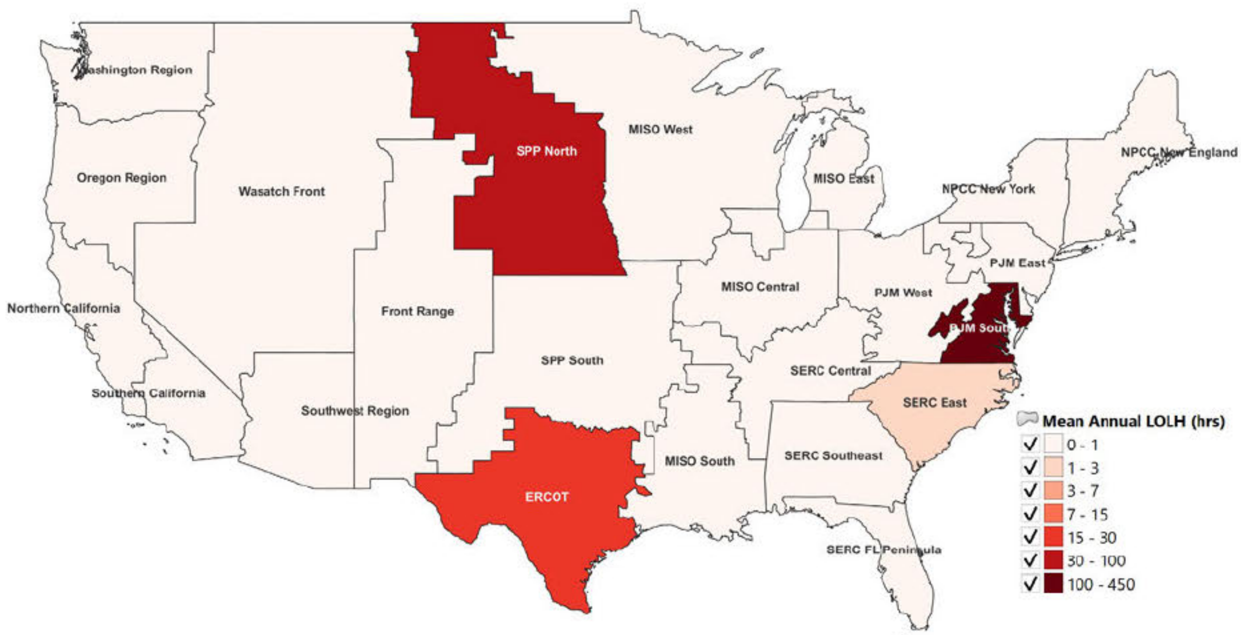


Figure 2. Mean Annual LOLH by Region (2030) – No Plant Closures

Table 1. Summary Metrics Across Cases

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

Current System Analysis

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

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

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

2030 Model Results

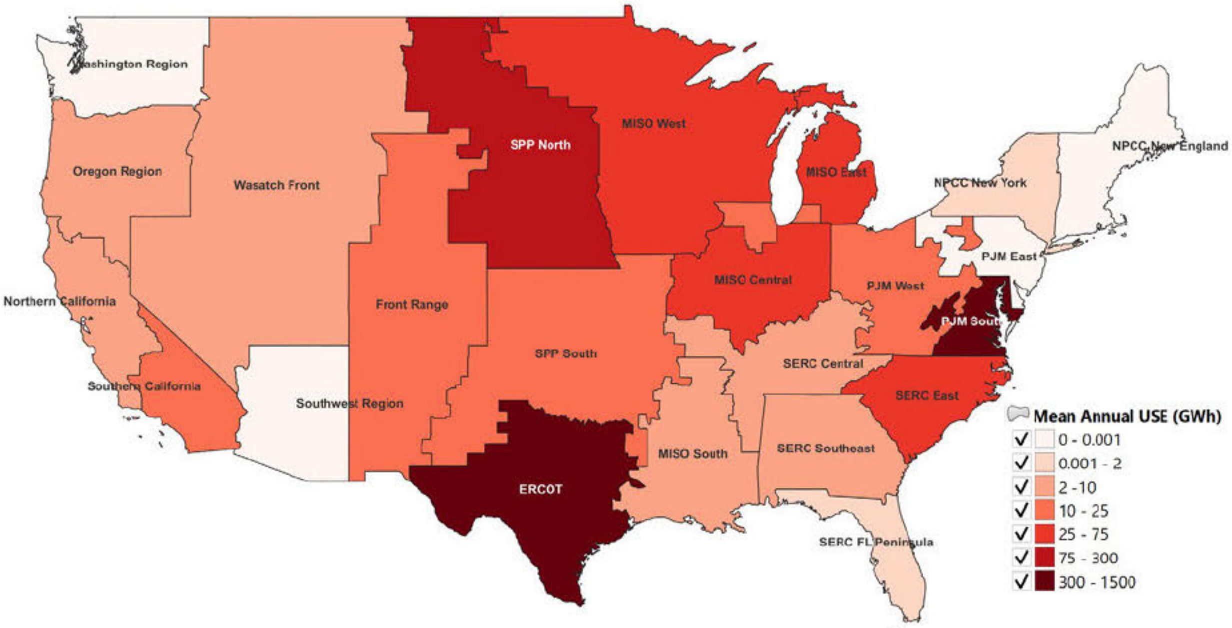


Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures

Key Findings – Plant Closures Case:

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

Key Findings – No Plant Closures Case:

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

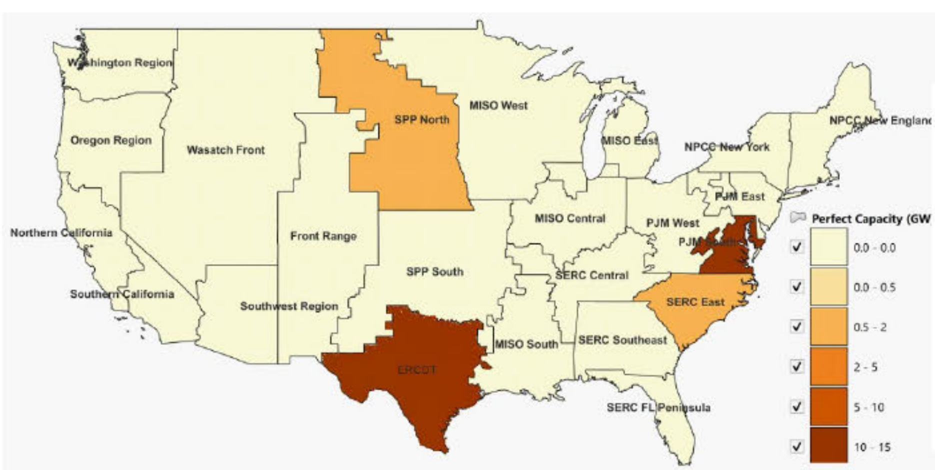
- **PJM**: 214 hours/year average, 0.066% normalized unserved energy, 644 hours in worst year, max 36% of load lost.
- **SPP**: 48 hours/year average, 0.008% normalized unserved energy, max 19% load lost.
- **ERCOT**: 20 average hours, 0.028% normalized unserved energy, 101 max hours/year, peak shortfall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

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

Required Build

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

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



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

Perfect Capacity/Additions

Figure 4. Tuned Perfect Capacity (MW) By Region

1 Modeling Methodology

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

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

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

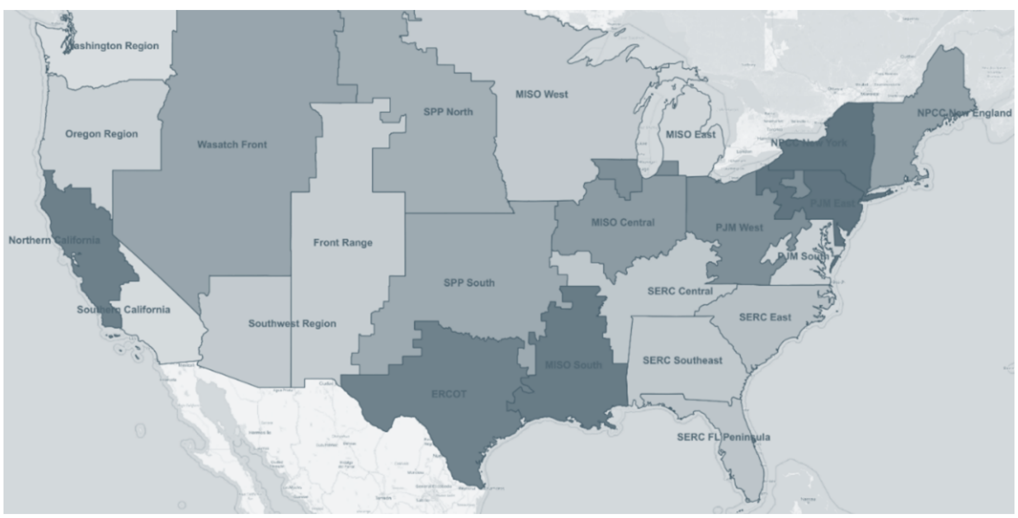


Figure 5. TPRs used in NERC ITCS

13. Energy Exemplar, "PLEXOS," https://www.energyexemplar.com/plexos.
14. The TPRs match the regional subdivisions in the NERC ITCS study, itself based on FERC's transmission planning regions.
15. Transmission within ERCOT is intrastate commerce. 16 U.S.C. § 824(b)(1) (provisions applying to "the transmission of electric energy in interstate commerce").
16. NERC "Integrated Transmission and Capacity System (ITCS)," accessed June 25, 2025, https://www.nerc.com/pa/RAPA/Pages/ITCS.aspx.

This methodology developed a current model and series of scenarios to explore how different assumptions impact resource adequacy. This sensitivity analysis includes assumptions regarding load growth, generation build-outs and retirements, and transfer capabilities. By comparing the results of the current model with the scenario results, we can assess how generation retirements and load growth affect future generation needs.

The assessment uses data from 2007–2013 (synthetic weather data) and 2019–2023 (historical data). A brief summary of the methodological assumptions is provided here, with additional details available in the relevant appendixes.

- **Solar and Wind Availability** – Created from historical output from EIA 930 data, with bias correction of any nonhistorical data to match regional capacity factors, as calibrated to EIA 930 data.[17] Synthetic years used 2018 technology characteristics from NREL based on the Variable Energy Potential (reV) model, then mapped to synthetic weather year data. See Appendix A for more details.

- **Thermal Availability** – Calculated according to NERC LTRA capacity data, adjusted for historical outages and derates, primarily with GADS data. GADS data does not capture historical outages caused by fuel supply interruptions.[18]

- **Hydroelectric Availability** – Historical outputs are processed by NERC to establish monthly power rating limits and energy budgets, but energy budgets are not enforced in alignment with how they were treated in the ITCS. The team evaluated performance under different energy budget restrictions, but did not find significant differences during peak hours, justifying NERC ITCS assumptions that hydroelectric resources could generally be dispatched to peak load conditions. Later work may benefit from exploring drought scenarios or combinations of weather and hydrological years, where energy budgets may be significantly decreased.

- **Outages and Derates** – Data for the actual data period (2019–2023) are based on historical forced outage rates and deratings. Outage and deratings data for the synthetic period (2007–2013) are based on the historical relationships observed between temperature and outages (see Appendix G of the NERC ITCS Final Report for more information).

- **Load Projections and AI Growth** – Load growth through 2030 is assumed to match NERC 2024 ITCS projections, scaling the 12 weather years to meet 2030 projections. Additional AI and data center load is then added according to reports from EPRI and S&P regarding potential futures.

- **Transfer Capabilities and Imports/Exports -** Each subregion is treated as a “copper plate,” with the transfer capacity between each subregion defined by the availability of transmission pathways. It is an approximation that assumes all resources are connected to a single point, simplifying the transmission system within the model. Subregions are generally assumed to exhaust their own capacity before utilizing capacity available from their neighbors. Once the net remaining capacity is at or below 10 percent of load, the subregion begins to use capacity from a neighbor.

17. See ITCS Final Report, Appendix F, for the method that was implemented to scale synthetic weather years 2007–2013.
18. See ITCS Final Report, Appendix G, for outage and derate methods.

- Imports are assumed to be available up to the minimum total transfer capacity and spare generation in the neighboring subregion.

- To the extent the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario, the model projects an energy shortfall. See “Outputs” in the appendix for more details.

- To ensure that transfers are dispatched only after local resources are exhausted, a wheeling charge of $1,000 is applied for every megawatt-hour of energy transferred between regions through transmission pathways.

- **Storage** – In alignment with the NERC ITCS methodology, storage was split into pumped hydro and battery storage. Pumped hydro was assumed to have 12 hours duration at rated capacity with 30% round-trip losses, while battery storage was assumed to have four hours and 13% round-trip losses. Storage is dispatched as an optimization to minimize USE and demand response usage under various constraints and is recharged during periods of surplus energy.
- **Demand Response –** Demand Response (DR) is treated as a supply-side resource and dynamically scheduled after all other regional resources and imports are exhausted. It is modeled with both capacity (MW) and energy (MWh) limitations and assumed to have three hours of availability at capacity but could be spread across more than three hours up to the energy limit. DR capacity was based on LTRA Form A data submissions for “Controllable and Dispatchable Demand Response – Available”, or firm, controllable DR capacity.
- **Retirements** – Retirements as per the NERC LTRA 2024 model. To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant level data are used to tabulate generation retirement or addition capacity for each ITCS region and NERC assessment area. Disaggregation fractions are then calculated by technology based on planned retirements through 2030. See Appendix B for further information. Retirements are categorized into two categories:
  1. *Announced Retirements*: Includes both confirmed retirements and announced retirements. Confirmed retirements are generators formally recognized by system operators as having started the official retirement process and are assumed to retire on their expected date. To go from LTRA regions to ITCS regions, weighting factors are derived in the same way as in the generation set, based on EIA retirement data. In addition to confirmed retirements, announced retirements are generators that have publicly stated retirement plans that have not formally notified system operators and initiated the retirement process. This disaggregation method for announced retirements mirrors used for confirmed retirements.[19]
  2. *None*: Removes all retirements (after 2024) for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirement contributes to some of the adequacy challenges in some regions.

- **Additions** – Assumes only projects that are very mature in the pipeline (such as those with a signed interconnection agreement) will be built. This data is based on projects

19. If announced retirements were less than or equal to confirmed retirements, the model adjusted the announced retirement to equal confirmed.

designated as Tier 1 in the NERC 2024 LTRA and are mapped to ITCS regions with EIA 860-derived weighting factors similar to those described for the retirements above. See Appendix A for further information.

- **Perfect Capacity Required** - Estimates perfect capacity (which is idealized capacity that has no outages or profile and is described in Section 2) until we reach a pre-defined reliability target. We used a metric of NUSE given the deterministic nature of the model, to be consistent with evolving metrics, and to be consistent with NERC's recent LTRAs. We targeted NUSE of below 0.002% for each region.

1.1 Modeling Resource Adequacy

This model calculates several reliability metrics to assess resource adequacy. These metrics were calculated using PLEXOS simulation outputs, which report the USE (in MWh) for all 8,760 hourly periods in each of the 12 weather years:

- **USE** refers to the amount of electricity demand that could not be met due to insufficient generation and/or transmission capacity. Several USE-derived indicators were considered:
  - *Normalized USE (percentage %):* The total amount of unserved load over 12 years of weather data, normalized by dividing by total load, and reported as a percentage.[20]
  - *Mean Annual USE (GWh)*: The 12-year average of each region's total USE in each weather year. This mean value represents the average annual USE across weather variability.
  - *Mean Max Unserved Power (GW)*: The 12-year average of each region's maximum USE value in each weather year. This mean value characterizes the typical non-coincident peak stress on system reliability.
  - *% Max Unserved Power*: The Mean Max Unserved Power expressed as a percentage of the average native load during those peak unserved hours for each region. This percentage value provides a normalized measure of the severity of peak unserved events relative to demand.
  - *Total number of customers without power*. The Mean Max Unserved Power expressed as the equivalent number of typical U.S. persons assuming a ratio of 17,625 persons/MW lost. This estimation contextualizes the effects of the outage on average Americans.
- **Loss of Load Hours (LOLH)** refers to the number of hours during which the system experiences USE (i.e., any hour with non-zero USE). Two LOLH-based indicators were considered:

20. NUSE can be reported as parts per million or as a percentage (or parts per hundred); though for power system reliability, this would include several zeros after the decimal point.

- *Mean Annual LOLH*: for each weather year and *TPR*, we count the total number of hours with USE across all 8,760 hours, and we then take the average of those 12 totals. *Annual LOLH Distribution* is represented in box and whisker plots for 12 samples, each sample corresponding to a unique weather year.

- *Max Consecutive LOLH (hours)*[21]: The longest continuous period with reported USE in each weather year.

It should be noted that USE is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system. Rather, it represents the unrealizable AI and data center load growth under the given assumptions for generator build outs by 2030, generator retirements by 2030, reserve requirements, and potential load growth. These numbers are used as indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need.

This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.

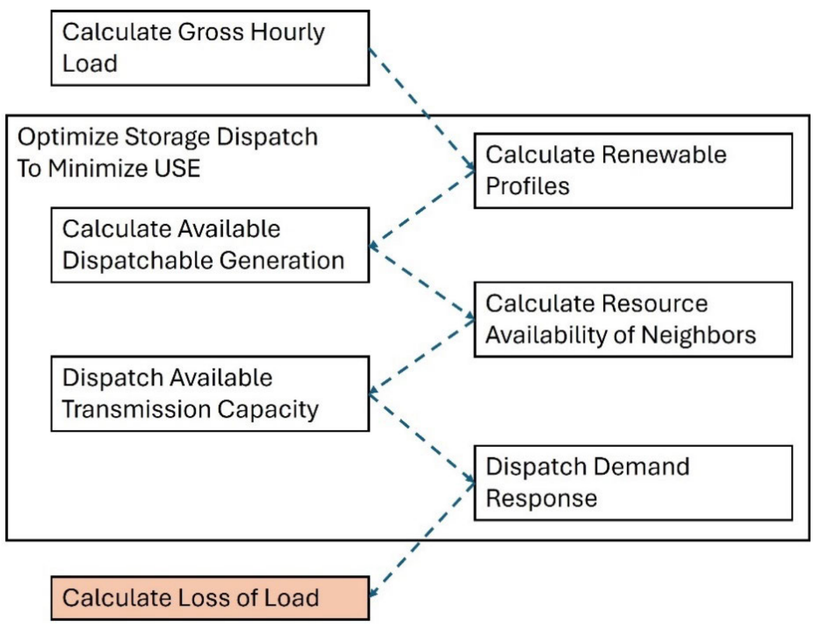


Figure 6. Simplified Overview of Model

21. One caveat on the maximum consecutive LOLH and max USE values is in how storage is dispatched in the model. Storage is dispatched to minimize the overall USE and is indifferent to the peak depth or the duration of the event. This may construe some of the max USE and max consecutive LOLH values to be higher than if storage was dispatched to minimize these values.

1.2 Planning Years and Weather Years

For the planning year (2030), historical weather year data are applied based on conditions between 2007 and 2024 to calculate load, wind and solar generation, and hydro generation. Dispatchable capacity (including dispatchable hydro capacity) is calculated through adjustment of the 2024 LTRA capacity data for historical outages from GADS data. Storage assets are scheduled to arbitrage hourly energy margins or else charge during periods of high energy margins (surplus resources) and discharge during periods of lower energy margins.

1.3 Load Modeling

Data Center Growth

Several utilities and financial and industry analysts identify data centers, particularly those supporting AI workloads, as a key driver of electricity demand growth. Multiple organizations have developed a wide range of projections for U.S. data center electricity use through 2030 and beyond, each using distinct methodologies tailored to their institutional expertise.

These datasets were used to explore reasonable boundaries for what different parts of the economy envision for the future state of AI and data center (AI/DC) load growth. For the purposes of this study, rather than focusing on any specific analysis, a more generic sweep was performed across AI/DC load growth and the various sensitivities that fit within those assumptions, as summarized below:

- McKinsey & Company projects ~10% annual growth in U.S. data center electricity demand, reaching 2,445 TWh by 2050. Their model blends internal scenarios with public signals, including announced projects, capital investment, server shipments, and chip-level power trends, supported by third-party market data.

- Lawrence Berkeley National Laboratory (LBNL) uses a bottom-up approach based on historical and projected IT equipment shipments, paired with assumptions on power draw, utilization, and infrastructure efficiency (PUE, WUE). Their projections through 2028 account for AI hardware adoption, operational shifts, and evolving cooling technologies.

- EPRI combines public data, expert input, and historical trends to define four national growth scenarios, low to higher, for 2023–2030, reflecting data processing demand, efficiency improvements, and AI-driven load impacts.

- S&P Global merges technology and power-sector models, evaluating grid readiness and facility growth under varying demand scenarios. Their forecasts consider AI adoption, efficiency trends, grid and permitting constraints, on-site generation, and offshoring risk, resulting in a wide range of outcomes.

These projections show wide variation, with 2030 electricity demand ranging from approximately 35 GW to 108 GW of average load. Given this uncertainty, including differences in hardware intensity, thermal management, siting assumptions, and behind-the-meter generation, the modeling team adopted a national midpoint assumption of approximately 50 GW by 2030.

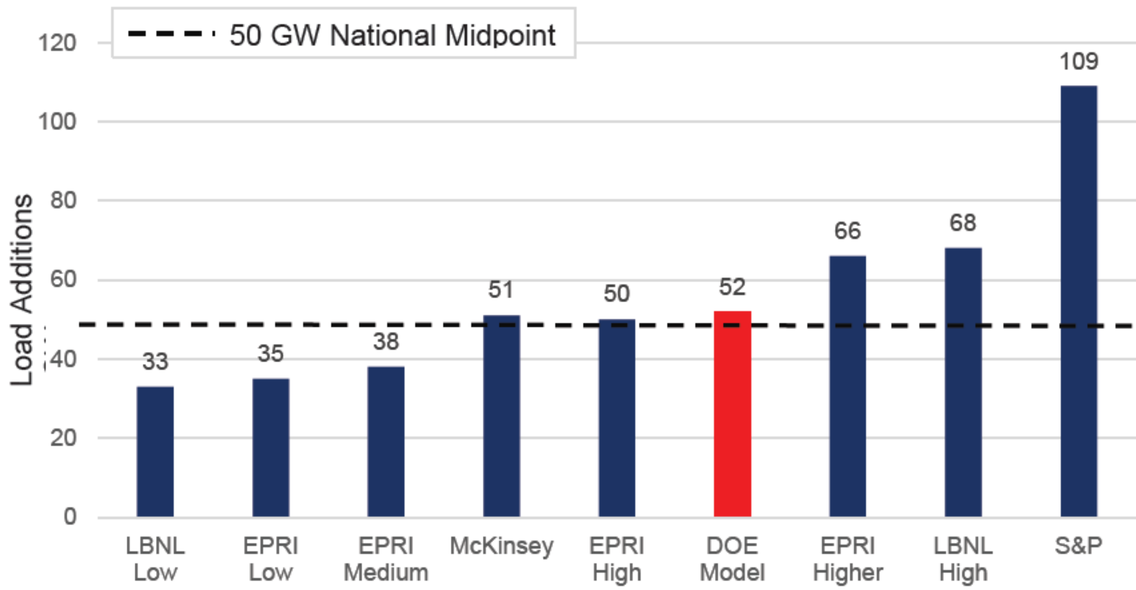


Figure 7. 2024 to 2030 Projected Data Center Load Additions

Figure 2 above displays a benchmark reflecting the median across major studies and aligns with central projections from EPRI and LBNL. Using a single planning midpoint avoids double counting and enables consistent load allocation across national transmission and resource adequacy models.

Data Center Allocation Method

To allocate the 50 GW midpoint regionally, the team used state-level growth ratios from S&P's forecast. These ratios reflect factors such as infrastructure, siting trends, and projected market activity. The modeling team mapped the state-level projections to NERC TPRs, ensuring transparent and repeatable regional allocation. While other methods exist, this approach ensured consistency with the broader modeling framework.

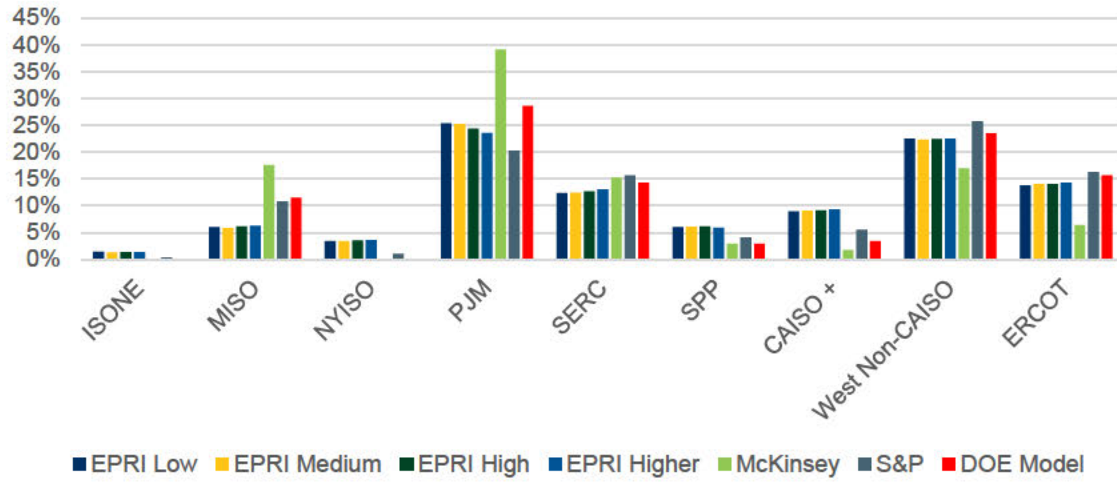


Figure 8. New Data Center Build (% Split by ISO/RTO) (2030 Estimated)

Non-Data Center Load Modeling

The current electricity demand projections were built from NERC data, using historical load (2019–2023) and simulated weather years (2007–2013). These were adjusted based on the EIA's 2022 energy forecast. To estimate 2030 demand, the team interpolated between 2024 and 2033, scaling loads to reflect energy use and seasonal peaks. NERC provided datasets to address anomalies and include behind-the-meter and USE.

Given the rapid emergence of AI/DC loads, additional steps were taken to account for this category of demand. It is difficult to determine how much AI/DC load is already embedded in NERC LTRA forecast, for example, the 2024 LTRA saw more than 50GW increase from 2023, signaling a major shift in utility expectations. To benchmark existing AI/DC contribution, DOE assumed base 2023 AI/DC load equaled the EPRI low-growth case of 166 TWh.

Overall Impact on Projected Peak Load

As a result of the methods applied above, the average year co-incident peak load is projected to grow from a current average peak of 774 GW to 889 GW in 2030. This represents a 15% increase or 2.3% growth rate per year. Excluding the impact of data centers, this would amount to a 51GW increase from 774 GW to 826 GW which represents a 1.1% annual growth rate.

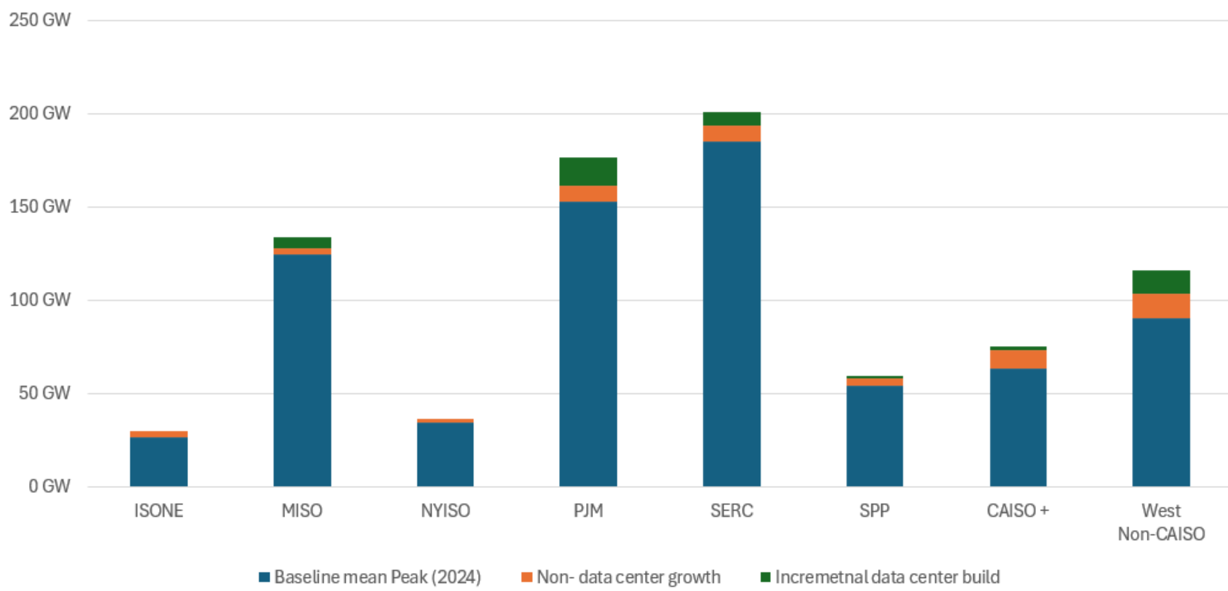


Figure 9. Mean Peak Load by RTO (Current Case vs 2030 Case)

1.4 Transfer Capabilities and Import Export Modeling

The methodology assumes electricity moves between subregions, when conditions start to tighten. Each region has a certain amount of capacity available, and the methodology determines if there is enough to meet the demand. When regions reach a "Tight Margin Level" of 10% of capacity, i.e., if a region's available capacity is less than 110% of load, it will start transferring from other regions if capacity is available. A scarcity factor is used to determine which regions to transfer from and at what fraction – those with a greater amount of reserve capacity will transfer more. A region is only allowed to export above when it is above the Tight Margin Level.

Total Transfer Capability (TTC) was used and is the sum of the Base Transfer Level and the First Contingency Incremental Transfer Capability. These were derived from scheduled interchange tables or approximated from actual line flows. It should be noted that the TTC does not represent a single line, but rather multiple connections between regions. It is similar to path limits used by many entities but may have different values.

Due to data and privacy limitations, the Canadian power system was not modeled directly as a combination of generation capacity and demand. Instead, actual hourly imports were used from nearly 20 years of historical data, along with recent trends (generally less transfers available during peak hours), to develop daily limits on transfer capabilities. See Appendix B for more details on Canadian transfer limits.

1.5 Perfect Capacity Additions

To understand how much capacity may need to be added to reach approximate reliability targets, we tuned two scenarios by adding hypothetical perfect capacity to reach the reliability threshold based on NUSE.[22] Today, NERC uses a threshold of 0.002% to indicate regions are at high risk of resource adequacy shortfalls. In addition, several system operators, including the Australia Energy Market Operator and Alberta Electric System Operator, are using NUSE thresholds in the range of 0.001% to 0.003%. Several U.S. entities are considering lower thresholds for U.S. power systems in the range of 0.0001% to 0.0002%. [23]

For this analysis, we target NUSE below 0.002% for each region to align with NERC definitions. We iteratively ran the model, hand-tuning the "perfect capacity" to be as small as possible while reaching NUSE values below 0.002% in all regions.[24] As the work was done by hand with a limited number of iterations (15), this should not be considered the minimum possible capacity to accomplish these targets. Further, because the perfect capacity can be located in various places, there would be multiple potential solutions to the problem. These scenarios represent the approximate quantity of perfect capacity each region would require (beyond announced retirements and mature generation additions only) that would lead to Medium or Low risk based on the NERC metrics for USE.

Due to some regions with zero USE, the tuned cases do not reach the same level of adequacy, where the national average is 0.00045% vs. 0.00013%. Due to transmission and siting selection of perfect capacity, there could be many solutions.

22. We are not using the standard term "expected unserved energy" because we are not running a probabilistic model, so we do not have the full understanding of long-term expectations

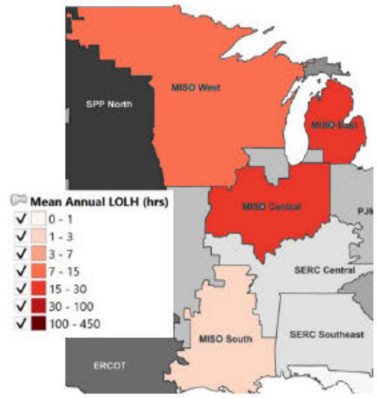
23. MISO, "Resource Adequacy Metrics and Criteria Roadmap," December 2024. https://cdn.misoenergy.org/Resource%20Adequacy%20Metrics%20and%20Criteria%20Roadmap667168.pdf.

24. NERC, "Evolving Criteria for a Sustainable Power Grid," July 2024. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Evolving_Planning_Criteria_for_a_Sustainable_Power_Grid.pdf.

2 Regional Analysis

This section presents more regional details on resource adequacy according to this analysis. For each of the nine Regional Transmission Organizations (RTOs) and sub-regions, comprehensive summaries are provided of reliability metrics, load assumptions, and composition of generation stacks.

2.1 MISO[25]



In the current system model and the No Plant Closures cases, MISO did not experience shortfall events. MISO's minimum spare capacity in the tightest year was negative, showing that adequacy was achieved by importing power from neighbors. In the Plant Closures case, MISO experienced significant shortfalls, with key reliability metrics exceeding each of the threshold criteria defined for the study.

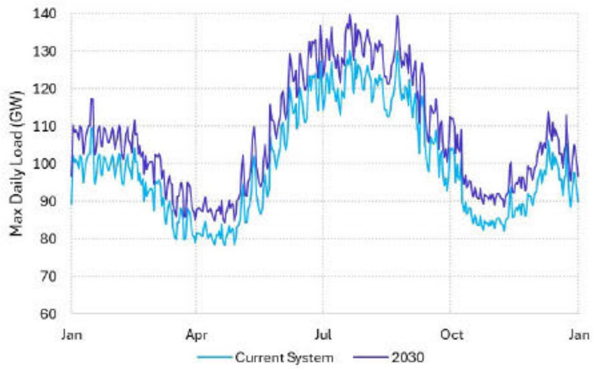
Table 2. Summary of MISO Reliability Metrics

Reliability Metric	Current System	2030 Projection		
		Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	37.8	-	-
Normalized Unserved Energy (%)	-	0.0211	-	-
Unserved Load (MWh)	-	157,599	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	124	-	-
Normalized Unserved Load (%)	-	0.0702	-	-
Unserved Load (MWh)	-	524,180	-	-

Load Assumptions

MISO's peak load was roughly 130 GW in the current model and projected to increase to roughly 140 GW by 2030. Approximately 6 GW of this relates to new data centers being installed (12% of U.S. total).

25. Following the initial data collection for this report, MISO issued its 2025 Summer Reliability Assessment. Based on that report, NERC revised evaluations from its 2024 LTRA and reclassified the MISO footprint from being an 'elevated risk' to 'high risk' in the 2028–2031 timeframe, depending on new resource additions/retirements. While DOE's analysis is based on the previously reported figures, DOE is committed to assessing the implications of updated data on overall resource adequacy and providing technical updates on findings, as appropriate.



Subregion	2024	2030
MISO-W	37,913	40,981
MISO-C	35,387	39,243
MISO-S	36,476	38,596
MISO-E	23,167	23,758
Total	130,136	139,846

Figure 10. MISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 207 GW.[26] In 2030, 21 GW of new capacity was added leading to 228 GW of capacity in the No Plant Closures case. In the Plant Closures case, 32 GW of capacity was retired such that net retirements in the Plant Closures case were -11 GW, or 196 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
MISO-W	71,612	67,453	77,605
MISO-C	51,982	47,735	58,823
MISO-S	54,511	52,756	59,710
MISO-E	29,213	28,105	32,255
Total	207,319	196,049	228,393

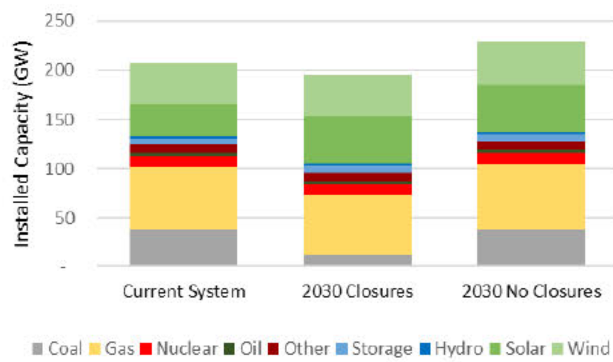


Figure 11. MISO Generation Capacity by Technology and Scenario

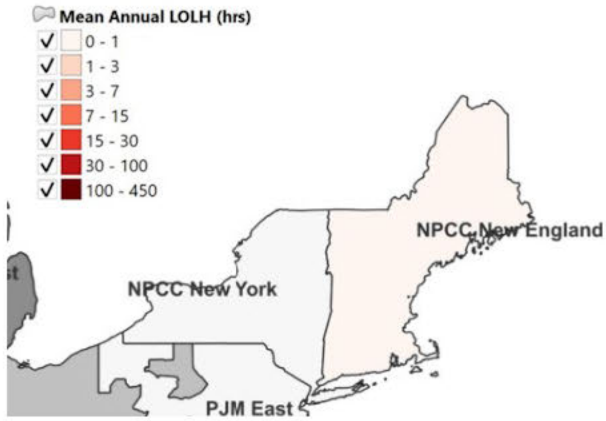
MISO's generation mix was comprised primarily of natural gas, coal, wind, and solar. In 2024, natural gas comprised 31% of nameplate, wind comprised 20%, coal 18%, and solar 14%. In 2030, most retirements come from coal and natural gas while additions occur for solar, batteries, and wind. In addition, the model assumed 3 GW of rooftop solar and 8 GW of demand response.

26. The total installed capacity numbers reported in this regional analysis section do not reflect the generating capability of all resources during stress conditions.

Table 3. Nameplate Capacity by MISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**37,914**	**64,194**	**11,127**	**2,867**	**8,717**	**5,427**	**2,533**	**32,826**	**41,715**	**207,319**
MISO-W	12,651	13,608	2,753	1,491	2,613	200	777	8,109	29,411	**71,612**
MISO-C	15,050	10,307	2,169	494	2,211	1,272	769	12,361	7,350	**51,982**
MISO-S	5,493	31,052	5,100	589	2,469	54	845	8,315	596	**54,511**
MISO-E	4,720	9,227	1,105	292	1,424	3,901	143	4,042	4,359	**29,213**
Additions	**0**	**2,535**	**0**	**330**	**0**	**1,929**	**0**	**14,354**	**1,926**	**21,074**
MISO-W	0	537	0	172	0	374	0	3,552	1,358	**5,993**
MISO-C	0	407	0	57	0	934	0	5,103	339	**6,841**
MISO-S	0	1,226	0	68	0	9	0	3,868	27	**5,199**
MISO-E	0	364	0	34	0	611	0	1,831	201	**3,042**
Closures	**(24,913)**	**(6,597)**	**0**	**(324)**	**(140)**	**(16)**	**(83)**	**0**	**(272)**	**(32,345)**
MISO-W	(8,313)	(1,398)	0	(168)	(56)	0	(25)	0	(192)	**(10,152)**
MISO-C	(9,889)	(1,059)	0	(56)	(7)	(3)	(25)	0	(48)	**(11,088)**
MISO-S	(3,609)	(3,191)	0	(67)	(55)	(0)	(28)	0	(4)	**(6,954)**
MISO-E	(3,102)	(948)	0	(33)	(21)	(13)	(5)	0	(28)	**(4,150)**

2.2 ISO-NE



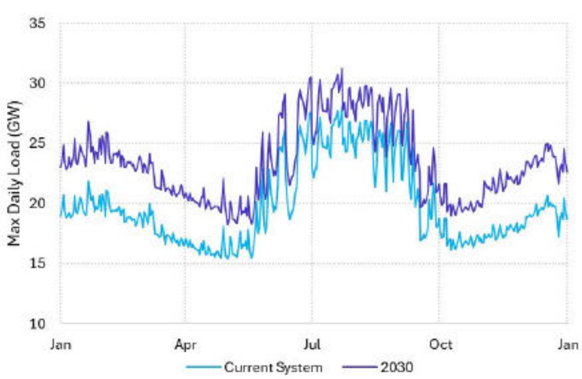
In the current system model and the No Plant Closures case, ISO-NE did not experience shortfall events. The region maintained adequacy throughout the study period through reliance on imports. In the Plant Closures case, ISO-NE still did not exceed any key reliability thresholds, despite moderate retirements. This finding is partly due to the absence of additional AI or data center load growth modeled in the region. Accordingly, no additional perfect capacity was deemed necessary by 2030 to meet the study's reliability standards.

Table 4. Summary of ISO-NE Reliability Metrics

Reliability Metric	Current System	2030 Projection Plant Closures	2030 Projection No Plant Closures	2030 Projection Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	-	-	-
Normalized Unserved Energy (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	-	-	-
Normalized Unserved Load (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
Max Unserved Load (MW)	-	-	-	-

Load Assumptions

ISO-NE's peak load was roughly 28 GW in the current model and projected to increase to roughly 31 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
ISO-NE	28,128	31,261
Total	28,128	31,261

Figure 12. ISO-NE Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 40 GW. In 2030, 5.5 GW of new capacity was added leading to 45.5 GW of capacity in the No Plant Closures case. In the Plant Closures case, 2.7 GW of capacity was retired such that net generation change in the Plant Closures case was +11 GW, or 42.8 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ISO-NE	39,979	42,845	45,534
Total	**39,979**	**42,845**	**45,534**

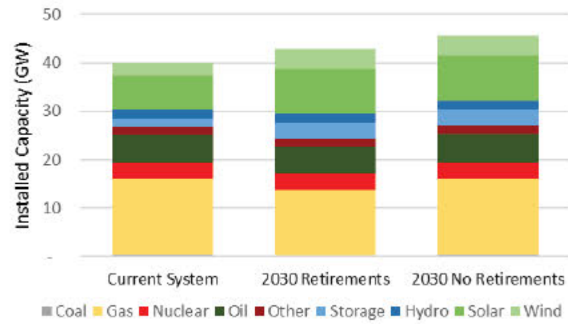


Figure 13. ISO-NE Generation Capacity by Technology and Scenario

ISO-NE's generation mix was comprised primarily of natural gas, solar, oil, and nuclear. In 2024, natural gas comprised 39% of nameplate, solar comprised 17%, oil 14%, and nuclear 8%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed nearly 2 GW of rooftop solar and 1.6 GW of energy storage.

Table 5. Nameplate Capacity by ISO-NE Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**541**	**15,494**	**3,331**	**5,710**	**1,712**	**1,628**	**1,911**	**7,099**	**2,553**	**39,979**
ISONE	541	15,494	3,331	5,710	1,712	1,628	1,911	7,099	2,553	**39,979**
Additions	**0**	**90**	**0**	**181**	**0**	**1,607**	**0**	**2,183**	**1,495**	**5,555**
ISONE	0	90	0	181	0	1,607	0	2,183	1,495	**5,555**
Closures	**(534)**	**(1,875)**	**0**	**(203)**	**(77)**	**0**	**0**	**0**	**0**	**(2,690)**
ISONE	(534)	(1,875)	0	(203)	(77)	0	0	0	0	**(2,690)**

2.3 NYISO

In both the current system model and the No Plant Closures case, NYISO maintained reliability and did not exceed any shortfall thresholds. Adequacy was preserved through reliance on imports. In the Plant Closures case, NYISO experienced shortfalls but average annual LOLH remaining well below the 2.4-hour threshold and NUSE under the 0.002% standard. The worst weather year produced only 6 hours of lost load and a peak unserved load of 914 MW. Given the modest impact of retirements and no additional AI/data center load modeled, the study concluded that NYISO would not require additional perfect capacity to remain reliable through 2030.

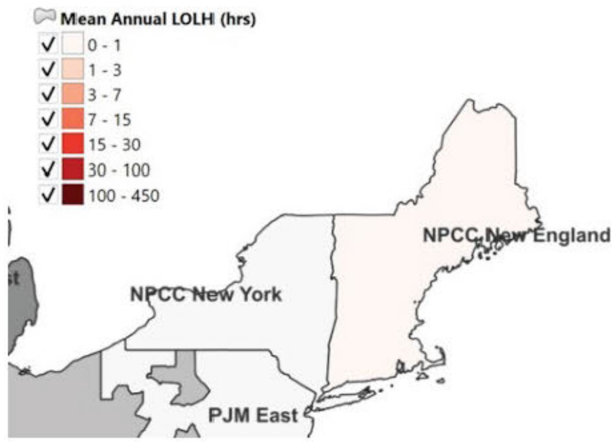
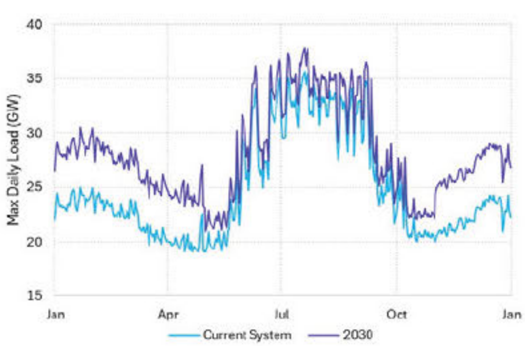


Table 6. Summary of NYISO Reliability Metrics

Reliability Metric	Current System	2030 Projection Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.2	0.5	-	-
Normalized Unserved Energy (%)	0.00001	0.0001	-	-
Unserved Load (MWh)	18	209	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	2	6	-	-
Normalized Unserved Load (%)	0.0001	0.0013	-	-
Unserved Load (MWh)	216	2,505	-	-
Max Unserved Load (MW)	194	914	-	-

Load Assumptions

NYISO's peak load was roughly 36 GW in the current system model and projected to increase to roughly 38 GW by 2030. No additional AI/DCs were projected to be installed.



Subregion	2024	2030
NYISO	35,669	37,844
Total	35,669	37,844

Figure 14. NYISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 46 GW. In 2030, 5.5 GW of new capacity was added leading to 51 GW of capacity in the No Plant Closures case. In the Plant Closures case, 1 GW of capacity was retired such that net generation in the Plant Closures case was +4 GW, or 50 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
NYISO	45,924	50,396	51,444
Total	**45,924**	**50,396**	**51,444**

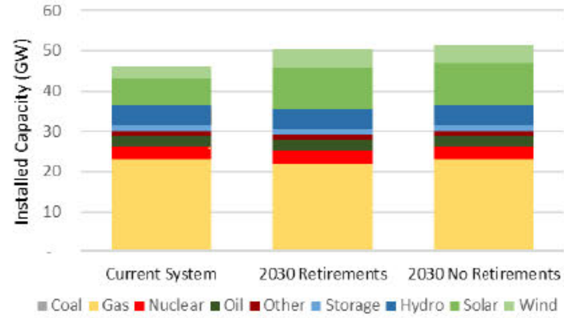


Figure 15. NYISO Generation Capacity by Technology and Scenario

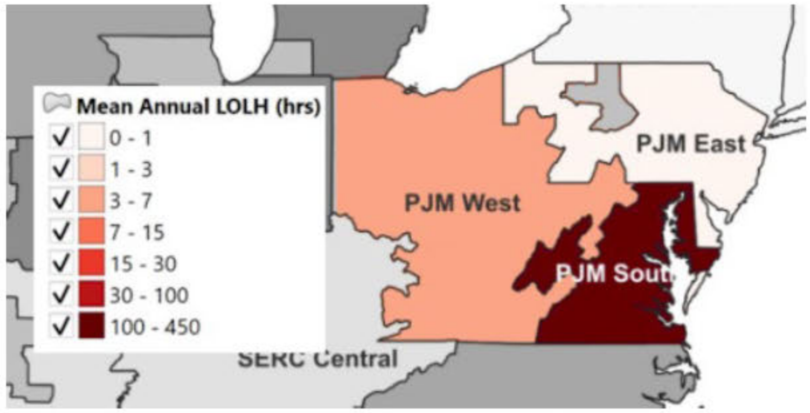
NYISO's generation mix was comprised primarily of natural gas, solar, and hydro. In 2024, natural gas comprised 50% of total nameplate generation, solar comprised 14%, and hydro 11%. In 2030, most retirements come from natural gas while additions occur for solar and wind. The model assumed 6 GW of rooftop solar and nearly 1 GW of demand response.

Table 7. Nameplate Capacity by NYISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**0**	**22,937**	**3,330**	**2,631**	**1,194**	**1,460**	**4,915**	**6,749**	**2,706**	**45,924**
NYISO	0	22,937	3,330	2,631	1,194	1,460	4,915	6,749	2,706	**45,924**
Additions	**0**	**0**	**0**	**15**	**0**	**0**	**0**	**3,604**	**1,902**	**5,521**
NYISO	0	0	0	15	0	0	0	3,604	1,902	**5,521**
Closures	**0**	**(1,030)**	**0**	**(19)**	**0**	**0**	**0**	**0**	**0**	**(1,049)**
NYISO	0	(1,030)	0	(19)	0	0	0	0	0	**(1,049)**

ADD40

2.4 PJM



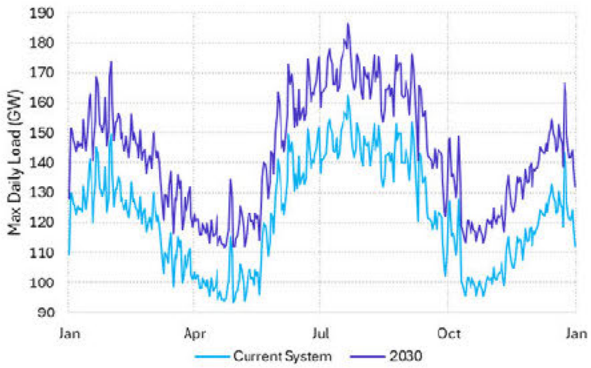
In the current system model, PJM experienced shortfalls, but they were below the required threshold. In the No Plant Closures case, shortfalls increased dramatically, with 214 average annual LOLH and peak unserved load reaching 17,620 MW, indicating growing strain even without retirements. In the Plant Closures case, reliability metrics worsened significantly, with annual LOLH surging to over 430 hours per year and NUSE reaching 0.1473%—over 70 times the accepted threshold. During the worst weather year, 1,052 hours of load were shed. To restore reliability, the study found that PJM would require 10,500 MW of additional perfect capacity by 2030.

Table 8. Summary of PJM Reliability Metrics

Reliability Metric	Current System	2030 Projection Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	2.4	430.3	213.7	1.4
Normalized Unserved Energy (%)	0.0008	0.1473	0.0657	0.0003
Unserved Load (MWh)	6,891	1,453,513	647,893	2,536
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	29	1,052	644	17
Normalized Unserved Load (%)	0.0100	0.4580	0.2703	0.0031
Unserved Load (MWh)	82,687	1,453,513	647,893	2,536
Max Unserved Load (MW)	4,975	21,335	17,620	4,162

Load Assumptions

PJM's peak load was roughly 162 GW in the current system model and projected to increase to roughly 187 GW by 2030. Approximately 15 GW of this relates to new AI/DC being installed (29% of U.S. total), primarily in PJM-S.



Subregion	2024	2030
PJM-W	81,541	92,378
PJM-S	39,904	51,151
PJM-E	41,003	43,118
Total	162,269	186,627

Figure 16. PJM Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 215 GW. In 2030, 39 GW of new capacity was added leading to 254 GW of capacity in the No Plant Closures case. In the Plant Closures case, 17 GW of capacity was retired such that net generation in the Plant Closures case was +22 GW, or 237 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
PJM-W	114,467	123,100	135,810
PJM-S	39,951	48,850	50,667
PJM-E	60,221	64,848	67,027
Total	214,638	236,798	253,504

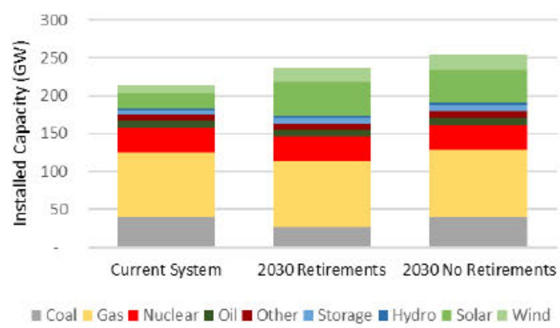


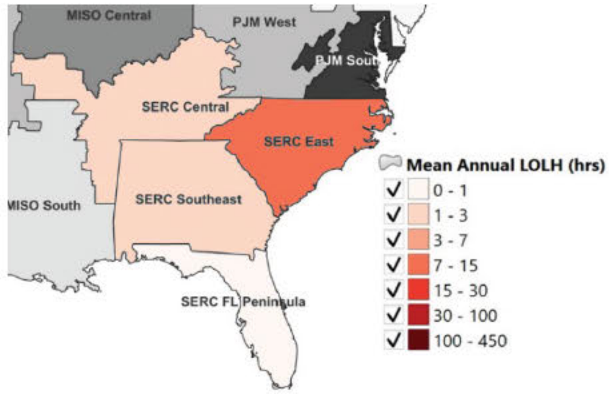
Figure 17. PJM Generation Capacity by Technology and Scenario

PJM's generation mix was comprised primarily of natural gas, coal, and nuclear. In 2024, natural gas comprised 39% of nameplate, coal comprised 19%, and nuclear 15%. In 2030, most retirements come from coal and some natural gas and oil while significant additions occur for solar plus lesser additions of wind, storage, and natural gas. The model assumed 9 GW of rooftop solar and 7 GW of demand response.

Table 9. Nameplate Capacity by PJM Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**39,915**	**84,381**	**32,535**	**9,875**	**8,248**	**5,400**	**3,071**	**19,495**	**11,718**	**214,638**
PJM-W	34,917	39,056	16,557	1,933	3,926	383	1,252	6,379	10,065	**114,467**
PJM-S	2,391	15,038	5,288	3,985	2,303	3,085	1,070	6,430	360	**39,951**
PJM-E	2,608	30,287	10,690	3,956	2,019	1,932	749	6,686	1,294	**60,221**
Additions	**0**	**4,499**	**0**	**32**	**317**	**1,938**	**0**	**24,991**	**7,089**	**38,866**
PJM-W	0	2,082	0	6	135	855	0	12,176	6,089	**21,343**
PJM-S	0	802	0	13	102	726	0	8,856	218	**10,717**
PJM-E	0	1,615	0	13	81	357	0	3,958	783	**6,806**
Closures	**(13,253)**	**(1,652)**	**0**	**(1,790)**	**(11)**	**0**	**0**	**0**	**0**	**(16,706)**
PJM-W	(11,593)	(765)	0	(350)	(1)	0	0	0	0	**(12,710)**
PJM-S	(794)	(294)	0	(722)	(6)	0	0	0	0	**(1,817)**
PJM-E	(866)	(593)	0	(717)	(3)	0	0	0	0	**(2,179)**

2.5 SERC



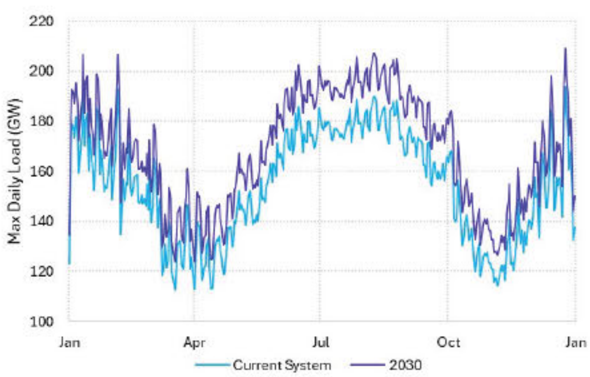
In the current system model and the No Plant Closures case, SERC maintained overall adequacy, though some subregions—particularly SERC-East—faced emerging winter reliability risks. In the Plant Closures case, shortfalls became more severe, with SERC-East experiencing increased unserved energy and loss of load hours during extreme cold events, including 42 hours of outages in a single winter storm. The analysis identified that planned retirements, combined with rising winter load from electrification, would stress the system. To restore reliability in SERC-East, the study found that 500 MW of additional perfect capacity would be needed by 2030. Other SERC subregions performed adequately, but continued monitoring is warranted due to shifting seasonal peaks and fuel supply vulnerabilities.

Table 10. Summary of SERC Reliability Metrics

Reliability Metric	Current System	2030 Projection Plant Closures	2030 Projection No Plant Closures	2030 Projection Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.3	8.1	1.2	0.8
Normalized Unserved Energy (%)	0.0001	0.0041	0.0004	0.0002
Unserved Load (MWh)	489	44,514	3,748	2,373
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	4	42	14	10
Normalized Unserved Load (%)	0.0006	0.0428	0.0042	0.0026
Unserved Load (MWh)	5,683	465,392	44,977	2,373
Max Unserved Load (MW)	2,373	19,381	6,359	5,859

Load Assumptions

SERC's peak load was roughly 193 GW in the current system model and projected to increase to roughly 209 GW by 2030. Approximately 7.5 GW of this relates to new AI/DCs being installed (14% of U.S. total).



Subregion	2024	2030
SERC-C	50,787	52,153
SERC-SE	48,235	54,174
SERC-FL	58,882	62,572
SERC-E	51,693	56,313
Total	193,654	209,269

Figure 18. SERC Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 254 GW. In 2030, 26 GW of new capacity was added leading to 279 GW of capacity in the No Plant Closures case. In the Plant Closures case, 19 GW of capacity was retired such that net generation change in the Plant Closures case was +7 GW, or 260 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SERC-C	53,978	54,014	59,660
SERC-SE	67,073	64,768	69,478
SERC-FL	72,714	83,127	86,173
SERC-E	59,914	58,513	63,973
Total	**253,680**	**260,423**	**279,285**

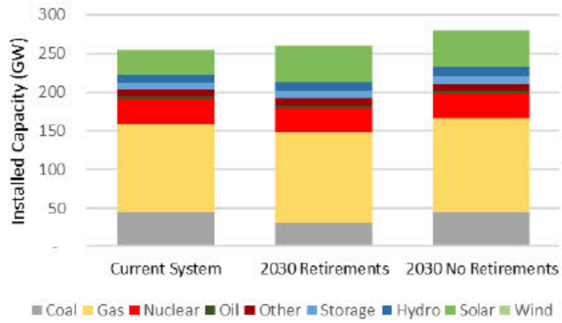


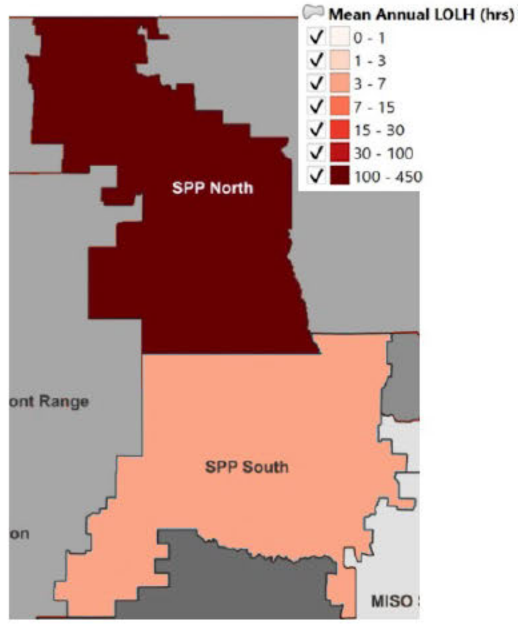
Figure 19. SERC Generation Capacity by Technology and Scenario

SERC's generation mix was comprised primarily of natural gas, coal, nuclear, and solar. In 2024, natural gas comprised 45% of nameplate, coal comprised 18%, nuclear 12%, and solar 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar and some storage. The model assumed 3 GW of rooftop solar and 8 GW of demand response.

Table 11. Nameplate Capacity by SERC Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	**45,747**	**113,334**	**31,702**	**4,063**	**8,779**	**7,469**	**11,425**	**30,180**	**982**	**253,680**
SERC-C	13,348	20,127	8,280	148	1,887	1,884	4,995	2,328	982	**53,978**
SERC-SE	13,275	29,866	8,018	915	2,493	1,662	3,260	7,584	0	**67,073**
SERC-FL	4,346	47,002	3,502	1,957	3,198	538	0	12,172	0	**72,714**
SERC-E	14,777	16,340	11,902	1,044	1,202	3,384	3,170	8,096	0	**59,914**
Additions	**0**	**6,898**	**0**	**0**	**381**	**2,254**	**0**	**16,073**	**0**	**25,606**
SERC-C	0	4,831	0	0	0	80	0	771	0	**5,682**
SERC-SE	0	906	0	0	19	0	0	3,135	0	**4,059**
SERC-FL	0	1,161	0	0	218	1,670	0	10,410	0	**13,459**
SERC-E	0	0	0	0	144	504	0	1,757	0	**2,405**
Closures	**(14,075)**	**(4,115)**	**0**	**(672)**	**0**	**0**	**0**	**0**	**0**	**(18,862)**
SERC-C	(4,465)	(1,181)	0	0	0	0	0	0	0	**(5,646)**
SERC-SE	(5,160)	(124)	0	(176)	0	0	0	0	0	**(5,460)**
SERC-FL	(1,495)	(1,071)	0	(480)	0	0	0	0	0	**(3,046)**
SERC-E	(2,955)	(1,739)	0	(16)	0	0	0	0	0	**(4,710)**

2.6 SPP



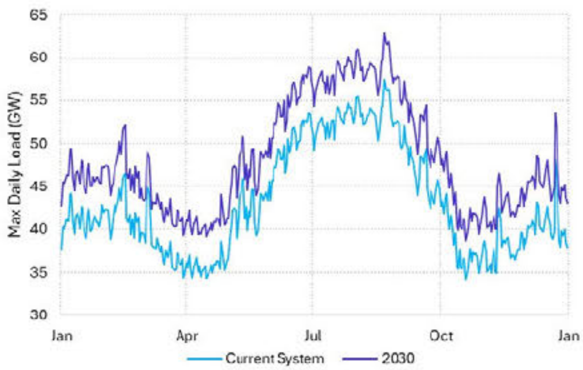
In the current system model, SPP experienced shortfalls, but they were below the required threshold. Adequacy was preserved through reliance on imports. In the No Plant Closures case, SPP experienced persistent reliability challenges, with average annual LOLH reaching approximately 48 hours per year and peak hourly shortfalls affecting up to 19% of demand. In the Plant Closures case, system conditions deteriorated further, with unserved energy and outage hours increasing substantially. These shortfalls were concentrated in the northern subregion, which lacks the firm generation and import capacity needed to meet peak winter demand. The analysis determined that 1,500 MW of additional perfect capacity would be needed in SPP by 2030 to restore reliability.

Table 12. Summary of SPP Reliability Metrics

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

Load Assumptions

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



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

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

Generation Stack

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

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

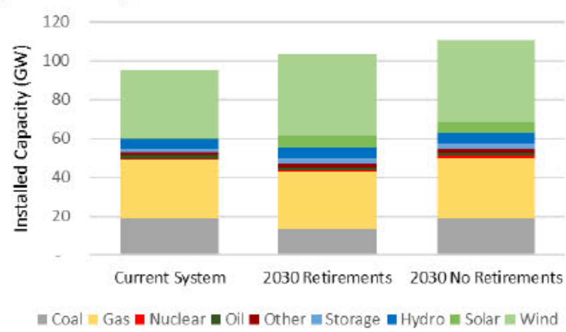


Figure 21. SPP Generation Capacity by Technology and Scenario

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

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

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

2.7 CAISO+

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

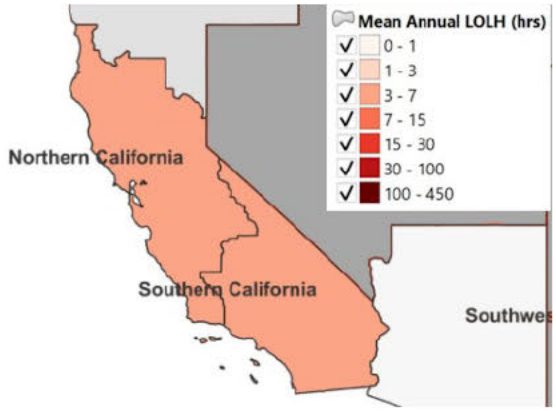
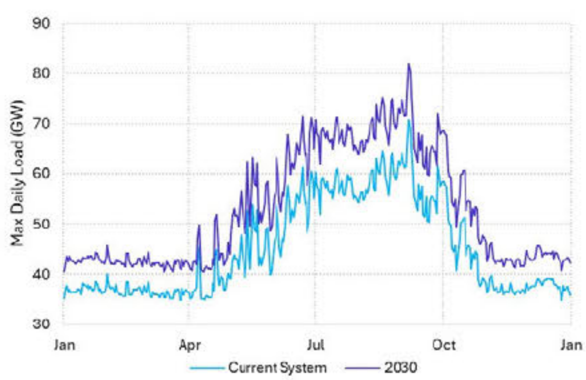


Table 14. Summary of CAISO+ Reliability Metrics

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

Load Assumptions

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



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

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

Generation Stack

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

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

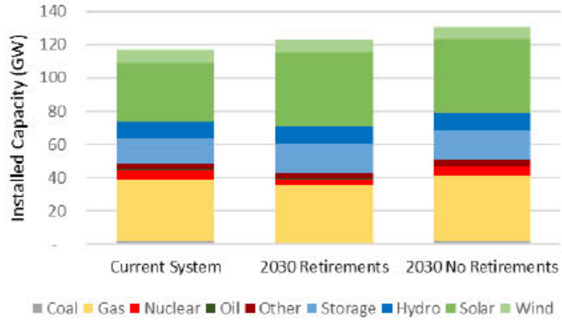


Figure 23. CAISO+ Generation Capacity by Technology and Scenario

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

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

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

2.8 West Non-CAISO

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

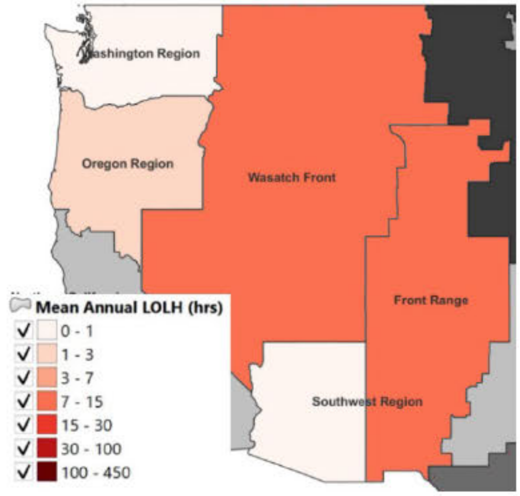
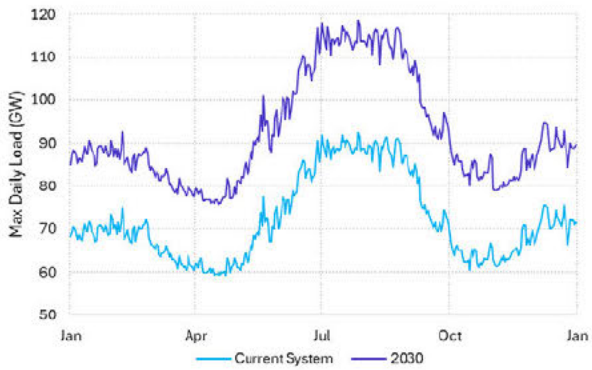


Table 16. Summary of West Non-CAISO Reliability Metrics

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

Load Assumptions

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



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

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

Generation Stack

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

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

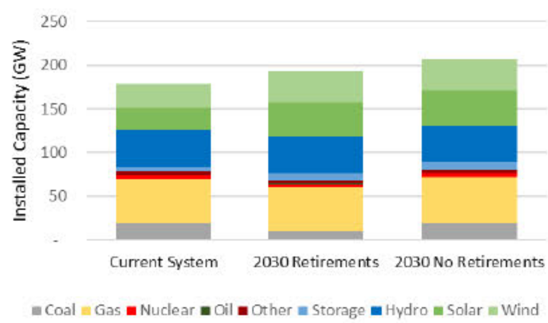


Figure 25. West Non-CAISO Generation Capacity by Technology and Scenario

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

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

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

2.9 ERCOT

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

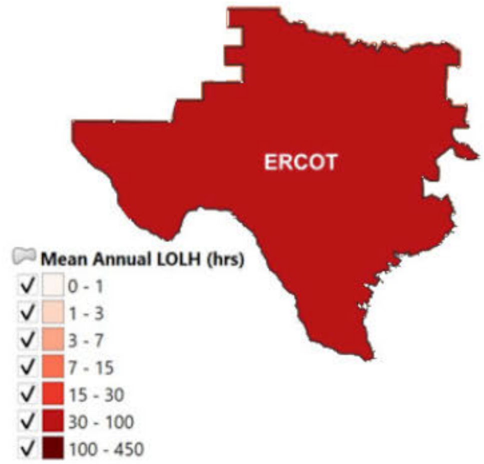
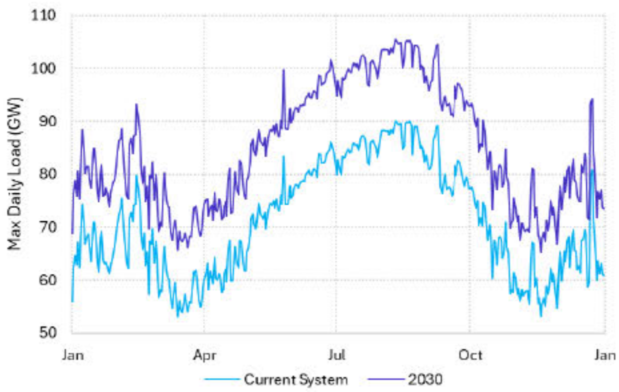


Table 18. Summary of ERCOT Reliability Metrics

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

Load Assumptions

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



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

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

Generation Stack

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

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

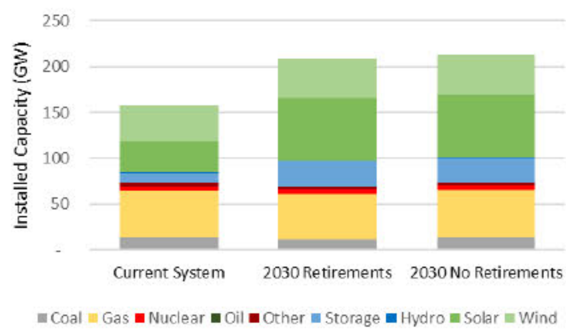


Figure 27. ERCOT Generation Capacity by Technology and Scenario

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

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

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

Appendix A - Generation Calibration and Forecast

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

2024 Resource Mix

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

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

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

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

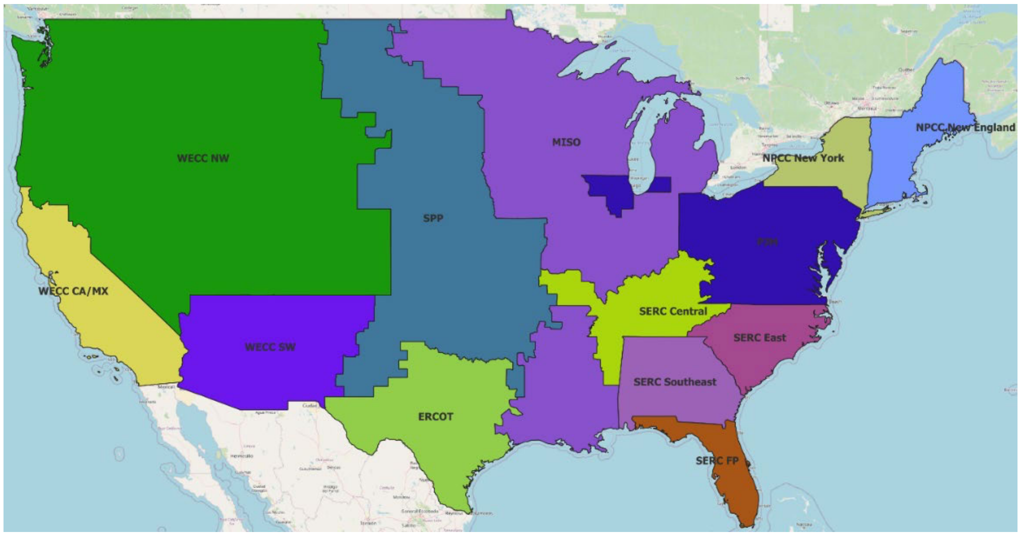

Figure A.1. NERC assessment areas.

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

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

Where $Capacity_{rf}$ is the capacity of fuel type f in ITCS region r and $ITCS(R)$ is the set of all ITCS regions mapped to the same NERC assessment area R. The denominator is the total capacity of that fuel type across all ITCS regions mapped to R.

Note that in cases where NERC assessment areas align one-to-one with ITCS regions, no mapping was required. Table A.1 summarizes which areas exhibited a direct one-to-one matching and which required disaggregation (1-to-many) or aggregation (many-to-one) to align with the ITCS regional structure.

An exception to this general approach is the case of the Front Range ITCS region, which geographically spans across two NERC assessment areas—WECC-NW and WECC-SW—resulting in two-to-one mapping. For this case, a separate allocation method was used: Plant-level data from EIA 860 were analyzed to determine the proportion of Front Range capacity located in each NERC area. These proportions were then used to derive custom weighting factors for allocating capacities from both WECC-NW and WECC-SW into the Front Range region.

30. NREL, "Regional Energy Development System," https://www.nrel.gov/analysis/reeds/.

Table A.1. Mapping of NERC assessment areas to ITCS regions.

NERC Area	ITCS Region	Match
ERCOT	ERCOT	1 to 1
NPCC-New England	NPCC-New England	1 to 1
NPCC-New York	NPCC-New York	1 to 1
SERC-C	SERC-C	1 to 1
SERC-E	SERC-E	1 to 1
SERC-FP	SERC-FP	1 to 1
SERC-SE	SERC-SE	1 to 1
WECC-SW	Southwest Region	1 to 1
MISO	MISO Central	1 to 4
MISO	MISO East	
MISO	MISO South	
MISO	MISO West	
SPP	SPP North	1 to 2
SPP	SPP South	
WECC-CAMX	Southern California	1 to 2
WECC-CAMX	Northern California	
WECC-NW	Oregon Region	1 to 3
WECC-NW	Washington Region	
WECC-NW	Wasatch Front	
WECC-NW	Front Range	2 to 1
WECC-SW	Front Range	

Table A.2 and Figure A.2 show the same combined capacities by ITCS region and NERC planning region, respectively.

Table A.2. Existing and Tier 1 capacities by NERC assessment area (in MW) in 2024.

2024 Exsting + Tier 1			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**143,035**	**330,342**	**82,793**	**26,771**	**3,624**	**-**	**991**	**19,607**	**3,298**	**28,980**	**72,757**	**94,364**	**25,753**	**24,367**	**856,682**
	ISONE	**Total**	541	15,494	3,331	5,710	818	-	233	1,571	57	1,911	3,386	2,553	661	3,713	39,979
	MISO	**Total**	**37,914**	**64,194**	**11,127**	**2,867**	**613**	**-**	**329**	**4,396**	**1,031**	**2,533**	**29,777**	**41,715**	**7,775**	**3,049**	**207,319**
		MISO-W	12,651	13,608	2,753	1,491	244	-	2	-	200	777	7,368	29,411	2,367	741	71,612
		MISO-C	15,050	10,307	2,169	494	32	-	152	773	499	769	10,587	7,350	2,026	1,774	51,982
		MISO-S	5,493	31,052	5,100	589	243	-	117	49	5	845	8,024	596	2,109	291	54,511
		MISO-E	4,720	9,227	1,105	292	94	-	57	3,574	327	143	3,799	4,359	1,273	243	29,213
	NYISO	**Total**	-	22,937	3,330	2,631	334	-	-	1,400	60	4,915	1,039	2,706	860	5,710	45,924
	PJM	**Total**	**39,915**	**84,381**	**32,535**	**9,875**	**851**	**-**	**-**	**5,062**	**338**	**3,071**	**10,892**	**11,718**	**7,397**	**8,603**	**214,638**
		PJM-W	34,917	39,056	16,557	1,933	112	-	-	234	149	1,252	5,780	10,065	3,814	599	114,467
		PJM-S	2,391	15,038	5,288	3,985	479	-	-	2,958	127	1,070	3,932	360	1,824	2,498	39,951
		PJM-E	2,608	30,287	10,690	3,956	260	-	-	1,870	62	749	1,180	1,294	1,759	5,506	60,221
	SERC	**Total**	**45,747**	**113,334**	**31,702**	**4,063**	**989**	**-**	**83**	**6,701**	**768**	**11,425**	**26,959**	**982**	**7,707**	**3,221**	**253,680**
		SERC-C	13,348	20,127	8,280	148	36	-	-	1,784	100	4,995	2,308	982	1,851	20	53,978
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	115	3,260	7,267	-	2,069	317	67,073
		SERC-FL	4,346	47,002	3,502	1,957	310	-	83	-	538	-	10,121	-	2,804	2,051	72,714
		SERC-E	14,777	16,340	11,902	1,044	219	-	-	3,369	15	3,170	7,263	-	983	833	59,914
	SPP	**Total**	**18,919**	**30,003**	**769**	**1,626**	**20**	**-**	**345**	**477**	**1,044**	**5,123**	**703**	**34,689**	**1,353**	**71**	**95,142**
		SPP-N	5,089	3,467	304	504	1	-	185	-	8	3,041	84	7,041	333	7	20,065
		SPP-S	13,829	26,536	465	1,121	19	-	160	477	1,037	2,082	619	27,649	1,020	64	75,078
ERCOT	**Total**		**13,568**	**50,889**	**4,973**	**10**	**163**	**-**	**-**	**-**	**10,720**	**583**	**31,058**	**39,532**	**3,464**	**2,531**	**157,490**
	ERCOT	**Total**	13,568	50,889	4,973	10	163	-	-	-	10,720	583	31,058	39,532	3,464	2,531	157,490
WEST	**Total**		**21,666**	**87,403**	**9,403**	**829**	**1,565**	**4,093**	**106**	**4,536**	**15,238**	**52,687**	**44,042**	**35,071**	**1,944**	**16,271**	**294,854**
	CAISO+	**Total**	**1,816**	**37,434**	**5,582**	**185**	**726**	**2,004**	**35**	**3,514**	**11,156**	**10,211**	**25,614**	**7,773**	**829**	**10,047**	**116,925**
		CALI-N	-	12,942	5,582	165	465	1,049	9	1,967	2,672	8,727	6,723	1,373	349	5,036	47,059
		CALI-S	1,816	24,492	-	20	261	955	26	1,547	8,484	1,483	18,891	6,400	480	5,011	69,866
	Non-CA WECC	**Total**	**19,850**	**49,969**	**3,820**	**644**	**839**	**2,089**	**71**	**1,022**	**4,082**	**42,476**	**18,428**	**27,298**	**1,115**	**6,224**	**177,929**
		WA	560	3,919	1,096	17	352	-	-	140	350	24,402	1,052	2,690	243	386	35,207
		OR	-	3,915	-	6	293	21	-	-	482	8,253	2,145	3,440	141	372	19,068
		SOUTHWEST	4,842	17,985	2,724	323	102	1,047	-	176	2,173	1,019	5,641	3,685	168	2,452	42,335
		WASATCH	7,033	14,061	-	87	56	1,011	61	444	750	7,587	5,625	4,052	305	1,674	42,746
		FRONT R	7,415	10,089	-	211	36	10	10	262	328	1,215	3,966	13,432	258	1,340	38,572
	Total		178,268	468,635	97,169	27,610	5,353	4,093	1,096	24,144	29,256	82,249	147,856	168,966	31,161	43,169	1,309,026

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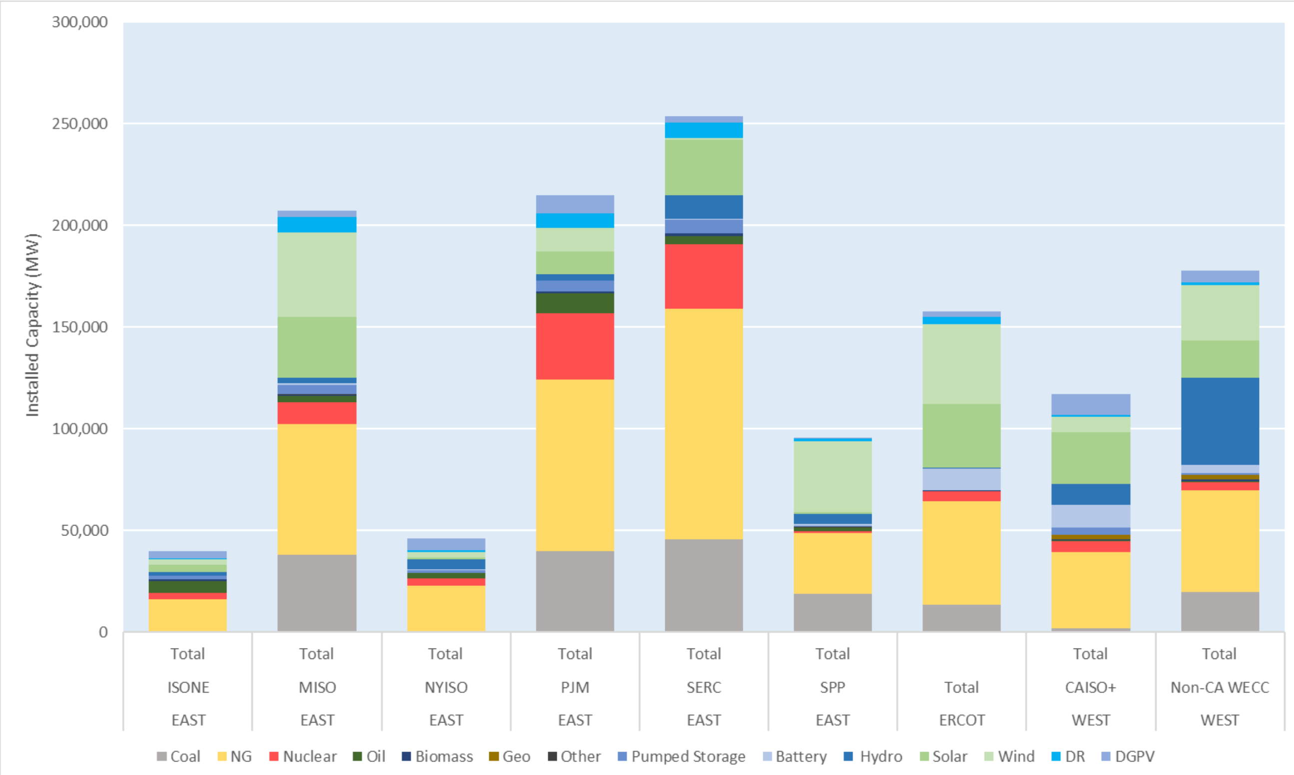

Figure A.2. Existing and Tier 1 capacities by NERC assessment area in 2024.

Forecasting 2030 Resource Mixes

To develop the 2030 ITCS generation portfolio, the study team added new capacity builds and removed planned retirements.

(i) *Tier 1*: Assumes that only projects considered very mature in the development pipeline—such as those with signed interconnection agreements—will be built. This results in minimal capacity additions beyond 2026. The data are based on projects designated as Tier 1 in the 2024 LTRA data for the year 2030.

Retirements

To project which units will retire by 2030, the study team primarily used the LTRA 2024 data and cross-checked it with EIA data. The assessment areas were disaggregated to ITCS zones based on the ratios of projected retirements in EIA 860 data. The three scenarios modeled are as follows:

(i) *Announced*: Assumes that in addition to confirmed retirements, generators that have publicly announced retirement plans but have not formally notified system operators have also begun the retirement process. This is based on data from the 2024 LTRA, which were collected by the NERC team from sources like news announcements, public disclosures, etc.

(ii) *None*: Assumes that there are no retirements between 2024 and 2030 for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirements contribute to resource adequacy challenges in regions where rapid AI and data center growth is expected.

Generation Stack for Each Scenario

Finally, when summing all potential future changes, the team arrived at a generation stack for each of the various scenarios to be studied. The first figure provides a visual comparison of all the cases, which vary from 1,309 GW to 1,519 GW total generation capacity for the entire continental United States, to enable the exploration of a range of potential generation futures. The tables below provide breakdowns by ITCS region and by resource type.

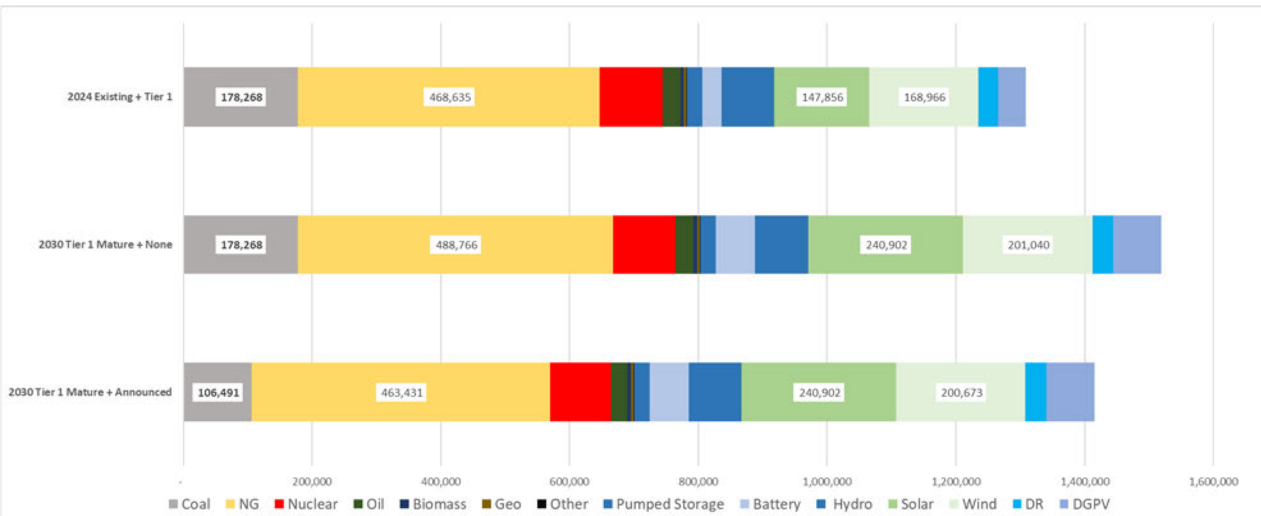

Figure A.9. Comparison of 2030 generation stacks for the various scenarios.

Table A.4. 2030 generation stack for Tier 1 mature + announced retirements.

2030 Tier 1 Mature + Announced			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**84,730**	**328,457**	**82,793**	**24,272**	**3,473**	**-**	**991**	**19,591**	**12,415**	**28,897**	**126,849**	**113,568**	**26,837**	**36,768**	**889,641**
	ISONE	**Total**	7	13,708	3,331	5,687	741	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	42,845
	MISO	**Total**	**13,001**	**60,132**	**11,127**	**2,873**	**473**	**-**	**329**	**4,380**	**2,960**	**2,450**	**44,132**	**43,369**	**7,775**	**3,049**	**196,049**
		MISO-W	4,338	12,747	2,753	1,494	188	-	2	-	574	751	10,920	30,577	2,367	741	67,453
		MISO-C	5,161	9,655	2,169	495	25	-	152	770	1,433	743	15,690	7,642	2,026	1,774	47,735
		MISO-S	1,883	29,087	5,100	591	187	-	117	49	14	817	11,892	619	2,109	291	52,756
		MISO-E	1,619	8,643	1,105	293	72	-	57	3,561	938	138	5,630	4,531	1,273	243	28,105
	NYISO	**Total**	-	21,907	3,330	2,628	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	50,396
	PJM	**Total**	**26,662**	**87,228**	**32,535**	**8,117**	**917**	**-**	**-**	**5,062**	**2,276**	**3,071**	**33,530**	**18,807**	**7,638**	**10,955**	**236,798**
		PJM-W	23,323	40,373	16,557	1,589	120	-	-	234	1,004	1,252	17,793	16,153	3,939	762	123,100
		PJM-S	1,597	15,546	5,288	3,276	516	-	-	2,958	853	1,070	12,105	577	1,883	3,181	48,850
		PJM-E	1,742	31,309	10,690	3,252	280	-	-	1,870	419	749	3,632	2,076	1,816	7,012	64,848
	SERC	**Total**	**31,672**	**116,117**	**31,702**	**3,391**	**989**	**-**	**83**	**6,701**	**3,021**	**11,425**	**38,360**	**982**	**8,088**	**7,893**	**260,423**
		SERC-C	8,883	23,777	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	54,014
		SERC-SE	10,321	28,127	8,018	899	424	-	-	1,548	618	3,260	9,024	-	2,213	317	64,768
		SERC-FL	2,851	47,092	3,502	1,477	310	-	83	-	2,208	-	16,717	-	3,022	5,865	83,127
		SERC-E	9,617	17,122	11,902	868	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	58,513
	SPP	**Total**	**13,389**	**29,365**	**769**	**1,576**	**20**	**-**	**345**	**477**	**2,434**	**5,123**	**5,991**	**41,755**	**1,815**	**71**	**103,130**
		SPP-N	3,602	3,394	304	489	1	-	185	-	18	3,041	717	8,475	447	7	20,679
		SPP-S	9,787	25,971	465	1,087	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	82,451
ERCOT	**Total**		**11,568**	**49,436**	**4,973**	**10**	**163**	**-**	**-**	**-**	**27,258**	**583**	**62,406**	**43,169**	**3,464**	**5,864**	**208,894**
	ERCOT	**Total**	11,568	49,436	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	208,894
WEST	**Total**		**10,193**	**85,538**	**7,103**	**823**	**1,427**	**3,983**	**106**	**4,366**	**21,330**	**52,060**	**51,648**	**43,935**	**1,981**	**31,931**	**316,424**
	CAISO+	**Total**	**16**	**35,789**	**3,282**	**185**	**726**	**2,059**	**35**	**3,514**	**14,316**	**10,211**	**27,112**	**7,773**	**866**	**17,055**	**122,938**
		CALI-N	-	12,373	3,282	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	48,897
		CALI-S	16	23,416	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	74,041
	Non-CA WECC	**Total**	**10,177**	**49,749**	**3,820**	**639**	**701**	**1,924**	**71**	**852**	**7,014**	**41,849**	**24,536**	**36,162**	**1,115**	**14,876**	**193,485**
		WA	243	3,971	1,096	16	286	-	-	111	459	24,033	1,404	3,631	243	1,092	36,588
		OR	-	3,967	-	6	238	18	-	-	632	8,128	2,865	4,644	141	1,051	21,689
		SOUTHWEST	3,657	17,343	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	47,022
		WASATCH	3,055	14,247	-	86	45	850	61	355	983	7,472	7,512	5,470	305	4,733	45,175
		FRONT R	3,221	10,222	-	208	30	8	10	209	430	1,197	5,296	18,133	258	3,789	43,011
		Total	**106,491**	**463,431**	**94,869**	**25,106**	**5,063**	**3,983**	**1,096**	**23,958**	**61,003**	**81,539**	**240,902**	**200,673**	**32,282**	**74,563**	**1,414,959**

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Table A.5. 2030 generation stack for Tier 1 mature + no retirements.

2030 Tier 1 Mature + No Retirements			Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	**Total**		**143,035**	**345,459**	**82,793**	**27,336**	**3,701**	**-**	**991**	**19,607**	**12,415**	**28,980**	**126,849**	**113,840**	**26,837**	**36,768**	**968,610**
	ISONE	**Total**	541	15,584	3,331	5,891	818	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	45,534
	MISO	**Total**	**37,914**	**66,729**	**11,127**	**3,197**	**613**	**-**	**329**	**4,396**	**2,960**	**2,533**	**44,132**	**43,641**	**7,775**	**3,049**	**228,393**
		MISO-W	12,651	14,145	2,753	1,662	244	-	2	-	574	777	10,920	30,768	2,367	741	77,605
		MISO-C	15,050	10,714	2,169	551	32	-	152	773	1,433	769	15,690	7,690	2,026	1,774	58,823
		MISO-S	5,493	32,278	5,100	657	243	-	117	49	14	845	11,892	623	2,109	291	59,710
		MISO-E	4,720	9,592	1,105	326	94	-	57	3,574	938	143	5,630	4,560	1,273	243	32,255
	NYISO	**Total**	-	22,937	3,330	2,646	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	51,444
	PJM	**Total**	**39,915**	**88,880**	**32,535**	**9,907**	**928**	**-**	**-**	**5,062**	**2,276**	**3,071**	**33,530**	**18,807**	**7,638**	**10,955**	**253,504**
		PJM-W	34,917	41,138	16,557	1,939	122	-	-	234	1,004	1,252	17,793	16,153	3,939	762	135,810
		PJM-S	2,391	15,840	5,288	3,998	522	-	-	2,958	853	1,070	12,105	577	1,883	3,181	50,667
		PJM-E	2,608	31,902	10,690	3,969	284	-	-	1,870	419	749	3,632	2,076	1,816	7,012	67,027
	SERC	**Total**	**45,747**	**120,232**	**31,702**	**4,063**	**989**	**-**	**83**	**6,701**	**3,021**	**11,425**	**38,360**	**982**	**8,088**	**7,893**	**279,285**
		SERC-C	13,348	24,958	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	59,660
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	618	3,260	9,024	-	2,213	317	69,478
		SERC-FL	4,346	48,163	3,502	1,957	310	-	83	-	2,208	-	16,717	-	3,022	5,865	86,173
		SERC-E	14,777	17,246	11,902	1,044	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	63,973
	SPP	**Total**	**18,919**	**31,098**	**769**	**1,632**	**20**	**-**	**345**	**477**	**2,434**	**5,123**	**5,991**	**41,755**	**1,815**	**71**	**110,449**
		SPP-N	5,089	3,594	304	506	1	-	185	-	18	3,041	717	8,475	447	7	22,385
		SPP-S	13,829	27,504	465	1,126	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	88,064
ERCOT	**Total**		**13,568**	**51,458**	**4,973**	**10**	**163**	**-**	**-**	**-**	**27,258**	**583**	**62,406**	**43,169**	**3,464**	**5,864**	**212,916**
	ERCOT	**Total**	13,568	51,458	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	212,916
WEST	**Total**		**21,666**	**91,849**	**9,403**	**829**	**1,565**	**4,156**	**106**	**4,536**	**21,330**	**52,687**	**51,648**	**44,030**	**1,981**	**31,931**	**337,717**
	CAISO+	**Total**	**1,816**	**39,560**	**5,582**	**185**	**726**	**2,059**	**35**	**3,514**	**14,316**	**10,211**	**27,112**	**7,773**	**866**	**17,055**	**130,809**
		CALI-N	-	13,677	5,582	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	52,501
		CALI-S	1,816	25,883	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	78,308
	Non-CA WECC	**Total**	**19,850**	**52,289**	**3,820**	**645**	**839**	**2,097**	**71**	**1,022**	**7,014**	**42,476**	**24,536**	**36,257**	**1,115**	**14,876**	**206,908**
		WA	560	4,166	1,096	17	352	-	-	140	459	24,402	1,404	3,642	243	1,092	37,573
		OR	-	4,161	-	6	293	22	-	-	632	8,253	2,865	4,658	141	1,051	22,081
		SOUTHWEST	4,842	18,294	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	49,158
		WASATCH	7,033	14,945	-	88	56	1,018	61	444	983	7,587	7,512	5,486	305	4,733	50,251
		FRONT R	7,415	10,723	-	212	36	10	10	262	430	1,215	5,296	18,187	258	3,789	47,844
	Total		**178,268**	**488,766**	**97,169**	**28,175**	**5,429**	**4,156**	**1,096**	**24,144**	**61,003**	**82,249**	**240,902**	**201,040**	**32,282**	**74,563**	**1,519,243**

Appendix B - Representing Canadian Transfer Limits

Introduction

The reliability and stability of cross-border electricity interconnections between the United States and Canada are critical to ensuring continuous power delivery amid evolving demands and variable supply conditions. In recent years, increased integration of wind and solar generation, coupled with extreme weather events, has introduced significant uncertainties in regional power flows.

This report describes the development and implementation of a machine learning (ML)-based model designed to project the maximum daily energy transfer (MaxFlow) across major United States–Canada interfaces, such as BPA–BC Hydro and NYISO–Ontario. Leveraging 15 years of high-resolution load and generation data, summarizing it into key daily statistics, and training a robust eXtreme Gradient Boosting (XGBoost) regressor can allow data-driven predictions to be captured with quantified uncertainty.

The project team provided percentile-based forecasts—25, 50, and 75 percent—to support both conservative and strategic planning. The conservative methodology (25 percent) was used for this report to ensure availability when needed.

The subsequent sections detail the methodology used for data processing and feature engineering, the architecture and training of the predictive model, and the validation metrics and feature importance analyses used. Future enhancements could include incorporating weather patterns, neighboring-region dynamics, and fuel-specific generation profiles to further strengthen predictive performance and support grid resilience.

Methodology

This section describes the ML approach used to build the MaxFlow prediction model.

Dataset Collection and Preparation

Data were collected for hourly and derived daily load and generation over a 15-year period (2010–2024), comprising 8,760 hourly observations annually. Hourly interconnection flow rates were collected for the same years across all major United States–Canada interfaces.[1–17]

Underlying Hypothesis

The team hypothesized that the MaxFlow between interconnected regions is critically influenced by regional load and generation extrema (maximum and minimum) and their variability. These statistics reflect grid stress conditions, influencing interregional energy flow. Additionally, nonlinear interactions due to imbalances in adjacent regions further affect energy transfer dynamics.

Regression Model

The XGBoost regression model was chosen because of its ability to capture complex, nonlinear relationships, regularization capability to prevent overfitting, high speed and performance, fast convergence, built-in handling of missing data, and ease of confidence interval approximation.

XGBoost builds many small decision trees, one after another. Each new tree learns to correct the mistakes of the previous ensemble by focusing on which predictions had the greatest error. Instead of creating one large, complex tree, it combines many simpler trees—each making a modest adjustment—so that, together, they capture nonlinear patterns and interactions. Regularization (penalties for tree size and leaf adjustments) prevents overfitting, and a “learning rate” scales each tree’s contribution so that improvements are made gradually. The final prediction is simply the sum of all those small corrections.

Model Training, Validation, and Assessment

Figure B.1 shows the data analysis and prediction process, which ties together seven stages—from raw CSV loading through outlier filtering, feature engineering, projecting to 2030, rebuilding 2030 features, training an XGBoost model, and finally making and evaluating the 2030 flow forecasts with quantiles. Each stage feeds into the next, ensuring that the features used for training mirror exactly those that will be available for future (2030) predictions.

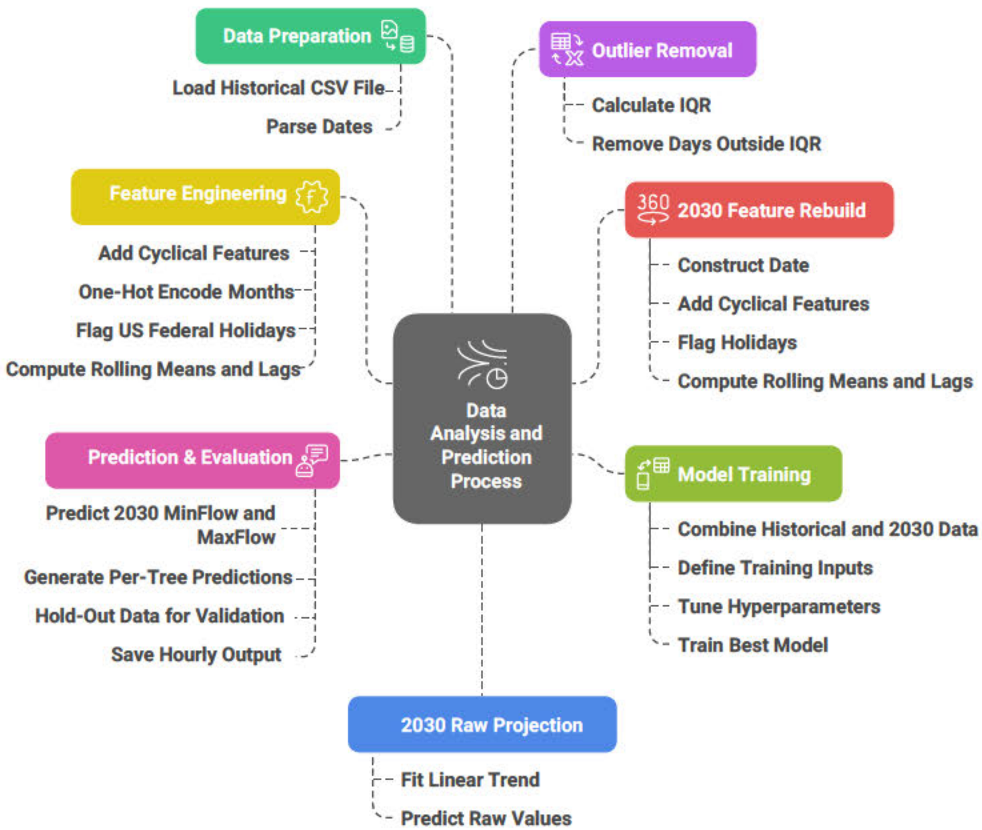

Figure B.1. Data analysis and prediction process.

Example Feature Importance for Predicting MaxFlow from Ontario to NYISO

The trained ML/XGBoost model can be used for predicting the desired year’s MaxFlow. In addition, feature importance analysis can be added to assess the contribution of each variable.

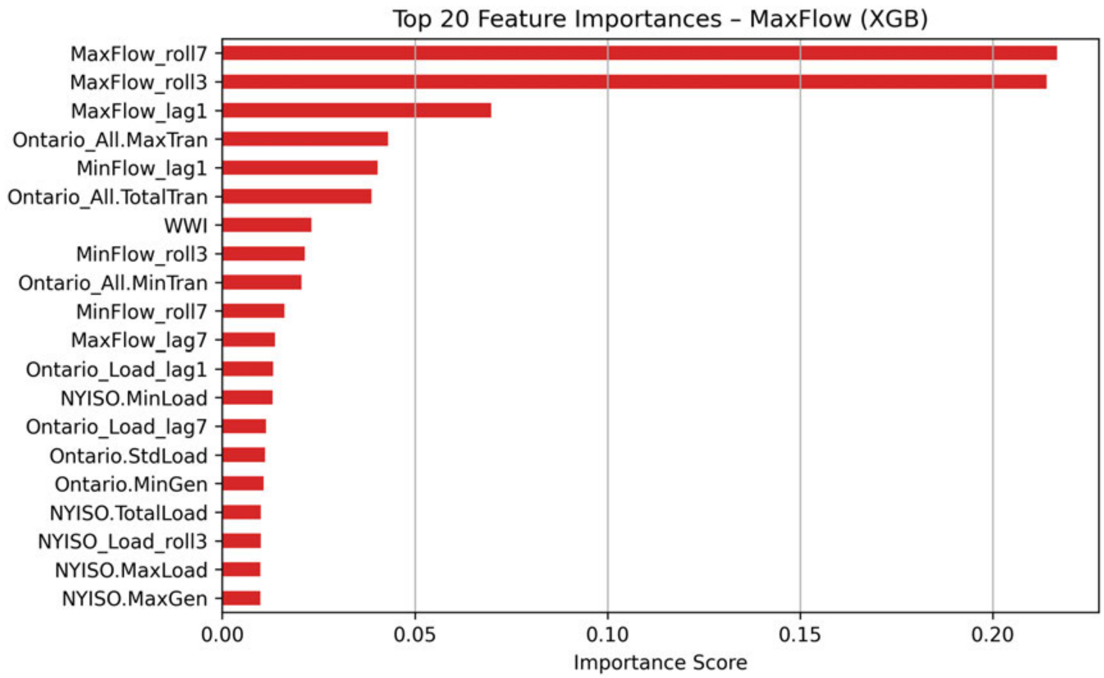

Figure B.2. Feature importance for predicting the hourly maximum energy transfer (MaxFlow) between NYISO and Ontario. XGB = eXtreme Gradient Boosting.

The feature importance plot shows that MaxFlow rolling/lagging features and Ontario_All.MaxTran are the dominant predictors of MaxFlow, meaning temporal patterns and Ontario's peak transfer capacity strongly influence interregional flow limits. Weather-related variables (WWI, e.g., temperature, humidity, etc.) and Ontario_All.TotalTran also rank highly. The 2030 MaxFlow prediction plot shows seasonal fluctuations, with higher values early and late in the year. The red shaded area represents a 95 percent confidence interval for the predictions.

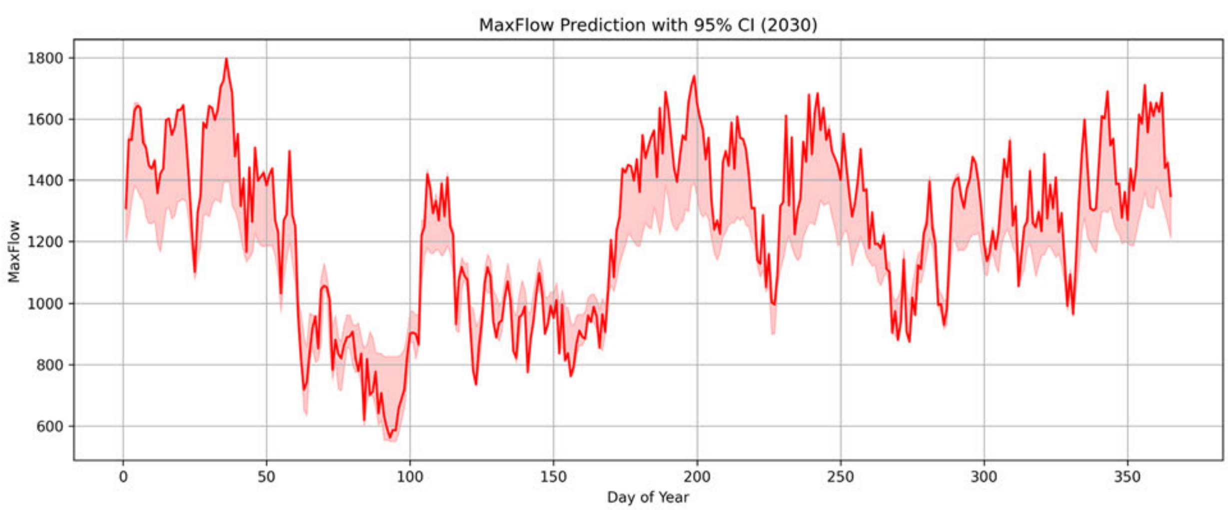

Figure B.3. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI).

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Model Performance

Validating model performance on unseen data is essential to ensure the model's reliability and generalizability. The following evaluation examines how well the XGBoost model predicts minimum energy transfer (MinFlow) and MaxFlow on the validation split, highlighting strengths and areas for improvement.

Rigorous performance evaluation is a fundamental step in any ML workflow. From quantifying error metrics (root mean square error and mean absolute error) and goodness-of-fit (R^2) on both training and validation splits, it is possible to identify overfitting, assess generalization, and guide model refinement. Table B.1 shows XGBoost model performance for the Ontario–NYISO transfer limit.

Table B.1. eXtreme Gradient Boosting model performance for the Ontario–NYISO transfer limit.

Metric	Value	Explanation
MinFlow RMSE (Train)	69.2528	Root mean square error (RMSE) on training data for minimum energy transfer (MinFlow)
MinFlow R^2 (Train)	0.9651	R^2 on training data for MinFlow (higher → better fit)
MinFlow RMSE (Validation)	163.6642	RMSE on held-out data for MinFlow
MinFlow R^2 (Validation)	0.8073	R^2 on held-out data for MinFlow (higher → better generalization)
MaxFlow RMSE (Train)	114.4234	RMSE on training data for maximum energy transfer (MaxFlow)
MaxFlow R^2 (Train)	0.8838	R^2 on training data for MaxFlow (higher → better fit)
MaxFlow RMSE (Validation)	144.9614	RMSE on held-out data for MaxFlow
MaxFlow R^2 (Validation)	0.8178	R^2 on held-out data for MaxFlow (higher → better generalization)

Overall, the XGBoost model delivers excellent in-sample as well as out-of-sample accuracy. Similar outputs are available for each transfer limit.

Maximum flow predictions: Ontario to New York

Ontario and NYISO are connected through multiple high-voltage interconnections, which collectively provide a total transfer capability of up to 2,500 MW, subject to individual tie-line limits. Table B.2 outlines the data sources, preparation process, and assumptions used in creating datasets for the prediction models.

Table B.2. Ontario to New York transmission flow data and assumptions overview.

	Description
Data source	https://www.ieso.ca/power-data/data-directory
Data preparation	IESO public hourly inter-tie schedule flow data can be accessed for the years spanning from 2002 to 2023.
Assumptions	Positive flow indicates that Ontario is exporting to NY, and negative flow indicates that Ontario is importing from NY.

Figure B.4 illustrates the historical monthly MaxFlow for Ontario from 2007 through 2024, alongside 2030 projected quartile scenarios (Q1, Q2, and Q3). Analyzing these trends helps assess future reliability and facilitates capacity planning under varying conditions.

Historical monthly peaks (2007–2023) reveal a clear seasonal cycle for ONT–NYISO transfers: flows typically increase in late winter/early spring (February–April) and again in late fall/early winter (November–December). Over 16 years, the average spring peaks hovered around 1,700–1,900 MW, with occasional spikes above 2,200 MW. The 2030 forecast for Q1, Q2, and Q3 aligns with this pattern, predicting a springtime peak near 1,800 MW, a summer trough around 1,400 MW, and a modest late-summer uptick near 1,500 MW.

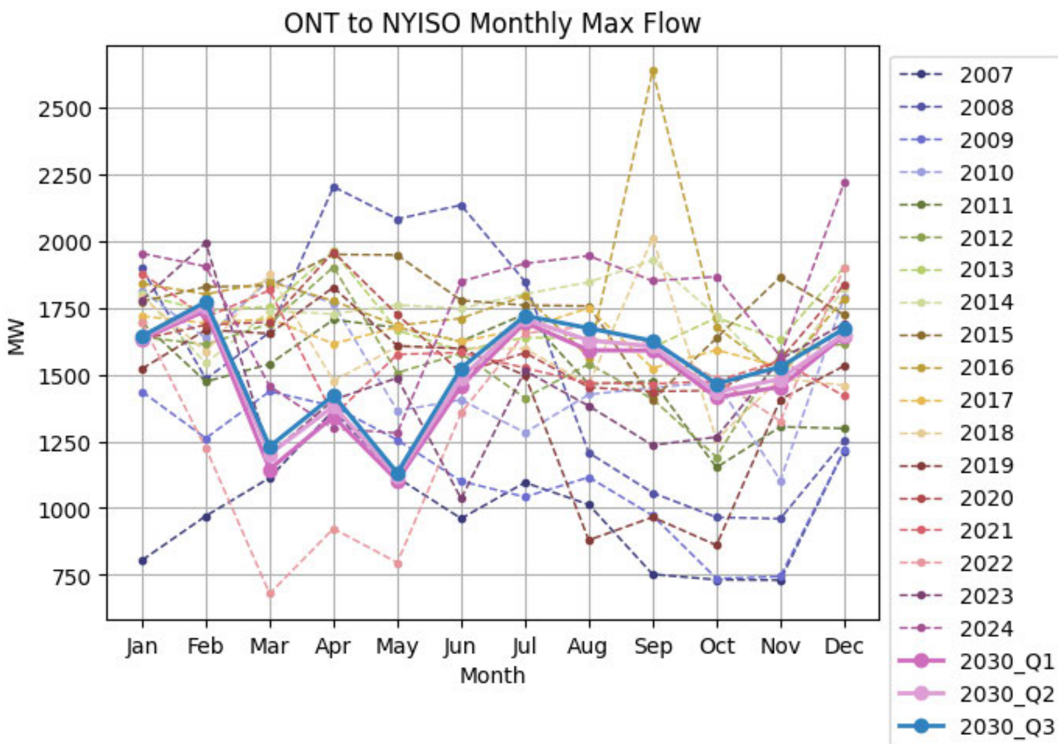

Figure B.4. Monthly maximum energy transfer between Ontario (ONT) and New York (NYISO).

The team used robust validation metrics to justify these results. When trained on daily data from the 2010–2024 period—incorporating projected 2030 loads, seasonal flags, and holiday effects—the XGBoost model achieved $R^2 > 0.80$ and a root mean square error below 150 MW on an unseen 20 percent hold-out dataset. Moreover, the 95 percent confidence intervals for monthly maxima were narrow (approximately ±150 MW), demonstrating low predictive uncertainty. A comparison of predicted maxima with historical extremes revealed that 2030 forecasts consistently fell within (or slightly above) the previous window of variability, implying realistic demand-driven behavior. In summary, the close alignment with historical peaks, strong cross-validated performance, and tight confidence bands collectively validate the results.

Discussion

The reason that the team used ML/XGBoost to approximate the 2030 transfer profiles was to ensure that there would be no violations or inconsistencies between transfer limits, load, and generation. The 15 years of data used were sufficient for having the models learn historical relationships and project them forward to 2030 to capture the underlying trends in load, generation, and their interactions. The use of such an extensive dataset justifies using ML to establish consistent transfer profiles.

However, in some regions, like Ontario to NYISO, the available data encompassed a shorter time period, and the relationships were only partially captured because of a lack of neighboring-region data. In such cases, it was necessary to incorporate additional predictors, such as rolling and lag features from the transfer limits. Although the direct use of transfer limit data to project future transfer limits would typically be avoided, these engineered features help improve predictions when data coverage is sparse and the model's goodness-of-fit is low.

In all cases, the ML models ensured that these historical relationships were not violated, maintaining internal consistency among load, generation, and transfer limits. Overall, the team relied on ML when long-term data were available for training and projecting load and generation profiles. Rolling and lag features were used to reinforce the model when data availability was limited, but always with the goal of upholding consistent physical relationships in the 2030 projections.

Supplementary Plots for Additional Transfers

This section presents figures and tables showing results and source data information for each transfer listed below:

(iii) Pacific Northwest to British Columbia

(iv) Alberta to Montana

(v) Manitoba to MISO West

(vi) Ontario to MISO West

(vii) Ontario to MISO East

(viii) Ontario to New York

(ix) Hydro-Quebec to New York

(x) Hydro-Quebec to New England

(xi) New Brunswick to New England

The figures show the daily MaxFlow for each transfer that was considered in this analysis.

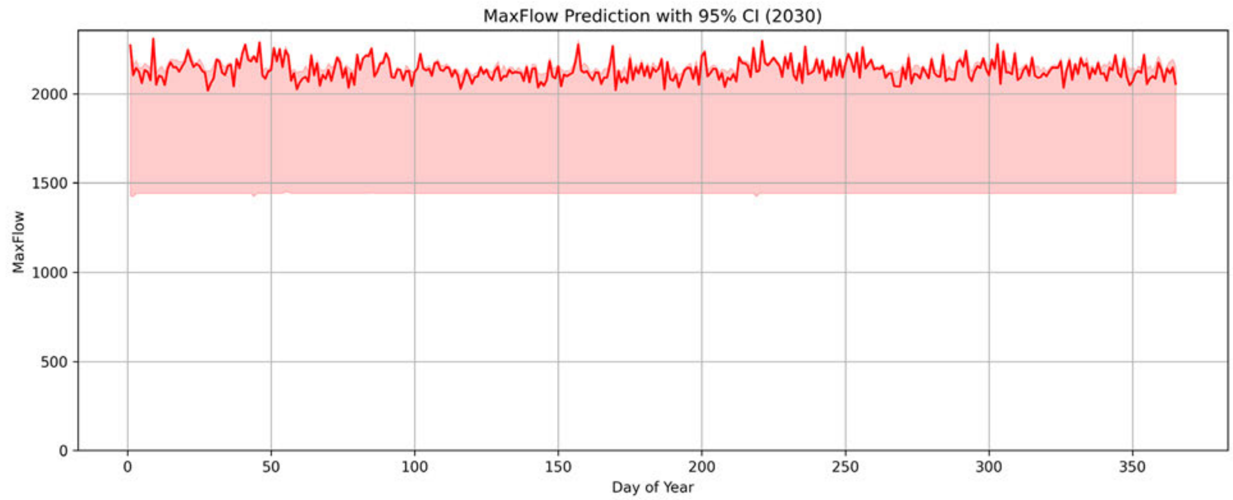

Figure B.5. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between British Columbia and the Pacific Northwest.

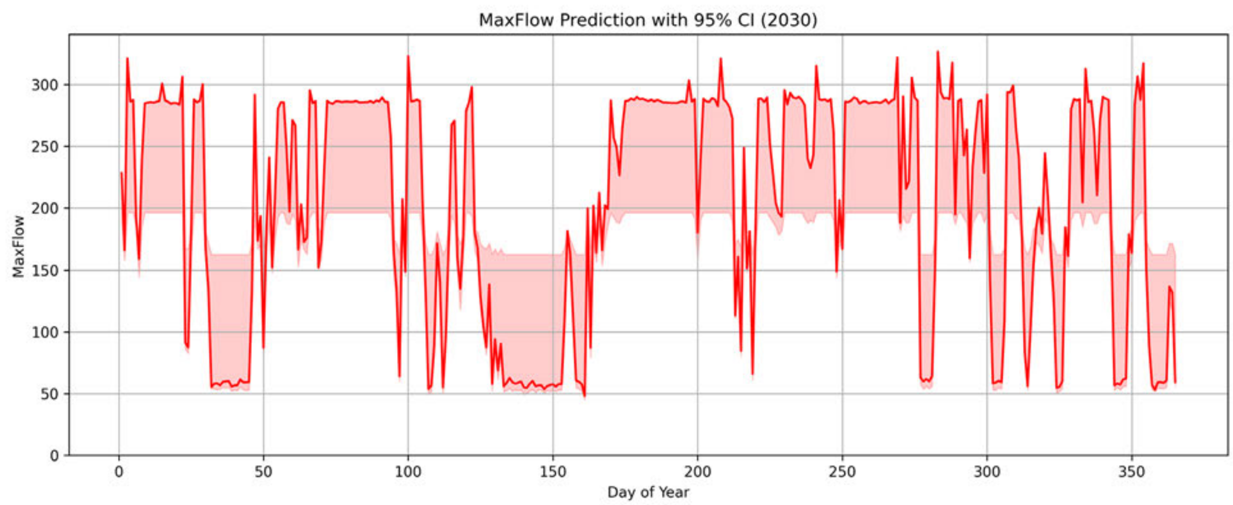

Figure B.6. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between AESO and Montana.

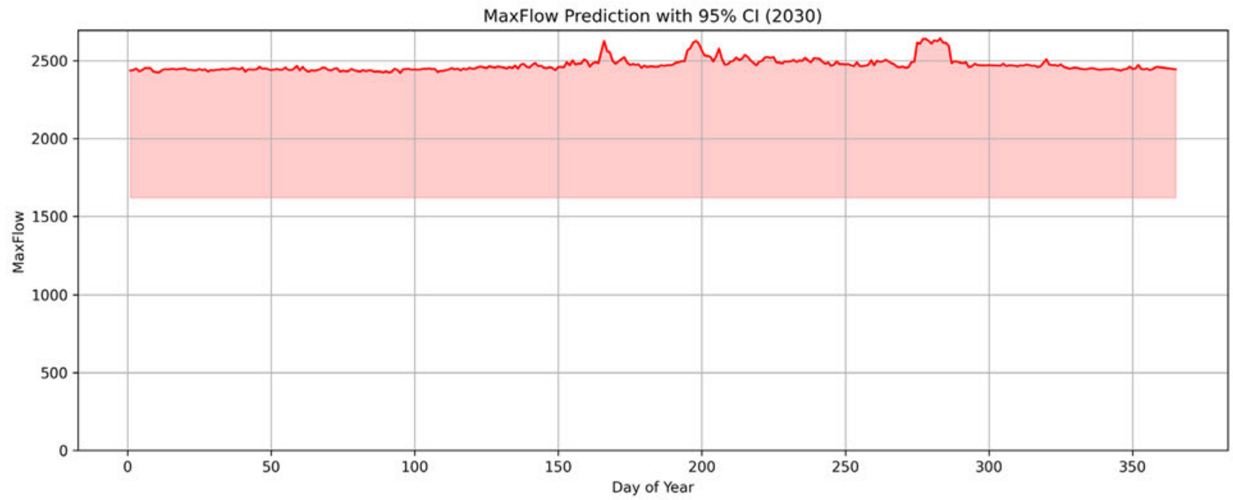

Figure B.7. Projected 2030 maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Manitoba and MISO.

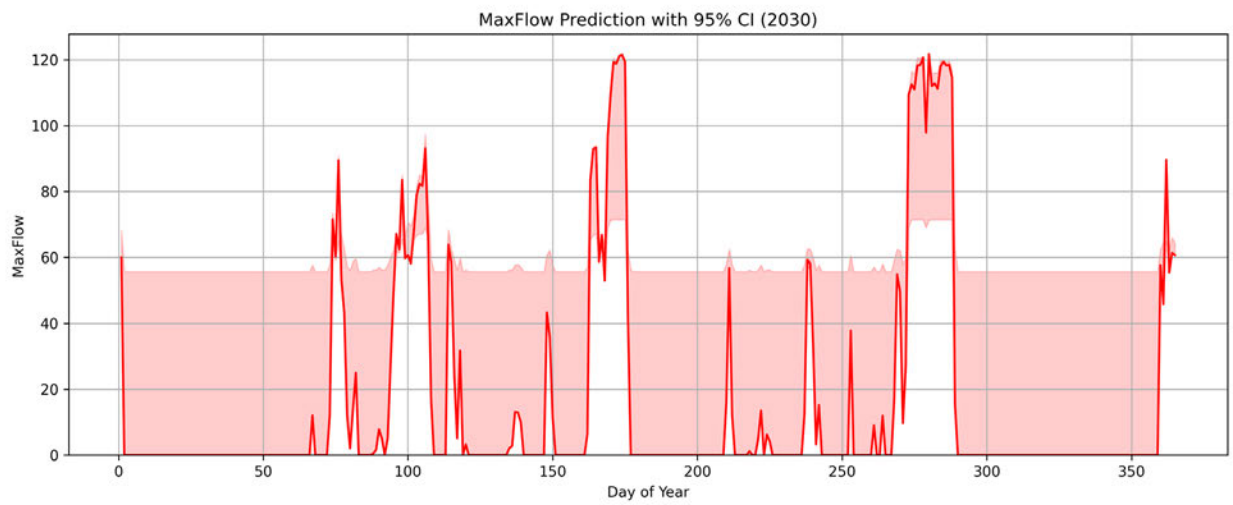

Figure B.8. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO West.

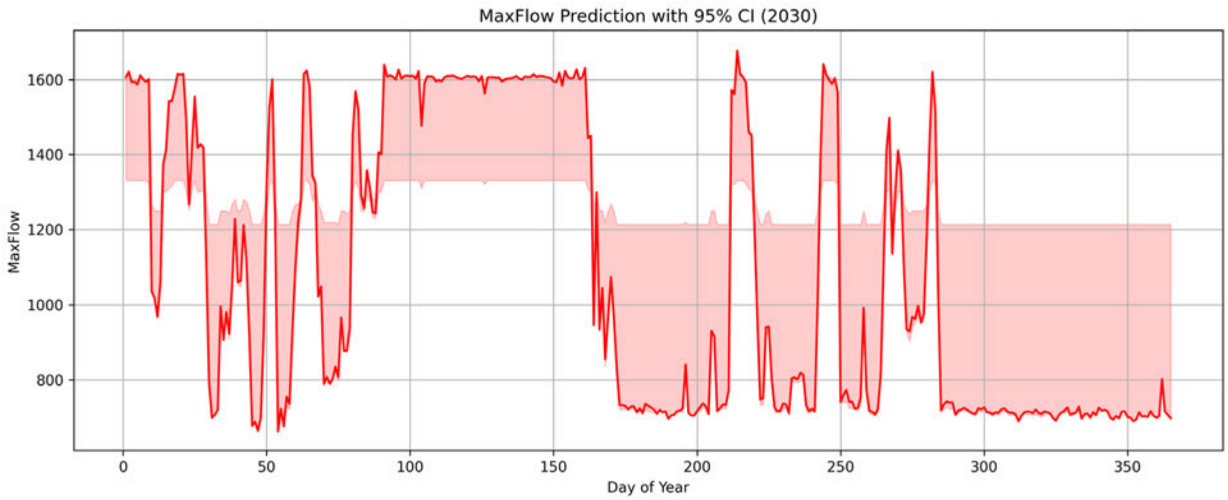

Figure B.9. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO East.

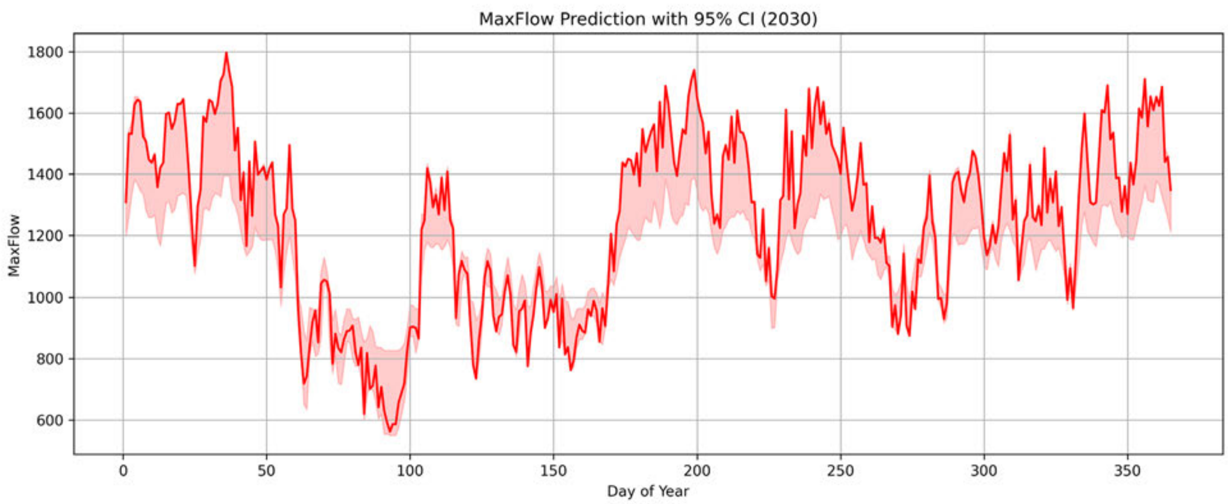

Figure B.10. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and New York.

ADD73

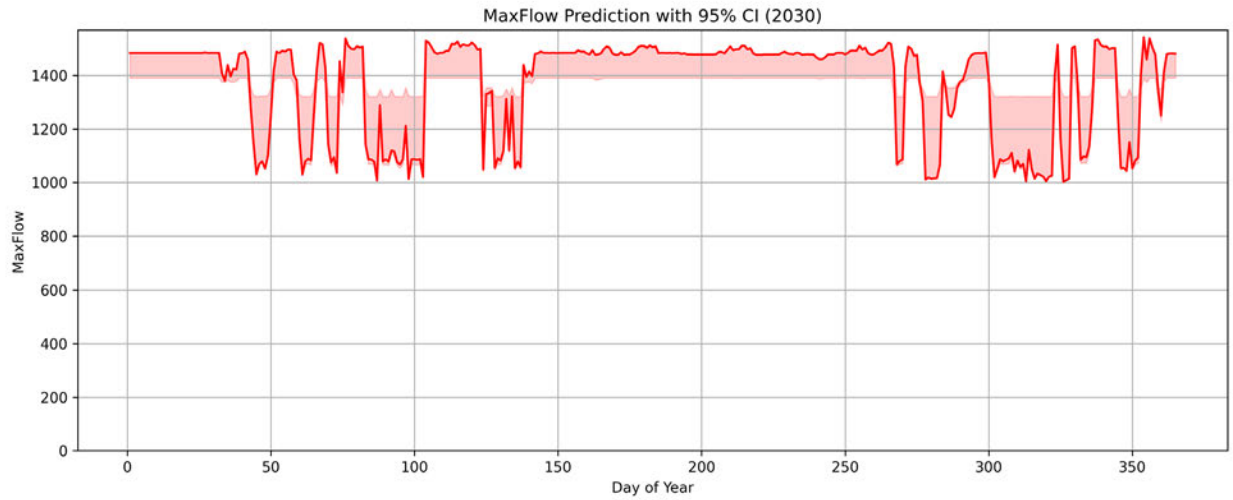

Figure B.11. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New York.

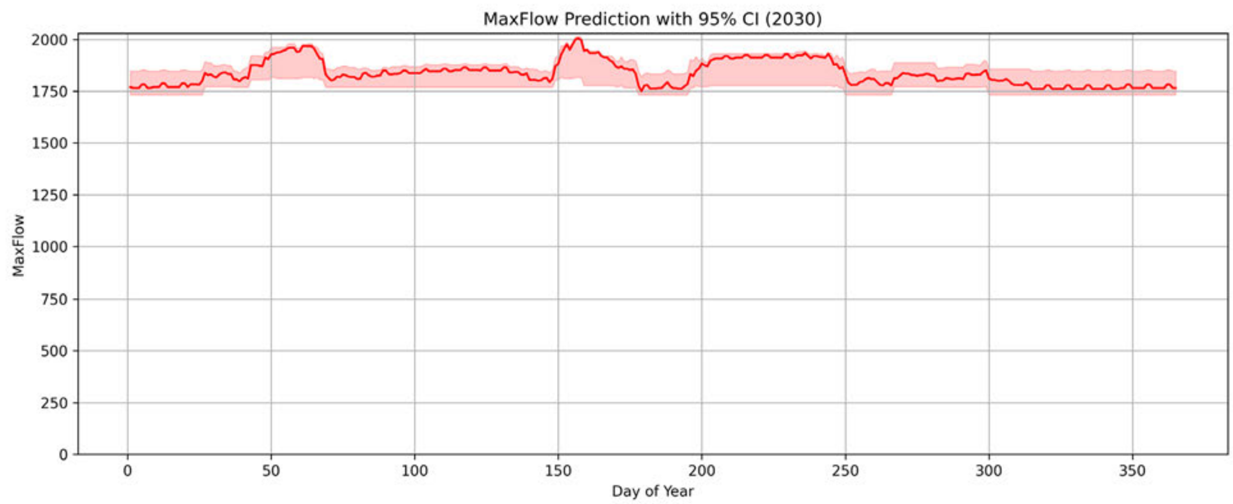

Figure B.12. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New England.

ADD74

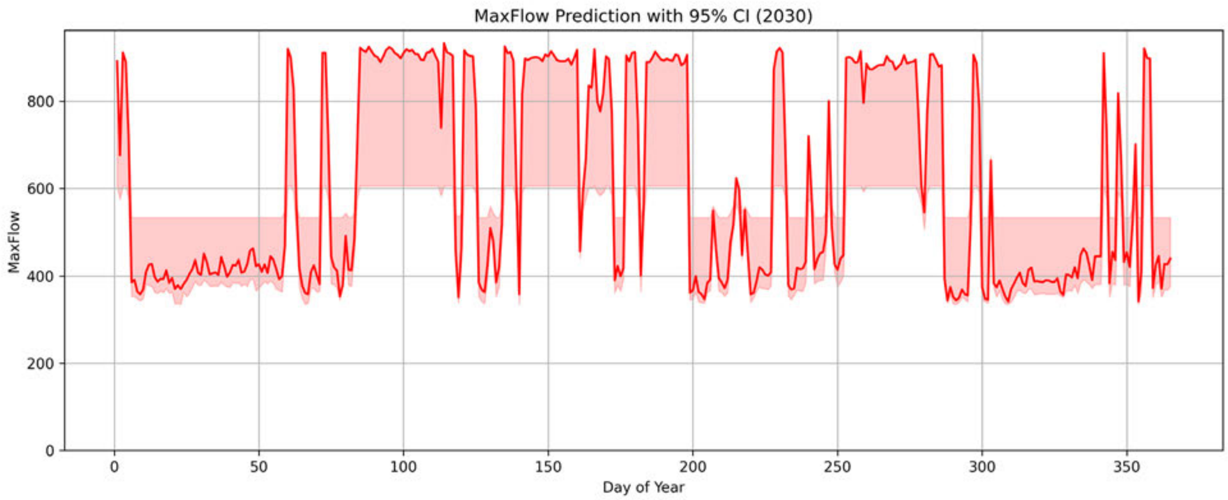

Figure B.13. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between New Brunswick and New England.

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EO 14262

Federal Register / Vol. 90, No. 70 / Monday, April 14, 2025 / Presidential Documents 15521

Presidential Documents

Executive Order 14262 of April 8, 2025

Strengthening the Reliability and Security of the United States Electric Grid

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered:

Section 1. *Purpose*. The United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and an increase in domestic manufacturing. This increase in demand, coupled with existing capacity challenges, places a significant strain on our Nation's electric grid. Lack of reliability in the electric grid puts the national and economic security of the American people at risk. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy from all available electric generation sources and the integrity of our Nation's electric grid.

Sec. 2. *Policy*. It is the policy of the United States to ensure the reliability, resilience, and security of the electric power grid. It is further the policy of the United States that in order to ensure adequate and reliable electric generation in America, to meet growing electricity demand, and to address the national emergency declared pursuant to Executive Order 14156 of January 20, 2025 (Declaring a National Energy Emergency), our electric grid must utilize all available power generation resources, particularly those secure, redundant fuel supplies that are capable of extended operations.

Sec. 3. *Addressing Energy Reliability and Security with Emergency Authority*. (a) To safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply is necessary to prevent a complete grid failure, the Secretary of Energy, in consultation with such executive department and agency heads as the Secretary of Energy deems appropriate, shall, to the maximum extent permitted by law, streamline, systemize, and expedite the Department of Energy's processes for issuing orders under section 202(c) of the Federal Power Act during the periods of grid operations described above, including the review and approval of applications by electric generation resources seeking to operate at maximum capacity.

(b) Within 30 days of the date of this order, the Secretary of Energy shall develop a uniform methodology for analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy. This methodology shall:

(i) analyze sufficiently varied grid conditions and operating scenarios based on historic events to adequately inform the methodology;

(ii) accredit generation resources in such conditions and scenarios based on historical performance of each specific generation resource type in the real time conditions and operating scenarios of each grid scenario; and

(iii) be published, along with any analysis it produces, on the Department of Energy's website within 90 days of the date of this order.

(c) The Secretary of Energy shall establish a process by which the methodology described in subsection (b) of this section, and any analysis and results it produces, are assessed on a regular basis, and a protocol to identify which generation resources within a region are critical to system reliability. This protocol shall additionally:

(i) include all mechanisms available under applicable law, including section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region; and

(ii) prevent, as the Secretary of Energy deems appropriate and consistent with applicable law, including section 202 of the Federal Power Act, an identified generation resource in excess of 50 megawatts of nameplate capacity from leaving the bulk-power system or converting the source of fuel of such generation resource if such conversion would result in a net reduction in accredited generating capacity, as determined by the reserve margin methodology developed under subsection (b) of this section.

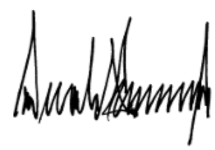
Sec. 4. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

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

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.



THE WHITE HOUSE,
April 8, 2025.

[FR Doc. 2025–06381
Filed 4–11–25; 8:45 am]
Billing code 3395–F4–P

Available at (accessed on 5/27/2025):
https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid

U.S. DEPARTMENT *of* ENERGY

For more information, visit:
energy.gov/topics/reliability

DOE/Publication Number • July, 7 2025

D. Order 202-25-7 (Campbell II)

Order No. 202-25-7

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

Order No. 202-25-3

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

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

First, the North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC indicated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[2] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply

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[1] *See Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation*, Consumers Energy (June 23, 2021), https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation. As a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline.

[2] *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, at 16 (May 2025), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf (NERC 2025 Summer Reliability Assessment).

shortfalls. NERC anticipated that the near-term period of greatest capacity shortfall for MISO would likely occur in August.[3]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[4] Additionally, EIA stated, "[t]ypically, Michigan's nuclear power plants have supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[5] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. While the Palisades nuclear power plant may reopen in 2025, it was not projected to be available during the peak demand period this summer.[6]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of the other 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024. Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts and Consumers acquired a 1,200 MW natural gas power plant in Covert, MI, the NERC Assessment still anticipates "elevated risk of operating reserve shortfalls."[7]

Fourth, MISO's Planning Resource Auction Results for the 2025-2026 Planning Year, released in April 2025, noted that for the northern and central zones, which includes Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[8] While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance" and these results "reinforce the need to increase capacity."[9]

Continuing Emergency Conditions

The emergency conditions that led to the issuance of Order No. 202-25-3 continue, both in the near and long term. The summer season has not yet ended, and the production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO this summer. That need is evidenced by the fact that the Campbell Plant was called on by MISO to generate large amounts of electricity during the heat wave that hit MISO this past June. According

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[3] *Id.*
[4] *Michigan State Profile and Energy Estimates*, U.S. Energy Info. Admin. (Oct. 17, 2024), https://www.eia.gov/state/print.php?sid=MI.
[5] *Id.*
[6] The start-up of Palisades is scheduled for the fourth quarter of 2025.
[7] NERC 2025 Summer Reliability Assessment at 16.
[8] *Planning Resource Auction—Results for Planning Year 2025–2026,* Midcontinent Independent System Operator, Inc., 13 (May 29, 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf. (MISO Planning Resource Auction – Results for Planning Year 2025-26).
[9] *Id*. at 2,12.

to the U.S. Environmental Protection Agency's data, over the month of June, the Campbell Plant generated approximately 664,000 MWh, running at 61% capacity.[10] In fact, between June 11 and August 18, MISO issued dozens of alerts to manage grid reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits. MISO issued alerts for the Central Region on at least 40 of the 69 days between June 11 and August 18. In June, MISO issued alerts affecting the Central Region on 18 days, including an Energy Emergency Alert (EEA) level 1 ("Max Gen Step 1b") on June 23 to enable MISO to take emergency action to ensure grid stability, including bringing additional resources online.[11] The Central Region had alerts on 21 days in July, including one Max Generation Warning on July 29 and two Max Generation Alerts on July 28 and 29.[12] Two Capacity Advisory Initiate alerts have been issued in August to date.[13] Moreover, the May 2025 NERC Summer Reliability Assessment referenced a Seasonal Outlook issued by the National Oceanic and Atmospheric Administration (NOAA), which estimates that much of the Midwest has a 33%-40% chance to experience above-normal temperatures this summer.[14] The Seasonal Outlook released by NOAA on July 17, 2025, increased this estimate for much of the region to a 40%-50% chance.[15]

MISO's resource adequacy problems are not limited to the summer. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[16] MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round

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

[11] An Energy Emergency Alert is an alert declared by the Transmission Provider in accordance with the NERC Operating Manual associated with the Transmission Provider's inability to provide for the Energy and Operating Reserve requirements of the MISO Balancing Authority Area. For more information, see MISO, FERC Electric Tariff, Module A, § 1.E (Definitions) (92.0.0). For more information on Energy Emergency Alert levels, see North American Electric Reliability Corporation. (n.d.). *EOP-011-1 Emergency Operations*. https://www nerc.com/pa/stand/reliability%20standards/eop-011-1.pdf.

[12] A Max Gen Alert occurs when MISO is forecasting a potential capacity shortage. A Max Gen Warning is a warning to prepare for a possible Max Gen Event. *See* MISO Operating Procedures, https://efis.psc.mo.gov/Document/Display/9379 (20180920).

[13] A Capacity Advisory alert is an advisory issued based on the potential for limited operating capacity margins (<5%) in the following 2-3 days. *See* MISO Operating Procedures, https://efis.psc.mo.gov/Document/Display/9379 (20180920).

[14] NERC 2025 Summer Assessment at 9.

[15] *Seasonal Outlook*, NOAA Climate Prediction Ctr., (July 17, 2025), https://www.cpc.ncep noaa.gov/products/predictions/long_range/seasonal.php?lead=1.

[16] M*idcontinent Independent System Operator, Inc.,* FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. Midcontinent Independent System Operator, Inc., 180 FERC ¶ 61,141 (2022).

concern."[17] MISO noted that over 60 percent of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[18]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[19] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projects that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[20]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative.*"[21] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[22]

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

The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Michigan.[23]

On June 6, 2025, subsequent to the issuance of Order No. 202-25-3, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy

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[17] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).
[18] *Id.* at 3-4.
[19] *Attributes Roadmap*, MISO (Dec. 2023), https://cdn misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[20] *Id.* at 11.
[21] *MISO's Response to the Reliability Imperative*, MISO (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.
[22] *Id.* at 12.
[23] MISO Planning Resource Auction – Results for Planning Year 2025-26 at 13.

planning reserve margin requirements.[24] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[25] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[26] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[27]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[28] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[29]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[30] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three year grace period to commence commercial operations.[31] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[32] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

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[24] *2025 OMS-MISO Survey Results*, OMS and MISO (Updated June 6, 2025) https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.
[25] *Id.* at 2.
[26] *Id.* at 7.
[27] *Id.* at 9.
[28] *Id.* at 7, 9.
[29] *Id.*
[30] M*idcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).
[31] 192 FERC ¶ 61,064 at P 84.
[32] *See generally*, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, S&P Global (May 2025), US gas-fired turbine wait times as much as seven years; costs up sharply | S&P Global. "With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."

Order 202-25-3 was preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. Specifically, in Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[33] President Trump likewise recognized, in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[34] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[35]

The Department's July 2025 Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid, issued pursuant to the President's directive in Executive Order 14262, details the myriad challenges affecting the Nation's energy outlook. "Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[36] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[37] In addition, as just one example, Consumers has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[38]

Grid operators—including MISO itself—have likewise acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the

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

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

[35] *Id*.

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

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

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

changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[39] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[40] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[41]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of the Department of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[42] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and accelerated retirements of generation facilities supporting the issuance of Order No. 202-25-3 will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the emergency and serve the public interest under FPA section 202(c).

To ensure the Campbell Plant will be available if needed to address emergency conditions, the Campbell Plant shall remain in operation until November 19, 2025.[43]

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

[40] *Id.* at 6.

[41] *Id.* at 7.

[42] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b) (2018).

[43] 16 U.S.C. § 824a(c)(4).

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

A. From August 21, 2025, MISO and Consumer Energy shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers Energy is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

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

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

D. By September 4, 2025, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

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

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

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

H. This Order shall be effective from 00:00 Eastern Daylight Time (EDT) on August 21, 2025, and shall expire at 00:00 EDT on November 19, 2025, with the exception of applicable compliance obligations in paragraph D.

I. Issued in Norfolk, Virginia at 8:50pm Eastern Daylight Time on this 20th day of August 2025.

Chris Wright

Chris Wright
Secretary of Energy

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

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

E. Order 202-25-9 (Campbell III)

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] *Midcontinent Independent System Operator, Inc.,* FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. Midcontinent Independent System Operator, Inc., 180 FERC ¶ 61,141 (2022).

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

[16] Id. at 3-4.

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

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

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

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

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

While the 2025 – 2026 NERC Winter Reliability Assessment has not yet been released as of the date of this Order, two recent winter studies (2024 – 2025 NERC Winter Reliability 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]

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[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:

<u>FERC Commissioners</u>
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

F. CMS Energy Corporation, Form 10-Q (period ended Sept. 30, 2025)

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.

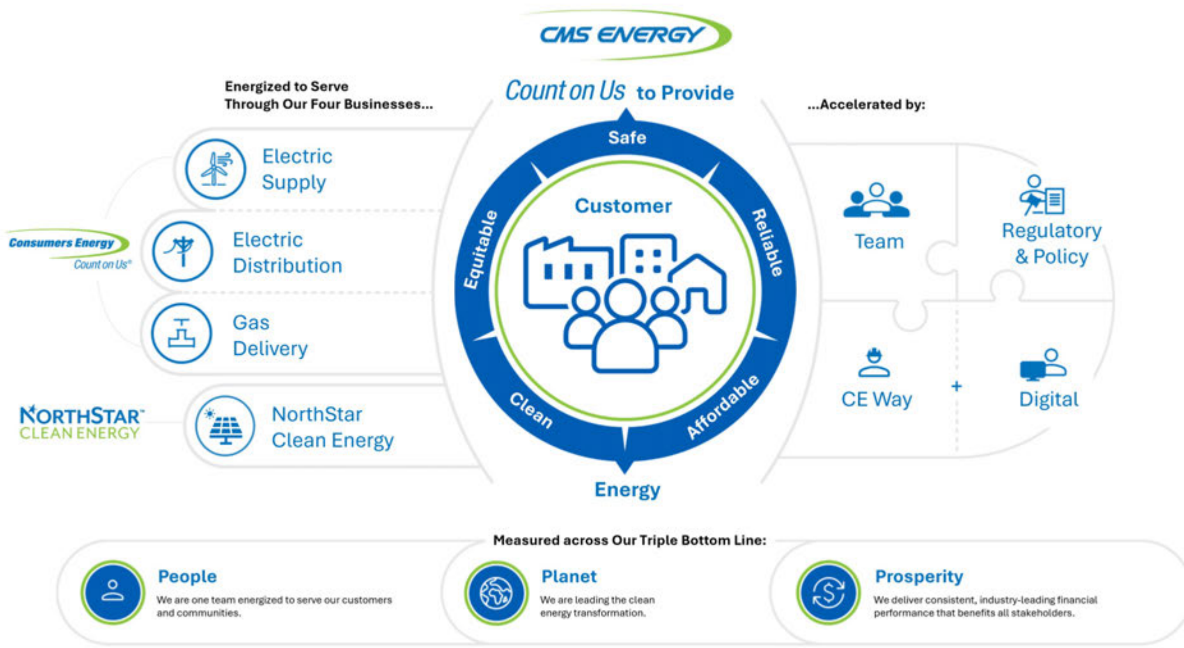
CMS Energy and Consumers manage their businesses by the nature of services each provides. CMS Energy operates principally in three business segments: electric utility; gas utility; and NorthStar Clean Energy, its non-utility operations and investments. Consumers operates principally in two business segments: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

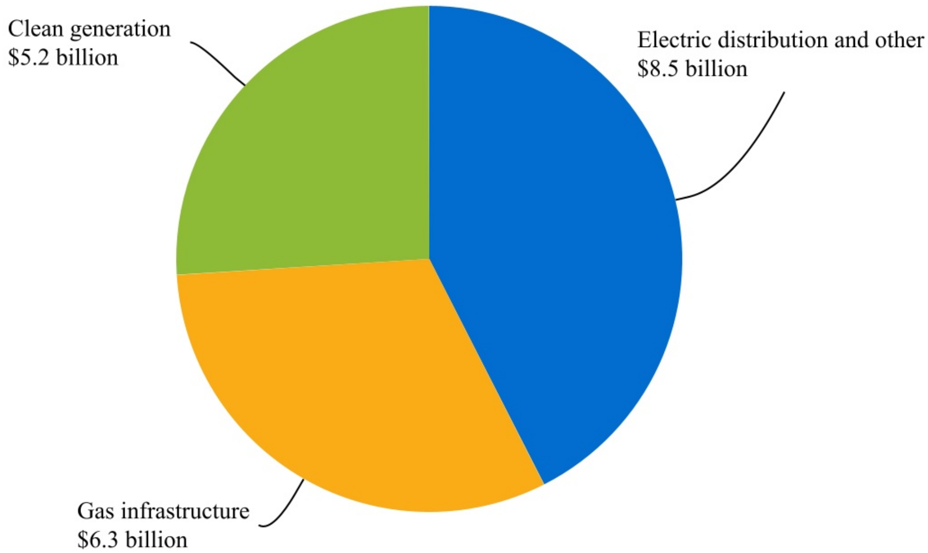
CMS Energy and Consumers remain committed to delivering safe, reliable, affordable, clean, and equitable energy in service of their customers and positively impacting the triple bottom line of people, planet, and prosperity. During 2025, CMS Energy and Consumers:

- 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.

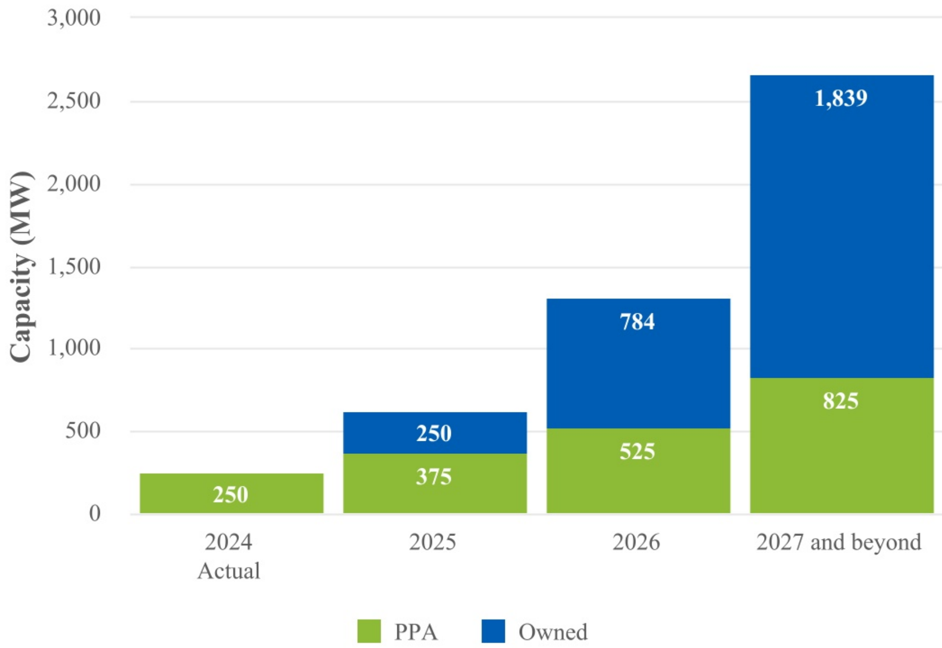
Consumers has also contracted to purchase 700 MW of capacity from battery storage facilities, which will be located in Michigan's Lower Peninsula and are expected to be operational by 2028. In an April 2025 report, the MPSC Staff indicated that Consumers' share of the 2,500-MW statewide energy storage 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

Exhibit 31.2

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

G. Affidavit of Douglas Jester

AFFIDAVIT OF DOUGLAS JESTER

Douglas Jester states that the following information is true and accurate to the best of my knowledge and belief:

1. I am the Managing Partner of 5 Lakes Energy, a clean-energy consulting firm. Previously, I served in various roles in Michigan state government and in the private sector. I began my career in ecosystem modeling, working for the State of Michigan from 1977 to 1999. In 2011, I cofounded 5 Lakes Energy.
2. I have a masters degree in statistics from Virginia Polytechnic Institute & State University and completed coursework for a Ph.D. in Environmental Economics from Michigan State University. I am a frequent expert witness before the Michigan Public Service Commission (MPSC).
3. I have used the Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA) regularly in my work, in part because the MPSC requires utilities in Michigan to use the COBRA tool to develop integrated resource plans.
4. The COBRA tool is a web-based model developed and maintained by the U.S. Environmental Protection Agency (EPA) to model the co-benefits of reductions in greenhouse gasses.[1] Those co-benefits are the benefits to public health due to reductions in co-pollutants, namely $PM_{2.5}$, NOx, SO_2, and VOCs.
5. The COBRA tool allows for the modeling of health impacts over time, based on emissions over a particular year. The model allows a user to specify particular scenarios of emission controls. It is available at: https://cobra.epa.gov/.
6. To estimate the health impacts of running the J.H. Campbell Plant during the period of the Order, I used the COBRA tool as follows.
7. I first selected the relevant county in Michigan—Ottawa County.
8. I then identified the relevant sector—Fuel Combustion: Electric Utility—and subsector—Coal.
9. I am aware that the J.H. Campbell plant is the only coal-fired power plant in Ottawa County.
10. I then selected a 100% reduction in each of the relevant pollutants.
11. Together, these parameters reflect the closure of the J.H. Campbell plant.

[1] *See* U.S. EPA, User's Manual for the Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA), Version: 5.2 (March 2025), *https://www.epa.gov/system/files/documents/2025-03/cobra-user-manual-v5.2.pdf*

12. Finally, I selected a discount rate—2%.
13. The resulting figures provide an estimate for the health benefits over time of a year's worth of emissions reductions from the closure of the J.H. Campbell plant.
14. These figures also provide an estimate of the health harms resulting from the continued operation of the J.H. Campbell plant.
15. According to the COBRA tool, those harms in all contiguous U.S. states include 27-46 excess deaths, as well as thousands of lost school and work days. In total, the COBRA tool estimates that the total monetized value of health effects are $417 million to $704 million in 2023 dollars.
16. I also filtered the results of the model to show health effects in Michigan only. For Michigan alone, the COBRA model estimates 8.1 - 13 excess deaths and monetized health effects of $130 million to $200 million in 2023 dollars.
17. I also filtered the results of the model to show health effects in Minnesota and Illinois. For Minnesota, the COBRA model estimates 0.3 to 0.5 excess deaths and monetized health effects of $4.1 million to $7.2 million in 2023 dollars. For Illinois, it estimates 2.4 to 4.6 excess deaths and monetized health effects of $3.8 million to $11.2 million in 2023 dollars.
18. These estimates of public-health benefits produced by the COBRA tool are based on closing the J.H. Campbell plant for a year.
19. I understand that the Order prevented the J.H. Campbell plant from closing from May 23, 2025, to August 21, 2025.
20. As a rough approximation, the benefits from closing the plant for the three-month period of the Order would be one quarter the benefits of a year-long closure. That would mean approximately 2.5-4.5 deaths and $34.5 to $54.6 million monetized health effects across Illinois, Michigan, and Minnesota.
21. To precisely estimate the harm from the continued operation of the J.H. Campbell plant, one would need to know, or model, which generation resources are displaced by its operation. Such precision is unrealistic. But it is almost certainly true that most of the generation displaced by the continued operation of J.H. Campbell comes from natural gas combined cycle plants.
22. The health impacts from running those plants vary depending on location, time of year, and the specific technologies employed by the plant, but they are invariably less than coal. For example, the most recent (2023) marginal emissions intensity data published by MISO indicates marginal emissions of 0.67 Lbs NOx/MWh, 1,020 Lbs CO_2/MWh and 0.62 Lbs SO_2/MWh. These figures compare favorably to the emissions intensity of the J.H. Campbell

Plant, which is 0.72 lbs NOx/MWh, 2,003 Lbs CO2/MWh, and 1.22 Lbs SO2/MWh as reported in EPA's Clean Air Markets Program Data (https://campd.epa.gov/data/custom-data-download).

23. Accordingly, I can conclude that the continued operation of the J.H. Campbell plant will have a net harmful effect on public health in Illinois, Michigan, and Minnesota.

Dated: December 18, 2025

Douglas B Jester

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